State of
North Dakota
Office of the Governor

John Hoeven
Governor

March 3, 2010

Lisa P. Jackson, Administrator
United States Environmental Protection Agency
c/o Ms. Carol Rushin
Acting Regional Administrator
United States Environmental Protection Agency, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Re: North Dakota State Implementation Plan for Regional Haze

Dear Administrator Jackson:

The State of North Dakota is hereby submitting an amendment to the State Implementation Plan (SIP) to address the requirements for Regional Haze of Section 308 of 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart P - Protection of Visibility. This SIP amendment was prepared by the North Dakota Department of Health, Air Quality Division.

Seven steam electric generating units in North Dakota have been identified as being subject to the BART requirements of 40 CFR 51.308(e). The installation of BART on these sources will result in a reduction of 98,618 tons per year of sulfur dioxide emissions and a reduction of 21,137 tons per year of nitrogen oxides emissions from the 2000-2004 average emissions. These reductions will significantly improve visibility in North Dakota's Class I areas as well as those in surrounding states.

With this submission, I am requesting the United States Environmental Protection Agency's approval of this SIP amendment.

If you have any questions regarding this submittal, please contact Terry O'Clair, P.E., Director, Division of Air Quality, North Dakota Department of Health, at 701-328-5178.

Sincerely,

John Hoeven
Governor

Enclosures

C: L. David Glatt, Chief, Environmental Health, ND Department of Health
Terry O'Clair, Director, Division of Air Quality, ND Department of Health
Gail Fallon, Environmental Protection Agency, Region 8

38:47:56

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North Dakota State Implementation Plan
for
Regional Haze

A Plan for Implementing the Regional Haze Program Requirements
of
Section 308 of 40 CFR Part 51, Subpart P - Protection of Visibility

North Dakota Department of Health
Adopted: February 24, 2010

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State Health Officer

Terry O'Clair, P.E.
Director

APPROVAL PAGE

North Dakota State Implementation Plan for Regional Haze

North Dakota Department of Health, Environmental Health Section, Division of Air Quality.

Approval by the following North Dakota Department of Health Management Personnel:

____________________	____________________
Terry L. O'Clair, P.E., Director Division of Air Quality	Date
____________________	____________________
L. David Glatt, P.E., Chief Environmental Health Section	Date

Adopted for the North Dakota Department of Health

____________________	____________________
Terry L. Dwelle, M.D., M.P.H.T.M. State Health Officer North Dakota Department of Health	Date

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List of Acronyms

AIRS	Aerometric Information Retrieval System
AQS	EPA's Air Quality System
AVS	Antelope Valley Station
ASOFA	Advanced separated overfire air
BADL	Badlands National Park, SD
Bag	Baghouse
BART	Best Available Retrofit Technology
B_{ext}	Light extinction (typically measured in inverse megameters: 1/Mm or $Mm^{-1)}$
BHP	Brake Horsepower
BOWA	Boundary Waters Canoe Area Wilderness Area, MN
BRCA	Bryce Canyon National Park, UT
BRID	Bridger Wilderness, WY
Btu	British thermal unit
CAA	Clean Air Act (42 United States Code Sections 7401, et seq)
CABI	Cabinet Mountains Wilderness Area, MT
CALPUFF	Multi-layer, multi-species, non-steadystate, puff, long range transport dispersion modeling system
CAMx	Comprehensive Air Quality Model with extensions
CANY	Canyonlands National Park, UT
CEM	Continuous emissions monitor
CENRAP	Central Regional Air Planning Association
CFR	Code of Federal Regulations
CM	Coarse mass ($PM_{2.5}$ mass subtracted from PM_{10} mass)
CMAQ	Community Multiscale Air Quality model
CTIC	Conservation Technology Information Center
D	Distance in kilometers
DGC	Dakota Gasification Company
DOA	United States Department of Agriculture
DOI	United States Department of the Interior
Dv	deciview
Δdv	Change in deciviews
EC	Elemental carbon
EDMS	Emissions Data Management System
EGU	Electrical Generating Unit
EPA	United States Environmental Protection Agency
ESP	Electrostatic precipitator
FGD	Flue gas desulfurization
FLM	Federal Land Manager
FM	Fine mass ($PM_{2.5}$ mass)
FR	Federal Register
FS	United States Forest Service (DOA)
FWS	United States Fish and Wildlife Service (DOI)
GAMO	Gates of the Mountains Wilderness Area, MT
GCVTC	Grand Canyon Visibility Transport Commission
GPSP	Great Plains Synfuels Plant
GRSA	Great Sand Dunes Wilderness Area, CO

HEGL	Hercules - Glades Wilderness Area, MO
Hp	Horsepower
IMPROVE	Interagency Monitoring of Protected Visual Environments
IPM	Integrated Planning Model
ISLE	Isle Royale National Park, MI
km	Kilometers
LADCO	Lake Michigan Air Directors Consortium
lb	Pounds
lb/10^6 Btu	Pounds per million British thermal units
LEC	Low Emission Combustion
LOST	Lostwood National Wildlife Refuge Wilderness Area, ND
ln	Natural logarithm
LNB	Low NO_x burner
LTPD	Long Tons Per Day
LTS	Long Term Strategy
LWA	Lostwood National Wildlife Refuge Wilderness Area, ND
MACT	Maximum Achievable Control Technology
MELA	Medicine Lake National Wildlife Refuge Wilderness Area, MT
MEVE	Mesa Verda National Park, CO
MI	Michigan
MING	Mingo Wilderness Area, MO
Mm	Megameters
MN	Minnesota
MOZI	Mount Zirkel Wilderness Area, CO
MPCA	Minnesota Pollution Control Agency
MT	Montana
MRPO	Midwest Regional Planning Organization
NAAQS	National Ambient Air Quality Standards
ND	North Dakota
NDAC	North Dakota Administrative Code (state rules)
NDCC	North Dakota Century Code (state laws)
NDDoH	North Dakota Department of Health
NEI	National Emissions Inventory
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NO_3	Nitrate
NO_x	Oxides of nitrogen or nitrogen oxides
NOAB	North Absaroka Wilderness, WY
NPS	National Park Service (DOI)
NSPS	New Source Performance Standard
OC	Organic carbon
OFA	Overfire air
PM	Particulate matter
PMC	Coarse particulate matter, $PM_{10} – PM_{2.5}$
PM_{coarse}	Coarse particulate matter, $PM_{10} – PM_{2.5}$
PMF	Fine particulate matter, $PM_{2.5}$
PM_{fine}	Fine particulate matter, $PM_{2.5}$

$PM_{2.5}$	Fine particulate matter; particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers as measured by an EPA approved reference method
PM_{10}	Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers as measured by an EPA approved reference method
POA	Primary Organic Aerosol
PSAT	Particulate Matter Source Apportionment Technology
PSD	Prevention of Significant Deterioration
Q	Emission rate in tons per year
RAVI	Reasonably Attributable Visibility Impairment
RPG	Reasonable Progress Goal
RHR	Regional Haze Rule/Regulation
ROMO	Rocky Mountain National Park, CO
SCR	Selective catalytic reduction
SENE	Seney National Wildlife Refuge Wilderness Area, MI
SD	South Dakota
SD	Spray dryer
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kernel Emissions
SMP	Smoke Management Plan
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SO_4	Sulfate
SO_x	Sulfur oxides
SRU	Sulfur recovery unit
THRO	Theodore Roosevelt National Park, ND
TRNP	Theodore Roosevelt National Park, ND
TPY	tons per year; also listed as tpy
TSD	Technical Support Document
TSS	WRAP Technical Support System
UCR	University of California at Riverside
ULBE	UL Bend National Wildlife Refuge Wilderness Area, MT
URP	Uniform rate of progress
USC	United States Code
VIEWS	Visibility Information Exchange Web System
VISTAS	Visibility Improvement State and Tribal Association of the Southeast
VOC	Volatile organic compounds
VOYA	Voyageurs National Park, MN
VR	Visual Range
WEMI	Weminuche Wilderness Area, CO
WICA	Wind Cave National Park, SD
WRAP	Western Regional Air Partnership
WS	Wet scrubber
YELL	Yellowstone National Park, MT & WY
ZION	Zion National Park, UT

i Submittal Letter

Lisa P. Jackson, Administrator
United States Environmental Protection Agency
c/o Ms. Carol Rushin
Acting Regional Administrator
United States Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver Colorado 80202-1129

Re: North Dakota State Implementation Plan for Regional Haze

Dear Ms. Jackson:

The State of North Dakota is hereby submitting an amendment to the State Implementation Plan (SIP) to address the requirements for Regional Haze of Section 308 of 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart P - Protection of Visibility. This SIP amendment was prepared by the North Dakota Department of Health, Air Quality Division.

We are enclosing two hard copies and three electronic copies of the SIP for your review.

Seven steam electric generating units in North Dakota have been identified as being subject to the BART requirements of 40 CFR 51.308(e). The installation of BART on these sources will result in a reduction of 98,618 tons per year of sulfur dioxide emissions and a reduction of 21,137 tons per year of nitrogen oxides emissions from the 2000-2004 average emissions. These reductions will significantly improve visibility in North Dakota's Class I areas as well as those in surrounding states.

With this submission, I am requesting the U. S. Environmental Protection Agency's approval of this SIP amendment and the BART for the seven Subject-to-BART Electrical Generating Units in North Dakota.

We would also call to your attention that visibility in the North Dakota Class I areas is adversely impacted by emissions from coal-fired electrical generating plants located north of the international border in southeastern Saskatchewan, Canada. These impacts and their sources are identified and discussed in Sections 6 and 8 of the SIP revision.

If you have any questions regarding this submittal, please feel free to contact Terry O'Clair, P.E., Director, Division of Air Quality, North Dakota Department of Health, at 701-328-5178.

Sincerely,

John Hoeven
Governor

Enclosures
xc: L. David Glatt, Chief, Environmental Heath Section, Department of Health
Terry O'Clair, Director, Division of Air Quality, Department of Health

ii Executive Summary

This document comprises the State of North Dakota’s State Implementation Plan (SIP) submittal to EPA to meet the requirements of Section 308 of the Regional Haze Regulation (40 CFR Part 51, Subpart P, Section 51.308). Adoption of the North Dakota State Implementation Plan For Regional Haze amends the Implementation Plan for the Control of Air Pollution for the State of North Dakota.

Section 1 describes the purpose of and legal authority of the SIP. Section 2 provides introductory and background information on the federal regional haze law and regulation, visibility impairment, a description of North Dakota’s Class I areas and reasonable progress towards the 2064 visibility goals. Section 3 describes plan development and consultation with federal land managers, other states, the EPA, and stakeholders. Section 4 describes the North Dakota monitoring strategy and commitments for future monitoring. Section 5 describes baseline and natural visibility conditions for the North Dakota Class I areas and the uniform rate of progress for each Class I area. Section 6 describes the sources of visibility impairment at North Dakota=s Class I areas. Section 7 describes and provides the results of the Best Available Retrofit Technology (BART) process including the Air Pollution Control Permits to Construct issued to the seven power plant boilers subject to BART. Section 8 describes the CMAQ and CALPUFF modeling used in developing the SIP. Section 9 describes the process for determining the reasonable progress goals for North Dakota’s Class I areas and what they are. Section 10 describes the long term strategy. Section 11 describes the commitments to future consultation, progress reports, periodic evaluations of SIP adequacy, and future SIP revisions. Section 12 summarizes the public participation and review process and the revisions made subsequent to the public hearing for the SIP. Appendices at the end of this document provide additional information on BART and reasonable progress modeling protocols, company BART analyses, Department BART determinations, the BART Air Pollution Control Permits to Construct, FLM and EPA comments during the 60-day FLM comment period, the public hearing record, Department responses to FLM, EPA, and public comments, consultation with the FLMs, EPA and other states, the legal opinions of the Attorney General, and the State BART rule.

The North Dakota BART determination process identified seven electrical generating units that are subject to the BART requirements. The installation of new control devices or modifications to existing control devices will reduce sulfur dioxide emission from point sources in the state by 98,618 tons per year and nitrogen oxides emissions by 21,139 tons per year. The BART reductions must be implemented no later than five years after EPA approves this SIP. The anticipated date of implementation is 2013. These reductions are expected to make a significant improvement in visibility in the affected Class I areas. Total sulfur dioxide emissions in North Dakota are expected to decline by 105,729 tons per year (60%) and nitrogen oxides emissions by 57,970 tons per year (25%) during this planning period.

The 2018 reasonable progress goals for the twenty percent worst days in the North Dakota Class I areas have been established at 16.9 deciviews for each unit of Theodore Roosevelt National Park (TRNP) and 18.9 deciviews at Lostwood Wilderness Area (LWA). The analyses conducted by the North Dakota Department of Health (NDDoH) and the Western Regional Air Partnership (WRAP) indicates there will be no degradation during the 20% best days.

1. **Purpose / Legal Authority**

The purpose of this submittal is to address the State Implementation Plan requirements for the State of North Dakota found in Paragraph 40 CFR 51.308, Regional Haze Program Requirements, of 40 CFR Part 51 Subpart P - Protection of Visibility.

The North Dakota Department of Health (the Department), the agency designated to administer and coordinate a statewide program of air pollution control, has general legal authority under North Dakota Century Code Sections 23-25-03 and 28-32-02 to adopt and enforce rules for visibility protection including regional haze visibility impairment.

The Department adopted rules in 1987 to implement Sections 40 CFR 51. 300 - 307 (NDAC Chapter 33-15-19 Visibility Protection, Effective date October 1, 1987) and in 2006 to implement Paragraph 40 CFR 51.308(e) (NDAC Chapter 33-15-25 Regional Haze Requirements, Effective Date January 1, 2007).

It is the legal opinion of the North Dakota Attorney General that the State Implementation Plan (SIP) is legal, valid and the Air Pollution Control Permits to Construct for the BART sources, and the Coyote Station, included within the SIP in Appendix D and Appendix A.4 have the force and effect of law. A copy of the Attorney General opinion is contained in Appendix G.

2. Overview

2.1 Introduction

The Clean Air Act (CAA) defines the general concept of protecting visibility in each of the 156 Mandatory Class I Federal Areas across the nation as shown in Figure 2.1. Section 169A from the 1977 CAA set forth the following national visibility goal:

> "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution."

The federal visibility regulations (40 CFR Part 51, Subpart P - Visibility Protection Section 51.300 - 309) detail a two-phased process to determine existing impairment in each of the Class I areas, how to remedy such impairment, and how to establish goals to restore visibility to "natural conditions" by the year 2064 in each of these areas. The federal regulations require states to prepare a SIP to: include a monitoring strategy, address existing impairment from major stationary facilities (Reasonably Attributable Visibility Impairment), prevent future impairment from proposed facilities, address Best Available Retrofit Technology (BART) for certain stationary sources, consider other major sources of visibility impairment, calculate baseline, current and natural visibility conditions, consult with the Federal Land Managers (FLMs) in the development or change to the SIP, develop a long-term strategy to address issues facing the state, set and achieve reasonable progress goals for each Class I area, and review the SIP every five years.

EPA promulgated regulations to implement the statute in December, 1980. Following litigation, a court settlement divided visibility protection into two phases.

Phase 1 of the visibility program, also known as Reasonably Attributable Visibility Impairment (RAVI), addresses impacts in Class I areas by establishing a process to evaluate source specific visibility impacts, or plume blight, from individual sources or small groups of sources. Part of that process relates to the evaluation of sources prior to construction through the Prevention of Significant Deterioration (PSD) permit program for major stationary sources. The plume blight part of the Phase 1 program also allows for the evaluation, and possible control, of reasonably attributable impairment from existing sources. North Dakota has developed, and EPA approved, a SIP for Phase 1 of the visibility program. The Phase 1 rule is NDAC 33-15-19, Visibility Protection.

Section 169B was added to the Clean Air Act Amendments of 1990 to address regional haze. Since regional haze does not respect state and tribal boundaries, the amendments authorized EPA to establish visibility transport regions as a way to combat regional haze.

Phase 2 of the visibility program addresses regional haze. This form of visibility impairment focuses on overall decreases in visual range, clarity, color, and ability to discern texture and details in Class I areas. The responsible air pollutants can be generated in the local vicinity or transported by the wind often many hundreds or even thousands of miles from where they originated. For technical and legal reasons the second part of the visibility program was not implemented in regulation until 1999.

In July 1999, the EPA finalized the Regional Haze Rule (RHR) requiring States to adopt State Implementation Plans to address this aspect of visibility impairment in the Class I areas. The rule was amended in July, 2005. Under the current rules the Regional Haze SIP was to be submitted to the EPA by December 17, 2007.

The two key requirements of the regional haze program are:

1. Improve visibility for the most impaired days, and
2. Ensure no degradation in visibility for the least impaired days.

Though the national visibility goals are to be ultimately achieved by the year 2064, the SIP seeks to meet the two requirements stated above by 2018, the first planning period established by the federal rule.

Pursuant to the requirements of 51.308(a) and (b), the SIP is intended to meet the requirements of EPA=s Regional Haze rules that were adopted to comply with requirements set forth in Section 169B of the Clean Air Act. Elements of this SIP are to address:

- The core regional haze program requirements pursuant to 40 CFR 51.308(d),
- The Best Available Retrofit Technology (BART) requirements of 40 CFR 51.308(e),
- The requirements for comprehensive periodic revisions of regional haze SIPs of 40 CFR 51.308(f),
- The requirements for periodic reports describing progress towards the reasonable progress goals of 40 CFR 51.308(g),
- The requirement for determination of the adequacy of the existing implementation plan of 40 CFR 51.308(h), and
- The requirements for State and Federal Land Manager coordination of 40 CFR 51.308(i).

In addition, 40 CFR 51.308(c) of the original July 1999 regulation provided options for a regional planning process to allow states to develop a coordinated approach to regional haze. In March 1999, North Dakota became a member of the Western Regional Air Partnership (WRAP), the regional planning organization serving 13 western states, tribes and federal agencies. Section 51.308(c) was deleted on July 6, 2005 when the BART Guidelines were added to the regional haze rule.

Figure 2.1 - Map of United States Class I Areas

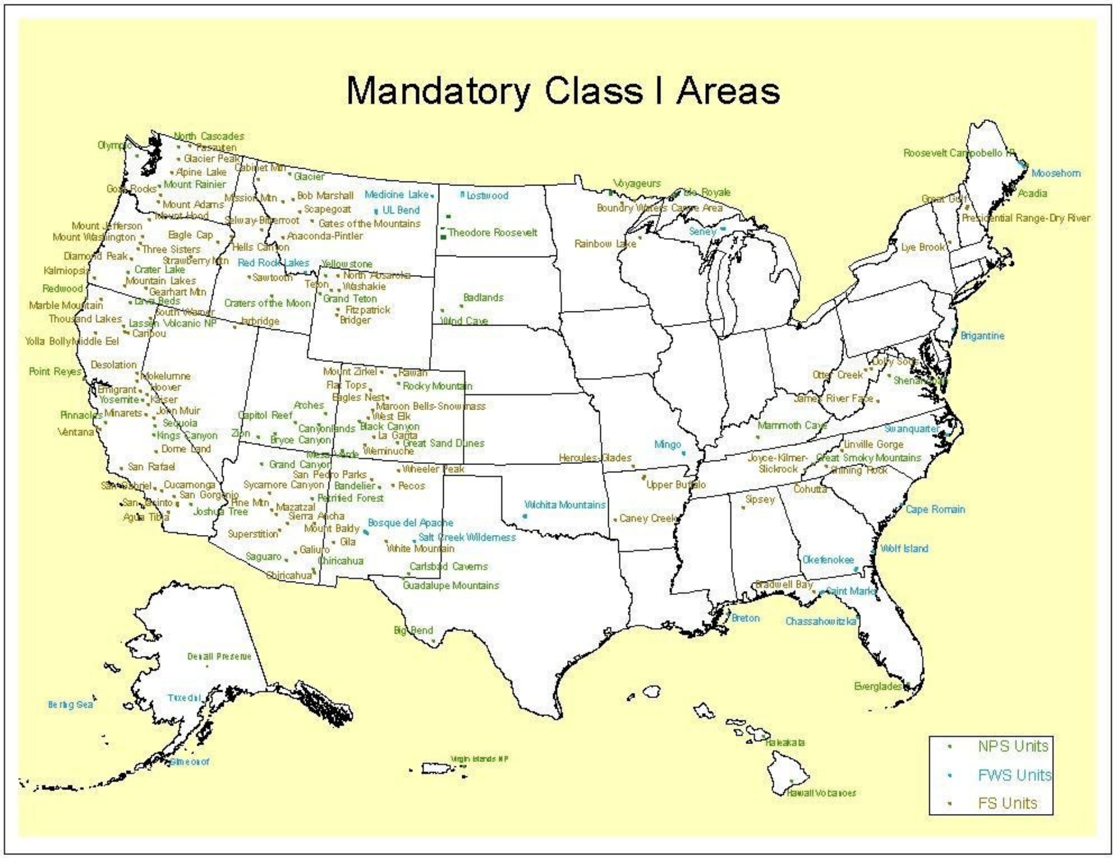
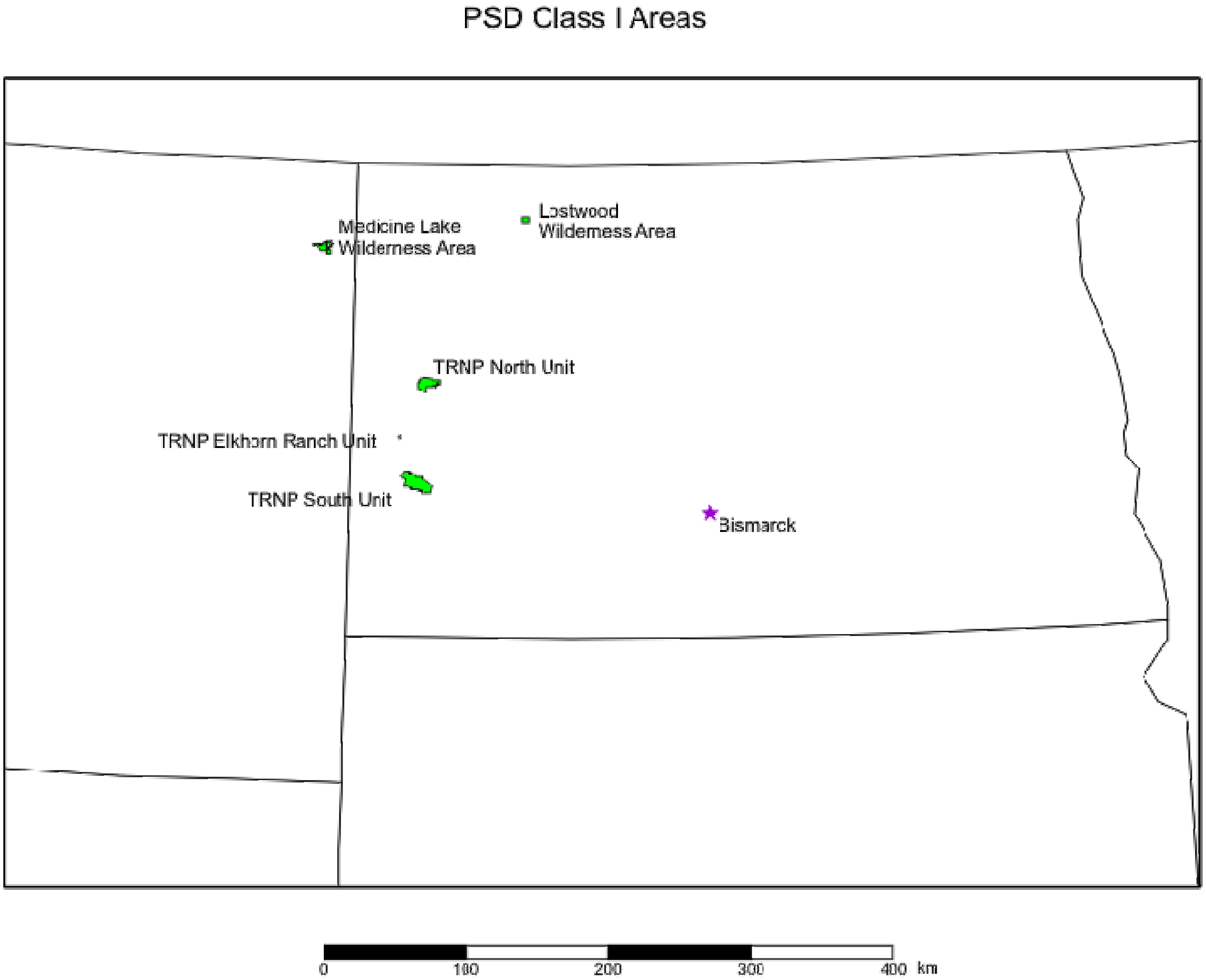


Figure 2.2 – Map of North Dakota Class I Areas



2.2 Visibility Impairment

Most visibility impairment occurs when pollution in the form of small particles scatters or absorbs light. Air pollutants come from a variety of natural and anthropogenic sources. Natural sources can include windblown dust and smoke from wildfires. Anthropogenic sources can include motor vehicles, electric utility and industrial fuel burning and manufacturing operations. More pollutants mean more absorption and scattering of light, which reduce the clarity and color of a scene. Some types of particles such as sulfates and nitrates, scatter more light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light. Commonly, the receptor is the human eye and the object may be a single viewing target or a scene.

In the 156 Class I areas across the country, visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from an average of 140 miles to 35-90 miles.

Some haze causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are carried many miles from the source of the pollutants. Some haze-forming pollutants are also linked to human health problems and other environmental damage. Exposure to very small particles in the air has been linked with increased respiratory illness, decreased lung function and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers and streams unsuitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings or other natural and man-made structures.

2.3 Description of North Dakota’s Class I Areas

The Class I areas in North Dakota include: the Theodore Roosevelt National Park (TRNP) which consists of three separate, distinct units and the Lostwood National Wildlife Refuge Wilderness Area (LWA). The North Dakota Class I Areas are shown on Figure 2.1 and Figure 2.2.

Theodore Roosevelt National Park is located within Billings and McKenzie Counties in North Dakota. The colorful badlands and Little Missouri River of western North Dakota provide the scenic backdrop to the park which memorializes the 26th president for his enduring contributions to the conservation of our nation’s resources. The park contains 70,447 acres divided among three separate units: South Unit, Elkhorn Ranch and North Unit and is managed by the National Park Service. The park is comprised of badlands, open prairie and hardwood draws that provide habitat for a wide variety of wildlife species including bison, prairie dogs, elk, deer, big horn sheep and other wildlife. The Little Missouri River passes through the three units of the park.

Lostwood National Wildlife Refuge Wilderness Area is located in Burke County in the northwestern part of the State. Created by an act of Congress in 1975, the wilderness covers an area of 5,577 acres. It is contained within Lostwood National Wildlife Refuge and is managed by the U.S. Fish and Wildlife Service. Lostwood National Wilderness Area is designated to preserve a region well known for numerous lakes and mixed grass prairie. The wilderness ensures that the finest duck and waterfowl breeding region in North America remains wild and unimproved.

2.4 Class I Areas in Other States Impacted by North Dakota Sources

In accordance with 40 CFR 51.308, emissions sources within North Dakota have or may be reasonably expected to have impacts on the following Class I Areas: Boundary Waters Canoe Area Wilderness Area (BOWA) and Voyageurs National Park (VOYA) in Minnesota, Isle Royale National Park (ISLE) and Seney National Wildlife Refuge Wilderness Area (SENE) in Michigan, Medicine Lake National Wildlife Refuge Wilderness Area (MELA) and U. L. Bend National Wildlife Refuge Wilderness Area ((ULBE) in Montana, and Badlands National Park (BADL) and Wind Cave National Park (WICA) in South Dakota. As shown in Table 2.1 and Figure 2.1, sources in North Dakota have only a small impact on out-of-state Class I areas. For Class I areas that are more distant, the impact will be even smaller. Impacts from emission sources in North Dakota contribute 5 percent or more of the total 2002 extinction (Bext) in the above Class I areas except those in Michigan and BOWA. A 5 percent or larger contribution is considered a significant contribution.

Table 2.1
North Dakota
Species Contribution (%)
20% Worst Days
2000-2004

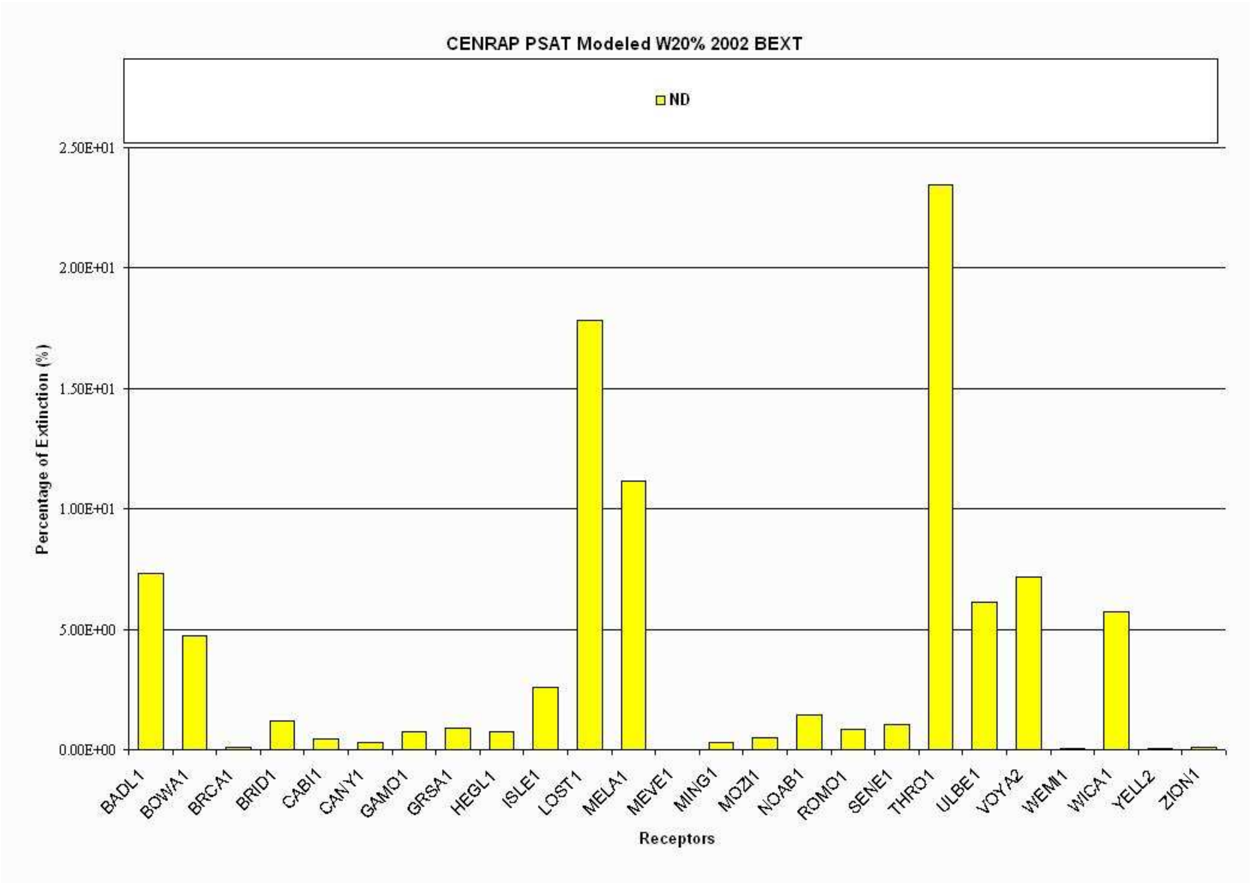
Class I Area	Sulfate	Nitrate	OC	EC	PMF	PMC	Sea Salt
TRNP	21	19	12	29	44	45	0
LWA	18	13	23	35	28	32	0
Badlands	8	10	2	4	3	3	0
Wind Cave	8	8	1	2	4	3	0
U.L. Bend	9	5	1	1	1	1	0
Medicine Lake	11	7	9	15	17	16	0
Gates of the Mountains	< 1	< 1	< 1	< 1	< 1	< 1	0
North Absaroka	1	1	< 1	< 1	< 1	< 1	0
Voyageurs	6	9	3*	6*	15*	22*	0
Boundary Waters*	3	10	2	4	10	7	0
Isle Royale*	2	4	1	2	6	6	0
Seney*	1	3	<1	<1	2	4	0

Based on WRAP's tracer analyses (SO_4 and NO_3) and weighted emissions potential (WEP) analyses unless otherwise noted.

*Based on CENRAP data.

From CENRAP's PSAT analysis, North Dakota's contribution to total extinction (20% worst days in base year 2002) at the nearby Class I areas is shown in Figure 2.3.

Figure 2.3



2.5 Programs to Address Visibility Impairment

North Dakota and EPA have many existing emission control programs/rules to improve and protect visibility in Class I areas.

North Dakota adopted and EPA approved a SIP for Phase 1 of the visibility program. This program addresses major source PSD permitting, source specific haze and plume blight aspects of visibility impairment. The Phase 1 rule is NDAC 33-15-19, Visibility Protection. It has an effective date of October 1, 1987.

North Dakota adopted NDAC 33-15-25, Regional Haze Requirements in 2006 with an effective date of January 1, 2007. This rule implements the BART provisions of the federal RHR.

North Dakota has several other emission control programs/rules that while not specifically written to address visibility impairment, do address visibility and work to improve and protect visibility in Class I areas. These include:

NDAC Chapter 33-15-02, Ambient Air Quality Standards, Section 33-15-02-03. Air quality guidelines. This rule states in part:

> "In keeping with the purpose of these ambient air quality standards, the quality should be such that:
>
> 4. Visibility will be protected.
>
> 7. Natural scenery will not be obscured."

NDAC Chapter 33-15-04, Open Burning Restrictions. Section 33-15-04-02. Permissible open burning. This rule states in part:

> "2. The following conditions apply to all types of permissible burning listed in subsection 1.
>
> h. Except in an emergency, burning may not be conducted is such proximity of any Class I area, as defined in chapter 33-15-15, that the ambient air of such area is adversely impacted.
>
> i. Except in an emergency, the visibility of any Class I area cannot be adversely impacted as defined in chapter 33-15-19."

NDAC Chapter 33-15-15, Prevention of Significant Deterioration of Air Quality, requires that a visibility analysis be prepared in accordance with chapter 33-15-19 as a part of the requirements for a PSD permit to construct.

NDAC Chapter 33-15-17. Restriction of Fugitive Emissions. Section 33-15-17-02 Restriction of fugitive particulate emissions. This rules states in part: "No person shall emit or cause to be emitted into the ambient air from any source of fugitive emissions as specified in section 33-15-17-01 any particulate matter which:

> 5. Would have an adverse impact on visibility, as defined in chapter 33-15-19, on any federal class I area."

In addition to the above programs, the following emission control programs/rules, which do not specifically address visibility impairment, control the emission of pollutants that cause or contribute to visibility impairment:

NDAC Chapter 33-15-03	Restriction of Emission of Visible Air Contaminants
NDAC Chapter 33-15-05	Emissions of Particulate Matter Restricted
NDAC Chapter 33-15-06	Emissions of Sulfur Compounds Restricted
NDAC Chapter 33-15-07	Control of Organic Compounds Emissions
NDAC Chapter 33-15-08	Control of Air Pollution from Vehicles and Other Internal Combustion Engines
NDAC Chapter 33-15-12	Standards of Performance for New Stationary Sources
NDAC Chapter 33-15-14	Designated Air Contaminant Sources, Permit to Construct, Minor Source Permit to Operate, Title V Permit to Operate
NDAC Chapter 33-15-20	Control of Emissions from Oil and Gas Well Production Facilities
NDAC Chapter 33-15-21	Acid Rain Program
NDAC Chapter 33-15-22	Emissions Standards for Hazardous Air Pollutants for Source Categories

It should be noted that unless specifically stated in the text, all references to existing rules or emission control programs are intended only to provide information about various aspects of the program described and are neither being submitted to EPA for approval nor being incorporated into the SIP as Federally enforceable measures if they haven't previous been incorporated.

This SIP is North Dakota's comprehensive visibility plan which now contains both Phase 1 and Phase 2 visibility requirements. It addresses all aspects of North Dakota's visibility improvement program.

North Dakota is also setting emission limits as a part of this SIP for those sources subject to Best Available Retrofit Technology (BART) requirements of Phase 2 of the RHR which are described in detail in chapter 7 of this SIP.

This SIP documents those programs, rules, processes and controls deemed appropriate as measures to reduce regional haze and protect good visibility in North Dakota toward meeting the 2018 and 2064 goals established in the EPA RHR and CAA.

EPA has several existing emission control programs/rules which do not specifically address visibility impairment that will control the emission of pollutants that cause or contribute to visibility impairment which will impact North Dakota Class I areas. They include:

CAIR. CAIR will permanently cap emissions of SO_2 and NO_x from EGUs in the eastern United States by 2015. When fully implemented, CAIR as originally promulgated would have reduced SO_2 emissions from EGUs in these states by more than 70%, and NO_x emissions by more than 60%, from 2003 levels. CAIR has been remanded with a replacement rule likely to take 2 years to finalize. Any emission reductions from a CAIR replacement rule are unknown at this time. When winds are from an easterly direction, North Dakota Class I areas will see some benefit from the CAIR reductions.

NO_x SIP Call. Phase I of the NO_x SIP call applies to certain EGUs and large non-EGUs, including large industrial boilers and turbines, and cement kilns in the eastern United States. It is expected to reduce NO_x emissions by 90% to mitigate ozone transport. When winds are from an easterly direction, North Dakota Class I areas will see some benefit.

Heavy Duty Diesel (2007) Engine Standard (for on-road trucks and buses). The EPA set a PM emissions standard for new heavy-duty engines of 0.01 grams per brake-horsepower-hour(g/bhp-hr), to take full effect for diesel engines in the 2007 model year. This rule also includes standards for NO_x and non-methane hydrocarbons (NMHC) of 0.20 g/bhp-hr and 0.14 g/bhp-hr, respectively. These NO_x and NMHC standards will be phased in together between 2007 and 2010, for diesel engines. Sulfur in diesel fuel must be lowered to enable modern pollution control technology to be effective on these trucks and buses. The EPA will require a 97 percent reduction in the sulfur content of highway diesel fuel from its current level of 500 parts per million (low sulfur diesel, or LSD) to 15 parts per million (ultra-low sulfur diesel, or ULSD).

Tier 2 Tailpipe (On-road vehicles). The EPA mobile source rules include the Tier 2 fleet averaging program, modeled after the California LEV II standards. Manufacturers can produce vehicles with emissions ranging from relatively dirty to zero emissions, but the mix of vehicles a manufacturer sells each year must have average NO_x emissions below a specified value. Tier 2 standards became effective in the 2005 model year.

Large Spark Ignition and Recreational Vehicle Rule. The EPA has adopted new standards for emissions of NO_x, hydrocarbons, and carbon monoxide from several groups of previously unregulated nonroad engines. Included in these are large industrial spark-ignition engines and recreational vehicles. Nonroad spark-ignition engines are those powered by gasoline, liquid propane gas, or compressed natural gas rated over 19 kilowatts (kW) (25 horsepower). These engines are used in commercial and industrial applications, including forklifts, electric generators, airport baggage transport vehicles, and a variety of farm and construction applications. Nonroad recreational vehicles include snowmobiles, off-highway motorcycles, and all-terrain-vehicles. These rules were initially effective in 2004 and will be fully phased-in by 2012.

Nonroad Diesel Rule. This rule sets standards that will reduce emissions by more than 90 percent from nonroad diesel equipment, and reduce sulfur levels by 99 percent from current levels in nonroad diesel fuel starting in 2007. This step will apply to most nonroad diesel fuel in 2010 and to fuel used in locomotives and marine vessels in 2012.

Industrial Boiler/Process Heater MACTs. The EPA issued final rules to substantially reduce emissions of toxic air pollutants from industrial, commercial and institutional boilers and process heaters. These rules reduce emissions of a number of toxic air pollutants, including hydrogen chloride, manganese, lead, arsenic and mercury by 2009. This rule also reduces emissions of SO_2 and PM in conjunction with the toxic air pollutant reductions. The applied Maximum Achievable Control Technology (MACT) control efficiencies were 4 percent for SO_2 and 40 percent for PM_{10} and $PM_{2.5}$. The EPA's industrial boiler MACT rules were vacated on June 8, 2007, however it is believed that by 2018 the USEPA will have re-promulgated a boiler MACT rule; however, the emission reductions may change from those of the vacated rule.

Combustion Turbine and Reciprocating Internal Combustion Engines MACTs. The EPA MACT regulations for Gas Turbines and stationary Reciprocating Internal Combustion will have NO_x co-benefit effects.

VOC 2-, 4-, 7-, and 10-year MACT Standards. Various point source MACTs and associated emission reductions have been implemented by EPA.

2.6 Reasonable Progress Toward the 2064 Visibility Goals

Section 51.308(d) contains the core requirements for the regional haze SIP. The requirements for reasonable progress goals (RPG) are found in 51.308(d)(1) which reads:

> "Reasonable progress goals. For each mandatory Class I Federal area located within the State, the State must establish goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions. The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period."

The reasonable progress goals are interim goals that represent incremental visibility improvement over time for the most-impaired (20% worst) days and no degradation in visibility for the least-impaired (20% best) days. The first regional haze plan that States must submit to EPA needs to include RPGs for the year 2018, also known as the "2018 milestone year". The State has the flexibility in establishing different RPGs for each Class I area. In establishing the RPG, the State must consider four factors:

- the costs of compliance;
- the time necessary for compliance;
- the energy and non-air quality environmental impacts of compliance; and
- the remaining useful life of any potentially affected sources.

States must demonstrate how these factors were taken into consideration in selecting the RPG for each Class I area.

The North Dakota Department of Health has worked with the Western Regional Air Partnership (WRAP) and with the WRAP's ongoing modeling program as well as implemented our own modeling program to establish and refine RPGs for 2018 for the North Dakota Class I areas. This process is described in detail in sections 8 and 9.

The RPGs for each North Dakota Class I area established for 2018 are found in section 9. Required BART controls will be installed and become operational as expeditiously as practicable, but no later than five years after this SIP is approved by EPA. The controls are expected to be operational in 2013 - 2014.

The technical analyses described in this SIP demonstrate that emissions both inside and outside of North Dakota have an appreciable impact on the State's Class I areas. This includes emissions from neighboring states as well as international emissions from Canada, especially from the provinces of Alberta and Saskatchewan. Emission controls from many sources outside of North Dakota will not be fully defined during this round of the Regional Haze SIP process, necessitating consideration of outside controls and further interstate and possibly tribal consultation in the reasonable progress process to establish refined reasonable progress goals. The EPA, through the Department of State, will have to work with Canada and its provinces to reduce visibility impairing pollutants that impact North Dakota and other states' Class I areas. Until SIP controls including BART and other programs outside of North Dakota are defined, modeled and analyzed, North Dakota cannot fully determine progress toward the 2018 goal or the 2064 goal. North Dakota will make its best attempt at demonstrating progress toward the goals based on addressing sources within its control.

3. Plan Development and Consultation

The State is required by Section 51.308(d) (3) (i) of the EPA Regional Haze Rule to consult with other states to develop coordinated emission management strategies for Class I areas in those states North Dakota's emissions impact or those states whose emissions impact North Dakota's Class I areas and by Section 51.308(i) to consult with the federal land managers of the Class I areas in our state and the Class I areas in other states that emissions from North Dakota impact.

3.1 Consultation with Federal Land Managers

The North Dakota Department of Health consults with the FLMs as a part of the WRAP and as needed directly with the National Park Service and U.S. Fish and Wildlife Service in Denver, CO. They have reviewed and commented on North Dakota's BART modeling protocol and draft BART determinations submitted by the BART sources.

The National Park Service, the U.S. Fish and Wildlife Service, and the U.S. Forest Service (federal land manager of Boundary Waters Canoe Area Wilderness in Minnesota) were each furnished copies of the draft SIP for review and comment as part of the required 60 day FLM comment period (Section 51.308(i)(2)). Continuing consultation with the three FLM's in the future as required by 40 CFR 51,308(i)(4) is addressed in Section 11.1.1.

3.1.1 FLM Comments Provided During 60 Day Comment Period

A draft was provided to the FLMs in August 2009 for their 60-day consultation period. The FLM comments are included in Appendix J.

3.1.2 Response to FLM Comments

The Department's responses to the FLM's comments are included in Appendix J.

3.1.3 FLM Comments Provided on BART Portion of SIP in 2008

The Department had originally planned to submit the BART portion of the regional haze SIP separately from the Reasonable Progress portion of the SIP. The BART portion (which is now Section 7) was submitted to the FLMs in June of 2008 as part of the required 60-day FLM comment period.

Comments that were received from the FLMs in August of 2008 are attached in Appendix J.1.1 and discussed further in Section 7. They have been reviewed and considered by the Department and included as appropriate in Section 7 of this current SIP. The Department's responses to the FLM comments are attached in Appendix J.1.2.

3.2 Consultation with EPA Region 8

The North Dakota Department of Health has consulted with EPA as a part of the WRAP and as needed directly with Air Program staff of the EPA Region 8 office in Denver, CO in developing this SIP. EPA has reviewed and commented on the State BART modeling protocol, the BART Air Pollution Control Permit to Construct template and the draft BART determinations submitted by the BART sources.

In June of 2008, the Department submitted the BART portion of the SIP to EPA Region 8 at the same time it was submitted to the FLMs as discussed in Section 3.1.3. Comments were received from EPA and are attached as Appendix J.3.1. The Department's responses to the EPA comments are attached as Appendix J.3.2.

EPA was also provided a copy for comment of the draft SIP at the time it was provided to the FLMs as a part of the FLM 60 day comment period. The Department considered the EPA comments and made appropriate revisions to the SIP.

The Department also consulted with EPA Region 8 concerning Class I areas in Montana as they are preparing a federal implementation plan for Montana.

3.3 Consultation with Other States

The North Dakota Department of Health has consulted with our neighboring states of South Dakota and Montana through the WRAP and as needed individually. We also participated in monthly teleconferences from 2004 through 2008 with Minnesota and Michigan, the states containing the four northern Class I areas (Boundary Waters Canoe Wilderness Area and Voyageurs National Park in Minnesota, Isle Royale National Park and Seney National Wildlife Refuge Wilderness Area in Michigan), and other states in CENRAP and LADCO. We also individually consulted as needed with Minnesota, our neighbor directly to the east.

As a result of the consultations, Minnesota sent a memorandum dated September 19, 2007 to North Dakota and other states impacting Minnesota's Class I areas. Minnesota requested a response documenting these consultations have taken place to the satisfaction of North Dakota or detailing areas where additional consultation should occur. In those states Minnesota has identified as additional contribution states, they asked those states to respond with their agreement or disagreement with Minnesota's determination of contributing states and the additional control strategies that will be evaluated. Minnesota's memorandum and the NDDoH letter of response dated August 22, 2008 are attached in Appendix J.2.

These states were notified of the availability of the draft SIP at the time it was sent to the FLMs.

3.4 Regional Planning Consultation

The North Dakota Department of Health became a member of the Western Regional Air Partnership (WRAP) in March of 1999. WRAP is one of five regional planning organizations representing 13 western states, tribes in those states, federal agencies including EPA and FLMs, environmental organizations, industry, academics, and other stakeholders. Department staff has participated and continues to participate in many WRAP committees and workgroups including the Air Managers Committee, the Initiatives Oversight Committee, the Technical Oversight Committee, the Emissions Forum, the Stationary Sources Joint Forum, the Technical Analysis Forum, the Implementation Workgroup, and the BART Workgroup. Membership in the WRAP and participation in its many committees, forums and workgroups allows consultation with the many organizations WRAP represents.

3.5 Consultation with Tribes

The Department notified the tribes in North Dakota of the public hearing and comment period on the draft RH SIP. The Department also notified the WRAP Tribal Caucus Coordinator of its intent to draft a SIP to address regional haze and provided a list of contacts within the Department (see Appendix J.4).

3.6 Other Consultation

The Department has monthly teleconferences with the Subject-to-BART sources in North Dakota and has quarterly meetings with the Lignite Energy Council, an organization representing lignite coal mines and users within the State.

4. Monitoring Strategy and Other Implementation Plan Requirements

Part 40 CFR 51.305 and 51.308(d)(4) of the Federal Regional Haze Rule requires states to have a monitoring strategy in the SIP for addressing reasonably attributable visibility impairment (RAVI) and regional haze visibility impairment in the federal Class I areas within the State. The monitoring strategy required by 40 CFR 51.305 is discussed in Section 4.1. The monitoring strategy required by 40 CFR 51.308(d)(4) is summarized in Section 4.2 and is made a part of this RH SIP.

4.1 RAVI Monitoring Strategy in Current North Dakota Long Term Strategy

The RAVI monitoring strategy required by 40 CFR 51.305 was first included in the long term strategy section of North Dakota's first visibility protection SIP dated October 1, 1987 as Section 6.10. The visibility monitoring strategy was replaced on March 1, 1994 with Section 6.12. It was again replaced on January 1, 1996 with Section 6.13 of the SIP which is the present RAVI monitoring strategy. Section 6.13 is:

> Air Quality Surveillance
>
> In April 1994, Section 6.12 of the SIP was submitted to EPA indicating visibility monitoring was not necessary due to a lack of visibility impairment and a database indicating stable conditions. In late 1994 and early 1995, there has been a resurgence of activity in the oil fields of Western North Dakota. The purpose of Section 6.13 is to withdraw Section 6.12 and identify current activities regarding visibility monitoring.
>
> An increase in oil drilling activities in 1995 has prompted the Park Service to revisit the idea of establishing visibility monitoring sites at the Class I areas in North Dakota. The Department has met with the Park Service to discuss arrangements for financing visibility monitoring. The Department has offered to use funds from an environmental trust that was established through deposits from penalties collected on several enforcement cases. Theodore Roosevelt National Park (TRNP) Service officials were receptive and have transmitted requests to their offices in Denver. Plans currently call for the Department and the Park Service to enter into a memorandum of understanding to proceed with establishing visibility monitoring at TRNP.

The Federal Land Managers installed IMPROVE monitors in Theodore Roosevelt National Park South Unit and Lostwood National Wildlife Refuge Wilderness Area in December of 1999.

The Department also worked with the National Park Service to install a webcam at the South Unit of TRNP using funds from the environmental trust as included in Section 6.13. The webcam became operational in August of 2002. It can be accessed on the internet at:

http://www.nature.nps.gov/air/WebCams/parks/throcam/throcam.cfm. In addition to the webcam picture, current conditions for ozone, sulfur dioxide, fine particulate matter ($PM_{2.5}$) and weather have been added and can be observed.

4.2 Regional Haze Visibility Impairment Monitoring Strategy and Other Implementation Plan Requirements

Section 51.308(d)(4) requires that the State must submit with the implementation plan a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the State. This monitoring strategy must be coordinated with the monitoring strategy required in section 51.305 for reasonably attributable visibility impairment. Compliance with this requirement may be met through participation in the Interagency Monitoring of Protected Visual Environments (IMPROVE) network. The IMPROVE monitoring program is discussed in section 4.3.

The state of North Dakota will depend on the Interagency Monitoring of PROtected Visual Environments (IMPROVE) monitoring program to collect and report aerosol monitoring data for long-term reasonable progress tracking as specified in the Regional Haze Rule (RHR). Because the RHR is a long-term tracking program with an implementation period nominally set for 60 years, the state expects that the IMPROVE program will provide data based on the following goals:

1. Maintain a stable configuration of the individual monitors and sampling sites, and stability in network operations for the purpose of continuity in tracking reasonable progress trends;
2. Assure sufficient data capture at each site of all visibility-impairing species;
3. Comply with EPA quality control and assurance requirements; and
4. Prepare and disseminate periodic reports on IMPROVE program operations.

The state of North Dakota is relying on the IMPROVE program to meet these monitoring operation and data collection goals, with the fundamental assumption that network data collection operations will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-2004 RHR baseline period. Technical analyses and reasonable progress goals in this implementation plan for Regional Haze are based on data from these sites. As such, the State asks that the IMPROVE program identify potential issues affecting RHR implementation trends and/or notify the State before changes in the IMPROVE program affecting a RHR tracking site are made.

Further, the state of North Dakota notes that the human resources to operate these monitors are provided by Federal Land Management agencies. Beyond that in-kind contribution, resources for operation and sample analysis of a complete and representative monitoring network of these long-term reasonable progress tracking sites by the IMPROVE program are a collaborative responsibility of the EPA, states, tribes, and FLMs and the IMPROVE program steering committee. The state of North Dakota will collaborate with the EPA, FLMs, other states, tribes, and the IMPROVE committee to assure adequate and representative data collection and reporting by the IMPROVE program. North Dakota will consult with the FLMs if IMPROVE monitoring budget changes will threaten Class I area monitoring within North Dakota, or in Class I areas affected by emissions from North Dakota.

Section 51.308(d)(4)(i) requires that the implementation plan must also provide for the following:

(i) The establishment of any additional monitoring sites or equipment needed to assess whether reasonable progress goals to address regional haze for all mandatory Class I Federal areas within the State are being achieved.

The state of North Dakota depends on the following IMPROVE program-operated monitors listed in Table 4.1 for tracking RHR reasonable progress.

Table 4.1
IMPROVE Monitoring Sites in North Dakota

IMPROVE Monitoring Site	**Class I Area**	**Sponsor**	**Start Date**	**Elevation MSL**
LOST1	Lostwood National Wilderness Area	US Fish and Wildlife Service	12/1999	696 m 2283 ft
THRO1	Theodore Roosevelt National Park-South Unit, North Unit, Elkhorn Ranch Unit	National Park Service	12/1999	862 m 2828 ft

Note that the THRO1 IMPROVE monitor is located at the Painted Canyon Overlook in the South Unit of Theodore Roosevelt National Park. The THRO1 IMPROVE monitor also serves and is representative of haze conditions in the separate North Unit and the separate Elkhorn Ranch Unit of the Park. The monitor was sited at the existing monitoring site at the Painted Canyon Overlook in December 1999 by the federal agencies running the IMPROVE program. Site selection followed criteria in the Improve Particulate Monitoring Network Procedures for Site Selection, February 24, 1999, to be representative of the Park's three units. The existing site at the Painted Canyon Overlook met all the siting criteria including that all areas represented by the site should be within 100 km of a current or potential site. The northern boundary of the North Unit is approximately 80 km away from the site and the Elkhorn Ranch Unit is approximately 45 km away.

The state of North Dakota will also operate additional non-IMPROVE monitors that may be used in the future evaluations of Class I area visibility. These may include $PM_{2.5}$ speciation or Federal Reference Methods, monitoring systems for SO_2, NO_x, ozone, continuous $PM_{2.5}$, continuous PM_{10}, and meteorological monitors for wind speed, wind direction, ambient temperature, ambient pressure, relative humidity, solar radiation, and precipitation. Monitors presently operating are listed in Table 4.2.

Table 4.2
Additional non-IMPROVE Monitors

Monitoring Site	Parameter	Sampling &Analysis Method	Operating Schedule
Lostwood National Wildlife Refuge AQS#: 38-013-0004 Co-located with the LOST1 IMPROVE site.	Sulfur Dioxide	Instrumental Pulsed Florescent	Continuous
	Nitrogen Dioxide	Instrumental Chemiluminescence	Continuous
	Ozone	Instrumental Ultra Violet	Continuous
	$PM_{2.5}$	$PM_{2.5}$ SCC W/No Correction TEOM Gravimetric 40^0 Celsius	Continuous
	PM_{10}	PM_{10} TEOM Gravimetric 50^0 Celsius	Continuous
	Wind Speed	Elec. or Mach Avg. Level 1	Continuous
	Wind Direction	Elec. or Mach Avg. Level 1	Continuous
	Ambient Temperature	Elec. or Mach Avg.	Continuous
	Delta Temperature	Elec. or Mach Avg.	Continuous
	Ambient Pressure	Barometric Pressure Transducer	Continuous
	Solar Radiation	Pyranometer	Continuous
	Relative Humidity	Hydgroscopic Plastic Film	Continuous
Theodore Roosevelt National Park North Unit AQS# 38-053-0002	Sulfur Dioxide	Instrumental Pulsed Florescent	Continuous
	Nitrogen Dioxide	Instrumental Chemiluminescence	Continuous
	Ozone	Instrumental Ultra Violet	Continuous
	$PM_{2.5}$	$PM_{2.5}$ SCC W/No Correction TEOM Gravimetric 40^0 Celsius	Continuous
	PM_{10}	PM_{10} TEOM Gravimetric 50^0 Celsius	Continuous
	Wind Speed	Elec. or Mach Avg. Level 1	Continuous
	Wind Direction	Elec. or Mach Avg. Level 1	Continuous
	Ambient Temperature	Elec. or Mach Avg.	Continuous
	Ambient Pressure	Barometric Pressure Transducer	Continuous
	Relative Humidity	Hydroscopic Plastic Film	Continuous
Theodore Roosevelt National Park South Unit Co-located with the THRO1 IMPROVE Site.	Sulfur Dioxide	Instrumental Pulsed Florescent	Continuous
	Ozone	Instrumental Ultra Violet	Continuous
	$PM_{2.5}$	$PM_{2.5}$ SCC W/ No Correction TEOM Gravimetric 50^0 Celsius	Continuous
	Wind Speed	Elec. or Mach Avg. Level 1	Continuous
	Wind Direction	Elec. or Mach Avg. Level 1	Continuous
	Ambient Temperature	Elec. or Mach Avg.	Continuous
	Relative Humidity	Hydroscopic Plastic Film	Continuous
	Solar Radiation	Pyranometer	Continuous
	Precipitation	Recording Weighting	Continuous

It should be noted that the two IMPROVE monitors located at the Theodore Roosevelt National Park South Unit and the Lostwood National Wilderness Area have complete data for the period 2000 through 2004 and are relied upon in this Regional Haze SIP to establish the baseline deciview conditions.

In addition, the National Park Service monitors dry deposition at the Theodore Roosevelt National Park South Unit monitoring site. The dry deposition is analyzed for SO_4, NO_3, HNO_3, NH_4, and SO_2 weekly.

Section 51.308(d)(4)(ii) requires that the implementation plan must also provide for the following:

> (ii) Procedures by which monitoring data and other information are used in determining the contribution of emissions from within the State to regional haze visibility impairment at mandatory Class I Federal areas both within and outside the State.

The state of North Dakota will use data reported by the IMPROVE program as part of the regional technical support analysis tools found at the Visibility Information Exchange Web System (VIEWS), as well as other analysis tools that are available from EPA, FLMs and other states and tribes. The state of North Dakota will participate in any ongoing regional analysis activities to collectively assess and verify the progress toward reasonable progress goals, also supporting interstate consultation as the RHR is implemented, and collaborate with EPA, states, tribes, and FLMs to ensure the continued operation of existing technical support analysis tools and systems developed by WRAP. If the WRAP systems disappear, North Dakota will develop or contract for other technical support analysis tools and systems as necessary.

The state of North Dakota may conduct additional analyses as needed.

Section 51.308(d)(4)(iv) requires that the implementation plan must also provide for the following:

> (iv) The implementation plan must provide for the reporting of all visibility monitoring data to the Administrator at least annually for each mandatory Class I Federal area in the State. To the extent possible, the State should report visibility monitoring data electronically.

The state of North Dakota will depend on the routine timely reporting of haze monitoring data by the IMPROVE program for the reasonable progress tracking sites to the EPA air quality data system and VIEWS. The state of North Dakota will collaborate with EPA, states, tribes, and FLMs to ensure the continued operation of existing WRAP technical support analysis tools and systems.

The additional non-IMPROVE monitoring is conducted and the data collected and reported in accordance with EPA guidance. It is reported through electronic data transfer techniques quarterly.

Section 51.308(d)(4)(v) requires that the implementation plan must also provide for the following:

> (v) A statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area. The inventory must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. The State must also include a commitment to update the inventory periodically.

The state of North Dakota has prepared a statewide inventory of emissions that can reasonably be expected to cause or contribute to visibility impairment in Federal Class I Areas. Section 6 of this plan summarizes the emissions by pollutant and source category.

The state of North Dakota commits to updating statewide emissions inventories periodically and submitting data to the EPA NEI system. The updates will be used for state tracking of emission changes, trends, and evaluation of whether reasonable progress goals are being achieved and other regional analyses. The inventories will be updated every one to three years on the same schedule as the every three-year reporting required by EPA's Consolidated Emissions Reporting Rule and the Air Emissions Reporting Requirements Rule. The Air Emissions Reporting Requirements Rule will completely replace the Consolidated Emissions Reporting Rule after the 2008 emission inventory data submittal which is due to June 1, 2010.

As a member of the WRAP, North Dakota will continue to use the WRAP-sponsored Emissions Data Management System (EDMS) and Fire Emissions Tracking System (FETS) to store and access emission inventory data for the region as long as they are maintained and available. If they are not available, North Dakota stores its data in house. North Dakota will continue to conduct its own modeling to simulate the air quality impacts of emissions for haze and other related air quality planning purposes. The state of North Dakota will collaborate with EPA, states, tribes and FLMs to ensure the continued operation of existing WRAP technical support analysis tools and systems.

Section 51.308(d)(4)(vi) requires that the implementation plan must also provide for the following:

> (vi) Other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility.

The state of North Dakota will track data related to RHR haze plan implementation for sources for which the state has regulatory authority, and will depend on the IMPROVE program for monitoring data. To ensure the availability of data and analyses to report on visibility conditions and progress toward Class I area visibility goals, the state of North Dakota will collaborate with EPA, states, tribes and FLMs to ensure the continued operation of the IMPROVE program and the existing WRAP-sponsored technical support analysis tools and systems for emissions inventory data.

4.3 Overview of the IMPROVE Monitoring Network

In the mid-1980's, the Interagency Monitoring of PROtected Visual Environments (IMPROVE) program was established to measure visibility impairment in mandatory Class I Federal areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, NOAA and U.S. Forest Service. In 1991, several additional organizations joined the effort: National Association of Clean Air Agencies, Western States Air Resources Council (WESTAR), Mid-Atlantic Regional Air Management Association (MARAMA) and Northeast States for Coordinated Air Use Management (NESCAUM).

The objectives of the IMPROVE program include establishing the current visibility and aerosol conditions in mandatory Class I Federal areas; identifying the chemical species and emission sources responsible for existing human-made visibility impairment; documenting long-term trends for assessing progress towards the national visibility goals; and supporting the requirements of the Regional Haze Rule by providing regional haze monitoring representing all visibility-protected Federal Class I areas where practical. Figure 4.1 shows the IMPROVE site at Lostwood National Wilderness Area, and Figure 4.2 shows the four separate modules used for sampling the different pollutant species.

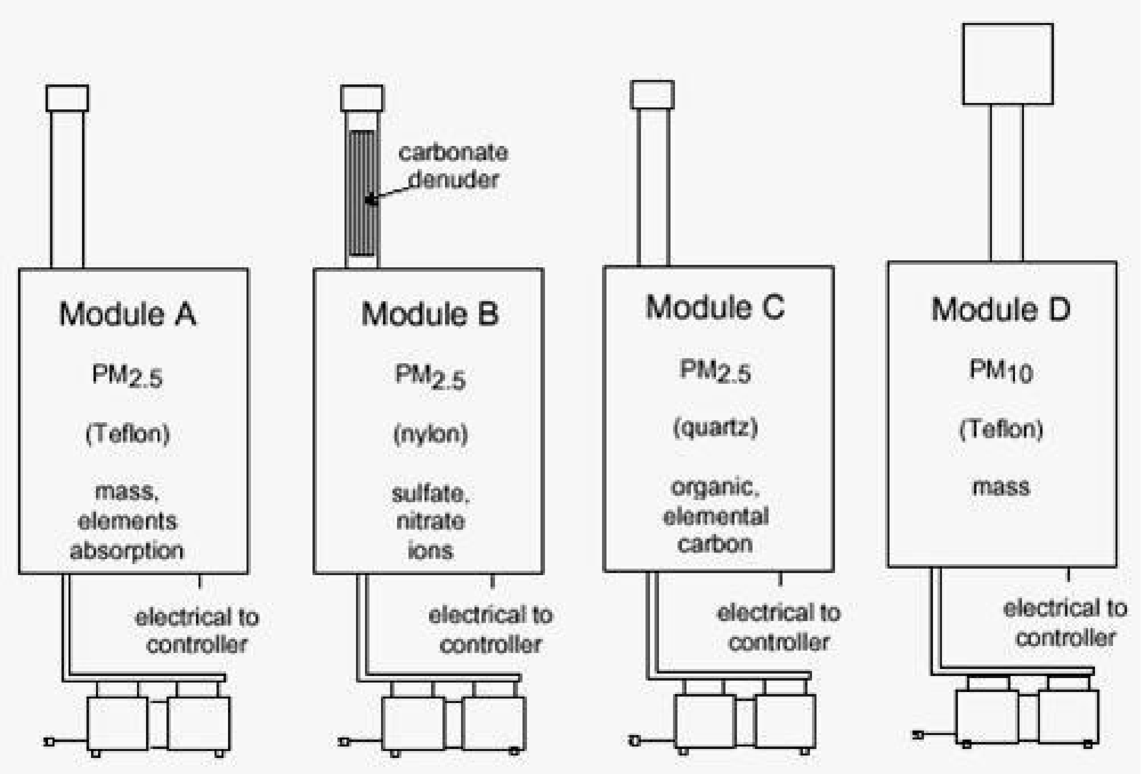
Figure 4.1
Pictures of the IMPROVE Monitoring Site at
Lostwood National Wilderness Area

Exterior

Interior

The IMPROVE sampler consists of four separate modules for measuring regional haze

Figure 4.2
IMPROVE Sampler Module



The data collected at the IMPROVE monitoring sites are used by land managers, industry planners, scientists, public interest groups and air quality regulators to better understand and protect the visual air quality resource in Class I areas. Most importantly, the IMPROVE Program scientifically documents the visual air quality of the wilderness areas and national parks.

The IMPROVE program has developed methods for estimating light extinction from speciated aerosol and relative humidity data. The three most common metrics used to describe visibility impairment are:

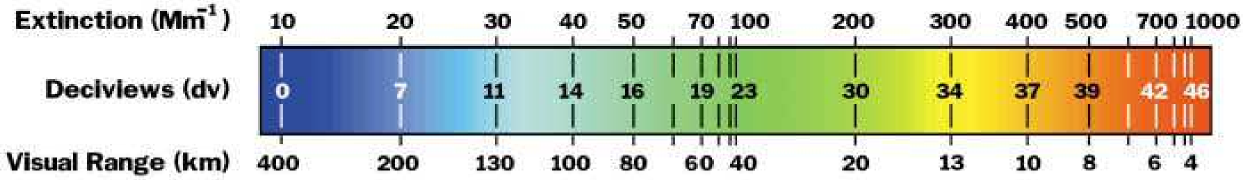
Extinction (b_{ext}) – Extinction is a measure of the fraction of light lost per unit length along a sight path due to scattering and absorption by gases and particles, expressed in inverse Megameters (Mm^{-1}). This metric is useful for representing the contribution of each aerosol species to visibility impairment and can be practically thought of as the units of light lost in a million meter distance.

Visual Range (VR) – Visual range is the greatest distance a large black object can be seen on the horizon, expressed in kilometers (km) or miles (mi).

Deciview (dv) – This is the metric used for tracking regional haze in the RHR. The deciview index was designed to be linear with respect to human perception of visibility. A one deciview change is approximately equivalent to a 10% change in extinction, whether visibility is good or poor. A one deciview change in visibility is generally considered to be the minimum change the average person can detect with the naked eye. See Section 5.1 for additional information.

For reference, Figure 4.3 compares b_{ext} in Mm^{-1}, deciviews (dv) which are unitless, and visual range in kilometers (km).

Figure 4.3
Comparison of Extinction (Mm^{-1}), Deciview (dv), and Visual Range (km)



The IMPROVE network estimates light extinction based upon the measured mass of various contributing aerosol species. EPA's 2003 guidance for calculating light extinction is based on the original protocol defined by the IMPROVE program in 1988. For further information, see: http://vista.cira.colostate.edu/improve/Publications/GuidanceDocs/guidancedocs.htm.

In December 2005, the IMPROVE Steering Committee voted to adopt a revised algorithm for use by IMPROVE as an alternative to the original approach.

The choice between use of the default or the revised equation for calculating the visibility metrics for each Class I area is made by the state in which the Class I area is located. North Dakota has chosen to use the revised equation. The revised algorithm for estimating light extinction is calculated as recommended for use by the IMPROVE steering committee using the following equations:

$$\begin{aligned}
b_{ext} \approx\ & 2.2\times f_S(RH)\times[\text{Small Amm. Sulfate}] + 4.8\times f_L(RH)\times[\text{Large Amm. Sulfate}] \\
& +2.4\times f_S(RH) \times [\text{Small Amm. Nitrate}] + 5.1\times f_L(RH) \times [\text{Large Amm. Nitrate}] \\
& +2.8\times [\text{Small Particulate Organic Matter}] + 6.1\times [\text{Large Particulate Organic Matter}] \\
& +10\times [\text{Elemental Carbon}] \\
& +1\times [\text{Fine Soil}] \\
& +1.7\times f_{SS}(RH) \times [\text{Sea Salt}] \\
& +0.6\times [\text{Coarse Mass}] \\
& +0.33\times [NO_2\ (\text{ppb})] \\
& +\text{Rayleigh Scattering (Site Specific)}
\end{aligned}$$

Where:
b_{ext} = light extinction in units of inverse megameters (Mm^{-1}),
$f_S(RH)$ = function of relative humidity for small size fraction,
$f_L(RH)$ = function of relative humidity for large size fraction,
$f_{SS}(RH)$ = function of relative humidity for sea salt, and
all species concentrations are provided in $\mu g/m^3$.

The revised algorithm splits ammonium sulfate ($(NH_4)_2SO_4$), ammonium nitrate (NH_4NO_3) and total particulate organic matter (POM =1.8 × organic carbon) concentrations into small and large size fractions. The equations for ammonium sulfate are:

$[\text{Large } (NH_4)_2SO_4] = [\text{Total } (NH_4)_2SO_4]^2 \div 20$, for $[\text{Total } (NH_4)_2SO_4] < 20\ \mu g/m^3$
$[\text{Large } (NH_4)_2SO_4] = [\text{Total } (NH_4)_2SO_4]$, for $[\text{Total } (NH_4)_2SO_4] \geq 20 \mu g/m^3$

$[\text{Small } (NH_4)_2SO_4] = [\text{Total } (NH_4)_2SO_4] - [\text{Large } (NH_4)_2SO_4]$

Similar equations are used to apportion total ammonium nitrate and total particulate organic matter concentrations into small and large size fractions.

Light extinction is converted to deciview using the following relationship:

$$dv = 10 \times \ln(b_{ext}/10)$$

Where:
dv = deciview,
b_{ext} = light extinction in units of inverse megameters (Mm^{-1}).

5. Baseline and Natural Visibility Conditions and Uniform Rate of Progress for North Dakota Class I Areas

5.1 The Deciview

The Clean Air Act (Section 169A(a)(1)) states “Congress hereby declares as a national goal the prevention of any future, and remedying of any existing impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution.” In order to achieve this goal, all man-made pollution must be eliminated such that natural conditions (visibility) are restored. Natural conditions include naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration (40 CFR 51.301). The State is required to develop a SIP that contains measures that make reasonable progress toward the national goal of no man-made visibility impairment.

The primary metric for assessing baseline conditions, natural conditions and the rate of progress is the deciview. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview index is calculated based on the following equation:

Deciview haze index = 10 ln (b_{ext}/10 Mm^{-1})

Where: b_{ext} = the atmospheric light extinction coefficient expressed in inverse megameters (Mm^{-1})

The deciview scale is zero for pristine conditions and increases as visibility degrades. Each one deciview change represents a perceptible or small just-noticeable change in visual air quality or haziness to the average person under most circumstances when viewing scenes in Class I areas regardless of background visibility conditions. This is approximately a 10% change in the light extinction (Mm^{-1}) reading.

In order to determine the rate of progress of visibility improvement, the baseline conditions and natural conditions must be determined for each Class I area. The baseline visibility conditions are calculated from IMPROVE data for the years 2000-2004. Natural visibility conditions are determined by estimating the natural concentrations of visibility impairing pollutants that existed prior to man’s influence. These concentrations are then used to calculate light extinction and the deciview metric.

5.2 Baseline Visibility Conditions

The Class I Federal Areas in North Dakota are the North Unit, South Unit and Elkhorn Ranch Unit of Theodore Roosevelt National Park and the Lostwood Wilderness Area. Although IMPROVE monitoring data is not available for the North Unit and Elkhorn Ranch Units of

TRNP, the Department considers monitoring data from the South Unit to be representative of conditions at the other two units. See Section 4.2 for a discussion of the representativeness of the monitor in the South Unit for the other two units of TRNP. Since the monitoring is representative, we only refer to the TRNP although there are three distinct separate areas.

Baseline visibility is the average of the IMPROVE monitoring data for 2000 through 2004. Baseline visibility is calculated for both the 20 percent best and 20 percent worst days. The monitoring data from the IMPROVE sites as plotted by WRAP and displayed on their TSS website are shown in Figures 5.1 - 5.4.

Figure 5.1

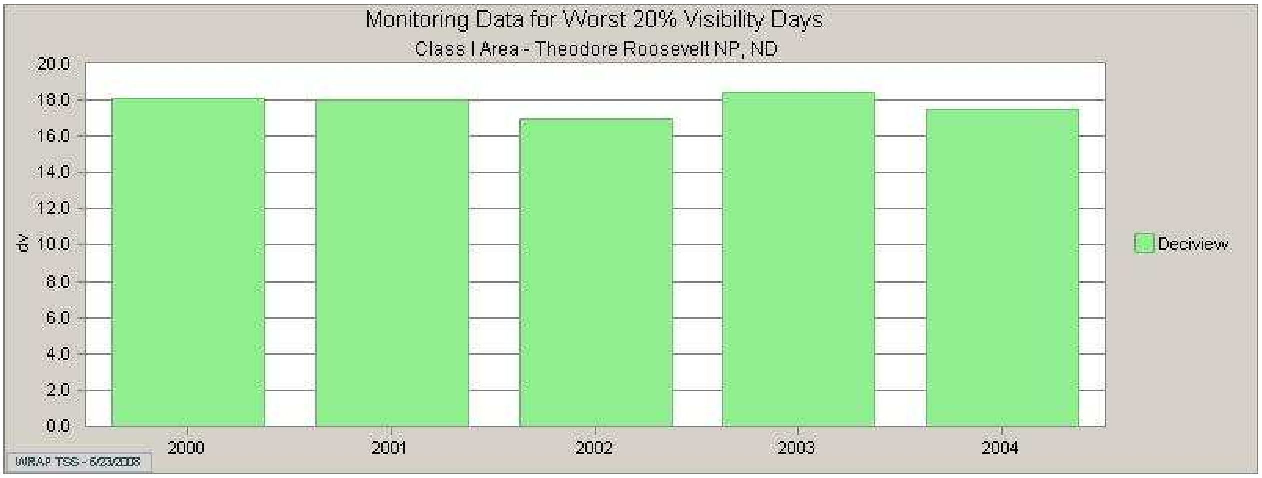


Figure 5.2

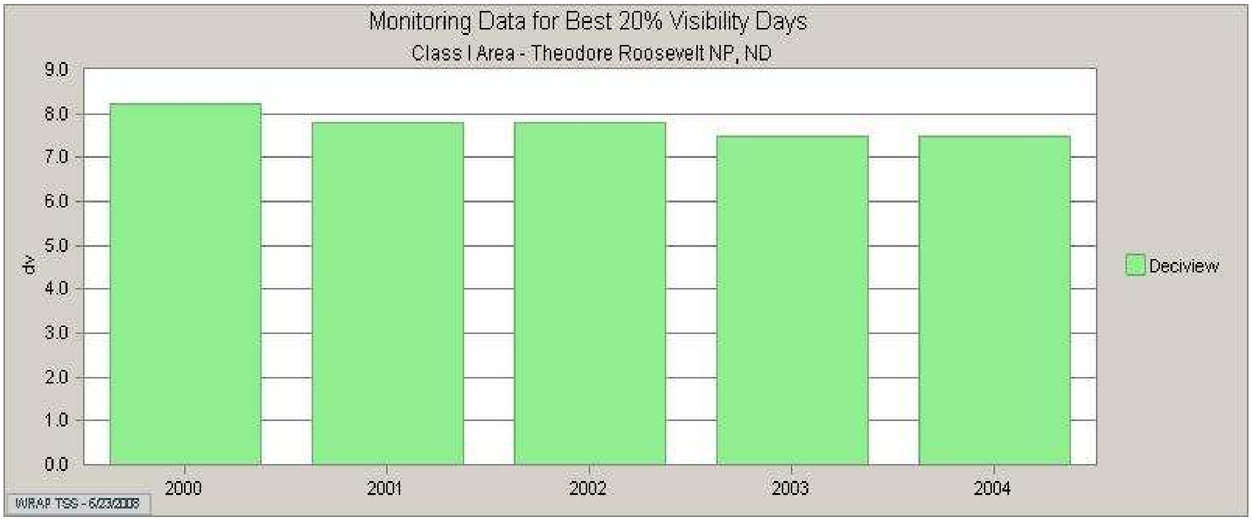


Figure 5.3

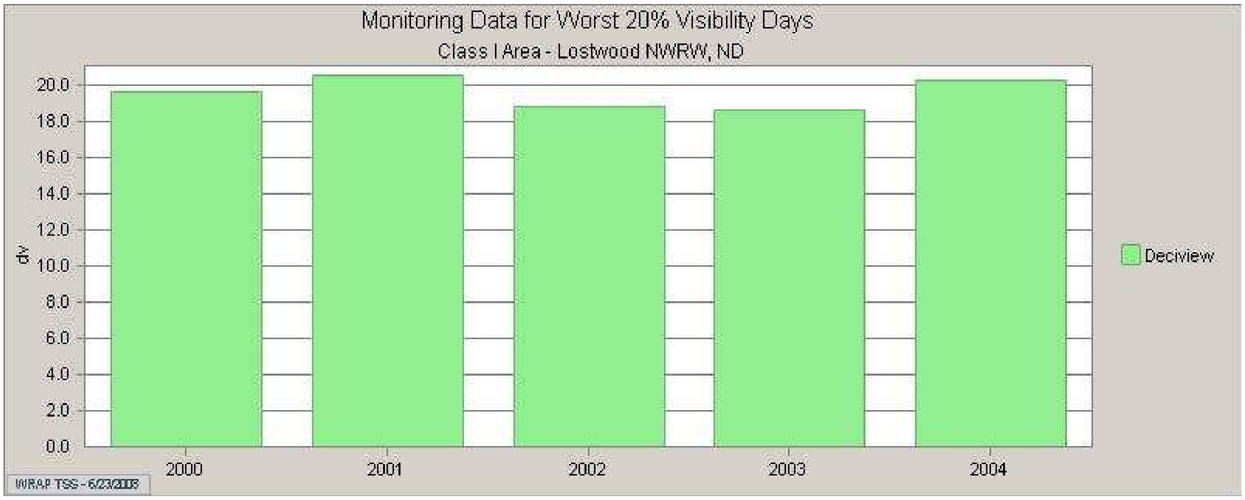
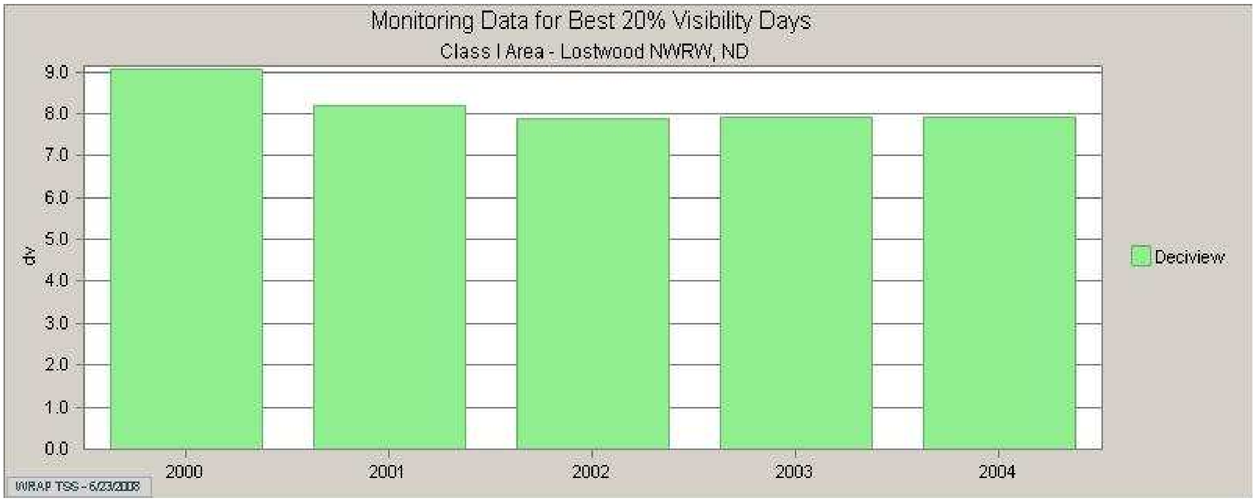


Figure 5.4



Based on the IMPROVE data, the baseline visibility conditions in the North Dakota Class I areas are shown in Table 5.1.

Table 5.1
Baseline Visibility (Deciviews)

	TRNP		**LWA**	
Year	**20% Best Days**	**20% Worst Days**	**20% Best Days**	**20% Worst Days**
2000	8.2	18.1	9.1	19.7
2001	7.8	18.0	8.2	20.6
2002	7.8	17.0	7.9	18.8
2003	7.5	18.4	7.9	18.6
2004	7.5	17.5	7.9	20.2
Baseline (avg.)	7.8	17.8	8.2	19.6

Note: Figures 5.1-5.4 and Table 5.1 are based on the revised IMPROVE Algorithm. The source of the figures and data is the WRAP TSS website. A description of the WRAP methodology is found in Appendix A.5.

5.3 Natural Visibility Conditions

EPA has prepared "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" (EPA-454/B-03-005, Sept. 2003) to aid states in estimating natural visibility conditions. Natural visibility conditions represent the long-term degree of visibility that is estimated to exist in a given Class I area in the absence of man-made impairment. Natural visibility conditions are not constant, but vary with changing natural processes such as fire, windblown dust, volcanic activity and biogenic emissions. EPA has developed a default approach which will satisfy the requirements for the initial SIP which addresses regional haze. The default approach defines two separate regions of the United States (1) The East, which consists of all states east of the Mississippi River, and up to one tier of states west of the Mississippi; and (2) the West, including the regions of the Mountain and Pacific time zones. States that are near the boundary between East and West are free to choose which set of natural visibility values are more appropriate and adopt those values. North Dakota is considered to be in the West Region; however, it is one of those states that are on the boundary of East and West. Appendix B of EPA guidance document provides the default natural extinction values (deciviews) for both the best and worst days. The values for the North Dakota Class I areas are shown in Table 5.2.

Table 5.2
EPA Default Natural Visibility Conditions (Deciviews)

Area	**Best Days**	**Worst Days**
TRNP	2.19	7.31
LWA	2.21	7.33

These natural visibility condition values were calculated based on an IMPROVE algorithm which has since been modified. The new IMPROVE equation accounts for the effect of particle size distribution on light extinction efficiency of sulfate, nitrate and organic carbon. The mass multiplier for organic carbon is increased from 1.4 to 1.8. New terms were added to the equation to account for light extinction by sea salt and light absorption by gaseous nitrogen dioxide. Site specific values are used for Rayleigh scattering to account for variations in elevation and temperature. Separate relative humidity enhancement factors are used for small and large size distributions of ammonium sulfate, ammonium nitrate and sea salt.

The WRAP calculated the natural background visibility conditions consistent with EPA's guidance using the revised IMPROVE equation. The results of that calculation are shown in Table 5.3.

Table 5.3
WRAP Calculated Natural Visibility Conditions (Deciviews)

Area	**Best Days**	**Worst Days**
TRNP	3.0	7.8
LWA	2.9	8.0

The values in Table 5.3 have been established as the natural background values for North Dakota and are used to establish the uniform rate of progress. The improvement necessary to achieve natural conditions is shown in Table 5.4.

Table 5.4
Improvement Necessary To Achieve Natural Conditions
(Deciviews)

Area	Baseline Best Days	Natural Best Days	Improvement Required	Baseline Worst Days	Natural Worst Days	Improvement Required
TRNP	7.8	3.0	4.8	17.8	7.8	10.0
LWA	8.2	2.9	5.3	19.6	8.0	11.6

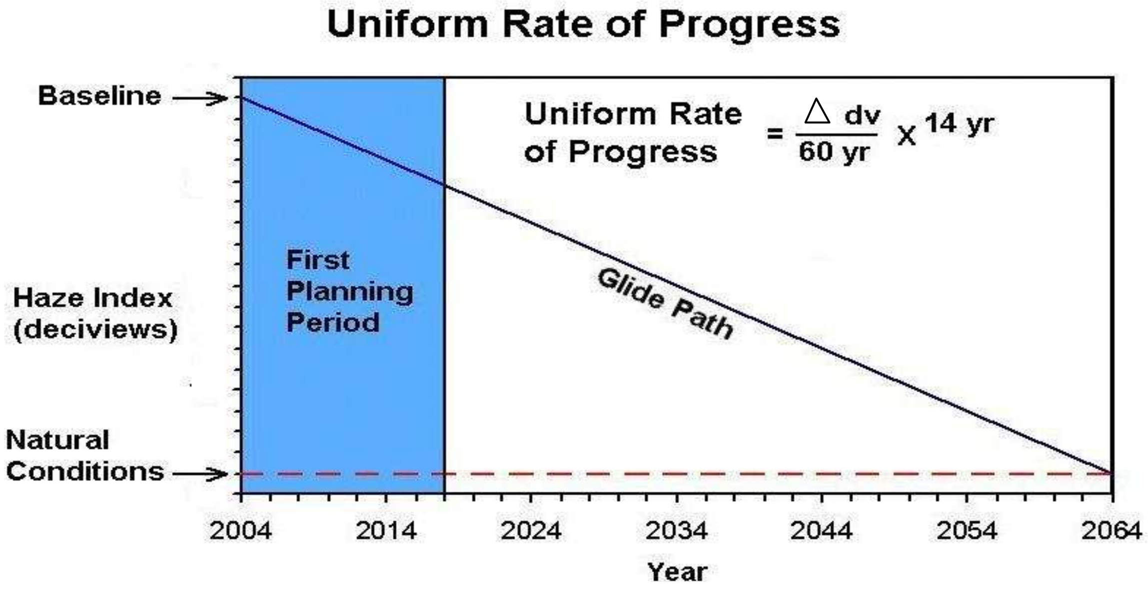
5.4 Uniform Rate of Progress

The uniform rate of progress to achieve natural conditions in any Class I Federal area is calculated as the difference between baseline condition for the 20% worst days and natural condition for the 20% worst days divided by 60 years (2004-2064). Mathematically it is determined by the following equation:

URP = [Baseline Condition - Natural Condition]) 60 yrs dv/yr

By multiplying the uniform rate of progress by 14 years in the first planning period (10 years thereafter), the progress needed by 2018 to be on the path to achieving natural conditions can be calculated as shown in Figure 5.5.

Figure 5.5



Δ dv = Baseline conditions minus natural conditions

Based on the above data, the uniform rate of progress is calculated as follows:

Theodore Roosevelt National Park

URP = (17.8 – 7.8)(14/60) dv
URP = 2.3 dv

Lostwood Wilderness Area

URP = (19.6 – 8.0)(14/60) dv
URP = 2.7 dv

The uniform rate of progress for the Theodore Roosevelt National Park and Lostwood Wilderness Area for the first planning period is shown graphically in Figures 5.5 and 5.6. For the best days, the State must ensure that no degradation occurs over the same planning period.

Figure 5.6

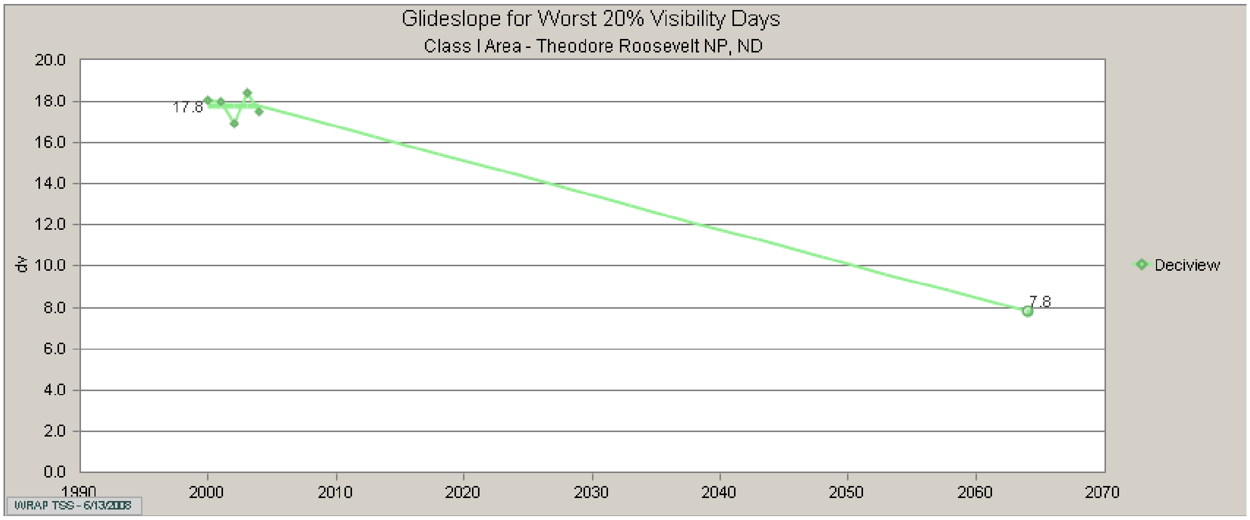
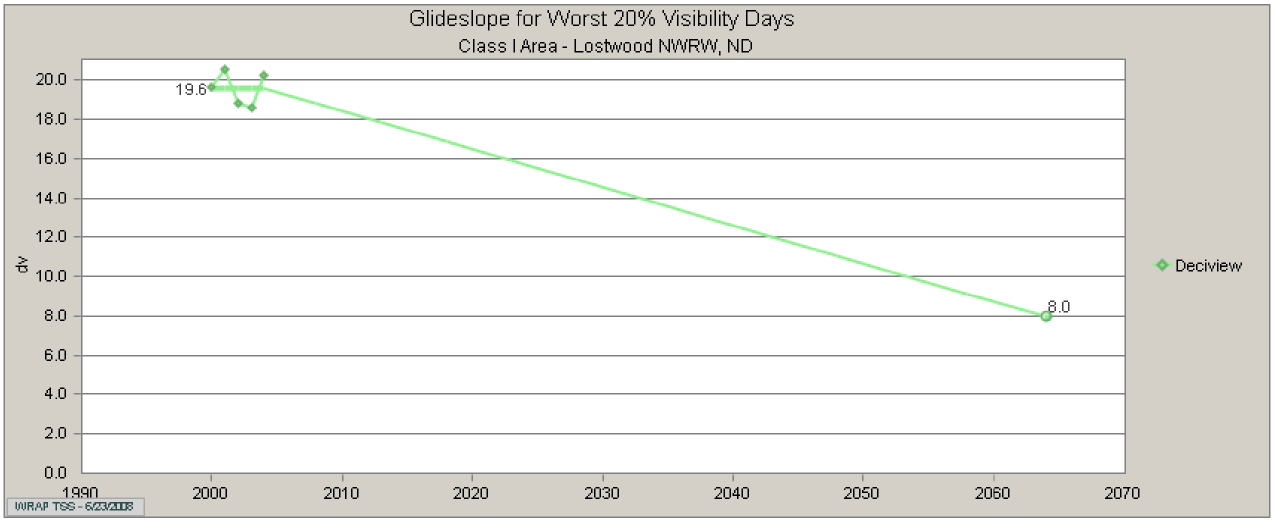


Figure 5.7


Glideslope for Worst 20% Visibility Days
Class I Area - Lostwood NWRW, ND
dv
20.0
18.0
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
1990
2000
2010
2020
2030
2040
2050
2060
2070
19.6
8.0
Deciview
WRAP TSS - 6/23/2008

6. Sources of Visibility Impairment in North Dakota Class I Areas

6.1 Introduction

40 CFR 51.308(d)(4)(v) requires a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal Area be included in the SIP. Emissions within North Dakota are both naturally occurring and man-made. Naturally occurring emissions include wildfires, windblown dust and others. In North Dakota, the primary sources of anthropogenic emissions include electric utility steam generating units (EGUs), energy production and processing sources, agricultural production and processing sources, prescribed burning and fugitive dust sources. The North Dakota inventory includes emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), fine particulate matter (PMF), coarse particulate matter (PMC), organic carbon (OC), volatile organic compounds (VOC), elemental carbon (EC) and ammonia (NH_3).

6.2 Emissions in North Dakota

The most recent complete inventory of all emission categories is from 2002. The point source data was compiled by the State while the rest of the inventory was prepared by the WRAP and its contractors with input from the state (Case Plan 02d – see Section 9 for a discussion of this case plan). A summary of the inventory is shown in Table 6.1. The WRAP Oil and Gas inventory for sulfur dioxide was adjusted to include sulfur dioxide emissions from flaring and lease use of sour gas at well sites (WRAP did not include flaring and lease use emissions). The adjustment was based on hydrogen sulfide data for the combusted gas, which is compiled by the Health Department, and the amount of gas flared or used onsite which is compiled by the North Dakota Oil and Gas Division.

Table 6.1
North Dakota 2002 Emissions Inventory (tons)

	Point	All Fire	Biogenic	Area	Area O&G	On-Road Mobile	Off-Road Mobile	Road Dust	Fugitive Dust	Wind Blown Dust	Total
SO_2	157,069	540	0	5,557	4,958	812	7,246	3	26	0	176,211
NO_x	87,438	1,774	44,569	10,833	4,631	24,746	55,502	3	40	0	229,536
OC	262	3,657	0	1,466	0	231	1,034	201	1,989	0	8,840
EC	29	510	0	262	0	272	3,625	15	135	0	4,847
PMF	2,002	821	0	1,617	0	0	0	3,086	36,354	17,639	61,519
PMC	565	503	0	199	0	141	0	28,711	172,066	158,752	360,936
NH_3	518	812	0	118,398	0	732	33	0	0	0	120,493
VOC	2,086	3,849	233,561	60,455	7,740	12,814	13,515	0	0	0	334,020
CO	11,944	60,735	67,769	21,933	36	211,842	95,869	0	0	0	470,129
Total	261,912	73,200	345,898	220,719	17,365	251,590	176,825	32,020	210,610	176,391	1,766,529

A complete emissions inventory is not available for a more recent year. However, more recent data for point source emissions are available for 2007. Those data are shown in Table 6.2.

Table 6.2
North Dakota Point Source Emissions Inventory 2007

	SO_2	**NO_x**	**OC**	**EC**	**PMF**	**PMC**	**NH_3**	**VOC**	**CO**
Point Sources	147,998	82,185	526	31	655	2,749	6,446	4,579	15,897

WRAP has developed a future inventory for North Dakota for the year 2018. The PRP18b emissions inventory for North Dakota is shown in Table 6.3. Again, sulfur dioxide emissions for the Area Oil and Gas inventory were increased by the Department to include emissions from flaring and lease use of sour gas. The PRP18b emissions inventory also included the proposed Gascoyne 500 coal-fired power plant. The Permit to Construct application for this facility has been withdrawn. The sulfur dioxide and nitrogen oxides emissions for this plant were removed from the inventory by the Department. The Department does not expect any additional coal-fired power plants to be constructed in North Dakota before 2018.

The Department does not agree with WRAP's estimate of nitrogen oxides emissions from the Area Oil and Gas industry for 2018. WRAP has predicted that 2018 NO_x emissions would be 4.5 times greater than 2002 emissions. The Department discussed this estimate with the Oil and Gas Division of the North Dakota Industrial Commission. It was the opinion of the Oil and Gas Division that most of the Bakken formation development will be over by 2018 and drilling rig activities are expected to settle back to the same ratio as production (i.e., 2-2.5 times the 2002 levels). Based on discussions with the Oil and Gas Division, it is believed that an increase of 2 – 2.5 times the 2002 emission rate is appropriate for 2018. In subsequent discussions with WRAP, representatives of WRAP admitted that 2018 estimates of NO_x emissions related to oil and gas activity in North Dakota may have been overstated. The inventory in Table 6.3 represents a 2.5 times increase for Area Oil and Gas sources.

The Department also disagrees with WRAP's estimate of PMF and PMC emissions for 2018. As explained in Section 9.5.2, agricultural conservation tillage practices, which reduce emissions, are expected to increase by 2018. Since agricultural activities and farm land are the major sources of fugitive and windblown PMF and PMC emissions, it is expected these emissions will decrease. Even though a decrease is expected, the emissions of PMF and PMC shown in Table 6.3 were not adjusted by the Department.

In future Regional Haze SIP reviews, the Department will use the most current, refined emissions inventories available.

Table 6.3
North Dakota 2018 Emission Inventory (tons)

	Point	All Fire	Biogenic	Area	Area O&G	On-Road Mobile	Off-Road Mobile	Road Dust	Fugitive Dust	Wind Blown Dust	Total
SO_2	59,560	337	0	5,995	4,200	81	276	3	30	0	70,482
NO_x	62,383	1,073	44,569	12,456	11,577	4,906	34,557	3	41	0	171,566
OC	248	2,647	0	1,387	0	151	457	193	2,041	0	7,126
EC	32	449	0	267	0	48	1,363	14	139	0	2,312
PMF	2,086	404	0	1,647	0	0	0	2,956	37,999	17,639	62,731
PMC	2,349	460	0	216	0	111	0	27,478	184,063	158,752	373,429
NH_3	462	379	0	118,493	0	739	47		0	0	120,120
VOC	2,418	2,346	233,561	69,597	17,968	3,487	8,357	0	0	0	337,735
CO	17,477	41,604	67,769	21,474	172	90,152	102,471	0	0	0	341,118
Total	147,015	49,699	345,898	231,532	33,917	99,675	147,528	30,648	224,314	176,391	1,486,618

The change in emissions during the planning period (2002-2018) is shown in Table 6.4.

Table 6.4
North Dakota Emission Inventory Planning Period Change

	2002 (TPY)	2018 (TPY)	Change (TPY)	Change (%)
SO_2	176,211	70,482	-105,729	-60.0
NO_x	229,536	171,566	-57,970	-25.3
OC	8,840	7,126	-1,714	-19.4
EC	4,847	2,312	-2,535	-52.3
PMF	61,519	62,731	1,212	2.0
PMC	360,936	373,429	12,493	3.5
NH_3	120,493	120,120	-373	-0.3
VOC	334,020	337,735	3,715	1.1
CO	470,129	341,118	-129,011	-27.4

6.3 Emissions from Other States and Canadian Provinces

The visibility in the Class I areas in North Dakota is influenced by emissions from surrounding states, Canada and sources outside WRAP's modeling domain. The three contiguous states to North Dakota are Montana, South Dakota and Minnesota. The 2002 emissions from the respective states are shown in Table 6.5.

Table 6.5
Nearby States 2002 Emissions (tons)

	Montana[a]	**South Dakota**[a]	**Minnesota**[b]	**North**[a] **Dakota**
SO_2	51,923	22,725	160,000	176,211
NO_x	243,142	146,822	485,000	229,536
OC	48,088	9,166		8,840
EC	11,873	4,703		4,847
PMF	77,239	82,414	169,000	61,519
PMC	621,276	615,354	610,000	360,936
NH_3	66,229	120,406	179,000	120,493
VOC	1,181,318	518,981	366,000	334,020
CO	1,639,949	509,702		470,129

[a] Source - WRAP TSS (Case Plan 02d)
[b] Source - Minnesota Draft Haze SIP

North Dakota's contribution to visibility impairment in TRNP and LWA is generally small (see Table 6.6). Sulfates and nitrates, as discussed further in Section 8, are the primary pollutants of concern in these Class I areas. In-state sources contribute 21 percent or less of sulfate or nitrate during the 20 percent worst baseline days at TRNP or LWA. It should be noted in Table 6.6 the sulfate and nitrate values are based on WRAP regional modeling using the CAM_x – PSAT source apportionment total, while the analyses of weighted emissions potential for organic carbon (OC), elemental carbon (EC), and particulate matter (PM) are based on emissions and residence time, not modeling.

Table 6.6
ND Sources Extinction Contribution
2000-2004
20% Worst Days

Class I Area	Pollutant Species	Extinction (Mm^{-1})	Species Contribution To Total Extinction (%)	ND Sources Contribution To Species Extinction (%) [a]
TRNP	Sulfate	17.53	35	21
	Nitrate	13.74	27	19
	OC	10.82	21	12
	EC	2.75	5	29
	PMF	0.9	2	44
	PMC	4.82	10	45
	Sea Salt	0.07	0	0
LWA	Sulfate	21.4	34	18
	Nitrate	22.94	36	13
	OC	11.05	18	23
	EC	2.84	5	35
	PMF	0.62	1	28
	PMC	3.93	6	32
	Sea Salt	0.26	0	0

[a] North Dakota contribution for sulfate and nitrate based on WRAP's tracer analysis and OC, EC, PMF, PMC and Sea Salt contribution based on WRAP's weighted emissions potential analysis.

In general, sources within Canada and sources outside WRAP's modeling domain are bigger contributors to regional haze in TRNP and LWA than North Dakota sources.

The influence of sources outside of North Dakota on TRNP and LWA for the 2000-2004 period can be seen in Figures 6.1-6.16 and Table 6.7. These figures and data were obtained from the WRAP TSS website. Figures 6.3, 6.4, 6.9 and 6.10 are based on WRAP's tracer analysis study which is considered a more rigorous analysis than the weighted emissions potential analysis (Figures 6.5 – 6.8 and 6.11 – 6.16). The Department does not agree with the WRAP's estimate of nitrogen oxides emissions from the oil and gas source category for 2018 (see Section 6.2). The Department believes WRAP has overestimated the 2018 nitrogen oxides emissions. Therefore, Figures 6.4 and 6.12 overestimate the percentage of oil and gas nitrogen oxides contribution for 2018.

Figure 6.1

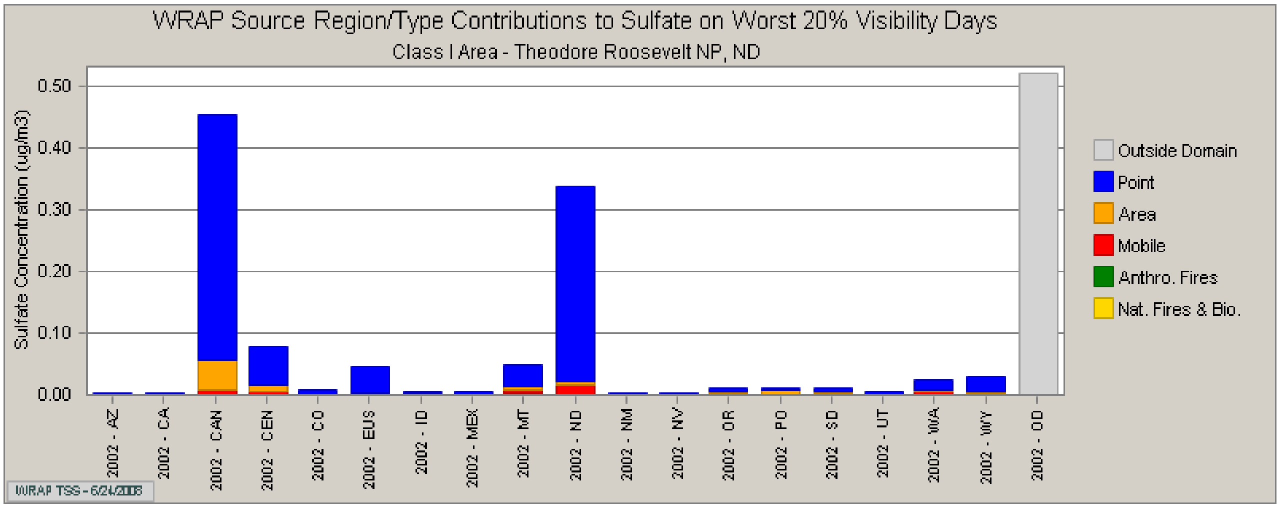


Figure 6.2

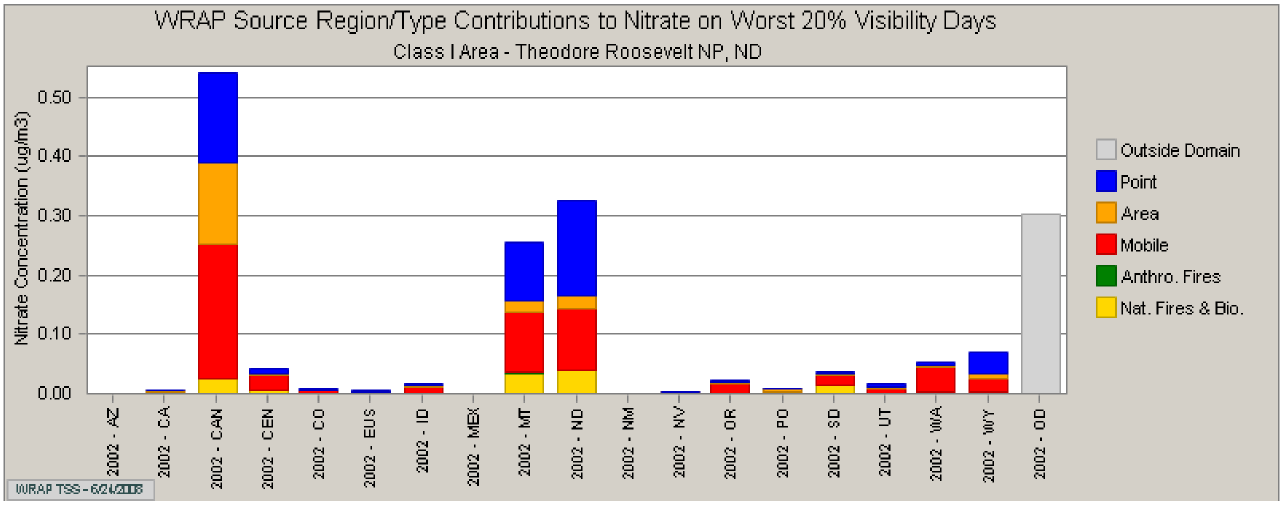


Figure 6.3

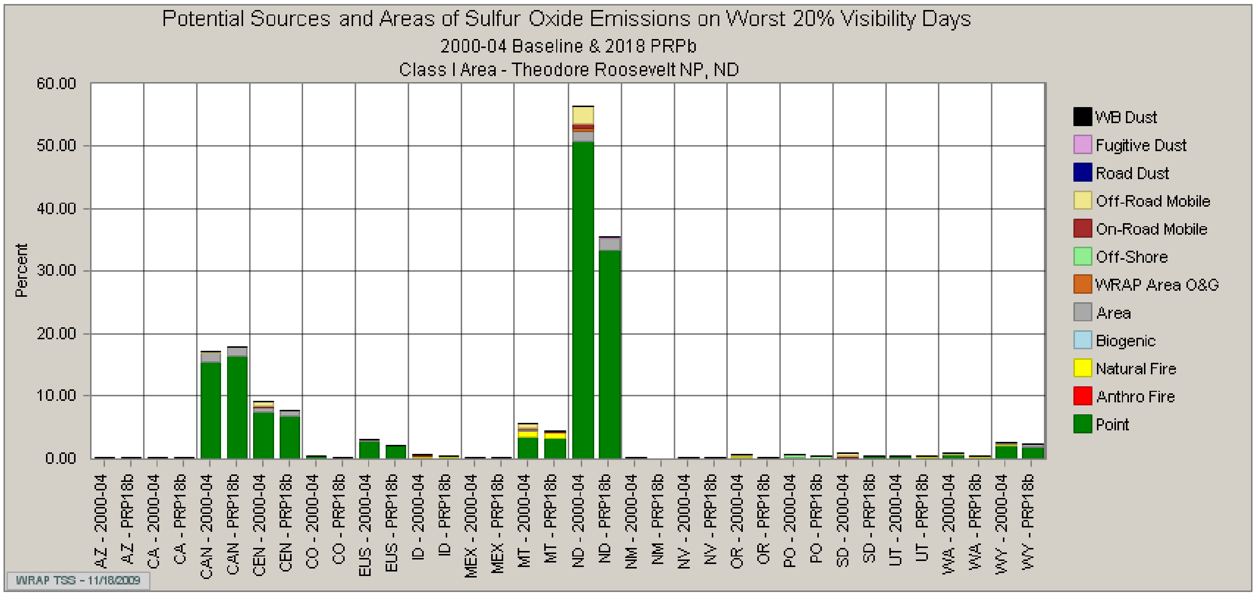


Figure 6.4

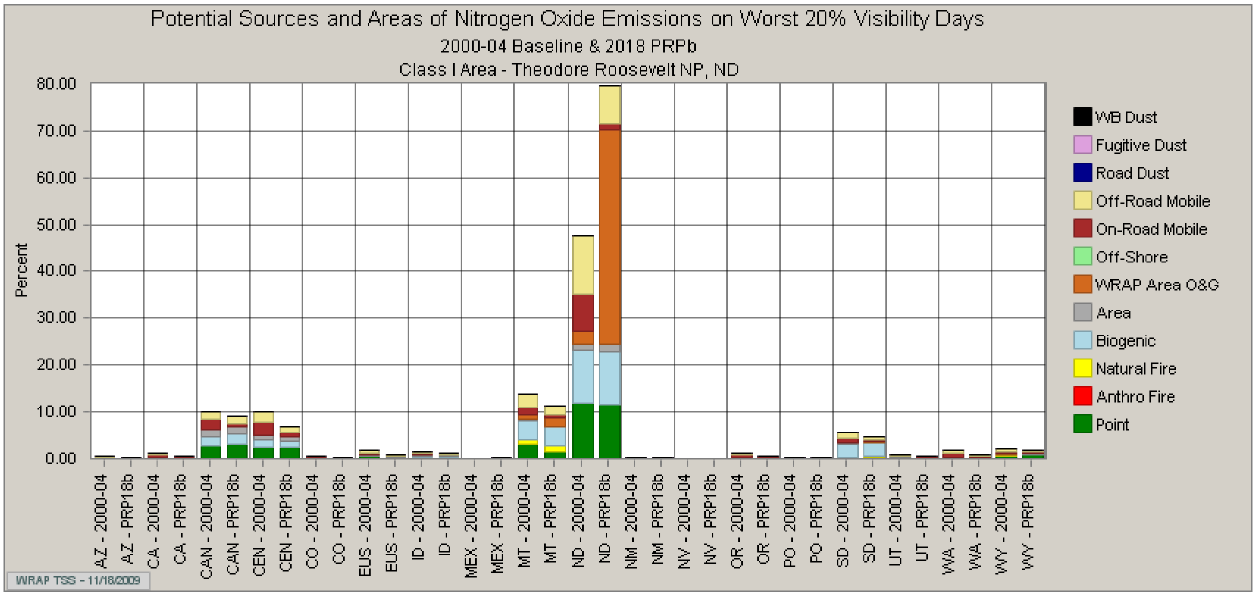


Figure 6.5

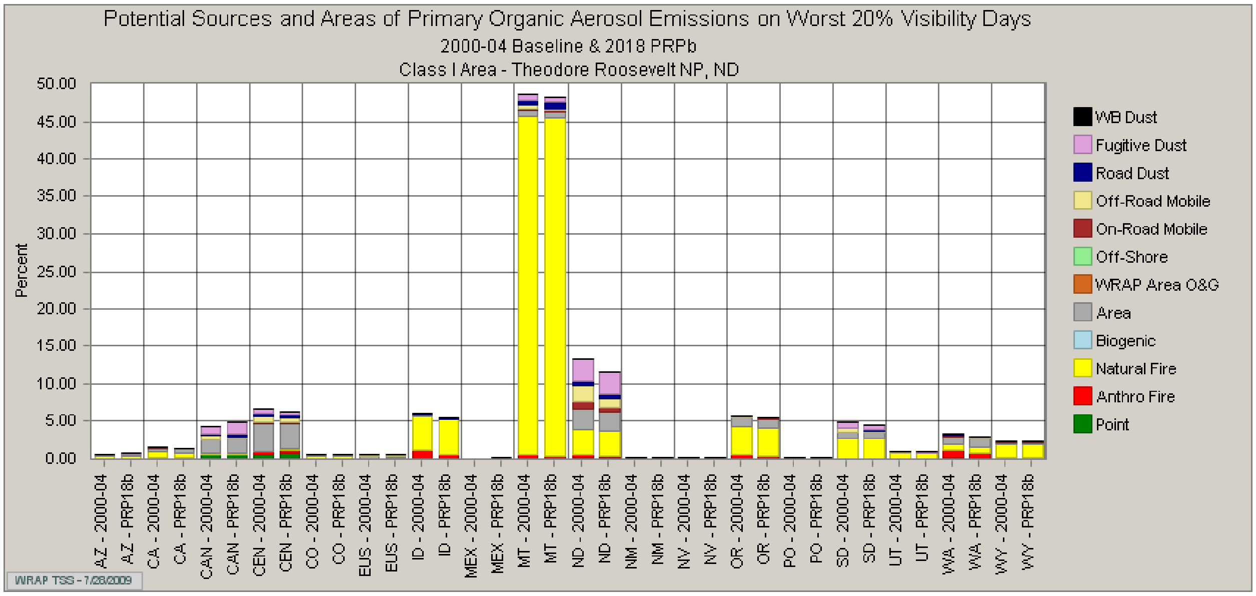


Figure 6.6

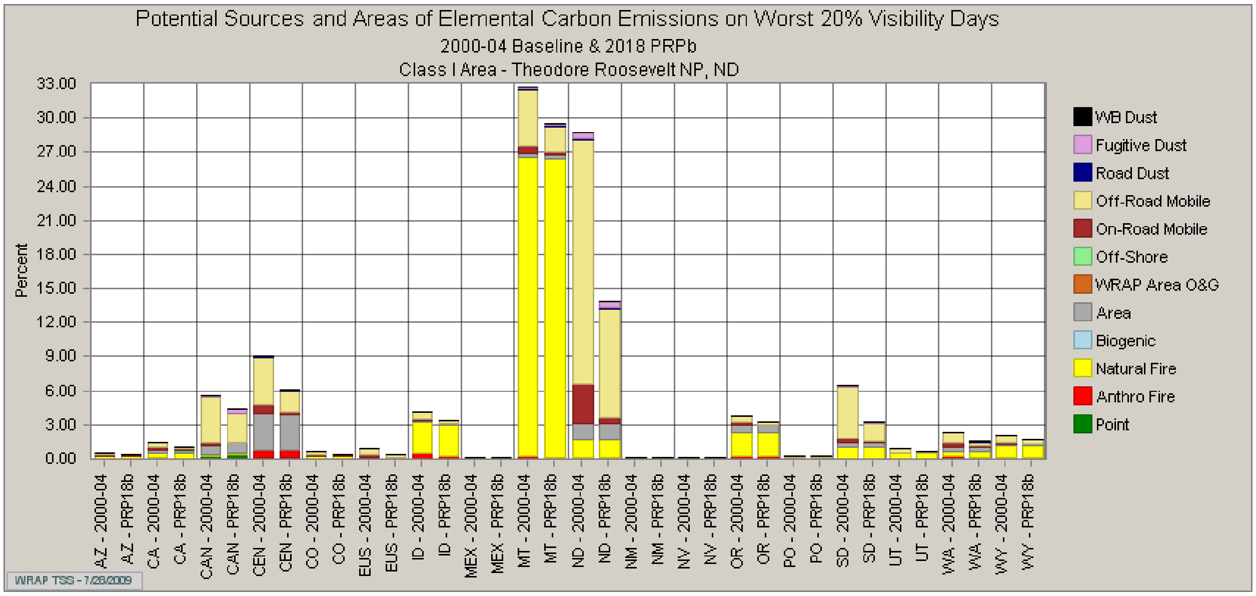


Figure 6.7

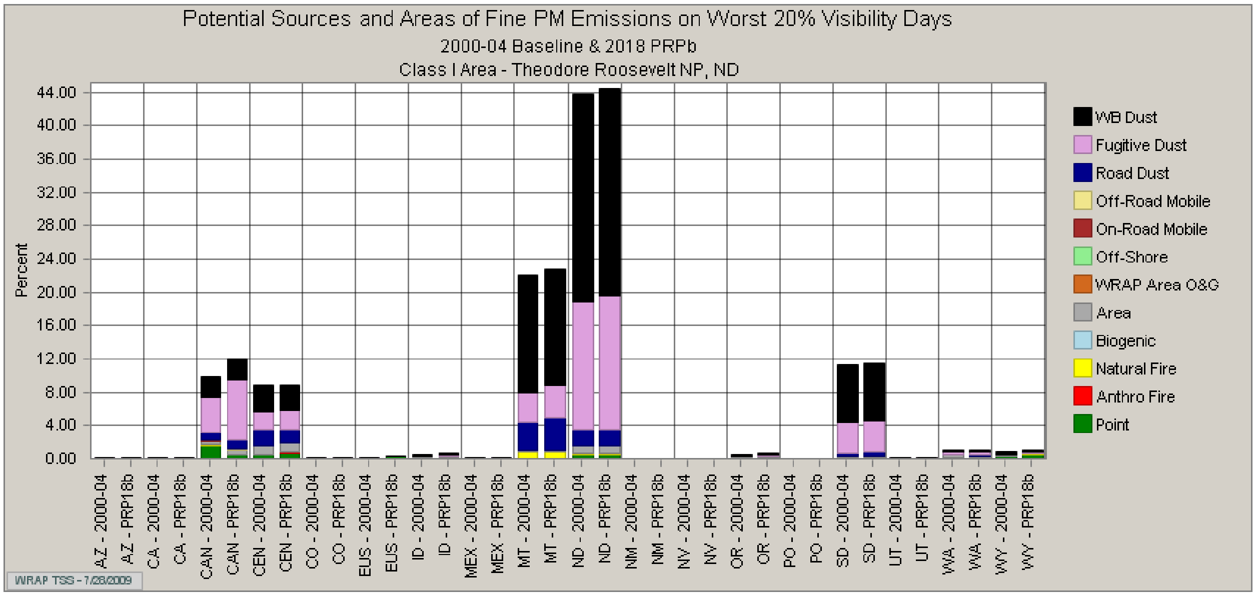


Figure 6.8

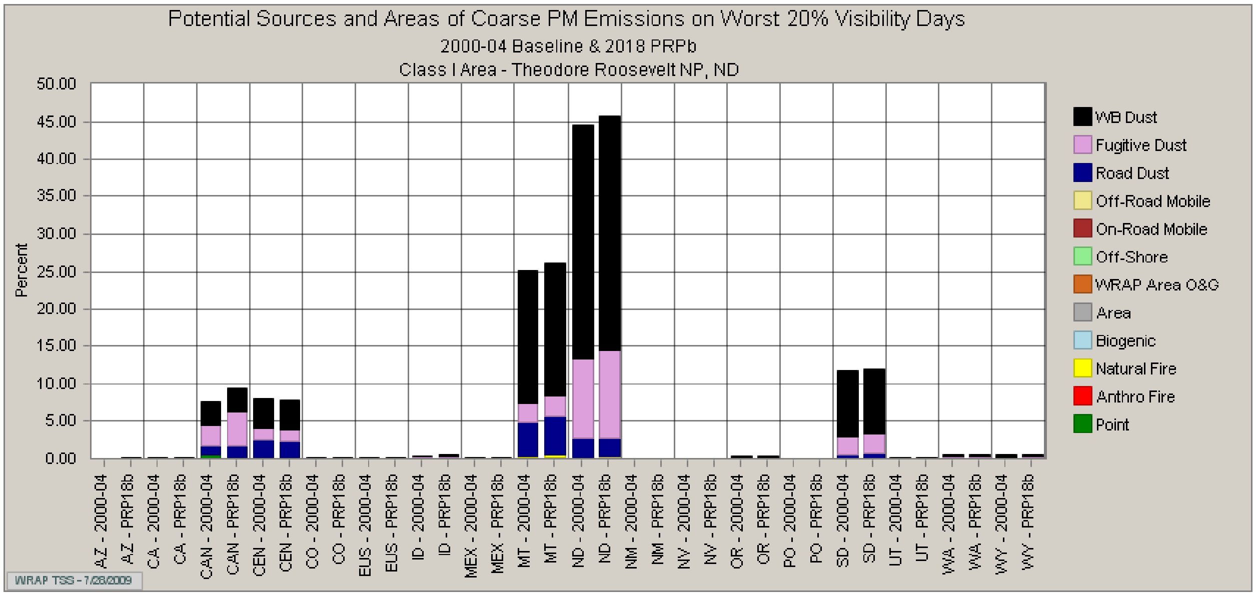


Figure 6.9

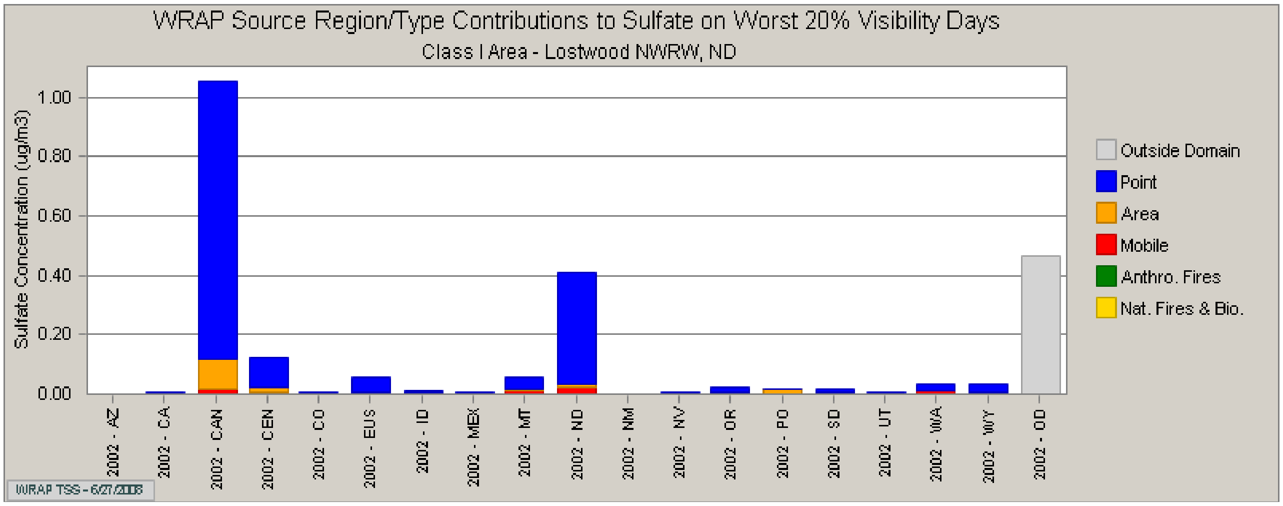


Figure 6.10

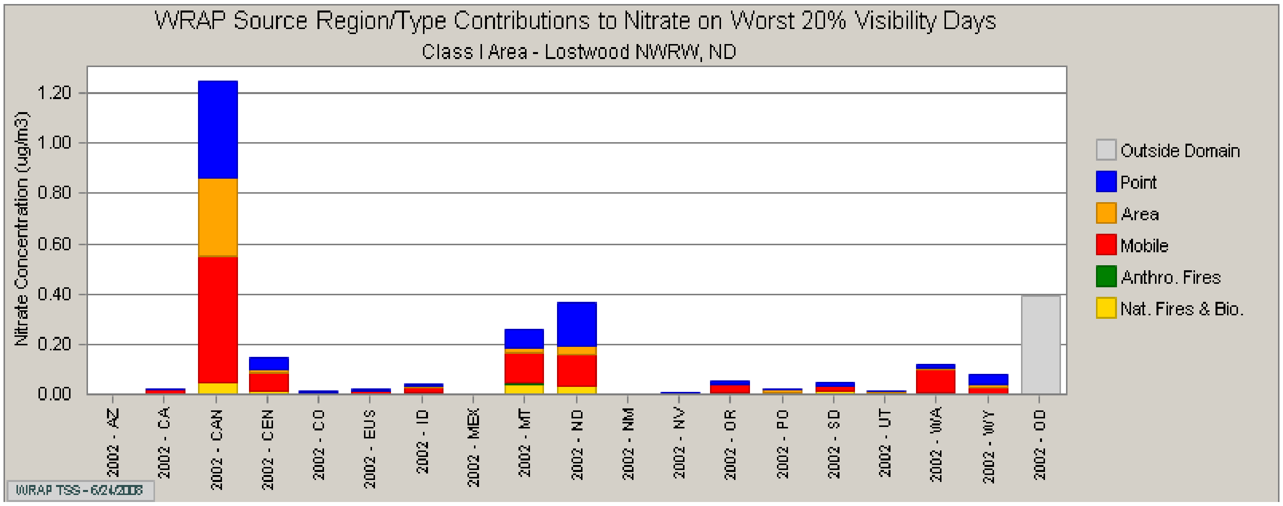


Figure 6.11

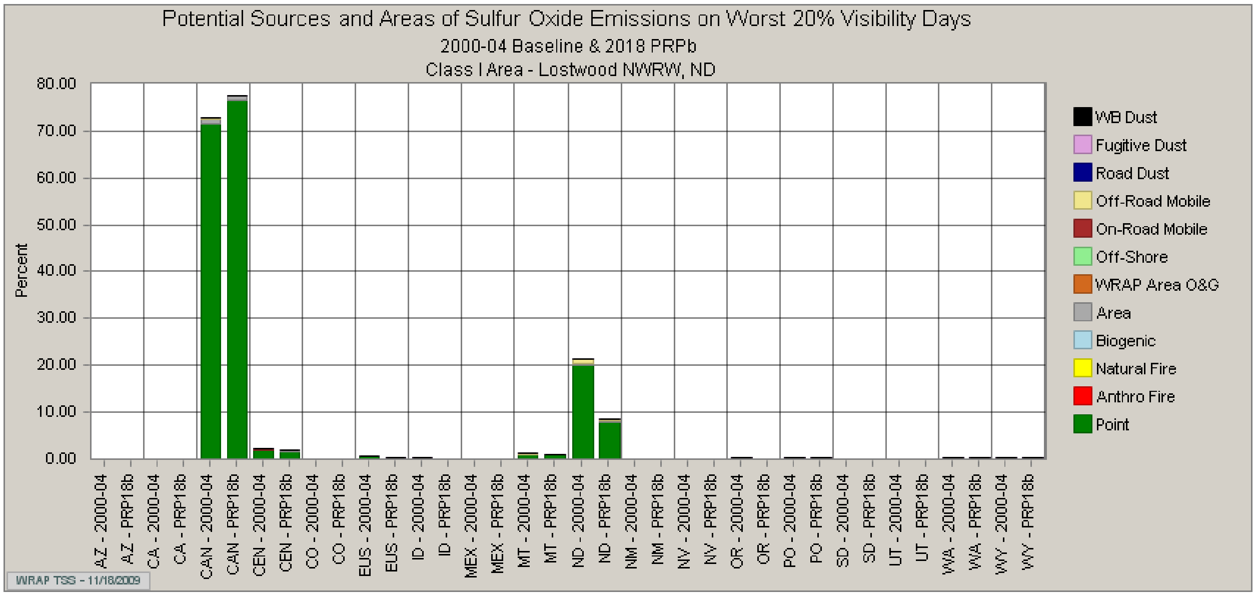


Figure 6.12

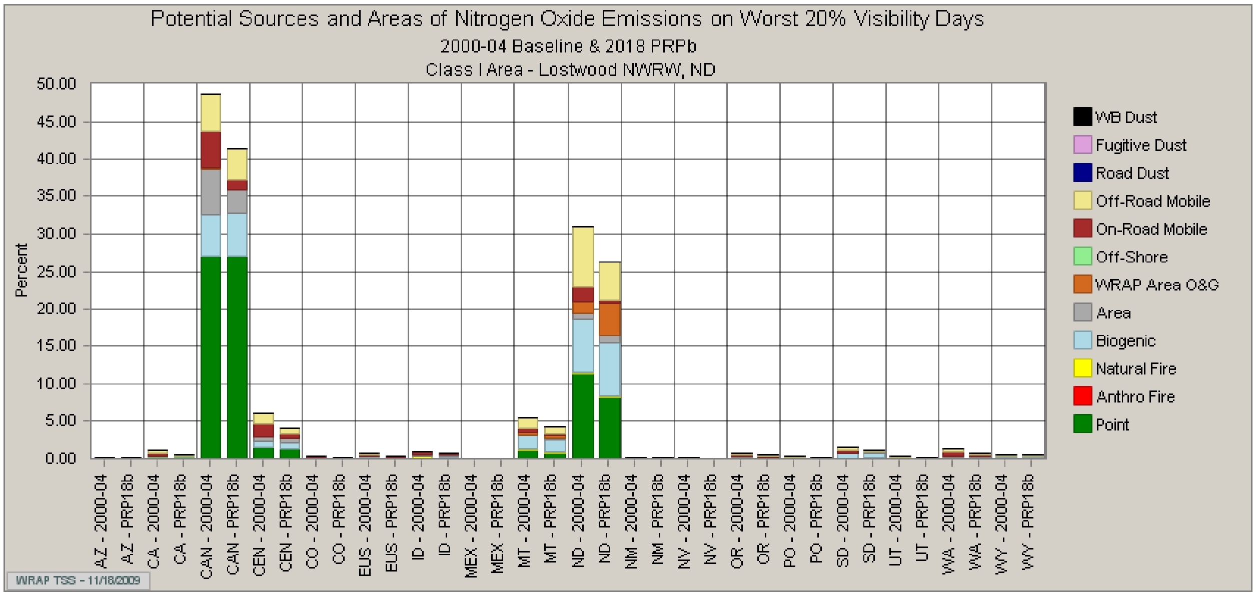


Figure 6.13

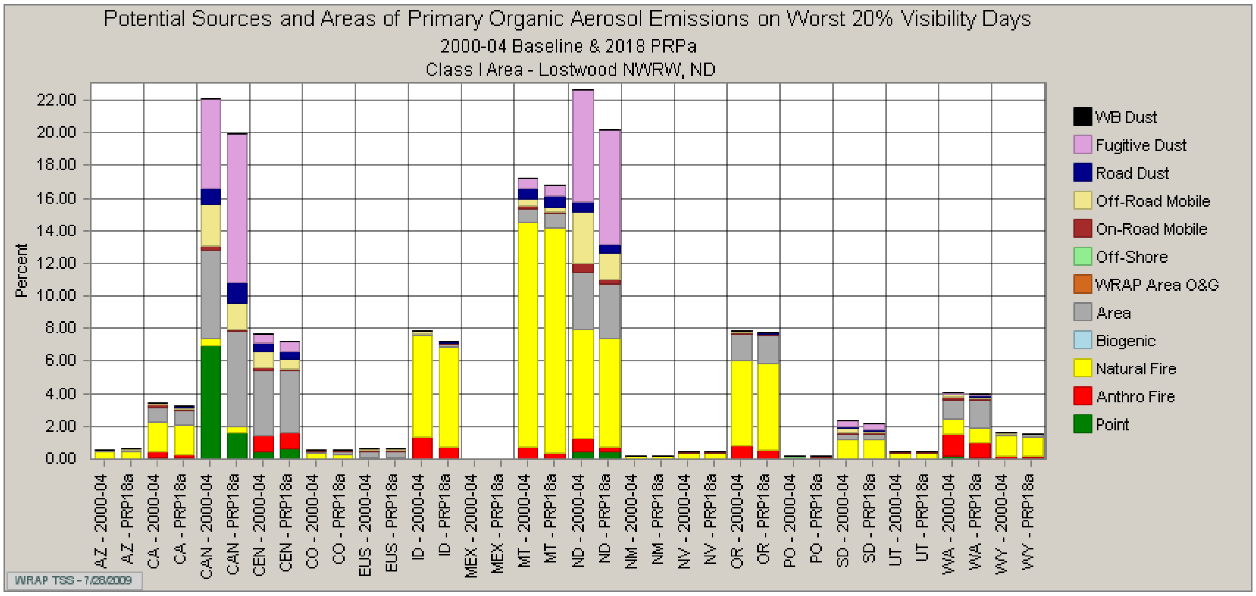


Figure 6.14

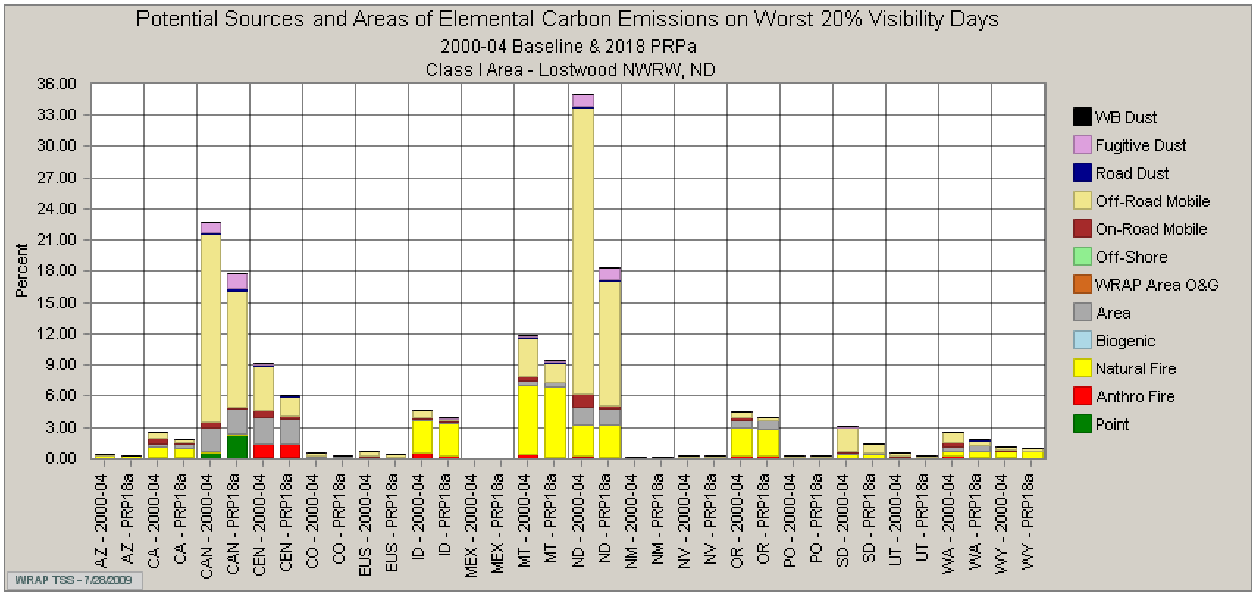


Figure 6.15

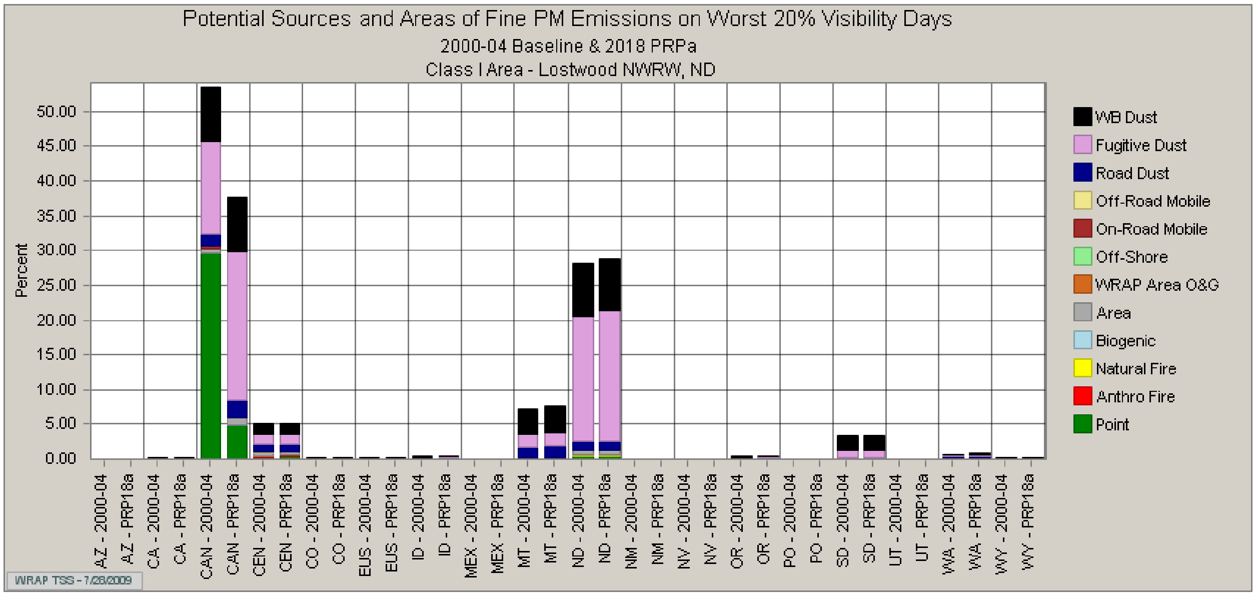


Figure 6.16

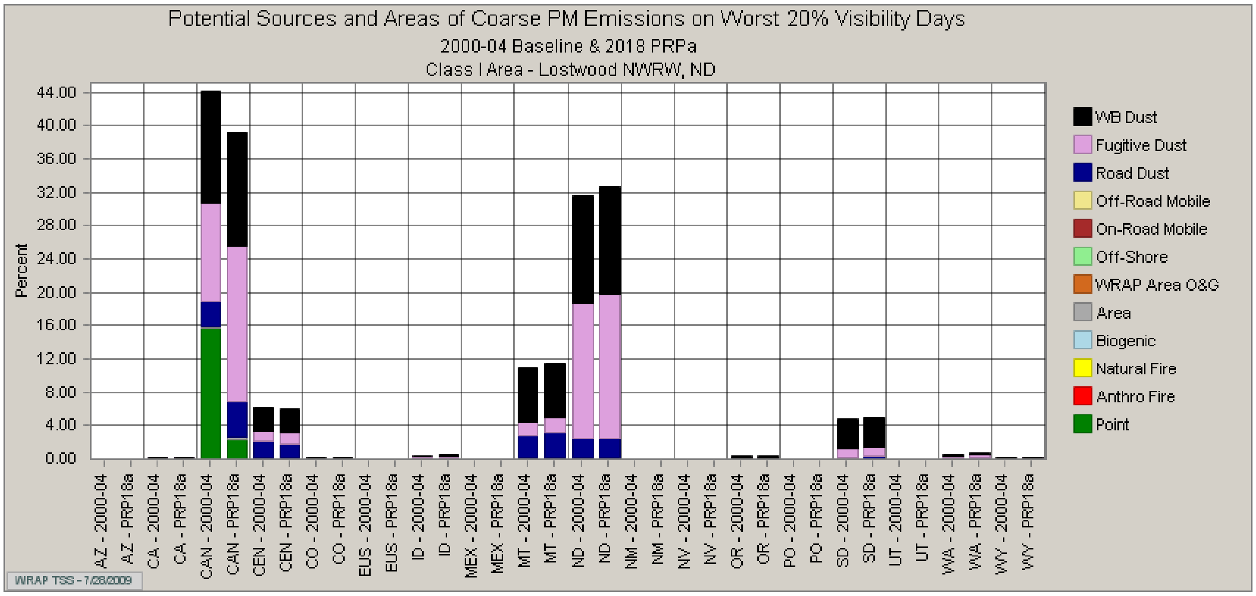


Table 6.7
Source Region Apportionment 20% Worst Days

Contributing Area	Class I Area			
	TRNP		LWA	
	SO_4	NO_3	SO_4	NO_3
North Dakota	21.1%	19.1%	17.9%	13.0%
Canada	28.3%	31.8%	45.9%	44.6%
Outside Domain	32.6%	17.9%	20.2%	14.0%
Montana	3.1%	15.0%	2.4%	9.3%
CENRAP	4.9%	2.5%	5.3%	5.1%
Other	10.5%	13.7%	8.3%	14.0%

The primary Canadian provinces which influence visibility in the Class I areas of North Dakota are Saskatchewan, Alberta, Manitoba and British Columbia. Emissions from these provinces in 2002, as reported in WRAP's TSS website, totaled more than one million tons of sulfur dioxide, 1.4 million tons of nitrogen oxides and 2 million tons of particulate matter as shown in Table 6.8.

Table 6.8
2002 Canadian Emissions (tons)

	SO_2	NO_x	PMC	PMF
Saskatchewan	126,528	292,539	364,739	78,108
Manitoba	398,806	142,685	144,928	25,403
Alberta	433,394	752,966	503,835	807,738
British Columbia	101,990	214,914	64,545	39,695

The location of sulfur dioxide and nitrogen oxides emissions, as reported by Environment Canada, are shown in Figures 6.17 and 6.18. As can be seen, the heaviest concentration of emissions of sulfur dioxide and nitrogen oxides are northwest, in the prevailing wind direction of North Dakota's Class I areas, especially the Lostwood Wilderness Area.

Figure 6.17

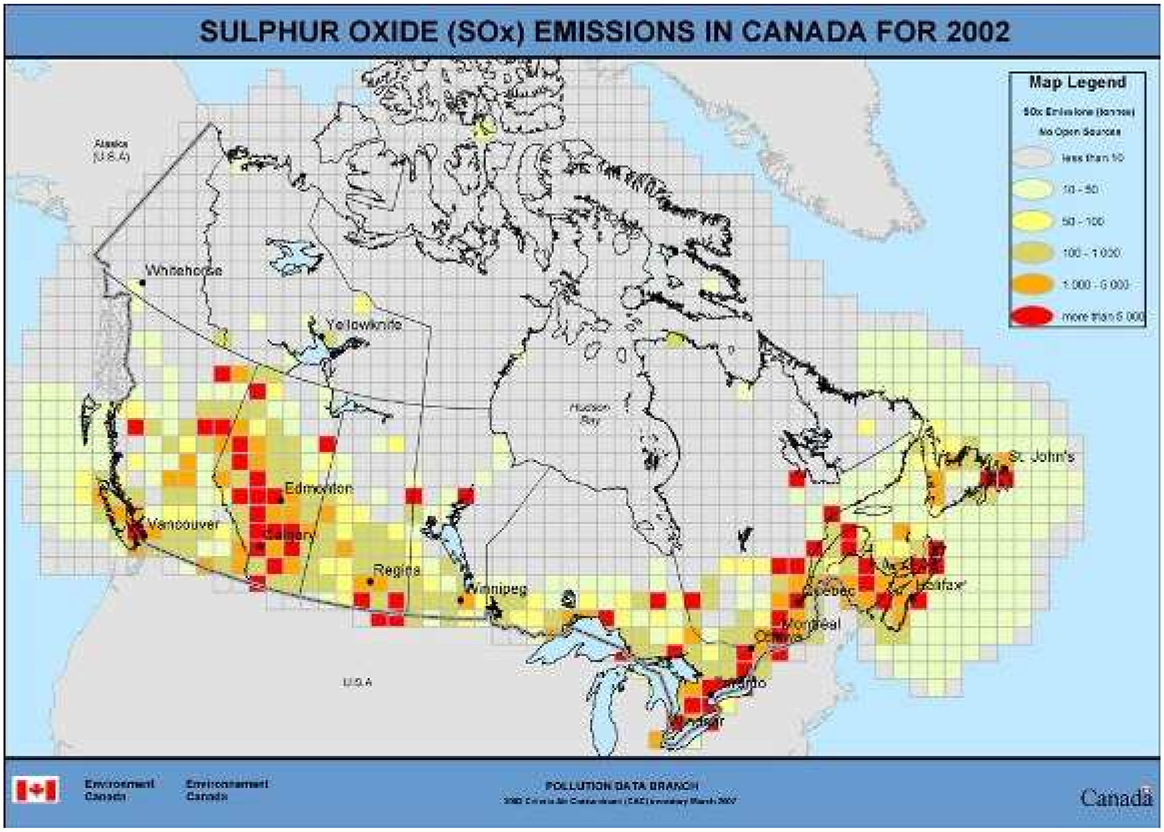
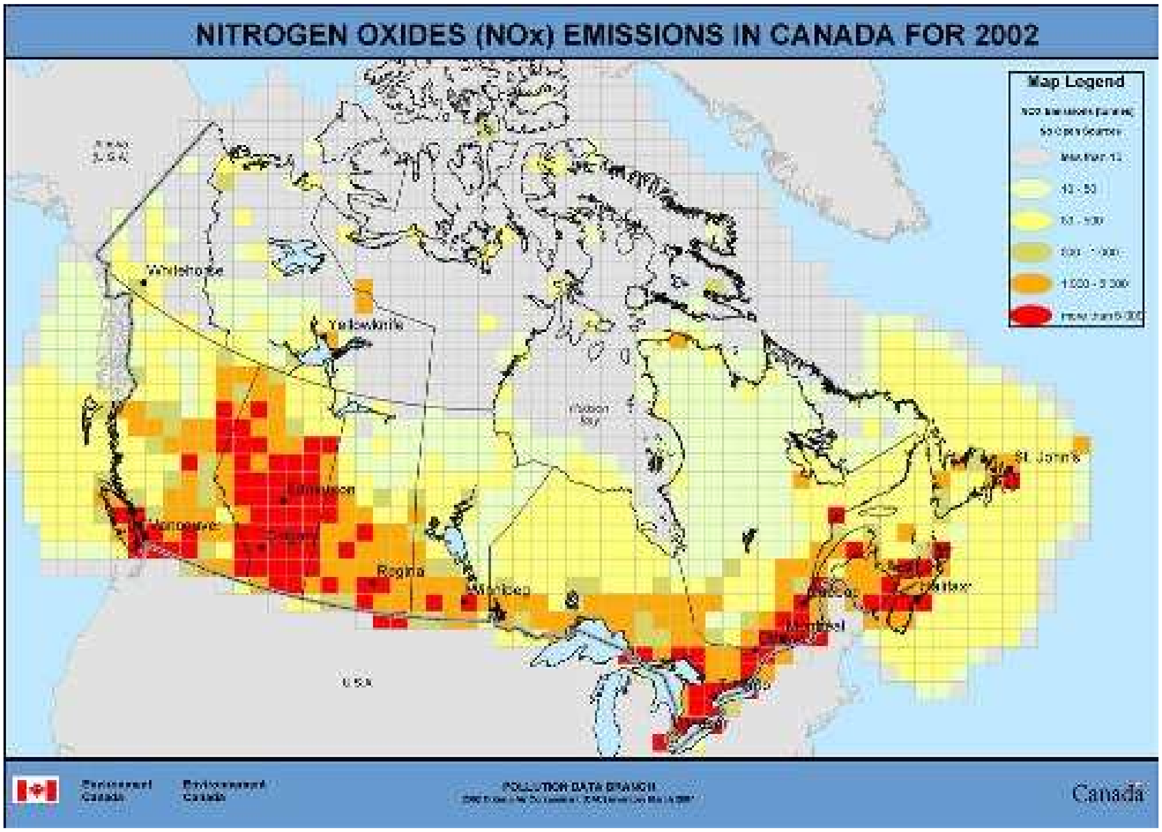

SULPHUR OXIDE (SOx) EMISSIONS IN CANADA FOR 2002
Map Legend
SOx Emissions (tonnes)
No Open Sources
less than 10
10 - 50
50 - 100
100 - 1 000
1 000 - 5 000
more than 5 000
Alaska (U.S.A)
Whitehorse
Yellowknife
Hudson Bay
Edmonton
Vancouver
Calgary
Regina
Winnipeg
St. John's
Halifax
Quebec
Montreal
Ottawa
Toronto
Windsor
U.S.A
Environment Canada
Environnement Canada
POLLUTION DATA BRANCH
2002 Criteria Air Contaminant (CAC) Inventory March 2007
Canada

Figure 6.18



Three major coal-fired electric utility steam generating plants within Saskatchewan are located just north of the U.S./Canada border within 250 km of the Lostwood Wilderness Area. During 2002, emissions from these plants totaled nearly 110,000 tons of sulfur dioxide and 38,000 tons of nitrogen oxides as shown in Table 6.9. The Boundary Dam plant, which has the largest amount of emissions, is located within 60 kilometers of LWA.

Table 6.9
Saskatchewan Power Plants 2002 Emissions (tons)

Plant	**SO_2**	**NO_x**	**PMC**	**PMF**
Boundary Dam	47,338	18,950	7,444	2.996
Shand	15,146	6,463	40	17
Poplar River	47,107	12,864	337	136

7. Best Available Retrofit Technology (BART)

7.1 Introduction

7.1.1 Overview of Paragraph 51.308(e) of the Federal Regional Haze Regulation - Best Available Retrofit Technology (BART) Requirements for Regional Haze Visibility Impairment

The requirements for Best Available Retrofit Technology (BART) are found in Section 51.308(e) of the federal regional haze regulation.

Paragraph (e) has six subparagraphs which identify the requirements as follows:

1. 51.308(e)(1) - BART for individual sources;
2. 51.308(e)(2) and (3) - An emissions trading program, or other alternative measure, rather than to require sources subject to BART to install, operate, and maintain BART;
3. 51.308(e)(4) - Participation in the EPA administered Clean Air Interstate Rule (CAIR) trading programs for sulfur dioxide and nitrogen oxides;
4. 51.308(e)(5) - Status of BART-eligible sources after a state has met the requirements for BART; and
5. 51.308(e)(6) - An exemption from BART requirements for BART-eligible sources.

Section 51.308(e) requires the State to submit an implementation plan containing emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area, unless the State demonstrates that an emissions trading program or other alternative measures will achieve greater reasonable progress toward natural visibility conditions, or the State participates in a Clean Air Interstate Rule (CAIR) trading program.

The Department has decided not to develop an emissions trading program or other alternate measures and is not eligible to participate in the CAIR program. Therefore only Sections 308(e)(1), (5), and (6) apply in North Dakota.

Each state implementation plan must contain two elements related to BART.

The first, found in Section 308(e)(1)(i), is the requirement that the State submit a list of the BART-eligible sources in the State.

The second requirement is detailed in Section 308 (e)(1)(ii) and requires the State to determine and include in the plan BART emission reductions for each BART-eligible source in the State which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I area.

BART must be determined for each visibility-impairing pollutant that is emitted by a BART-eligible source which may reasonably be anticipated to cause or contribute to regional haze. The definition for BART 51.301 reads:

> Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and the non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Visibility-impairing pollutants include sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM_{10} and $PM_{2.5}$) volatile organic compounds (VOC), and ammonia (NH_3).

In developing source specific emission limits for BART, the State must take into consideration the control technology available and a number of specific factors:

- The costs of compliance;
- The energy and non-air environmental impacts of compliance;
- Any existing pollution control technology in use at the source;
- The remaining useful life of the source; and
- The degree of improvement in visibility which may reasonably be anticipated from the use of such technology.

The State has the discretion as to how much weight will be given to each of the factors.

EPA issued final guidance for the determination of BART on July 6, 2005 as 40 CFR Part 51 Appendix Y - Guidelines for BART Determinations Under the Regional Haze Rule (BART guideline).

The SIP for source-specific BART (51.308(e)(1)) must contain the requirement that each source subject to BART install and operate BART as expeditiously as practicable, but in no event later than five years after approval of the implementation plan revision by EPA.

The SIP must contain procedures to ensure control equipment is properly maintained and operated in the BART requirements (51.308(e)(1)(v)).

Paragraph 51.308(e)(5) provides that after a State has met the requirements for source-specific BART, BART-eligible sources will be subject to the core requirements of Section 51.308(d) in the same manner as other sources. This would include enforceable emissions limitations, compliance schedules and other measures as necessary to achieve the reasonable progress goals set out in the long-term strategy to attain natural conditions by 2064.

Paragraph 51.308(e)(6) provides that even where a BART-eligible source may reasonably be anticipated to cause or contribute to visibility impairment, section 169A(c) of the Clean Air Act allows for the exemption of any source from the BART requirements if it can be demonstrated that the source, by itself or in combination with other sources, is not reasonably anticipated to cause or contribute to significant visibility impairment. Significant impairment 51.301 is defined as:

> "Significant impairment means, for purposes of Section 51.303, visibility impairment which, in the judgement of the Administrator, interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the mandatory Class I Federal area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of the visibility impairment, and how these factors correlate with (1) times of visitor use of the mandatory Class I Federal area, and (2) the frequency and timing of natural conditions that reduce visibility."

EPA believes that the question of whether a source can be reasonably anticipated to cause or contribute to significant visibility impairment requires an analysis of the cumulative effects of emission sources on a region. Regional modeling will be one appropriate method to determine whether a source could qualify for a BART exemption. If a significant cumulative impact is demonstrated from the sources across the relevant regional modeling domain, then any BART-eligible source in the region would most likely be found to be reasonably anticipated to cause or contribute to significant visibility impairment.

A source may apply to EPA for an exemption from the BART requirement. The EPA will grant or deny an application after providing notice and opportunity for a public hearing. Any exemption granted by EPA must have the concurrence from all affected Federal Land Managers. The requirements for an exemption are found in Section 51.303. The authority to grant an exemption is reserved to EPA and will not be delegated to a state.

7.1.2 Visibility-Impairing Pollutants of Concern

For both BART applicability and degree of visibility improvement analyses, the BART guideline specifies that only primary emissions need to be considered. These primary emissions include SO_2, NO_x, and direct particulate matter (PM) emissions specified as either coarse (PM_{10} minus $PM_{2.5}$) or fine ($PM_{2.5}$). If this distinction in size of PM emissions cannot be made, it would be appropriate to consider all PM_{10} emissions as $PM_{2.5}$.

The BART guideline also discusses volatile organic compounds (VOC) or ammonia (NH_3) emissions as possibly impacting visibility. For the BART-eligible sources identified in North Dakota, these emissions (and associated visibility impacts) are negligible, and therefore the Department will not require inclusion of VOC or ammonia species in BART-related visibility analyses.

7.1.3 BART Identification Process

The first step in preparing the RH BART SIP is to develop a list of all BART-eligible sources within the State.

The regional haze rule contains the following definitions in Section 51.301:

> BART-eligible source means an existing stationary facility as defined in this section.
>
> Existing stationary facility means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

(1) Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,
(2) Coal cleaning plants (thermal dryers),
(3) Kraft pulp mills,
(4) Portland cement plants,
(5) Primary zinc smelters,
(6) Iron and steel mill plants,
(7) Primary aluminum ore reduction plants,
(8) Primary copper smelters,
(9) Municipal incinerators capable of charging more than 250 tons of refuse per day,
(10) Hydrofluoric, sulfuric, and nitric acid plants,
(11) Petroleum refineries,
(12) Lime plants,
(13) Phosphate rock processing plants,
(14) Coke oven batteries,
(15) Sulfur recovery plants,
(16) Carbon black plants (furnace process),
(17) Primary lead smelters,
(18) Fuel conversion plants,
(19) Sintering plants,
(20) Secondary metal production facilities,
(21) Chemical process plants,
(22) Fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
(23) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
(24) Taconite ore processing facilities,
(25) Glass fiber processing plants, and
(26) Charcoal production facilities.

The following three steps identify the key elements in the definition of existing stationary facility and other related definitions that should be considered when determining whether a source is a BART-eligible source.

STEP 1. IDENTIFY EMISSION UNITS IN THE 26 BART LISTED SOURCE CATEGORIES.

Listed Source Categories - The facility must fall within one of the 26 listed categories in the definition of existing stationary facility. These are the same categories that are included in the definitions of major source under PSD. PSD guidance documents and case history can be used to answer any questions related to the 26 categories.

Aggregated Unit Applicability - the definition for existing stationary facility includes stationary sources. Stationary source is defined as:

> Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant.

Building, structure, or facility are defined as:

> Building, structure, or facility means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities must be considered as part of the same industrial grouping if they belong to the same Major Group (i.e., which have the same two-digit code) as described in the Standard Industrial Classification Manual, 1972 as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0 respectively).

Installation is defined as:

> Installation means an identifiable piece of process equipment.

The above definitions have been interpreted by EPA to mean that all of the units within the source that meet the BART criteria should be aggregated together to determine if the source is BART-eligible.

STEP 2. IDENTIFY THE STARTUP DATES OF THE EMISSION UNITS.

Date of Operation/Construction/Reconstruction - BART review is limited to units that were constructed during a 15-year window between 1962 and 1977. There are several nuances in the definition of existing stationary facility that must be considered when determining if a unit falls within this 15-year window. The unit must not have been in operation prior to August 7, 1962. In operation is defined as:

> In operation means engaged in activity related to the primary design function of the source.

The date that the unit is permitted is not important to meet this test because the focus is on actual operation of the unit.

In addition, the unit must have been in existence as of August 7, 1977. In existence is defined as:

> In existence means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.

The actual date a unit begins operation may not be important to meet this test. For example, a unit that did not begin operation until 1983 may still be considered BART-eligible if the unit had all the necessary preconstruction approvals or permits and had begun, or caused to begin, a continuous program of physical on-site construction of the facility, or entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss prior to August 7, 1977.

STEP 3. COMPARE THE POTENTIAL TOTAL EMISSIONS FOR EACH POLLUTANT FROM THE EMISSION UNITS TO THE 250 TON PER YEAR CUT OFF.

Potential Emissions - The emission units that meet the source category and date of construction or operation requirements must then be aggregated together to determine if the combined emission units have the potential to emit 250 tons per year of any air pollutant.

Potential to emit is defined as:

> Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.
>
> Applicability for BART is determined on a pollutant-by-pollutant basis. The total emissions for each pollutant from all the units at the source remaining after step 2 above is compared to the 250 ton per year cut off.

> Pollutants to be considered include the visibility-impairing pollutants, SO_2, NO_x, $PM_{2.5}$ and PM_{10}, VOC, and NH_3.

Fugitive emissions, to the extent quantifiable, must be counted. Fugitive emissions are defined as:

> Fugitive Emissions means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

As noted in the definition for Potential to emit, secondary emissions do not count in determining the potential to emit of a stationary source. Secondary emissions are defined as:

> Secondary emissions means emissions which occur as a result of the construction or operation of an existing stationary facility but do not come from the existing stationary facility. Secondary emissions may include, but are not limited to, emissions from ships or trains coming to or from the existing stationary facility.

A SOURCE THAT PASSES ALL THREE STEPS IS A BART-ELIGIBLE SOURCE.

7.1.4 CALPUFF Screening Model Protocol

The Department has established a protocol for BART-related dispersion modeling applicable to BART-eligible sources in North Dakota. The protocol uses the CALPUFF model and conforms to the requirements of Appendix Y to Part 51- Guidelines for BART Determinations Under the Regional Haze Rule. It follows recommendations for long range transport of Appendix W to Part 51 - The Guideline on Air Quality Models and EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. The protocol was reviewed by EPA and Federal Land Manager meteorologists in Denver, CO prior to finalizing.

The protocol, "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota, November 2005", is included as Appendix A.1. Both BART applicability and degree of visibility improvement analyses were conducted following this protocol.

7.1.5 Screening Impact Threshold

In general, to determine which BART-eligible sources must apply BART, single facility modeling results for PSD Class I areas are compared with a visibility threshold, expressed in deciviews. The Department will follow recommendations in the July 6, 2005 BART guideline which states:

> "A single source that is responsible for a 1.0 deciview change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 deciview change may still "contribute" to visibility impairment and thus be subject to BART .... As

> a general matter, any threshold that you use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 deciviews."

As a practical matter, the NDDH sees no reason to distinguish among BART-eligible sources which "cause" visibility impairment versus those sources which "contribute" to visibility impairment in PSD Class I areas. Therefore, the Department will generally use one threshold to determine which BART-eligible sources must apply BART.

The Department, in accordance with the BART guidelines, used a contribution threshold of 0.5 deciview for determining which sources were subject to BART. The BART guidelines provide States the discretion to set a threshold below 0.5 deciviews if "the location of a large number of BART-eligible sources within the State and proximity to a Class I area justifies this approach." This decision was based on several factors:

- It equates to the 5 percent extinction threshold for new sources under the PSD New Source Review rules,
- It is consistent with the threshold selected by other States in the West (all selected 0.5 dv),
- It represents the limit of perceptible change

There are only a few major point sources in North Dakota affecting the Class I areas and they are mostly 100 or more miles away, downwind in the prevailing wind direction. BART screening modeling indicates the visibility impact to either be much greater than 1.0 deciview or 0.5 deciview or less (See Section 7.3.1.), and there was no clear rationale or justification for selecting a lower level.

The Department therefore has established 0.5 deciview as the threshold to determine which BART-eligible sources must apply BART and included it in the State rules. Definition 2 of NDAC Section 33-15-25-01, Definitions, is:

> "Contributes to visibility impairment" means a change in visibility impairment in a Class I federal area of five-tenths deciviews or more (24-hour average) above the average natural visibility baseline. A source exceeds the threshold when the ninety-eighth percentile of the modeling results based on any one year of the three years of meteorological data modeled exceeds five-tenths deciviews.

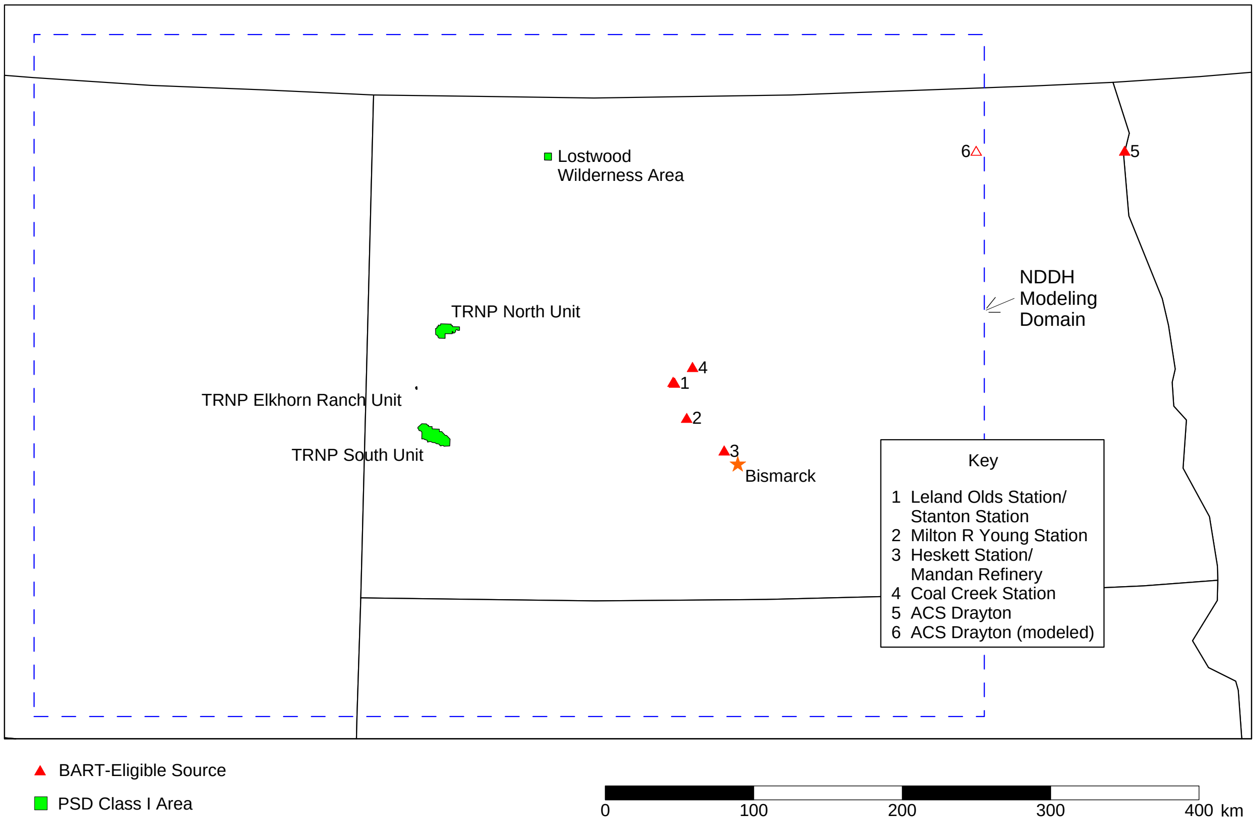
7.2 BART - Eligible Sources in North Dakota

The ten BART-eligible sources in the State of North Dakota and their locations are listed in Table 7.1. The locations of the BART-eligible sources with respect to Class I areas in North Dakota are illustrated in Figure 7.1.

Table 7.1
BART-Eligible Sources in North Dakota

Source and Unit	Location
American Crystal Sugar Company Main Boiler and Lime Kiln	Drayton, Pembina County
Basin Electric Power Cooperative Leland Olds Station Unit 1	Stanton, Mercer County
Basin Electric Power Cooperative Leland Olds Station Unit 2	Stanton, Mercer County
Great River Energy Coal Creek Station Unit 1	Falkirk, McLean County
Great River Energy Coal Creek Station Unit 2	Falkirk, McLean County
Great River Energy Stanton Station Unit 1	Stanton, Mercer County
Minnkota Power Cooperative Milton R. Young Station Unit 1	Center, Oliver County
Minnkota Power Cooperative Milton R. Young Station Unit 2	Center, Oliver County
MDU Resources Group, Inc. R. M. Heskett Station Unit 2	Mandan, Morton County
Tesoro Petroleum Corporation Mandan Refinery Carbon Monoxide Furnace	Mandan, Morton County

Figure 7.1
BART-Eligible Sources and Class I Areas in North Dakota



The BART-eligible sources were identified using the methodology in the Guidelines for BART Determinations Under the Regional Haze Rule, 40 CFR Part 51, Appendix Y, and summarized in 7.1.3.

Eight of the BART-eligible sources are fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input. One is a fossil-fuel fired boiler of more than 250 million British thermal units per hour heat input and a lime plant (the main boiler and the lime kiln at the American Crystal Sugar Company sugar beet processing plant at Drayton) and one is a process unit at a petroleum refinery (the carbon monoxide furnace at the Tesoro Petroleum Corporation refinery at Mandan).

7.3 Determination of BART-Eligible Sources Subject to BART

7.3.1 Sources Subject to BART

The modeled visibility impact of each of the ten BART-eligible sources listed in Table 7.1 on the Class I areas in North Dakota is shown in Table 7.2. The maximum 24-hour 98th percentile deciview represents the result for the worst year of the three years modeled (2000-2002).

The visibility impact of each BART-eligible source is considered significant if the projected change in the maximum 24-hour impact at a Class I area compared against natural conditions is equal to or greater than 0.5 deciviews. The source is then subject to BART. If the impact is less than 0.5 deciviews, the source is exempt from BART.

The modeling to determine if each BART-eligible source has a significant impact on visibility was performed by the Department using the CALPUFF model following EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts specified in the Guidelines for BART Determinations Under the Regional Haze Rule, 40 CFR Part 51, Appendix Y. The modeling protocol is included in Appendix A as Appendix A.1.

After completion of the subject-to-BART screening modeling, the eight subject-to-BART sources were notified they were subject-to-BART by letters dated November 30, 2005. These letters are attached as Appendix A.3.

The Department was contacted by Montana Dakota Utilities who requested approval to do a more refined CALPUFF screening analysis considering that the Department's results were slightly above the 0.5 deciview cutoff. MDU submitted a refined analysis in May 2006. This analysis is attached in Appendix A.2 and is discussed in 7.3.4 below.

Table 7.2
Individual BART-Eligible Source Visibility Impact on Class I Areas

Source and Unit	Class I Area	Maximum 24 Hour 98th Percentile Visibility Impact Value Deciview	Subject to BART or Exempt
American Crystal Sugar Company Main Boiler and Lime Kiln	Lostwood TRNP South Unit TRNP North Unit TRNP Elk. Ranch Unit	0.04 0.04 0.04 0.04	Exempt
Basin Electric Power Cooperative Leland Olds Station Unit 1 and Unit 2	Lostwood TRNP South Unit TRNP North Unit TRNP Elk. Ranch Unit	5.42 6.22 5.32 4.49	Subject to BART
Great River Energy Coal Creek Station Unit 1 and Unit 2	Lostwood TRNP South Unit TRNP North Unit TRNP Elk. Ranch Unit	4.04 4.48 3.56 3.04	Subject to BART
Great River Energy Stanton Station Unit 1	Lostwood TRNP South Unit TRNP North Unit TRNP Elk. Ranch Unit	1.35 1.68 1.54 1.43	Subject to BART
Minnkota Power Cooperative Milton R. Young Station Unit 1 and Unit 2	Lostwood TRNP South Unit TRNP North Unit TRNP Elk. Ranch Unit	4.88 6.69 5.58 6.10	Subject to BART
MDU Resources Group, Inc. R. M. Heskett Station Unit 2	Lostwood TRNP	0.23[1] 0.28[1]	Exempt
Tesoro Petroleum Corporation Mandan Refinery Carbon Monoxide Furnace	Lostwood TRNP South Unit TRNP North Unit TRNP Elk. Ranch Unit	0.04 0.05 0.04 0.04	Exempt

[1] MDU BART Screening Results (12/09)

Detailed descriptions of the seven subject-to-BART sources can be found in the Department BART Determinations in Appendix B and in the Company BART Analyses in Appendix C.

7.3.2 Exclusion of Tesoro Mandan Petroleum Refinery

The Department single-source modeling for the Tesoro Petroleum Corporation Mandan Refinery Carbon Monoxide Furnace predicted the highest maximum 24 hour 98th percentile visibility impact value to be 0.05 deciviews at Theodore Roosevelt National Park South Unit. This is a factor of 10 less than the 0.5 deciview threshold for determining whether a BART-eligible source causes or contributes to visibility impairment. Therefore, the unit is exempt and not subject to BART.

7.3.3 Exclusion of American Crystal Sugar Drayton Refinery

The Department single-source modeling for the American Crystal Sugar Company Drayton Plant Main Boiler and Lime Kiln predicted the highest maximum 24 hour 98th percentile visibility impact value to be 0.04 deciview at all four Class I areas. This is more than a factor of 10 less than the 0.5 deciview threshold for determining whether a BART-eligible source causes or contributes to visibility impairment. Therefore, the unit is exempt and not subject to BART.

As shown in Figure 7.1, the American Crystal Sugar Company Drayton Plant is located outside the Department's modeling domain. Even if the domain was extended eastward to incorporate the Drayton plant, the plant is located about 400 kilometers from the nearest North Dakota Class I area (Lostwood Wilderness Area), and this distance is beyond the accepted range of CALPUFF (about 300 kilometers). For modeling purposes, therefore, the Department repositioned the Drayton plant about 100 kilometers to the west, to create a virtual source located just inside the east boundary of the current modeling domain (represented by the "ACS Drayton (modeled)" source in Figure 7.1). This adjustment provided a source-receptor distance more consistent with the documented limits of CALPUFF, and should ensure results are conservative.

In addition, the Minnesota Pollution Control Agency modeled the American Crystal Sugar Company Drayton plant and found similar impact levels at the Class I areas in Minnesota, Voyagers National Park which is about 300 kilometers from the plant and Boundary Waters Canoe Area Wilderness which is about 350 kilometers from the plant.

7.3.4 Exclusion of Montana Dakota Utilities Heskett Unit No. 2

The Department single-source modeling for the Montana Dakota Utilities R.M. Heskett Station Unit 2 located near Mandan predicted the highest maximum 24 hour 98th percentile visibility impact value to be 0.82 deciview at the Theodore Roosevelt National Park South Unit, and 0.54 deciview at the North Unit, 0.61 deciview at the Elkhorn Ranch Unit and 0.58 deciview at Lost wood National Wilderness Area. Because these values were slightly above the threshold of 0.5 deciviews, Montana Dakota Utilities hired a consultant, ENSR Corporation, to perform a refined

CALPUFF modeling analysis. The ENSR analysis submitted June 9, 2006 is included as Appendix A.2.

The ENSR analysis made three refinements to the analysis performed by the Department:

- A 1 km grid size was used instead of 3 km,
- Particulate matter emissions were speciated into several components that have different light scattering potential, and
- The annual average background visibility was used instead of the annual 20 percent best day's background visibility (as per an EPA court settlement agreement).

The results of the refined ENSR analysis predicted the highest maximum 24 hour 98th percentile visibility impact value to be 0.436 deciviews at Lostwood National Wilderness area in 2001.

The Department had originally reviewed the ENSR analysis and found it acceptable. Additionally, MDU has committed to reduce the potential sulfur dioxide emissions from Heskett Unit 2 by a minimum of 70 percent within five years of EPA approval of this SIP. This would have reduced sulfur dioxide emissions to 1,847 tons per year from the 2000-2004 emissions of 2,400 tons per year, a 553 tons per year reduction. The Department had determined that Heskett Unit 2 was not subject to BART. See the Department's letter of May 8, 2007 in Appendix A.3. The FLMs and EPA have expressed concerns about the modeling that was conducted. MDU agreed to remodel using a revised modeling protocol approved by EPA. The Department reassessed the determination to exclude Heskett Station Unit 2 following review of the revised modeling. That reassessment shows that Heskett Unit 2 is not subject to the BART requirements. The results of the analysis using the protocol as approved by EPA indicated the highest maximum 24-hour 98th percentile visibility impact value to be 0.28 deciviews at TRNP and 0.23 deciviews at LWA. Based upon the refined analysis and the reassessment analysis, Heskett Unit 2 is exempt from the BART requirements.

7.4 Determination of BART Requirements for Subject-to-BART Sources

7.4.1 Company BART Analyses

The Department met individually with the seven subject-to-BART sources in December 2005 and requested they complete and submit BART analyses within nine months of the notification letters dated November 30, 2005 or by September 1, 2006. The nine month time was required by NDAC 33-15-25-02.1. This was agreed to by the seven sources. They were required to address BART for sulfur dioxide, nitrogen oxides, fine particulates and condensable particulates.

The Department also requested the sources follow requirements of Appendix Y to Part 51 - Guidelines for BART Determinations Under the Regional Haze Rule in conducting their analyses.

The seven BART analyses were submitted in final form in late 2007 to early 2008. The final company BART analyses are attached as Appendix C.

7.4.2 Department BART Determinations

The Department has reviewed the company BART determinations and conducted its own determinations for each source. The BART determinations followed the methodology of Section IV of Appendix Y to Part 51 - Guidelines for BART Determinations Under the Regional Haze Rule. This includes identifying the best system of continuous emission reduction taking into account:

1. The available retrofit control options,
2. Any pollution control equipment in use at the source (which affects the availability of options and their impacts),
3. The costs of compliance with control options,
4. The remaining useful life of the facility,
5. The energy and non-air quality environmental impacts of control options, and
6. The visibility impacts analysis.

A case-by-case top down BART analysis using the five basic steps was followed. The five steps are:

STEP 1 - Identify all available retrofit technologies,
STEP 2 - Eliminate technically infeasible options,
STEP 3 - Evaluate control effectiveness of remaining technologies,
STEP 4 - Evaluate impacts and document the results, and
STEP 5 - Evaluate Visibility impacts.

The Department BART determinations are included as Appendix B. Each BART determination includes a source description including the major boiler units and the minor sources such as auxiliary boilers, emergency generators, coal/materials handling dust controls, and coal storage piles; the site characteristics; BART evaluations for the major and minor sources; and a permit to construct description.

As detailed in Appendix B, Department BART determinations included an evaluation of visibility impacts. Single-source modeling was conducted by the companies to determine the degree of visibility improvement associated with various control options for individual units. This modeling was based on EPA guidance for BART determinations[1]. The Department asked companies to provide a 90th percentile 24-hr visibility modeling result (delta-deciview) along with the 98th percentile 24-hr value referenced in the guidance, because the 90th percentile would

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[1] Federal Register, 2005. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, July 6, 2005, Vol.70, No. 128, p. 39103-39172.

be more consistent with the *average of 20% worst days* metric utilized for assessing visibility improvement progress under the Regional Haze Rule.

Single-source visibility modeling as provided by the affected companies was reviewed by the Department, and results related to visibility improvement were considered in Department BART determinations. Because the Department had concerns regarding the viability of single-source modeling in representing actual visibility improvement, however, modeling was given less weight than other factors in the BART determination process.

Though single-source modeling is specified in the BART guidance for determining degree of visibility improvement, it is clear that this modeling overstates the real single-source visibility impact, given the complexity of multiple-source emissions and chemistry actually affecting visibility impairment in Class I areas. As suggested by the logarithmic relationship between deciview and light extinction (Section 5.1), an observer's perception of visibility change is affected by the total loading of visibility-affecting species in the atmosphere. The observer's perception of visibility change, due to a reduction (or increase) in visibility-affecting emissions from one source, depends on cumulative visibility impact due to all sources. For example, a unit reduction in visibility-affecting emissions (from one source) will have only half the visual impact on the observer (delta-deciview) if total light extinction is 80 Mm^{-1} compared to the impact if total light extinction is 40 Mm^{-1}. By excluding the impact of all other sources, therefore, single-source modeling is overstating the perceived (delta-deciview) change in visibility. Based on Department experience, single-source modeling results (delta-deciview) tend to be five to seven times larger than results obtained for the same source when it is combined with all other sources in a cumulative analysis.

It is because of this anomaly that the Department has been very cautious in the interpretation of single-source modeling results, and has focused BART determinations on factors other than visibility modeling. In some instances, as discussed in Appendix B, the Department has conducted supplemental cumulative modeling to more realistically assess the visibility impact of emissions reductions associated with optional control strategies for individual sources. Cumulative modeling is consistent with the procedure for determining status with respect to *uniform rate of progress* goals, which is discussed in Section 8.

BART determinations were made for sulfur dioxide, nitrogen oxides, filterable particulate matter, and condensable particulate matter for all seven sources. A summary of the BART determinations for the main boilers by pollutant follows.

Sulfur Dioxide

Three of the seven sources have existing sulfur dioxide removal equipment. Great River Energy Coal Creek Station Unit 1and Unit 2 and Minnkota Power Cooperative Milton R. Young Station Unit 2 are equipped with wet limestone scrubbers. The existing scrubbers at the Coal Creek Station employ a bypass for flue gas heat and achieve a 68 percent sulfur dioxide reduction. The lime/fly ash wet scrubber at Milton R. Young Unit 2 achieves a 65 percent sulfur dioxide reduction.

Great River Energy Coal Creek Station Unit 1 and Unit 2 - The BART selected by the Department for Unit 1 and Unit 2 is a 95 percent reduction efficiency or a limit of 0.15 pounds per million Btu of heat input on a 30-day rolling average basis to be achieved by modifying the existing wet scrubbers and the adding of a new coal dryer serving both units. Unit 1 and Unit 2 emissions may be averaged provided the average does not exceed the limit.

Minnkota Power Cooperative Milton R. Young Station Unit 2 - The BART for sulfur dioxide selected by the Department for Unit 2 is a 95 percent reduction efficiency or limit of 0.15 pounds per million Btu of heat input on a 30-day rolling average basis to be achieved by modifying the existing wet scrubber. The Consent Decree for Minnkota requires a minimum of 90 percent reduction of sulfur dioxide at Unit 2. The 90 percent reduction requirement will apply when Minnkota chooses to comply with the 0.15 lb/10^6 Btu limit. The 90 percent reduction requirement is included in the BART permit.

Minnkota Power Cooperative Milton R. Young Station Unit 1 - Unit 1 has no existing sulfur dioxide removal equipment. The BART selected by the Department for Unit 1 is a 95 percent reduction efficiency on a 30-day rolling average basis to be achieved by the installation of a new wet scrubber. The EPA/State Consent Decree states that if Minnkota installs a wet scrubber, they must comply with a 95 percent reduction requirement with no alternative pounds per million Btu of heat input limit.

Basin Electric Power Cooperative Leland Olds Station Unit 1 and Unit 2 - Unit 1 and Unit 2 have no existing sulfur dioxide removal equipment. The BART selected by the Department for Unit 1 and for Unit 2 is a 95 percent reduction efficiency or a limit of 0.15 pounds per million Btu of heat input on a 30-day rolling average basis to be achieved by the installation of new wet scrubbing system.

Great River Energy Stanton Station Unit 1 - Unit 1 has no existing sulfur dioxide removal equipment. Unit 1 burns either lignite coal or subbituminous coal. Because these coals have different average sulfur contents, Btu contents and chemical characteristics, the Department will issue BART limits appropriate to each coal. The BART selected by the Department for Unit 1 is a 90 percent reduction on a 30-day rolling average basis burning either coal or a limit of 0.24 pounds per million Btu of heat input on a 30-day rolling average basis when burning only lignite coal, a limit of 0.16 pounds per million Btu of heat input on a 30-day rolling average basis when burning subbituminous coal, and weighted average emission limit when burning a combination of lignite and subbituminous coal.

The sulfur dioxide emissions before and after BART control, the BART controls, and the sulfur dioxide emission limits for each of the seven sources are summarized in Table 7.3.

Table 7.3
BART-Level Emissions Reductions From the 2000-2004 Sulfur Dioxide Average

Source and Unit	2000-2004 Average Emissions Tons per Year	Baseline Level of Control % Reduction	BART Level of Control % Reduction*	Control Device	Emissions after Controls Tons per Year**	Emission Reduction Tons per Year**	Emission Limit
Basin Electric Power Cooperative Leland Olds Station Unit 1	16,666	0%	95%	New Wet Scrubber	1,376	15,290	95% reduction or 0.15 lb/10^6 Btu 30 day rolling average
Basin Electric Power Cooperative Leland Olds Station Unit 2	30,828	0%	95%	New Wet Scrubber	2,530	28,298	95% reduction or 0.15 lb/10^6 Btu 30 day rolling average
Great River Energy Coal Creek Station Unit 1	14,086	68%	95%	Modified Existing Wet Scrubber and Coal Dryer	3,781	10,305	95% reduction or 0.15 lb/10^6 Btu 30 day rolling average
Great River Energy Coal Creek Station Unit 2	12,407	68%	95%	Modified Existing Wet Scrubber and Coal Dryer	3,621	8,786	95% reduction or 0.15 lb/10^6 Btu 30 day rolling average
Great River Energy Stanton Station Unit 1	8,312	0%	90%	New Spray Dryer and Fabric Filter	1,179	7,133	90% reduction or 0.24 lb/10^6 Btu (lignite) or 0.16 lb/10^6 Btu (PRB) 30 day rolling average
Minnkota Power Cooperative Milton R. Young Station Unit 1	20,148	0%	95%	New Wet Scrubber	1,007	19,141	95% reduction 30 day rolling average
Minnkota Power Cooperative Milton R. Young Station Unit 2	12,404	65%	95%	Modified Existing Wet Scrubber	2,739	9,665	95% reduction; or 90% reduction and 0.15 lb/10^6 Btu 30 day rolling average
Total	114,851	----	----	----	16,233	98,618	----

*Based on the two year baseline emission rate for BART.
** Based on the average 2000-2004 operating rate and emission rates.

Nitrogen Oxides

There are many different technologies available for controlling nitrogen oxides emissions from coal fired boilers. The technical feasibility for a particular technology is dependent on the type and size of the boiler and the type of coal being combusted. The types of boiler used at the seven BART sources in the state are cyclone (3), tangentially-fired pulverized coal (2), and wall-fired pulverized coal (2). The types of coal burned in the state are lignite coal with varying characteristics from several different mines near the plants and subbituminous coal from the Powder River Basin (PRB) in Wyoming and Montana.

The nitrogen oxides control technologies that are applicable to a particular boiler are listed in the Company BART Analyses in Appendix C and in the Department BART Determinations in Appendix B.

One technology, selective catalytic reduction (SCR), has one of the highest nitrogen oxides removal rates (in the range of 90 percent) and has been commercially installed on many different types of boilers burning different types of coal. However, it has never been installed on any type of boiler burning North Dakota lignite. The only pilot scale testing conducted on North Dakota lignite failed after two months. The seven BART sources determined SCR is not technically feasible for installation on boilers in North Dakota burning lignite coal. The Department agrees that high dust SCR is not technically feasible; however, low dust and tail end SCR are considered technically feasible. A detailed discussion on the technical feasibility of SCR is provided in Appendix B.5. The BART for nitrogen oxides for each source follows:

Basin Electric Power Cooperative Leland Olds Station Unit 1 - This unit is a wall-fired pulverized coal boiler combusting primarily lignite coal (80-100%) and PRB subbituminous coal (20-0%). The existing nitrogen oxides control equipment is low NO_x burners installed in 1995. The BART selected by the Department is a limit of 0.19 pounds per million Btu of heat input on a 30-day rolling average basis. This limit is to be achieved by the installation of selective noncatalytic reduction (SNCR) and basic separated overfire air (SOFA).

Basin Electric Power Cooperative Leland Olds Station Unit 2 - This unit is a cyclone boiler combusting primarily lignite coal (80-100%) and PRB subbituminous coal (20-0%). The unit has no existing nitrogen oxides control equipment. The BART selected by the Department is a limit of 0.35 pounds per million Btu of heat input on a 30-day rolling average basis. This limit is to be achieved by the installation of selective noncatalytic reduction (SNCR) and advanced separated overfire air (ASOFA).

Great River Energy Coal Creek Station Unit 1 and Unit 2 - Unit 1 and Unit 2 are identical tangentially-fired pulverized coal boilers combusting lignite coal. The existing nitrogen oxides control equipment is low NO_x burners (LNB) and separated overfire air (SOFA). The BART selected by the Department for each unit is a limit of 0.17 pounds per million Btu of heat input on a 30-day rolling average basis. This limit is to be achieved by the use of the existing low NO_x burners (LNB) and modified/additional separated overfire air (SOFA).

Great River Energy Stanton Station Unit 1 - Unit 1 is a wall-fired pulverized coal boiler combusting PRB subbituminous coal and lignite coal. The existing nitrogen oxides control equipment is low NO_x burners. The BART selected by the Department is a limit of 0.29 pounds per million Btu of heat input on a 30-day rolling average basis when burning only lignite coal, a limit of 0.23 pounds per million Btu of heat input on a 30-day rolling average basis when burning subbituminous coal, and a weighted average emission limit when burning a combination of lignite and subbituminous coal. These limits are to be achieved by the installation of low NO_x burners (LNB), overfire air (OFA), and selective noncatalytic reduction (SNCR).

Minnkota Power Cooperative Milton R. Young Station Unit 1 and Unit 2 - Unit 1 and Unit 2 are both cyclone boilers burning lignite coal. The units have no existing nitrogen oxides control equipment. The BART selected by the Department for Unit 1 is a limit of 0.36 pounds per million Btu of heat input on a 30-day rolling average basis and for Unit 2 is a limit of 0.35 pounds per million Btu of heat input on a 30-day rolling average basis. These limits will be achieved by the installation of selective noncatalytic reduction (SNCR) and advanced separated overfire air (ASOFA). These limits do not apply during startup. During startup, NO_x emissions from Unit 1 shall not exceed 2070.1 pounds per hour on a 24-hour rolling average basis and 3995.6 pounds per hour from Unit 2 on a 24-hour rolling average basis.

The nitrogen oxides emissions before and after BART control, the BART controls, and the nitrogen oxide emission limits for each of the seven sources are summarized in Table 7.4.

Table 7.4
BART-Level Emissions Reductions From the 2000-2004 Nitrogen Oxides Average

Source and Unit	2000-2004 Average Emissions Tons per Year	Baseline Level of Control % Reduction	BART Level of Control % Reduction*	Control Device	Emissions after Controls Tons per Year**	Emission Reduction Tons per Year**	Emission Limit
Basin Electric Power Cooperative Leland Olds Station Unit 1	2,501	0%	42%	SOFA and SNCR	1,744	757	0.19 lb/10^6 Btu 30 day rolling average
Basin Electric Power Cooperative Leland Olds Station Unit 2	10,422	0%	54.5%	ASOFA and SNCR	5,904	4,518	0.35 lb/10^6 Btu 30 day rolling average
Great River Energy Coal Creek Station Unit 1	5,116	0%	30%	SOFA	4,285	831	0.17 lb/10^6 Btu 30 day rolling average
Great River Energy Coal Creek Station Unit 2	5,391	0%	30%	SOFA	4,104	1,287	0.17 lb/10^6 Btu 30 day rolling average
Great River Energy Stanton Station Unit 1	2,048	0%	45%	LNB, Overfire Air and SNCR	1,425	623	0.29 lb/10^6 Btu lignite coal 0.23 lb/10^6 Btu PRB coal 30 day rolling average
Minnkota Power Cooperative Milton R. Young Station Unit 1	8.665	0%	58.1%	ASOFA and SNCR	3,857	4,808	0.36 lb/10^6 Btu 30 day rolling average
Minnkota Power Cooperative Milton R. Young Station Unit 2	14,705	0%	58.0%	ASOFA and SNCR	6,392	8,313	0.35 lb/10^6 Btu 30 day rolling average
Total	48,848	----	----	----	27,711	21,137	----

*Based on the two year baseline emission rate for BART.
** Based on the average 2000-2004 average operating rate.

Filterable Particulate Matter

Filterable particulate matter is solid and liquid (non-condensable) matter that is captured in the front half of EPA test method five, the standard test method for determining particulate emissions from boilers.

The existing control devices for filterable particulate matter on all seven boilers are dry electrostatic precipitators (ESPs) with control efficiencies of 99+ percent. Each unit has an existing particulate emission limit of 0.1 pounds per million Btu of heat input.

Recent test results submitted to the Department show the actual emissions from the seven units average 0.03 to 0.05 pounds per million Btu of heat input with occasional values approaching 0.07 pounds per million Btu of heat input.

Upgrading or replacing existing ESPs could reduce the particulate emission rates to 0.013 to 0.015 pounds per million Btu of heat input. However, the BART analyses conducted by the sources indicate the cost effectiveness in dollars per ton is unreasonable and there is very little benefit to visibility in the federal Class I areas.

The existing particulate emissions from all seven boilers are very low, ranging from 74 tons per year, 2000-2004 average, at Stanton Station Unit 1 to 589 tons per year, 2000-2004 average, at Coal Creek Station Unit 2. The BART screening modeling indicates the maximum visibility impact improvement from reducing actual existing emissions levels of approximately 0.03 pounds per million Btu of heat input to 0.015 pounds per million Btu of heat input at any Class I area from any of the seven sources was 0.037 deciviews 98th percentile or less. Detailed particulate emissions data and modeling visibility impact improvement data for each source can be found in the Department BART determinations in Appendix B.

The Department has determined that the BART for filterable particulate matter for all seven sources is no additional controls and allowable particulate emission rate of 0.1 pounds per million Btu of heat input be reduced to 0.07 pounds per million Btu of heat input for five of the seven units. The Minnkota Power Cooperative Milton R. Young Station Unit 1 and Unit 2 are subject to an EPA/State consent decree for New Source Review violations. The consent decree requires filterable particulate emissions not to exceed 0.030 pounds per million Btu of heat input. Therefore 0.030 pounds per million Btu of heat input will be the BART limit for these two units.

Condensable Particulate Matter (PM_{10})

Condensable particulate matter is made up of both organic and inorganic substances. Organic condensable particulate matter will be made up of organic substances, such as volatile organic compounds, which are in a gaseous state through the air pollution control devices but will eventually turn to a solid or liquid state. The primary inorganic substance expected from the boiler is sulfuric acid mist, with lesser amounts of hydrogen fluoride and ammonium sulfate.

Since sulfuric acid mist is the largest component of condensable particulate matter, controlling it will control most of the condensable particulate matter. The options for controlling sulfuric acid mist are the same options for controlling sulfur dioxide. These include wet and dry scrubbers. Three of the sources have existing wet scrubbers that will be upgraded. Three of the remaining four units will be equipped with new wet scrubbers and one with a dry scrubber/baghouse system. These technologies will achieve greater than 40-60 percent reduction of sulfuric acid mist emissions. Changes that would provide additional reductions are economically infeasible considering the minimal improvement in visibility that could be achieved.

The control of volatile organic compounds at power plants is generally achieved through good combustion practices. The Department is not aware of any BACT determination at a power plant that resulted in any control technology being used. BACT has been found to be good combustion practices which are already in use since it minimizes the amount of fuel to generate electricity.

EPA document AP-42, Compilation of Air Pollutant Emission Factors, indicates the emission rate of condensable particulate matter could be expected to be 0.02 pounds per million Btu. This emission rate is less than the current emissions of filterable particulate matter and the emissions of filterable particulate matter were determined to have a negligible impact on visibility.

Having considered all the factors, the Department has determined that BART for condensable particulate matter is represented by good sulfur dioxide control and good combustion control. Since the primary constituent of condensable particulate matter is sulfuric acid mist which is controlled proportionately to the sulfur dioxide controlled, the BART limit for sulfur dioxide can act as a surrogate for condensable particulate matter along with a requirement for good combustion practices.

BART Modifications Description

A summary description of the BART modifications proposed at each of the seven subject-to-BART sources follows:

Basin Electric Power Cooperative Leland Olds Station Unit 1 and Unit 2 - A wet scrubbing system will be installed to remove sulfur dioxide from the flue gas of each unit. Nitrogen oxides emissions from Unit 1 will be controlled by basic separated overfire air (SOFA) and selective noncatalytic reduction (SNCR). Nitrogen oxides from Unit 2 will be controlled by advanced separated overfire air (ASOFA) and selective noncatalytic reduction (SNCR).

Great River Energy Coal Creek Station Unit 1 and Unit 2 - Sulfur dioxide emissions will be controlled by the installation of a coal drying system; the installation of trays or new liquid distribution rings (LDRs) and high flow mist eliminators (MEs) in the existing wet scrubbers; the elimination of the bypass of the wet scrubbers and the modification of the existing stacks for wet operating conditions. Nitrogen oxides emissions will be controlled by the installation of an additional level of separated overfire air (SOFA) in each boiler.

Great River Energy Stanton Station Unit 1 - Sulfur dioxide emissions will be controlled by the installation of a spray dryer and fabric filter system (dry scrubber). Nitrogen oxides emissions will be controlled by the installation of low-NO_x burners plus overfire air plus selective noncatalytic reduction (SNCR) technology.

Minnkota Power Cooperative Milton R. Young Station Unit 1 and Unit 2 - Sulfur dioxide emissions will be controlled by the installation of a new wet scrubber on Unit 1 and by upgrading the existing wet scrubber on Unit 2. Nitrogen oxides emissions from both units will be reduced using advanced separated overfire air (ASOFA) and selective noncatalytic reduction (SNCR).

The control technology to be installed on each source unit is described in more detail in the company BART determinations in Appendix C and the Department BART determinations in Appendix B.

7.4.3 Summary of Emission Reductions

BART for the BART-eligible sources in the State of North Dakota that are significant contributors to visibility impairment in a Class I area are shown in Tables 7.3 and 7.4 for sulfur dioxide and nitrogen oxides. BART is the emission limit for each pollutant based on the degree of reduction achievable through the application of the best system of continuous emission reduction, taking into consideration the technology available, the costs of compliance, the energy and the non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. The Department BART determination analysis for each BART-eligible source is included in Appendix B.

The application of BART to all BART-eligible sources provides an estimated emission reduction from the 2000-2004 average baseline emissions of 98,618 tons per year of sulfur dioxide and 21,137 tons per year of nitrogen oxides. These reductions are shown in Tables 7.3 and 7.4 for each source and in total.

BART for each BART-eligible source was determined using the methodology in the Guidelines for BART Determinations Under the Regional Haze Rule. 40 CFR Part 51, Appendix Y.

7.5 Air Pollution Control Permit to Construct for Subject-to-BART Sources

Section V of Appendix Y to Part 51 - Guidelines for BART Determinations Under the Regional Haze Rule requires the State establish enforceable emission limits that reflect the BART determinations and require compliance within a given period of time. In particular, the State must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. The Department worked closely with the staff of the EPA Region 8 Air Programs office to ensure the permit template contents and language were acceptable to meet the requirements of Section V.

The emission limits, monitoring, recordkeeping and reporting requirements specified in the Department BART determination for each subject-to-BART source are included in a federally enforceable Air Pollution Control Permit to Construct that will be issued by the Department to the owner/operator of the facility before the SIP is submitted to EPA. The permits are issued by the Department under existing authority pursuant to NDAC Chapter 33-15-14 and Chapter 33-15-25.

There are four Permits to Construct, one for both Unit 1 and Unit 2 at the Basin Electric Power Cooperative Leland Olds Station, one for both Unit 1 and Unit 2 at the Great River Energy Coal Creek Station, one for Unit 1 at the Great River Energy Stanton Station, and one for Unit 1 and Unit 2 at the Minnkota Power Cooperative Milton R. Young Station. The four permits are included in Appendix D.

7.5.1 Enforceable Emission Limits

Enforceable emission limits that reflect the BART determinations are included in each Air Pollution Control Permit to Construct as permit condition II.A.1. Conditions for sulfur dioxide are in II.A.1.a., nitrogen oxides in II.A.1.b., and filterable (non-condensable) particulate matter in II.A.1.c. Each Air Pollution Control Permit to Construct is incorporated as a part of this Regional Haze SIP.

As required by Section V of Appendix Y, the limitations for sulfur dioxide and nitrogen oxides specify an averaging time of a 30-day rolling average, and contain a definition of “boiler operating day” which is any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

7.5.2 Monitoring, Recordkeeping, and Reporting Requirements

Monitoring, recordkeeping, and reporting requirements have been included in each Air Pollution Control Permit to Construct. The owner/operator is required to conduct monitoring, recordkeeping and reporting as required by NDAC Chapter 33-15-14-06, Title V Permit to Operate and NDAC 33-15-21, Acid Rain Program (40 CFR 72, 75, and 76). The conditions in each source’s existing Title V operating permit will be revised as necessary to cover the new BART emissions limits as they are included these permits. Monitoring requirements are found in permit condition II. A. 4, recordkeeping requirements are found in II.A.5, and reporting requirements are found in II. A. 6.

7.5.3 Operating and Maintenance Requirements

Item 51.308(e)(1)(v) of the EPA BART rule requires that each source subject to BART maintain the control equipment and establish procedures to ensure such equipment is properly operated. This requirement is also included in the state rules at NDAC 33-15-25-02.3.

Each Air Pollution Control Permit to Construct has condition II. B. 4 which requires that the owner shall at all times, including periods of startup, shutdown, and malfunction, maintain and operate the BART unit(s) and all other emission units including associated air pollution equipment and fugitive dust suppression operations in a manner consistent with good air pollution control practices for minimizing emissions.

7.5.4 Compliance Date

The Department is requiring that each source subject to BART shall install and operate BART as expeditiously as practicable but in no event later than five years after approval of the implementation plan revision by EPA as required by Section V of Appendix Y to 40 CFR Part 51 and Item 51.308(e)(1)(iv) of the EPA BART Rule. This requirement is also included in the State rule as NDAC 33-15-25-02.2.

This requirement is included as Condition II.A.2 in the Air Pollution Control Permit to Construct issued for each source subject to BART. When this implementation plan is approved by EPA, a Title V operating permit will be issued for each source incorporating the conditions of the Permits to Construct.

8. Visibility Modeling

8.1 Introduction

Computer modeling to determine progress with respect to visibility improvement goals was conducted in support of this North Dakota Regional Haze SIP. The Regional Haze Rule[2] (Rule) specifies that modeling must be applied to demonstrate reasonable progress toward the goal of achieving natural visibility conditions in each PSD Class I area by 2064. As discussed in Section 5.4, the *uniform rate of progress* defines the visibility improvement which would be needed for each planning period to achieve natural visibility conditions by 2064. The first planning period begins at the end of the baseline (2004) and terminates in 2018. The visibility improvement progress needed by 2018 (or 2018 target) is determined by interpolating from the uniform rate of progress glide path, as illustrated in Figure 5.5.

Modeling analyses completed in support of the North Dakota SIP and discussed here address the first planning period, and the 2018 target. These analyses assume that the 2018 goal for each Class I area is the uniform rate of progress (glide path) target for 2018. The Regional Haze Rule, however, gives states the option of establishing *reasonable progress goals* which are independent of the uniform rate of progress. The reasonable progress goals established by a state for 2018 will not necessarily equal the uniform rate of progress target for 2018 (see Section 10).

To demonstrate reasonable progress with respect to visibility goals for the first planning period, the Rule specifies that visibility on the 20 percent worst (most impaired) days must improve, while visibility on the 20 percent best (least impaired) days must not deteriorate, between the base period (2000-2004) and 2018. Computer modeling was used to project future visibility, accounting for proposed BART controls and other visibility-affecting emissions increases/decreases. Modeling was applied in a relative sense. Baseline and projected future emission inventories were modeled to develop a future/baseline prediction ratio (relative response factor). The ratio was then applied to baseline monitoring data for visibility-affecting species to project future visibility.

The Western Regional Air Partnership (WRAP) regional planning organization has established a Regional Modeling Center (RMC) to assist member states, including North Dakota, with modeling to determine status with respect to the 2018 goals. The RMC has applied a chemically sophisticated grid model (CMAQ), on a regional basis, to project future visibility in Class I areas in the WRAP region[3]. The RMC has developed comprehensive base period and future period visibility-affecting emission inventories to use with CMAQ, and has performed numerous studies

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[2] 40 CFR 51.308

[3] Tonnesen, G., R. Morris, Z. Adelman, et. al., 2006. 2006 Report for the Western Regional Air Partnership (WRAP) Regional Modeling Center (RMC). Western Regional Air Partnership, Denver, CO 80202.

using base period model and monitoring data to evaluate CMAQ performance[4]. Finally, the RMC has applied CMAQ to project 2018 visibility for each Class I area in the WRAP region, including the Theodore Roosevelt National Park and Lostwood Wilderness Class I areas in North Dakota.

To supplement work done by the WRAP RMC, the North Dakota Department of Health (NDDoH) has conducted further modeling analysis to address 2018 visibility goals for North Dakota Class I areas. Though the NDDoH utilized WRAP RMC results in assessing progress with respect to visibility goals in North Dakota Class I areas, the NDDoH also recognized it would have to develop further modeling capability for visibility projection in order to address weight of evidence issues not included in WRAP modeling, such as discounting the impact of international sources. In addition, the NDDoH had concerns regarding the spatial resolution of the WRAP CMAQ simulations, particularly for large point sources.

The RMC is applying CMAQ on a national basis using a grid resolution of 36 km, with no plume-in-grid treatment. This means that emissions from point sources are immediately mixed uniformly throughout a 36 km (square) grid cell volume, which may overstate the dilution of the plume, and the speed of chemical reactions for species contained in the plume. This may be problematic, especially for sources located relatively near Class I areas. Consequently, the contribution of visibility-affecting species from these sources may be misrepresented for both base period and future period modeling. This limitation in treatment of point sources is recognized in CMAQ documentation[5].

The NDDoH utilized a hybrid modeling approach for determining status with respect to the visibility goals. This approach involved nesting the local NDDoH CALPUFF domain within the WRAP National CMAQ domain, and applying the Lagrangian CALPUFF model in a retrospective sense to more realistically define plume geometry for local point sources. To implement the nesting, hourly output concentrations from WRAP CMAQ were used to set hourly boundary conditions for CALPUFF. The use of CMAQ output to set CALPUFF boundary conditions has been suggested by Escoffier-Czaja and Scire[6]. Location of the NDDoH CALPUFF domain within the National CMAQ domain is illustrated in Figure 8.1.

Given limitations in the CALPUFF chemistry for other species, the NDDoH hybrid modeling system was used for simulation of SO_2-SO_4-NO_X-HNO_3-NO_3 chemistry and transport, and thus sulfate (SO_4) and nitrate (NO_3) predictions, only. Results for all other visibility-affecting

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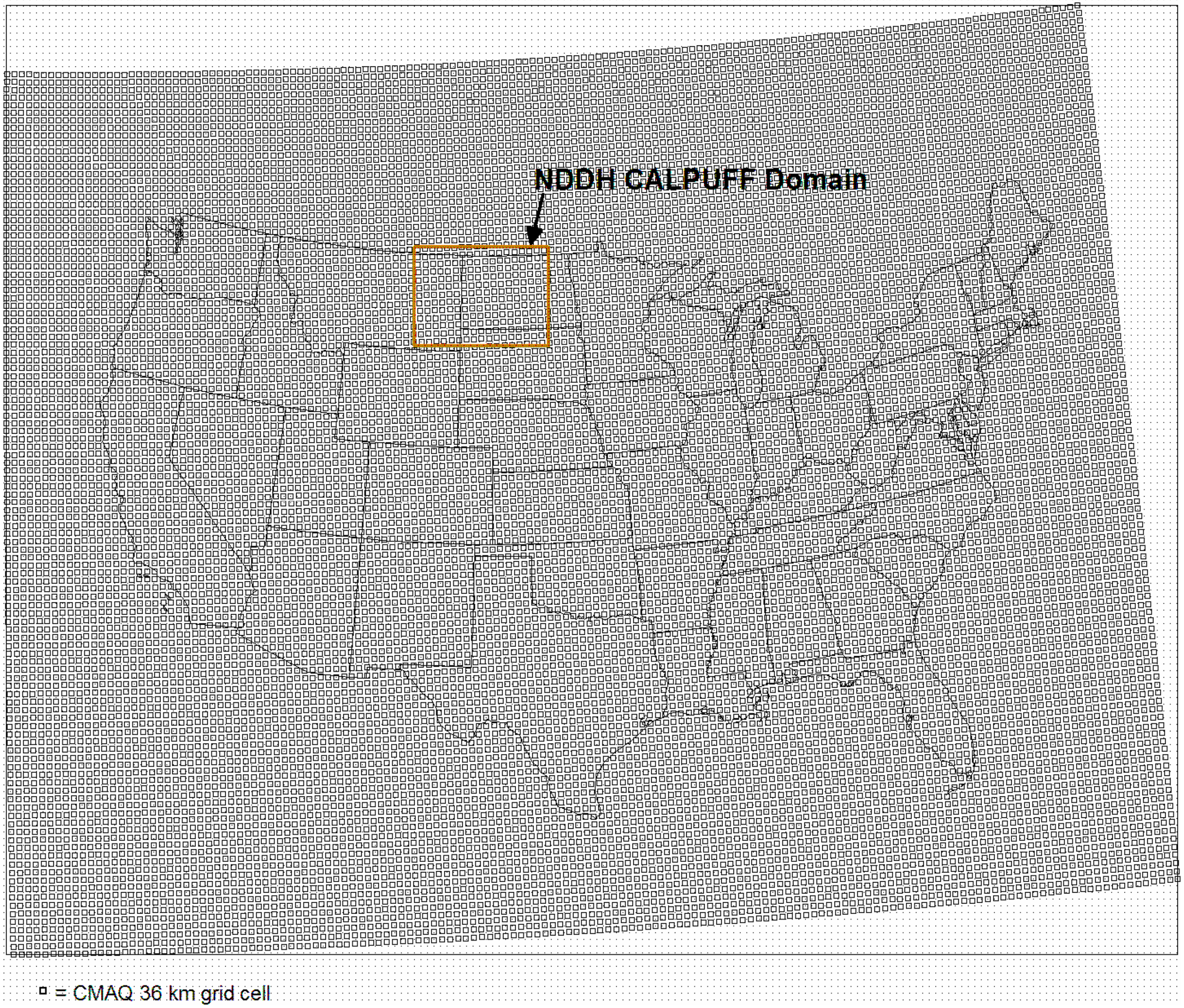
[4] See WRAP RMC web site at http://pah.cert.ucr.edu/aqm/308/

[5] EPA, 1999. Science Algorithms of the EPA Models-3 Community Multiscale Air Quality (CMAQ) Modeling System. Office of Research and Development, Washington DC 20460.

[6] Escoffier-Czaja, C., and J. Scire, 2005. Comments on the Computation of Nitrate Using the Ammonia Limiting Method in CALPUFF. Appendix A, Draft Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART), VISTAS.

Figure 8.1
WRAP CMAQ Domain and NDDoH CALPUFF Domain



species, including organic carbon mass (OMC), elemental carbon (EC), fine particulate (Soil), and coarse particulate (CM), were obtained directly from the CMAQ output for the grid cell containing each subject Class I area IMPROVE monitor. CMAQ output was combined with CALPUFF results for sulfate and nitrate in order to perform necessary light extinction calculations. In this way, the NDDoH benefits from the sophistication of the RMC approach for other particulate components, which reflect a very small percentage of emissions from the local point sources of concern.

WRAP and NDDoH protocols for modeling visibility progress goals generally adhere to EPA *Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone*, *$PM_{2.5}$, and Regional Haze*[7]. An evaluation of modeling system performance was conducted first. Then baseline (2000-2004) and future (2018) emission scenarios were modeled in order to develop relative response factors (RRFs). Finally, RRFs were applied to baseline IMPROVE monitoring data to project future visibility in North Dakota Class I areas.

Class I areas in North Dakota include the three units of Theodore Roosevelt National Park (TRNP), and the Lostwood Wilderness Area (LWA). IMPROVE monitors are located at the TRNP South Unit and LWA, only. Therefore, these two Class I areas were the focus of the modeling analyses. Locations of North Dakota Class I areas, IMPROVE monitor sites, and larger visibility-affecting sources are depicted in Figure 8.2.

While this presentation (Section 8) addresses both WRAP and NDDoH visibility modeling analyses, focus is on the NDDoH modeling as WRAP procedures are extensively documented elsewhere. The WRAP protocol for regional haze visibility modeling is summarized in *2006 Report for the Western Regional Air Partnership (WRAP) Regional Modeling Center (RMC)*[8]. The NDDoH protocol for regional haze progress goal modeling is attached as Appendix E to this document.

8.2 Regional Haze Metrics

To address progress in visibility improvement, modeling is used to provide mass concentrations of visibility-affecting species. These concentrations are translated into light extinction using the IMPROVE algorithm. Finally, light extinction is converted to deciviews to accommodate comparison with visibility goals. Use of the deciview metric to assess baseline visibility, natural visibility, and improvement in visibility was discussed in Section 5.

Calculation of light extinction from visibility-affecting aerosol concentrations for the WRAP

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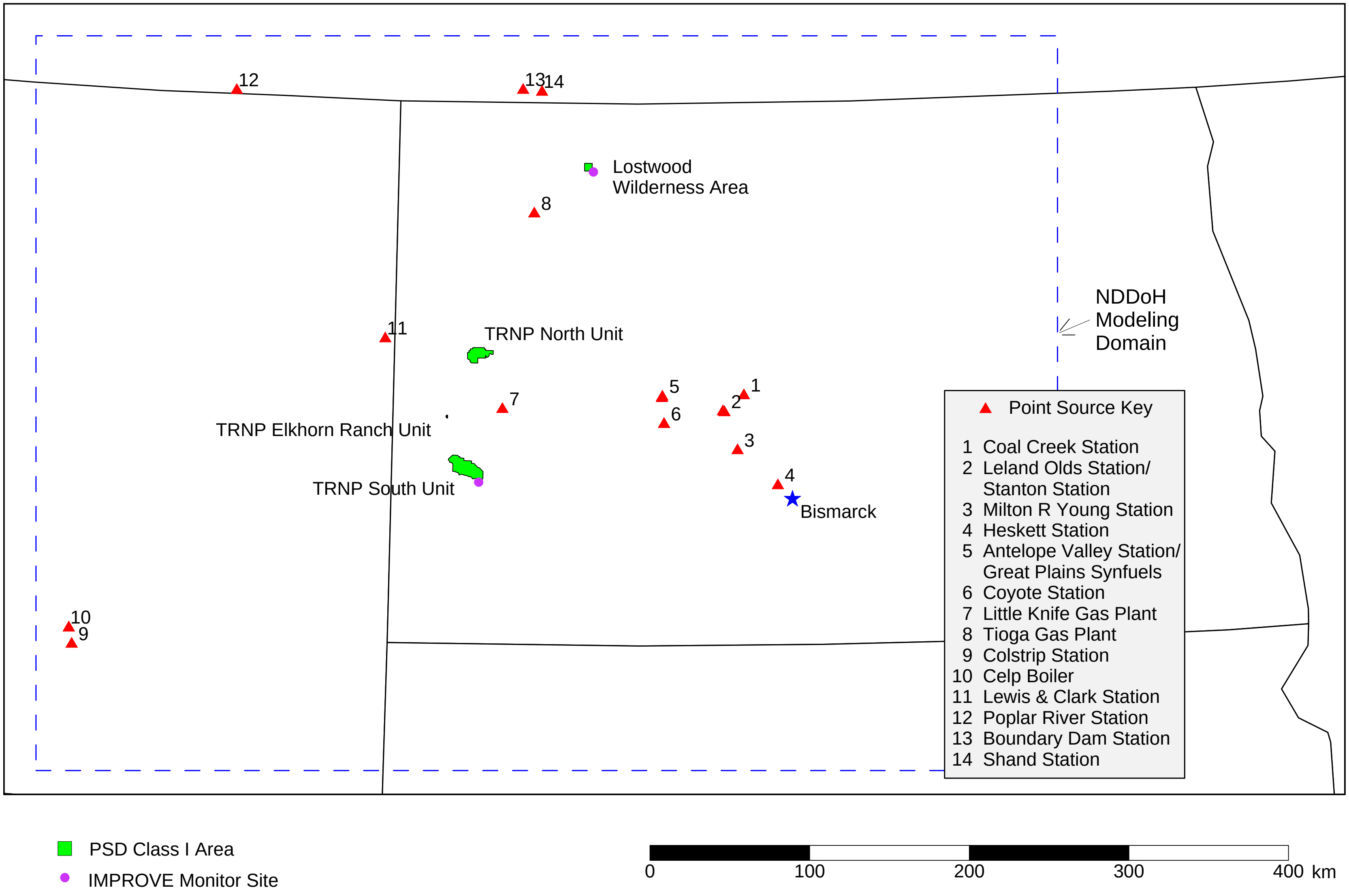
[7] EPA, 2007. Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze. Publication No. EPA 454/B-07-002, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

[8] See supra note 3.

Figure 8.2
Larger Point Sources and PSD Class I Areas



RMC and NDDoH regional haze analyses is based on the "new" IMPROVE algorithm[9]. This new system was seen to reduce bias associated with use of the "old" IMPROVE algorithm, and was adopted as an alternative by the IMPROVE Steering Committee in December 2005. The new algorithm splits ammonium sulfate, ammonium nitrate, and organic mass concentrations into two fractions: small and large. The new algorithm for light extinction is:

$$
\begin{aligned}
b_{ext} = {} & 2.2 \times f_s(RH) \times [\text{small amm. sulfate}] + 4.8 \times f_L(RH) \times [\text{large amm. sulfate}] \\
& + 2.4 \times f_s(RH) \times [\text{small amm. nitrate}] + 5.1 \times f_L(RH) \times [\text{large amm. nitrate}] \\
& + 2.8 \times [\text{small organic mass}] + 6.1 \times [\text{large organic mass}] \\
& + 10.0 \times [\text{elemental carbon}] \\
& + 1.0 \times [\text{fine soil}] \\
& + 1.7 \times f_{ss}(RH) \times [\text{sea salt}] \\
& + 0.6 \times [\text{coarse mass}] \\
& + \text{Rayleigh scattering (site-specific)} \\
& + 0.33 \times [NO_2\ (\text{ppb})]
\end{aligned}
$$

where

b_{ext} = light extinction in units of inverse megameters (Mm^{-1}),
$f_s(RH)$ = function of relative humidity for small size fraction,
$f_L(RH)$ = function of relative humidity for large size fraction,
$f_{ss}(RH)$ = function of relative humidity for sea salt,
all species concentrations (with exception of NO_2) are provided in ug/m^3,
amm. sulfate / amm. nitrate means ammonium sulfate / ammonium nitrate.

Apportionment of total sulfate concentrations into small and large size fractions is defined:

$$[\text{large amm. sulfate}] = \frac{[\text{total amm. sulfate}]^2}{20\ ug/m^3}, \text{ for } [\text{total amm. sulfate}] < 20\ ug/m^3$$

$$[\text{large amm. sulfate}] = [\text{total amm. sulfate}], \text{ for } [\text{total amm. sulfate}] \geq 20\ ug/m^3$$

$$[\text{small amm. sulfate}] = [\text{total amm. sulfate}] - [\text{large amm. sulfate}]$$

Similar equations are used to apportion total ammonium nitrate and total organic matter concentrations into small and large size fractions.

A solution for the NO_2 term in the extinction algorithm is problematic as the IMPROVE network does not include NO_2 sampling. However, WRAP and the NDDoH have determined that the NO_2 term has very little impact on total light extinction. A review of observational NO_2 data from an NDDoH monitoring site in Theodore Roosevelt National Park revealed that readings were less than the minimum detectable level of 2.0 ppb more than 80% of the time in 2002.

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[9] IMPROVE, 2005. New IMPROVE algorithm for estimating light extinction approved for use. The IMPROVE Newsletter, Volume 14, Number 4. Air Resource Specialists, Inc., Fort Collins, CO 80525.

Accordingly, both WRAP and the NDDoH have omitted the NO_2 term in analyses for future visibility.

The IMPROVE network does include sampling for sea salt. But monitored values are very low in North Dakota Class I areas. Further, the WRAP RMC found that the CMAQ model was not a reliable predictor for sea salt. Therefore, WRAP has omitted sea salt as a modeled species, and both WRAP and the NDDoH are assuming a relative response factor of 1.0.

Light extinction is converted to deciview using the following relationship:

$$dv = 10 \times \ln(b_{ext} / 10)$$

where

dv = deciview,
b_{ext} = light extinction in units of inverse megameters (Mm^{-1}).

Visibility goals are generally expressed as deciviews.

8.3 Projection of Future Visibility

Methodology for WRAP and NDDoH projection of future visibility is based on EPA *Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze*[10]. The guidance proposes a relative modeling approach to project future (2018) visibility, in order to determine compliance status with respect to visibility goals at Class I areas. Implementation of the relative modeling approach relies on relative response factors (RRFs) which represent the modeled impact of the future (visibility affecting) source emissions inventory divided by the modeled impact of the baseline source inventory at Class I areas. These RRFs are applied to baseline IMPROVE monitoring data to project future visibility for each Class I area.

Per the Regional Haze Rule, projection of future visibility is needed for the 20% worst and 20% best visibility days at each Class I area. The 20% worst days and 20% best days are determined from Class I area IMPROVE monitoring data for each year for the 5-year baseline period 2000-2004. Because IMPROVE sampling occurs once every three days, the maximum number of monitored days per year would be 122, and the maximum number of 20% worst or best days per year would be 24.

According to the EPA guidance, worst-day RRFs are developed by comparing the future average predicted mass concentration for 20% worst days to the baseline average predicted mass concentration for 20% worst days, for each visibility affecting species. The 20% worst modeled days are temporally consistent with the worst monitored days, which requires that modeling is

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[10] See supra note 7.

based on 2000-2004 meteorological data (i.e., meteorological data used for modeling represents the same period as baseline monitoring), if all five years are modeled[11]. For each visibility affecting species (SO_4, NO_3, OMC, EC, Soil, CM), a single RRF is developed for each Class I area. The RRF is calculated by dividing the predicted future concentration averaged over all worst days by the predicted baseline concentration averaged over all worst days. Then, future concentrations for each species are projected by multiplying the RRF by the observed species concentration on each of the baseline worst days. The same process is used to develop best-day RRFs, and project best-day concentrations.

The RRF approach can be expressed mathematically:

$$X^{i,j}_{of} = X^{i,j}_{ob}\,(RRF^{i}) = X^{i,j}_{ob}\,(\overline{X}^{i}_{pf}/\overline{X}^{i}_{pb})$$

where

$X^{i,j}_{of}$ represents projected observed future concentration for species i on day j (each of 20% worst days for each baseline year),

$X^{i,j}_{ob}$ represents **o**bserved baseline (IMPROVE data) concentration for species i on day j (each of 20% worst days for each baseline year),

$\overline{X}^{i}_{pf}$ represents average predicted future concentration for species i (average of 20% worst days),

$\overline{X}^{i}_{pb}$ represents average predicted baseline concentration for species i (average of 20% worst days),

RRF^{i} represents the relative response factor for species i.

The same system is applied to project 20% best day concentrations.

The set of projected future worst-day concentrations (including all species above) is converted to light extinction through application of the IMPROVE equation (Section 8.2) for each day, then daily light extinction is converted to deciview for each day. Finally, projected daily deciview is averaged over all worst-case days for each year, then averaged over all years to produce the single future value needed to address visibility goals for each Class I area. This procedure is repeated for projected future best-day concentrations.

Both the WRAP RMC and the NDDoH followed this general methodology for projecting future visibility-affecting species concentrations, and subsequently, worst day and best day future deciview.

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[11] Because of the resource demands of the CMAQ model, the WRAP RMC limited their visibility modeling analysis to the use of 2002 meteorology, only. Consequently, the NDDoH analysis was likewise limited to 2002 meteorology. The RRFs developed from modeling based on 2002 meteorology were then applied to all five years of monitoring data for future projection.

8.4 WRAP Visibility Modeling Methodology

The Western Regional Air Partnership (WRAP) is a Regional Planning Organization (RPO) representing the western states, including North Dakota. WRAP is one of five RPOs which together cover all states in the country. These RPOs are responsible for assisting states in the development of State Implementation Plans (SIPs) and Tribal Implementation Plans (TIPs) to address requirements of the Regional Haze Rule, and to assist with other air quality issues.

WRAP has established a Regional Modeling Center (RMC) to conduct visibility modeling and provide technical modeling guidance to support regional haze SIPs and TIPs for western states. This RMC reflects a consortium of technical expertise from University of California Riverside, University of North Carolina, and ENVIRON International Corporation. With funding from the western states, the RMC conducted an extensive modeling effort to project future visibility for each Class I area in the western United States, including the Class I areas in North Dakota.

WRAP RMC visibility modeling methodology is largely described in *Final Report for the Western Regional Air Partnership (WRAP) Regional Modeling Center (RMC) for the Project Period March 1, 2004 through February 28, 2005*[12] and *2006 Report for the Western Regional Air Partnership (WRAP) Regional Modeling Center (RMC)*[13]. Specific documentation for most recent baseline and future modeling cases is provided in *2002 Planning Simulation Version D*[14] and *2018 Preliminary Reasonable Progress Simulation Version A*[15], respectively. These and other resources can be obtained from the WRAP web site at http://pah.cert.ucr.edu/rmc.

Primary modeling tools used by the WRAP RMC include:

- the Fifth-Generation Pennsylvania State University/National Center for Atmospheric Research (PSU/NCAR) Mesoscale Model (MM5) meteorological modeling system,
- the Sparse Matrix Operator Kernel Emissions (SMOKE) emissions modeling system,
- the Community Multiscale Air Quality (CMAQ) air quality modeling system, and

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[12] Tonnesen, G., R. Morris, Z. Adelman, et. al., 2005. Final Report for the Western Regional Air Partnership (WRAP) Regional Modeling Center (RMC) for the Project Period March 1, 2004, through February 28, 2005. Western Regional Air Partnership, Denver, CO 80202.

[13] See supra note 3.

[14] WRAP, 2008. 2002 Planning Simulation Version D. Western Regional Air Partnership, Denver, CO 80202.

[15] WRAP, 2008. 2018 Preliminary Reasonable Progress Simulation Version A. Western Regional Air Partnership, Denver, CO 80202.

- the PM Source Apportionment Technology extension (PSAT) of the Comprehensive Air Quality Model (CAMx).

The modeling domain established by the RMC includes all of the contiguous United States, and parts of Mexico and Canada (see Figure 8.1). The RMC used the MM5 model to develop the meteorological fields necessary for execution of CMAQ and PSAT within the domain. Grid cell size was specified as 36 kilometers in the horizontal direction, and vertical structure was defined by 19 layers of varying depth. Because of resource and time constraints (primarily related to CMAQ and PSAT), preparation of meteorological data was limited to Year 2002 of the baseline period.

Emissions inventory development for WRAP RMC visibility modeling relied primarily on the EPA National Emissions Inventory (NEI), and information collected from states and other RPOs. County emissions data for visibility affecting species, as well as all other species necessary to execute the chemistry in CMAQ and PSAT, were collected and processed into the format required by SMOKE. Then SMOKE was executed to apportion emissions to the appropriate grid cell and vertical layer within the modeling domain, on an hourly basis. Where appropriate, temporal emissions patterns were applied during the execution of SMOKE. All source categories shown in Table 8.1 were accounted for in the processing of emissions data in SMOKE.

Table 8.1
WRAP RMC Source Categories

Source Category	
Stationary Point Sources Stationary Area Sources On-Road Mobile Off-Road Mobile Biogenic Oil & Gas Offshore Platforms Offshore Shipping	Road Dust Fugitive Dust Wind-Blown Dust Wild Fires Natural Fires Anthropogenic Fires Agricultural Ammonia

The WRAP RMC has included three basic emissions cases in their visibility modeling, for performance evaluation and the development of relative response factors.

- Case BASE02b reflects year 2002 emissions which are concurrent with the year 2002 meteorology. WRAP used this case for performance evaluations.

- Case PLAN02d reflects a composite interpretation of emissions for the 2000-2004 period. WRAP used this case for the baseline period to generate relative response factors.

- Case PRP18a (Preliminary Reasonable Progress 2018 Scenario A) reflects projected year 2018 emissions. Case PRP18a represents base period emissions projected to 2018, accounting for estimates of the effect of BART controls, and assuming other growth and control factors. WRAP used this case for the future period to generate relative response factors.

Note that WRAP recently completed modeling for an updated Case PRP18b future emissions scenario, as discussed in Section 6. Because NDDoH visibility modeling was initiated and largely completed well before the WRAP PRP18b emissions inventory and modeling results were available, however, Case PRP18b is not included in the visibility modeling results discussed in this SIP. For North Dakota sources, Case PRP18b reflects only a slight decrease in emissions relative to Case PRP18a. Therefore, results and conclusions of the visibility analyses reported here would not be meaningfully changed with the use of Case PRP18b emissions.

To define boundary conditions for the WRAP modeling domain, species concentrations for the perimeter of the domain were derived from the global GEOS-CHEM model.

Before beginning production modeling for development of RRFs, the WRAP RMC conducted extensive performance evaluations for both CMAQ and CAMx/PSAT. These performance evaluations were used to refine emissions inventories and other input conditions. CMAQ was subsequently applied to baseline (PLAN02d) and future (PRP18a) emissions inventories to generate RRFs and project future visibility in Class I areas. Development of RRFs and projection of future visibility followed default EPA methodology[16], as outlined in Section 8.3. Finally, PSAT was applied to assess source and species attribution for projected visibility impacts.

Results of WRAP RMC modeling for North Dakota Class I areas are reviewed in Section 8.6.2.

8.5 NDDoH Visibility Modeling Methodology

In support of the North Dakota Regional Haze SIP, the North Dakota Department of Health (NDDoH) conducted refined progress goal visibility modeling to supplement and update the modeling conducted by WRAP RMC. The NDDoH developed an in-house modeling capability to address weight of evidence issues, and concerns regarding the resolution of the WRAP CMAQ simulations, particularly as applied to large point sources located near Class I areas. As discussed in Section 8.4, WRAP RMC modeling focused on the default EPA methodology for regional haze[17], and did not address weight of evidence issues such as discounting the effect of

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[16] See supra note 7.

[17] See supra note 7.

international source emissions. The RMC applied CMAQ on a regional basis using a grid resolution of 36 km, with no plume-in-grid treatment.

The NDDoH regional haze modeling constitutes a hybrid approach as it involved nesting the local NDDoH CALPUFF domain within the WRAP National CMAQ domain, and applying the Lagrangian CALPUFF model in a retrospective sense to more realistically define plume-receptor geometry for local point sources. To implement the nesting, hourly output concentrations from WRAP CMAQ modeling were used to set hourly boundary conditions for CALPUFF. CMAQ output used to set CALPUFF boundary conditions reflects corresponding WRAP cases for baseline and future emission inventories.

The hybrid modeling approach was used for simulation of SO_2-SO_4-NO_X-HNO_3-NO_3 chemistry and transport and, thus, sulfate and nitrate predictions, only. RRFs and projected future concentrations for other visibility affecting species, including organic carbon (OMC), elemental carbon (EC), fine particulate (Soil), and coarse mass (CM), were taken directly from the WRAP RMC results for North Dakota Class I areas. The deferral to WRAP CMAQ results for these species is based on limitations in the CALPUFF chemistry, and the fact that larger point sources located relatively near North Dakota Class I areas, where CMAQ resolution is a concern, are primarily emitters of SO_2 and NO_X. Further, IMPROVE measurements at North Dakota Class I areas indicate that sulfate and nitrate are primary contributors to light extinction on most worst-case days. Individual species contribution to light extinction for worst-case days at Theodore Roosevelt National Park is illustrated in Figure 8.3. Therefore, weight of evidence assessments should be most affected by changes in sulfate and nitrate concentrations.

The NDDoH used the hybrid modeling system in a supportive sense to add value to the original WRAP CMAQ modeling results for sulfate and nitrate. The hybrid system was used to adjust WRAP CMAQ results in order to offset coarseness in the CMAQ resolution for large local point sources, and in order to discount the effect of international (Canadian) sources. Procedures for adjusting WRAP CMAQ results are discussed in Section 8.5.6.

For hybrid modeling, the NDDoH used the State's point source inventory for SO_2 and NO_X, and has imported WRAP RMC data for all other source categories (and for point source SO_4 and NO_3) to apportion emissions within the CALPUFF domain. WRAP used the SMOKE emissions model[18] to develop the emissions inventory for CMAQ. The NDDoH has obtained and processed WRAP SMOKE output to define area source emissions for the CALPUFF domain. The CALPUFF area source emissions inventory includes the species SO_2, SO_4, NO_X, and NO_3. In addition, primary SO_4 and NO_3 emissions data were extracted from the SMOKE inventory for point sources, and apportioned to the CALPUFF domain as area sources. WRAP CMAQ source categories included in the CALPUFF emissions inventory are outlined in Table 8.2. Note that WRAP SMOKE output did not contain all four species for some source categories.

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[18] University of North Carolina, 2007. SMOKE User's Manual. The Institute for the Environment, University of North Carolina.

Figure 8.3
IMPROVE 20% Worst Days – TRNP 2000

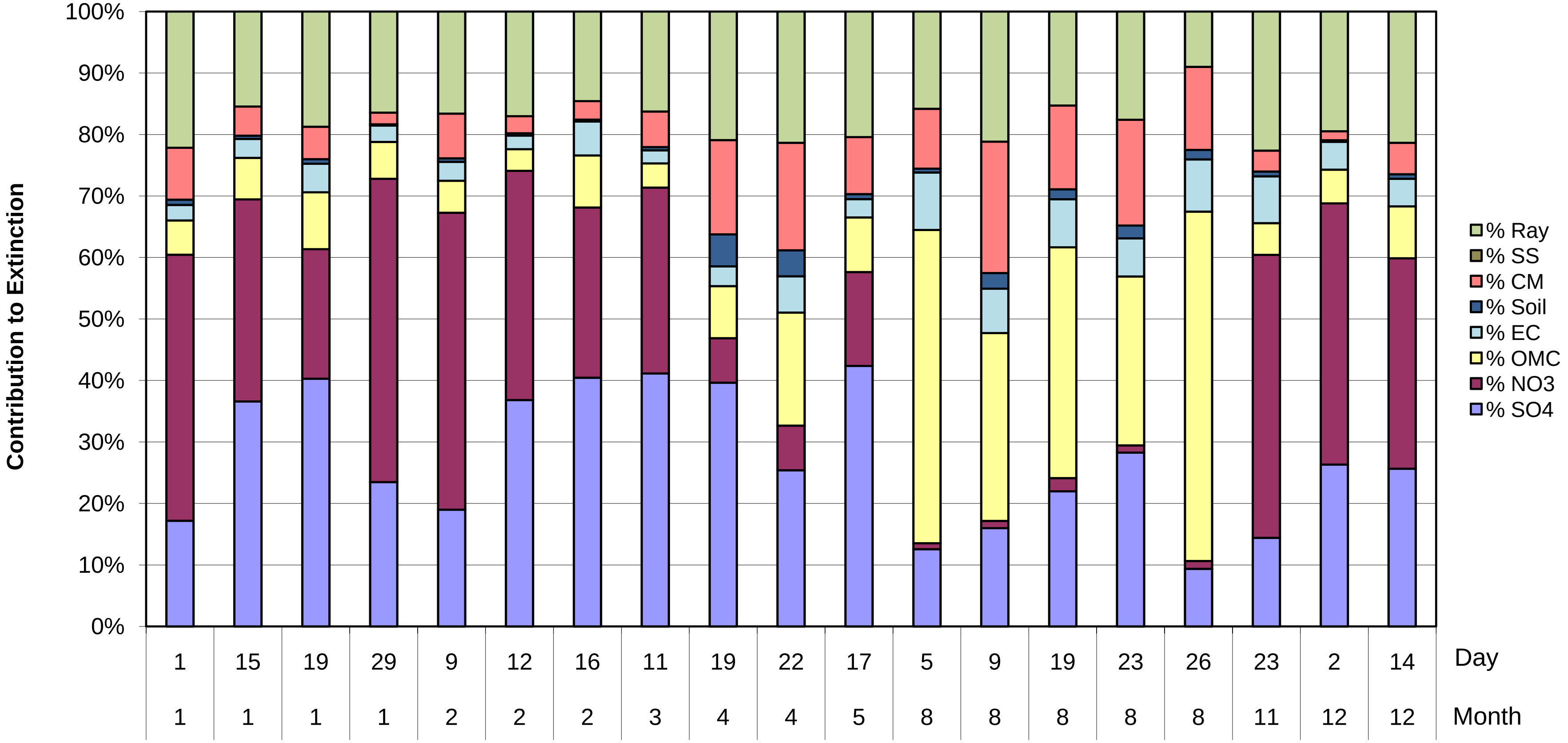


Table 8.2
CMAQ-CALPUFF Area Source Categories

Source Category	Species Included
All Fires	SO_2, NO_X, SO_4, NO_3
Biogenics	NO_X
Fugitive Dust	SO_4, NO_3
On-Road Mobile	SO_2, NO_X, SO_4
Off-Road Mobile	SO_2, NO_X, SO_4, NO_3
Road Dust	SO_4, NO_3
Oil & Gas	SO_2, NO_X
Conventional Area	SO_2, NO_X, SO_4, NO_3
Point	SO_4, NO_3

The interfacing of CMAQ and CALPUFF modeling systems for the NDDoH hybrid approach is illustrated in the flow diagram in Figure 8.4. Necessary software for processing input data and projecting future visibility has been developed by the NDDoH.

To confirm effectiveness of the hybrid CMAQ-CALPUFF modeling system, the NDDoH conducted a performance evaluation prior to commencing production modeling. The evaluation focused on performance of the hybrid system for sulfate and nitrate concentrations, and prompted changes to some model inputs to improve performance relative to observations. CMAQ performance evaluations conducted by WRAP RMC for OMC, EC, Soil, and CM species are also relevant. The NDDoH Performance evaluation is discussed in Section 8.6.1.

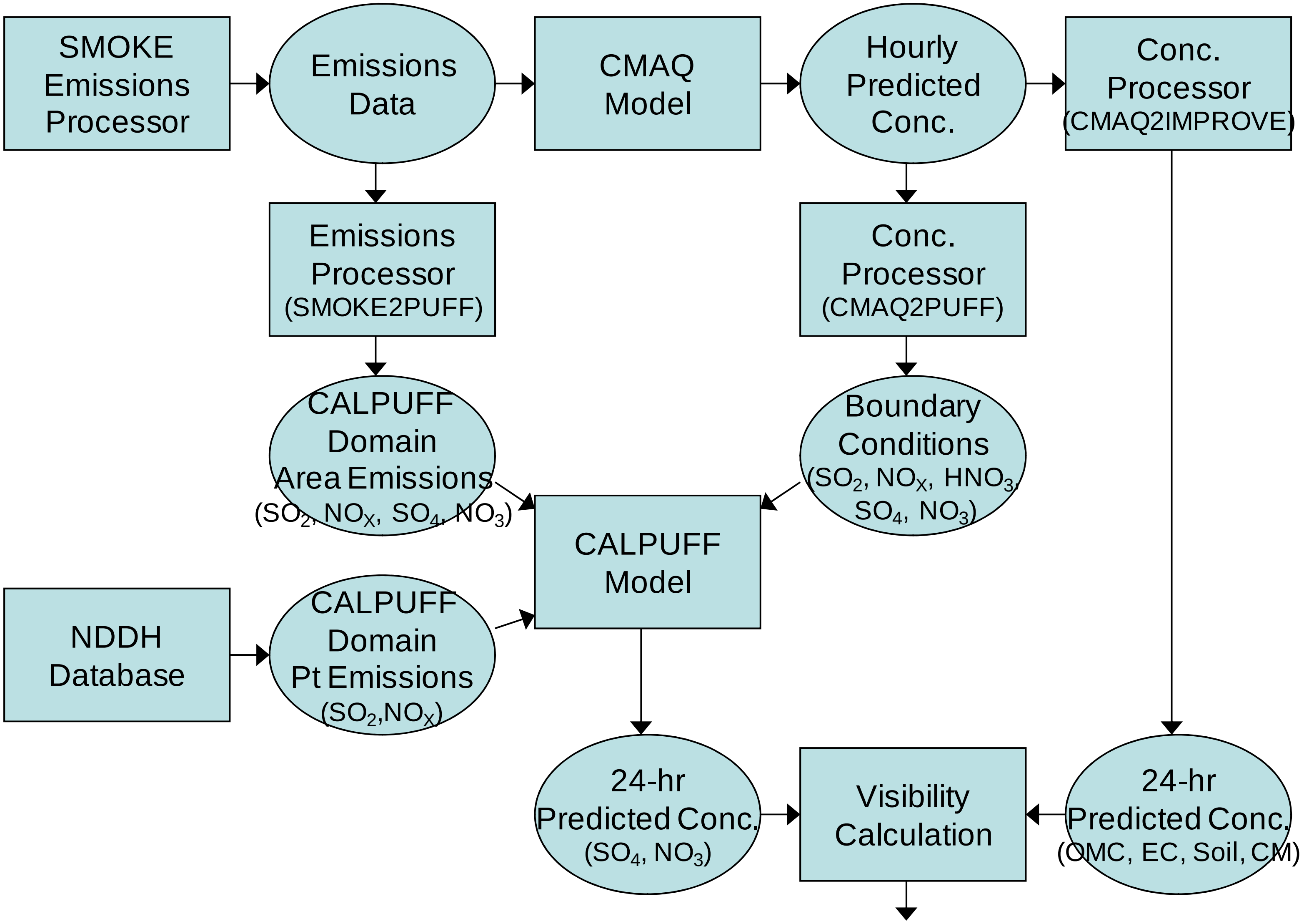
The NDDoH has obtained CMAQ emissions input data (SMOKE output) and hourly concentration output files from the WRAP RMC. CMAQ data used to set CALPUFF boundary conditions and develop the CALPUFF area source inventory will be based on WRAP cases BASE02b, PLAN02d, and PRP18a, for performance evaluation, baseline case, and future case modeling, respectively. These WRAP scenarios are described as follows.

- Case BASE02b reflects CMAQ modeling using year 2002 emissions with year 2002 meteorology. The NDDoH used this case for performance evaluations.

- Case PLAN02d reflects CMAQ modeling using composite 2000-2004 emissions with 2002 meteorology. The NDDoH used this case for the base period to generate relative response factors.

- Case PRP18a (Preliminary Reasonable Progress 2018 Scenario A) reflects CMAQ modeling using projected year 2018 emissions with 2002 meteorology. Case PRP18a represents base period emissions projected to 2018, accounting for estimates of the effect of BART controls, and assuming other growth and control factors. The NDDH used this case for the future period to generate relative response factors.

Figure 8.4
Hybrid Interfacing of CMAQ and CALPUFF Modeling Systems



Again, WRAP recently completed modeling for an updated Case PRP18b future emissions scenario, as discussed in Section 6. Because NDDoH visibility modeling was initiated and largely completed well before the WRAP PRP18b emissions inventory and modeling results were available, however, Case PRP18b is not included in the visibility modeling results discussed in this SIP. For North Dakota sources, Case PRP18b reflects only a slight decrease in emissions relative to Case PRP18a. Therefore, results and conclusions of the visibility analyses reported here, although conservative, would not be meaningfully changed with the use of Case PRP18b emissions.

The modeling system, emissions inventory, other model inputs, and procedures for the NDDoH regional haze modeling analysis are discussed in following Sections 8.5.1 through 8.5.6. A detailed, step-by-step outline of NDDoH visibility modeling procedure is also provided in Appendix E of this report.

Results of the NDDoH hybrid visibility modeling for North Dakota Class I areas are reviewed in Section 8.6.

8.5.1 Hybrid Modeling System

For sulfate and nitrate predictions, the NDDoH applied the CALPUFF model, using regional WRAP CMAQ output concentrations to set boundary conditions for the CALPUFF domain. The CALPUFF computer modeling system includes the CALMET meteorological model[19], the CALPUFF dispersion/chemistry model[20], and the POSTUTIL and CALPOST post processing programs. POSTUTIL implements the ammonia limiting method, which provides an adjustment to avoid overstating available ammonia for NO_x to NO_3 conversion chemistry in CALPUFF. In the NDDoH implementation of the CALPUFF system for production visibility modeling, the CALPOST processor was replaced with CALHAZE, a module which directly processes relative response factors and projects future visibility, using hourly output from CALPUFF (POSTUTIL) baseline and future model runs.

With the exception of CALHAZE (developed by NDDoH), CALPUFF and associated software was developed and is maintained by TRC Corporation (previously by Earth Tech, Inc.). The versions of CALPUFF and associated programs which the NDDoH utilized for regional haze modeling are summarized in Table 8.3.

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[19] Earth Tech, Inc., 2000. A User’s Guide for the Calmet Meteorological Model. Earth Tech, Inc., Concord, MA 01742.

[20] Earth Tech, Inc., 2000. A User’s Guide for the Calpuff Dispersion Model. Earth Tech, Inc., Concord, MA 01742.

Table 8.3
CALPUFF System Versions
Applicable For Regional Haze Modeling

Program	**Version**	**Level**
CALMET	5.8	70623
CALPUFF	5.8	70623
POSTUTIL	1.56	70627

The meteorological/computational modeling domain used by the NDDoH for CALPUFF visibility modeling is illustrated in Figure 8.5. Dimensions of the domain are 639 kilometers east-west by 459 kilometers north-south, with a horizontal grid cell size of 3 kilometers. In the vertical, the domain is defined by twelve vertical layers. The domain is sized and positioned to encompass all large visibility-affecting point sources located within 250 km of North Dakota Class I areas. Because the domain is relatively large for CALPUFF modeling, all location coordinates are based on the Lambert Conformal map projection to mitigate distortions due to the earth's curvature.

8.5.2 CALMET Input

Input requirements for the CALMET model include various meteorological and geophysical data sets, and a control input file with appropriate settings. Required meteorological data include surface, upper-air, and precipitation observations, and mesoscale model output data fields. Geophysical input data include terrain elevation and land-use data. Though CALMET may be run with mesoscale model meteorological data, alone (i.e., no observations), the EPA modeling guideline[21] recommends "blending" observations with the mesoscale model fields. Therefore, the NDDoH included surface and upper-air observations in a blended approach.

Because WRAP RMC modeling was limited to the single year 2002 meteorology due to resource limitations, the NDDoH hybrid approach was necessarily limited to the same single year of meteorology.

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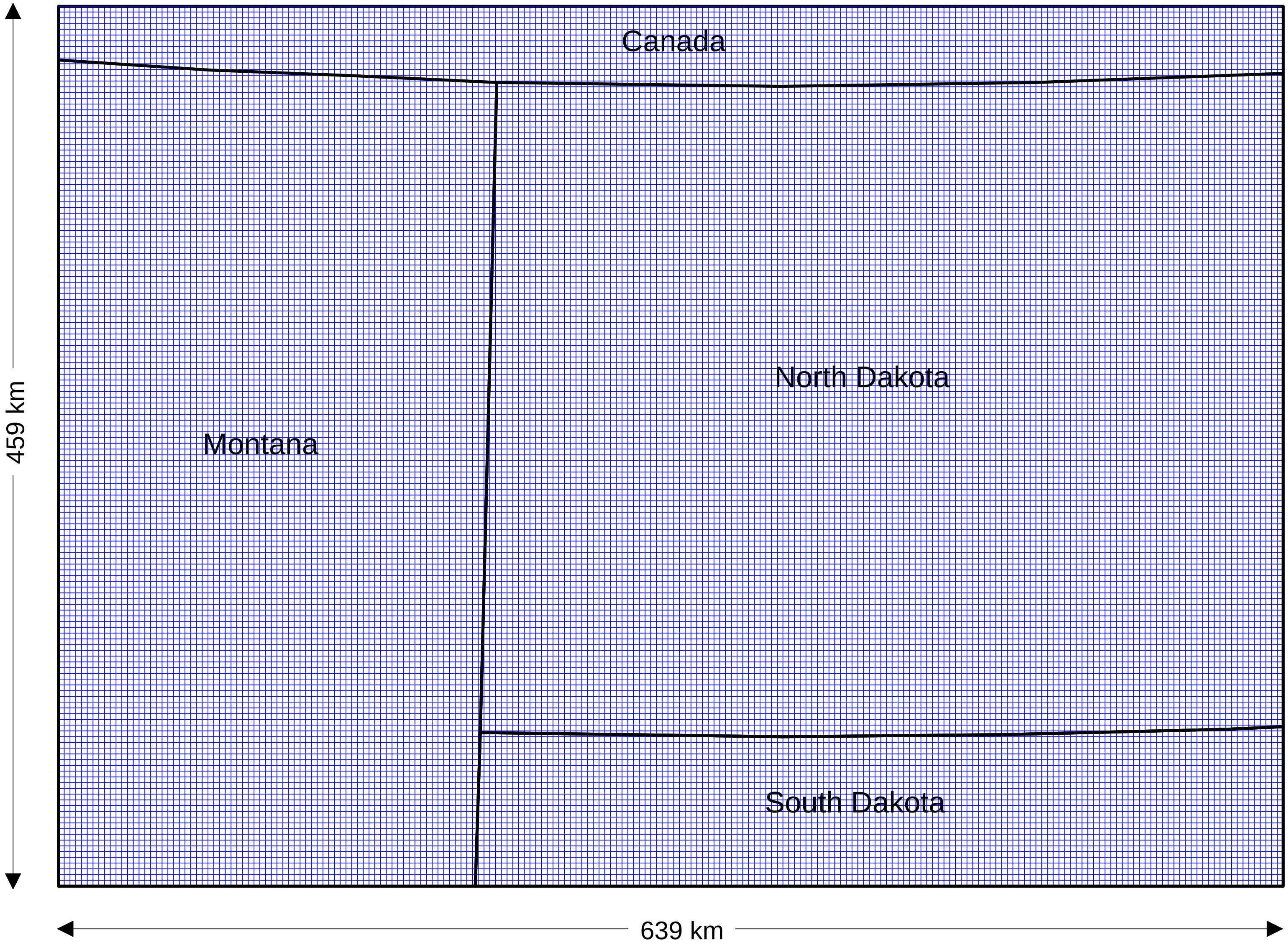
[21] CFR, 2005. EPA Guideline on Air Quality Models. 40 CFR (Code of Federal Regulations) Part 51, Appendix W.

Figure 8.5
CALPUFF 3-km Meteorological/Computational Grid



8.5.2.1 Meteorological Data

8.5.2.1.1 Mesoscale Model Data

NDDoH mesoscale model wind fields used with CALMET are based on the National Center for Environmental Predictions (NCEP) Rapid Update Cycle (RUC) forecast model. Mesoscale model fields in the MM5.DAT format required by CALMET were developed by a contractor[22]. The contractor obtained and archived RUC hourly initial analyses from NCEP for years 2000 through 2002. Resolution of these initial analyses was 40 km. The contractor used the ARPS Data Assimilation System (ADAS) to enhance resolution to 10 km, and converted the resultant hourly wind fields to the MM5.DAT format recognized by CALMET. The domain of these hourly wind fields is consistent with the CALMET/CALPUFF domain used by NDDoH (Section 8.5.1).

In the process of model performance evaluation, the NDDoH also tested the hybrid modeling system with the 2002 36-km MM5 data set prepared by the WRAP RMC for CMAQ modeling. Hybrid model performance was similar using either MM5 or RUC mesoscale data.

8.5.2.1.2 Surface Observations

Concurrent surface observations for 2002 were obtained in surface hourly abbreviated format from the National Climatic Data Center (NCDC). Data were obtained for 40 ASOS and manual stations located within or near the NDDoH CALMET/CALPUFF domain. The ASOS/manual observations reflect data from stations operated by the National Weather Service, Federal Aviation Administration, U.S. Air Force, and Environment Canada. Locations of these stations are shown in Figure 8.6.

To compensate for well-documented deficiencies in ASOS cloud data above 12,000 feet, NDDoH also obtained concurrent GOES ASOS satellite cloud data for all selected surface stations. The satellite hourly observations included cloud amount (sky cover) and cloud height (ceiling height) data above 12,000 feet, and were therefore used to supplement the ASOS observations.

NDDoH prepared custom software to merge the ASOS and satellite data. Earth Tech utility software was then used to quality assure merged data, and convert to the format required by CALMET (SURF.DAT). Standard methods were applied to provide substitutions for missing

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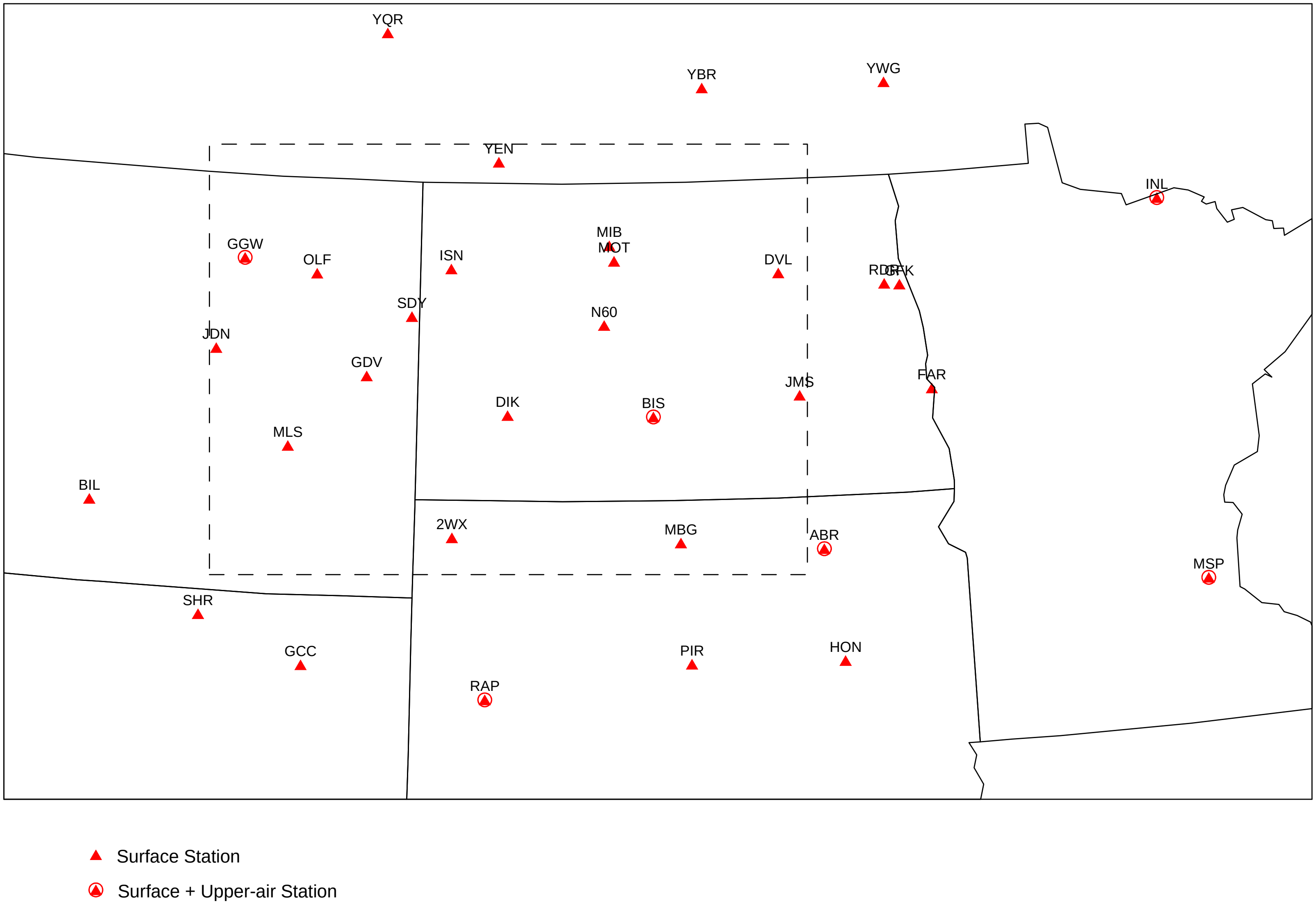
[22] WindLogics, 2004. RUC Analysis-Based CALMET Meteorological Data for the State of North Dakota. WindLogics, Inc., St. Paul, MN 55108.

Figure 8.6
CALMET Surface / Upper Air Meteorological Stations



data.[23,24] The occurrence of missing data elements in the surface observations was generally very limited, and within the tolerances suggested by EPA.

8.5.2.1.3 Upper-Air Observations

Upper-air observations for 2002 were obtained from NOAA's Earth Systems Research Laboratories (ESRL) in Boulder, Colorado. Upper-air sounding files were downloaded from the website (www.fsl.noaa.gov) in the original FSL format, which is accepted for CALMET input as the option "NCDC CD-ROM". Data were obtained for six upper-air stations (NWS) located within or near the NDDoH CALMET/CALPUFF domain. Locations of these stations are also shown in Figure 8.6.

Processing of the upper-air data for CALMET input involved using Earth Tech utility software, running custom software written by NDDoH staff, and manual editing of data files. The main Earth Tech program quality checked the upper-air data files, output error messages to identify problems in the data to be corrected by the user, and converted the data to the format required by CALMET. The NDDoH custom software performed additional quality checks, and, combined with manual editing of data files, corrected additional errors or problems in the data and filled in for missing data when necessary. Substitutions for missing data generally followed standard EPA guidance. [22,23] Upper-air soundings were processed up to the 500-mb level to accommodate mixing heights up to 4000 meters above ground level at Rapid City, South Dakota. In addition, the main Earth Tech processing program had to be modified slightly (corrected) to correctly read longitude for Glasgow, Montana.

8.5.2.1.4 Precipitation Data

Hourly precipitation data for 2002 were obtained from NCDC in TD-3240 format. Data were included for 93 NWS hourly recording stations located within or near the NDDoH CALMET/CALPUFF modeling domain. Location of these stations is shown in Figure 8.7.

Earth Tech utility software was employed to quality assure the TD-3240 data, and process it into the format required by CALMET (PRECIP.DAT). No substitutions were made for missing data, because CALMET substitutes internally from the nearest available station, and the station resolution was relatively good (Figure 8.7).

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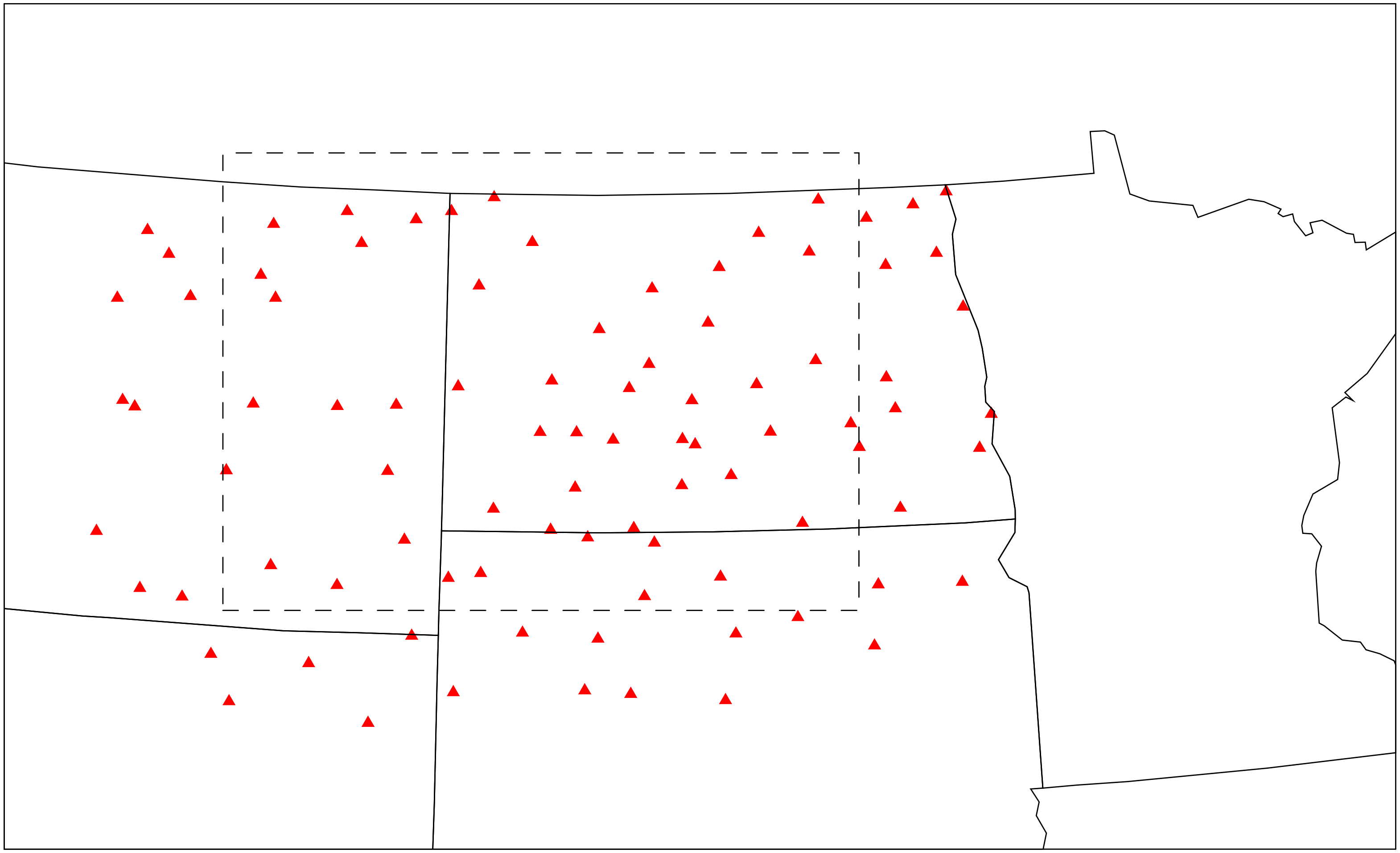
[23] Atkinson, D., and R. F. Lee, 1992. Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models.

[24] EPA, 1987. On-Site Meteorological Program Guidance for Regulatory Modeling Application. Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

Figure 8.7
CALMET Precipitation Stations



8.5.2.2 Geophysical Data

CALMET requires specification of terrain elevation, and parameters related to the land-use profile, for each grid cell in the modeling domain. The NDDoH derived terrain elevations from United States Geological Survey (USGS) GTOPO30 data sets for North America central and mountain zones. Land-use profiles were derived from the USGS Global Data Set for North America.

Using CALMET utility software, all gridded terrain and land-use data were processed into the single geophysical file (GEO.DAT) required by CALMET. NDDoH assumed default values relating surface roughness length, albedo, Bowen ratio, soil heat flux, and leaf area index to land-use type.

8.5.2.3 CALMET Control File Settings

CALMET control file settings used for processing year 2002 meteorological data for visibility analyses are generally consistent with guidance from the Interagency Workgroup on Air Quality Modeling (IWAQM)[25]. To the extent applicable, the settings are also consistent with the North Dakota alternative protocol for PSD Class I increment analyses[26].

IWAQM recommendations for CALMET control file variable settings fall into two categories. IWAQM-defined variables are those for which IWAQM provides a default value as a general recommendation for all analyses. User-defined variables are those where IWAQM recognizes the input value will need to be tailored for a given application, and default values are therefore not provided.

For visibility analyses, the NDDoH has established appropriate settings for user-defined variables, and has determined the need to adjust a limited number of IWAQM-defined variables from recommended values, as discussed below. The CALMET control file user-defined settings, as well as the IWAQM-defined settings which have been adjusted by NDDoH, are summarized in Table 8.4. IWAQM-defined settings adjusted by NDDoH have a shaded background in the Table.

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[25] EPA, 1998. IWAQM Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. Publication No. EPA-454/R-98-019, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

[26] NDDoH, 2005. A Proposed Alternative Air Quality Modeling Protocol to Examine the Status of Attainment of PSD Class I Increment. North Dakota Department of Health, Bismarck, ND 58506.

Most of the user-defined settings are intuitive, related to parameterization of the meteorological grid used with CALMET, as previously discussed. The remaining user-defined variables, (RMAX1, RMAX2, RMAX3, TERRAD, R1, R2) control the influence of mesoscale model data, station observations, and terrain features in development of the final wind field. Settings for these variables are based on the NDDoH alternative protocol for PSD Class I increment analyses.

NDDoH settings for IWAQM-defined variables are consistent with IWAQM recommendations, with limited exceptions as established in the alternative protocol for PSD Class I increment analyses. Because the use of mesoscale meteorological data is now being generally recommended for long-range modeling analyses, the IPROG variable has been changed from 0 to 14, which reflects use of MM5 format data (in this case RUC data) as the initial guess wind field. The ZUPWND setting has been changed for consistency with default values in recent versions of CALMET (the IWAQM setting reflected defaults for an older version of CALMET). Based on visual feedback testing, IWAQM settings for variables related to spatial averaging of mixing heights, MNMDAV and ILEVZI, were adjusted to provide averaging over a larger area.

Because the NDDoH CALMET/CALPUFF modeling domain extends into the western part of the upper Great Plains, maximum mixing height settings (ZIMAX/ZIMAXW) were increased from 3000 to 4000 meters to be consistent with maximum mixing heights reported for this region.[27] Note that the CALMET BIAS factors have no effect when mesoscale data are used as the initial guess wind field.

8.5.3 CALPUFF Input

Along with the CALMET-processed meteorological data, CALPUFF input requirements for NDDoH hybrid visibility modeling include emissions and stack data, background ozone data, background ammonia data, receptor locations, boundary conditions, and input control file settings. These CALPUFF input requirements are discussed here.

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[27] Holzworth, 1972. Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States. EPA Publication No. AP-101, Office of Air Programs.

Table 8.4
User-Defined and Non-IWAQM Settings for CALMET Control File*

Variable	**Description**	**Value**
NSSTA	No. of surface stations	40
NUSTA	No. of upper-air stations	5
NPSTA	No. of precipitation stations	93
IBTZ	Base time zone	7
PMAP	Map projection (LCC=Lambert Conformal Conic)	LCC
FEAST	False easting at origin	0.0
FNORTH	False northing at origin	0.0
RLAT0	Origin latitude of projection	44.0N
RLON0	Central meridian of projection	102.0W
XLAT1	Latitude of 1st standard parallel for projection	46.0N
XLAT2	Latitude of 2nd standard parallel for projection	48.5N
DATUM	Datum-region for output coordinates	NWS-27
NX	No. of X grid cells	213
NY	No. of Y grid cells	153
DGRIDM	Grid spacing (km)	3.0
XORIGKM	Southwest grid cell X coordinate	-380
YORIGKM	Southwest grid cell Y coordinate	140
NZ	No. vertical layers	12
ZFACE	Cell face heights (m)	0.,20.,50.,90.,140.,200., 270.,370.,500.,1000., 1700.,2500.,4200.
NOOBS	No observation mode (0 = no)	0
IPROG	Use MM5.DAT file as initial guess wind field (14=yes)	14

Variable	**Description**	**Value**
RMAX1	Max. radius of influence of surface observation (km)	100
RMAX2	Max. radius of influence of upper-air observation (km)	200
RMAX3	Max. radius of influence over water (km)	200
TERRAD	Radius of influence of terrain features (km)	10
R1	Distance from a surface observation station at which the wind observation and the first guess field are equally weighted (km)	10
R2	Distance from an upper-air observation station at which the wind observation and the first guess field are equally weighted (km)	10
ISURFT	Surface station number used for the surface temperature for the diagnostic wind field module (Bismarck)	17
IUPT	Upper-air station number used to compute the domain-scale temperature lapse rate for the diagnostic wind field module (Bismarck)	1
ZUPWND	Bottom and top of layer through which the domain-scale winds are computed (m)	1.,2500.
MNMDAV	Max. search distance (in grid cells) for spatial averaging of mixing ht. and temperature	7
ILEVZI	Layer of winds used in upwind averaging of mixing heights	3
ZIMAX	Maximum over land mixing height (m)	4000.
ZIMAXW	Maximum over water mixing height (m)	4000.

*Shaded background indicates IWAQM-defined setting adjusted by NDDoH

8.5.3.1 Emissions Inventory

The emissions inventory utilized in the NDDoH hybrid visibility modeling analysis accounted for all SO_2-SO_4-NO_X-HNO_3-NO_3 emission sources located within and outside of the NDDoH CALPUFF domain. The impact of emission sources located outside of the domain was accounted for using the boundary condition feature of CALPUFF, with WRAP CMAQ output concentrations used to set appropriate boundary concentrations. Within the CALPUFF domain, all SO_2-SO_4-NO_X-NO_3 emissions were configured as conventional point and area sources.

Note that HNO_3 is not directly emitted by any visibility affecting source. However, HNO_3 is an important component of nitrate chemistry (both CMAQ and CALPUFF), and is provided as an output species in CMAQ. Therefore, HNO_3 is included as a boundary concentration for CALPUFF boundary conditions, but it is not directly emitted by any of the visibility affecting sources configured within the CALPUFF domain.

For SO_2-SO_4-NO_X-NO_3 sources located within the NDDoH CALPUFF domain and within the North Dakota border, stack data for point sources, including stack operating parameters and SO_2 and NO_X emission rates, were obtained from an internal Department database. Point source data were reviewed by NDDoH to confirm viability of all stack parameters, and emission rates were updated, if necessary, to reflect values representative of the 2000-2004 period.

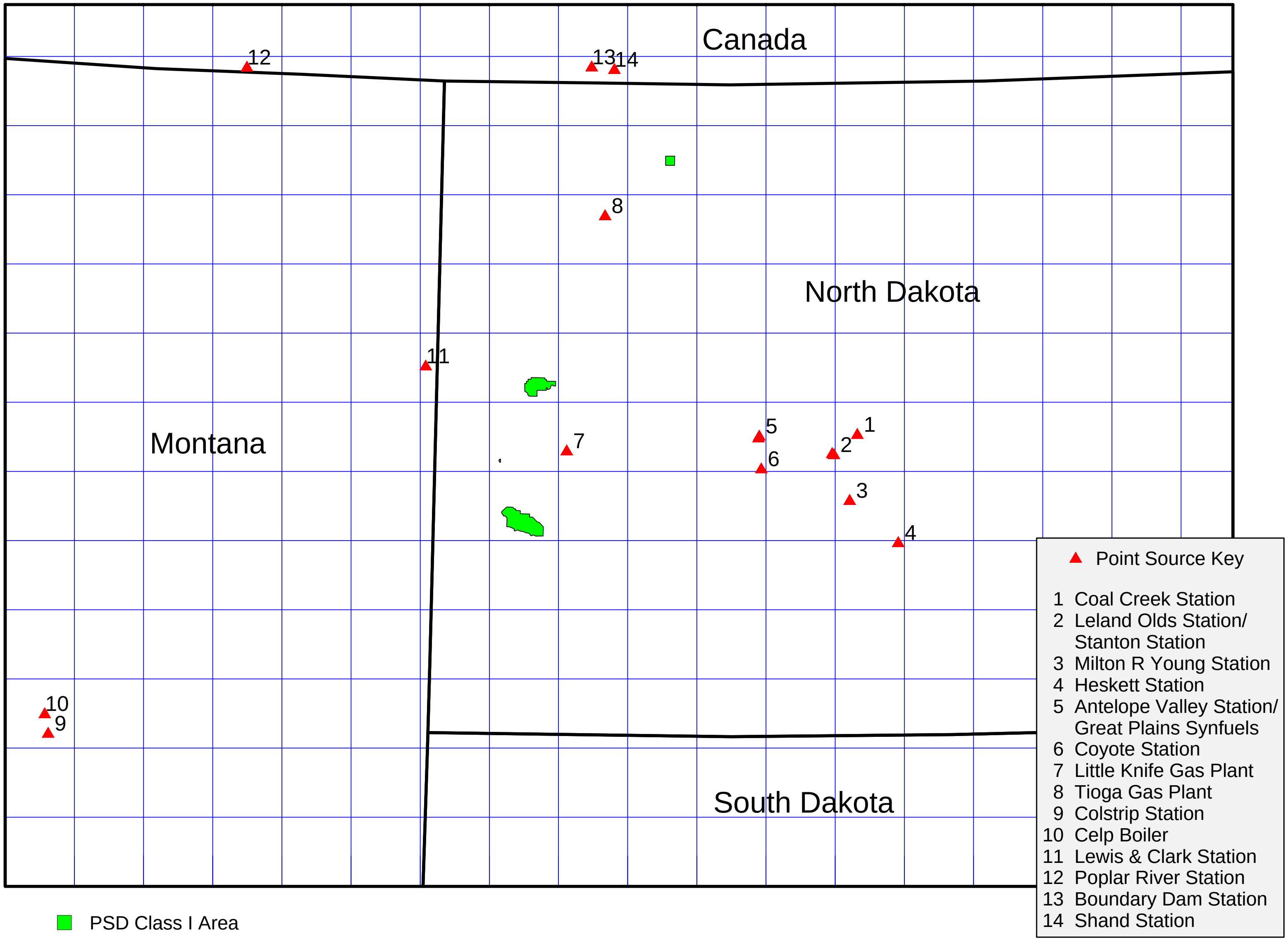
For SO_2 and NO_X point sources located within the NDDoH CALPUFF domain, but outside of North Dakota (South Dakota, Montana, Canada), the NDDoH obtained appropriate stack parameters and emission rates from governing agencies representing these jurisdictions. Most Montana data was obtained directly from the facility operators. Data representing the 2000-2004 period were requested. Data were reviewed by NDDoH to confirm viability of all stack parameters.

Note that the size threshold for configuring visibility-affecting sources as point versus area is generally connected to the availability of point source data in the National Emissions Inventory (NEI). All point sources included in the NEI (and located within the NDDoH CALPUFF domain) were configured as point sources for the visibility analysis. The exception is oil and gas related SO_2 sources for which the NDDoH maintains a separate database. These oil and gas related sources, though not included in the NEI, were also configured as point sources for the visibility analysis.

The location of larger visibility-affecting point sources within the CALPUFF domain is depicted in Figure 8.8.

All remaining SO_2-SO_4-NO_X-NO_3 sources located within the NDDoH CALPUFF domain, but not included in the North Dakota or adjoining jurisdiction's point source inventories, were configured as 36-kilometer area sources using a predefined grid structure in CALPUFF. The area-source grid is illustrated in Figure 8.8. Emission rates for the CALPUFF area source grid were developed using WRAP CMAQ input (SMOKE output) for the CMAQ grid cells located within the NDDoH CALPUFF domain. The NDDoH obtained the SMOKE output data from WRAP RMC. Because the location and orientation of the CMAQ and CALPUFF grids are not

Figure 8.8
NDDoH Domain - Locations of Larger Point Sources and 36-km Area Source Grid



consistent, software was developed by NDDoH to accurately apportion emissions from 36-kilometer CMAQ grid cells to the 36-kilometer CALPUFF area source grid.

Based on availability in WRAP SMOKE output, the CALPUFF area source emissions inventory included the source categories and species summarized in Table 8.2 . Note that SMOKE output did not include all four species (SO_2-SO_4-NO_X-NO_3) for some source categories. Although NDDoH developed a conventional point source inventory for SO_2 and NO_X, the NDDoH database did not include primary SO_4 and NO_3 emissions for point sources. Therefore, SO_4 and NO_3 emissions for the point source category were obtained from WRAP SMOKE output, and these components of point source emissions were configured as area sources in CALPUFF.

Based on testing during the performance evaluation, and on consultation with Joe Scire (TRC)[28,29], area sources in CALPUFF were configured for best model performance, and to be more consistent with the grid cell treatment in CMAQ. This involved proper settings for the CALPUFF "release height" and "initial sigma z" input parameters for area sources.

Emission rates used for both point and area sources reflect total actual tons per year. CALPUFF apportions these total emissions, on a temporal basis, equally to each hour of the year. The NDDoH tested the use of temporal profiles to vary emission rates on a seasonal, monthly, or hourly basis, but found that such adjustments made little difference in the hybrid model performance evaluation (see Section 8.6.1). For example, North Dakota electrical generating stations (EGUs) were modeled using an annual profile of actual hourly emissions for SO_2 and NO_X, and results (compared to default total tons per year modeling) were unchanged for most of the metrics included in the comparison. The NDDoH attributes this finding to the fact that the characterization of model output used for developing RRFs is the *average* of the 20 percent worst or best day predictions, and this longer-term average was also the focus of the performance evaluation. Using the average of 20 percent of the days in a year serves to dampen out differences attributable to shorter-term temporal variations in emissions.

To address hybrid model performance and the development of RRFs, the NDDoH prepared separate emissions inventories for base period, future period, and performance evaluation scenarios. SMOKE data used to apportion area source emissions was based on WRAP cases BASE02b, PLAN02d, and PRP18a for performance evaluation, base period, and future period modeling, respectively. These WRAP cases are described as follows.

- Case BASE02b reflects use of year 2002 emissions with year 2002 meteorology. NDDoH used this case for performance evaluations.

- Case PLAN02d reflects use of composite 2000-2004 emissions with 2002 meteorology. NDDH used this case for base period modeling to generate relative response factors.

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[28] TRC, 2008. Telephone consultation with Joe Scire, May 29, 2008. Joe Scire, TRC Corporation, Lowell, MA 01854.

[29] Joe Scire previously affiliated with Earth Tech, Inc.

- Case PRP18a (Preliminary Reasonable Progress 2018 Scenario A) reflects use of projected year 2018 emissions with 2002 meteorology. Case PRP18a represents base period emissions projected to 2018, accounting for estimates of the effect of BART controls, and assuming other growth and control factors. NDDoH used this case for future period modeling to generate relative response factors.

To complete emission inventories for the three modeling scenarios, the NDDoH developed point source inventories (SO_2 and NO_X) consistent with the WRAP cases. For EGUs, the inventory for performance evaluation was based on actual emissions for 2002, while the base period inventory assumed the five-year average of 2000-2004 actual emissions. The future period inventory for EGUs included emission reductions consistent with BART controls (see Section 6.2), but remained consistent with base period emissions for non-BART facilities. The possible addition of new EGUs was also accounted for in the future inventory (e.g., the potential “Gascoyne 500” EGU was added to the future inventory).

For point sources other than EGUs (reflecting generally small sources), the source inventory for performance evaluation was based on 2002 actual emissions, and the inventory for base period and future period modeling was relatively consistent with that used for the performance evaluation. For non-EGU point sources, little change in the emissions inventory is expected between base and future periods. Emissions increases associated with new sources will be no greater (and likely less) than emissions decreases associated with retiring sources.

When considering weight of evidence options in the NDDoH hybrid visibility modeling analysis, emissions inventories as described above were adjusted to eliminate sources. For example, when exercising the option to discount the impact of international sources, all Canadian sources of visibility affecting emissions (SO_2-SO_4-NO_X-NO_3) were eliminated from the base and future period inventories (see Section 8.6.3.1). Weight of evidence assumptions are discussed in Section 8.6.3.

In developing its emission inventories for hybrid modeling using the default EPA methodology, as well as weight of evidence options, the NDDoH adjusted WRAP future period emissions (PRP18a) for NO_X associated with oil and gas related sources. The total North Dakota oil and gas NO_X emissions estimated by WRAP for the future inventory was about 4.5 times higher than the total estimate for the baseline inventory. Based on recent projections from the North Dakota Department of Mineral Resources, oil and gas activity in 2018 is expected to be about 2 to 2.5 times higher than the 2002 level.[30] Moreover, in a subsequent telephone consultation, WRAP representatives admitted that 2018 estimates of NO_X related to oil and gas activity in North Dakota may have been overstated[31]. Therefore, the NDDoH applied a constant correction to WRAP future oil and gas NO_X emissions for all area sources in North Dakota, such that total 2018 emissions are 2.5 times higher than total baseline emissions for oil and gas related NO_X.

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[30] ND Department of Mineral Resources, 2008. December 2, 2008 Electronic Communication from Lynn Helms to Terry O’Clair.

[31] WRAP, 2008. December 12, 2008 Telephone Communication between representatives of WRAP and NDDoH.

The NDDoH also had concerns regarding WRAP estimates of future Soil (fine particulate) emissions. Because the NDDoH is not directly modeling the Soil species, this concern was related to the RRF developed by WRAP for North Dakota Class I areas. The Soil RRFs applied by WRAP are 1.13 for TRNP and 1.11 for LWA. Both values imply some significant increase in future Soil emissions (or precursors). Given recent increases in the practice of conservation tillage farming in North Dakota and adjoining states, and recent decreases in the existence of summer fallow (retiring a portion of cultivated land for one growing season), an increase in Soil emissions between the baseline and 2018 seems unlikely, with a decrease probable. This issue is discussed in more detail in Section 9.5.2. The NDDoH addressed the Soil inconsistency by adjusting the TRNP and LWA RRFs to 1.0 to implement the default EPA methodology, as well as weight of evidence options. This value is probably still conservative, but more in line with current and predicted future farming practices than RRFs developed by WRAP.

8.5.3.2 Boundary Conditions

Boundary conditions account for the additive impact of all emission sources located outside of the CALPUFF domain. Out-of-domain source emissions generally constitute a large component of total predicted concentrations for sulfate and nitrate species.

The NDDoH is using the boundary condition feature of CALPUFF to effectively nest the CALPUFF domain within the WRAP CMAQ domain to facilitate its hybrid modeling approach. The use of CMAQ output to set CALPUFF boundary conditions has been suggested by Escoffier-Czaja and Scire[32]. Location of the NDDoH CALPUFF domain within the WRAP CMAQ domain was illustrated in Figure 8.1.

To implement the feature in CALPUFF, a supplemental boundary condition data file must be provided as part of the CALPUFF input conditions. In this file, the user provides the length and location of boundary segments which follow the perimeter of the Calpuff domain. For each segment, the concentration of each species being modeled is provided, and an air mass depth is assigned. Species concentrations for boundary segments can be updated as frequently as hourly.

For NDDoH hybrid visibility modeling, the length of boundary segments was set to match the resolution of the CALPUFF meteorological/computational grid, which is 3 kilometers. Accordingly, a boundary segment was placed adjacent to each computational grid cell along the perimeter of the domain. Boundary segment hourly concentrations for SO_2-SO_4-NO_X-HNO_3-NO_3 species were taken from CMAQ hourly output concentration files provided by WRAP RMC. For each segment, concentrations from the 36-km CMAQ grid cell containing the largest part of the segment were utilized. A constant air mass depth of 3000 meters was assumed for all boundary segments. (Though air mass depth of 1000-2000 meters is nominally suggested in

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[32] See supra note 6.

guidance for CALPUFF boundary conditions[33], the NDDoH found the use of 3000 meters provided better agreement with observations in performance evaluations.)

Separate boundary condition files were prepared for cases BASE02b, PLAN02d, and PRP18a for performance evaluation, baseline, and future hybrid modeling, respectively.

8.5.3.3 Ozone Background

CALPUFF utilizes background ozone values in its chemistry module. The model accepts either a single constant background ozone value, or an input file of hourly ozone values commensurate with the period of meteorological data. The NDDoH uses the hourly ozone file option with CALPUFF, and would regard this as the appropriate implementation for visibility modeling (this is also the IWAQM default option). The hourly ozone file was constructed using year 2002 hourly ozone data obtained from four NDDoH monitoring sites located within the corridor of primary plume transport between major electric generating stations and Theodore Roosevelt National Park (TRNP). These monitoring sites include Hannover, Beulah, Dunn Center and TRNP South Unit. As indicated in Section 8.5.3.6, a constant ozone background value (30 ppb) is also provided in the CALPUFF control file, so that it can be substituted when the hourly value is missing. This value represents the approximate annual average for North Dakota ozone monitoring sites.

8.5.3.4 Ammonia Background

The need for ammonia background concentrations in CALPUFF is also related to chemistry processing. CALPUFF accepts either a single annual value, or twelve monthly averages from a single site. To achieve a more realistic seasonal progression of sulfate and nitrate predictions, the NDDoH used monthly average ammonia background values for CALPUFF hybrid visibility modeling input (note that temporal ammonia resolution is improved to hourly in the POSTUTIL processing step described in Section 8.5.4).

Monthly average ammonia concentrations suitable for visibility modeling in North Dakota are provided in Table 8.5. These values were derived from data collected at the State’s ammonia monitor located near Beulah. Hourly monitor data from years 2001-2002 (data not available for year 2000) were filtered to eliminate data from wind directions associated with sources causing a local bias, then remaining data were processed to produce the monthly averages. The Table 8.5 values should be generally representative of background ammonia concentrations in western North Dakota.

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[33] See supra note 6.

Table 8.5
Monthly Ammonia Background Concentrations*

Month	Value (ppb)
Jan	1.22
Feb	1.23
Mar	1.60
Apr	1.94
May	2.29
Jun	1.63
Jul	1.65
Aug	1.69
Sep	0.98
Oct	1.04
Nov	1.37
Dec	1.06

* Data reflect NDDoH Beulah monitoring site.

8.5.3.5 Receptors

Receptors for NDDoH visibility progress goal modeling are located at the TRNP and Lostwood NWA IMPROVE monitoring sites. In its guidance for regional haze modeling[34], EPA recommends including nearby receptors or grid cells in order to provide spatial averaging of the design concentration. Use of a spatial average addresses possible “migration” of the predicted peak, and some uncertainties in the formulation of the model and model inputs. Therefore, the NDDoH used a 3 by 3 receptor grid (9 receptors) which is centered on the IMPROVE site, at each Class I area. Receptor spacing in the grid is 5 kilometers. Receptor elevation was set to the ground elevation of the IMPROVE monitor site for all 9 receptors in the grid.

Recognizing that visibility is not necessarily a “ground level” concept, the NDDoH also tested the effect of elevated or “flag pole” receptors. A sensitivity test was conducted using a flag pole elevation of 18 meters, which is one-half the height of the surface layer used in WRAP CMAQ modeling. Results of this test showed a negligible difference compared to predictions for ground level receptors.

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[34] See supra note 7.

8.5.3.6 CALPUFF Control File Settings

CALPUFF control file settings used for NDDoH hybrid visibility analyses are generally consistent with IWAQM guidance[35]. To the extent applicable, the settings are also consistent with the North Dakota alternative protocol for PSD Class I increment analyses[36].

IWAQM recommendations for CALPUFF control file settings fall into two categories. IWAQM-defined variables are those for which IWAQM provides a default value as a general recommendation for all analyses. User-defined variables are those where IWAQM recognizes the input value will need to be tailored for a given application, and default values are therefore not provided.

For visibility analyses, the NDDoH has established appropriate settings for user-defined variables, and has determined the need to adjust a limited number of IWAQM-defined variables from recommended values, as discussed below. The CALPUFF control file user-defined settings, as well as the IWAQM-defined settings which have been adjusted by NDDoH, are summarized in Table 8.6. IWAQM-defined settings adjusted by NDDoH have a shaded background in the table.

Most of the user-defined settings are intuitive, involving variables related to defining the meteorological/computational grid, variables related to the Lambert map projection, and the use of default values for dry and wet deposition parameterization. The variable IRESPLIT was set such that puffs are eligible for splitting on any hour of the day.

NDDoH settings for IWAQM-defined variables are equivalent to IWAQM recommendations, with exception of settings for a limited number of variables related to puff splitting, dispersion, and mixing height. Variable MSPLIT was set to allow puff splitting, as this option is generally recommended when modeling source-receptor distances of 200 km or more. Based on performance testing of the CALPUFF model for PSD Class I increment modeling[37], the NDDoH used adjusted settings for dispersion-related variables MDISP and MPDF, and for variables IVEG and ROLDMAX, as these adjustments provided better model performance. NDDoH settings for MDISP and MPDF, reflecting the use of micrometeorological variables in calculating dispersion, are also more consistent with dispersion treatment in the local-scale model AERMOD[38]. Values for background ozone and ammonia (variables BCKO3 and

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[35] See supra note 20

[36] See supra note 21.

[37] See supra note 21.

[38] EPA, 2004. User's Guide for the AMS/EPA Regulatory Model – AERMOD. Publication No. EPA-454/B-03-001, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27701.

Table 8.6
User-Defined and Non-IWAQM Settings for CALPUFF Control File*

Variable	Description	Value
IBTZ	Base time zone	7
NSPEC	Number of chemical species	5
NSE	Number of chemical species emitted	4
MSPLIT	Allow puff splitting (1=yes)	1
MDISP	Method used to compute dispersion coefficients	2
MPDF	PDF used for dispersion under convective conditions (1=yes)	1
PMAP	Map projection (LCC=Lambert Conformal Conic)	LCC
FEAST	False easting at origin	0.0
FNORTH	False northing at origin	0.0
RLAT0	Origin latitude of projection	44.0N
RLON0	Central meridian of projection	102.0W
XLAT1	Latitude of 1st standard parallel for projection	46.0N
XLAT2	Latitude of 2nd standard parallel for projection	48.5N
DATUM	Datum-region for output coordinates	NWS-27
NX	No. of X grid cells	213
NY	No. of Y grid cells	153
NZ	No. vertical layers	12
DGRIDM	Grid spacing (km)	3.0
ZFACE	Cell face heights (m)	0.,20.,50.,90.,140.,200.,270.,370.,500.,1000.,1700.,2500.,4200.
XORIGKM	Southwest grid cell X coordinate	-380
YORIGKM	Southwest grid cell Y coordinate	140

Variable	**Description**	**Value**
IBCOMP	Southwest X-index of computational grid	1
JBCOMP	Southwest Y-index of computational grid	1
IECOMP	Northeast X-index of computational grid	213
JECOMP	Northeast Y-index of computational grid	153
Dry Gas Dep.	Chemical parameters of gaseous deposition species	Model defaults
Dry Part. Dep.	Chemical parameters of particulate deposition species	Model defaults
IVEG	Vegetative state in unirrigated areas (2=active and stressed vegetation)	2
Wet Dep.	Wet deposition parameters	Model defaults
BCKO3	Monthly ozone background concentration (ppb)	30.0**
BCKNH3	Monthly ammonia background concentration (ppb)	Table 8.5
XMAXZI	Maximum mixing height	4000.
IRESPLIT	Hours when puff is eligible for vertical split	hours 1-24
ROLDMAX	Vertical puff split allowed only when the ratio of last hour's mixing height to max. mixing height experienced by the puff is smaller than this value	0.33
NSPLITH	Number of puffs that result when a puff is split horizontally	5
SYSPLITH	Minimum sigma-y (grid cell units) of puff before it may split horizontally	1.0
SHSPLITH	Minimum puff elongation rate (SYSPLITH/hr) due to wind shear, before it may split horizontally	2.0
CNSPLITH	Minimum concentration (g/m^3) in puff before it may split horizontally	1.0E-07
NREC	Number of discrete receptors	18

* Shaded background indicates IWAQM-defined setting adjusted by NDDoH
**Use same value for each month.

BCKNH3, respectively) were set to be consistent with local monitoring data. Maximum mixing height (XMAXZI) was set to 4000 meters for consistency with CALMET settings.

8.5.4 POSTUTIL Input

Because CALPUFF allows the full amount of the specified background concentration of ammonia to be available to each puff for forming nitrate, the same ammonia may be used multiple times, resulting in an overestimate of nitrate formation. The POSTUTIL processor provides repartitioning of total nitrate at the *receptor* location to adjust for over-counting of ammonia in the CALPUFF chemistry. This repartitioning in POSTUTIL is commonly referred to as the ammonia limiting method[39]. The repartitioning process in POSTUTIL generates a modified hourly concentration file in the same format as the input CALPUFF hourly concentration file. Species HNO_3 and NO_3, only, are modified in the repartitioning process. Concentrations for all other species remain unchanged.

To implement the ammonia limiting method, POSTUTIL requires an input control file, the hourly concentration output file from CALPUFF, and (optionally) an hourly file of ammonia background concentrations. Among other intuitive input assignments (file names and carryover of settings from CALPUFF), the POSTUTIL input control file specifies the setting for the MNITRATE parameter, which is related to the method of nitrate repartitioning. The control file also provides the source and temporal resolution for ammonia background concentrations to be used in nitrate repartitioning. POSTUTIL provides for the use of annual, monthly, or hourly ammonia background concentrations from a single site. By allowing use of hourly ammonia background, POSTUTIL improves on the maximum temporal resolution available in CALPUFF (monthly).

The POSTUTIL processor also accommodates the 3-step ammonia limiting method, which is used to determine the contribution of a subgroup of sources (from the complete source inventory) to total nitrate formation. Effectively, the 3-step method allows consideration of the effect of excluded sources on the model chemistry (e.g., excluded sources still "use up" some of the available ammonia). The MNITRATE parameter is used to control processing for each step of the 3-step sequence. The 3-step ammonia limiting method requires three separate executions of POSTUTIL. Input/output for the 3 steps, along with appropriate MNITRATE settings, is outlined in Table 8.7.

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[39] Escoffier-Czaja, C., and J. Scire, 2002. The Effects of Ammonia Limitation on Nitrate Aerosol Formation and Visibility Impacts in Class I Areas. Earth Tech, Inc., Extended Abstract. 12th Joint Conference on the Applications of Air Pollution Meteorology with the Air and Waste Management Association, American Meteorological Society, J5.13.

Table 8.7
3-Step Ammonia Limiting Method

Step	**MNITRATE Setting**	**Description**
1	1	Using CALPUFF hourly concentration file for entire source inventory as input, repartitioning is performed based on entire source inventory. Modified hourly concentration file is created (affects HNO_3 and NO_3 species).
2	0	Using Step 1 modified hourly file as input, new species names are assigned to HNO_3 and NO_3 (HNO3ALL and NO3ALL). Hourly concentration file containing only renamed species is created.
3	2	Using both CALPUFF new hourly concentration file for source group (subset of entire source inventory in Step 1) and Step 2 hourly concentration output file (HNO3ALL and NO3ALL species representing entire source inventory), repartitioning is performed based on the source group contribution to the entire source inventory. Modified hourly concentration file is created (affects HNO_3 and NO_3 species).

The NDDoH utilized POSTUTIL and the ammonia limiting method in its hybrid modeling analysis. The NDDoH developed an hourly ammonia background concentration file to use with POSTUTIL repartitioning. To create the hourly file, observed hourly ammonia concentrations were obtained from the State's Beulah monitoring site (the only ammonia site in North Dakota) for the three-year period 2001-2003. Hourly data for the three years were filtered to eliminate data from wind directions associated with sources causing a local bias. Then the three years were averaged together, on a temporally consistent basis, to produce a single hourly file considered representative of 2002, and appropriate for use with 2002 meteorological data modeling. Years 2001 and 2003 were incorporated in an averaging scheme because year 2002 contained missing periods of hourly data, and some additional data were lost due to filtering as described above. Finally, smoothing was applied to the resultant hourly data set, in the form of a 24-hour running average, to dampen the effect of discontinuities in the ammonia data.

The resultant background hourly ammonia file was tested during the performance evaluation of the hybrid modeling system (Section 8.6.1). While the adjusted Beulah data provided good modeled comparisons with TRNP observed nitrate, the LWA nitrate observations were consistently under predicted. The NDDoH found that agreement with LWA nitrate observations was significantly improved if hourly values in the ammonia file are approximately doubled. Moreover, the NDDoH found empirical evidence (discussed below) that ammonia levels in the vicinity of LWA would be typically higher than ammonia levels at TRNP. Therefore, the

NDDoH applied the original hourly ammonia file (above) for all POSTUTIL processing associated with TRNP, and doubled the hourly ammonia profile for all POSTUTIL processing associated with LWA.

In addition to performance evaluation results, there is empirical support for the assumption of higher ammonia background at LWA than at TRNP and Beulah. Figure 8.9 provides an illustration of ammonia emissions density (tons/year/square mile) for North Dakota counties and adjoining Canadian provinces. These data were obtained from the WRAP RMC 2004/2005 report[40], and represent ammonia input conditions for CMAQ modeling. As shown in the figure, the TRNP and LWA IMPROVE sites, and the Beulah monitoring site, are all located in counties with the lowest ammonia emissions density (0.000-0.001 tons/year/square mile). However, the proximity of the LWA site is such that prevailing local winds (northwest and southeast wind direction) will likely direct higher density ammonia emissions from Saskatchewan (0.075-0.25 tons/year/square mile) and Ward county (0.005-0.025 tons/year/square mile) toward the LWA site.

For comparing predicted visibility progress with respect to the default (EPA) glide path, the NDDoH applied the basic ammonia limiting method, presented as Step 1 in Table 8.7. In order to determine progress in the context of weight of evidence arguments, such as discounting the effect of Canadian emissions, it was necessary to apply the 3-step ammonia limiting method (Section 8.6.3).

POSTUTIL output was subsequently processed with the NDDoH CALHAZE program to project future visibility (Section 8.5.5).

8.5.5 CALHAZE

The NDDoH has developed a software system to generate relative response factors (RRFs) from WRAP CMAQ and NDDoH CALPUFF (POSTUTIL) hourly concentration output files for baseline and future scenarios, project future concentrations of visibility affecting aerosols by applying RRFs to baseline IMPROVE data, and convert projected future concentrations to visibility (deciview). This system is informally known as CALHAZE. CALHAZE represents the final step in the NDDoH hybrid visibility modeling sequence (CALMET-CALPUFF-POSTUTIL-CALHAZE). Effectively, CALHAZE replaces CALPOST.

CALHAZE accesses NDDoH CALPUFF (POSTUTIL) hourly concentration files for baseline and future scenarios to generate 20 percent worst/best day RRFs for sulfate and nitrate. CALHAZE accesses WRAP CMAQ hourly concentration files (provided by WRAP RMC) for baseline and future scenarios to generate 20 percent worst/best day RRFs for all other visibility

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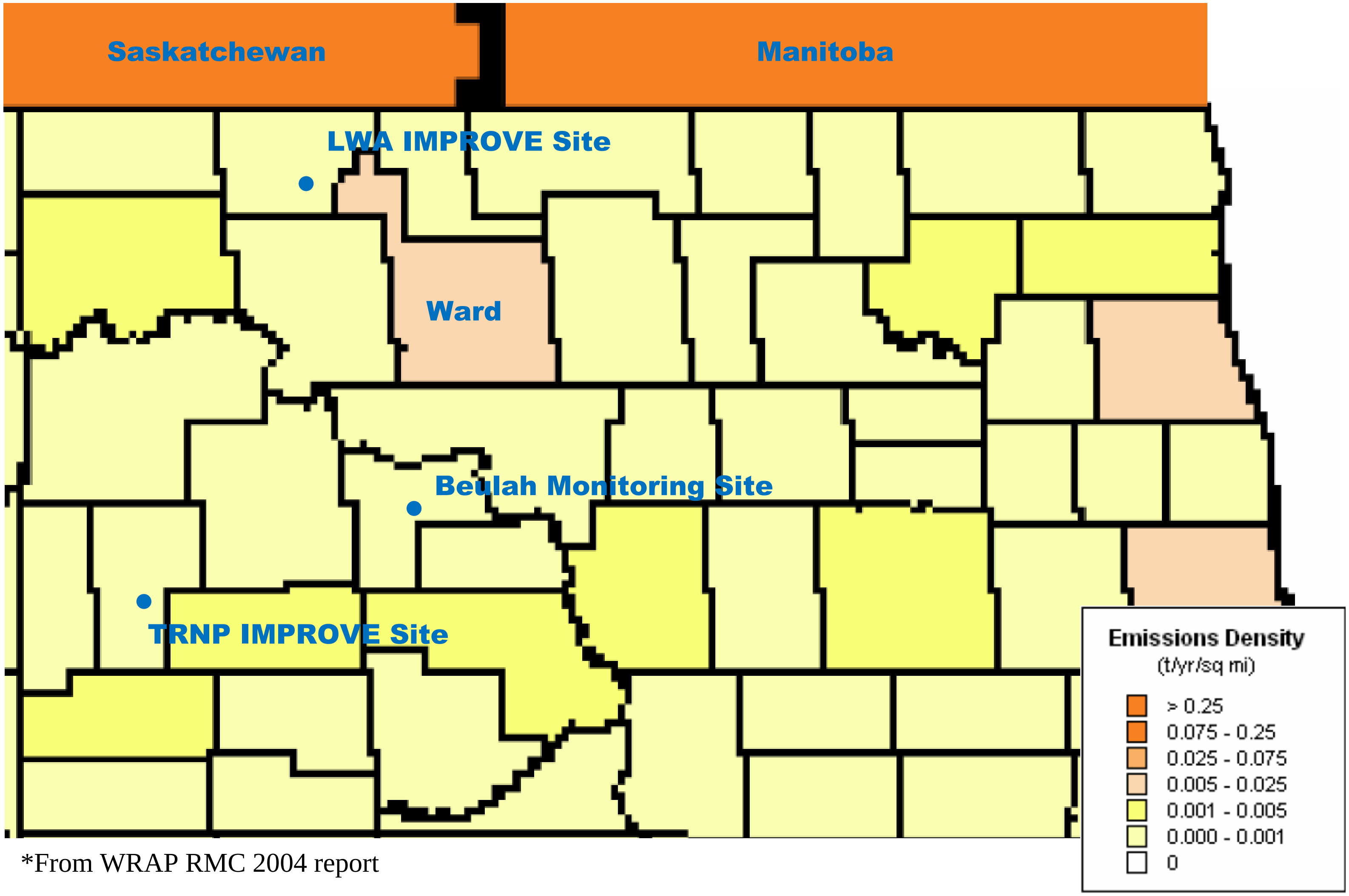
[40] Tonnesen, G., R. Morris, Z. Adelman, et. al., 2005. Final Report for the Western Regional Air Partnership (WRAP) Regional Modeling Center (RMC) for the Project Period March 1, 2004, through February 28, 2005, Appendices A Through E. Western Regional Air Partnership, Denver, CO 80202.

Figure 8.9
NH_3 Emissions Density for North Dakota Counties and Adjoining Canadian Provinces*



*From WRAP RMC 2004 report

affecting species. RRFs are applied to IMPROVE baseline monitoring (2000-2004) data files, obtained from the WRAP TSS (Technical Support System) internet site (http://vista.cira.colostate.edu/tss/), to project future concentrations of each visibility affecting species for each worst/best day for each year. Next, CALHAZE applies the new IMPROVE algorithm to calculate light extinction (using projected future concentrations) for each worst/best day for each year. Finally, deciview is calculated for each worst/best day, and averaged across all worst/best days and all years. CALHAZE repeats this procedure for each Class I area. CALHAZE incorporates the default EPA methodology to calculate RRFs and future deciview (Section 8.3).

Input files required by CALHAZE, as applied by NDDoH, are summarized:

1) WRAP CMAQ hourly concentration output file for baseline scenario (2002),

2) WRAP CMAQ hourly concentration output file for future scenario (2018),

3) NDDoH CALPUFF (POSTUTIL) hourly concentration output file for baseline scenario (2002 results for both TRNP and LWA receptors),

4) NDDoH CALPUFF (POSTUTIL) hourly concentration output file for future scenario (2018 results for both TRNP and LWA receptors),

5) IMPROVE daily baseline monitoring data for TRNP (2000-2004),

6) IMPROVE daily baseline monitoring data for LWA (2000-2004).

CMAQ hourly concentrations are taken from the grid cell containing the North Dakota Class I area. Note that all additional parameters necessary for calculating light extinction, via the new IMPROVE algorithm, are provided in the IMPROVE baseline monitoring data files. This includes function of relative humidity for sea salt and small and large size fractions, and the Rayleigh scattering coefficient. Consistent with WRAP RMC conclusions addressing the viability of CMAQ coarse mass predictions, CALHAZE forces a RRF of 1.0 for the coarse mass species. As discussed in Section 8.2, a constant RRF of 1.0 is also applied for sea salt.

As an option, the CALHAZE system also accepts a control input file which allows the user to set RRF for each species, and set the visibility target (in deciviews), for each Class I area. Use of this feature was necessary when applying the normalization procedure described in Section 8.5.6.

The NDDoH has applied the CALHAZE software to complete the hybrid modeling procedure and visibility projections for North Dakota Class I areas. To address quality assurance issues with respect to the CALHAZE system, the NDDoH has successfully cross-checked CALHAZE output with data on the TSS internet site. For example, the worst-day RRFs generated by CALHAZE for elemental carbon, organic mass, fine soil, and coarse mass for North Dakota Class I areas agree exactly with the corresponding values obtained from the TSS site.

8.5.6 Hybrid System Used to Adjust WRAP CMAQ Modeling Results

Based on performance testing of direct hybrid model predictions (operational evaluation), as conducted by NDDoH (see Section 8.6.1), the hybrid CMAQ-CALPUFF modeling system performed well in replicating observed concentrations of SO_4 and NO_3. However, performance regarding sensitivity to changes in NO_X emissions (diagnostic evaluation) was not good, with the hybrid modeling system significantly overstating future case nitrate formation compared to predictions obtained by WRAP using CMAQ alone. The NDDoH concluded this anomaly is an artifact of the chemistry in CALPUFF, and acknowledges that CMAQ chemistry is superior.

For this reason, the NDDoH chose not to accept direct hybrid modeling system results to independently address progress with respect to regional haze goals. Rather, the NDDoH used the hybrid modeling system in a supportive sense to add value to the original WRAP CMAQ modeling results. The hybrid system was used to provide a "correction" to WRAP CMAQ results in order to offset coarseness in the CMAQ spatial resolution for large, local point sources. Similarly, the hybrid system was applied to adjust WRAP CMAQ results in order to discount the effect of international (Canadian) sources. (WRAP did not provide regional haze modeling results which discount the impact of international sources, a modeling interpretation which had been requested by EPA and others, and which the NDDoH wanted to include in its weight of evidence discussion.)

8.5.6.1 Adjusting WRAP CMAQ Modeling Results for Local Point Sources

To address the concern regarding spatial resolution of the WRAP CMAQ simulations for local point sources, the NDDoH concluded that the hybrid modeling system could be used in an indirect manner to apply a reasonable and conceptually simple "correction" to the WRAP CMAQ RRFs (relative response factors) for sulfate and nitrate. Given that CALPUFF has the capability of treating point sources as well as area sources, all point sources within the NDDoH CALPUFF domain can be allocated (converted) to area sources, or more specifically to a 36-km area source grid, in order to emulate the coarse treatment of point sources in CMAQ. Then a correction factor can be established which adjusts the WRAP CMAQ prediction based on the predicted difference between point sources treated as conventional point sources and point sources treated as area sources (i.e., CMAQ emulation) with the hybrid model. This adjustment can be expressed

$$\overline{\chi}_{NDDH} = \overline{\chi}_{CMAQ}\left(\frac{\overline{\chi}_{HybridPt}}{\overline{\chi}_{HybridArea}}\right) \qquad (8-1)$$

where

$\overline{\chi}_{NDDH}$ is the adjusted average concentration (sulfate or nitrate) for 20% worst days. Note that both WRAP and NDDoH were consistent in basing 20% worst days on IMPROVE monitoring data (2002),

$\overline{\chi}_{CMAQ}$ is the average concentration for 20% worst days obtained by WRAP using CMAQ,

$\overline{\chi}_{HybridPt}$ is the average concentration for 20% worst days predicted by the hybrid model when point sources (within the NDDoH CALPUFF domain) are treated as conventional point sources,

$\overline{\chi}_{HybridArea}$ is the average concentration for 20% worst days predicted by the hybrid model when point sources (within the NDDoH CALPUFF domain) are allocated as 36-km area sources.

The ratio $\overline{\chi}_{HybridPt}$ / $\overline{\chi}_{HybridArea}$ in the equation is effectively a correction factor to address the coarse resolution of local point sources in CMAQ. Equation 8-1 can be thought of as an emulation of the result CMAQ would have produced had the plume-in-grid feature been deployed for local point sources (WRAP did not deploy CMAQ plume-in-grid for regional haze modeling). The Equation 8-1 adjustment involves modifying only the point source component of the hybrid model emissions inventory. Boundary conditions and sources originally treated as area sources (Section 8.5.3.1) remain equivalent in *HybridPt* and *HybridArea* emissions inventories.

Equation 8-1 is applicable for both baseline and future period modeling. Recall that the RRF for each species is defined[41],

$$RRF = \left(\frac{\overline{\chi}_{Future}}{\overline{\chi}_{Baseline}}\right)$$

where $\overline{\chi}_{Future}$ is the future 20% worst day average concentration and $\overline{\chi}_{Baseline}$ is the baseline 20% worst day average concentration. Therefore, if the future period implementation of Equation 8-1 is divided by the baseline period implementation of Equation 8-1, it follows that the adjustment for CMAQ treatment of point sources can be specified in terms of RRF,

$$RRF_{NDDH} = RRF_{CMAQ}\left(\frac{RRF_{HybridPt}}{RRF_{HybridArea}}\right) \qquad (8-2)$$

where

RRF_{NDDH} is the adjusted relative response factor ultimately used by NDDoH to project future concentrations of sulfate and nitrate,

RRF_{CMAQ} is the relative response factor obtained by WRAP using CMAQ,

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[41] See supra note 7.

$RRF_{HybridPt}$ is the relative response factor produced by the hybrid model when point sources (within NDDoH CALPUFF domain) are treated as conventional point sources,

$RRF_{HybridArea}$ is the relative response factor produced by the hybrid model when point sources (within NDDoH CALPUFF domain) are allocated as 36-km area sources.

Thus, Equation 8-2 was used by NDDoH to implement the adjustment for WRAP CMAQ treatment of point sources. The adjustment was utilized for 20% best days as well as 20% worst days, and was applied for each Class I area in North Dakota. It was applied directly to the RRFs from WRAP CMAQ modeling (specific day option[42]), which are shown in Table 8.8.

Table 8.8
WRAP CMAQ RRF
(Specific Day Option)

	TRNP Worst Day	**TRNP Best Day**	**LWA Worst Day**	**LWA Best Day**
SO_4	0.92	1.02	0.91	1.02
NO_3	0.92	0.93	0.96	0.89
OMC	1.01	1.01	1.05	1.01
EC	0.72	0.78	0.73	0.74
Soil	1.13	1.08	1.11	0.96
CM	1.00	1.00	1.00	1.00

To develop the *HybridArea* CALPUFF input files, all point source emissions were allocated to the CALPUFF 36-km area source grid, which is discussed in Section 8.5.3.1 and shown in Figure 8.8. The CALPUFF "effective height" (plume height) and "initial sigma z" area source input parameters were used to assign point source emissions to discrete vertical "layers" which are consistent with the WRAP CMAQ layers. Effective height is based on stack height plus plume rise as calculated externally.

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[42] In addition to the EPA-recommended specific day option for generating RRFs, WRAP also generated RRFs and projected future visibility based on monthly and quarterly weighting. The NDDoH used the specific day option exclusively in hybrid visibility modeling.

To complete emulation of the WRAP CMAQ 36-km grid resolution, receptor treatment was also addressed in the *HybridArea* input files. Effective "receptor" resolution in WRAP CMAQ is limited to the average concentration in the 36-km surface grid cell volume containing the Class I area IMPROVE site. To emulate WRAP CMAQ in *HybridArea* input files, the NDDoH averaged across a uniform receptor grid which filled the CALPUFF area-source 36-km grid cell containing each IMPROVE site (Figure 8.8). Receptors were spaced at 3 km for a total of 12 x 12 or 144 discrete receptors for each Class I area. Note that this type of receptor averaging was only applied in CALPUFF runs for CMAQ emulation (*HybridArea*), and not in runs for conventional point source treatment (*HybridPt*) or performance evaluation.

Given that the NDDoH hybrid modeling was limited to sulfate and nitrate species (and precursors), the Equation 8.2 adjustment was also limited to sulfate and nitrate species. The RRFs for all other light affecting species were taken directly from WRAP CMAQ modeling, as shown in Table 8.8. Therefore, it is likely that the correction for CMAQ resolution of point sources, in terms of the total projected future light extinction, is somewhat understated. However, the primary contributors to light extinction from the local point sources of concern in North Dakota are sulfate and nitrate.

The Equation 8.2 adjustment as applied by NDDoH also accounted for the WRAP overestimate of future oil and gas related NO_X emissions in North Dakota, as discussed in Section 8.5.3.1. This error affected the future period modeling only. Therefore, the *HybridArea* input file (CMAQ emulation) for the future period included WRAP estimated NO_X emissions for oil and gas, while the *HybridPt* input file for the future period included the NDDoH corrected future NO_X emissions for oil and gas. (The base period NO_X emissions in both cases were based on WRAP estimates for 2002.) This accounting for the WRAP error in future oil and gas NO_X emissions was not expected to make a significant difference in results.

When applying the Equation 8.2 adjustment, the NDDoH found the ratio $RRF_{HybridPt}$ to $RRF_{HybridArea}$ to be consistently less than 1.0, providing a resultant RRF_{NDDH} which was significantly lower than the WRAP CMAQ RRF, with subsequently lower projected future concentrations and greater projected visibility improvement than predicted by WRAP. This expected response is related primarily to the resolution of modeling systems as applied to local point sources. When local point sources are treated as conventional point sources, the higher density point-source plumes cause higher predictions at the IMPROVE monitor site (for both baseline and future periods) such that the future reduction in emissions from local point sources may cause a relatively large impact compared to the more static contribution of all other sources (area and boundary). When local point sources are configured as 36-km area sources, the associated diluted plumes cause lower predictions compared to the contribution of all other sources (other area and boundary), such that the future reduction in emissions may be overwhelmed by the more static contribution of other sources.

8.5.6.2 Discounting the Impact of Canadian Sources

In the process of analyzing progress with respect to visibility goals, it was necessary for the NDDoH to address the impact of Canadian sources north of the International border. This interpretation of modeling results was requested by EPA and others, and was an important element of the NDDoH weight of evidence discussion (see Section 8.6.3). No specific guidance is provided for this type of analysis. The method used by NDDoH was to eliminate Canadian sources from the baseline and future emissions inventories used to develop RRFs, and to develop a modified glide path which discounts the effect of Canadian sources. This approach is similar to methods proposed by CENRAP[43] and others.

Again, the NDDoH implemented its procedure for discounting Canadian sources in terms of an adjustment to WRAP CMAQ modeling results. If Canadian sources are eliminated from baseline and future emissions inventories for conventional point sources, Equation 8-2 becomes

$$RRF_{NDDH} = RRF_{CMAQ}\left(\frac{RRF_{HybridPt-C}}{RRF_{HybridArea}}\right) \qquad (8-3)$$

where

$RRF_{HybridPt-C}$ represents the resultant relative response factor after eliminating Canadian sources from the conventional point source baseline and future emissions inventories used with the hybrid modeling system.

Equation 8-3 was used by the NDDoH to develop adjusted RRFs for sulfate and nitrate. Note that with the implementation of Equation 8-3, the adjustment to discount the impact of Canadian sources is effectively “added on” to the adjustment for WRAP CMAQ point source resolution.

To complete the illustration, the impact of Canadian sources must also be discounted from the glide path used to assess progress with respect to visibility goals. In this case, the NDDoH applied the hybrid modeling system exclusively to estimate the baseline starting point (deciview) of the modified glide path. The estimation process involved adjusting the IMPROVE baseline concentration for each worst-case day for the five-year period 2000-2004, in order to approximate the daily observations without the impact of Canadian sources. The estimation procedure for each worst-case day can be expressed

$$\chi_{obs(us)} = \chi_{obs}\left(\frac{\overline{\chi}_{pred(us)}}{\overline{\chi}_{pred}}\right) \qquad (8-4)$$

where

$\chi_{obs(us)}$ is the estimated sulfate or nitrate concentration for one worst case day of IMPROVE monitoring data for all non-Canadian sources (plus natural background),

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[43] CENRAP, 2007. CENRAP Policy Oversight Group (POG) - Summary of PM Source Apportionment Modeling and 2018 Projection Approaches. Power Point presentation, Joint Workgroup Meeting, Kansas City, Missouri, March 7, 2007.

χ_{obs} is the original IMPROVE observed sulfate or nitrate concentration for the worst case day,

$\overline{\chi}_{pred(us)}$ is the average prediction for 20% worst days when hybrid model is applied for non-Canadian sources only (Year 2002 baseline emissions inventory),

$\overline{\chi}_{pred}$ is the average prediction for 20% worst days when hybrid model is applied for the entire source inventory (Year 2002 baseline emissions inventory).

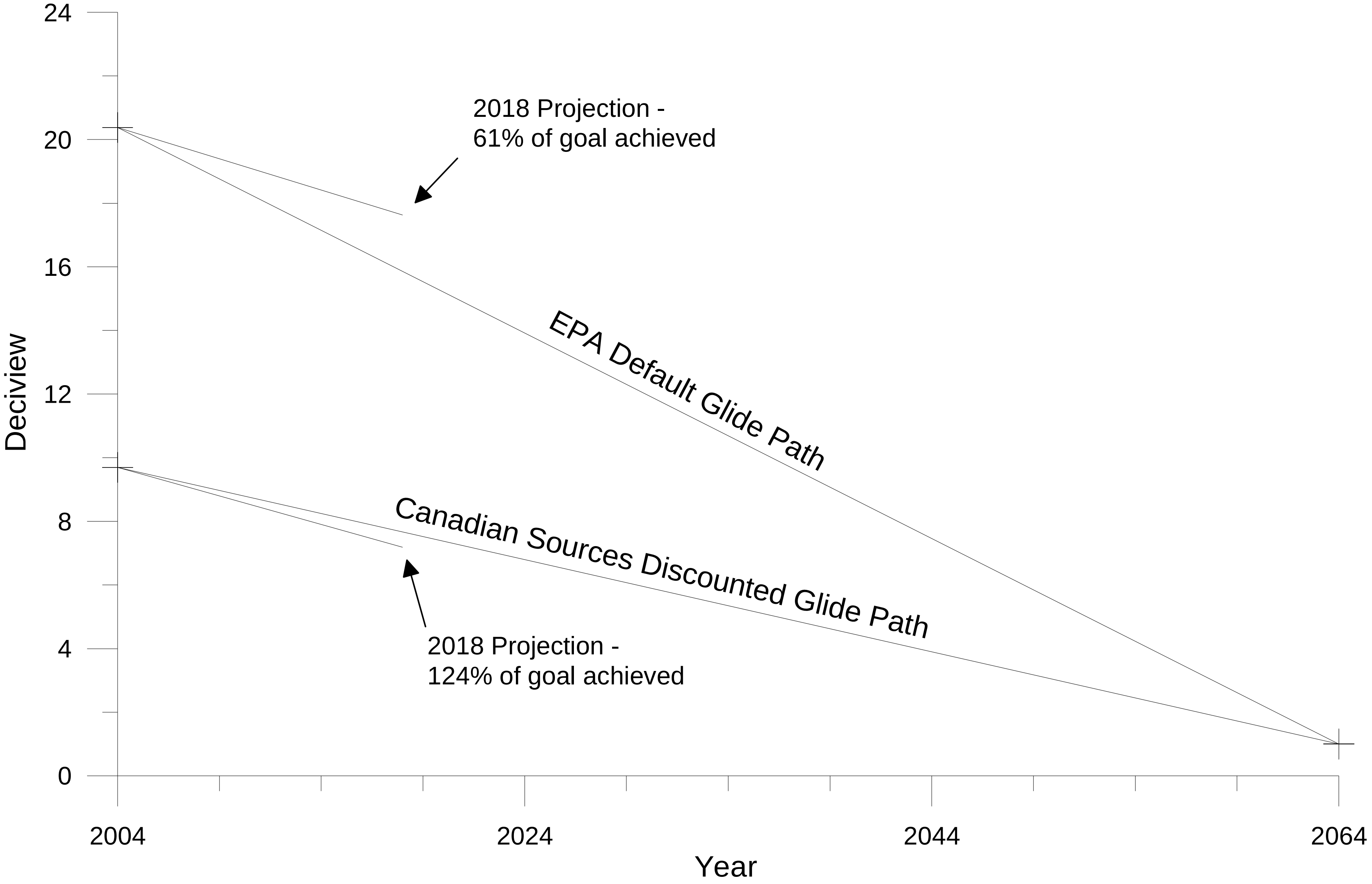
Using the adjusted worst day observations for sulfate and nitrate, along with the original IMPROVE worst day observations for all other visibility-affecting species, light extinction and deciview were calculated for each 20% worst day of the 2000-2004 period. Finally, the five-year average deciview was calculated to set the starting point for the “Canadian sources discounted” glide path for 20% worst days.

The NDDoH next considered the end point (2064) of the modified glide path. When adjusting baseline and future emissions inventories to exclude Canadian sources, the intent of NDDoH was to eliminate the impact of non-natural sources only, leaving the contribution of all other non-Canadian sources plus natural sources. Therefore, an adjustment was made to CALPUFF boundary conditions (baseline and future) to eliminate the contribution of Canadian source emissions, while retaining the impact of natural Canadian sources of sulfate and nitrate. This adjustment is described in Section 8.6.3.1. And recall that the NDDoH adjustment does not affect the impact of all other visibility-affecting species on the glide path. As such, the NDDoH concluded that it was not necessary or appropriate to change the end point (default natural conditions) of the modified glide path.

A modified glide path is illustrated in Figure 8.10, for a hypothetical case where Canadian source emissions contribute about one-half of total visibility degradation.

Using the modified glide path, the NDDoH applied RRFs generated using Equation 8-3 to the adjusted starting point to estimate visibility improvement progress by 2018 (see Section 8.6.3.1). As expected, visibility improvement increased significantly when Canadian sources were discounted. Canadian source emissions were discounted only for 20% worst days, as the impact of Canadian sources was not problematic in meeting visibility goals for best days.

Figure 8.10
Illustration of Visibility Improvement Using EPA Default Glide Path and Canadian Sources Discounted Glide Path



8.6 Modeling Process and Results

The NDDoH hybrid modeling system was applied to adjust WRAP CMAQ results, using input conditions and procedures as described in Section 8.5. A performance evaluation was conducted first to ensure that selected inputs were producing viable results relative to observed concentrations of sulfate and nitrate. (Note that the performance evaluation was based on predictions taken directly from hybrid model output, rather than adjusted WRAP CMAQ output described in Section 8.5.6.) Next, the hybrid modeling system was executed in default production mode to determine progress with respect to the glide path and URP target based on default EPA methodology. Finally, the hybrid modeling system was applied to test several weight of evidence scenarios. NDDoH hybrid results and WRAP CMAQ results were compared for the default EPA methodology.

8.6.1 Hybrid CMAQ-CALPUFF Performance Evaluation

The NDDoH conducted a limited operational evaluation to assess performance of the hybrid CMAQ-CALPUFF modeling system. The focus of the evaluation was to assess performance in reproducing observed concentrations of sulfate and nitrate at IMPROVE monitoring sites in North Dakota. These sites include the Theodore Roosevelt National Park South Unit (TRNP) and the Lostwood Wilderness Area (LWA). Alternative input options which might improve performance were also explored. To the extent applicable, the performance evaluation followed EPA guidance for Regional Haze modeling analyses[44].

An emissions inventory for the performance evaluation was developed by NDDoH. WRAP CMAQ hourly concentration output (SO_2-SO_4-NO_X-HNO_3-NO_3) for Case BASE02B was used to set hourly boundary conditions for CALPUFF. The emissions inventory (SO_2-NO_X) for the point source category was developed using data from the NDDoH emissions database for 2002, and sources were configured as conventional point sources in CALPUFF. This inventory included point sources located in adjacent parts of South Dakota, Montana, and Canada, which are included in the NDDoH CALPUFF domain (see Figure 8.5). This inventory also included SO_2 emissions associated with oil and gas production facilities (treaters and flares) in North Dakota, which did not appear to be accounted for in the WRAP inventory for BASE02B. Emission rates for the point source inventory reflect actual emissions for Year 2002.

All other source categories (see Table 8.2) were treated as area sources in CALPUFF, and the emissions inventory (SO_2-SO_4-NO_X-NO_3) for these categories was based on WRAP CMAQ input (SMOKE output) for all sources other than point sources. Software was prepared and implemented to apportion the gridded SMOKE output emissions for BASE02B into a 36-km area source grid structure developed for the NDDoH CALPUFF domain (Figure 8.8), on a consistent spatial basis. Emission rates for this area source inventory reflect annual averages for the SMOKE data.

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[44] See supra note 7.

The CALPUFF modeling system (CALMET-CALPUFF-POSTUTIL-CALPOST) was applied for SO_2-SO_4-NO_X-NO_3 source inventories and boundary conditions as described above. All other input conditions were consistent with the description of the hybrid modeling system in Section 8.5. Single receptors were placed at the TRNP and LWA IMPROVE sites. Monthly average ammonia data were utilized from the Beulah monitoring site in both CALPUFF and POSTUTIL.

After initial application of CALPUFF for the performance evaluation, it was concluded that certain scientifically-defensible adjustments to CALPUFF input conditions may improve performance for the hybrid modeling system, and should be investigated. Thus, the performance evaluation evolved into a suite of tests which are described below.

1) Test 1 - Calpuff executed with default input conditions, as outlined above. Air mass depth for boundary conditions was set to 2000 meters.

2) Test 2 - CALPUFF as in Test 1, but using CEMS 2002 hourly emissions data (SO_2, NO_X) for point sources, where available.

3) Test 3 - CALPUFF as in Test 1, but using WRAP MM5 12 km 2002 mesoscale data in CALMET, rather than the default NDDoH RUC 2002 mesoscale data.

4) Test 4 - CALPUFF as in Test 1, but increasing air mass depth for boundary conditions from 2000 to 3000 meters.

5) Test 5 - CALPUFF as in Test 1, but with addition of SO_4 and NO_3 emissions from point sources. (Previous tests excluded this component, because SO_4 and NO_3 emissions are not included in the NDDoH point source inventory. For Test 5, an SO_4-NO_3 emissions inventory was derived from SMOKE gridded output for the point source category, and configured as area sources for CALPUFF.)

6) Test 6 - CALPUFF as in Tests 4 and 5 (air mass depth = 3000 meters, SO_4 and NO_3 emissions from point sources included), but area sources configured as 4 separate groups to account for varying release heights of different source types, and Beulah hourly profile used for background NH_3 in POSTUTIL. (Area sources were configured as a single CALPUFF group in previous tests.)

7) Test 7 - CALPUFF as in Test 6, but Beulah hourly NH_3 profile doubled for LWA.

Results of the performance evaluation are summarized in Tables 8.9 and 8.10. Table 8.9 compares predicted NO_3 and SO_4 concentrations to observed concentrations for both IMPROVE sites, while Table 8.10 provides predicted-to-observed ratios. Note that both tables include a column labeled “CMAQ only”, which provides the original WRAP CMAQ results for Case BASE02B.

Table 8.9
Hybrid CMAQ-CALPUFF Performance Evaluation
Observed and Predicted Concentrations Year 2002 (ug/m^3)

	Observed	Hybrid CMAQ-CALPUFF Predicted*							CMAQ only
		Test 1	Test 2	Test 3	Test 4	Test 5	Test 6	Test 7	
TRSU NO3									
98th Percentile Day	**2.03**	2.11	2.11	2.20	1.96	2.11	2.06	2.06	3.21
90th Percentile Day	**1.21**	1.50	1.46	1.55	1.43	1.47	1.21	1.21	1.62
Avg 20% Worst Days	**1.42**	1.59	1.59	1.65	1.56	1.59	1.41	1.41	1.84
Annual Average	**0.50**	0.71	0.71	0.73	0.70	0.71	0.53	0.53	0.57
TRSU SO4									
98th Percentile Day	**3.29**	2.57	2.57	2.47	2.53	2.57	2.58	2.58	2.36
90th Percentile Day	**1.88**	1.72	1.72	1.66	1.77	1.72	1.79	1.79	1.60
Avg 20% Worst Days	**2.43**	1.96	1.97	1.83	1.96	1.98	1.99	1.99	1.76
Annual Average	**1.03**	0.90	0.90	0.86	0.90	0.91	0.91	0.91	0.84
Lostwood NO3									
98th Percentile Day	**3.65**	1.91	1.91	2.01	1.94	1.85	2.15	2.74	3.64
90th Percentile Day	**1.95**	1.48	1.50	1.56	1.47	1.44	1.13	1.76	2.04
Avg 20% Worst Days	**2.33**	1.55	1.55	1.61	1.52	1.50	1.30	2.03	2.34
Annual Average	**0.79**	0.70	0.70	0.73	0.69	0.67	0.47	0.80	0.79
Lostwood SO4									
98th Percentile Day	**3.10**	2.91	2.90	2.74	2.88	3.11	3.12	3.12	3.65
90th Percentile Day	**2.22**	2.06	2.03	1.90	2.07	2.19	2.21	2.21	2.43
Avg 20% Worst Days	**2.49**	2.21	2.21	2.09	2.22	2.35	2.36	2.36	2.74
Annual Average	**1.18**	1.07	1.07	1.03	1.08	1.15	1.17	1.17	1.32

* Test 1 - Calpuff run with default BART screening protocol + full emissions inventory + boundary conditions
Test 2 - Calpuff as in Test 1 but using CEMS hrly emissions (SO2, NOX) where available
Test 3 - Calpuff as in Test 1 but using WRAP MM5 12km mesoscale data (in CALMET)
Test 4 - Calpuff as in Test 1 but assuming boundary air mass depth as 3000 m rather than 2000 m
Test 5 - Calpuff as in Test 1 but with addition of NO3 and SO4 emissions from point sources
Test 6 - Calpuff as in Test 1 but assuming boundary air mass depth as 3000 m (Test 4) and with addition of NO3 and SO4 emissions from point sources (Test 5). Area sources configured as 4 groups and Beulah hourly profile used for backgound NH3.
Test 7 - Calpuff as in Test 6 but Beulah hourly NH3 profile doubled for Lostwood

Table 8.10
Hybrid CMAQ-CALPUFF Performance Evaluation
Predicted to Observed Ratios 2002

	Hybrid CMAQ-CALPUFF*							CMAQ only
	Test 1	Test 2	Test 3	Test 4	Test 5	Test 6	Test 7	
TRSU NO3								
98th Percentile Day	1.04	1.04	1.08	0.97	1.04	1.01	1.01	1.58
90th Percentile Day	1.24	1.21	1.28	1.18	1.21	1.00	1.00	1.34
Avg 20% Worst Days	1.12	1.12	1.16	1.10	1.12	0.99	0.99	1.30
Annual Average	1.42	1.42	1.46	1.40	1.42	1.06	1.06	1.14
TRSU SO4								
98th Percentile Day	0.78	0.78	0.75	0.77	0.78	0.78	0.78	0.72
90th Percentile Day	0.91	0.91	0.88	0.94	0.91	0.95	0.95	0.85
Avg 20% Worst Days	0.81	0.81	0.75	0.81	0.81	0.82	0.82	0.72
Annual Average	0.87	0.87	0.83	0.87	0.88	0.88	0.88	0.82
Lostwood NO3								
98th Percentile Day	0.52	0.52	0.55	0.53	0.51	0.59	0.75	1.00
90th Percentile Day	0.76	0.77	0.80	0.75	0.74	0.58	0.90	1.05
Avg 20% Worst Days	0.67	0.67	0.69	0.65	0.64	0.56	0.87	1.00
Annual Average	0.89	0.89	0.92	0.87	0.85	0.59	1.01	1.00
Lostwood SO4								
98th Percentile Day	0.94	0.94	0.88	0.93	1.00	1.01	1.01	1.18
90th Percentile Day	0.93	0.91	0.86	0.93	0.99	1.00	1.00	1.09
Avg 20% Worst Days	0.89	0.89	0.84	0.89	0.94	0.95	0.95	1.10
Annual Average	0.91	0.91	0.87	0.92	0.97	0.99	0.99	1.12

* Test 1 - Calpuff run with default BART screening protocol + full emissions inventory + boundary conditions
Test 2 - Calpuff as in Test 1 but using CEMS hrly emissions (SO2, NOX) where available
Test 3 - Calpuff as in Test 1 but using WRAP MM5 12km mesoscale data (in CALMET)
Test 4 - Calpuff as in Test 1 but assuming boundary air mass depth as 3000 m rather than 2000 m
Test 5 - Calpuff as in Test 1 but with addition of NO3 and SO4 emissions from point sources
Test 6 - Calpuff as in Test 1 but assuming boundary air mass depth as 3000 m (Test 4) and with addition of NO3 and SO4 emissions from point sources (Test 5). Area sources configured as 4 groups and Beulah hourly profile used for backgound NH3.
Test 7 - Calpuff as in Test 6 but Beulah hourly NH3 profile doubled for Lostwood

As shown in Tables 8.9 and 8.10, the primary metrics selected to measure performance for this evaluation are 90th percentile day concentration (24-hour average), average of 20% worst days concentration, and annual average concentration. The first two metrics were selected for consistency with the time scale that applies to regional haze modeling, i.e., average of the 20% worst or 20% best days. The third metric, annual average concentration, is a measure of the model's ability to accurately conserve total annual mass. The comparison between predicted and observed concentrations for the first two metrics is unpaired in time.

Also shown in Tables 8.9 and 8.10 is the 98th percentile day prediction (24-hour average). This metric was included for completeness at the request of EPA. The 98th percentile prediction has relevance as the primary metric used in BART single-source modeling.

Results in Tables 8.9 and 8.10 indicate that the hybrid modeling system performed well, in general. Even for the initial Test 1, predictions were well within a factor of two of observations. In most cases, the hybrid system predictions were closer to observations than predictions from CMAQ, alone. Table 8.10 illustrates that the hybrid system slightly over-predicted observations for TRNP NO_3, and slightly under-predicted, otherwise.

A comparison of results for Tests 1 through 5 reveals very little difference in predictions. The implication is that the input changes reflected in Tests 2 through 5 did not add significant value to the hybrid model's ability to accurately reproduce observations. The increased temporal resolution obtained by using the CEMS hourly emissions for applicable point sources (Test 2) provided no consistent improvement. Test 3 results suggest that the NDDoH RUC mesoscale data is consistent with the WRAP MM5 mesoscale data. Test 4 results indicate that Calpuff is not very sensitive to boundary air mass depth. Even the addition of point source NO_3 and SO_4 emissions in Test 5 achieved no meaningful improvement in predictions, suggesting that sources configured as area sources in CALPUFF may have only a small contribution to the total prediction.

While the operational evaluation to compare predictions with observations was being conducted, the NDDoH also undertook a preliminary diagnostic evaluation[45] to assess the response of the hybrid modeling system to changes in NO_X and SO_2 emissions. In response to significant reductions in both SO_2 and NO_X emissions, the NDDoH found that the hybrid system responded reasonably well with correspondingly lower SO_4 predictions, but seemed to overstate NO_3 predictions for the reduced emission scenario. In fact, NO_3 concentrations actually increased under some assumptions, possibly an overreaction to the newly freed ammonia in the reduced SO_2 emissions scenario (SO_2 preferentially scavenges ammonia in the CALPUFF chemistry). This behavior was not as obvious in the WRAP CMAQ results for baseline versus future predictions.

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[45] See supra note 7.

To address the problematic NO_3 response, the NDDoH discussed the issue with Joe Scire (TRC)[46], a recognized CALPUFF expert in the regulatory modeling community. Mr. Scire indicated that TRC testing has shown that the NO_3 response may improve if hourly background ammonia is used rather than monthly average values. Also, Mr. Scire provided some insight on configuring area sources in CALPUFF to be more consistent with the area source treatment in CMAQ. This involves proper settings for the CALPUFF "release height" and "initial sigma z" input parameters for area sources. The NDDoH retested after incorporating Mr. Scire's suggestions, i.e., using hourly ammonia background and reconfigured area sources. Although the NO_3 response improved, predicted reductions were still not consistent with CMAQ.

As a result of the initial diagnostic performance testing, the NDDoH concluded that the use of hourly ammonia background concentrations is preferable to the use of monthly averages, and that CALPUFF inputs for area sources should be reconfigured. Additional operational evaluation tests (Tests 6 and 7) were thus conducted to determine how these changes would affect the comparison with observations. Test 6 was conducted by first assuming a boundary air mass depth of 3000 meters (Test 4) and accounting for NO_3 and SO_4 emissions from point sources (Test 5). Then area sources were configured as suggested by Scire, including the use of 4 area source groups to account for varying release heights for different source categories (as opposed to one group in Tests 1-5). Finally, Test 6 included use of the Beulah hourly ammonia profile in POSTUTIL.

Results of Test 6, as shown in Tables 8.9 and 8.10, indicate significantly improved performance with respect to TRNP NO_3, but worse performance for LWA NO_3. Results for SO_4 were not significantly affected. This tendency for conflicting results for TRNP and LWA NO_3 was also exhibited in Tests 1 through 5, and led the NDDoH to conclude that the Beulah data may not be representative of ammonia background for both TRNP and LWA. Moreover, the actual ammonia background affecting LWA may be significantly higher than the background affecting TRNP.

In Test 7, the NDDoH found that observational agreement for LWA NO_3 can be vastly improved if the ammonia hourly backgound values are approximately doubled (for LWA only). All other conditions for Test 7, including the ammonia background for TRNP, remain the same as in Test 6. NO_3 predictions for Test 7 in Tables 8.9 and 8.10 now show good agreement with observations at both TRNP and LWA.

Finally, the NDDoH developed time series plots (consistent with Test 1 assumptions) to compare temporal patterns of predictions with observations for year 2002. In Figure 8.11, daily model predictions for nitrate at TRNP are compared with IMPROVE observations for 2002 (note that observations are only available for every third day). Time series for both NDDoH hybrid predictions and WRAP CMAQ predictions are included. As shown in the figure, both modeling systems appear to reproduce the general seasonal pattern of nitrate observations, with significantly lower concentrations in the summer. When compared with observations, the overall magnitude of predictions for the hybrid modeling system appears better, as CMAQ seems to under predict in the summer (many daily values very close to 0.0) and over predict otherwise.

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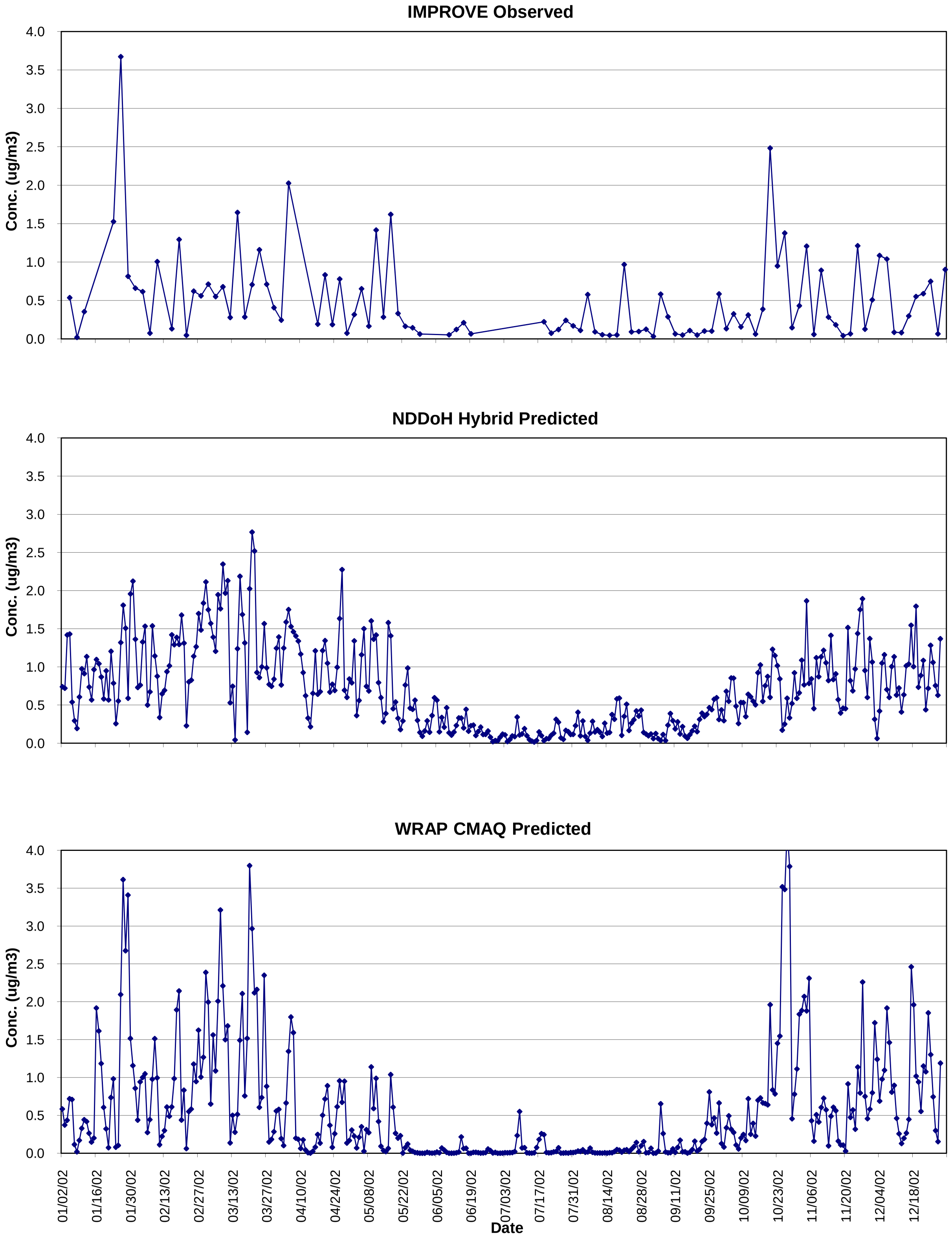
[46] See supra note 28.

Figure 8.11
Observed and Predicted Time Series TRNP NO_3 2002



CMAQ, however, may be more effective in reproducing some of the peak observed concentrations (paired in time).

In summary, the NDDoH concluded that the hybrid modeling system performs effectively, and may be used to adjust WRAP CMAQ modeling results. Further, agreement with sulfate and nitrate observations would be optimized using the following input conditions with the hybrid system:

- use RUC mesoscale data for CALMET,
- use boundary air mass depth of 3000 meters,
- include SO_4 and NO_3 emissions from point sources,
- configure area sources as four groups,
- use Beulah hourly background ammonia for TRNP, and
- use double Beulah hourly background ammonia for LWA.

8.6.2 Results for Default EPA Methodology

8.6.2.1 Cumulative Results

The NDDoH hybrid modeling system was applied to adjust WRAP CMAQ results, using input conditions and procedures consistent with optimal model performance, and described in Section 8.5. Hybrid modeling for the default EPA methodology included the entire emissions inventory. NDDoH projections for 2018 visibility are compared here with WRAP RMC projections for 2018 visibility, based on default EPA methodology.

Results of WRAP CMAQ and NDDoH hybrid visibility modeling for the default EPA scenario are summarized in Table 8.11. The table includes visibility projections for North Dakota Class I areas for 20% worst monitored days and 20% best monitored days. The table includes deciview values for baseline conditions, natural conditions, and the 2018 uniform rate of progress (URP) target. WRAP and NDDoH projections provided in the table include the absolute visibility projection in deciviews, and the percentage of the visibility target achieved by the projection. Note that the URP target and projected percentage of target are not included for best days, because the Regional Haze Rule specifies the URP target only for worst days. The requirement for best days is simply that the visibility projection for 2018 is no higher than the baseline monitored value.

Table 8.11
WRAP and NDDoH Visibility Modeling Results
Uniform Rate of Progress – Default EPA Methodology

Class I Area	20% Worst/Best Days	2000-2004 Baseline Conditions (dv)	2064 Natural Conditions (dv)	2018 URP Target (dv)	WRAP 2018 Projected Visibility (dv)	WRAP 2018 Projected Percent of Target	NDDoH 2018 Projected Visibility (dv)	NDDoH 2018 Projected Percent of Target
Theodore Roosevelt National Park	Worst	17.80	7.8	15.47	17.24	24.0	16.91	38.1
	Best	7.76	3.04	-----	7.67	-----	7.62	-----
Lostwood Wilderness Area	Worst	19.57	8.0	16.87	19.12	16.7	18.85	26.7
	Best	8.19	2.92	-----	8.06	-----	8.10	-----

Figure 8.12
TRNP Uniform Rate of Progress – EPA Default Methodology

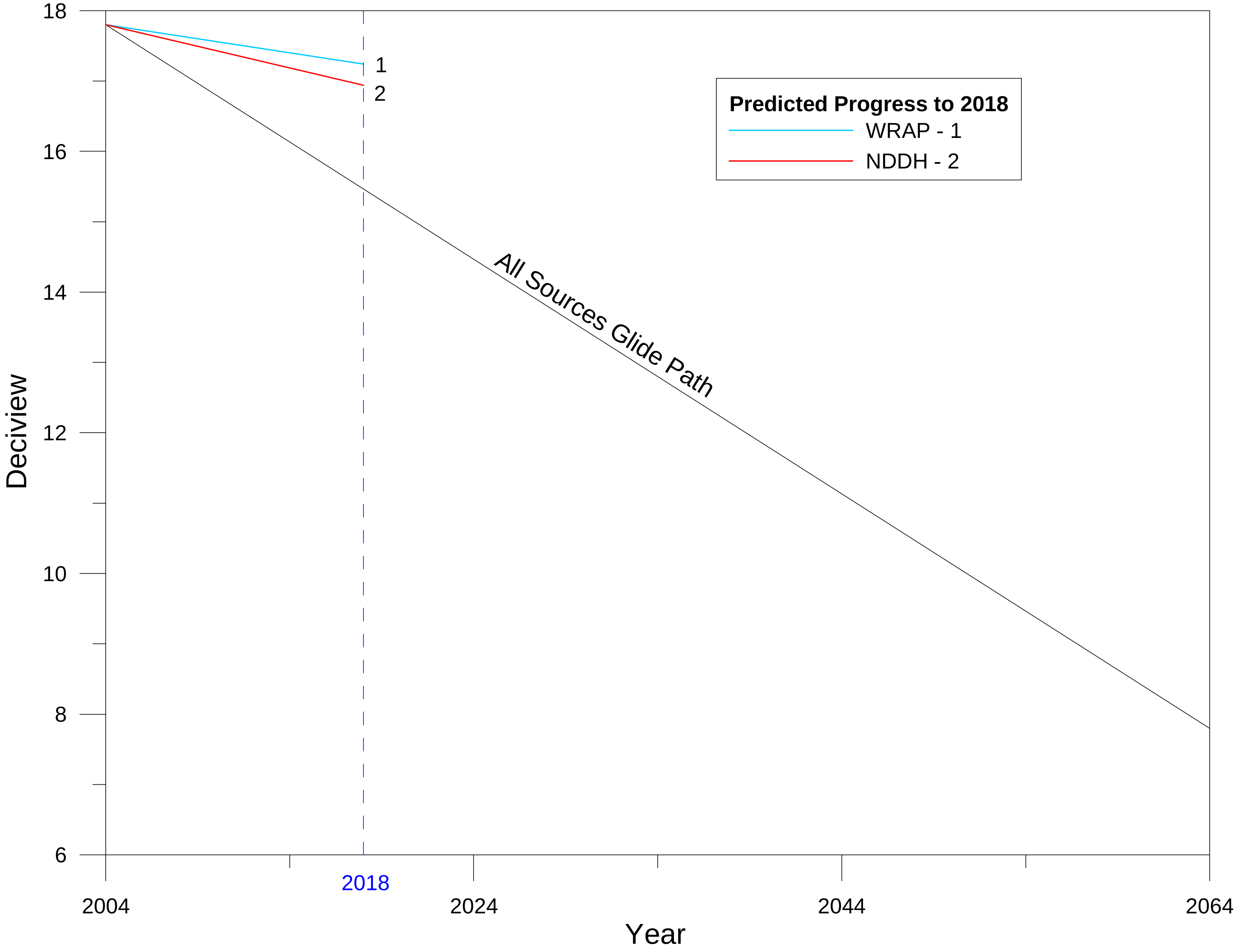
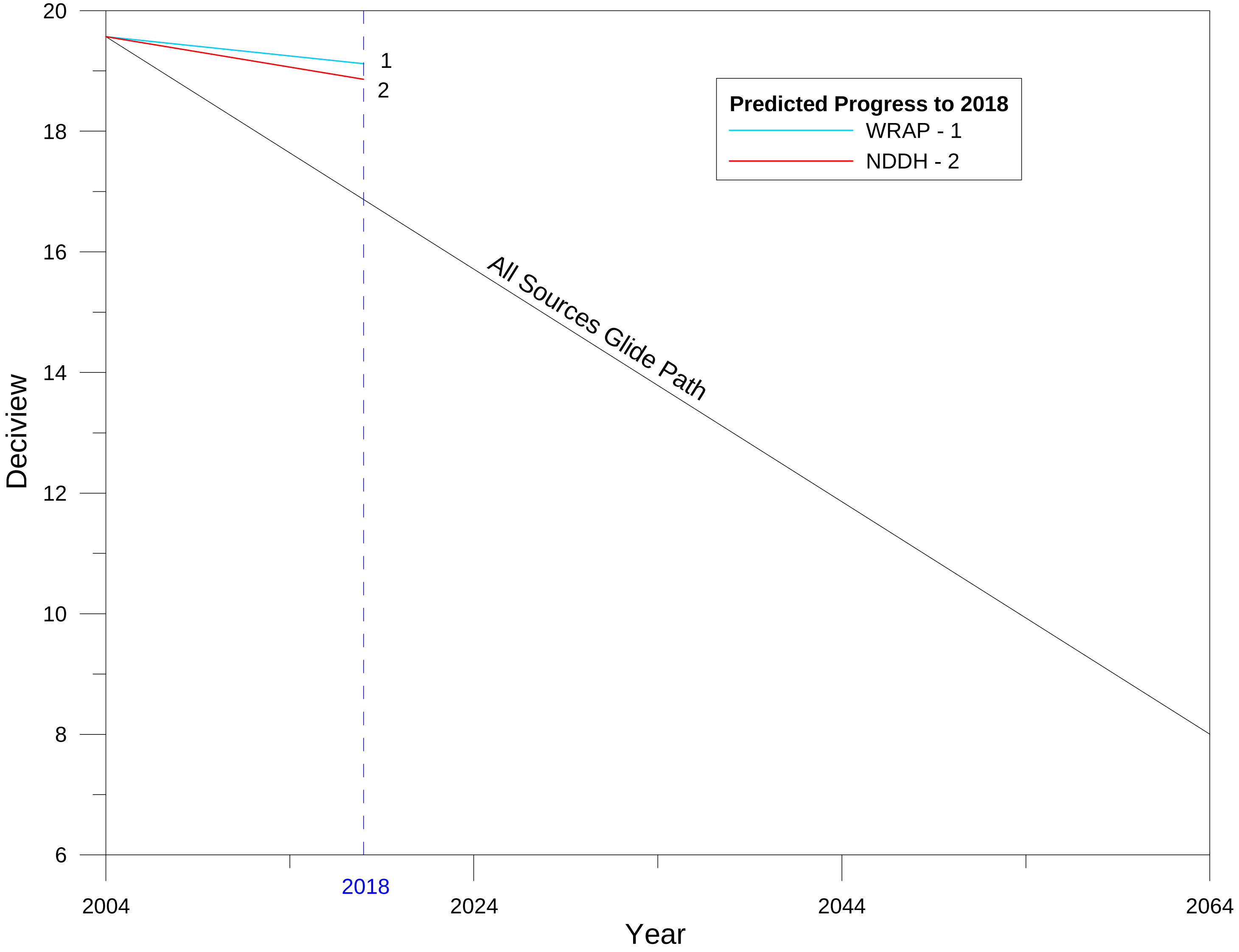


Figure 8.13
LWA Uniform Rate of Progress – EPA Default Methodology



As shown in Table 8.11, the NDDoH projections for 20% worst days indicate greater progress with respect to the 2018 goals than the WRAP projections, but both sets of projections fall well short of the URP targets. The WRAP projection constitutes 24.0 percent of the visibility goal at Theodore Roosevelt National Park (TRNP), while the NDDoH projection is 37.1 percent of the goal at that Class I area. For Lostwood Wilderness Area (LWA), WRAP projects 16.7 percent of the URP goal while the NDDoH projects that 26.3 percent of the goal will be achieved.

On the 20% best monitored days, both WRAP and NDDoH predictions in Table 8.11 illustrate that 2018 visibility will be better than baseline monitored values for both TRNP and LWA Class I areas. The WRAP 2018 projection of 7.67 deciviews and the NDDoH 2018 projection of 7.63 deciviews compare favorably with the baseline value of 7.76 deciviews for TRNP. At the LWA Class I area, the WRAP 2018 prediction of 8.06 deciviews and the NDDoH prediction of 8.10 deciviews both fall below the baseline value of 8.19 deciviews. Thus, requirements of the Regional Haze rule for the 20% best days will be satisfied.

Worst-day results of WRAP and NDDoH visibility modeling for the EPA default scenario are graphically interpreted with respect to the uniform rate of progress in Figure 8.12 and Figure 8.13 for TRNP and LWA, respectively. The “all sources” glide paths in Figures 8.12 and 8.13 originate with the monitored baseline deciview value in 2004, and terminate with the natural background deciview value in 2064. Using the same point of origination, the projected visibility progress is plotted against the glide path in each figure.

Figures 8.12 and 8.13 illustrate how NDDoH hybrid modeling projects better visibility improvement to 2018 than WRAP CMAQ modeling for both Class I areas. The figures also illustrate how far WRAP and NDDoH projections are from meeting the 2018 URP targets for 20% worst day visibility.

8.6.2.2 Apportionment by Species

The contribution of individual visibility-affecting species to total observed and projected light extinction for 20% worst/best days is discussed here. According to the IMPROVE algorithm, light affecting species include sulfate (SO_4), nitrate (NO_3), organic carbon (OMC), elemental carbon (EC), fine soil (Soil), coarse material (CM), and sea salt (SS). An additional component of light extinction which is included in the IMPROVE algorithm is Rayleigh scattering (Ray), which was also addressed in the projection of future visibility.

IMPROVE speciated monitoring data for 20% worst days at TRNP and LWA are summarized in the bar charts of Figures 8.14 and 8.15, respectively. The figures provide the percentage contribution of each visibility-affecting species, as well as Rayleigh scattering, to each 20% worst visibility day in baseline year 2004. The worst days are identified by month and day of the month at the bottom of the charts.

As seen in Figures 8.14 and 8.15, most of the 20% worst day light extinction at North Dakota Class I areas is dominated by sulfate and nitrate contributions. Rayleigh scattering is also a significant component, but otherwise the contribution of other visibility-affecting species (OMC,

Figure 8.14
IMPROVE 20% Worst Days – TRNP 2004

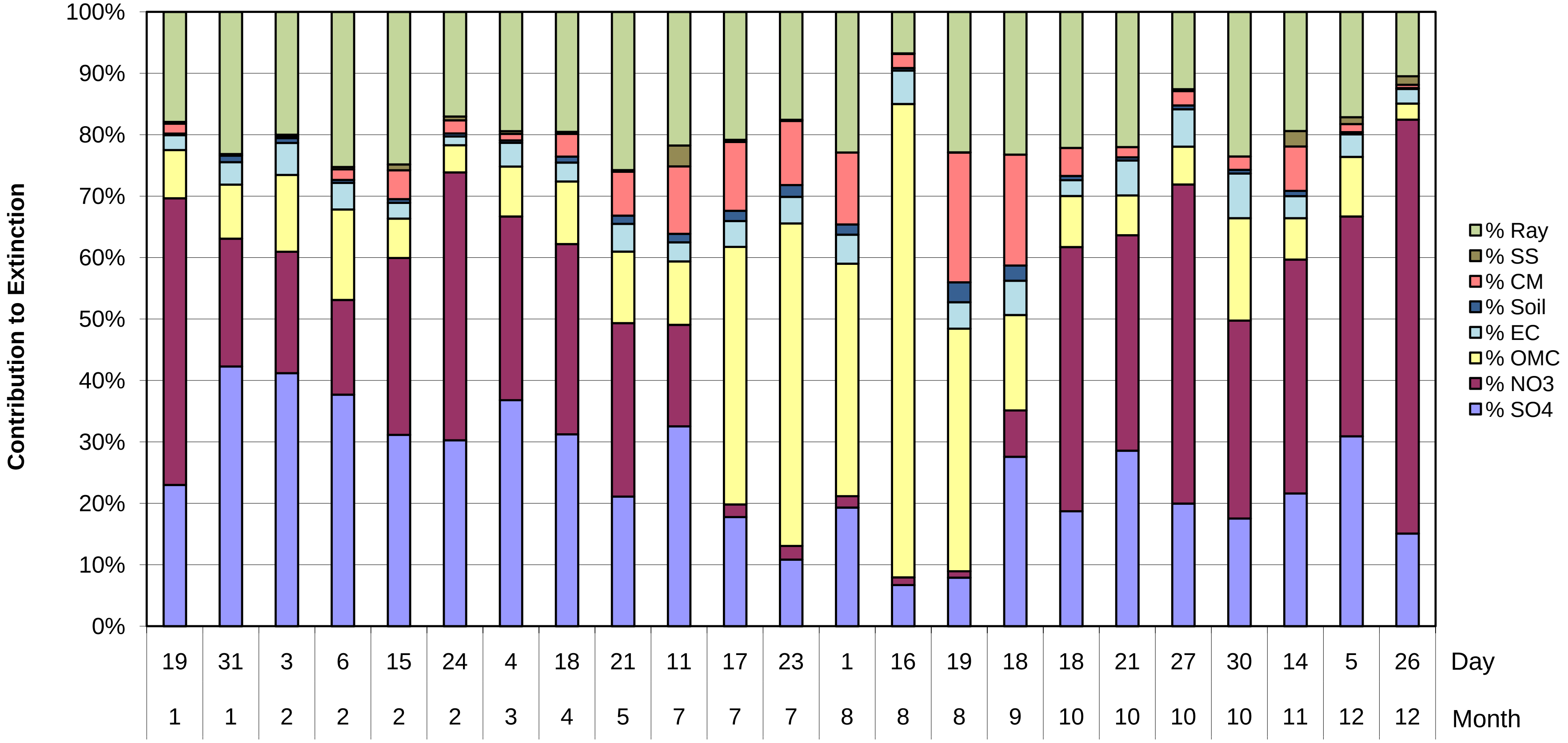


Figure 8.15
IMPROVE 20% Worst Days – LWA 2004

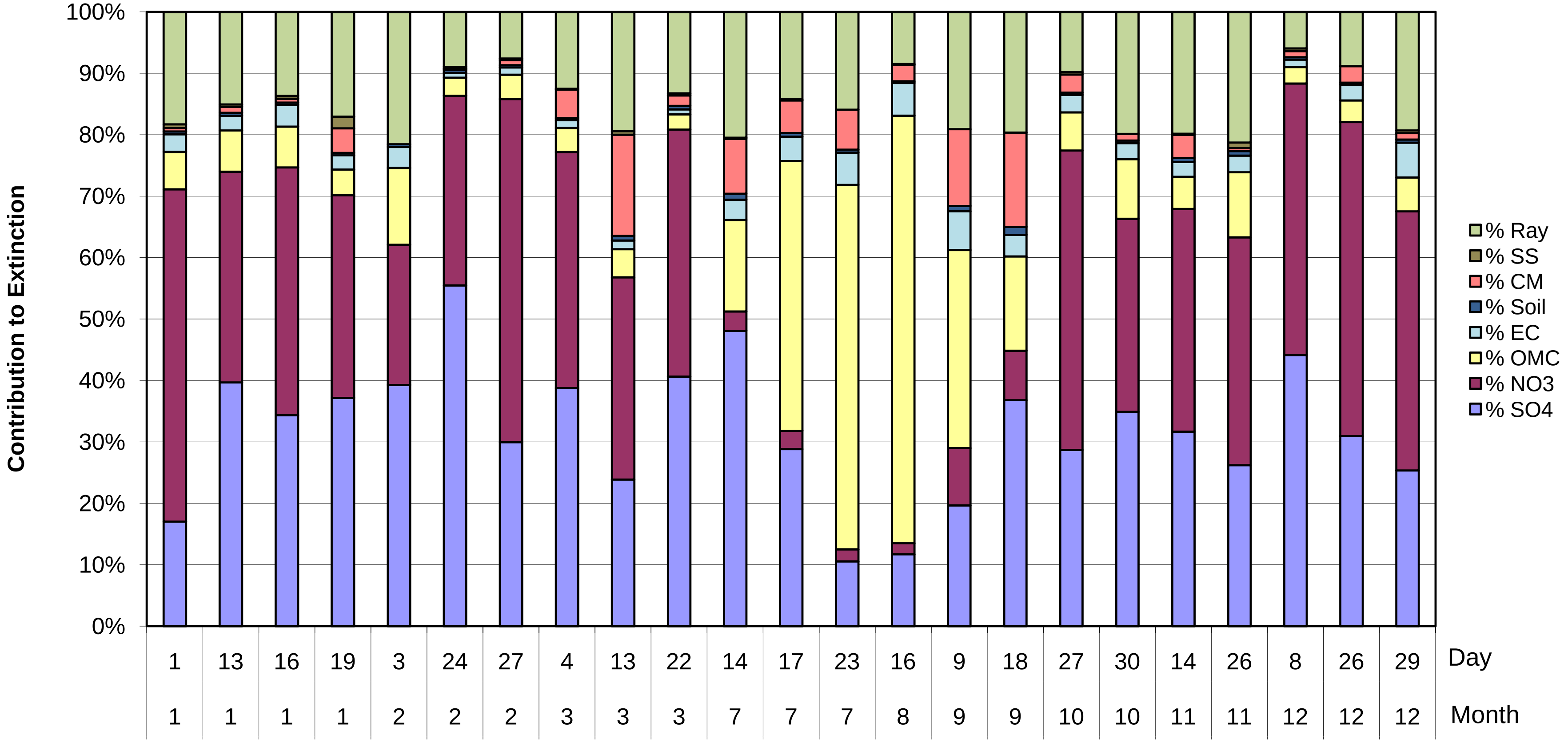


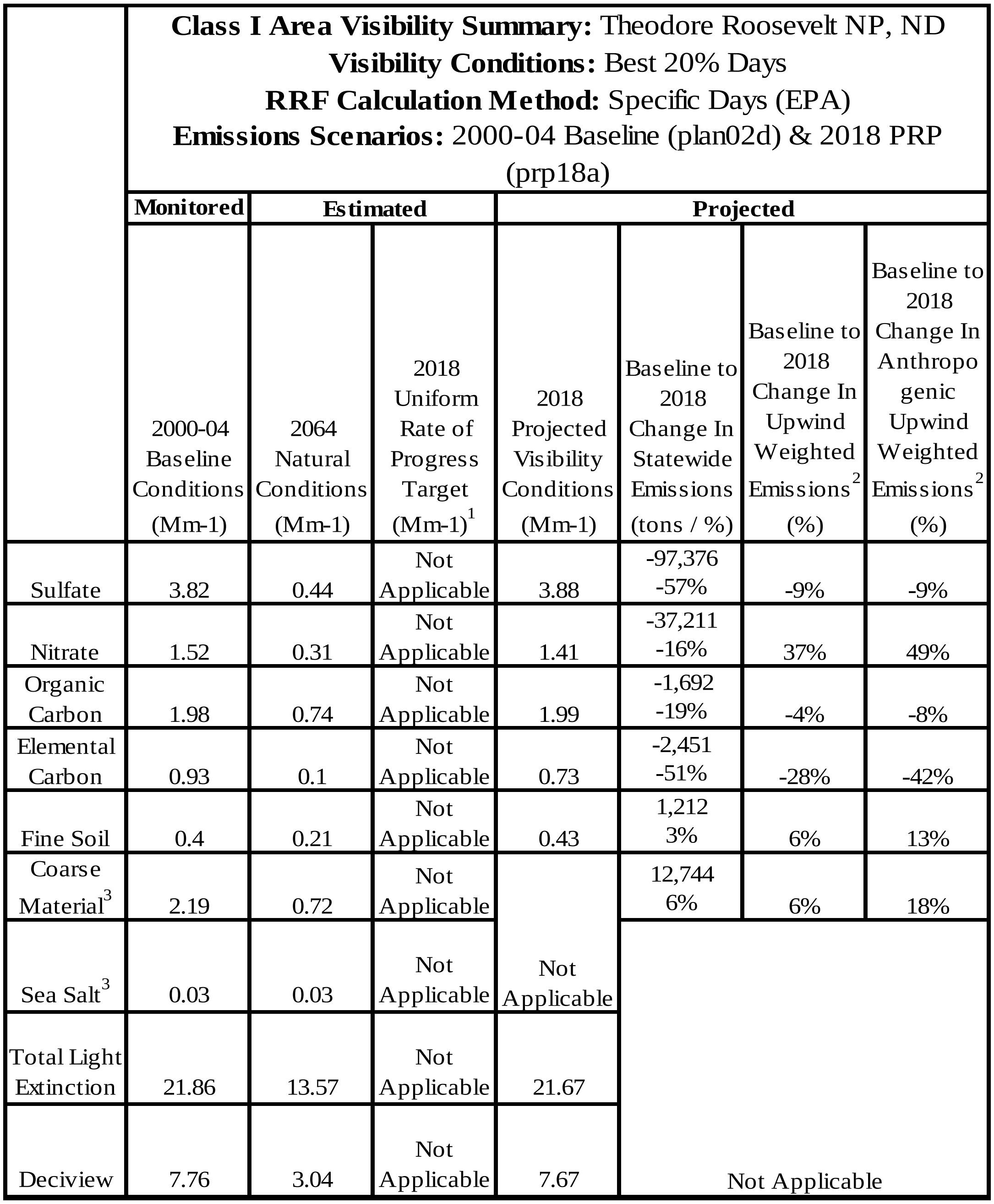
Table 8.12
Summary of WRAP CMAQ Visibility Projections for Worst 20% Days at TRNP

	Class I Area Visibility Summary: Theodore Roosevelt NP, ND **Visibility Conditions:** Worst 20% Days **RRF Calculation Method:** Specific Days (EPA) **Emissions Scenarios:** 2000-04 Baseline (plan02d) & 2018 PRP (prp18a)						
	Monitored	**Estimated**		**Projected**			
	2000-04 Baseline Conditions (Mm-1)	2064 Natural Conditions (Mm-1)	2018 Uniform Rate of Progress Target (Mm-1)[1]	2018 Projected Visibility Conditions (Mm-1)	Baseline to 2018 Change In Statewide Emissions (tons / %)	Baseline to 2018 Change In Upwind Weighted Emissions[2] (%)	Baseline to 2018 Change In Anthropogenic Upwind Weighted Emissions[2] (%)
Sulfate	17.53	1	12.23	15.94	-97,376 -57%	-21%	-21%
Nitrate	13.74	1.04	9.85	12.5	-37,211 -16%	27%	36%
Organic Carbon	10.82	3.92	8.95	10.94	-1,692 -19%	-3%	-8%
Elemental Carbon	2.75	0.32	2.13	1.98	-2,451 -51%	-28%	-44%
Fine Soil	0.9	0.97	0.91	1.02	1,212 2%	5%	10%
Coarse Material[3]	4.82	3.66	4.54	Not Applicable	12,744 4%	4%	13%
Sea Salt[3]	0.07	0.24	0.11		Not Applicable		
Total Light Extinction	61.62	22.14	48.41	58.26			
Deciview	17.8	7.8	15.47	17.24			

WRAP TSS

1) 2018 Uniform Rate of Progress Target for Best 20% Days is not defined.
2) Results based on Weighted Emissions Potential analysis using the 2000-04 Baseline (plan02d) & 2018 PRP (prp18a) emissions scenarios.
3) Visibility projections not available due to model performance issues.

Table 8.13
Summary of WRAP CMAQ Visibility Projections for Best 20% Days at TRNP



Class I Area Visibility Summary: Theodore Roosevelt NP, ND
Visibility Conditions: Best 20% Days
RRF Calculation Method: Specific Days (EPA)
Emissions Scenarios: 2000-04 Baseline (plan02d) & 2018 PRP (prp18a)

	Monitored	**Estimated**		**Projected**			
	2000-04 Baseline Conditions (Mm-1)	2064 Natural Conditions (Mm-1)	2018 Uniform Rate of Progress Target (Mm-1)[1]	2018 Projected Visibility Conditions (Mm-1)	Baseline to 2018 Change In Statewide Emissions (tons / %)	Baseline to 2018 Change In Upwind Weighted Emissions[2] (%)	Baseline to 2018 Change In Anthropogenic Upwind Weighted Emissions[2] (%)
Sulfate	3.82	0.44	Not Applicable	3.88	-97,376 -57%	-9%	-9%
Nitrate	1.52	0.31	Not Applicable	1.41	-37,211 -16%	37%	49%
Organic Carbon	1.98	0.74	Not Applicable	1.99	-1,692 -19%	-4%	-8%
Elemental Carbon	0.93	0.1	Not Applicable	0.73	-2,451 -51%	-28%	-42%
Fine Soil	0.4	0.21	Not Applicable	0.43	1,212 3%	6%	13%
Coarse Material[3]	2.19	0.72	Not Applicable	Not Applicable	12,744 6%	6%	18%
Sea Salt[3]	0.03	0.03	Not Applicable		Not Applicable		
Total Light Extinction	21.86	13.57	Not Applicable	21.67			
Deciview	7.76	3.04	Not Applicable	7.67			

WRAP TSS

1) 2018 Uniform Rate of Progress Target for Best 20% Days is not defined.
2) Results based on Weighted Emissions Potential analysis using the 2000-04 Baseline (plan02d) & 2018 PRP (prp18a) emissions scenarios.
3) Visibility projections not available due to model performance issues.

Table 8.14
Summary of WRAP CMAQ Visibility Projections for Worst 20% Days at LWA

Class I Area Visibility Summary: Lostwood NWRW, ND
Visibility Conditions: Worst 20% Days
RRF Calculation Method: Specific Days (EPA)
Emissions Scenarios: 2000-04 Baseline (plan02d) & 2018 PRP (prp18a)

	Monitored	**Estimated**		**Projected**			
	2000-04 Baseline Conditions (Mm-1)	2064 Natural Conditions (Mm-1)	2018 Uniform Rate of Progress Target (Mm-1)[1]	2018 Projected Visibility Conditions (Mm-1)	Baseline to 2018 Change In Statewide Emissions (tons / %)	Baseline to 2018 Change In Upwind Weighted Emissions[2] (%)	Baseline to 2018 Change In Anthropogenic Upwind Weighted Emissions[2] (%)
Sulfate	21.4	1.05	14.61	19.21	-97,376 -57%	-9%	-9%
Nitrate	22.94	1.1	15.56	21.94	-37,211 -16%	-16%	-19%
Organic Carbon	11.05	3.79	9.07	11.68	-1,692 -19%	-7%	-11%
Elemental Carbon	2.84	0.36	2.21	2.07	-2,451 -51%	-32%	-40%
Fine Soil	0.62	0.95	0.7	0.69	1,212 2%	-14%	-19%
Coarse Material[3]	3.93	3.74	3.89	Not Applicable	12,744 4%	-3%	-5%
Sea Salt[3]	0.26	0.52	0.32		Not Applicable		
Total Light Extinction	74.05	22.52	55.93	70.78			
Deciview	19.57	8	16.87	19.12			

WRAP TSS

1) 2018 Uniform Rate of Progress Target for Best 20% Days is not defined.
2) Results based on Weighted Emissions Potential analysis using the 2000-04 Baseline (plan02d) & 2018 PRP (prp18a) emissions scenarios.
3) Visibility projections not available due to model performance issues.

Table 8.15
Summary of WRAP CMAQ Visibility Projections for Best 20% Days at LWA

	Class I Area Visibility Summary: Lostwood NWRW, ND **Visibility Conditions:** Best 20% Days **RRF Calculation Method:** Specific Days (EPA) **Emissions Scenarios:** 2000-04 Baseline (plan02d) & 2018 PRP (prp18a)						
	Monitored	**Estimated**		**Projected**			
	2000-04 Baseline Conditions (Mm-1)	2064 Natural Conditions (Mm-1)	2018 Uniform Rate of Progress Target (Mm-1)[1]	2018 Projected Visibility Conditions (Mm-1)	Baseline to 2018 Change In Statewide Emissions (tons / %)	Baseline to 2018 Change In Upwind Weighted Emissions[2] (%)	Baseline to 2018 Change In Anthropogenic Upwind Weighted Emissions[2] (%)
Sulfate	4.39	0.42	Not Applicable	4.47	-97,376 -57%	-1%	-1%
Nitrate	1.86	0.34	Not Applicable	1.65	-37,211 -16%	-16%	-19%
Organic Carbon	2.26	0.66	Not Applicable	2.27	-1,692 -19%	-8%	-12%
Elemental Carbon	0.71	0.1	Not Applicable	0.52	-2,451 -51%	-31%	-38%
Fine Soil	0.34	0.22	Not Applicable	0.33	1,212 3%	-20%	-25%
Coarse Material[3]	2.31	0.63	Not Applicable	Not Applicable	12,744 6%	-6%	-10%
Sea Salt[3]	0.03	0.03	Not Applicable		Not Applicable		
Total Light Extinction	22.89	13.4	Not Applicable	22.58			
Deciview	8.19	2.92	Not Applicable	8.06			

WRAP TSS

1) 2018 Uniform Rate of Progress Target for Best 20% Days is not defined.
2) Results based on Weighted Emissions Potential analysis using the 2000-04 Baseline (plan02d) & 2018 PRP (prp18a) emissions scenarios.
3) Visibility projections not available due to model performance issues.

EC, Soil, CC, and SS) is generally very small. The exception is worst days in late July and August, where organic carbon replaces sulfate and nitrate as the dominate contributor to extinction. This pattern was similar in other years of IMPROVE baseline data (2000-2003). A possible explanation is that fugitives associated with agricultural burning, prescribed burning within Class I areas, and wild fires may be the largest contributors to light extinction during late July and August, while emissions from conventional large point sources are the largest contributors during the remainder of the year.

WRAP CMAQ modeling results for the default EPA methodology were used to review the contribution of individual visibility-affecting species to projected light extinction for 20% worst/best days (NDDoH hybrid modeling did not include all species). Summaries of WRAP CMAQ modeling results including 2018 projections for individual species are provided in Tables 8.12 through 8.15. Tables 8.12 and 8.13 provide speciated summaries (averages) of 20% worst and best days, respectively, for TRNP. Tables 8.14 and 8.15 address speciated summaries of 20% worst and best days, respectively, for LWA. The tables include light extinction values for baseline conditions, natural conditions, 2018 uniform rate of progress target, and 2018 projected visibility conditions for each visibility-affecting species. Values for total light extinction and deciview are provided as well (note these values are consistent with results in Table 8.11). Note that 2018 projected values are not provided for CM and SS species, due to model performance issues. For these species, WRAP (and NDDoH) assumed an RRF of 1.0, and set the 2018 projection equal to the monitored baseline value.

In reviewing the 20% worst day summaries for TRNP and LWA in Tables 8.12 and 8.14, respectively, sulfate and nitrate are found to be the largest contributors to light extinction. This is true for both baseline monitored conditions and for future (2018) projected conditions. Because of its dominance in the late summer months, organic carbon is also a major overall contributor to 20% worst day light extinction for both baseline monitored and future projected conditions. As discussed previously, WRAP modeling results for 20% worst days (summarized in Tables 8.12 and 8.14) indicate the total light extinction URP target will not be achieved at either TRNP or LWA. Further, results for individual species indicate the URP species-specific target will be met only for elemental carbon and sea salt.

The 20% best day summaries for TRNP and LWA are reported in Tables 8.13 and 8.15, respectively. With exception of sea salt, all species appear to be significant contributors to light extinction on 20% best days. Sulfate is the largest contributor at both TRNP and LWA. As shown in the tables, the 2018 projected light extinction is lower than the baseline light extinction for both Class I areas. Thus, Regional Haze Rule requirements for 20% best days will be satisfied at TRNP and LWA for the first planning period.

Note that the WRAP projected emissions values for nitrate (NO_X) in Tables 8.12 through 8.15 are not consistent with the levels used by NDDoH in hybrid modeling. The NDDoH adjusted the WRAP NO_X emissions associated with oil and gas activity, as described in Section 8.5.3.1.

8.6.2.3 Apportionment by Source Group

As established in Section 8.6.2.2, sulfate and nitrate are the primary contributors to 20% worst day visibility in North Dakota Class I areas. In its hybrid modeling analysis, the NDDoH tracked the contribution of source groups to the total predicted sulfate and nitrate concentration for 20% worst days, in order to enhance the interpretation of modeling results. Contributions are available for the following source groups:

- North Dakota electrical generating units (EGU),
- all other point sources within the CALPUFF domain,
- all sources modeled as area sources within the CALPUFF domain,
- North Dakota oil and gas related sources (O&G), and
- boundary conditions representing the impact of all sources located outside of the CALPUFF domain.

Focus is on the ND EGU and boundary condition groups because of their relatively small and large contributions, respectively. O&G contributions are available for sulfate, only.

Contributions of the above source groups to 20% worst day average predictions, based on NDDoH hybrid modeling, are illustrated in Figures 8.16 through 8.19. Predictions for the base period (2000-2004) are compared with predictions for the future period (2018) in the figures. Contributions for sulfate at TRNP are compared in Figure 8.16. Figure 8.17 provides contributions for sulfate at LWA. Source group contributions for nitrate at TRNP are illustrated in Figure 8.18. Finally, Figure 8.19 addresses contributions for nitrate at LWA. Source group contributions in the figures reflect the percent of the total average predicted concentration for 20% worst days.

As consistently shown in Figures 8.16 through 8.19, the contribution of North Dakota EGUs to total sulfate and total nitrate is relatively small, while the contribution of boundary conditions is relatively large. This is true for both baseline and future projections. For sulfate, boundary conditions contributed no less than two-thirds of the total at North Dakota Class I areas. For nitrate, the boundary condition contribution was no less than 59 percent. The contribution of North Dakota EGUs to sulfate was no more than 21 percent, and to nitrate was no more than 6 percent, at North Dakota Class I areas.

As shown in Figures 8.16 and 8.17, the reduced impact from North Dakota EGUs due to BART controls is apparent. The projected future contribution of North Dakota EGUs to sulfate is less than one-half the baseline contribution for both TRNP and LWA. The difference for other source groups is less pronounced, although an exception would be area sources at LWA, where the baseline contribution of 4.0 percent is reduced to 2.4 percent in 2018. In comparing future with baseline contributions in Figures 8.16 and 8.17, it appears the contribution of boundary

Figure 8.16
Hybrid Modeling Results
Source Group Contributions to 20% Worst Day SO_4 at TRNP (Base & Future)

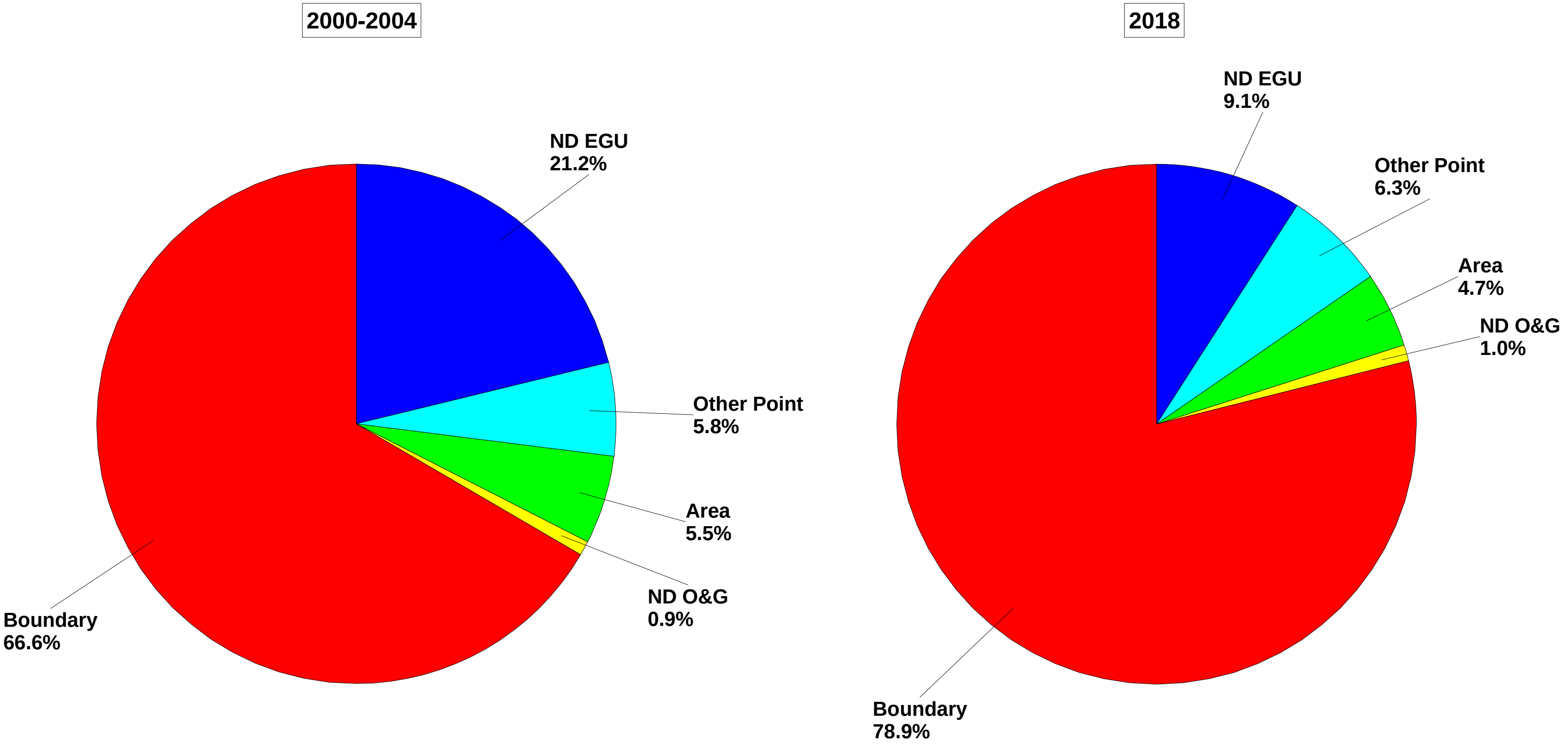


Figure 8.17
Hybrid Modeling Results
Source Group Contributions to 20% Worst Day SO_4 at LWA (Base & Future)

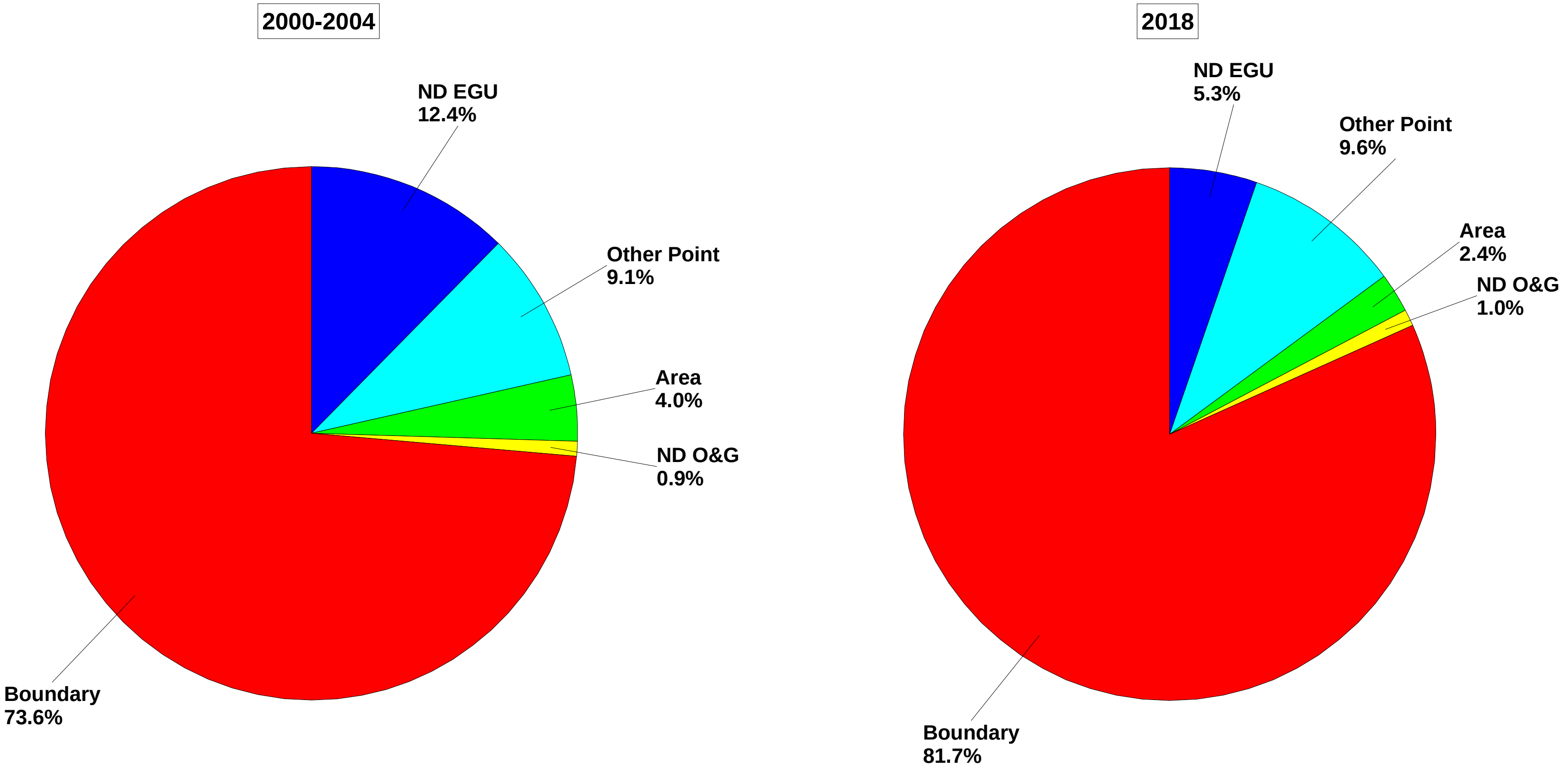
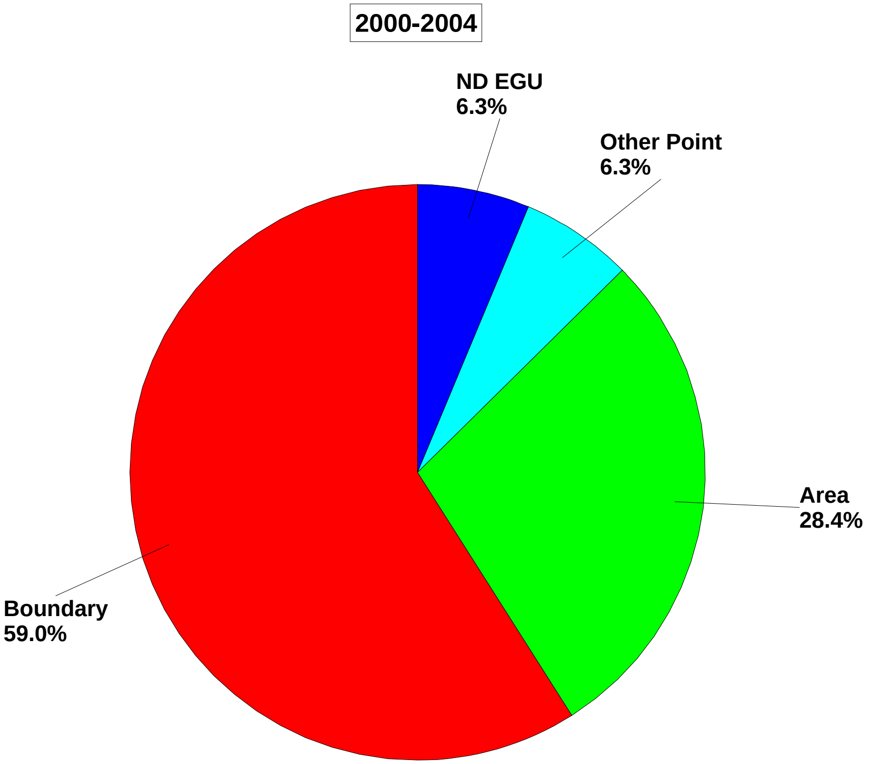


Figure 8.18
Hybrid Modeling Results
Source Group Contributions to 20% Worst Day NO_3 at TRNP (Base & Future)



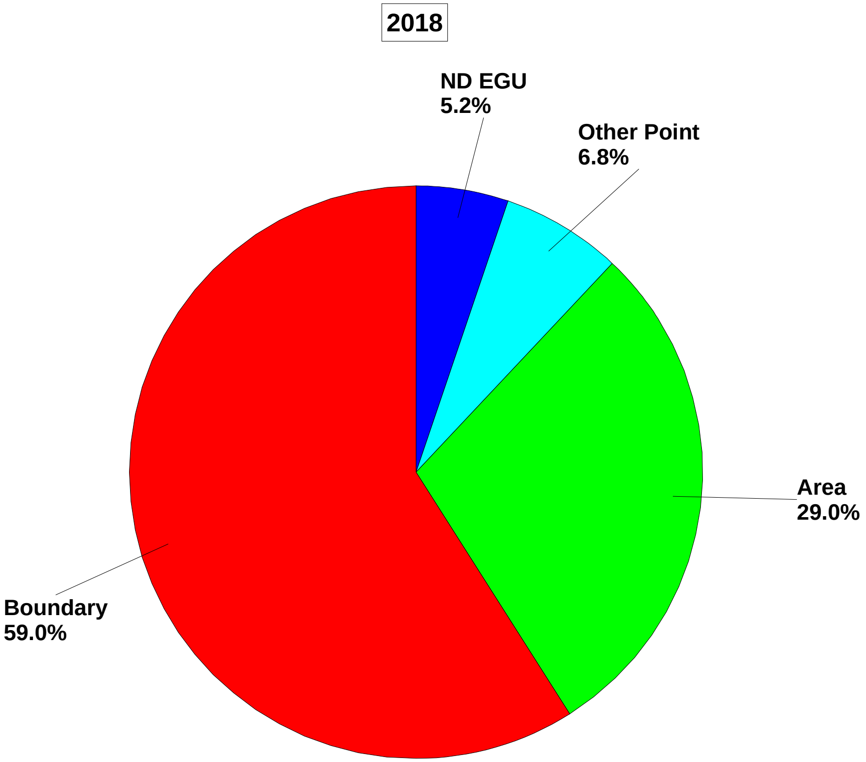
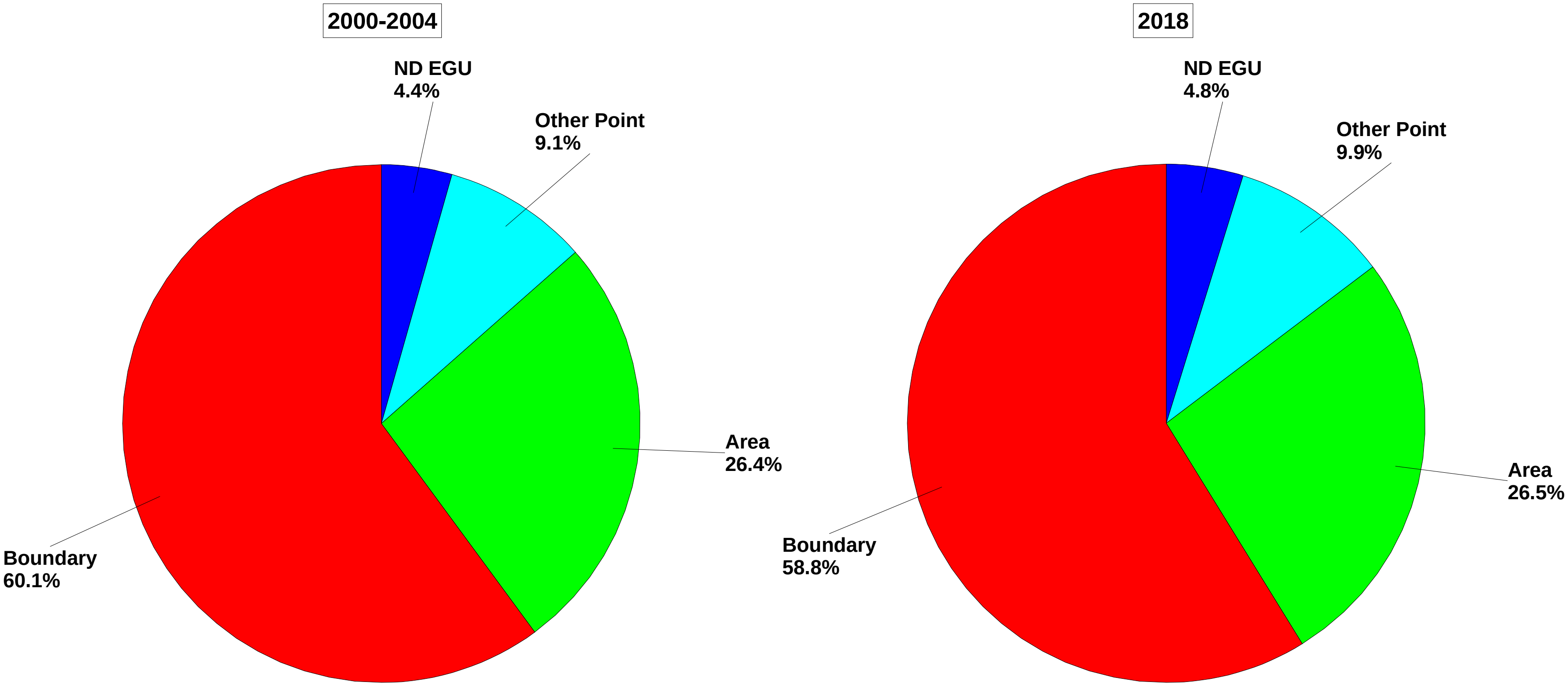


Figure 8.19
Hybrid Modeling Results
Source Group Contributions to 20% Worst Day NO_3 at LWA (Base & Future)



conditions is increasing as the contribution of North Dakota EGUs decreases in the future (other source groups remain relatively stable).

In Figures 8.18 and 8.19, the difference between future and baseline contributions for nitrate is less apparent than for sulfate. Percentage contributions for nitrate remained relatively stable from baseline to future for both Class I areas. Reduction in NO_X emissions due to BART controls was less than BART reductions for SO2, but the NO_X reduction was still significant. This lack of response to future BART reductions in NO_X may be linked to the CALPUFF chemistry, and the tendency observed in the performance evaluation (Section 8.6.1) for NO_3 production to overreact to newly freed ammonia from the lower production of SO_4.

NDDoH hybrid modeling results were further refined in order to extract the contribution of all North Dakota sources to total predicted sulfate and nitrate concentrations for 20% worst days. This additional source group includes all North Dakota EGUs, all North Dakota point sources other than EGUs, and all North Dakota emissions modeled as area sources. Because the NDDoH CALPUFF domain excludes the far eastern part of North Dakota, some adjustments in inventory and procedure were necessary to estimate the contribution of this source group.

Contributions of the North Dakota only source group to total sulfate and nitrate are summarized in Table 8.16. Percentage contributions are provided for baseline and future predicted concentrations at both North Dakota Class I areas. As shown in the table, contributions from North Dakota sources are relatively small and comprise no more than 29 percent of the total prediction for 20% worst days. Significant reduction in future sulfate concentrations due to BART controls on North Dakota EGUs is again apparent.

Table 8.16
Hybrid Modeling Results
Total North Dakota Contribution to 20% Worst Days Predictions

	Class I Area	**Baseline Percent**	**2018 Percent**
SO_4	TRNP	27.3	15.0
	LWA	17.6	9.7
NO_3	TRNP	29.0	28.6
	LWA	26.4	28.7

The relatively small contributions of North Dakota EGUs (and North Dakota sources in general) and the relatively large contributions of boundary conditions to 20% worst day visibility in North Dakota Class I areas, as observed in Figures 8.16 through 8.19, and Table 8.16, translates to restricted options for meeting visibility progress goals. These results indicate that most of the visibility impact on the 20% worst days in North Dakota Class I areas is due to impact from sources located outside of the State, and beyond the jurisdiction of the NDDoH. From additional hybrid modeling, the NDDoH found that even with *all future North Dakota* SO_2 *and* NO_X *emissions reduced to zero*, North Dakota Class I areas would not achieve the 2018 uniform rate of progress target (see Section 8.6.3).

Weight of evidence perspectives which address the contributions of sources located outside of North Dakota to worst day visibility at TRNP and LWA are discussed in Section 8.6.3.

8.6.2.4 Apportionment by Source Region

Visibility modeling conducted by WRAP RMC for North Dakota Class I areas included source-region attribution for all western states, central US, eastern US, Mexico, and Canada. In addition, WRAP also tracked the contribution of sources located outside of the CMAQ domain which includes the contiguous United States, southern Canada, and northern Mexico.

Results of the WRAP attribution analysis are summarized in the bar charts of Figures 8.20 through 8.23. These charts provide source-region contributions to baseline (PLAN02c) predicted concentrations of sulfate and nitrate for the 20% worst days. Figures 8.20 and 8.21 provide source region contributions for sulfate and nitrate, respectively, at TRNP. Figures 8.22 and 8.23 provide the corresponding contributions at LWA. Along with the bars labeled with familiar abbreviations for western states, the figures also include contributions with the following labels:

CAN – Canada,
CEN – Central US (CENWRAP),
EUS – Eastern US,
MEX – Mexico,
PO – Pacific Offshore, and
OD – Outside WRAP US-Canada-Mexico Modeling Domain.

The bar charts used in Figures 8.20 through 8.23 were obtained from the WRAP TSS web site. Note that the values in the charts actually reflect WRAP case PLAN02c, which is a predecessor to the updated PLAN02d. The differences between PLAN02c and PLAN02d, however, are not significant enough to affect conclusions regarding these charts.

In reviewing the bar charts of Figures 8.20 and 8.22, it is seen that emissions from North Dakota, Canada, and from outside the WRAP US-Canada-Mexico modeling domain (Figure 8.1) dominate total sulfate concentrations at North Dakota Class I areas on the 20% worst visibility days. The contribution of sources located outside the WRAP domain is larger than the

Figure 8.20
WRAP Modeling Results
Source Region Contributions to 20% Worst Day SO_4 at TRNP (baseline)

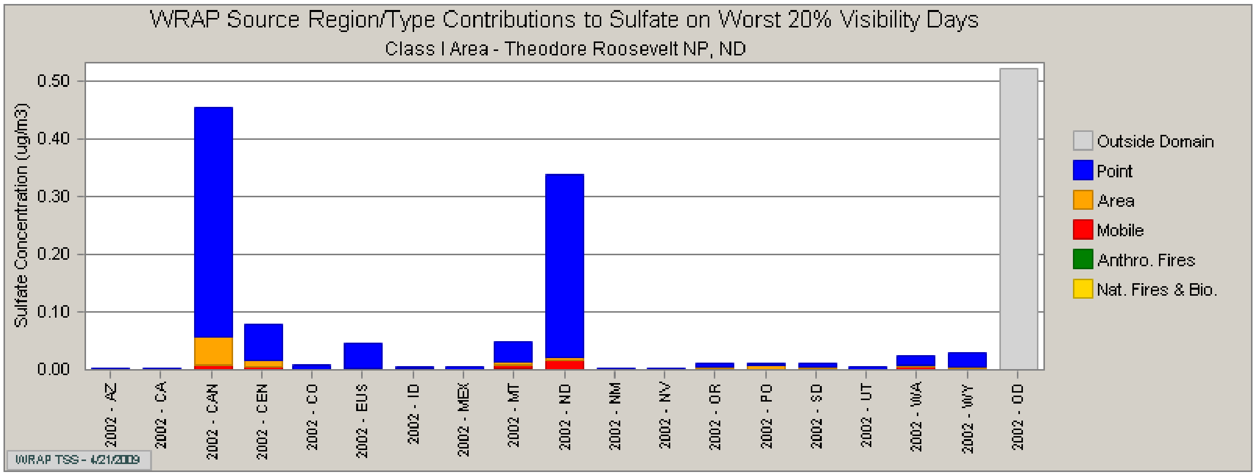


Figure 8.21
WRAP Modeling Results
Source Region Contributions to 20% Worst Day NO_3 at TRNP (baseline)

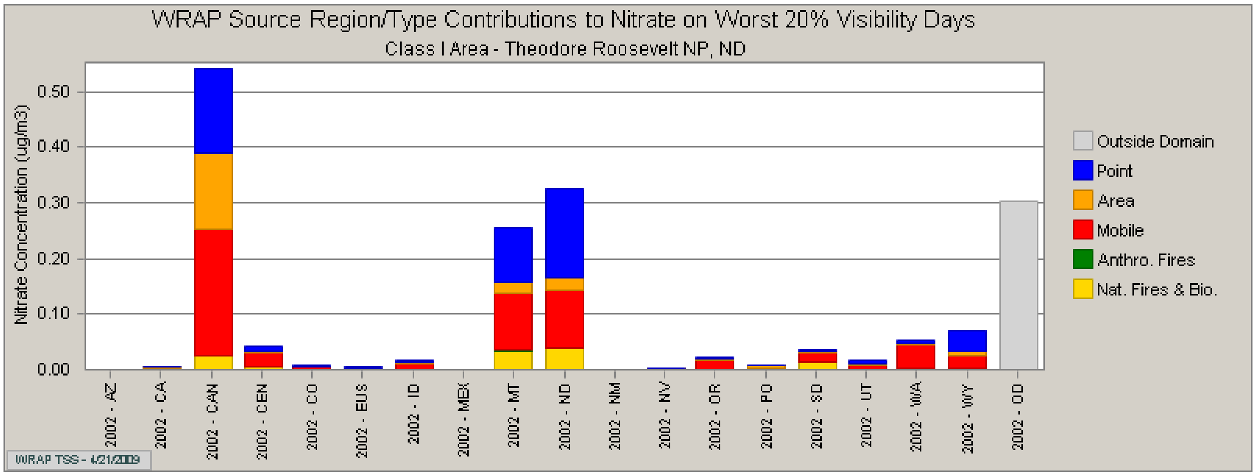


Figure 8.22
WRAP Modeling Results
Source Region Contributions to 20% Worst Day SO_4 at LWA (baseline)

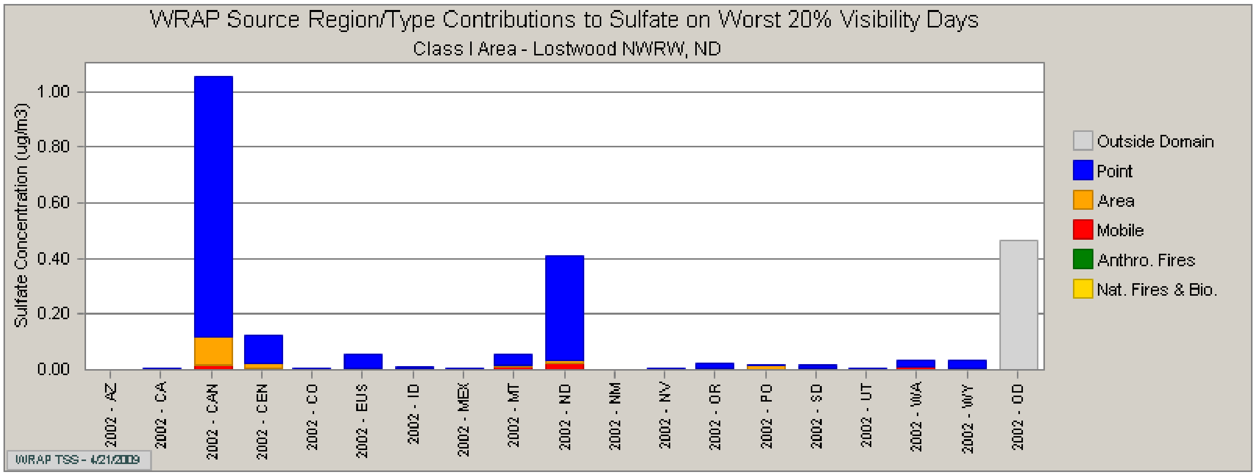
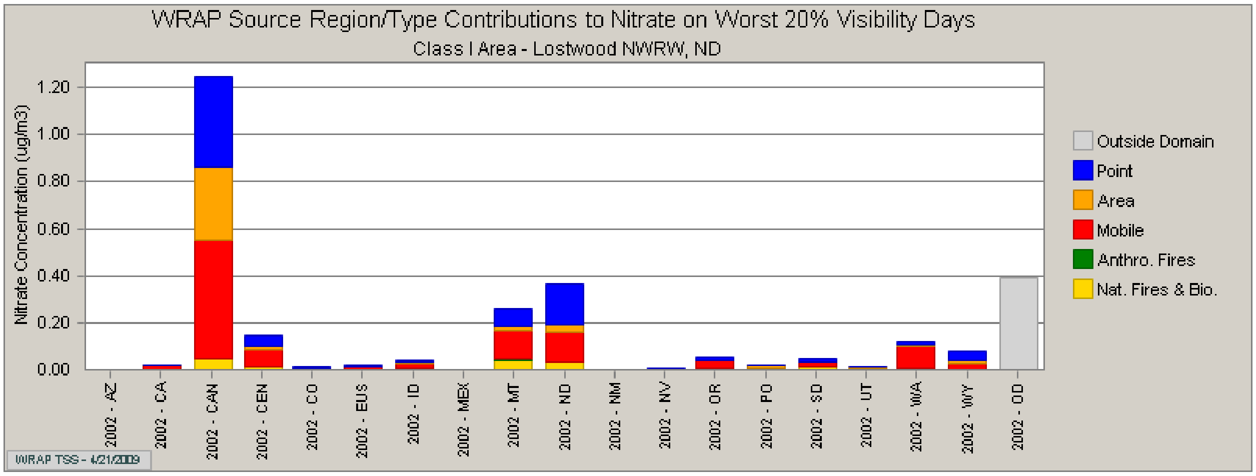


Figure 8.23
WRAP Modeling Results
Source Region Contributions to 20% Worst Day NO_3 at LWA (baseline)



contribution from North Dakota sources at both Class I areas, and the contribution of Canadian emissions is significantly larger than the contribution from North Dakota sources at both Class I areas.

From Figures 8.21 and 8.23, one observes a similar pattern of dominant source-region contributors for 20% worst day nitrate concentrations, except that Montana becomes a dominate contributor in addition to North Dakota, Canada, and sources located outside of the WRAP domain. The overall dominance of Canadian emissions is even greater for nitrate than for sulfate, and at LWA the contribution to 20% worst day nitrate concentrations from Canadian sources is more than three times the contribution from North Dakota sources.

These source-region apportionment results illustrate that most of the contributions to 20% worst day nitrate and sulfate (species with the greatest effect on visibility impairment) at North Dakota Class I areas come from sources located outside of the state. Again, these sources are beyond the jurisdiction of the NDDoH, which poses a dilemma when seeking solutions for achieving visibility goals. This issue was addressed in the NDDoH weight of evidence interpretations which are discussed in Section 8.6.3.

8.6.2.5 Conclusions

Visibility progress modeling was conducted by WRAP and NDDoH using the default EPA methodology. This modeling was based on preliminary estimates of the effect of BART controls, and other growth and control factors. Results have been discussed in terms of general status with respect to the uniform rate of progress for North Dakota Class I areas, and in terms of apportionment by species, source group, and source region. Based on these modeling results, the following conclusions apply.

1) The uniform rate of progress goal for 2018 for 20% worst days will not be achieved at either TRNP or LWA. Therefore, weight of evidence arguments were addressed (see Section 8.6.3).

2) The Regional Haze Rule requirement for 2018 for 20% best days will be achieved at both TRNP and LWA.

3) NDDoH hybrid modeling (adjusted WRAP CMAQ) predicted better progress with respect to the 20% worst day uniform rate of progress goals than did WRAP modeling, at both TRNP and LWA.

4) Apportionment modeling results indicate the contribution of sources located outside of North Dakota is much greater than the contribution of in-state sources to 20% worst day visibility at TRNP and LWA (both baseline and 2018).

5) Though the addition of proposed BART controls substantially decreases the visibility impact of North Dakota EGUs, these EGUs comprise only a small component of total 20% worst day impact at TRNP and LWA. However, on certain worst days when meteorology favors

transport of North Dakota EGU emissions to TRNP or LWA, proposed BART reductions alone will significantly improve visibility.

6) Of the visibility affecting aerosols, sulfate and nitrate are primary contributors to 20% worst day visibility at North Dakota Class I areas.

7) The primary source-region contributors to 20% worst day visibility at TRNP and LWA are Canada, sources located outside of the WRAP modeling domain, North Dakota, and Montana (in that order).

8) When implemented as an adjustment to WRAP CMAQ modeling results, the NDDoH hybrid modeling approach is not critically tied to the parameterized CALPUFF chemistry.

8.6.3 Weight of Evidence Options

WRAP and NDDoH visibility modeling based on the default EPA methodology and glide path has been reviewed, with results as discussed in Section 8.6.2. Because projected 2018 visibility did not meet uniform rate of progress goals for 20% worst days in North Dakota Class I areas, the NDDoH pursued alternative or supplemental modeling approaches, which are discussed here. The Regional Haze Rule specifies that the State Implementation Plan may be based, in part, on evidence apart from modeling using the default EPA methodology. For example, the analysis could logically be modified to discount the impact of visibility-affecting emission sources over which the NDDoH has no jurisdiction.

These supplemental analyses are defined in the Rule as “weight of evidence” options. The following supplemental modeling analyses were conducted by NDDoH in the assessment of visibility progress goals.

1) Discounted the impact of international (in this case, Canadian) source visibility-affecting emissions on North Dakota Class I areas.

2) Discounted the impact of visibility-affecting emissions from all sources located outside of North Dakota, on North Dakota Class I areas.

3) Used the complete emissions inventory for the default EPA method, but zeroed out future SO_2 and NO_X emissions from all sources located in North Dakota (i.e., assumed 100 percent future control of all SO_2 and NO_X emissions in North Dakota), to determine progress with respect to the default glide path for North Dakota Class I Areas.

4) Based 20% worst visibility days for determining RRFs on baseline model results (CALPUFF) rather than IMPROVE monitoring data. This may be justified because neither CMAQ nor CALPUFF perform well on a “paired-in-time” basis. The resultant RRFs were still applied to 20% worst days based on IMPROVE monitoring to project future visibility.

Procedures and results for these supplemental, weight of evidence analyses are discussed in Sections 8.6.3.1 through 8.6.3.4.

8.6.3.1 Discounting the Impact of Canadian Source Emissions

The procedure used by the NDDoH to discount the impact of Canadian source emissions in the projection of future visibility at North Dakota Class I areas is consistent with the methodology described in Section 8.5.6.2. To discount the impact of Canadian source emissions on visibility projections, Canadian sources were removed from the baseline and future emissions inventories used with the hybrid modeling system to develop RRFs, and the URP glide path was adjusted by subtracting the impact of Canadian emissions from the baseline starting value. This weight of evidence analysis was applied for 20% worst days, only. The adjusted glide path is compared with the default glide path in Figure 8.24 for TRNP and LWA.

Because the NDDoH hybrid modeling addresses S and N species only, the discounting of Canadian source impact was limited to sulfate and nitrate, only. The RRFs and projected future contribution to light extinction of other visibility affecting species remained unchanged from the default EPA methodology (i.e., included Canadian emissions). As sulfate and nitrate are the primary contributors to light extinction at North Dakota Class I areas on the 20% worst days (see Section 8.6.2.2), this limitation should not significantly impact conclusions based on this weight of evidence analysis.

Note that once the glide path has been adjusted, the URP 2018 target value changes along with the baseline starting value (the adjusted glide path terminates at the same natural background value in 2064). Therefore, it is no longer meaningful to compare the 2018 projected progress with the absolute deciview target from the default EPA methodology (Table 8.11). Instead, for this weight of evidence scenario and others, 2018 progress is expressed as a percentage of the target rather than as a specific deciview value.

The NDDoH procedure used to discount the impact of Canadian source emissions is outlined as follows.

1) Canadian sources located within the NDDoH CALPUFF domain were eliminated from the *HybridPt* baseline and future emissions inventories to be used in Equation 8-3.

2) CALPUFF hourly boundary conditions (baseline and future *HybridPt*) were adjusted to eliminate the contribution of Canadian (anthropogenic) source emissions (leaving only the contribution of natural background) for 3-km boundary segments located in Canada (see Figure 8.5). The fixed adjustment factor utilized represents the ratio of species-specific natural background light extinction to species-specific baseline monitored light extinction for the 20% worst day average, at each Class I area. The adjustment was applied to all boundary species (SO_2, SO_4, NO_X, HNO_3, and NO_3). The SO_4 ratio was used for scaling SO_4 and SO_2 species. The NO_3 ratio was used for scaling NO_3, HNO_3, and NO_X species.

3) Hybrid modeling was applied to prepare a revised glide path and 2018 target using Equation 8-4 with the revised baseline emissions inventories (non-Canadian sources only) from Steps 1 and 2, for each Class I area. The 3-step ammonia limiting method was applied to refine NO_3 concentrations for non-Canadian sources.

4) Hybrid modeling was applied to project future visibility using Equation 8-3 with the revised baseline and future emissions inventories (non-Canadian sources only) from Steps 1 and 2, for each Class I area. The 3-step ammonia limiting method was applied to refine NO_3 concentrations for non-Canadian sources.

5) The projected future deciview value was compared with the revised glide path 2018 target deciview value to calculate the percent of the 2018 target achieved, at each Class I area.

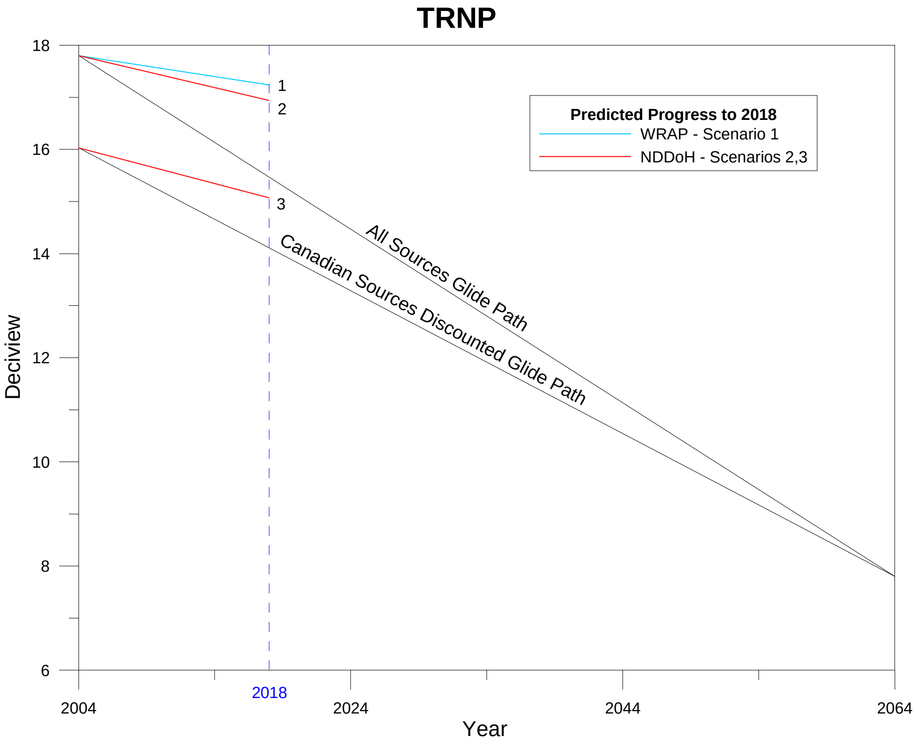
Results of the weight of evidence analysis for discounting the impact of Canadian source emissions are summarized in Table 8.17 and illustrated in Figure 8.24. Uniform rate of progress illustrations in Figure 8.24 are provided for both TRNP and LWA Class I areas. For comparison, the table and figure also include previous WRAP and NDDoH results for the complete emissions inventory and default EPA methodology from Table 8.11. WRAP results for the default EPA methodology are labeled Scenario 1 and NDDoH results for the default EPA methodology are labeled Scenario 2. They are compared with the weight of evidence entry which is identified as Scenario 3. For each scenario, the table provides percentage progress with respect to the 2018 target.

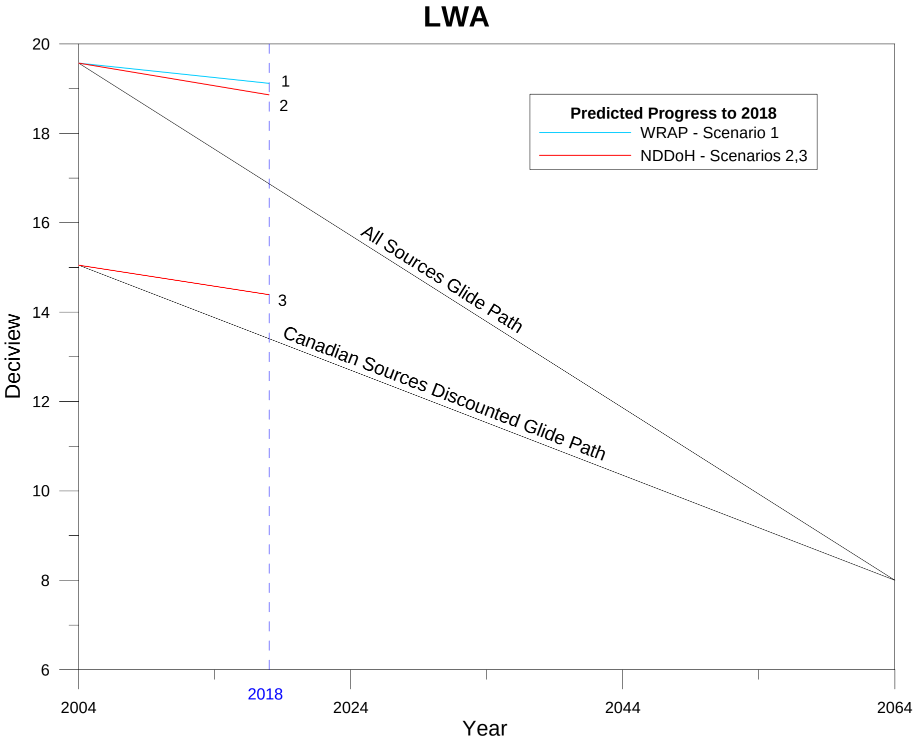
Table 8.17
NDDoH Visibility Modeling Results 20% Worst Days
Weight of Evidence – Discounting Canadian Emissions

Scenario	Description	Class I Area	Projected Percent of 2018 Target
1	WRAP CMAQ Default EPA Methodology	TRNP	24.0
		LWA	16.7
2	NDDoH Hybrid Default EPA Methodology	TRNP	38.1
		LWA	26.7
3	NDDoH Hybrid Canada Sources Discounted	TRNP	50.0
		LWA	40.2

As shown in Table 8.17 and Figure 8.24, progress with respect to the 2018 target is significantly improved when Canadian sources are discounted. The projected percent of the 2018 target with Canadian sources discounted is more than double the percentage obtained by WRAP for the default EPA methodology, and about 50 percent greater than the percentage obtained by NDDoH for the default EPA methodology, at both Class I areas. Though progress is significantly

Figure 8.24
Uniform Rate of Progress
EPA Default Methodology and Canadian Sources Discounted





improved under this scenario, the potential for greater improvement was limited because the contribution of US sources located outside of the hybrid model domain is very large (with little emissions reduction in the future), and the scenario could only address the discounted impact of SO_4 and NO_3.

8.6.3.2 Discounting the Impact of All Sources Located Outside of North Dakota

Because discounting the impact of Canadian emissions did not provide compliance with glide path targets, the NDDoH pursued other weight of evidence options. The next logical test after discounting Canadian emissions was to discount the visibility-affecting impact of all sources located outside of the jurisdiction of the NDDoH. Therefore, this new analysis discounted all contributions to North Dakota Class I areas, except for the impact of North Dakota sources and natural background. To discount the impact of *all sources located outside of North Dakota* on visibility projections, these sources were removed from the baseline and future emissions inventories used with the hybrid modeling system to develop RRFs, and the URP glide path was adjusted by subtracting the impact of these sources from the baseline starting value. This weight of evidence analysis was applied for 20% worst days, only. The adjusted glide path is compared with the default glide path in Figure 8.25 for TRNP and LWA.

Since the CALPUFF domain used by the NDDoH for hybrid visibility modeling excludes the extreme eastern part of North Dakota, area emissions for the easternmost column of the area source grid (see Figure 8.8) were adjusted upward to account for the impact of eastern North Dakota sources. Specifically, WRAP CMAQ (SMOKE) emissions for all grid cells located between the eastern edge of the CALPUFF domain and the eastern North Dakota border were added to the easternmost column of the CALPUFF area source grid. This addition was performed on a row by row basis. Because eastern North Dakota visibility affecting sources are relatively small and distant from TRNP and LWA Class I areas, this adjustment should have minimal impact on modeling results.

Because the NDDoH hybrid modeling addresses S and N species only, the discounting of out-of-state source impact was limited to sulfate and nitrate, only. The RRFs and projected future contribution to light extinction of other visibility affecting species remained unchanged from the default EPA methodology (i.e., included complete emissions inventory). As sulfate and nitrate are the primary contributors to light extinction at North Dakota Class I areas on most of the 20% worst days (see Section 8.6.2.2), this limitation should not significantly impact conclusions based on this weight of evidence analysis.

The procedure used by NDDoH to discount the impact of *all sources located outside of North Dakota* is similar to the 5-step procedure used to discount Canadian emissions, as outlined in Section 8.6.3.1., except that variables representing North Dakota sources replaced variables representing US sources in Equations 8.3 and 8.4. The procedure for discounting the impact of all out-of-state sources is outlined below.

1) All out-of-state sources located within the NDDoH CALPUFF domain were eliminated from the *HybridPt* baseline and future emissions inventories to be used in Equation 8-3.

2) As discussed above, emissions from all sources located outside of CALPUFF domain, but inside North Dakota, were added to easternmost column of CALPUFF area source grid.

3) CALPUFF hourly boundary conditions (baseline and future *HybridPt*) were scaled to eliminate the contribution of all out-of-state source emissions (leaving only the contribution of natural background) for all boundary segments. Scaling was based on the inverse distance squared weighted average of natural-to-baseline (2002) ratio from seven nearby IMPROVE monitoring locations. The ratio was obtained for the 20% worst day average SO_4 and NO_3 natural and baseline extinction for Theodore Roosevelt NP, Lostwood NWA, Medicine Lake NWA, UL Bend, Badlands NP, Wind Cave, and Voyageurs NP IMPROVE sites. The average SO_4 ratio was used for scaling SO_4 and SO_2 species. The average NO_3 ratio was used for scaling NO_3, HNO_3, and NO_X species.

4) Hybrid modeling was applied to prepare a revised glide path and 2018 target using Equation 8-4 with the revised baseline emissions inventories from Steps 1 and 2, for each Class I area (equation variables for North Dakota sources replaced variables for US sources). The 3-step ammonia limiting method was applied to determine NO_3 concentrations for North Dakota sources.

5) Hybrid modeling was applied to project future visibility using Equation 8-3 with the revised baseline and future emissions inventories from Steps 1 and 2, for each Class I area (equation variables for North Dakota sources replaced variables for US sources). The 3-step ammonia limiting method was applied to determine NO_3 concentrations for US sources.

6) The projected future deciview value was compared with the revised glide path 2018 target deciview value to calculate the percent of the 2018 target achieved, at each Class I area.

Results of the weight of evidence analysis for discounting the impact of *all sources located outside of North Dakota* are summarized in Table 8.18 and illustrated in Figure 8.25. Uniform rate of progress illustrations in Figure 8.25 are provided for both TRNP and LWA Class I areas. For comparison, the table and figure also include previous WRAP and NDDoH results for the complete emissions inventory with default EPA methodology from Table 8.11. WRAP results for the default EPA methodology are labeled Scenario 1 and NDDoH results for the default EPA methodology are labeled Scenario 2. They are compared with the new weight of evidence entry which is identified as Scenario 4. For each scenario, the table provides percentage progress with respect to the 2018 target.

As shown in Table 8.18 and Figure 8.25, progress with respect to the 2018 target is significantly improved after discounting the impact of *all sources located outside of North Dakota*, but projections do not meet the revised glide path targets. Also, the improvement is notably better at TRNP than at LWA. A likely explanation is that the location of BART sources in North Dakota, combined with prevailing meteorology, favors visibility improvement at TRNP compared with improvement at LWA (i.e., when there are no out of state influences).

Table 8.18
NDDoH Visibility Modeling Results 20% Worst Days
Weight of Evidence – Discounting All Out-of-State Sources

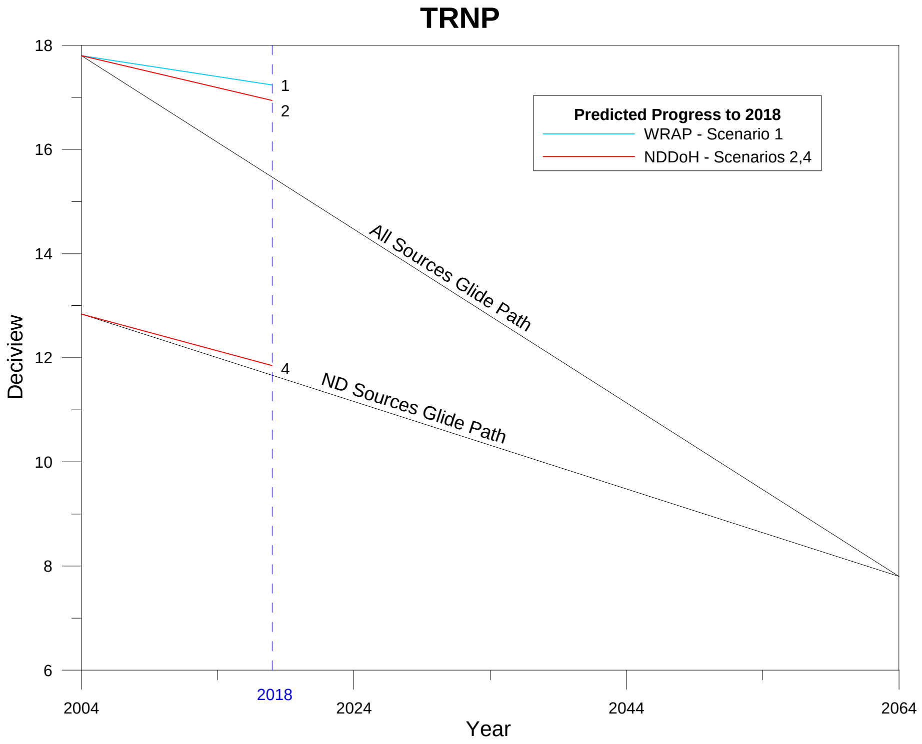
Scenario	Description	Class I Area	Projected Percent of 2018 Target
1	WRAP CMAQ Default EPA Methodology	TRNP	24.0
		LWA	16.7
2	NDDoH Hybrid Default EPA Methodology	TRNP	38.1
		LWA	26.7
4	NDDoH Hybrid All Sources Other Than ND Discounted	TRNP	83.9
		LWA	59.6

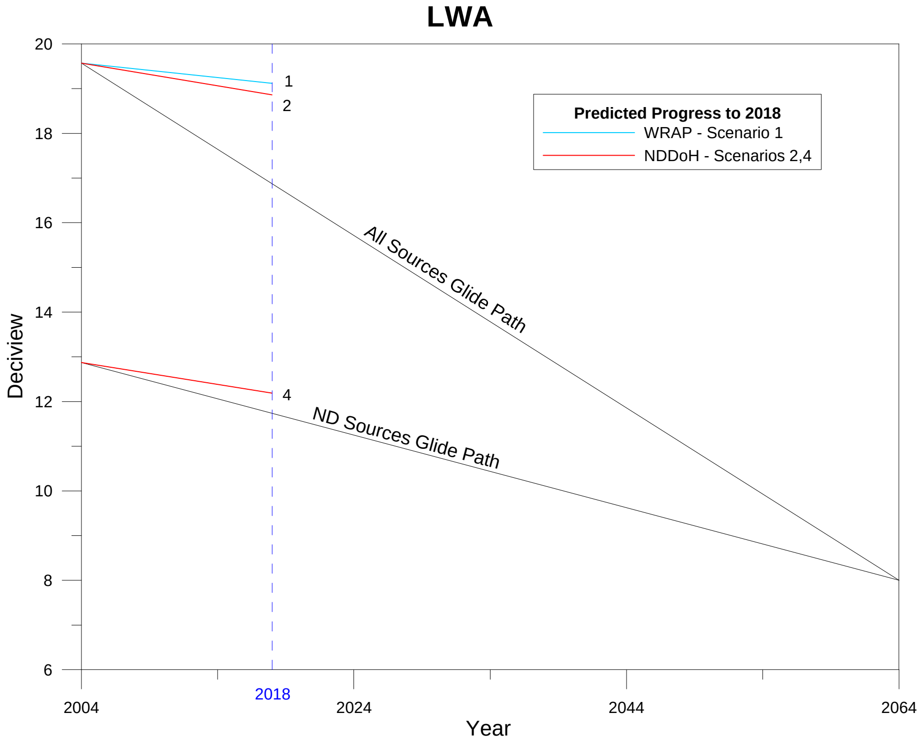
8.6.3.3 Use Default EPA Methodology with Zero North Dakota Future Emissions

The NDDoH next examined a “what if” scenario to see what would happen if all North Dakota sources were controlled to the hypothetical maximum degree and simply emitted no SO_2, SO_4, NO_X, or NO_3 in the future case. The concept here was to determine if the 2018 URP targets for the default EPA methodology for 20% worst days could be achieved even under maximum (albeit unrealistic) control conditions for North Dakota sources. Hybrid modeling for the baseline case (*HybridPt* in Equation 8-3) included the complete emissions inventory as used for the NDDoH EPA methodology analysis. Future case modeling (*HybridPt* in Equation 8-3) included the complete emissions inventory as applied by NDDoH for EPA methodology, except that all emissions for sources located in North Dakota were reset to zero. For this scenario, the glide path remains consistent with the default EPA methodology scenario.

Procedure for this new scenario followed the default EPA methodology, as discussed in Section 8.5. The only change was in the future case emissions inventory, where the emission rates for all North Dakota point and area sources were reset to zero. Note that because extreme eastern North Dakota is not included in the NDDoH CALPUFF domain, it was not possible to model the effect of zero future emissions from that part of the state. However, because visibility-affecting sources in extreme eastern North Dakota are relatively small and distant from the Class I areas

Figure 8.25
Uniform Rate of Progress
EPA Default Methodology and Non-ND Sources Discounted





which are both located in the western part of the state, this limitation should not detract from conclusions established regarding the analysis.

Results of the weight of evidence analysis involving zero future emissions for North Dakota visibility affecting sources are summarized in Table 8.19. For comparison, the table also includes previous WRAP and NDDoH results for the complete emissions inventory with default EPA methodology from Table 8.11. WRAP results for the default EPA methodology are labeled Scenario 1 and NDDoH results for the default EPA methodology are labeled Scenario 2. They are compared with the new weight of evidence entry which is identified as Scenario 5. For each scenario, the table provides percentage progress with respect to the 2018 target.

As illustrated in Table 8.19, even with all future North Dakota SO_2, SO_4, NO_X, and NO_3 emissions set to zero, the URP 20% worst day targets for 2018 are not achieved at North Dakota Class I areas. This result is consistent with earlier conclusions in this report that most of the visibility affecting impact on TRNP and LWA is coming from sources located outside of North Dakota. The implication of this weight of evidence test is that compliance with 20% worst day URP targets at North Dakota Class I areas cannot be achieved without significant additional emissions reductions from visibility affecting sources located outside of North Dakota.

Table 8.19
NDDoH Visibility Modeling Results 20% Worst Days
Weight of Evidence – Zero Future North Dakota Emissions

Scenario	Description	Class I Area	Projected Percent of 2018 Target
1	WRAP CMAQ Default EPA Methodology	TRNP	24.0
		LWA	16.7
2	NDDoH Hybrid Default EPA Methodology	TRNP	38.1
		LWA	26.7
5	NDDoH Hybrid Base Emissions Inv = Default Future Emissions Inv = All ND S and N Emissions set to zero	TRNP	83.8
		LWA	72.6

As indicated previously, the NDDoH CALPUFF visibility modeling was limited to the contribution of SO_2, SO_4, NO_X, and NO_3 species, only. Even if the effect of zeroing out all other visibility affecting species could have been accounted for, it is unlikely that 2018 URP targets for North Dakota Class I areas could have been achieved under this weight of evidence scenario.

8.6.3.4 Base 20% Worst Days on Modeling Results Rather than IMPROVE Monitoring Data

Though both models perform well when predicting maximum concentrations over a period of time, CMAQ and CALPUFF are less reliable when performance tests are based on predictions paired with concurrent observations. But the reliance of the Regional Haze Rule on the 20% worst/best monitored days to track visibility progress implies that the modeling system must demonstrate some skill on a temporal basis. To address possible temporal performance limitations in the NDDoH hybrid modeling system, visibility projection results based on the 20% worst monitored days were compared with results based on the 20% worst modeled days for the baseline case. The following procedure was used to develop results based on worst modeled days.

1) The hybrid modeling system was executed for the baseline case, using the emissions inventory for the default EPA methodology, and the entire year of 2002 meteorological data.

2) Daily modeling results for the baseline case were ranked in order to determine the 20% worst days (73 days) for visibility at both Class I areas (TRNP and LWA).

3) The hybrid modeling system was executed for the future (2018) case, using the emissions inventory for the default EPA methodology, and the 20% worst days determined for the baseline case in Step 2.

4) Relative response factors (RRFs) were developed from the modeling results for baseline and future cases in Steps 1 and 3, respectively.

5) RRFs were applied to IMPROVE baseline monitoring data for original 20% worst days to project future visibility.

This procedure provided deciview improvement predictions which were very similar to the original improvement predictions obtained through modeling the 20% worst IMPROVE days. Typical differences were less than five percent of the original predicted values at both Class I areas. Therefore, the NDDoH did not pursue this approach for any of the visibility modeling documented in this report (i.e., all modeling was based on the 20% worst/best IMPROVE days).

8.6.3.5 Weight of Evidence Summary and Conclusions

Results of the weight of evidence modeling analyses are summarized in Table 8.20, and in the illustrations of Figures 8.26 and 8.27. For comparison, the table and figures include results from all weight of evidence analyses, as well as previous WRAP and NDDoH results for the complete emissions inventory and default EPA methodology from Table 8.11. Scenarios are labeled as previously noted. For each scenario, the table provides percentage progress with respect to the 2018 target for 20% worst days at both North Dakota Class I areas. Figure 8.26 illustrates progress with respect to the URP glide path at TRNP for all scenarios, and Figure 8.27 illustrates progress with respect to the URP glide path at LWA for all scenarios.

Conclusions based on weight of evidence modeling analyses follow.

1) Compliance with 20% worst day URP 2018 targets at North Dakota Class I areas cannot be achieved through additional emissions reductions from North Dakota sources, alone. It will require significant additional visibility affecting emissions reductions from other western states, Canada, and from sources located outside of the WRAP CMAQ modeling domain.

2) A visibility progress analysis methodology which discounts the impact of International (Canadian) visibility affecting source emissions on 20% worst days is plausible, and was developed and implemented by the NDDoH. Using similar methodology, the NDDoH was able to also develop and implement a procedure to discount the impact of *all sources located outside of North Dakota* on 20% worst days.

3) After discounting the impact of Canadian sources, significantly greater progress (50 percent greater) was demonstrated, relative to URP 2018 targets for North Dakota Class I areas, than modeling with the entire emissions inventory. But 20% worst day targets were still not achieved.

4) After discounting the impact of *all sources located outside of North Dakota*, even greater progress was demonstrated, relative to URP 2018 targets for North Dakota Class I areas, than modeling with Canadian sources discounted. However, 20% worst day targets were still not achieved.

5) After zeroing out all future SO_2 and NO_X emissions in North Dakota under default EPA methodology (emulating a 100 percent, unrealistic control of all sources), compliance with 20% worst day targets was still not achieved at North Dakota Class I areas.

6) Basing 20% worst days on baseline model results rather than IMPROVE monitoring data made no meaningful difference in future visibility projections.

Table 8.20
NDDoH Visibility Modeling Results 20% Worst Days
Weight of Evidence Analysis Summary

Scenario	Description	Class I Area	Projected Percent of 2018 Target
1	WRAP CMAQ Default EPA Methodology	TRNP	24.0
		LWA	16.7
2	NDDoH Hybrid Default EPA Methodology	TRNP	38.1
		LWA	26.7
3	NDDoH Hybrid Canada Sources Discounted	TRNP	50.0
		LWA	40.2
4	NDDoH Hybrid All Sources Other Than ND Discounted	TRNP	83.9
		LWA	59.6
5	NDDoH Hybrid Base Emissions Inv = Default Future Emissions Inv = All ND SO_2 and NO_X Emissions set to zero	TRNP	83.8
		LWA	72.6

Figure 8.26
TRNP Uniform Rate of Progress
EPA Default Methodology and NDDoH Weight of Evidence

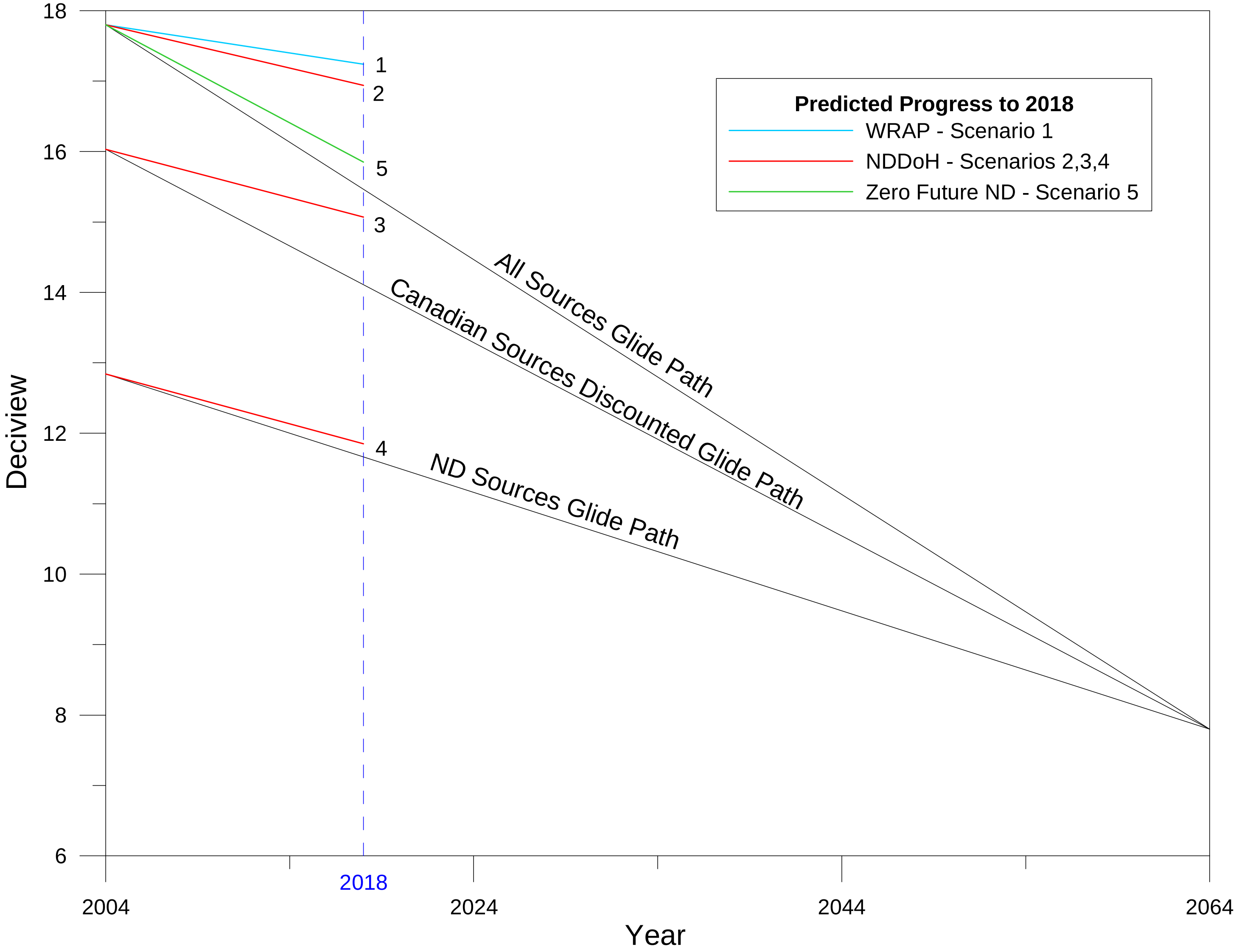
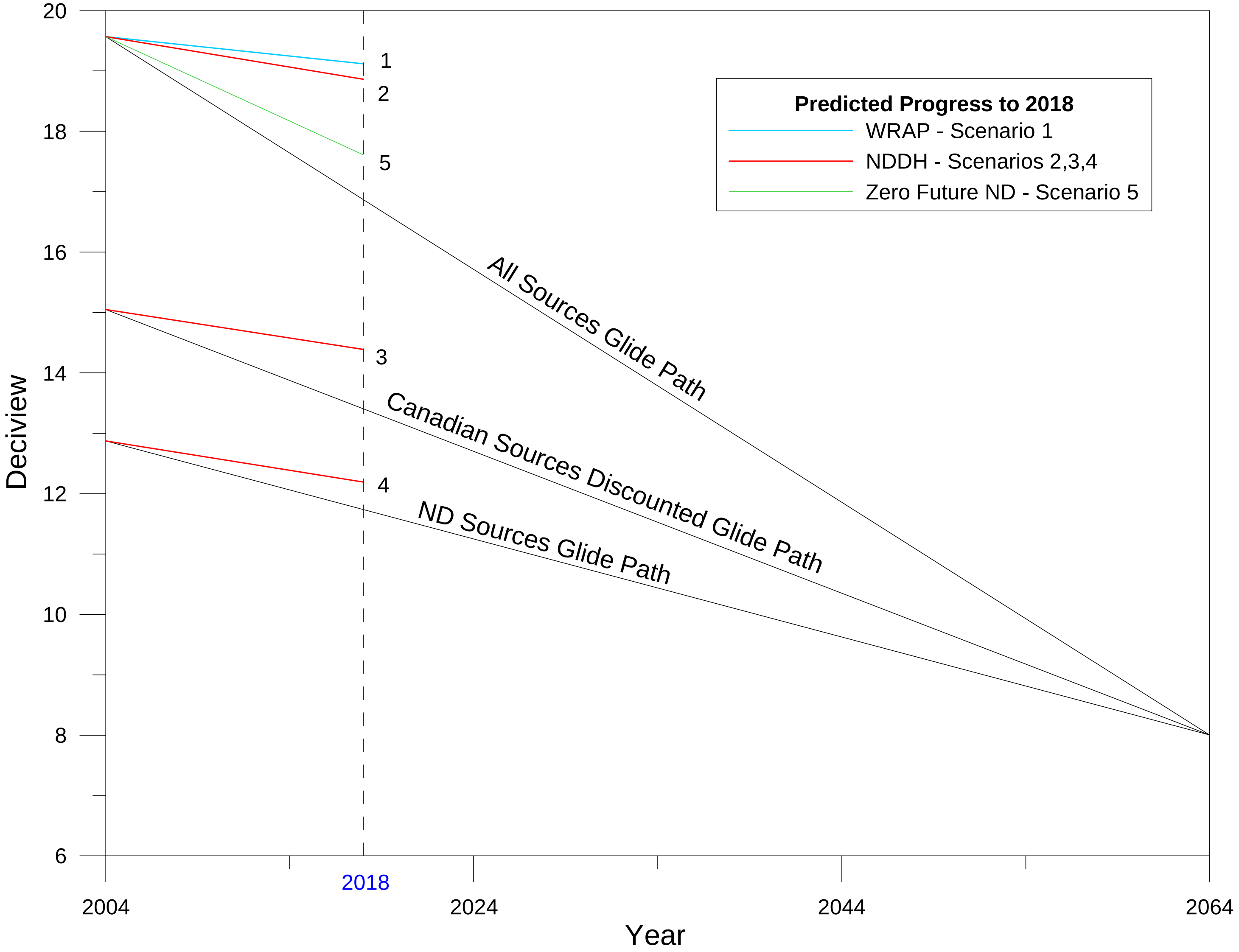


Figure 8.27
LWA Uniform Rate of Progress
EPA Default Methodology and NDDoH Weight of Evidence



9. Reasonable Progress Goals

9.1 Introduction

The Regional Haze Rule states that for each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State, the State must establish reasonable progress goals for each area. For out-of-state Class I areas that are affected by in-state emissions, the State must consult with the affected state regarding the reasonable progress goals for those Class I areas. The reasonable progress goals (expressed in deciviews) must provide for reasonable progress towards achieving natural visibility conditions including improvement in visibility for the most impaired days (20% worst days) and ensuring no degradation in visibility for the least impaired days (20% cleanest days) over the planning period.

The EPA has published guidance[1] for setting reasonable progress goals. The basic steps include:

1. Establish Baseline and Natural Visibility Conditions

2. Determine the Glidepath, or Uniform Rate of Progress

3. Identify and Analyze the Measures Aimed at Achieving the Uniform Rate of Progress

    a. Identify the key pollutants and sources and/or source categories that are contributing to visibility impairment at each Class I area. The sources of impairment for the most impaired and least impaired days may differ.

    b. Identify the control measures and associated emission reductions that are expected to result from compliance with existing rules and other available measurements for the sources and source categories that contribute significantly to visibility impairment.

    c. Determine what additional control measures would be reasonable based on the statutory factors and other relevant factors for the sources and/or source categories you have identified.

    d. Estimate through the use of air quality models the improvement in visibility that would result from implementation of the control measures you have found to be reasonable and compare this to the uniform rate of progress.

4. Establish the Reasonable Progress Goal

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[1] U.S. EPA 2007; Guidance for Setting Reasonable Progress Goals under the Regional Haze Rule: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, June 1, 2007.

9.2 Establish Baseline and Natural Visibility Conditions

The baseline visibility conditions are established in Section 5.3 while the natural visibility conditions are addressed in Section 5.4. The following table summarizes the results for North Dakota's Class I Federal areas.

Table 9.1
Baseline and Natural Visibility Conditions

Area	Baseline (dv)		Natural Conditions (dv)	
	20% Best	20% Worst	20% Best	20% Worst
TRNP	7.8	17.8	3.0	7.8
LWA	8.2	19.6	2.9	8.0

9.3 Determine the Glide Path or Uniform Rate of Progress

The uniform rate of progress necessary to achieve natural conditions is addressed in Section 5.4. The results of that analysis are as follows:

Table 9.2
Visibility Improvement Required

Area	Total Improvement Required (dv) 20% Worst Days	2018 Target Improvement (dv) 20% Worst Days
TRNP	10.0	2.3
LWA	11.6	2.7

9.4 Identify and Analyze the Measures Aimed at Achieving the Uniform Rate of Progress

A. Identify key pollutants and sources contributing to visibility impairment in each Class I area.

The key pollutants contributing to visibility degradation in North Dakota's Class I areas are sulfur dioxide and nitrogen oxides which form sulfates and nitrates (see analysis in Section 8.7.2.2). For sulfates, the contributing sources are primarily point sources in Canada, sources outside WRAP's modeling domain and point sources in North Dakota.

For nitrates, point/area/mobile sources in Canada, North Dakota, Montana and sources outside of WRAP's modeling domain area are the primary contributors (see analysis in Section 6.3 and Section 8). North Dakota sources contributed 21% of the sulfate and 19% of the nitrate at TRNP during the 20% worst days of the baseline (WRAP Case Plan 02c). At LWA, North Dakota sources contributed 18% of the sulfate and 13% of the nitrate for the same period.

Organic carbon (primary organic aerosols) is the next largest contributor to extinction in the Class I areas of North Dakota. Organic carbon contributes 17.5% of the total extinction at TRNP and 14.9% at LWA during the baseline 20% worst days. As can be seen in Figures 9.1 and 9.2, much of the organic carbon emissions in North Dakota are from the "natural fire" source category or from the "fugitive dust" category. Natural fire cannot be controlled and will vary year to year in each state. Fugitive dust is addressed in Sections 9.5.2 and 10.6.2. Off-road mobile sources of organic carbon are expected to decrease 54% by 2018.

Figure 9.1

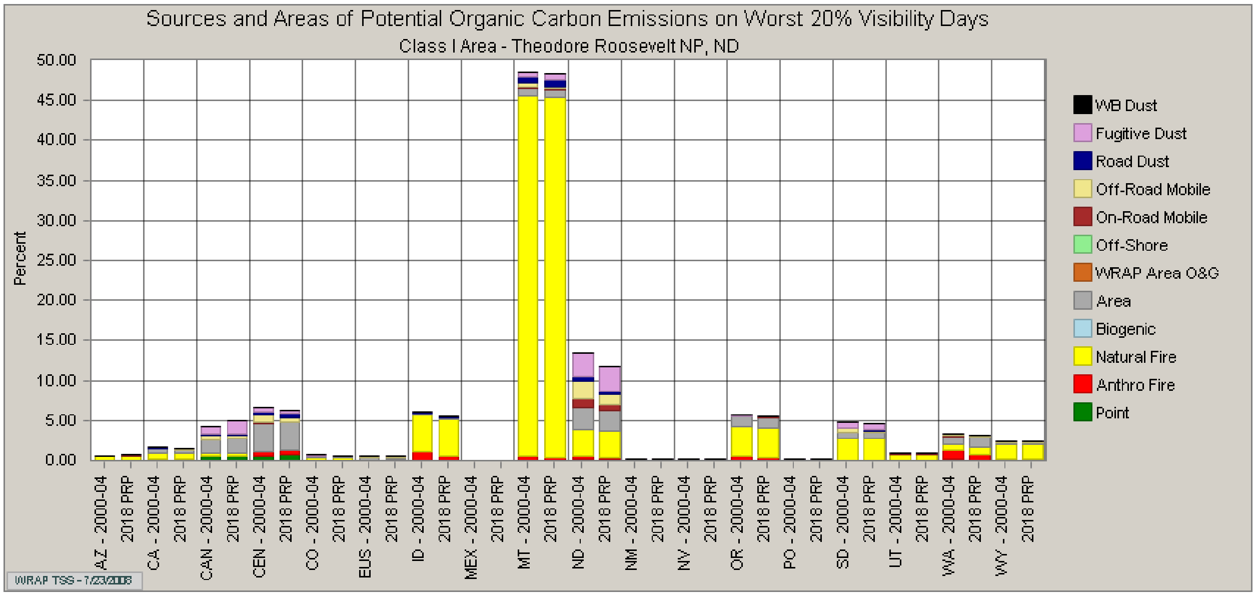
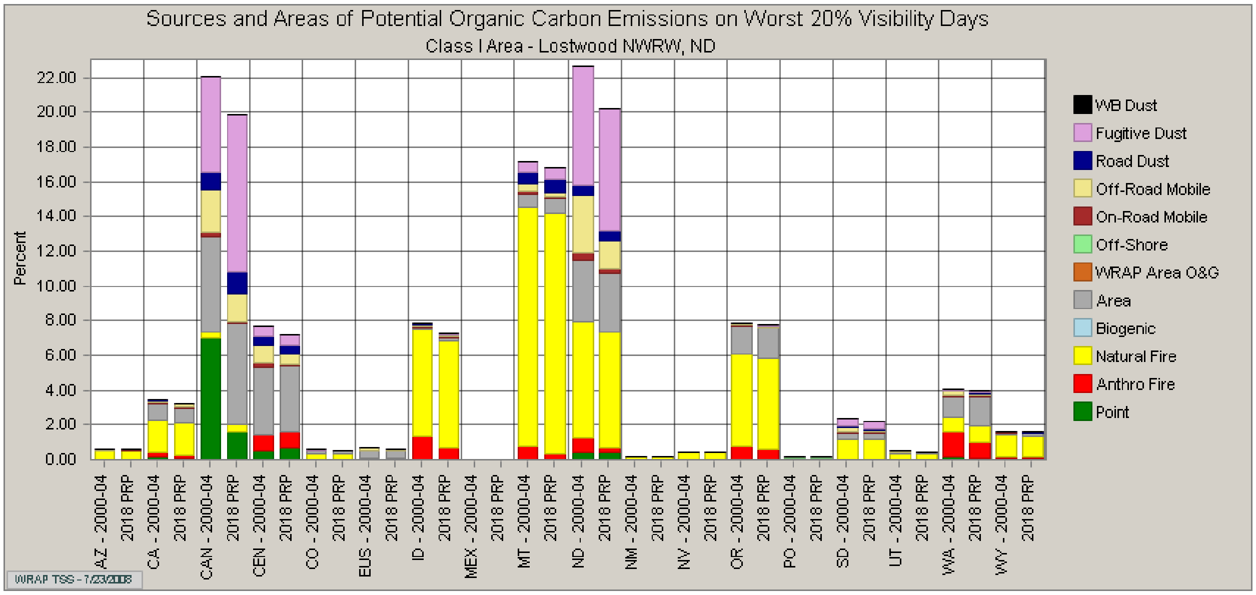


Figure 9.2



With regard to the contribution of North Dakota sources to the sulfate~~s~~ and nitrate~~s~~ concentration in the Class I areas, the sources in North Dakota are:

Table 9.3
North Dakota Sources
of
Sulfate and Nitrates
2000-2004

Area	**Source**	**In-State Sulfate Contribution (µg/m^3)**	**In-State Nitrate Contribution (µg/m^3)**	**Percent of Total In-State Contribution**	
				Sulfate	**Nitrate**
TRNP	Point	0.3148	0.1587	98	49
	Anthropogenic Fire	0.0002	0.0003	< 1	< 1
	Mobile	0.0151	0.1038	4	32
	Natural Fire & Biogenic	0.0002	0.0389	< 1	12
	Area	0.0071	0.0233	2	7
LWA	Point	0.3797	0.1760	92	48
	Anthropogenic Fire	< 0.0001	< 0.0001	< 1	< 1
	Mobile	0.0216	0.1197	5	33
	Natural Fire & Biogenic	0.0004	0.0362	< 1	10
	Area	0.0089	0.0334	2	9

North Dakota sources only contribute 21% of the total sulfate concentration in TRNP and 19% of the total nitrate concentration during the 20% worst days. At LWA, North

Dakota sources contribute 18% of the total sulfate and 13% of the total nitrate (see Table 2.1). Although mobile sources are a significant contributor to North Dakota's emissions that form nitrates, mobile sources in North Dakota only contribute 6% of the total nitrate concentration in TRNP and 4% in LWA during the 20% worst days (WRAP Case Plan 02c). Nitrogen oxides emissions from mobile sources are expected to decline by 51% by 2018 (see Table 6.1 and 6.3). Based on the above results, efforts to reduce sulfates and nitrates are primarily directed towards point sources of sulfur dioxide and nitrogen oxides emissions.

B. Identify the Control Measures and Associated Emission Reductions from Existing Rules

See Section 10. The WRAP has estimated that the "on-the-books" controls will reduce emissions of nitrogen oxides by approximately 28,000 tons per year, sulfur dioxide 1,700 tons per year, elemental carbon 2,700 tons per year, and fine particulate matter by 900 tons per year. Coarse particulate matter is expected to increase by 18,000 tons primarily due to fugitive dust. These "on the books" controls include:

- Tier 1 light-duty vehicle standards, beginning MY 1996;
- National Low Emission Vehicle (NLEV) standards, beginning MY 2001;
- Tier 2 light-duty vehicle standards beginning MY 2005, with low sulfur gasoline beginning summer 2004;
- Heavy-duty vehicle standards beginning MY 2004;
- Heavy-duty vehicle standards beginning MY 2007, with low sulfur diesel beginning summer 2006;
- Emission standards for new nonroad spark-ignition engines below 25 hp;
- Phase 2 emission standards for new spark-ignition hand-held engines below 25 hp;
- Phase 2 emission standards for new spark-ignition nonhand-held engines below 25 hp;
- Emission standards for new gasoline spark-ignition marine engines;
- Tier 1 emission standards for new nonroad compression-ignition engines above 50 hp;
- Tier 1 and Tier 2 emission standards for new nonroad compression-ignition engines below 50 hp including recreational marine engines;
- Tier 2 and Tier 3 standards for new nonroad compression-ignition engines of 50 hp and greater not including recreational marine engines greater than 50 hp; and
- Tier 4 emissions standards for new nonroad compression-ignition engines above 50 hp, and reduced nonroad diesel fuel sulfur levels.

Modeling by the WRAP indicates these "on-the-books" rules will improve visibility by 0.1 deciviews in the 20% worst day at TRNP and 0.2 deciviews at LWA.

C. Determine What Additional Control Measures Would be Reasonable Based on the Statutory Factors and Other Relevant Factors

See Section 9.5 and 9.6.

D. Estimate Through the Use of Air Quality Models the Improvement in Visibility that Would Result From the Implementation of the Control Measures Found to be Reasonable

See Section 9.5.

E. Establish the Reasonable Progress Goals

See Section 9.7.

9.5 Additional Controls

9.5.1 Point Sources Contributing to Visibility Impairment in the North Dakota Class I Areas

In determining reasonable progress goals for any Class I Federal area, 40 CFR 51.308(d)(1)(i)(A) requires a state to consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

In determining the cost of compliance for individual sources or source categories potentially subject to emission limitations, the following steps are suggested:

A. Identify the emission units to be controlled.

B. Identify the design parameters for emission controls, and

C. Develop cost estimates based upon those design parameters.

The Guidance for Setting Progress Goals under the Regional Haze Program states “it is not necessary for you to reassess the reasonable progress factors for sources subject to BART for which you have already completed a BART analysis.”

Cost of Compliance

Step 1: **Identify Emission Units to be Controlled**

The Department has identified sulfur dioxide and nitrogen oxides as the primary pollutants that are emitted by stationary point sources that contribute most of the visibility impairment. Particulate emissions from stationary sources have very little impact on visibility in North Dakota (see Figures 6.5 and 6.6) and represent only 1% of the total PM emissions in 2002 (see Table 6.1). Therefore, PM emissions from point sources were not evaluated under this section.

Under BART, it was determined that no additional controls were required for the largest sources of PM, the electric utility steam generating units. Primary sulfuric acid mist emissions are also a very small contributor to visibility impairment. The sources that were subject to BART, the largest emitters of sulfuric acid mist, were evaluated for emissions of this pollutant. Because of the small impact of sulfuric acid mist on visibility, sulfuric acid mist was not included in the reasonable progress analysis.

To identify point sources in North Dakota that potentially affect visibility in Class I Federal areas, the list of sources subject to Title V permitting requirements was established as the starting point. This represents more than 99% of the sulfur dioxide emissions from all point sources in North Dakota that have an operating permit (Title 5 or Minor Source Operating Permit) and greater than 98% of the nitrogen oxides emissions based on 2007 data. The sources subject to BART were also eliminated from the list as suggested by EPA guidance. The Department has included all controls on BART sources that have a reasonable cost. Any controls rejected under BART would also be rejected under the four factors for determining reasonable progress. Although sources were excluded from this analysis, all sources, including sources subject to BART, will be reviewed during future planning periods.

To further evaluate the list of sources, the actual emissions from the source were compared to the distance the source is located from the nearest Class I Federal area. The Department has determined from previous BART modeling that particulate matter emissions from point sources have a very small contribution to visibility impairment in the Class I areas. Therefore, only emissions of nitrogen oxides and sulfur dioxide were evaluated in this comparison. The Department initially used the average of the 2000-2004 emission rate for this analysis. The emission rate (Q) in tons per year was divided by the distance (D), in kilometers, to the nearest Class I area. A value of Q/D greater than 10 was chosen as a point for further evaluation of those sources. A Q/D of greater than 10 was chosen based on the FLM's proposed FLAG guidance amendments initial screening criteria for sources that may affect air quality related values. In addition, EPA in the preamble to the BART Guideline states, "Our analyses of visibility impacts from model plants provide a useful example of the type of analyses that might be used to exempt categories of sources from BART. Based on our model plant analysis, EPA believes that a State could reasonably choose to exempt sources that emit less than 500 tons per year of NO_x or SO_2 (or combined NO_x and SO_2), as long as they are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tons per year of NO_x or SO_2 (or combined NO_x and SO_2) that are located more than 100 kilometers from any Class I area." EPA's criteria is equivalent to a Q/D of 10. For all sources, except EGUs, the total SO_2 and NO_x emissions from the facility were used and no distinction was made for individual units. EGU's were separated by units because they can act as standalone facilities while other process units cannot.

Table 9.4
North Dakota Title V Sources Q/D Analysis

Permittee	Plant	$SO_2 + NO_x$ 2000-2004 Average (tons)	Nearest Class I Area	Distance to Nearest Class I Area (km)	Nearest Q/D (tons/km)
ADM Corn Processing	Walhalla Ethanol Plant	287	Lostwood	324	0.9
ADM Processing	Velva Facility	45	Lostwood	125	0.4
Alliance Pipeline	Fairmount Comp. Station	58	Voyageurs	327	0.2
Alliance Pipeline	Towner Comp. Station	57	Lostwood	120	0.5
Alliance Pipeline	Wimbledon Comp. Station	60	Lostwood	335	0.2
American Crystal Sugar Co.	Drayton Sugarbeet Plant	1,109	Voyageurs	294	3.8
American Crystal Sugar Co.	Hillsboro Sugarbeet Plant	1,085	Voyageurs	315	3.4
Basin Electric	AVS Unit 1	13,864	TRNP/NU	107	129.6
Basin Electric	AVS Unit 2	12,796	TRNP/NU	107	119.6
Bear Paw Energy	Alexander Comp. Station	139	TRNP/NU	36	3.9
Bear Paw Energy	Fort Buford Comp. Station	42	TRNP/NU	44	1.0
Bear Paw Energy	Grasslands Gas Plant	748	TRNP/NU	38	19.7
Bear Paw Energy	Lignite Gas Plant	463	Lostwood	15	30.9
Bear Paw Energy	Tree Top Comp. Station	54	TRNP/SU	17	3.2
Cargill Corn Milling	Wahpeton Facility	109	Voyageurs	320	0.3
Cargill, Inc.	West Fargo Plant	56	Voyageurs	311	0.2
Cavalier AFS	CAFS Power Plant	234	Lostwood	280	0.8
City of Fargo	Landfill	9	Voyageurs	309	<0.1
City of Minot	Landfill	1	Lostwood	80	<0.1
CNH America, LLC	Fargo Plant	1	Voyageurs	310	<0.1
Continental Resources	Medicine Pole Hills	58	TRNP/SU	94	0.6
Dakota Gasification Co.	Great Plains Synfuels	10,802	TRNP/NU	107	101.0
DMI Industries	Fargo Plant	2	Voyageurs	321	<0.1
Grand Forks AFB	Heating Plant	9	Voyageurs	342	< 0.1
Hebron Brick Company	Hebron Brick Plant	30	TRNP/SU	97	0.3
Health Care	Fargo Incinerator	4	Voyageurs	313	<0.1
Hess Corporation	Hawkeye Comp. Station	116	Lostwood	53	2.2
Hess Corporation	Tioga Gas Plant	3,655	Lostwood	35	104.4
Hillsboro MEU	Hillsboro	1	Voyageurs	318	<0.1
Idahoan Foods	Grand Forks Plant	104	Voyageurs	316	0.3
J.R. Simplot	Grand Forks Plant	53	Voyageurs	317	0.2

Permittee	Plant	$SO_2 + NO_x$ 2000-2004 Average (tons)	Nearest Class I Area	Distance to Nearest Class I Area (km)	Nearest Q/D (tons/km)
Jahner Sanitation	Landfill	1	Voyageurs	340	<0.1
Kaneb Pipeline Co.	Jamestown Plant	1	TRNP/SU	351	<0.1
LM Glasfiber	Grand Forks Plant	1	Voyageurs	325	<0.1
Minn-Dak Farmers Coop	Wahpeton Facility	601	Voyageurs	319	1.9
Minot AFB	Heating Plant	24	Lostwood	79	0.3
MDU Company	Heskett Plant Unit 1	1,269	TRNP/SU	182	7.0
MDU Company	Heskett Plant Unit 2	3,411	TRNP/SU	182	18.7
Mor Tech Fab	Williston Plant	1	TRNP/NU	60	<0.1
Nordic Fiberglass	Devils Lake Plant	1	TRNP/NU	335	<0.1
NDSU	Heating Plant	500	Voyageurs	310	1.6
Northern Border Pipeline	Comp. Station No. 4	188	TRNP/NU	18	10.4
Northern Border Pipeline	Comp. Station No. 5	104	TRNP/NU	56	1.9
Northern Border Pipeline	Comp. Station No. 6	101	TRNP/SU	116	0.9
Northern Border Pipeline	Comp. Station No. 7	104	TRNP/SU	190	0.5
Northern Border Pipeline	Comp. Station No. 8	108	TRNP/SU	282	0.4
Northern Sun ADM	Enderlin Facility	105	Voyageurs	335	0.3
Otter Tail Power Company	Coyote Station	27,804	TRNP/NU	112	248.3
Petro-Hunt	Little Knife Gas Plant	422	TRNP/NU	39	10.8
Red Trail Energy	Richardton Ethanol Plant	329	TRNP/SU	74	4.4
Tesoro	Mandan Refinery	5,757	TRNP/SU	182	31.6
UND	Heating Plant	868	Voyageurs	318	2.7
Whiting Oil & Gas	Wabek Station	73	Lostwood	71	1.0
WBI Pipeline Company	Dickinson Comp. Station	137	TRNP/SU	39	3.5
WBI Pipeline Company	Glen Ullin Comp. Station	67	TRNP/SU	116	0.6
Wil Rich, Inc.	Wahpeton Plant	1	Voyageurs	317	<0.1

The Northern Border Pipeline Company Compressor Station No. 4 is powered by a natural gas turbine. In 2005, Northern Border replaced this turbine with a lower emitting turbine. From 2006-2008, the average nitrogen oxides plus sulfur dioxide emissions were 118 tons per year for a Q/D of 6.6. Because of the installation of the lower emitting turbine, this facility was eliminated from consideration of additional controls during this planning period.

The Tesoro Refining and Marketing Company's Mandan Refinery is subject to a Consent Decree which requires substantial emissions reductions. Since the baseline period, Tesoro has installed a wet scrubber and wet ESP to control sulfur dioxide emissions from the catalytic cracking unit, installed new lower emitting furnaces at the alkylation unit and are installing low NO_x burners in the boilers. From 2006-2008, the total sulfur dioxide and nitrogen oxides emissions from the facility averaged 1,438 tons per year for a Q/D of 7.9. This ratio is expected to decline significantly when the modifications to the boilers are brought on-line. Because of these changes, this facility was not considered for additional controls during this planning period.

Since the baseline period, Bear Paw Energy has been injecting the acid gas into deep wells at their Grasslands and Lignite Gas Plants. This injection eliminates all sulfur dioxide emissions except for those emissions due to a malfunction of the injection equipment. When a malfunction occurs, the acid gas goes to a flare which will emit sulfur dioxide. In 2007, total emissions of sulfur dioxide and nitrogen oxides (including malfunctions) from the Grasslands Gas Plant were 274 tons for a Q/D of 9.8. Without malfunction emissions, the total was 52 tons for a Q/D of 1.4. At the Lignite Gas Plant, the 2007 total sulfur dioxide and nitrogen oxides emissions (including malfunctions) were 121 tons for a Q/D of 8.1. Without malfunction emissions, the total was 48 tons for a Q/D of 3.2. These malfunctions are generally unplanned, short duration-episodes (a few hours) with very high SO_2 emission rates that vary from year-to-year. Controlling emissions during these malfunctions is not feasible and the acid gas is flared to prevent the release of high concentrations of hydrogen sulfide. These two sources were eliminated based on their change to acid gas injection which greatly reduces sulfur dioxide emissions. The requirement to inject their acid gas is included in the Title V Permit to Operate for each facility.

Petro Hunt’s Little Knife Gas Plant emissions include those emissions associated with malfunctions. If the malfunction emissions are eliminated, the average sulfur dioxide and nitrogen oxides emission rate for 2000-2004 is 337.7 tons for a Q/D of 8.7. The Little Knife Gas Plant has seen reduced operations recently due to a decline in gas volume. New oil wells that are being drilled are generally producing from the Bakken formation which contains sweet natural gas. In 2008, SO_2 plus NO_x emissions (including malfunctions) totaled 295 tons for a Q/D of 7.6. Because of the small amount of emissions and the expected decline in the future, the Little Knife Gas Plant was eliminated from consideration for additional control during this planning period.

All of the facilities that were eliminated from consideration for additional air pollution controls will be considered and reviewed again during future planning periods.

After review of the sources in Table 9.4, the following sources in Table 9.5 were considered for additional controls during this planning period:

Table 9.5
Sources Evaluated for Additional Control

Source	Owner	Unit	Type	Capacity
Antelope Valley Station	Basin Electric Power Coop.	1	EGU	435 MWe
Antelope Valley Station	Basin Electric Power Coop.	2	EGU	435 MWe
Coyote Station	OtterTail Power Co.	Main Boiler	EGU	450 MWe
Great Plains Synfuels Plant	Dakota Gasification Co.	Boilers A, B & S	Industrial Boilers	763 x 10^6 Btu/hr each
Tioga Gas Plant	Hess Corp.	3	Sulfur Recovery Unit	225 LTPD
Tioga Gas Plant	Hess Corp.	C1-A to F	Compressor Engines	1920-2350 BHp each

Step 2: Identify the Design Parameters for Emission Controls

All of the source units identified for possible additional air pollutant control are equipped with varying degrees of air pollution control equipment, as shown in Table 9.6.

Table 9.6
Remaining Sources Existing Conditions

Source	Pollutant	Control Equipment	Current[a] Emission Rate	Current[a] Control Efficiency (%)
AVS 1	SO_2 NO_x	Spray Dryer OFA	0.36 lb/10^6 Btu 0.37 lb/10^6 Btu	77 --
AVS 2	SO_2 NO_x	Spray Dryer OFA	0.38 lb/10^6 Btu 0.34 lb/10^6 Btu	76 --
Coyote	SO_2 NO_x	Spray Dryer None	0.71 lb/10^6 Btu 0.68 lb/10^6 Btu	66 --
Tioga Gas Plant SRU	SO_2	3 Stage Claus +4 bed Cold Bed Absorber	1097 tpy	98.8
Engines	NO_x	None	1353	--
GPSP - Boilers	SO_2 NO_x	Wet Scrubber None	2169 tpy 0.5 lb/10^6 Btu[b]	96-97 --

[a] Based on 2005-2007 data

[b] Based on 2007 data

Work is currently underway to increase the efficiency of the spray dryers at AVS I and II. This work is being done because of an expected increase in the sulfur content of the coal used at the facilities. The increase in efficiency is expected to approach 90% which the Department considers the limit of spray dryer efficiency. Even though the efficiency will be increased, no reduction in emissions is expected because of the higher sulfur coal. Because upgrades of the spray dryers are already in progress, this option was not considered at AVS I or II during this planning period. At the Coyote Station, upgrades to the spray dryer would require a detailed engineering analysis to determine if improvements are possible. For this planning period, replacing the spray dryer is evaluated. Any upgrades to the spray dryer (if possible) will produce less emissions reductions and less visibility improvement when compared to a new wet scrubber. This source will also be reevaluated during future planning periods to determine if additional controls are reasonable.

The boilers at the Great Plains Synfuels Plant (GPSP) are equipped with an ammonia reagent wet scrubbing system followed by a wet electrostatic precipitator. This system is achieving 96-97% removal of sulfur dioxide from the flue gas. This removal efficiency is comparable to BACT or BART for industrial boilers of this size. Therefore, sulfur dioxide controls for these boilers were not evaluated further during this planning period.

The following control options were reviewed for possible implementation at the remaining sources:

Table 9.7
Control Options Evaluated

Source	Pollutant	Control Considered	Estimated Control Efficiency (%)
AVS 1 and 2	SO_2	New Wet Scrubber	95
	NO_x	LNB	30-75
		SNCR	30-75
		SCR w/Reheat	40-90[c]
Coyote	SO_2	New Wet Scrubber	95
	NO_x	ASOFA	40
		SNCR	30
		ASOFA + SNCR	50-60
		SCR w/Reheat	40-90[c]
Tioga Gas Plant SRU	SO_2	Tail Gas Cleanup	99.8-99.98[a]
1920 BHp Engines	NO_x	SCR	80-90[c]
		Engine Remanufacture	80-90
		Air-Fuel Ratio Controller	10-40
		Ignition Timing Retard	15-30
2350 BHp Engines	NO_x	SCR	33-67
GPSP – Boilers	NO_x	SNCR[b]	30-40
		SCR[b]	40-90[c]

[a] Overall efficiency of the sulfur recovery unit and tail gas cleanup unit. BACT determinations range from 99.8% for existing units to 99.98% for new units.
[b] The Department has concerns whether SCR and SNCR are technically feasible for the GPSP (see DGC's comments in Appendix I).
[c] The Department considers 90% efficiency reasonable for new installations and 80% reasonable for retrofits.

Step 3: Develop Cost Estimates Based on the Design Parameters

The available control options were evaluated by WRAP's contractor EC/R Incorporated. The report on this evaluation is found in Appendix I.1. The cost for the wet scrubber at the Coyote Station was adjusted to represent the gross capacity of the facility (450 MWe vs 427 MWe) which is larger than EC/R evaluated. Also, the removal efficiency for a new wet scrubber was adjusted from 90% to 95%. The costs associated with the various control technologies are shown in Table 9.8.

The cost effectiveness ($/ton) for new scrubbers at AVS I & II and Coyote Station is higher than at the BART sources that are not equipped with scrubbers. Because AVS and Coyote Station are already equipped with spray dryers, the cost effectiveness is higher because less sulfur dioxide will be removed than at the unit without a scrubber. The following control options were found to have an excessive cost effectiveness:

AVS 1 & 2 – Wet scrubber; SCR w/reheat; and LNB + SCR w/reheat
Coyote – SCR w/reheat and ASOFA + SCR w/reheat
Tioga Gas Plant – Tail Gas Cleanup
DGC – SNCR and SCR

The SRU at the Tioga Gas Plant is currently operating at less than 45% of its rated capacity. It is expected that the amount of sulfur recovered and emissions from the tail gas incinerator will continue to decline due to a decline in sour gas production in the area the Tioga Gas Plant serves. Most new gas produced comes from the Bakken formation which is sweet gas.

The Department has concerns whether SCR or SNCR can be successfully applied at the GPSP (see DGC comments in Appendix I). Pilot scale testing may be necessary to determine the technical feasibility of SCR or SNCR for the boilers which produce a flue gas with a high carbon dioxide and sulfur concentration.

Therefore, these control technologies were not evaluated further.

For the most efficient control options for which the cost effectiveness (as described in Table 9.8) was considered reasonable on a $/ton basis, the 2018 projected emissions were modeled by the NDDoH to determine the source-specific improvement in visibility. Cumulative modeling was conducted using the procedures (default EPA methodology), hybrid modeling system, and baseline and future (2018) emissions inventories as described in Section 8.5. The

Table 9.8
Control Options Cost

Source	Unit	Pollutant	Control Technology	Total Annualized Cost ($)	Control Efficiency (%)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
AVS	1	SO_2	New Wet Scrubber	32,170,000	95	6,780	4,745
		NO_x	LNB	2,280,000	51	3,889	586
			SNCR	8,960,000	40	3,050	2,938
			LNB+SNCR	11,240,000	65	4,956	2,268
			SCR w/reheat[1]	44-63.2 million	80	6,100	7,213-10,360
			LNB + SCR w/reheat	46.3-65.5 million	90	6,863	6,746-9,544
AVS	2	SO_2	New Wet Scrubber	32,170,00	95	5,899	5,453
		NO_x	LNB	2,280,000	51	3,450	661
			SNCR	8,960,000	40	2,706	3,311
			LNB+SNCR	11,240,000	65	4,397	2,556
			SCR w/reheat[1]	44-63.2 million	80	5,411	8,132-11,680
			LNB + SCR w/reheat	46.3-65.5 million	90	6,087	7,606-10,761
Coyote	1	SO_2	New Wet Scrubber	33,280,000	95	12,835	2,593
		NO_x	ASOFA[1]	1,284,000	40	5,223	246
			SNCR	8,520,000	40	5,223	1,631
			ASOFA & SNCR[1]	11,245,000	55	7,182	1,566
			SCR w/reheat[1]	45.3-65.1 million	80	10,446	4,337-6,232
			ASOFA + SCR w/reheat	46.6-66.4 million	90	11,752	3,965-5,650
Tioga Gas Plant[3]	SRU	SO_2	Tail Gas Clean Up[2]	5,800,000	99.8	1,018	5,697
	1920 Hp Engines	NO_x	Air Fuel Ratio Controller	260,000	25	305	852
			Ignition Timing Retard	140,000	22	268	522
			LEC Retrofit	560,000	85	1,035	541
			SCR	1,600,000	80	974	1,643
	2350 Hp Engines		SCR	500,000	50	34	1,471
DGC	Boilers (each)		SNCR	1,690,000	30	259	6,525
			SCR	5,505,000	80	670	8,216

Notes: A) The Department does not consider high dust SCR to be technically feasible for North Dakota lignite (see BART analysis in Section 7). The uncertainties associated with designing an SCR system because of the high sodium and potassium submicron aerosols in the flue gas, even after the air pollution control equipment, dictates the use of the high end of the SCR cost range.

B) Replacement of the compressor engines with electric motors is not technically feasible since the compressor cylinder connecting rods are an integral part of the engines crankshaft.

[1] Based on BART cost estimate for Leland Olds Unit 2 and Minnkota 1 & 2 shared cost estimate.

[2] Based on an overall efficiency of the SRU and tail gas cleanup unit of 99.8%.

[3] Reductions are the total for all engines with the specified horsepower rating.

future emissions inventory was modified to reflect the control technology for each candidate source (AVS 1 EGU, AVS 2 EGU, Coyote EGU, and Tioga Gas Plant), and modeling was conducted using the revised future inventory for one source at a time. The reasonable progress goals in 40 CFR 51.308(d)(1) requires improvement in the most impaired days. The most impaired days are defined in 40 CFR 51.301 as the average visibility impairment for the twenty percent days with the highest amount of visibility impairment. Therefore, modeling addressed the 20% worst days for both TRNP and LWA Class I areas. The results for each candidate source were compared with the results using the unmodified future emissions inventory (Table 8.11) to determine the additional visibility improvement due to the tested control technology.

Modeled visibility improvement, for each candidate source/technology, is provided in Table 9.9. The single source controlled emissions (modeled tons per year) and annualized cost effectiveness (dollars per deciview) are also reported in the table. Reported visibility improvement (in deciviews) reflects the higher value for either TRNP or LWA. Note that visibility improvement reported for Coyote represents the total for both SO_2 and NO_x control technologies, and the improvement reported for the Tioga Gas Plant represents the total for all 1920 and 2350 horsepower engines. As shown in the table, predicted visibility improvement is very marginal for all candidate sources/technologies, and consequently cost per deciview is very high.

Table 9.9
Visibility Improvement and Cost Effectiveness

Source	**Pollutant**	**Control Technology**	**Emissions (TPY)**	**Visibility Improvement (dv)***		**Visibility Improvement (%)*****		**Cost Effectiveness ($/dv)****
				TRNP	**LWA**	**TRNP**	**LWA**	
AVS 1	NO_x	LNB+SNCR	2,358	0.005	0.01	0.03	0.05	1,124,000,000
AVS 2	NO_x	LNB+SNCR	2,144	0.005	0.01	0.03	0.05	1,124,000,000
Coyote	SO_2 NO_x	Wet Scrubber ASOFA+SNCR	1,924 5,871	0.02	0.04	0.11	0.20	1,113,000,000
Tioga G.P. 1920 BHp Engines 2350 BHp Engines	NO_x NO_x	LEC Retrofit SCR	268 33	0	0.5	0	0.26	21,200,000

*The less efficient technologies evaluated would provide less improvement.
**Based on the maximum visibility improvement (per source) at any Class I area in North Dakota.
***Improvement (%) from baseline conditions.

Time Necessary for Compliance

Up to 6.5 years after SIP approval is necessary to achieve compliance (see EC/R report in Appendix I.1). Additional time may be necessary if normal maintenance outages do not coincide with the projected schedule. It is anticipated that all required changes could be implemented by 2018 depending on the date of approval of this SIP. It is not anticipated that any of the remaining sources will be retired prior to 2018.

Energy and Non-Air Impacts

All of the control technologies for the various sources will consume energy (see EC/R report in Appendix I.1). In the case of the Antelope Valley Station and the Coyote Station, this would mean less electricity available for sale. The enhancement of the sulfur dioxide scrubbing system at the Coyote Station would increase the amount of solid waste generated (ash/$CaSO_4$) which must be handled and properly disposed. However, there are no non-air impacts identified that would preclude additional reductions of SO_2 or NO_x from the facilities.

Remaining Useful Life of the Source

The following table lists the expected remaining useful life of the remaining sources.

Table 9.10
Remaining Useful Life

Source	Unit	Startup Date	Estimated Remaining Useful Life (yrs)
AVS	Unit 1	1983	20-40
	Unit 2	1985	20-40
Coyote	Unit 1	1981	20-40
Tioga Gas Plant	Engines	1954	5-40

The engines at the Tioga Gas Plant are now 55 years old. Engines D and F have recently been refurbished. It is expected that the other engines could be refurbished which will extend their remaining useful life an indefinite period. Other than the engines at the Tioga Gas Plant, the remaining useful life of the affected sources would not preclude additional air pollution controls.

Reasonable Progress Goals - Required Controls for Point Sources

EPA has stated in their Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 1, 2007) “in assessing additional emissions reduction strategies for source categories or individual, large scale sources, simple cost effectiveness based on a dollar-per-ton calculation may not be as meaningful as a dollar per deciview calculation.” It has been determined that requiring additional controls, beyond BART, on existing point sources will not substantially improve visibility in the Class I Federal Areas. The maximum combined improvement based on the Department’s cumulative modeling for the average of the 20% worst days is 0.11 deciviews at LWA and 0.03 deciviews at TRNP for the most efficient control options for each source that is cost effective. This amounts to a 0.17% improvement at TRNP over the baseline condition for the most impaired days and 0.56% improvement at LWA. Other less efficient control technology options would provide substantially less visibility improvement in the Class I areas. The total capital cost to achieve this improvement is approximately 243 million dollars with an annualized cost of approximately 68 million dollars. Based on the data in Tables 9.8 and 9.9, the cost effectiveness is over 618 million dollars per deciview of improvement at LWA and 2.3 billion dollars per deciview at TRNP. For all sources evaluated individually and cumulatively, the cost ($/dv) is considered excessive. Therefore, no additional controls are proposed for these non-BART sources during this planning period. However, conditions at the plants and control technologies may change in the future. Therefore, all of these sources will be reevaluated during future planning periods.

9.5.2 Agricultural Tillage Operations

North Dakota has approximately 38 million acres of farm and ranch land or approximately 86% of the State’s area. Working the land can contribute significant amounts of fugitive and windblown dust. The WRAP has estimated that emission sources in North Dakota put more than 420,000 tons of particulate matter into the atmosphere in 2002. Fugitive dust from agricultural activities and windblown dust from farm fields were a major contributor to these emissions. Although there was a large amount of particulate matter emissions, the effect on visibility in the North Dakota Class I areas was small, but not insignificant, as shown in Figures 9.1 and 9.2 from the WRAP’s TSS. At TRNP, coarse mass and soil (fine mass) combined to contribute approximately 11% of the total extinction during the 20% worst days of the baseline period. At the Lostwood Wilderness Area, approximately 7% of the total extinction was due to coarse mass and soil. North Dakota sources contributed approximately 45 percent of the PMF and PMC at TRNP and approximately 30 percent at LWA during the 20 percent worst days in 2000-2004 (based on WRAP’s weighted emissions potential analysis).

Figure 9.2
TRNP Species Apportionment
20% Worst Days

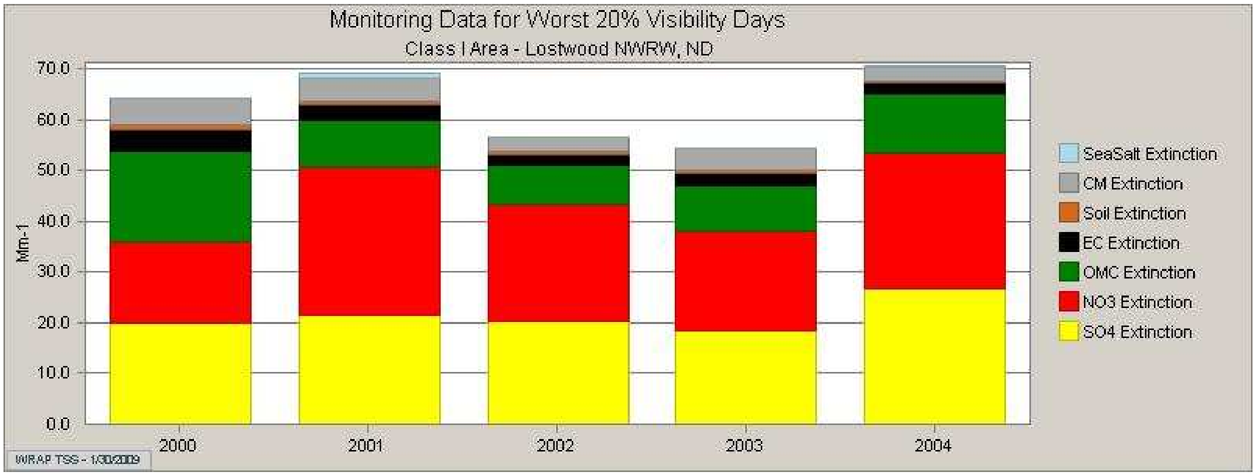
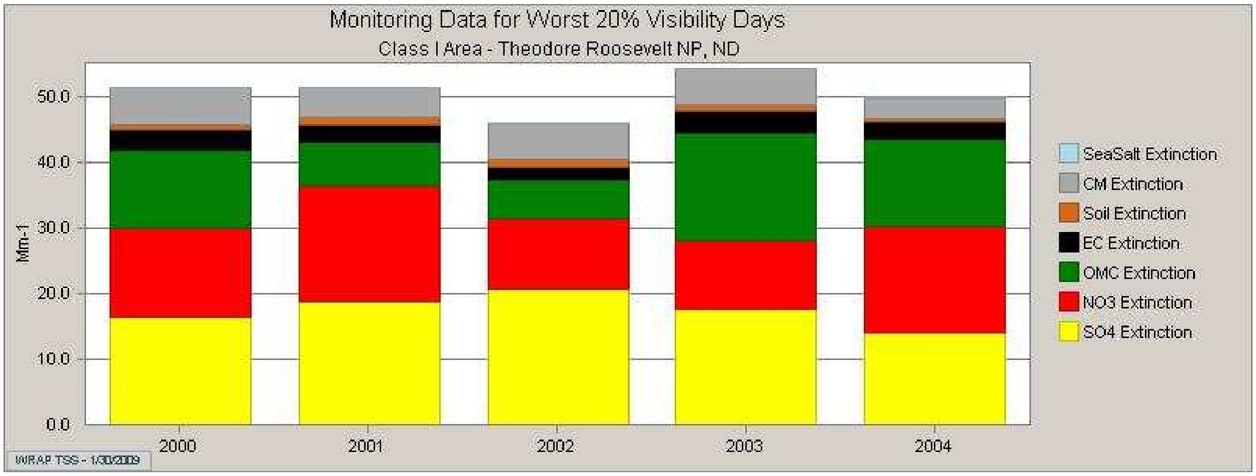


Figure 9.3
LWA Species Apportionment
20% Worst Days



The practice of conservation tillage is becoming more popular in North Dakota. The Conservation Technology Information Center (CTIC) in West Lafayette, Indiana specifies that 30 percent or more of crop residue must be left after planting to qualify as a conservation tillage system. Some specific types of conservation tillage include Minimum Tillage, Zone Tillage, No-till, Ridge-till, Mulch-till, Reduced-till, Strip-till, Rotational Tillage and Crop Residue Management. According to the Crop Residue Management survey conducted by the CTIC, total conservation tillage in North Dakota increased from 28% to 39% of total planted acres from 1998 to 2004. In general, conservation tillage practices are used more in the western part of the

State (near the Class I areas) than in the eastern part of the State due to the more arid conditions, thinner topsoil and the types of crops grown. In 2006, 77% of the crop acreage in Williams County in Western North Dakota was planted using conservation tillage practices versus 28% in Sargent County (southeastern North Dakota). It is expected that conservation tillage practices will increase over the planning period. Higher fuel, equipment and labor costs will entice farmers to reduce tillage. Other added benefits include better soil moisture storage and eventually less fertilizer usage. Additionally, conservation tillage practices, such as No-till farming, help sequester carbon which can be sold as carbon credits. As carbon dioxide controls are instituted, the money earned by farmers for carbon sequestration will also provide an incentive for conservation tillage practices.

Given the small contribution of coarse mass and soil to total extinction and that conservation tillage practices are increasing, the Department concludes there is no need to implement controls on farming practices. As outlined earlier, free market incentives should increase conservation tillage which will reduce emissions. The trend of increased conservation tillage practices from 1998-2004 is expected to continue during the planning period.

Sources in this category are subject to NDAC 33-15-17-02.6 which requires agricultural activities be managed in a manner as to minimize dust from becoming airborne. The Department will reevaluate the source category in future planning periods to determine if additional controls are required.

9.5.3 Smoke Management for Agricultural, Forest Management and Prescribed Burning

It has been determined that no additional rules or controls for smoke management are required (see Section 10.6.5). The worst short-term visibility degradation that occurs in the Class I areas is caused by prescribed burning conducted by the Federal Land Managers. In 2005, the entire LWA (5,577 acres) was burned by the FLM. In addition, 3,579 acres in the immediately adjacent Lostwood Wildlife Refuge were burned on 7 different days. Although the State of North Dakota recognizes the position of the FLMs that prescribed burning is necessary to maintain a healthy ecosystem, it must also be recognized that the actions of the FLMs that affect visibility in the Class I areas must be considered when evaluating controls for others that use prescribed burning (e.g., farming, road maintenance, etc). No additional smoke management requirements are proposed in this planning period. However, the Department will reevaluate this source category during future planning periods to determine if additional regulation is required.

9.5.4 Reserved

9.5.5 Oil and Gas Exploration and Production

Oil and natural gas production in North Dakota is generally limited to the western one-third of the State. In September 2009, there were 4,348 operating wells that produced approximately 238,000 barrels of oil per day. This is in contrast to states like Wyoming that has approximately

45,000 producing oil and gas wells and Colorado which has approximately 40,000 active wells. The primary difference is that North Dakota does not have any coal bed methane (CBM) wells. The lack of CBM wells means there are much fewer pumps, compressors and gas processing plants needed even though North Dakota produces more oil than either of these states. The baseline SO_2 and NO_x emissions from area oil and gas sources are estimated at less than 5000 tons per year of each pollutant (see Table 6.1).

North Dakota's oil production is highly dependent on the price of oil. Several peaks in production (i.e. 1996 and 1983) have been achieved only for production to drop severely (i.e. 42% from 1983 to 2003) and then increase as the price of oil increases. Several projections have been made regarding the amount of oil that will be produced in the future, the number of wells that will be producing and the number of drilling rigs that will operate in the State. All of these projections are highly speculative because of the volatility of oil prices. The price of North Dakota crude oil reached a high of approximately $127 per barrel in 2008 and dropped to as low as $25 per barrel in 2009. The number of drilling rigs also dropped dramatically from a high of 92 in November 2008 to 35 in May 2009. WRAP has projected a 4-5 fold increase in NO_x emissions from oil and gas activities by 2018. Although emissions may increase this amount during the planning period, the North Dakota Oil and Gas Division of the State Industrial Commission believes that emissions will decrease by 2018 to a level that is 2.0 to 2.5 times the baseline emission rate. The Oil and Gas Division believes that activity associated with the major oil producing formation (Bakken formation) will be decreasing by 2018 with a peak during this planning period. However, any estimate of future activity is suspect because the future of oil prices is unknown. Because current estimates of future oil and gas activity, and emissions from that activity, are very questionable, the Independent Petroleum Association of Mountain States (IPAMS) is sponsoring development of a third, or Phase III, inventory of emissions from the Williston Basin in North Dakota. This inventory is not complete and available for this planning period. Because of the serious flaws in the Phase I and Phase II inventories, the Department believes that the Phase III inventory is necessary for any planning activities for oil and gas emissions in North Dakota.

A Q/D type analysis does not work well for oil exploration or production facilities. These individual facilities generally have very low sulfur dioxide and nitrogen oxides emissions. However, when the facilities emissions are aggregated, there may be significant impact on visibility in a Class I area. The Q/D analysis in 9.5.1 included the larger compressor stations and natural gas processing plants (sources subject to Title V). North Dakota also permits minor oil and gas sources including small compressor stations (greater than 500 Hp), natural gas processing plants and tank batteries. The Q/D analysis indicates that only the larger facilities (i.e. larger Title V sources) have a significant impact on visibility in North Dakota Class I areas. Sulfur dioxide emissions from future oil and gas activities are not a concern because most new oil and gas production is from the Bakken formation which contains sweet (negligible sulfur content) oil and gas. In addition, engines will be required by Federal rule to use ultra low sulfur gasoline and diesel fuel. Nitrogen oxides emissions are the primary concern. These will emanate from vehicles, drilling rig engines, glycol dehydrators, flares, compressor engines, and other combustion sources. Stationary engines are subject to a number of New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards which will help limit NO_x emissions. The EPA has also promulgated a 1-hour

NAAQS for NO_2. North Dakota had a 1-hour NO_2 AAQS set at 100 ppb until December of 1994. The new NAAQS is slightly more stringent than the former SAAQS for NO_2. The Department's experience indicates that oil and gas facilities will have to limit NO_x emissions through the use of control devices such as catalytic convertors on engines or low NO_x burners at heater/treaters or glycol dehydration unit boilers. Particulate emissions from oil and development and production are not expected to change appreciably from the baseline emission rate. Emissions from the production site are mostly from development of the well pad which is of short duration. Vehicle traffic would be the only other significant source of particulate matter emissions. Once the well is developed, these emissions should decrease substantially.

The WRAP, through its contractor EC/R Incorporated, has prepared an analysis of the four factors for reasonable progress for oil and gas exploration and production operations (see Appendix I.2, Section 4). Given the small amount of baseline emissions and the uncertainty of the projection of future emissions, the Department proposes no additional controls for oil and gas exploration and production facilities at this time. The Department will continue to track oil and gas emissions and will take into consideration the Phase III inventory when it is available. During the mid planning period review, the Department will review oil and gas emissions and take action if necessary. Oil and gas emissions will also be addressed during subsequent planning periods.

9.6 Visibility Modeling and Weight of Evidence

As detailed in Section 8, modeling has been conducted by both WRAP and the NDDoH to estimate visibility improvement resulting from implementation of BART and other reasonable control measures. Modeling addressed TRNP and LWA Class I areas in North Dakota. Visibility improvement modeling accounted for the cumulative effect of BART controls, and other growth and control factors. Modeling was initially conducted using the default EPA methodology, and results were compared with the default EPA uniform rate of progress (URP). Because results based on the default EPA methodology did not achieve compliance with default URP targets for 2018, additional modeling was conducted by the NDDoH for various weight of evidence options.

Supplemental weight of evidence modeling analyses conducted by the NDDoH, which have a bearing on the selection of reasonable progress goals, include the following.

1) Discounted the impact of international (in this case, Canadian) source visibility-affecting emissions on North Dakota Class I areas.

2) Discounted the impact of visibility-affecting emissions from all sources located outside of North Dakota, on North Dakota Class I areas.

3) Used the complete emissions inventory for the default EPA method, but zeroed out future SO_2 and NO_X emissions from all sources located in North Dakota (i.e., assumed 100 percent future control of all SO_2 and NO_X emissions in North Dakota), to determine progress with respect to the default glide path for North Dakota Class I areas.

4) Conducted modeling to determine the incremental visibility improvement, and cost effectiveness ($/dv), of enhanced control technology at AVS generating station, Coyote generating station, and Tioga Gas Plant (Section 9.5.1).

Modeling results for the default EPA methodology and weight of evidence analyses are summarized in Table 9.11. In the table, Scenarios 1 and 2 represent the implementation of default EPA methodology by WRAP and NDDoH, respectively. Scenarios 3, 4, and 5 reflect the first three NDDoH weight of evidence analyses outlined above. Results for the fourth weight of evidence analysis (above) were provided in Table 9.9. Results in Table 9.11 are presented as the projected percent of the 2018 target.

From results of visibility modeling based on standard EPA methodology, and results of the weight of evidence analyses, the following conclusions are applicable to the establishment of reasonable progress goals for North Dakota Class I areas.

1) The uniform rate of progress goal for 2018 for 20% worst days will not be achieved at either TRNP or LWA.

2) Apportionment modeling results indicate the contribution of sources located outside of North Dakota is much greater than the contribution of in-state sources to 20% worst day visibility at TRNP and LWA (both baseline and 2018).

3) Though the addition of proposed BART controls substantially decreases the visibility impact of North Dakota EGUs, these EGUs comprise only a small component of total 20% worst day impact at TRNP and LWA.

Table 9.11
NDDoH Visibility Modeling Results 20% Worst Days
EPA Methodology and Weight of Evidence Analysis Summary

Scenario	Description	Class I Area	Projected Percent of 2018 Target
1	WRAP CMAQ Default EPA Methodology	TRNP	24.0
		LWA	16.7
2	NDDoH Hybrid Default EPA Methodology	TRNP	38.1
		LWA	26.7
3	NDDoH Hybrid Canada Sources Discounted	TRNP	50.0
		LWA	40.2
4	NDDoH Hybrid All Sources Other Than ND Discounted	TRNP	83.9
		LWA	59.6

Scenario	Description	Class I Area	Projected Percent of 2018 Target
5	NDDoH Hybrid Base Emission Inv = Default Future Emissions Inv = All ND SO_2 and NO_x Emissions set to zero	TRNP LWA	83.8 72.6

4) Compliance with 20% worst day URP 2018 targets at North Dakota Class I areas cannot be achieved through additional emissions reductions from North Dakota sources, alone. It will require significant additional visibility affecting emissions reductions from Canada, other western states and from sources located outside of the WRAP CMAQ modeling domain.

5) After discounting the impact of Canadian sources, significantly greater progress (50 percent greater) was demonstrated, relative to URP 2018 targets for North Dakota Class I areas, than modeling with the entire emissions inventory but the 20% worst day targets were still not achieved.

6) After discounting the impact of *all sources located outside of North Dakota*, even greater progress was demonstrated, relative to URP 2018 targets for North Dakota Class I areas, than modeling with Canadian sources discounted. However, 20% worst day targets were still not achieved.

7) After zeroing out all future SO_2 and NO_X emissions in North Dakota under default EPA methodology (emulating a 100 percent, unrealistic control of all sources), compliance with 20% worst day targets was still not achieved at North Dakota Class I areas.

8) The use of enhanced control technology at AVS generating station, Coyote generating station, and Tioga Gas Plant provides minimal incremental improvement in 2018 visibility (Table 9.9), and does not meaningfully change status with respect to 2018 visibility goals.

Given these conclusions based on modeling, it appears most of the visibility impact at North Dakota Class I areas is due to emissions from sources located outside the jurisdiction of the NDDoH. But regardless of the extent to which visibility-affecting sources located outside of North Dakota are discounted, compliance with URP targets cannot be achieved. Further, the use of enhanced control technology on additional candidate sources (Item 8, above) within jurisdiction of the NDDoH does not provide a meaningful improvement in terms of 2018 URP visibility goals. It is not realistic to expect significant additional controls (beyond BART or other current controls) will be implemented in states or Canadian provinces apart from North Dakota before 2018. From a modeling perspective, therefore, setting reasonable progress goals for 20% worst days to be consistent with 2018 modeling results for the default EPA methodology (Table 9.11) would seem most realistic.

9.7 Establish Reasonable Progress Goals

As indicated in Section 8, control of emissions from North Dakota sources has only a small effect on visibility conditions in the North Dakota Class I areas. The source apportionment (based on WRAP modeling) for the 20% worst days in the Class I areas indicates that sources outside of North Dakota contribute from 79-87% of the sulfate or nitrate which cause the greatest visibility impairment in the North Dakota Class I areas. The source region apportionment provided by WRAP is presented in Table 9.12 for the North Dakota Class I areas. Note that the WRAP modeled contributions for North Dakota sources in Table 9.12 are somewhat smaller than the contributions based on NDDoH modeling in Table 8.16. This is because the NDDoH approach incorporated a more realistic representation of point source plumes, resulting in higher predictions for North Dakota sources (and greater visibility improvement).

Table 9.12
Source Region Apportionment 20% Worst Days

Contributing Area	Class I Area			
	TRNP		LWA	
	SO_4	NO_3	SO_4	NO_3
North Dakota	21.1%	19.1%	17.9%	13.0%
Canada	28.3%	31.8%	45.9%	44.6%
Outside Domain	32.6%	17.9%	20.2%	14.0%
Montana	3.1%	15.0%	2.4%	9.3%
CENRAP	4.9%	2.5%	5.3%	5.1%
Other	10.5%	13.7%	8.3%	14.0%

An analysis was conducted to determine if the uniform rate of progress could be achieved in the North Dakota Class I areas by controlling sulfur dioxide and nitrogen oxides emissions from in-state sources (see Section 8.7.3.3). The results indicate the uniform rate of progress cannot be achieved by reductions in North Dakota alone. If all sulfur dioxide and nitrogen oxides emissions in North Dakota were completely controlled (zero emissions), only 72.6% of the uniform rate of progress for the 20% worst days would be achieved at LWA and only 83.8% at TRNP. Significant reductions of emissions from sources outside of North Dakota will be required in order to meet the uniform rate of progress for this planning period.

North Dakota can only require emission controls for sources within its boundaries. Because of the large contribution to visibility impairment from sources outside of North Dakota, any estimate of reasonable progress on a deciview basis is tenuous at best. Any increase in emissions from sources external to North Dakota could offset any improvement from the reduction of emissions at in-state sources. By 2018, North Dakota BART controls plus other regulatory requirements are expected to reduce in-state SO_2 emissions by more than 60% and NO_x emissions by more than 25%. Table 9.13 shows the projected change in emissions for North Dakota as well as surrounding states and Canada.

Table 9.13
Projected Change in Emissions
2002-2018
(%)

	South Dakota	Montana	Minnesota	Canada	North Dakota
SO_2	-35.7	-11.8	-28.8	-6.8	-60.0
NO_x	-17.9	-26.0	-39.4	-0.8	-25.3
OC	-6.1	-3.3	-5.3	22.7	-19.4
EC	-51.1	-16.6	-28.9	75.2	-52.3
PMF	2.2	7.5	-1.3	34.8	2.0
PMC	4.2	8.8	-4.4	33.8	3.5
NH_3	0.3	1.2	33.9	-31.9	-0.3
VOC	-0.5	-0.6	2.9	-1.2	1.1
CO	-17.0	-15.9	-20.8	-11.7	-27.4

Note: Based on WRAP's Case Plans 02d and PRP18b.

The reasonable progress goals based on the Department's hybrid modeling approach in Table 9.14 are established. The analyses conducted indicate there will be no degradation in the 20% best days. The Department's modeling results show that visibility in the 20% best days will improve 0.14 deciviews at TRNP and 0.09 deciviews at LWA.

Table 9.14
Reasonable Progress Goals

Class I Area	Baseline Visibility 20% Worst Days (dv)	2018 RPG[a] 20% Worst Days (dv)	2018 RPG[b] 20% Worst Days (dv)
TRNP	17.8	16.9	17.2
LWA	19.6	18.9	19.1

[a] Based on Department's hybrid modeling approach.
[b] Based on WRAP's modeling approach.

40 CFR 51.308(d)(1)(ii) requires the State to provide for public review an assessment of the number of years it would take to attain natural conditions if visibility improvement continues at the rate of progress selected by the State as reasonable. Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve

natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO_2 and NO_x emissions in North Dakota will not achieve the uniform rate of progress for this, or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources. The number of years required to achieve natural conditions based on the proposed reasonable goals are as follows:

Table 9.15
Time Necessary to Achieve Natural Conditions

Class I Area	Baseline Visibility	Natural Visibility	Improvement Rate this Planning Period	Years to Natural Conditions[a]
	20% Worst Days (dv)	20% Worst Days (dv)	20% Worst Days (dv/yr)	20% Worst Days
TRNP	17.8	7.8	0.06429	156
LWA	19.6	8.0	0.05000	232

[a]Based on the Department's hybrid modeling approach.

If the most efficient cost effective control options evaluated for Coyote Station, Antelope Valley Station and the Tioga Gas Plant were implemented, the number of years to reach natural conditions would be 151 years at the three units of TRNP and 201 years at LWA. Implementing additional controls at these sources will not significantly affect current visibility conditions or the amount of time necessary to achieve natural conditions.

10. Long -Term Strategy

10.1 Long -Term Strategy Requirements

40 CFR 51.308(d)(3) contains the requirements for the long-term strategy for regional haze. Each State listed in §51.300(b)(3) must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State which may be affected by emissions from the State. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I areas. In establishing its LTS for regional haze, the State must meet requirements of §51.308(d)(3)(i) through (3)(v).

10.2 Consultation With Other States

40 CFR 51.308(d)(3)(i) requires “Where the State has emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another State or States, the State must consult with the other State(s) in order to develop coordinated emission management strategies. The State must consult with any other State having emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area within the State.”

North Dakota emissions are reasonably anticipated to contribute to visibility impairment in mandatory Class I Federal areas in Minnesota (Boundary Waters Canoe Area Wilderness Area and Voyageurs National Park), Montana (Medicine Lake National Wildlife Refuge Wilderness Area and U.L. Bend National Wildlife Refuge Wilderness Area), and South Dakota (Badlands National Park and Wind Cave National Park). Reasonably anticipated to contribute is considered to be a contribution of more than 5 percent to the total extinction (B_{ext}) in the Class I area. North Dakota emissions impacts on Michigan Class I areas (Isle Royal National Park and Seney National Wildlife Refuge Wilderness Area) are small or less than 5 percent of the extinction (B_{ext}). North Dakota emissions impacts on other more distant Class I areas are considered minimal. See the discussion in Section 2.4.

The NDDoH has consulted with Minnesota and Michigan as a part of the Northern Class I Areas consultation group and Minnesota individually. As a result of the consultations, Minnesota sent a memorandum dated September 19, 2007 to North Dakota and other states impacting Minnesota Class I areas. Minnesota requested a response documenting these consultations have taken place to the satisfaction of North Dakota or detailing areas where additional consultation should occur. In those states Minnesota has identified as additional contribution states, they asked such states to respond with their agreement or disagreement with Minnesota’s determination of contributing states and the additional control strategies that will be evaluated. Minnesota’s memorandum and the NDDoH letter of response dated August 22, 2008 are attached in Appendix J.2.

The NDDoH has consulted with Montana and South Dakota through the WRAP which we are members and as needed individually. Additionally the NDDoH has consulted with EPA Region 8 in Denver concerning the Montana Class I areas as they are preparing a FIP at the request of the State.

Minnesota, Montana and South Dakota are the only states that have emissions that are reasonably anticipated to contribute to visibility impairment in the North Dakota Class I Federal areas.

Consultation is further addressed in Section 3, Plan Development and Consultation.

10.3 Demonstration of Inclusion of Measures to Obtain RPGs in Class I Areas

40 CFR 51.308(d)(3)(ii) requires "Where other States cause or contribute to impairment in a mandatory Class I Federal area, the State must demonstrate that it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area. If the State has participated in a regional planning process, the State must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process."

The control measures and emission limits incorporated in this SIP for the seven electrical generating units subject to BART combined with Federal mobile source and other rules will reduce North Dakota sulfur dioxide emissions by 60 percent, nitrogen oxide emissions by 25 percent, organic carbon emissions by 19 percent and elemental carbon emissions by 52 percent. These percent reductions compare favorably with the uniform rate of progress first planning period required overall reduction by 2018 of approximately 23.3 percent (14 years ÷ 60 years x 100 = 23.3 percent). In addition, existing State smoke management and fugitive dust control rules will adequately control emissions from agricultural and forest burning and construction activities. North Dakota has met and included in this SIP all measures needed to achieve its apportionment of emission obligations agreed upon by the members of WRAP. These emission reductions will provide North Dakota's share of emission reductions needed for Class I Federal areas in Minnesota, Michigan, Montana and South Dakota.

10.4 Documentation of the Technical Basis for Modeling, Monitoring and Emissions Information

40 CFR 51.308(d)(3)(iii) requires "The State must document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area it affects. The State may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all State participants. The State must identify the baseline emissions inventory on which its strategies are

based. The baseline emissions inventory year is presumed to be the most recent year of the consolidated periodic emissions inventory."

North Dakota is a member of the Western Regional Air Partnership (WRAP) regional planning organization and relied on the modeling, monitoring and emissions information and technical analyses developed by WRAP.

The NDDoH relied on the use of CALPUFF for single source BART screening modeling, WRAP CMAQ and PSAT modeling, and its own hybrid CALPUFF modeling in its cumulative impact analyses. The BART modeling conformed to the requirements of the BART guidelines and is described in Section 7. The WRAP CMAQ and PSAT modeling and the NDDoH hybrid CALPUFF modeling conformed with EPA modeling guidelines and are described in Section 8.

The NDDOH relied on IMPROVE monitoring data as available on the WRAP TSS website and discussed in Section 4.

The NDDoH used the WRAP Plan02d emissions inventory for the baseline emissions year 2002 which reflects a composite interpretation of emissions for the base 2000-2004 period; and the WRAP CMAQ PRP18a (Preliminary Reasonable Progress 2018 Scenario A) emissions inventory which reflects projected year 2018 emissions. Case PRP18a represents base period emissions projected to 2018, accounting for estimates of the effect of BART controls, and assuming other growth and control factors. The Plan02d and PRP18a emissions inventories were used in modeling and are discussed further in Section 8. A later Case PRP18b emissions inventory was prepared by WRAP and included in Section 6, Sources of Visibility Impairment in North Dakota Class I Areas.

10.5 Identification of Anthropogenic Sources of Visibility Impairment

40 CFR 51.308(d)(3)(iv) requires "The State must identify all anthropogenic sources of visibility impairment considered by the State in developing its long-term strategy. The State should consider major and minor stationary sources, mobile sources and area sources."

The anthropogenic sources of visibility impairment are identified in Section, 6 Sources of Visibility Impairment in North Dakota Class I Areas.

10.6 Seven Factors That Must be Considered in Developing the LTS

40 CFR 51.308(d)(3)(v) requires "The State must consider, at a minimum, the following factors in developing its long-term strategy:

(A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;

(B) Measures to mitigate the impacts of construction activities;

(C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;

(D) Source Retirement and Replacement schedules;

(E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;

(F) Enforceability of emissions limitations and control measures; and

(G) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy."

10.6.1 Emission Reductions Due to Ongoing Air Pollution Control Programs

10.6.1.1 In-Place Programs

40 CFR 51.308(d)(3)(v)(A) requires an assessment of emission reductions due to ongoing air pollution control programs. Programs that are in place which will assist in reducing emissions and help achieve reasonable progress toward the national visibility goal include:

- Minor Source Permit to Construct Program (NDAC 33-15-14-02)
- Prevention of Significant Deterioration Program (NDAC 33-15-15)
- New Source Performance Standards (NDAC 33-15-12)
- Emission Standards for Hazardous Air Pollutants (NDAC 33-15-13)
- Emission Standards for Hazardous Air Pollutants for Source Categories (NDAC 33-15-22)
- Oil and Gas Production Facilities Rules (NDAC 33-15-21)
- Open Burning Requirements (NDAC 33-15-04)
- Fugitive Dust Control Requirements (NDAC 33-15-17)
- Control of Sulfur Dioxide from Point Sources (NDAC 33-15-06)
- Control of Particulate Matter (NDAC 33-15-05)
- Control Requirements for Organic Compounds Sources (NDAC 33-15-07)
- Heavy Duty Diesel Engine Standard (2007)
- Tier 2 Tailpipe Standards
- Large Spark Ignitor and Recreational Vehicle Rule
- Nonroad Diesel Rule
- Industrial Boiler MACT
- Combustion Turbine and Reciprocating Internal Combustion Engines NSPS and MACT Standards

The Federal programs are described in more detail in Section 2.5.

Some MACT standards have been vacated; however, it is expected that revised versions of these standards will be promulgated by EPA during the planning period. The Department will continue to operate a PSD program and take delegation of NSPS standards and major source MACT standards for source categories located in North Dakota. As older sources are replaced, the new applicable rules should reduce emissions.

North Dakota has implemented a reasonably attributable visibility impact (RAVI) protection program since 1987. The rules implementing this program are found in NDAC 33-15-19, Visibility Protection. The control strategy and monitoring strategy are found in Chapters 3 and 6 of the State Implementation Plan. The existing RAVI program, with the existing permitting and emissions rules listed above is compatible with those needed for regional haze and no revisions are needed or planned at this time. The NDDoH will address the periodic review and revision requirements of the long-term RAVI strategy as required by 40 CFR 51.306(c) and coordinate them with the regional haze LTS periodic progress reports required by 40 CFR 51.308(g).

10.6.1.2 Coyote Station

Once reductions are achieved from the BART sources, the Coyote Station will be the largest point source of NO_x emissions in North Dakota. The analysis in Section 9.5.1 indicates that additional controls on the Coyote Station are not reasonable at this time; however, the State, through recent discussions with Otter Tail Power Company, has reached an agreement whereby Otter Tail has committed to reduce NO_x emissions at the station. Otter Tail Power Company has indicated they will install equipment by July 1, 2018 in order to reduce NO_x emissions to 0.50 lb/10^6 Btu. This represents a 35% decrease from the 2008 emission rate of 0.77 lb/10^6 Btu and 26% from the baseline emission rate evaluated in Section 9.5.1. The reductions are expected to be achieved by installing separated over fire air. This will reduce annual NO_x emissions by 4,213 tons from the 2000-2004 baseline, a 32% decrease. The mechanism/requirement for reducing NO_x emissions is included in a Permit to Construct found in Appendix A. Although there will be NO_x reductions at this facility, it will be reevaluated during future planning periods to determine if additional emissions reductions are required.

10.6.1.3 Heskett Station Unit 2 – Reserved

10.6.2 Measures to Mitigate the Impacts of Construction Activities

40 CFR 51.308(d)(3)(v)(B) requires the consideration of measures to mitigate the impacts of construction activities. North Dakota regulates fugitive emissions by rule (NDAC 33-15-17). This rule states:

> "No person shall cause or permit fugitive emissions from any source whatsoever, including a building, its appurtenances, or a road, to be used, constructed, altered, repaired, or demolished; or activities such as loading, unloading, storing, handling, or transporting of material without taking reasonable precautions to prevent such emissions from causing air pollution as defined in section 33-15-01-04."

NDAC 33-15-17-02 also states in part:

> "No person shall emit or cause to be emitted into the ambient air from any source of fugitive emissions as specified in section 33-15-17-01 any particulate matter which:
>
> 2. Exceed the ambient air quality standards of chapter 33-15-02 at or beyond the property line of the source.
>
> 3. Exceed the prevention of significant deterioration of air quality increments of chapter 33-15-15 at or beyond the property line of the source for sources subject to chapter 33-15-15.
>
> 4. Exceed the restrictions on the emission of visible air contaminants of chapter 33-15-03, at or beyond the property line of the source.
>
> 5. Would have an adverse impact on visibility, as defined in chapter 33-15-19, on any class 1 federal area."

The Department requires permits for asphalt concrete plants and rock, sand and gravel plants which are generally associated with major construction projects. The Department requires notification of the relocation of asphalt plants in order to track the emissions from these facilities.

The Federal Class I areas in North Dakota are located in the western part of the State, generally away from the major population centers. These population centers are 40 - 500 km away from the Class I areas. Any construction in these areas should have little effect on visibility in the Class I areas because of the transport distance and prevailing winds will generally move the fugitive emissions in the opposite direction. Any impacts on visibility in a Class I area due to construction activities would most likely be associated with energy development including oil and gas well pad construction, compressor station construction and gas processing plant construction. Owners of sources subject to permitting requirements, including the above energy facilities, are subjected to fugitive dust control requirements included in the permit issued for the construction of the facility. In addition, all sources are subject to the requirements of NDAC 33-15-17. NDAC 33-15-17-03 lists the measures which are considered reasonable precautions for abating and preventing fugitive dust. These include:

1. Unpaved roads and unpaved parking areas. Abatement and preventive measures include but shall not be limited to frequent watering, addition of dust palliatives, detouring, paving, closure, speed control, or other means such as surface treatment with penetration chemicals (ligninsulfonates, oil, water, cutbacks, etc.) or methods of equal or greater effectiveness in reducing the air contaminant produced.

2. Demolition, wrecking and explosive detonation activities; earth and construction material moving, mining, and excavation activities.

a. Abatement and preventive fugitive particulate control measures include, but are not limited to:

    (1) Wetting down, including prewatering.

    (2) Landscaping and replanting with native vegetation.

    (3) Covering, shielding or enclosing the area.

    (4) Paving, temporary or permanent.

    (5) Treating, the use of dust palliatives and chemical stabilization.

    (6) Detouring.

    (7) Restricting the speed of vehicles on sites.

    (8) Preventing the deposit of dirt and mud on improved streets and roads.

    (9) Minimizing topsoil disturbance and reclaiming as soon as possible.

b. Sequential blasting be employed whenever or wherever feasible to reduce the amounts of particulate matter.

c. Such dust control strategies as revegetation, delay of topsoil disturbance until necessary, or surface compaction and sealing, be applied.

d. Haulage equipment be washed or wetted down, treated, or covered when necessary to minimize the amount of dust becoming airborne in transit and in loading.

e. Stockpile of materials be treated to prevent blowing or the material be contained in silos or other suitable enclosures.

f. Waste disposal sites be so operated and constructed as to prevent particulate matter from becoming airborne.

g. All conveyors, transfer points, crushers, screens, and dryers be so constructed, protected, or treated as to prevent particulate matter from becoming airborne.

h. These measures also be used during period when actual construction work is not being conducted, such as on weekends and holidays.

The construction of oil well pads are normally a one or two-day undertaking. The emissions are generally ground level emissions and do not travel very far. In general, compressor stations and gas plant construction are subject to the Permit to Construct program. These permits and rules will assure that construction activities will not adversely affect visibility in any Federal Class I area.

Emissions from construction activities including construction of oil well pads, compressor stations and gas plants will be reevaluated in future Regional Haze SIP planning periods since this has the potential to be a growing source category.

10.6.3 Emissions Limitations and Schedules for Compliance

40 CFR 51.308(d)(3)(v)(C) requires the State to consider emissions limitations and schedules for compliance to achieve the reasonable progress goal in developing its LTS.

Emissions limitations and schedules for the seven BART sources are found in Section 7, Best Available Retrofit Technology (BART). They are included in the Air Pollution Control Permit to Construct for each source. The permits found in Appendix D are incorporated as part of this SIP.

10.6.4 Source Retirement and Replacement Schedules

40 CFR 51.308(d)(3)(v)(D) requires the State consider any source retirement and replacement schedules in developing its LTS. The Department is not aware of any anticipated major source retirements or replacements. Replacement of existing facilities will be managed in conformance with the existing State Implementation Plan including the Prevention of Significant Deterioration program.

The 2018 modeling conducted by WRAP included three new power plants to be located in the State. It is now unlikely that two of these plants will be built. Thus the modeling results for 2018 are probably conservative. Construction of new power plants or replacement of existing plants prior to 2018 is unlikely.

10.6.5 Smoke Management Techniques for Agriculture and Forest Management

40 CFR 51.308(d)(3)(v)(E) requires the State to consider smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes in developing its LTS. North Dakota has an area of approximately 68,994 square miles (44.16 million acres). Of this total, 26.5 million acres is crop land, 10.98 million acres is pasture/rangeland and 236,000 acres is woodland/forest with the five State forests comprising 13,300 acres. The North Dakota State Implementation Plan contains rules which govern prescribed burning on crop land, pasture/rangeland or woodland. NDAC 33-15-04-02.2 lists the conditions that apply to any prescribed burning including:

c. Care must be used to minimize the amount of dirt on the material being burned and the material must be dry enough to burn cleanly.

d. Oils, rubber, and other materials that produce unreasonable amounts of air contaminants may not be burned.

e. The burning may be conducted only when meteorological conditions favor smoke dispersion and air mixing.

h. Except in an emergency, burning may not be conducted in such proximity of any class 1 area, as defined in chapter 33-15-15, that the ambient air of such area is adversely impacted.

i. Except in an emergency, the visibility of any class 1 area cannot be adversely impacted as defined in chapter 33-15-19.

j. Burning activities must be attended and supervised at all times burning is in progress.

Fires purposely set to woodland/forest or rangeland for the management of the land or game must be in accordance with practices recommended by State and Federal agencies and must be approved in advance by the Department (NDAC 33-15-04-02.1.e). Although agricultural crop burning does not require advanced approval by the Department, most of this burning takes place in the eastern two thirds of State away from the Class I areas in North Dakota. In general, prevailing winds carry the smoke from crop land burning away from the North Dakota Class I areas. For 2000-2004 (Case Plan 02d), the WRAP has estimated the annual emissions from fire in North Dakota as shown in Table 10.1.

Table 10.1
Annual Average Emissions from Fire (2000-2004)

Source	**PM_{fine} (tpy)**	**PM_{coarse} (tpy)**	**NO_x (tpy)**	**SO_2 (tpy)**	**Organic Carbon (tpy)**	**Elemental Carbon (tpy)**
Natural	225	441	773	250	2,214	424
Anthropogenic	596	62	1001	290	1,443	86
Total	821	503	1774	540	3,657	510

Based on the source apportionment analyses conducted by the WRAP, anthropogenic fire emissions in North Dakota contribute less than 1% of the total emissions of any of the pollutant species listed above during the 20% worst visibility days for either Lostwood Wilderness Area or Theodore Roosevelt National Park as shown in Table 10.2. The contribution of anthropogenic fire is expected to decrease by 2018. As indicated earlier, open burning is subject to regulation under NDAC 33-15-04 which specifically prohibits burning that will adversely affect visibility in any Class I area. The Department has determined that the current smoke management rules are sufficient to achieve reasonable progress toward the national visibility goal. However, the smoke management rules will be reevaluated during future planning periods.

Table 10.2
North Dakota Anthropogenic Fire Contribution to the 20% Worst Days

Class I Area	Pollutant	Contribution 2000-2004 (%)	Contribution 2018 (%)
TRNP	SO_x	0.013	0.004
	NO_x	0.019	0.006
	POA	0.364	0.112
	EC	0.067	0.024
	PMF	0.04	0.013
	PMC	0.001	0
LWA	SO_x	0.008	0.002
	NO_x	0.024	0.007
	POA	0.823	0.252
	EC	0.13	0.046
	PMF	0.049	0.015
	PMC	0.001	0

10.6.6 Enforceability of Emission Limitations and Control Measures

40 CFR 51.308(d)(3)(v)(F) requires the State must consider the enforceability of emission limitations and control measures in developing its LTS. The BART emission limits and control measures will be included in a BART Air Pollution Control Permit to Construct that is issued to each BART source and are incorporated into this SIP. The Permit to Construct program is established in the State Air Pollution Control Rules (NDAC 33-15-14-02). The program is also approved into the State Implementation Plan. The BART permits are included in Appendix D of this SIP. Other ongoing programs are already included in the State rules. Future NSPS and MACT rules for major sources will be adopted into the State Rules and delegation will be requested from EPA.

10.6.7 The Anticipated Net Effect on Visibility Due to Projected Changes in Point, Area and Mobile Source Emissions

40 CFR 51.308(d)(3)(v)(G) requires the State consider the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy in developing its LTS. The anticipated net effect on visibility due to projected changes in emissions from 2004 to 2018 is discussed in Section 8, Visibility Modeling.

10.7 Prevention of Significant Deterioration

In North Dakota, new and modified existing major stationary sources triggering significance thresholds are analyzed under the Prevention of Significant Deterioration (PSD) permitting program. The PSD program rules are found in NDAC Chapter 33-15-15 and have been approved as a part of the North Dakota SIP by EPA. The PSD permitting program is an integral part of North Dakota's long-term strategy for meeting its regional haze goals.

Among other things, the PSD permit program is designed to protect air quality and visibility in Class I areas by requiring best available control technology (BACT) and involving the public in permit decisions. The PSD permitting process requires a technical air quality analysis and additional analyses to assess the potential impacts of emissions on soils, vegetation and visibility. The cumulative impacts of emissions subject to the PSD program will be evaluated to ensure there is no degradation from baseline conditions on the 20 percent worst days and the 20 percent best days.

Therefore, North Dakota's current PSD program ensures that visibility at the Class I areas will not be impacted by growth in stationary sources.

11. Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

11.1 Future Consultation Commitments

11.1.1 FLM Consultation and Coordination

40 CFR 51.308(i) contains the requirements for State and Federal Land Manger consultation and coordination. §51.308(i) reads "What are the requirements for State and Federal Land Manager coordination?

(1) By November 29, 1999, the State must identify in writing to the Federal Land Managers the title of the official to which the Federal Land Manager of any mandatory Class I Federal area can submit any recommendations on the implementation of this subpart including, but not limited to:

  (i) Identification of impairment of visibility in any mandatory Class I Federal area(s); and

  (ii) Identification of elements for inclusion in the visibility monitoring strategy required by § 51.305 and this section.

(2) The State must provide the Federal Land Manager with an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on an implementation plan (or plan revision) for regional haze required by this subpart. This consultation must include the opportunity for the affected Federal Land Managers to discuss their:

  (i) Assessment of impairment of visibility in any mandatory Class I Federal area; and

  (ii) Recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment.

(3) In developing any implementation plan (or plan revision), the State must include a description of how it addressed any comments provided by the Federal Land Managers.

(4) The plan (or plan revision) must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required by this subpart, including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas."

North Dakota commits to coordinate and consult with the Federal Land Managers as required in §51.308(i)(1) through (4).

11.1.2 Tribal Consultation

North Dakota will continue to remain in contact with those Tribes which may reasonably be anticipated to cause or contribute to visibility impairment in North Dakota mandatory Class I Federal area(s). For those Tribes that adopted a RH TIP, North Dakota will consult with them directly. For those Tribes without a RH TIP, North Dakota will consult with both the Tribe and EPA. Documentation of the consultations will be maintained.

11.1.3 Interstate Consultation and Coordination

40 CFR 51.308(d)(1)(iv) and 40 CFR 51.308(d)(3)(i) contain the requirements for interstate consultation and coordination. §(d)(1)(iv) reads:

> "In developing each reasonable progress goal, the State must consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal area. In any situation in which the State cannot agree with another such State or group of States that a goal provides for reasonable progress, the State must describe in its submittal the actions taken to resolve the disagreement. In reviewing the State's implementation plan submittal, the Administrator will take this information into account in determining whether the State's goal for visibility improvement provides for reasonable progress towards natural visibility conditions." §(d)(3)(i) reads:
>
> "Where the State has emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another State or States, the State must consult with the other State(s) in order to develop coordinated emission management strategies. The State must consult with any other State having emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area within the State."

In accordance with 40 CFR 51.308(d)(1)(iv) and 51.308(d)(3)(i), North Dakota commits to continue consultation with Minnesota, Montana, and South Dakota, and any other state which may reasonably be anticipated to cause or contribute to visibility impairment in federal Class I areas located within North Dakota. North Dakota will also continue consultation with Michigan, Minnesota, Montana, and South Dakota and any other state for which North Dakota's emissions may reasonably be anticipated to cause or contribute to visibility impairment in those state's federal Class I areas.

With reference to the established or updated goals for reasonable progress, should disagreement arise between another state or group of states, North Dakota will describe the actions taken to resolve the disagreement in future RH SIP revisions for EPA's consideration. With reference to assessing or updating long-term strategies, North Dakota commits to coordinate its emission management strategies with affected states and will continue to include in its future RH SIP revisions all measures necessary to obtain its share of emissions reductions for meeting progress goals.

11.2 Commitment to Progress Reports

Requirements for the State to submit periodic progress reports are found in 40 CFR 51.308(g) which reads “Requirements for periodic reports describing progress towards the reasonable progress goals. Each State identified in §51.300(b)(3) must submit a report to the Administrator every five years evaluating progress towards the reasonable progress goal for each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State. The first progress report is due 5 years from the submittal of the initial implementation plan addressing paragraphs (d) and (e) of this section. The progress reports must be in the form of implementation plan revisions that comply with the procedural requirements of §51.102 and §51.103. Periodic progress reports must contain at a minimum the following elements:

(1) A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the State.

(2) A summary of the emissions reductions achieved throughout the State through implementation of the measures described in paragraph (g)(1) of this section.

(3) For each mandatory Class I Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired and least impaired days expressed in terms of 5-year averages of these annual values.

    (i) The current visibility conditions for the most impaired and least impaired days;

    (ii) The difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions;

    (iii) The change in visibility impairment for the most impaired and least impaired days over the past 5 years;

(4) An analysis tracking the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. The analysis must be based on the most recent updated emissions inventory, with estimates projected forward as necessary and appropriate, to account for emissions changes during the applicable 5-year period.

(5) An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred over the past 5 years that have limited or impeded progress in reducing pollutant emissions and improving visibility.

(6) An assessment of whether current implementation plan elements and strategies are sufficient to enable the State, or other States with mandatory Federal Class I areas affected by emissions from the State, to meet all established reasonable progress goals.

(7) A review of the State's visibility monitoring strategy and any modifications to the strategy as necessary."

In accordance with the requirements listed in 40 CFR 51.308(g) of the federal regional haze rule, North Dakota commits to submitting periodic progress reports to EPA every five years following the initial submittal of the SIP. The periodic progress reports will address at a minimum all the elements of §51.308(g). The periodic progress reports will be in the form of implementation plan revisions that comply with the procedural requirements of 40 CFR 51.102 and 51.103.

11.3 Determination of Current Plan Adequacy

Based on the findings of the 5-year periodic progress report, 40 CFR 51.308(h) requires a State to make a determination of adequacy of the existing implementation plan. §51.308(h) reads "Determination of the adequacy of existing implementation plan. At the same time the State is required to submit any 5-year progress report to EPA in accordance with paragraph (g) of this section, the State must also take one of the following actions based upon the information presented in the progress report:

(1) If the State determines that the existing implementation plan requires no further substantive revision at this time in order to achieve established visibility goals for visibility improvement and emissions reductions, the State must provide to the Administrator a negative declaration that further revision of the existing implementation plan is not needed at this time.

(2) If the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another State(s) which participated in a regional planning process, the State must provide notification to the Administrator and the other State(s) which participated in the regional planning process with the States. The State must also collaborate with the other State(s) through the regional planning process for the purpose of developing additional strategies to address the plan's deficiencies.

(3) Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another country, the State shall provide notification, along with available information, to the Administrator.

(4) Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources within the State, the State shall revise its implementation plan to address the plan's deficiencies within one year."

North Dakota commits, in accordance with 40 CFR 51.308(h), to make a determination of the adequacy of the existing implementation plan at the same time a five-year periodic progress report is due.

Should North Dakota determine that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another State or States, North Dakota will provide notification to the Administrator and the other State(s) and collaborate with the other States(s) through the regional planning process for the purpose of developing additional strategies to address the plan's deficiencies as required by §51.308(h)(2). In the event that no regional planning organizations or process exists, North Dakota will work directly with the other State(s).

Should North Dakota determine that the current implementation plan is or may be inadequate due to emissions from within the State itself, North Dakota will develop additional strategies to address the plan deficiencies and revise the implementation plan within one year, as required by §51.308(h)(4).

Should North Dakota determine that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another country, the State will provide notification, along with available information, to the Administrator as required by §51.308(h)(3).

Should North Dakota determine that the existing implementation plan requires no further substantive revision in order to achieve established goals for visibility improvement and emissions reductions, North Dakota will provide the Administrator a negative declaration that further revision of the existing implementation plan is not needed as required by §51.308(h)(1).

In addition, North Dakota commits to revise the implementation plan, including the reasonable progress goals, once RH SIPs from neighboring states become available and are approved by EPA, or if the unexpected or unforeseen occurs. This would include, but not be limited to, projected future emissions reductions that do not occur, are distributed differently over an alternate geographic area, or are found to be incorrect or flawed. These revisions will be made within one year as required by §51.308(h)(4). North Dakota also commits to accelerate this revision schedule if the present RH SIP is found to be significantly flawed and the 2018 reasonable progress goals cannot be reasonably attained.

11.4 Commitment to Future SIP Revisions

In addition to a SIP revision made for periodic progress reports as addressed in Section 11.2 and plan inadequacy as addressed in Section 11.3, 40 CFR 51.308(f) requires a State to revise and submit its regional haze implementation plan to EPA by July 31, 2018, and every ten years thereafter. 40 CFR 51.308(f) reads "Requirements for comprehensive periodic revisions of implementation plans for regional haze. Each State identified in §51.300(b)(3) must revise and submit its regional haze implementation plan revision to EPA by July 31, 2018 and every ten years thereafter. In each plan revision, the State must evaluate and reassess all of the elements required in paragraph (d) of this section, taking into account improvements in monitoring data collection and analysis techniques, control technologies, and other relevant factors. In evaluating and reassessing these elements, the State must address the following:

(1) Current visibility conditions for the most impaired and least impaired days, and actual progress made towards natural conditions during the previous implementation period. The period for calculating current visibility conditions is the most recent five year period preceding the required date of the implementation plan submittal for which data are available. Current visibility conditions must be calculated based on the annual average level of visibility impairment for the most and least impaired days for each of these five years. Current visibility conditions are the average of these annual values.

(2) The effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s); and

(3) Affirmation of, or revision to, the reasonable progress goal in accordance with the procedures set forth in paragraph (d)(1) of this section. If the State established a reasonable progress goal for the prior period which provided a slower rate of progress than that needed to attain natural conditions by the year 2064, the State must evaluate and determine the reasonableness, based on the factors in paragraph (d)(1)(i)(A) of this section, of additional measures that could be adopted to achieve the degree of visibility improvement projected by the analysis contained in the first implementation plan described in paragraph (d)(1)(i)(B) of this section."

In accordance with the requirements of section 51.308 (d) and (f) of the regional haze rule, North Dakota commits to revising and submitting its regional haze SIP by July 31, 2018 and every ten years thereafter addressing current visibility conditions, effectiveness of the long-term strategy and affirming or revising the reasonable progress goal for each mandatory Class I Federal area in North Dakota.

11.5 Monitoring Strategy

North Dakota commits to review and reevaluate the adequacy of and revise as necessary the existing RAVI monitoring strategy required by Section 51.305 and the existing regional haze monitoring strategy required by Section 51.308(d)(4) as a minimum, concurrently with the 5-year periodic progress reports and the 10-year plan revisions which start July 31, 2018 and every ten years thereafter. North Dakota will coordinate all reviews, reevaluations and revisions to both monitoring strategies with each other and will consult and coordinate any revisions with EPA and FLMs. The monitoring strategies are discussed further in Section 4 of this plan.

11.6 Rules for Non-BART Point and Area Sources

The Department adopted rules in 1987 to implement Phase 1 of the federal visibility program which is Section 40 CFR 51.300 – 307 (NDAC Chapter 33-15-19 Visibility Protection, effective date October 1, 1987) and in 2006 to implement the BART portion of Phase 2 which is Paragraph 40 CFR 51.308(e) (NDAC Chapter 33-15-23 Regional Haze Requirements, effective date January 1, 2007). For a more detailed description of Phase 1 and Phase 2 of the federal visibility program see Section 2.

As a result of addressing the core requirements of the federal visibility program which are found in 40 CFR 51.308(d), the Department has determined it will be necessary to clarify its legal authority to address emissions which adversely impact visibility in the Class I areas from non-BART and area sources which may in the future be found to be reasonably controllable and reduced (see Section 9).

The Department commits to develop and adopt any necessary rules to clarify its legal authority to control and reduce emissions from non-BART and area sources that adversely impact Class I areas as expeditiously as possible but no later than December 31, 2012.

12. Public Participation and Review Process

The Public Hearing Record is Appendix F. Included are the Hearing Notice (F.1), Press Release (F.2), Affidavit of Publication (F.3), Invoice of Publication (F.4), Registration List of Attendees (F.5), Hearing Transcript (F.6), Certification of Hearing (F.7), and Response to Public Comments (F.8).

12.1 Summary of Comments Received during Public Comment Period/Hearing

The written comments and oral comments received during the 30 day public comment period and public hearing are included in Appendix F.6 as a part of the Hearing Transcript and Response to Comments.

Written comments were received from the U.S. Environmental Protection Agency Region 8 in Denver CO; The U.S. Department of the Interior National Park Service in Denver CO; the National Parks Conservation Association in Chicago IL on behalf of the National Parks Conservation Association, the Dakota Resource Council, the Friends of the Boundary Waters Wilderness, the Plains Justice and the Dakotah Chapter of the Sierra Club; Basin Electric Power Cooperative in Bismarck ND; Great River Energy in Maple Grove MN; and Bob Paine of AECOM Environment on behalf of Basin Electric Power Cooperative, Great River Energy, and Minnkota Power Cooperative, Inc.

In addition, the Department received 31 nearly identical emails from various individuals. Mr. Jim Kambeitz presented oral testimony at the public hearing and submitted written comments that reiterated his oral comments.

12.2 Response to Public Comments

The Department’s responses to the comments received during the 30 day public comment period and public hearing are included in Appendix F.8.

12.3 Revisions to the State Implementation Plan

The Department made the following revisions to Regional Haze State Implementation Plan based on its review of the comments received during the 30 public comment period and public hearing:

- Page ii – An Approval Page was added.
- Section 4.2 – A discussion on the representativeness of the IMPROVE monitor at the South Unit of the Theodore Roosevelt National Park for the North Unit and Elkhorn Ranch Unit was added.

- Section 5.2 – A reference to the discussion in Section 4.2 on the representativeness of the IMPROVE monitor in the South Unit of TRNP was added.
- Section 5.2 – A reference was added for the WRAP methodology for determining baseline conditions under Table 5.1.
- Section 7.3.4 - Exclusion of Montana Dakota Utilities Heskett Unit No. 2 was updated.
- Section 8.6.1 – Performance evaluation expanded to include results for the 98th percentile metric.
- Section 8.6.2.5 – Per EPA suggestion, conclusions modified to acknowledge that BART emissions reductions from ND sources can significantly improve visibility under some meteorological conditions.
- Table 9.4 – MDU Heskett Unit No. 2 was added.
- Table 9.9 – Table was modified to add additional information.
- Section 9.5.1 – Reasonable Progress Goals – Required Controls for Point Sources – A sentence was added regarding the percent improvement in visibility for the control options evaluated.
- Section 9.5.4 – The section was relocated to Section 10.6.1.2 and updated.
- Section 9.5.5 – The section was updated to discuss PM emissions and Q/D for oil wells.
- Section 9.7 – The section was updated to indicate that the Reasonable Progress Goals are based on the Department's hybrid modeling.
- Section 10.6.1.2 – The section was added to address emissions reductions from the Coyote Station.
- Section 10.6.5 – The section was updated to indicate the North Dakota smoke management rules will be reevaluated during future planning periods.
- Section 11.6 – The section was updated.
- Section 12 – Each item is now addressed as the 30 day public comment period and hearing has been completed.
- Appendix A.5 – A new appendix was added to address the WRAP methodology for determining baseline visibility conditions.
- Appendix F.9 – The section was deleted as it was not required.
- Appendix I.2 – A new appendix was added to provide supplementary information for the four factor analysis by the WRAP states.
- Several spelling, grammatical and typographical corrections were made throughout the document.

12.4 Revisions to the BART Air Pollution Control Permits to Construct

The Department made the following revisions to BART Air Pollution Control Permits to Construct based on its review of the comments received during the 30 day public comment period and public hearing:

- The definition of 30 day rolling average was modified to match the NSPS Subpart Da language in all the BART permits.
- Condition II.A.2 was changed from "BART" to "Regional Haze" in the Stanton, Leland Olds and Minnkota permits.

- The location of the CEM was added to Condition II.A.3 in the Stanton permit. The condition was also changed to specify that emissions from Unit 1 and Unit 10 must be measured separately.
- Condition II.A.1.c was revised to include a procedure for demonstrating compliance if a startup is less than 24 hours in the Minnkota permit.
- Condition II.A.2 was changed from “Data” to “Date” in the Coyote permit.
- Condition II.A.4.a was changed from “94%” to “95%” in the Coal Creek permit.
- Condition II.A.1.a of the Coyote permit was amended to specify that EUI 1 is the main boiler.
- In Condition II.B.4 of the Coyote permit, Unit 1 was changed to EUI 1.
- In Condition II.A.5.e of the Coyote permit, “Condition II.5” was changed to “Condition II.A.5.”
- In Condition II.A.5.b of the Minnkota, Coal Creek, Leland Olds and Stanton permits, “Condition II.5.a” was changed to “Condition II.A.5.a.”

APPROVAL PAGE

North Dakota State Implementation Plan for Regional Haze

North Dakota Department of Health, Environmental Health Section, Division of Air Quality.

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Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota

(Final)

November, 2005

North Dakota Department of Health
Division of Air Quality
1200 Missouri Avenue
Bismarck, ND 58506

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Appendix A NDDH PSD Class I Area Receptors

1 Overview

On June 15, 2005, EPA issued final amendments to its July 1999 regional haze rule[1]. These amendments apply to the provisions of the regional haze rule that require emission controls known as Best Available Retrofit Technology, or BART, for industrial facilities emitting air pollutants that reduce visibility in PSD Class I areas. These pollutants include fine particulate matter ($PM_{2.5}$), and compounds which contribute to $PM_{2.5}$ formation, such as nitrogen oxides, sulfur dioxide, certain volatile organic compounds, and ammonia. The amendments include final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the types of controls the facilities must use.

The June 15 guidelines address how to identify BART-eligible sources, how to identify sources "subject to BART", and the BART determination including analysis of BART options. As part of this process, visibility computer modeling will assist in the identification of sources "subject to BART", and in the consideration of BART options to determine the degree of visibility improvement. The North Dakota Department of Health (NDDH) has established a protocol for BART-related modeling applicable to BART-eligible sources in North Dakota, which is the focus of this document. This protocol is intended to apply to visibility modeling for both identification of sources "subject to BART" (BART screening), and for determining the degree of visibility improvement related to the selection of BART control.

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[1] Federal Register, 2005. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, July 6, 2005, Vol. 70, No. 128, p. 39103-39172.

To ultimately determine compliance with Regional Haze visibility improvement goals, four phases of visibility modeling are anticipated. In chronological order, these are:

1) single-source modeling to determine which BART-eligible sources are subject to BART (or BART-applicable),
2) single-source modeling to determine the degree of visibility improvement attributable to proposed BART control for each BART-applicable source,
3) cumulative modeling to determine the combined effect of proposed BART controls for BART-applicable sources in North Dakota, and
4) regional-scale modeling to determine if the combined effect of proposed BART controls, and other emissions reductions, for all western states ultimately satisfies visibility improvement goals.

The protocol outlined in this document applies only to the first two phases involving single-source modeling, that is, screening to determine which BART-eligible sources are subject to BART, and single-source modeling to determine the degree of improvement related to the proposed BART control. With the exception of emission rates and stack parameters, the methodologies for these first two phases of modeling, including all model inputs, are identical. The NDDH recognizes that the "degree of improvement" modeling will be only one of several criteria used to establish optimum BART controls.

The NDDH will conduct visibility modeling to determine which North Dakota BART-eligible sources are subject to BART. It is expected that BART-applicable sources will want to conduct their own single-source modeling to determine the degree of visibility improvement, as they consider a variety of BART control options. Upon request, the NDDH will also perform the single-source degree of improvement modeling. Ultimately, the NDDH will review and verify all single-source degree of visibility improvement modeling analyses. Note that all BART-related single-source modeling for sources in North Dakota must follow the protocol outlined here. Because of this requirement, the NDDH will not expect companies which operate BART-eligible sources to provide individual protocols for their BART-related modeling.

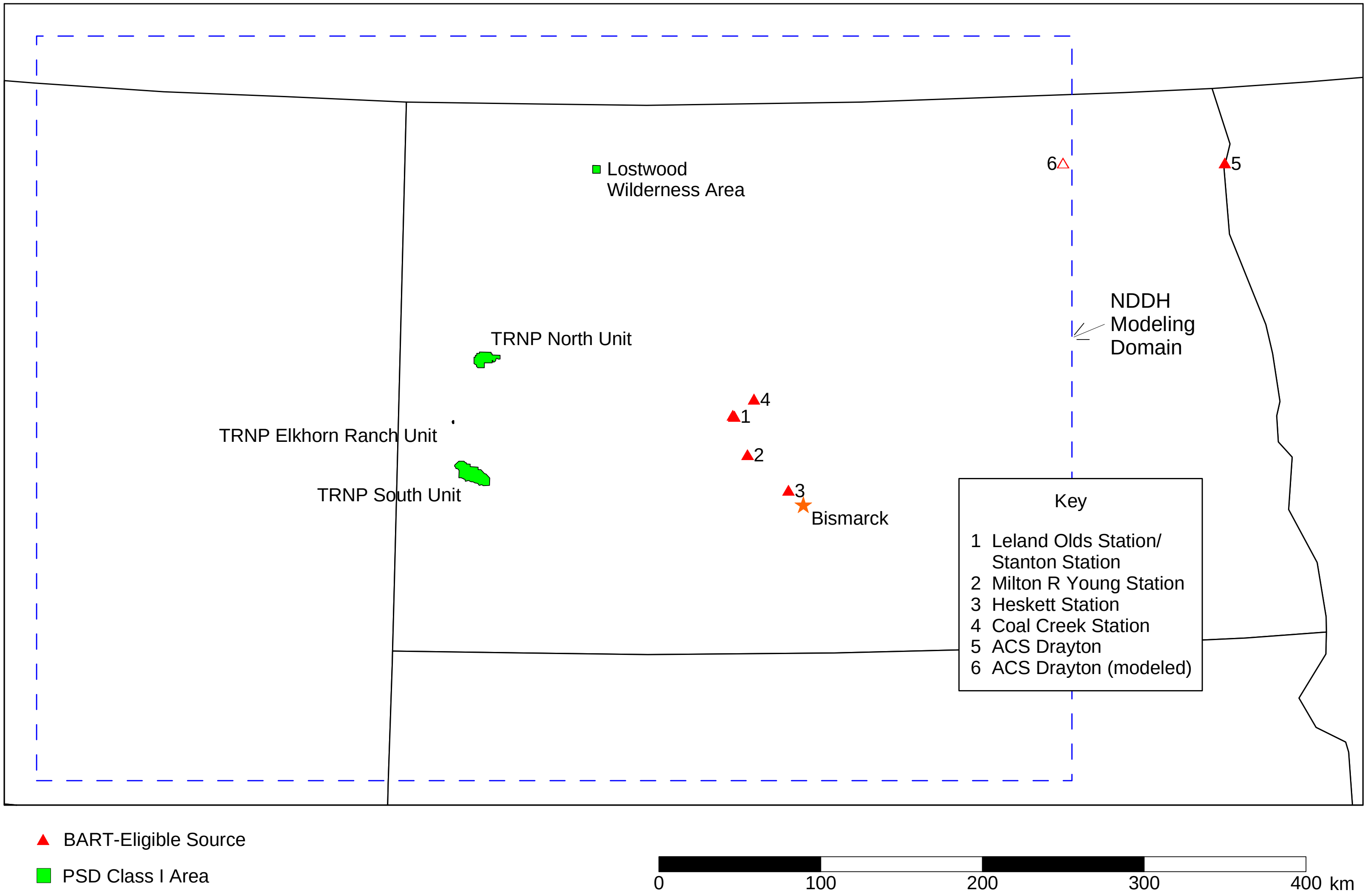
When all BART proposals have been submitted, the NDDH will conduct a cumulative modeling analysis to determine the combined effect of proposed North Dakota BART controls on visibility improvement in North Dakota Class I areas (Phase 3 modeling). A separate protocol for that analysis will be completed by the NDDH prior to modeling. The final regional-scale modeling analysis to ultimately determine compliance with visibility improvement goals (Phase 4 modeling) will be conducted by the Western Regional Air Partnership (WRAP) regional planning organization. WRAP is developing the protocol and establishing input data for that analysis. At this point, the timing of the WRAP regional-scale modeling analysis is unclear. Also unclear is the manner in which the NDDH cumulative analysis might interface with the WRAP regional-scale analysis.

BART-eligible sources in North Dakota have been previously determined by NDDH, and are listed in Table 1-1. BART-related visibility modeling for North Dakota BART-eligible sources will focus on PSD Class I areas in North Dakota, which include the Theodore Roosevelt National Park (three units) and the Lostwood Wilderness Area. Note that the three units of Theodore Roosevelt National Park will be treated as separate Class I areas for purposes of interpreting visibility modeling results (Section 4). Locations of BART-eligible sources with respect to PSD Class I areas in North Dakota are illustrated in Figure 1-1.

Table 1-1
BART-Eligible Sources in North Dakota

Facility	**Operator**
Leland Olds Station 1 Leland Olds Station 2	Basin Electric Power Coop.
Milton R. Young Station 1 Milton R. Young Station 2	Minnkota Power Coop.
Heskett Station 2	Montana-Dakota Utilities
Stanton Station 1	Great River Energy
Coal Creek Station 1 Coal Creek Station 2	Great River Energy
Drayton Sugar Beet Processing	American Crystal Sugar
Mandan Refinery	Tesoro

Figure 1-1: BART-Eligible Sources and PSD Class I Areas



Regarding the requirement to use the BART guideline for all BART-related visibility analyses, the guideline states,

> *"Section 169A(b) requires us to issue guidelines for states to follow in establishing BART emission limitations for fossil-fuel fired power plants having a capacity in excess of 750 megawatts .... For sources other than 750 megawatt power plants, however, states retain the discretion to adopt approaches that differ from the guidelines."*

In this matter, the NDDH has elected to use its discretion to require use of the BART guideline for all BART-eligible sources in North Dakota.

The single-source modeling protocol outlined here provides sufficient detail to ensure consistency among BART-related analyses for sources in North Dakota. In developing this protocol, the NDDH has implemented guidance outlined in the June 15, 2005 rule. Where clarification was needed, this guidance has been augmented through communications with EPA and FLM's.[2] To the extent applicable, the NDDH BART modeling protocol is consistent with the North Dakota alternative protocol for PSD Class I increment analyses.[3]

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[2] EPA, 2005. Electronic message from Kathy Kaufman, Research Triangle Park, NC 27711.

[3] NDDH, 2005. A Proposed Alternative Air Quality Modeling Protocol to Examine the Status of Attainment of PSD Class I Increment. North Dakota Department of Health, Bismarck, ND 58506.

The remainder of this document describes the NDDH single-source visibility modeling protocol. Modeling methodology for BART-related visibility analyses is discussed in general in Section 2. Section 3 provides detailed information regarding modeling system components and input data requirements. Model execution and interpretation of output are discussed in Section 4. NDDH Class I area receptor coordinates/elevations are provided in Appendix A.

NDDH contacts for questions on BART-related modeling and general Regional Haze issues are provided in Table 1-2.

Table 1-2
NDDH Contact Information

Name	Task	Phone	E-mail
Dana Mount	General Regional Haze Coordination	(701)328-5150	dmount@state.nd.us
Tom Bachman	Emissions/Rules/BART	(701)328-5188	tbachman@state.nd.us
Steve Weber	Modeling	(701)328-5188	sweber@state.nd.us
Rob White	Modeling	(701)328-5188	rwhite@state.nd.us

2 Modeling Methodology

For the determination of BART applicability for BART-eligible sources (BART screening), modeling methodology involves execution of an appropriate visibility model, then comparison of model predictions with the BART applicability threshold. To determine the degree of improvement from selected BART options, the visibility model is executed again for post-BART control conditions, and results are compared with those for pre-BART conditions. In both cases, modeling is applied on a single facility basis. With the exception of emission rates and stack parameters, model settings and input data for both pre-BART and post-BART model runs are identical.

For BART screening, all BART-eligible units contained within a subject facility must be modeled together before comparing results with the BART applicability threshold. This would include, for example, both BART-eligible units of a power plant. To determine the degree of visibility improvement from selected BART options, however, it may be desirable to model units individually, as required improvement and BART options may vary by unit.

2.1 BART Applicability Threshold

In general, to determine which BART-eligible sources must apply BART, single facility modeling results for PSD Class I areas are compared with a visibility threshold, expressed in deciviews. The NDDH will follow recommendations in the June 15 BART guideline which states,

> *"A single source that is responsible for a 1.0 deciview change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 deciview change may still "contribute" to visibility impairment and thus be subject to BART .... As a general matter, any threshold that you use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 deciviews."*

As a practical matter, the NDDH sees no reason to distinguish among BART-eligible sources which "cause" visibility impairment versus those sources which "contribute" to visibility impairment in PSD Class I areas. Therefore, the NDDH will generally use a 0.5 deciview threshold to determine which BART-eligible sources must apply BART. The NDDH may reconsider the threshold value if subsequent multi-source modeling reveals difficulty in meeting visibility improvement goals.

2.2 **Pollutants to Consider**

For both BART applicability and degree of visibility improvement analyses, the BART guideline specifies that only primary emissions need to be considered. These primary emissions include SO_2, NO_x, and direct particulate matter (PM) emissions specified as either coarse (PM_{10} minus $PM_{2.5}$) or fine ($PM_{2.5}$). If this distinction in size of PM emissions cannot be made, it would be appropriate to consider all PM_{10} emissions as $PM_{2.5}$.

The BART guideline also discusses VOC or ammonia emissions as possibly impacting visibility. For BART eligible sources in North Dakota, the NDDH considers these emissions (and associated visibility impacts) to be negligible, and will not require inclusion of VOC or ammonia species in BART-related visibility analyses.

Emission rates and stack parameters for BART-related visibility modeling are discussed in detail in Section 3.

2.3 **Visibility Modeling System**

As shown in Figure 1-1, all BART-eligible sources will be located more than 50 kilometers from the nearest PSD Class I area in North Dakota. Source-receptor distances greater than 50 kilometers constitute long-range transport, and the EPA-approved model for long-range distances is CALPUFF[4]. As specified in the BART guideline,

> *"CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment and is currently the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long-range transport of primary pollutants. It can also be used for some other purposes, such as the visibility assessments addressed in today's rule, to account for the chemical transformation of* SO_2 *and* NO_x *."*

---

[4] CFR, 2003. EPA Guideline on Air Quality Models. 40 CFR (Code of Federal Regulations) Part 51, Appendix W.

The NDDH therefore recommends and will use CALPUFF for BART-related modeling.

The CALPUFF computer modeling system includes the CALMET meteorological model[5], the CALPUFF dispersion model[6], and the CALPOST post processing program. The CALPOST program accommodates the visibility calculations. For visibility analyses, the CALPUFF system also provides the optional POSTUTIL program. POSTUTIL implements the ammonia limiting method to address double-counting of available ammonia for NO_x to NO_3 conversion chemistry in CALPUFF. In the sequence of execution, POSTUTIL would follow CALPUFF and precede CALPOST. CALPUFF system execution is depicted schematically in Figure 2-1. Earth Tech (Earth Tech, Inc., Concord, MA), the primary model developer, also provides several utility programs to accommodate pre-processing of meteorological and geophysical data for CALMET.

Appropriate versions of CALPUFF software for BART-related modeling are shown in Table 2-1. Note that these newer versions of CALPUFF software are not the same as versions utilized in the recent periodic review of PSD Class I increment in North Dakota. These newer versions, however, contain coding error corrections and other enhancements, and appear to be consistent with the versions being recommended by most Regional Planning Organizations for BART-related modeling. The CALPUFF system software can be downloaded free of charge from the Earth Tech web site

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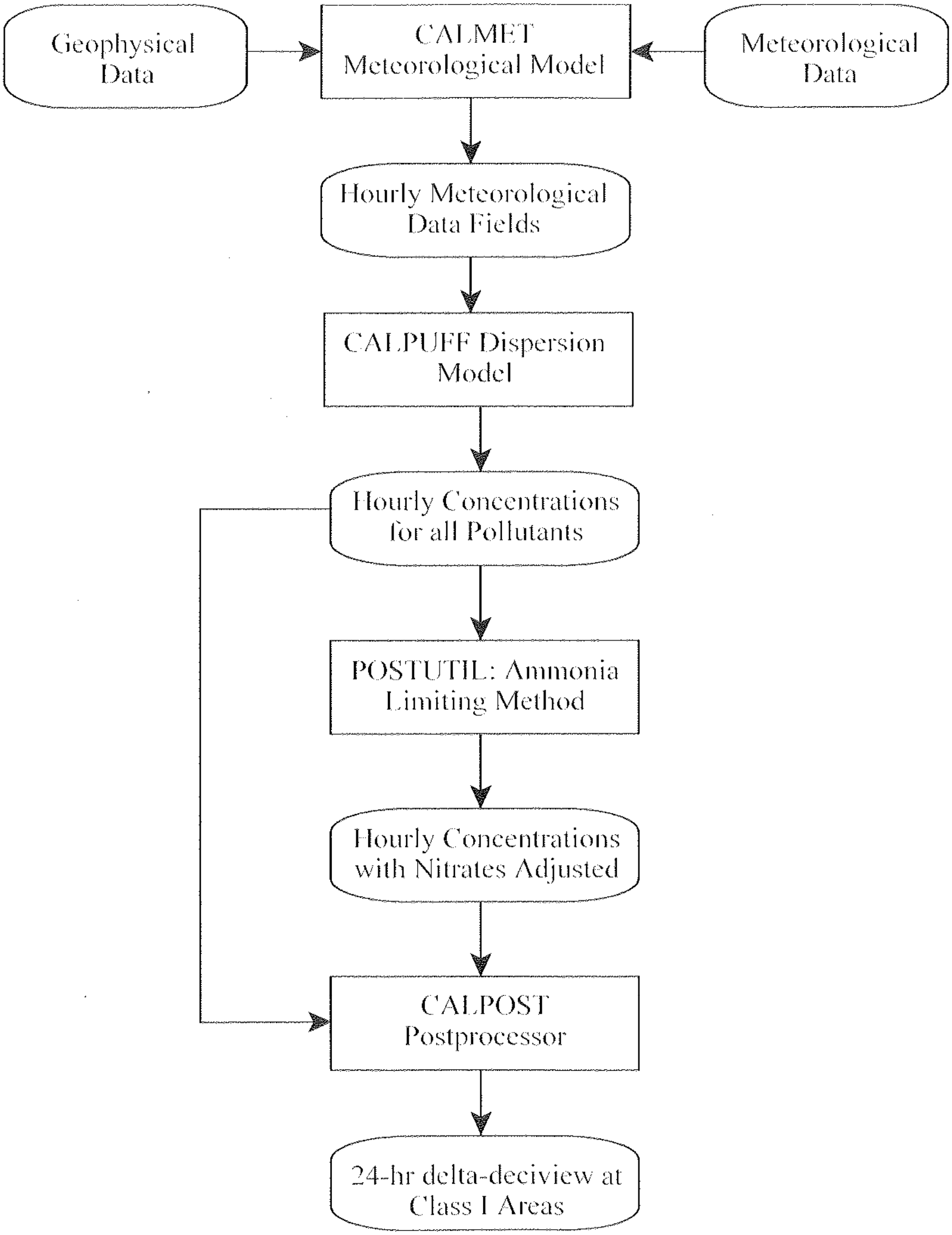
[5] Earth Tech, Inc., 2000. A User's Guide for the Calmet Meteorological Model (Version 5). Earth Tech, Inc., Concord, MA 01742.

[6] Earth Tech, Inc., 2000. A User's Guide for the Calpuff Dispersion Model (Version 5). Earth Tech, Inc., Concord, MA 01742.

Figure 2-1. Calpuff Processing to Compute Visibility Impacts



(www.src.com/calpuff/calpuff1.htm). For consistency and to ensure executables can accommodate large file sizes, however, it is recommended that the software be obtained directly from NDDH.

Table 2-1
CALPUFF System Versions Applicable For BART Modeling

Program	**Version**	**Level**
CALMET	5.53a	040716
CALPUFF	5.711a	040716
POSTUTIL	1.4	040818
CALPOST	5.51	030709

Application of the ammonia limiting method, utilizing POSTUTIL, is recommended by NDDH. The NDDH will be applying the ammonia limiting method in BART-applicability analyses.

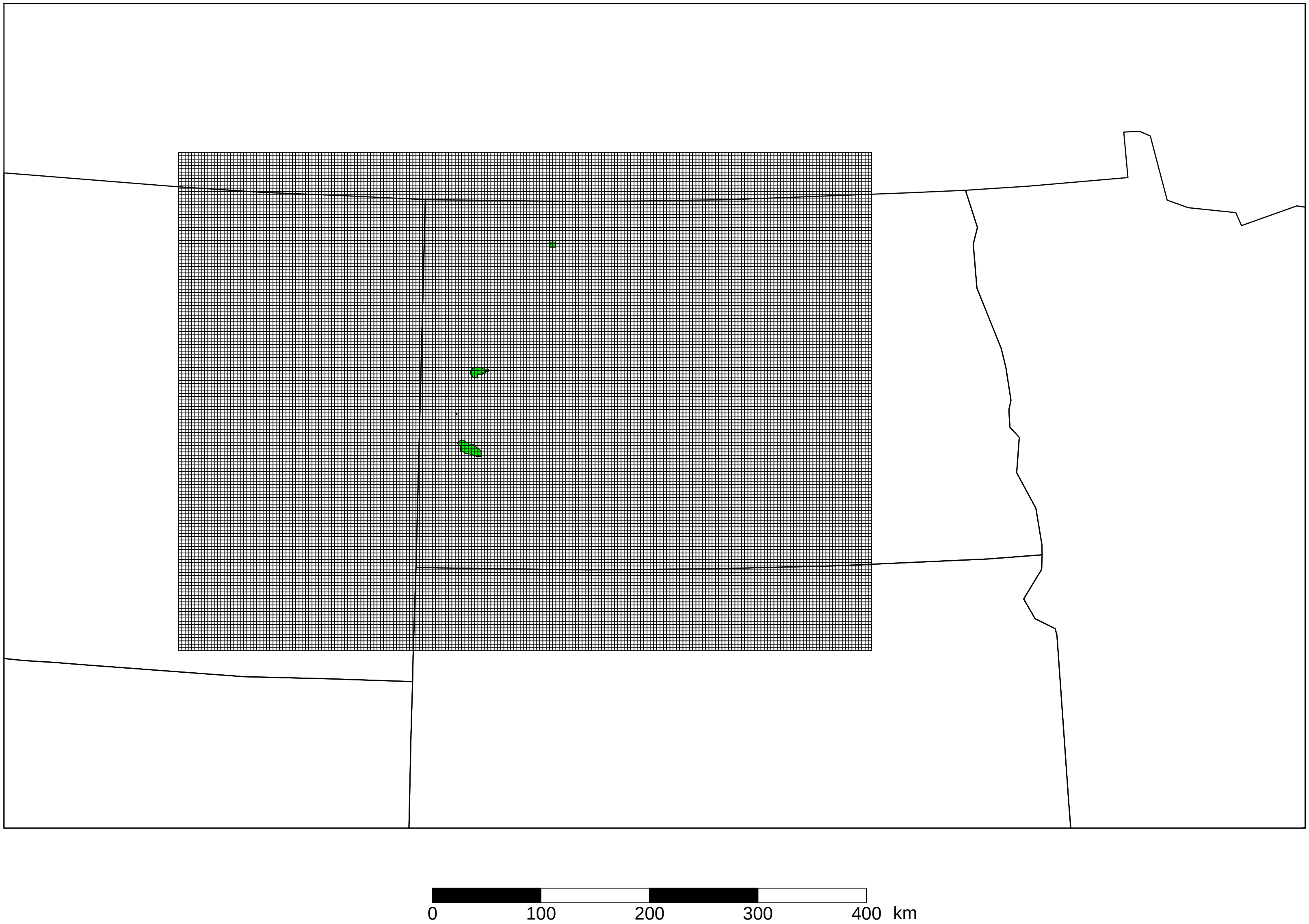
3 Model Input Data/Settings

The CALPUFF modeling system includes the CALMET meteorological model, the CALPUFF dispersion model, the CALPOST postprocessing program, and (optionally) the POSTUTIL program which can be used to implement the ammonia limiting method in visibility analyses. Each of these modules includes a control file which contains user-selected settings to control processing during model execution. CALMET and CALPUFF have additional input data requirements. Input data/settings which are consistent with the use of these programs for BART-related visibility analyses in North Dakota are discussed in Sections 3.1 through 3.4.

The CALMET/CALPUFF modeling domain preferred by the NDDH for BART-related modeling is illustrated in Figure 3-1. Dimensions of the domain are 639 kilometers east-west by 459 kilometers north-south, with a grid cell size of 3 kilometers. In the vertical, the domain is defined by twelve vertical layers. The domain is sized and positioned to encompass all North Dakota PSD Class I areas and BART-eligible sources (with exception noted below), with sufficient buffer area. Because the domain is relatively large, the Lambert Conformal map projection is used to better accommodate the earth's curvature.

As shown in Figure 1-1, the American Crystal Sugar Drayton plant is located outside of the NDDH modeling domain. Even if the domain was extended eastward to incorporate the Drayton plant, the plant is located about 400 kilometers from the nearest Class I area (Lostwood Wilderness Area), and

Figure 3-1: Gridded Modeling Domain



this distance is beyond the accepted range of CALPUFF (about 300 kilometers). For modeling purposes, therefore, the NDDH will reposition the Drayton plant about 100 kilometers to the west, to create a virtual source located just inside the east boundary of the current modeling domain (represented by the "ACS Drayton (modeled)" source in Figure 1-1). This adjustment will provide a source-receptor distance more consistent with the documented limits of CALPUFF, and should ensure conservative results.

3.1 CALMET Input

Input requirements for the CALMET model include various meteorological and geophysical data sets, and a control input file with appropriate settings. Required meteorological data include surface, upper-air, and precipitation observations, and mesoscale model output data fields. Geophysical input data include terrain elevation and land-use data. Though CALMET may be run with mesoscale model meteorological data, alone (i.e., no observations), the EPA modeling guideline[4] recommends "blending" observations with the mesoscale model fields. Therefore, the NDDH will include observations in a blended approach. As required in the EPA modeling guideline, meteorological observations and mesoscale model fields for three years (2000-2002) will be used with CALMET.

All meteorological and geophysical input data sets required for CALMET execution have been previously prepared for BART-related modeling analyses in North Dakota. Upon request, NDDH will provide these meteorological and geophysical data sets.

3.1.1 **Meteorological Data**

3.1.1.1 **Mesoscale Model Data**

Mesoscale model wind fields used with CALMET are based on the National Center for Environmental Predictions (NCEP) Rapid Update Cycle (RUC) forecast model. Mesoscale model fields in the MM5.DAT format required by CALMET were developed by a contractor[7]. The contractor obtained and archived RUC hourly initial analyses from NCEP for years 2000 through 2002. Resolution of these initial analyses was 40 km. The contractor used the ARPS Data Assimilation System (ADAS) to enhance resolution to 10 km, and converted the resultant hourly wind fields to the MM5.DAT format recognized by CALMET. The domain of these hourly wind fields is consistent with the CALMET/CALPUFF domain used by NDDH.

3.1.1.2 **Surface Observations**

Concurrent surface observations for the three-year period 2000-2002 were obtained in surface hourly abbreviated format from the National Climatic Data Center (NCDC). Data were obtained for approximately 35 ASOS/manual stations located within or near the NDDH CALMET/CALPUFF domain, although the specific number of stations varied among the three years. The ASOS/manual observations reflect data from stations operated by the National Weather Service, Federal Aviation

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[7] WindLogics, 2004. RUC Analysis-Based CALMET Meteorological Data for the State of North Dakota. WindLogics, Inc., St. Paul, MN 55108.

Administration, U.S. Air Force, and Environment Canada. Location of these stations is shown in Figure 3-2.

To compensate for well-documented deficiencies in ASOS cloud data above 12,000 feet, NDDH also obtained concurrent GOES ASOS satellite cloud data for all selected surface stations. The satellite hourly observations included cloud amount (sky cover) and cloud height (ceiling height) data above 12,000 feet, and were therefore used to supplement the ASOS observations.

NDDH prepared custom software to merge the ASOS and satellite data. Earth Tech utility software was then used to quality assure merged data, and convert to the format required by CALMET (SURF.DAT). Standard methods were applied to provide substitutions for missing data.[8,9] The occurrence of missing data elements in the surface observations was generally very limited, and within the tolerances suggested by EPA.

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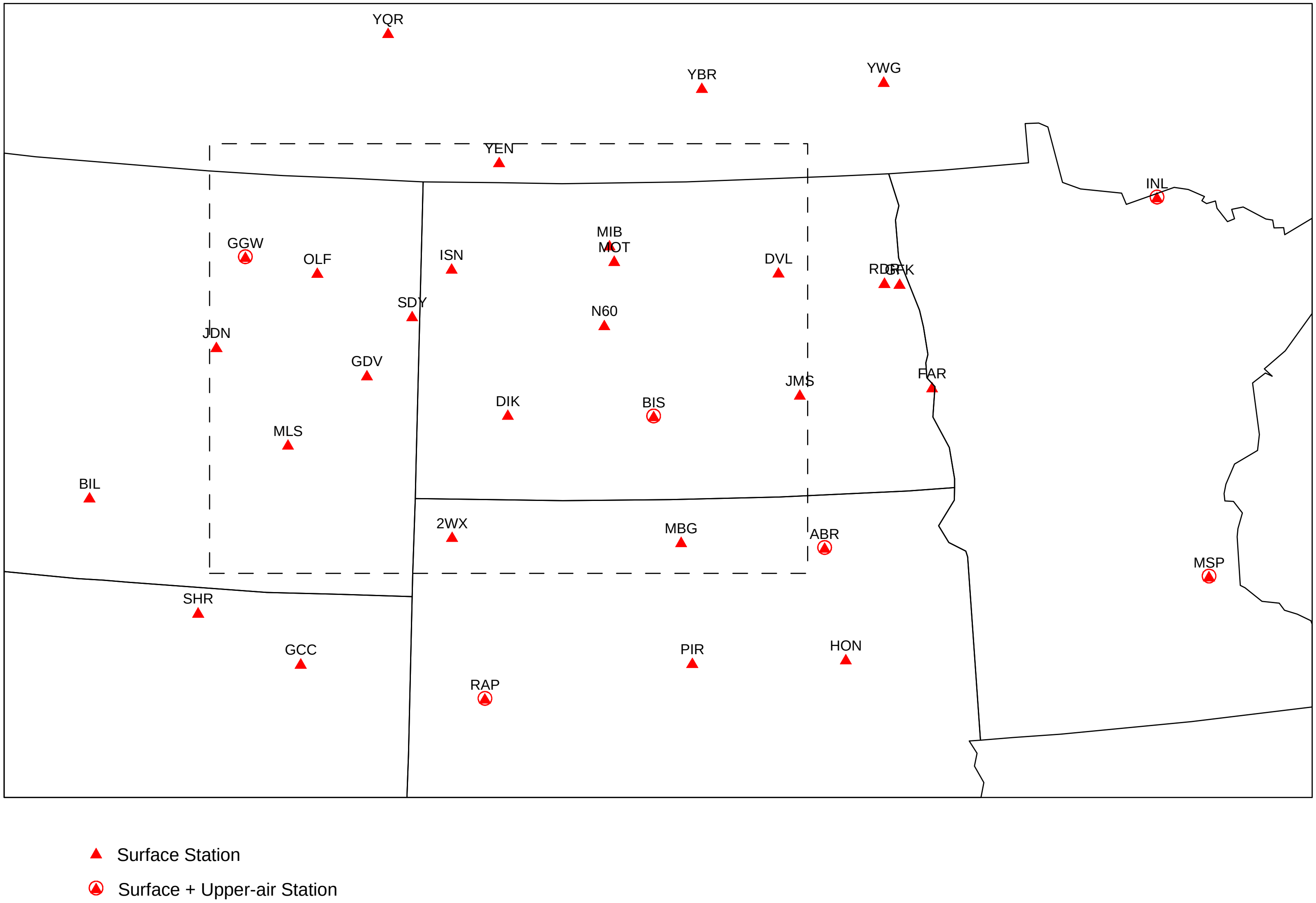
[8] Atkinson, Dennis and Russell F. Lee, 1992. Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models.

[9] EPA, 1987. On-Site Meteorological Program Guidance for Regulatory Modeling Application. Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

Figure 3-2: Surface / Upper-air Meteorological Stations



3.1.1.3 **Upper-Air Observations**

Upper-air observations for the three-year period 2000-2002 were obtained from NOAA's Forecast Systems Laboratory (FSL) in Boulder, Colorado. Upper-air sounding files were downloaded from the FSL website (www.fsl.noaa.gov) in the original FSL format, which is accepted for CALMET input as the option "NCDC CD-ROM". Data were obtained for six upper-air stations (NWS) located within or near the NDDH CALMET/CALPUFF domain. Location of these stations is shown in Figure 3-2.

Processing of the upper-air data for CALMET input involved using Earth Tech utility software, running custom software written by NDDH staff, and manual editing of data files. The main Earth Tech program quality checked the upper-air data files, output error messages to identify problems in the data to be corrected by the user, and converted the data to the format required by CALMET. The NDDH custom software performed additional quality checks, and, combined with manual editing of data files, corrected additional errors or problems in the data and filled in for missing data when necessary. Substitutions for missing data generally followed standard EPA guidance.[8,9] Upper-air soundings were processed up to the 500-mb level to accommodate mixing heights up to 4000 meters above ground level at Rapid City, South Dakota. In addition, the main Earth Tech processing program had to be modified slightly (corrected) to correctly read longitudes for Glasgow, Montana.

3.1.1.4 Precipitation Data

Hourly precipitation data for years 2000-2002 were obtained from NCDC in TD-3240 format. Data were included for approximately 90 NWS hourly recording stations located within or near the NDDH CALMET/CALPUFF modeling domain, although the specific number of stations varied among the three years. Location of these stations is shown in Figure 3-3.

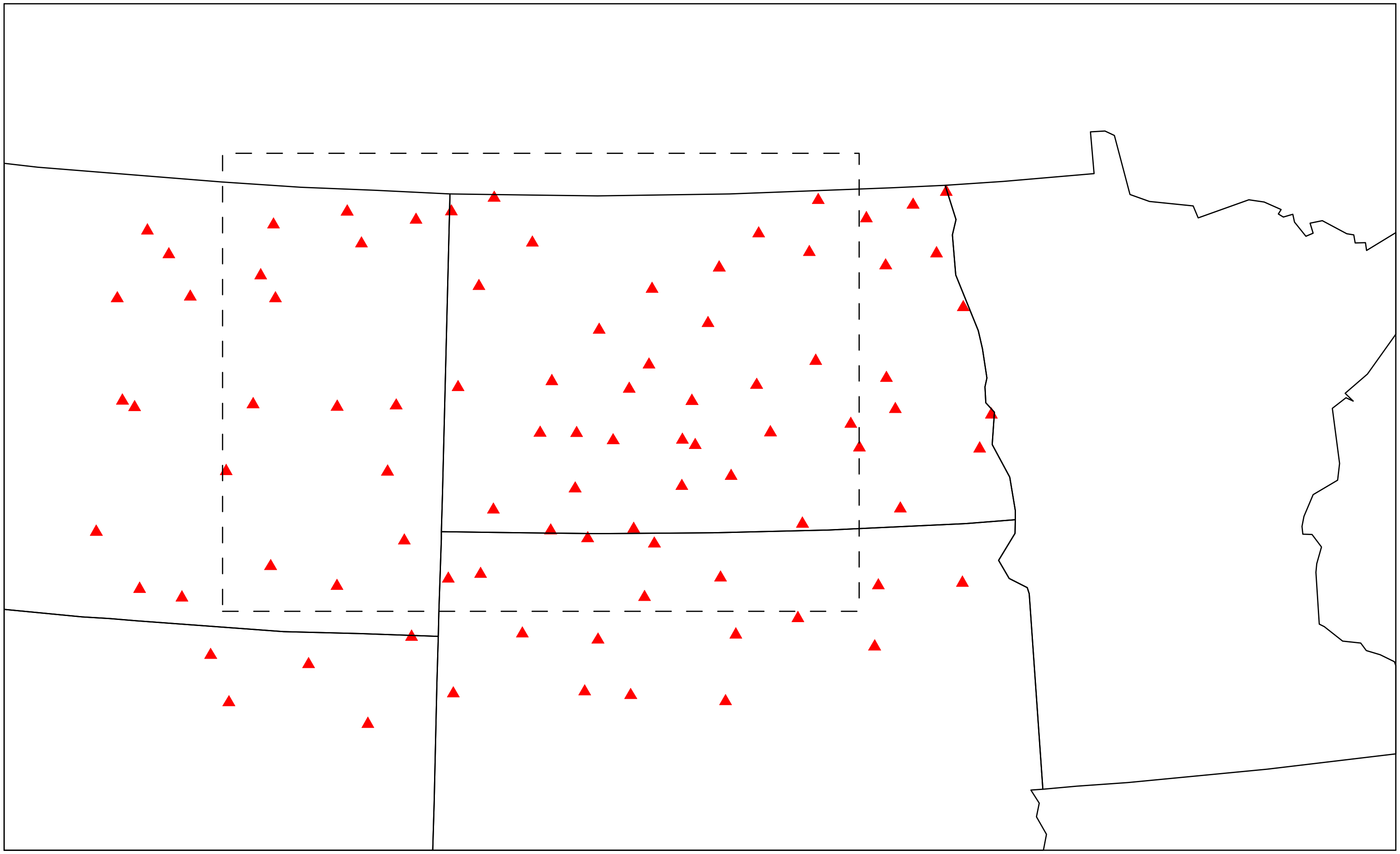
Earth Tech utility software was employed to quality assure the TD-3240 data, and process it into the format required by CALMET (PRECIP.DAT). No substitutions were made for missing data, because CALMET substitutes internally from the nearest available station, and the station resolution was relatively good (Figure 3-3).

3.1.2 Geophysical Data

CALMET requires specification of terrain elevation, and parameters related to the land-use profile, for each grid cell in the modeling domain. The NDDH derived terrain elevations from United States Geological Survey (USGS) GTOPO30 data sets for North America central and mountain zones. Land-use profiles were derived from the USGS Global Data Set for North America.

Using Earth Tech utility software, all gridded terrain and land-use data were processed into the single geophysical file (GEO.DAT) required by CALMET. NDDH assumed Earth Tech default values

Figure 3-3: Precipitation Stations



relating surface roughness length, albedo, Bowen ratio, soil heat flux, and leaf area index to land-use type.

3.1.3 **CALMET Control File Settings**

CALMET control file settings recommended for processing years 2000 through 2002 data for BART-related visibility analyses are generally consistent with guidance from the Interagency Workgroup on Air Quality Modeling (IWAQM)[10]. IWAQM recommendations for CALMET control file variable settings fall into two categories. IWAQM-defined variables are those for which IWAQM provides a default value as a general recommendation for all analyses. User-defined variables are those where IWAQM recognizes the input value will need to be tailored for a given application, and default values are therefore not provided.

For BART-related visibility analyses, the NDDH has established appropriate settings for user-defined variables, and has determined the need to adjust a limited number of IWAQM-defined variables from recommended values, as discussed below. The CALMET control file user-defined settings, as well as the IWAQM-defined settings which have been adjusted by NDDH, are summarized in Table 3-1. IWAQM-defined settings adjusted by NDDH have a highlighted background in the Table.

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[10] EPA, 1998. IWAQM Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. Publication No. EPA-454/R-98-019, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

Table 3-1
User-Defined and Non-IWAQM Settings for CALMET Control File

Variable	**Description**	**Value**
NSSTA	No. of surface stations	32,41,40*
NUSTA	No. of upper-air stations	5
NPSTA	No. of precipitation stations	89,93,93*
IBTZ	Base time zone	7
PMAP	Map projection (LCC=Lambert Conformal Conic)	LCC
FEAST	False easting at origin	0.0
FNORTH	False northing at origin	0.0
RLAT0	Origin latitude of projection	44.0N
RLON0	Central meridian of projection	102.0W
XLAT1	Latitude of 1st standard parallel for projection	46.0N
XLAT2	Latitude of 2nd standard parallel for projection	48.5N
DATUM	Datum-region for output coordinates	NWS-27
NX	No. of X grid cells	213
NY	No. of Y grid cells	153
DGRIDM	Grid spacing (km)	3.0
XORIGKM	Southwest grid cell X coordinate	-380
YORIGKM	Southwest grid cell Y coordinate	140
NZ	No. vertical layers	12
ZFACE	Cell face heights (m)	0.,20.,50.,90.,140.,200., 270.,370.,500.,1000., 1700.,2500.,4200.
NOOBS	No observation mode (0 = no)	0

Variable	Description	Value
IPROG	Use MM5.DAT file as initial guess wind field (14=yes)	14
RMAX1	Max. radius of influence of surface observation (km)	100
RMAX2	Max. radius of influence of upper-air observation (km)	200
RMAX3	Max. radius of influence over water (km)	200
TERRAD	Radius of influence of terrain features (km)	10
R1	Distance from a surface observation station at which the wind observation and the first guess field are equally weighted (km)	10
R2	Distance from an upper-air observation station at which the wind observation and the first guess field are equally weighted (km)	10
ISURFT	Surface station number used for the surface temperature for the diagnostic wind field module (Bismarck)	12,17,17*
IUPT	Upper-air station number used to compute the domain-scale temperature lapse rate for the diagnostic wind field module (Bismarck)	1
ZUPWND	Bottom and top of layer through which the domain-scale winds are computed (m)	1.,2500.
MNMDAV	Max. search distance (in grid cells) for spatial averaging of mixing ht. and temperature	7
ILEVZI	Layer of winds used in upwind averaging of mixing heights	3
ZIMAX	Maximum over land mixing height (m)	4000.
ZIMAXW	Maximum over water mixing height (m)	4000.

* Values for years 2000, 2001, 2002

Most of the user-defined settings are intuitive, related to parameterization of the meteorological grid used with CALMET, as previously discussed. The remaining user-defined variables, (RMAX1, RMAX2, RMAX3, TERRAD, R1, R2) control the influence of mesoscale model data, station observations, and terrain features in development of the final wind field. Settings for these variables are based on the NDDH alternative protocol for PSD Class I increment analyses.[3]

NDDH settings for IWAQM-defined variables are consistent with IWAQM recommendations, with limited exceptions as established in the alternative protocol for PSD Class I increment analyses. Because the use of mesoscale meteorological data is now being generally recommended for long-range modeling analyses, the IPROG variable has been changed from 0 to 14, which reflects use of MM5 format data (in this case RUC data) as the initial guess wind field. The ZUPWND setting has been changed for consistency with default values in recent versions of CALMET (the IWAQM setting reflected defaults for an older version of CALMET). Based on visual feedback testing, IWAQM settings for variables related to spatial averaging of mixing heights, MNMDAV and ILEVZI, are adjusted to provide averaging over a larger area. Because the NDDH CALMET/CALPUFF modeling domain extends into the western part of the upper Great Plains, maximum mixing height settings (ZIMAX/ZIMAXW) are increased from 3000 to 4000 meters to be consistent with maximum mixing heights reported for this region.[11] Note that the CALMET BIAS factors have no effect when mesoscale data are used as the initial guess wind field.

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[11] Holzworth, 1972. Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States. EPA Publication No. AP-101, Office of Air Programs

Settings as discussed above are incorporated in the CALMET control file prepared by NDDH for BART-related visibility analyses. A sample file with NDDH settings will be provided upon request.

3.2 CALPUFF Input

Along with the CALMET-processed meteorological data, CALPUFF requires the user to provide emissions and stack data, receptor locations, input control file settings, and (optionally) hourly ozone data before the model can be executed. A background ammonia value is also required.

3.2.1 Emissions and Stack Data

To determine which BART-eligible sources are subject to BART, the BART guideline stipulates modeling primary pollutants SO_2, NO_x, and PM_{10} (coarse and fine) using maximum emission rates. The guideline states,

> *"The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used, as such emission rates could produce higher than normal effects than would be typical of most facilities. We recommend that States use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods of start-up, shutdown, or malfunction."*

Since the meteorological period modeled will be 2000 through 2002, the NDDH requested companies operating BART-eligible sources to provide maximum 24-hour emission rates (with exception of start-up, shutdown, and malfunction conditions) for this three-year period. Other stack data required by CALPUFF include stack height, stack diameter, exit velocity, exit temperature, location, and stack-base elevation. Entries for these stack parameters are taken from PSD increment modeling recently completed by NDDH.[3] Entries for the dynamic stack parameters, exit velocity and exit temperature, reflect an average for the 2000-2002 period.

Emission rates provided by BART-eligible source companies, and appropriate for BART-related visibility modeling, are shown in Table 3-2. When the BART-eligible source company only provided total particulate matter emission rates, PM_{10} emission rates were calculated based on data from recent Annual Emission Inventory Reports. Furthermore, the NDDH believes that assuming all PM_{10} emissions are $PM_{2.5}$ would be too conservative. Therefore, $PM_{2.5}$ emissions were calculated based on data in the 2004 Annual Emission Inventory Report. The NDDH recognizes that better data may become available on the particle size distribution of PM emissions at individual sources. BART-applicable source companies are free to use the better data in the BART-related modeling provided a justification is included as part of the BART analysis.

Associated stack parameters for modeling are found in Table 3-3. Tables 3-2 and 3-3 provide the appropriate emission rates and stack data to use in the CALPUFF analyses to determine which BART-eligible sources are subject to BART. Building downwash effects will not be considered in the CALPUFF visibility analyses.

To determine the degree of visibility improvement from BART controls, the BART guideline recommends comparing results of pre-control modeling with results of post-control modeling. Pre-control emission rates and stack data would be equivalent to those used for the BART screening analysis from Tables 3-2 and 3-3. Post-control emission rates and stack data must be provided by the BART applicable source company as part of the BART analysis. Post-control emission rates are calculated as a percentage of the pre-control emission rates, using the efficiency of the proposed control equipment and/or process changes.

If CALPUFF multi-source analyses are eventually conducted to address the combined effect of proposed BART controls, as alluded to in Section 1, it may be appropriate to reevaluate the use of peak 24-hour emission rates. Use of a non-peak emission characterization may be more realistic for determination of cumulative visibility impact.

3.2.2 **Ozone Background**

CALPUFF utilizes background ozone values in its chemistry module. The model accepts either a single constant background ozone value, or an input file of hourly ozone values commensurate with

Table 3-2
BART Eligible Sources
Screening Analysis
Emission Rates

Company	Unit	PM_{10} (lb/hr)	$PM_{2.5}$ (Fine) (lb/hr)	PM Coarse* (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)
Basin Electric Power Coop.	Leland Olds 1	155.2	16.5	138.7	5,970.0	813.0
Basin Electric Power Coop.	Leland Olds 2	253.2	26.9	226.3	12,205.0	3,959.0
Minnkota Power Coop.	M.R. Young 1	42.2	5.5	36.7	7,231.2	2,855.2
Minnkota Power Coop.	M.R. Young 2	206.8	28.1	178.7	6,879.0	5,364.2
Montana Dakota Utilities	Heskett 2	25.8	21.6	4.2	1,475.5	302.8
Great River Energy	Stanton 1	31.8	1.9	29.9	3,418.0	669.0
Great River Energy	Coal Creek 1	249.2	101.9	147.3	5,733.5	1,772.3
Great River Energy	Coal Creek 2	216.1	88.4	127.7	4,969.3	1,822.4
American Crystal Sugar	Drayton Boiler Drayton Lime Kiln**	25.7 1.0	4.9 0.2	20.8 0.8	197.0 0.2	150.0 2.5
Tesoro	Mandan Ref CO Furn	14.4	14.4	0.0	55.8	46.6

*PM coarse = PM_{10} - $PM_{2.5}$

**Entries reflect total for lime kiln emission points.

Table 3-3
BART Eligible Sources
Screening Analysis
Stack Parameters

Unit	X Coord.* (km)	Y Coord.* (km)	Stack Height (m)	Base Elevation (m)	Stack Diam. (m)	Exit Velocity (m/s)	Exit Temp. (K)
Leland Olds 1	51.180	365.146	106.7	518.3	5.3	19.7	450.0
Leland Olds 2	51.282	365.080	152.4	518.3	6.7	25.0	448.6
M.R. Young 1	59.473	341.392	91.4	597.4	5.8	18.5	449.1
M.R. Young 2	59.455	341.308	167.6	597.4	7.6	19.2	361.8
Heskett 2	84.846	319.403	91.4	514.8	3.7	17.4	419.7
Stanton 1	50.361	365.705	77.7	518.3	4.6	19.9	411.1
Coal Creek 1	63.387	376.062	201.0	602.0	6.7	25.9	358.5
Coal Creek 2	63.492	376.068	201.0	602.0	6.7	24.9	354.5
Drayton Boiler**	254.569	521.644	36.6	245.1	2.4	21.7	493.2
Drayton L. Kiln**	254.554	521.657	35.1	245.1	0.3	21.0	376.5
Mandan Ref CO F.	85.094	317.518	60.5	518.5	2.44	12.6	333.0

*Coordinates reflect North Dakota Lambert Projection.

**The coordinates for Drayton boiler and lime kiln reflect the location of the repositioned virtual sources used for modeling. Stack parameters for the lime kiln reflect a composite of all lime kiln emission points.

the period of meteorological data. The NDDH uses the hourly ozone file option with CALPUFF, and would regard this as the appropriate implementation for BART-related visibility modeling (this is also the IWAQM default option). The hourly ozone file option is implemented using year 2000-2002 hourly ozone data obtained from four NDDH monitoring sites located within the corridor of primary plume transport between major electric generating stations and Theodore Roosevelt National Park (TRNP). These monitoring sites include Hannover, Beulah, Dunn Center and TRNP South Unit. As indicated in Section 3.2.5, a constant ozone background value is also entered in the CALPUFF control file, so that it can be substituted when the hourly value is missing.

The NDDH prepared software to merge and format these ozone data into the input file required by CALPUFF (OZONE.DAT). The NDDH CALPUFF-compatible hourly ozone files for years 2000-2002 will be provided upon request.

3.2.3 **Ammonia Background**

The need for ammonia background concentrations in CALPUFF is also related to chemistry processing. CALPUFF accepts either a single annual value, or twelve monthly averages. To achieve a more realistic seasonal progression of nitrate predictions, the NDDH will be using monthly average ammonia background values for BART-related visibility analyses.

Monthly average ammonia concentrations suitable for visibility modeling in North Dakota are provided in Table 3-4. These values were derived from data collected at the State's only ammonia monitor located near Beulah. Hourly monitor data from years 2001-2002 (data not available for year 2000) were filtered to eliminate data from wind directions associated with sources causing a local bias, then remaining data were processed to produce the monthly averages. The Table 3-4 values should be generally representative of background ammonia concentrations in western North Dakota.

Table 3-4
Monthly Ammonia Background Concentrations*

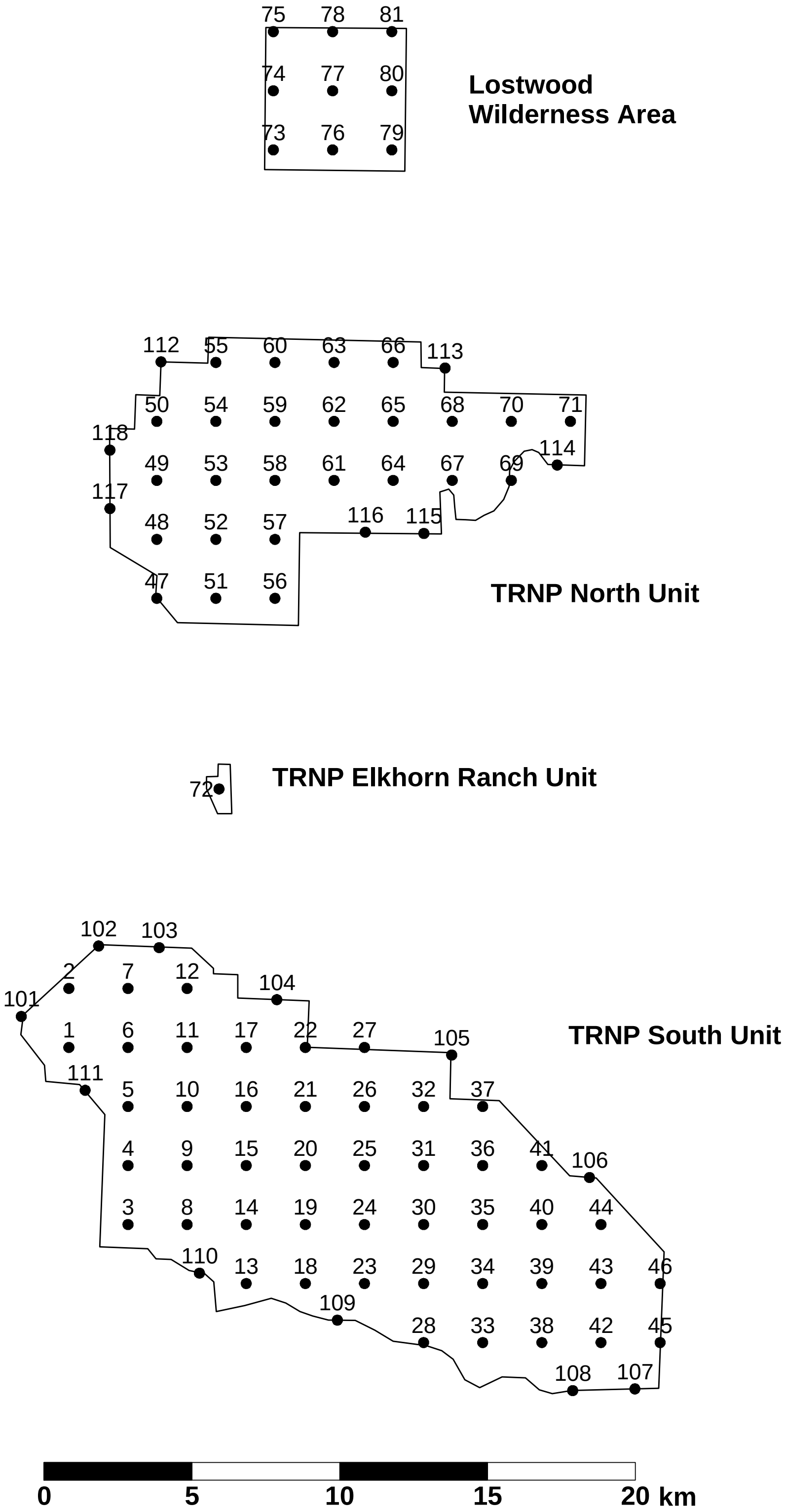
Month	Value (ppb)
Jan	1.22
Feb	1.23
Mar	1.60
Apr	1.94
May	2.29
Jun	1.63
Jul	1.65
Aug	1.69
Sep	0.98
Oct	1.04
Nov	1.37
Dec	1.06

* Data reflect NDDH Beulah monitoring site.

3.2.4 Receptor Locations

Receptor locations used by NDDH for PSD Class I area modeling analyses are shown in Figure 3-4. Receptor spacing for all Class I areas is generally 2 kilometers (km). Given the minimum distance of BART-eligible sources from Class I areas in North Dakota (about 100 km), single-source

Figure 3-4: Receptor Locations - North Dakota Class I Areas



concentration gradients (for visibility-related species) in the vicinity of Class I areas are not expected to be significant, and the 2 km receptor grids should be adequate for visibility analyses.

The BART guideline focuses on receptors at the nearest Class I area, only. Because all four Class I areas in North Dakota are located at relatively equal distances from BART-eligible sources, however, it is recommended that receptors for all Class I areas be accounted for in all BART-related visibility analyses. Class I area receptor coordinates and elevation, as implemented by NDDH, are provided in Appendix A. Receptor coordinates/elevation are also found in the example CALPUFF control file discussed in Section 3.2.5.

Note that receptor coordinates are provided in the same Lambert map projection as is used for source locations (Table 3-3). If needed, the NDDH can provide a utility (MAPCONI) to convert UTM or geographic coordinates to the North Dakota Lambert system.

3.2.5 **CALPUFF Control File Settings**

CALPUFF control file settings recommended for BART-related visibility analyses are generally consistent with IWAQM guidance.[10] IWAQM recommendations for CALPUFF control file settings fall into two categories. IWAQM-defined variables are those for which IWAQM provides a default value as a general recommendation for all analyses. User-defined variables are those where IWAQM recognizes the input value will need to be tailored for a given application, and default values are therefore not provided.

For BART-related visibility analyses, the NDDH has established appropriate settings for user-defined variables, and has determined the need to adjust a limited number of IWAQM-defined variables from recommended values, as discussed below. The CALPUFF control file user-defined settings, as well as the IWAQM-defined settings which have been adjusted by NDDH, are summarized in Table 3-5. IWAQM-defined settings adjusted by NDDH have a highlighted background in the table.

Most of the user-defined settings recommended by NDDH are intuitive, involving variables related to defining the meteorological/computational grid, variables related to the Lambert map projection, and the use of default values for dry and wet deposition parameterization. The variable IRESPLIT is set such that puffs are eligible for splitting on any hour of the day.

NDDH settings for IWAQM-defined variables are equivalent to IWAQM recommendations, with exception of settings for a limited number of variables related to puff splitting, dispersion, and mixing height. Variable MSPLIT is set to allow puff splitting, as this option is generally recommended when modeling source-receptor distances of 200 km or more. Based on performance testing of the CALPUFF model for PSD Class I increment modeling,[3] the NDDH uses adjusted settings for dispersion-related variables MDISP and MPDF, and for variables IVEG and ROLDMAX, as these adjustments provide better model performance. NDDH settings for MDISP and MPDF, reflecting the use of micro meteorological variables in calculating dispersion, are also more consistent with dispersion treatment in the local-scale model AERMOD. Values for background ozone and ammonia (variables BCKO3 and BCKNH3, respectively) are set to be

Table 3-5
User-Defined and Non-IWAQM Settings for CALPUFF Control File

Variable	Description	Value
IBTZ	Base time zone	7
NSPEC	Number of chemical species	7
NSE	Number of chemical species emitted	4
MSPLIT	Allow puff splitting (1=yes)	1
MDISP	Method used to compute dispersion coefficients	2
MPDF	PDF used for dispersion under convective conditions (1=yes)	1
PMAP	Map projection (LCC=Lambert Conformal Conic)	LCC
FEAST	False easting at origin	0.0
FNORTH	False northing at origin	0.0
RLAT0	Origin latitude of projection	44.0N
RLON0	Central meridian of projection	102.0W
XLAT1	Latitude of 1st standard parallel for projection	46.0N
XLAT2	Latitude of 2nd standard parallel for projection	48.5N
DATUM	Datum-region for output coordinates	NWS-27
NX	No. of X grid cells	213
NY	No. of Y grid cells	153
NZ	No. vertical layers	12
DGRIDM	Grid spacing (km)	3.0
ZFACE	Cell face heights (m)	0.,20.,50.,90.,140.,200.,270.,370.,500.,1000.,1700.,2500.,4200.
XORIGKM	Southwest grid cell X coordinate	-380
YORIGKM	Southwest grid cell Y coordinate	140

Variable	**Description**	**Value**
IBCOMP	Southwest X-index of computational grid	20
JBCOMP	Southwest Y-index of computational grid	6
IECOMP	Northeast X-index of computational grid	213
JECOMP	Northeast Y-index of computational grid	153
Dry Gas Dep.	Chemical parameters of gaseous deposition species	Model defaults
Dry Part. Dep.	Chemical parameters of particulate deposition species	Model defaults
IVEG	Vegetative state in unirrigated areas (2=active and stressed vegetation)	2
Wet Dep.	Wet deposition parameters	Model defaults
BCKO3	Monthly ozone background concentration (ppb)	30.0*
BCKNH3	Monthly ammonia background concentration (ppb)	Table 3-4
XMAXZI	Maximum mixing height	4000.
IRESPLIT	Hours when puff is eligible for vertical split	hours 1-24
ROLDMAX	Vertical puff split allowed only when the ratio of last hour's mixing height to max. mixing height experienced by the puff is smaller than this value	0.33
NSPLITH	Number of puffs that result when a puff is split horizontally	5
SYSPLITH	Minimum sigma-y (grid cell units) of puff before it may split horizontally	1.0
SHSPLITH	Minimum puff elongation rate (SYSPLITH/hr) due to wind shear, before it may split horizontally	2.0
CNSPLITH	Minimum concentration (g/m^3) in puff before it may split horizontally	1.0E-07
NREC	Number of discrete receptors	99

*Use same value for each month.

consistent with local monitoring data. Maximum mixing height (XMAXZI) is set to 4000 meters for consistency with CALMET settings.

Settings as discussed above are incorporated in the CALPUFF control file developed by NDDH for BART-related visibility analyses. A sample file with NDDH settings will be provided upon request.

3.3 **POSTUTIL Input**

The POSTUTIL processor provides repartitioning of total nitrate to adjust for possible double (or multiple) counting of ammonia in the CALPUFF chemistry. According to Escoffier-Czaja and Scire[12],

> *"In CALPUFF, a continuous plume is simulated as a series of puffs, or discrete plume elements. The total concentration at any point in the model is the sum of the contribution of all nearby puffs from each source. Because CALPUFF allows the full amount of the specified background concentration of ammonia to be available to each puff for forming nitrate, the same ammonia may be used multiple times in forming nitrate, resulting in an overestimate of nitrate formation .... In POSTUTIL, ammonia availability is computed based*

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[12] Escoffier-Czaja, Christelle and J. Scire, 2002. The Effects of Ammonia Limitation on Nitrate Aerosol Formation and Visibility Impacts in Class I Areas. Earth Tech, Inc., Extended abstract. 12th Joint Conference on the Applications of Air Pollution Meteorology with the Air and Waste Management Association, American Meteorological Society, J5.13.

> *on receptor concentrations of total sulfate and total nitrate (HNO_3 + NO_3), not on a puff-by-puff basis."*

Input required by POSTUTIL includes an input control file and the hourly concentration output file from CALPUFF. Primary settings for the POSTUTIL control file include the ammonia background concentrations and a variable (MNITRATE) related to recomputing the nitrate partition. The monthly ammonia background concentrations are equivalent to the values used in CALPUFF (Table 3-4), and the appropriate setting for MNITRATE in BART-related visibility analyses is '1'. Species processing information (POSTUTIL Input Group 2) for BART-related visibility analyses is specified as shown in Figure 3-5, with PMC representing the name used in CALPUFF for coarse particulate, and PMF representing the name used for fine particulate. Note that entries are not necessary for Subgroups 2.c and 2.d. All other POSTUTIL settings are intuitive, with some simply repeated from the CALPUFF control file.

Settings as discussed above are incorporated in the POSTUTIL control file developed by NDDH for BART-related visibility analyses. A sample file with NDDH settings will be provided upon request.

3.4 **CALPOST Input**

CALPOST produces summary 24-hour average visibility results (in delta-deciviews) which are compared to the BART-related thresholds (Section 2.1). Required input for CALPOST includes an input control file and the hourly concentration output file from either CALPUFF or POSTUTIL.

Figure 3-5: POSTUTIL Control Input File: Input Group 2

```
 INPUT GROUP: 2 -- Species Processing Information
--------------

-------------
Subgroup (2a)
-------------

  The following NSPECINP species will be processed:

! ASPECI =          SO2 !         !END!
! ASPECI =          SO4 !         !END!
! ASPECI =          NOX !         !END!
! ASPECI =         HNO3 !         !END!
! ASPECI =          NO3 !         !END!
! ASPECI =          PMF !         !END!
! ASPECI =          PMC !         !END!


-------------
Subgroup (2b)
-------------

  The following NSPECOUT species will be written:

! ASPECO =          SO2 !         !END!
! ASPECO =          SO4 !         !END!
! ASPECO =          NOX !         !END!
! ASPECO =         HNO3 !         !END!
! ASPECO =          NO3 !         !END!
! ASPECO =          PMF !         !END!
! ASPECO =          PMC !         !END!
```

CALPOST control file settings recommended by NDDH for BART-related visibility analyses are summarized in Table 3-6. The BART guideline specifies that daily (24-hour) visibility values should be calculated for each receptor as the change in deciviews (delta-deciview) compared against natural background visibility conditions. More specifically, the preamble to the final BART rule specifies use of natural background for the 20 percent best visibility days. The guideline also provides for the use of monthly average relative humidity (RH) values for BART-related visibility analyses. The preference for monthly average relative humidity implies the use of CALPOST visibility Method 6 (MVISBK = 6).

In order to develop background conditions for visibility Method 6, CALPOST requires monthly background concentrations of ammonium sulfate, ammonium nitrate, coarse particulate mass, organic carbon, soil, and elemental carbon. Annual averages reflective of natural background conditions for these species are found in EPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" (2003)[13]. For each Class I area, this guidance document provides separate deciview values representative of annual average natural background, and natural background for the 20 percent best days.

The EPA natural visibility guidance document does not provide speciated background concentrations (above) representative of the 20 percent best days, as would be needed for implementation of

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[13] EPA, 2003. Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program. Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

Table 3-5
CALPOST Control File Settings

Variable	**Description**	**Value**
ASPEC	Species to process	VISIB
ILAYER	Enter “1" to process concentrations in CALPUFF hourly file	1
A	Scaling factor	0.0
B	Scaling factor	0.0
LBACK	Add hourly background concentration	F
RHMAX	Maximum relative humidity	95.0
LBSO4	Include modeled sulfate?	T
LVNO3	Include modeled nitrate?	T
LVOC	Include modeled organic carbon	F
LVPMC	Include modeled coarse particles	T
LVPMF	Included modeled fine particles	T
LVEC	Include modeled elemental carbon	F
LVBK	Include background in output tables	F
EEPMC	Extinction efficiency for PM coarse	0.6
EEPMF	Extinction efficiency for PM fine	1.0
EEPMCBK	Extinction efficiency for background PM coarse	0.6
EESO4	Extinction efficiency for ammonium sulfate	3.0
EENO3	Extinction efficiency for ammonium nitrate	3.0
EEOC	Extinction efficiency for organic carbon	4.0
EESOIL	Extinction efficiency for soil	1.0
EEEC	Extinction efficiency for elemental carbon	10.0
MVISBK	Visibility calculation method	6

Variable	Description	Value
RHFAC	Monthly RH adjustment factor	Table 3-8
BKSO4	Background ammonium sulfate conc.	Table 3-7*
BKNO3	Background ammonium nitrate conc.	Table 3-7*
BKPMC	Background coarse particulate conc.	Table 3-7*
BKOC	Background organic carbon conc.	Table 3-7*
BKSOIL	Background soil conc.	Table 3-7*
BKEC	Background elemental carbon	Table 3-7*
BEXTRAY	Extinction due to Rayleigh scattering	10.0

* Use same value for each month.

CALPOST Method 6 consistent with the BART rule. Upon consultation with EPA and National Park Service/Fish and Wildlife Service representatives[14], it was concluded that the annual concentrations (Table 2-1 in guidance document) should be scaled back, in equal proportion, until they converge to lower concentratons that produce the deciview value specified for the 20 percent best days (guidance document Appendix B) to provide the necessary CALPOST input. The scaling procedure would be conducted separately for each Class I area.

The scaling procedure as applied by NDDH is illustrated here for Theodore Roosevelt National Park (TRNP). From Appendix B in the natural visibility guidance document, the deciview value for annual average natural conditions at TRNP is 4.75, and the deciview value for the 20 percent best days is 2.19. Note that the TRNP annual average deciview value reflects natural background components for the US west region. To obtain the speciated background concentrations representative of the 20 percent best days at TRNP, the deciview value (2.19) must first be converted to light extinction. The relationship between deciviews and light extinction is expressed,

$$dv = 10 \ln (b_{ext}/10)$$

or

$$b_{ext} = 10 \exp (dv/10)$$

where

dv represents deciviews,
b_{ext} represents total light extinction expressed in inverse megameters (Mm^{-1}).

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[14] NDDH, 2005. Electronic message summarizing BART modeling-related conference-call discussion with representatives of EPA, National Park Service, and Fish and Wildlife Service, August 31, 2005.

Using this relationship with a deciview value of 2.19, one obtains a light extinction value of 12.45 Mm^{-1}. Next, the natural visibility guidance document background concentrations for annual average (Table 2-1, west) are adjusted in order to provide the extinction value just determined (12.45 Mm^{-1}). The relationship between light extinction and background concentrations is:

$$\begin{aligned} b_{ext} = {} & (3)\ f\ (RH)\ [\text{ammonium sulfate}] + (3)\ f\ (RH)\ [\text{ammonium nitrate}] + \\ & (0.6)\ [\text{coarse mass}] + (4)\ [\text{organic carbon}] + (1)\ [\text{soil}] + \\ & (10)\ [\text{elemental carbon}] + b_{ray} \end{aligned}$$

where

bracketed quantities represent background concentrations in $\mu g/m^3$,
values in parenthesis represent scattering efficiencies,
f (RH) is the relative humidity adjustment factor (applied to hygroscopic species only),
b_{ray} is light extinction due to Rayleigh scattering (10 Mm^{-1} used for all Class I areas).

Substituting the annual average natural background values and TRNP f (RH) from the natural visibility guidance document, and including the coefficient for scaling, one obtains

$$\begin{aligned} 12.45 = {} & (3)\ (2.56)\ [0.12]\ X + (3)\ (2.56)\ [0.1]\ X + (0.6)\ [3.0]\ X + (4)\ [0.47]\ X + \\ & (1)\ [0.5]\ X + (10)\ [0.02]\ X + 10 \end{aligned}$$

where

X represents scaling factor to convert annual average natural background concentrations to values representative of 20 percent best days.

Solving for X provides a value of 0.403. This scaling factor was applied to the annual average natural background components in the natural visibility guidance document (Table 2-1, west region) to obtain background components for the 20 percent best days for TRNP. The scaling procedure was repeated for Lostwood Wilderness Area.

Results of the scaling procedure are shown in Table 3-7, which includes speciated natural background concentrations representative of annual average visibility, 20 percent best days for Theodore Roosevelt National Park, and 20 percent best days for Lostwood Wilderness Area. Note that west region natural conditions are assumed for North Dakota Class I areas. The Table 3-7

Table 3-7
Natural Levels of Aerosol Components
(µg/m^3)

Component	**Annual Average West Region ***	**20% Best Days Theodore Roosevelt NP**	**20% Best Days Lostwood NWA**
Ammonium sulfate	0.12	0.048	0.049
Ammonium nitrate	0.10	0.040	0.041
Organic carbon mass	0.47	0.189	0.190
Elemental carbon	0.02	0.008	0.008
Soil	0.50	0.202	0.203
Coarse mass	3.00	1.209	1.215
Natural deciview**		2.19	2.21

*From “Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program” (EPA, 2003), Table 2-1.
**From “Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program” (EPA, 2003), Appendix B.

values for 20 percent best days should be used for BART-related analyses. The same value is used for each month in the CALPOST control file.

Monthly RH adjustment factors (RHFAC input in CALPOST) for Theodore Roosevelt National Park and Lostwood Wilderness Area BART-related analyses are provided in Table 3-8. These values are also from the EPA guidance document for natural visibility conditions. One other setting needed for CALPOST development of natural background is extinction due to Rayleigh scattering (BEXTRAY), which should be left at the default value of 10.0.

Table 3-8
Monthly RH Adjustment Factors*

Month	Theodore Roosevelt NP	Lostwood NWA
Jan	2.9	3.0
Feb	2.8	2.9
Mar	2.8	2.9
Apr	2.3	2.3
May	2.3	2.3
Jun	2.5	2.6
Jul	2.4	2.7
Aug	2.2	2.4
Sep	2.2	2.3
Oct	2.3	2.4
Nov	3.0	3.2
Dec	3.0	3.2

* From "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" (EPA, 2003)

The remainder of CALPOST control file settings are intuitive, and mirror settings in the CALPUFF control file. Settings as discussed above are incorporated in the CALPOST control file developed by the NDDH for BART-related visibility analyses. A sample file with NDDH settings will be provided upon request.

4 Model Execution and Output Interpretation

For BART-related single-source visibility analyses in North Dakota, the CALPUFF modeling system should be executed with input data and settings as described in Section 3. Delta-deciview results necessary for comparison with visibility thresholds are obtained from the "24HR VISIBILITY (deciview)" table in the CALPOST output file.

The BART guideline states that the 98th percentile of 24-hour CALPUFF modeling results should be compared with the contribution threshold established by the State for purposes of determining BART applicability. Upon clarification from EPA and FLM's[14], the context of the 98th percentile 24-hour delta-deciview prediction is with respect to days of the year, and is not receptor specific. A 24-hour prediction greater than 0.5 delta-deciview at any receptor in a Class I area would constitute a day of exceedance, and up to 7 days of exceedance would be allowed per year per Class I area (i.e., the 98th percentile is approximated by the eighth-highest daily prediction).

4.1 BART Screening

To complete the BART screening analysis for North Dakota sources, CALPUFF (and optionally POSTUTIL) is executed for each year of meteorological data processed with CALMET (2000-2002). And for each year of CALPUFF (POSTUTIL) hourly output, CALPOST is executed separately for receptor groups representing each Class I area. Delta-deciview modeling results applicable to BART screening are found in the summary section at the bottom of the "24HR VISIBILITY (deciview)" table in the CALPOST output file. If the number of days with delta-deciview prediction greater than 0.5 is more than 7, for any year of meteorological data for any Class I area, the source is concluded to be BART-applicable. Note that the three units of Theodore Roosevelt National Park are treated as separate Class I areas for BART-related visibility analyses.

4.2 **Degree of Visibility Improvement**

For analyses to determine the degree of visibility improvement due to BART controls, the modeling system is executed as described above for BART screening. Model execution and results are needed for both pre-BART control and post-BART control scenarios, to allow comparison of CALPOST delta-deciview predictions for both scenarios. The context of this comparison is not specifically defined, leaving it to the State to determine the appropriate metric. The BART guideline states:

> *"Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvement due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment."*

Consistent with the goals stated in the BART guideline, the NDDH recommends the following specific approaches for evaluating the degree of visibility improvement from BART controls:

- Compare the 98th percentile delta-deciview prediction from pre-control and post-control modeling scenarios.
- Compare the number of days of exceedance of the 0.5 delta-deciview threshold for pre-control and post-control scenarios (to address "duration", the maximum number of consecutive days of exceedance should also be reported for both scenarios).
- For consistency with goals of the Regional Haze program (and WRAP regional-scale modeling), compare the 90th percentile delta-deciview prediction from pre-control and post-control modeling scenarios (i.e., average of the 20 percent worst days).

Again, these comparisons would be made for each Class I area and for each year of meteorological data.

While the above comparisons are proposed in the context of total deciview improvement attributable to BART controls for all species combined, it may be desirable to also test the relative effectiveness of controls for individual species. When evaluating visibility improvement for individual species, the following should be considered.

- To maintain reasonable balance in the CALPUFF chemistry, all four species (SO_2, NO_X, PM coarse, PM fine) should be included in the model input files for pre-control and post-control scenarios. The post-control input file should reflect the BART-control emission rate for the tested species, while the emission rate for other species remains at pre-control levels. Post-control input file stack parameters should reflect post-control values for the tested species.

- Alternatively, to refine the accuracy of single-species testing, the reactive species SO_2 and NO_X may be grouped separately from the non-reactive species PM coarse and PM fine (primary only) in the post-control input file. That is, the BART-applicable source unit would be configured as two virtual co-located sources in the post-control input file. One virtual source would include emission rates for reactive species SO_2 and NO_X, and the other virtual source would include emission rates for non-reactive species PM coarse and PM fine. If the species being tested is reactive, then post-control stack parameters (for the tested species) would be entered for the reactive virtual sources, and pre-control stack parameters would be entered for the non-reactive virtual source. If the species being tested is non-reactive, then post-control stack paramters would be entered for the non-reactive virtual source, and pre-control stack parameters would be assigned for the reactive virtual source.

- If information on particle size distribution is not available for the post-control scenario for primary particulate, the ratio of PM fine to PM coarse for the post-control scenario should be considered equivalent to the PM ratio for the pre-control scenario (Table 3-2).

Whether testing degree of visibility improvement for ensemble species or for one species at a time, testing should be conducted separately for each BART-applicable unit within a facility. When testing for individual species is complete, the overall degree of visibility improvement should be evaluated for each unit. When testing for individual units is complete, the degree of visibility improvement should be evaluated for the entire facility.

It is not the intent of the NDDH to develop specific thresholds for the comparisons of modeled visibility impact recommended above. Rather, the degree of visibility improvement represented by these modeled comparisons (and possibly others) will be evaluated in a qualitative manner, in concert with the review of other prescribed analyses of BART control options (i.e., technology available, cost of compliance, etc.), to establish an appropriate BART control.

4.3 **CALBART Utility**

To expedite recommended comparisons for determining the degree of visibility improvement, the NDDH has developed the CALBART utility software program. CALBART processes the hourly output file from either CALPUFF or POSTUTIL to provide the 24-hr delta-deciview metrics recommended for assessing the degree of visibility improvement due to BART controls. CALBART replaces CALPOST in the sequence of visibility model processing. CALBART produces delta-deciview results equivalent to CALPOST (i.e., when CALPOST input is set as prescribed in Section 3.4), but in a summarized format which includes results for all Class I areas in a single execution.

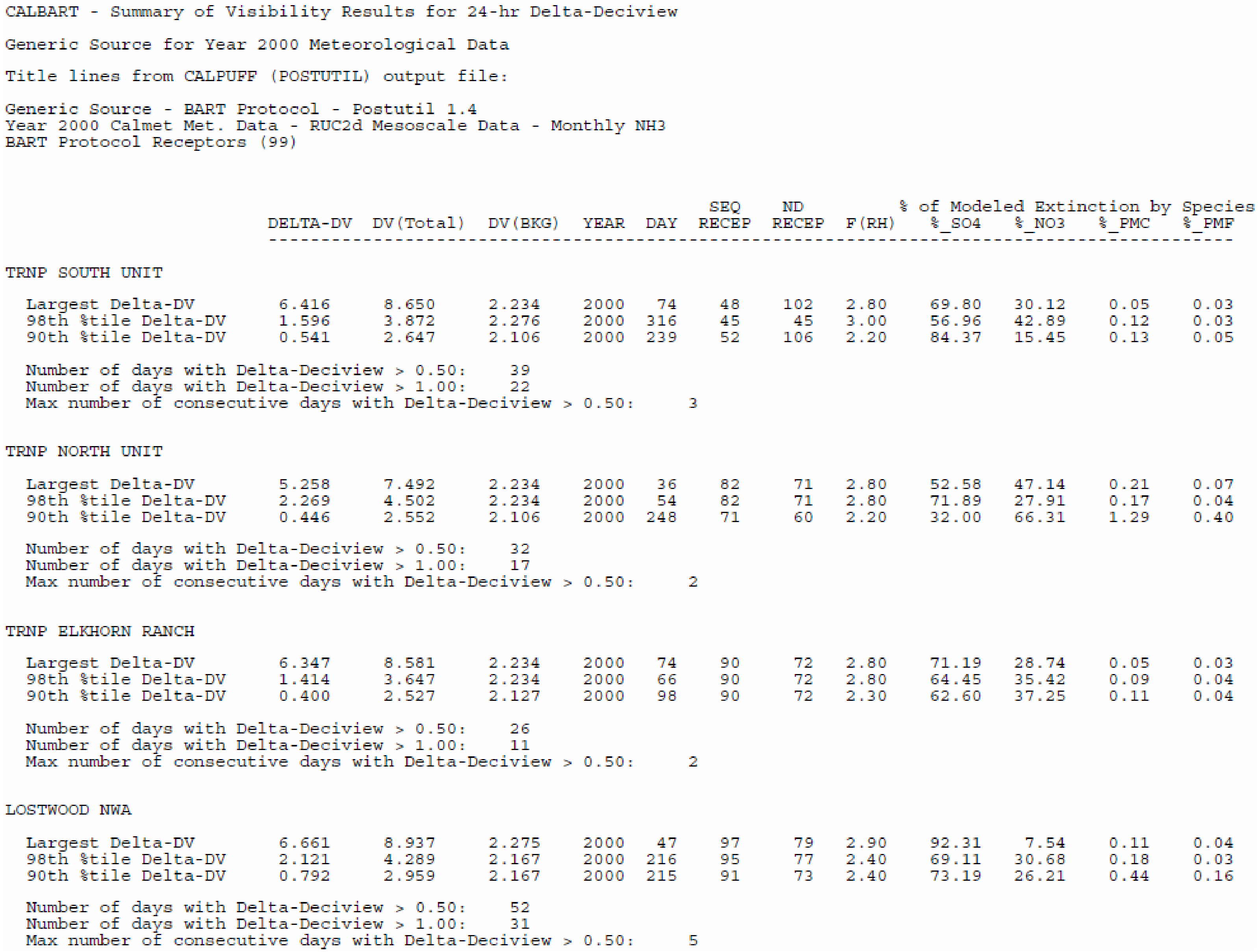
CALBART requires an input control file which must be named ‘CALBART.INP'. The file includes three lines:

Line 1 - Title (up to 80 characters)
Line 2 - File name and path for CALPUFF (POSTUTIL) output file (up to 40 characters)
Line 3 - Beginning year, julian day, and hour for the CALBART run (free format, time must be

equal to or later than that specified in the CALPUFF or POSTUTIL input file; also, the hour should always be specified as '0' to ensure that calendar days are simulated)

An example of CALBART output (file CALBART.LST) is provided in Figure 4-1. The CALBART software will be provided upon request.

Figure 4-1: CALBART Output Example



```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Generic Source for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Generic Source - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ     ND             % of Modeled Extinction by Species
                         DELTA-DV   DV(Total)   DV(BKG)   YEAR   DAY  RECEP   RECEP   F(RH)    %_SO4     %_NO3     %_PMC     %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        6.416      8.650      2.234     2000    74    48     102    2.80     69.80     30.12      0.05      0.03
  98th %tile Delta-DV     1.596      3.872      2.276     2000   316    45      45    3.00     56.96     42.89      0.12      0.03
  90th %tile Delta-DV     0.541      2.647      2.106     2000   239    52     106    2.20     84.37     15.45      0.13      0.05

  Number of days with Delta-Deciview > 0.50:    39
  Number of days with Delta-Deciview > 1.00:    22
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        5.258      7.492      2.234     2000    36    82      71    2.80     52.58     47.14      0.21      0.07
  98th %tile Delta-DV     2.269      4.502      2.234     2000    54    82      71    2.80     71.89     27.91      0.17      0.04
  90th %tile Delta-DV     0.446      2.552      2.106     2000   248    71      60    2.20     32.00     66.31      1.29      0.40

  Number of days with Delta-Deciview > 0.50:    32
  Number of days with Delta-Deciview > 1.00:    17
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        6.347      8.581      2.234     2000    74    90      72    2.80     71.19     28.74      0.05      0.03
  98th %tile Delta-DV     1.414      3.647      2.234     2000    66    90      72    2.80     64.45     35.42      0.09      0.04
  90th %tile Delta-DV     0.400      2.527      2.127     2000    98    90      72    2.30     62.60     37.25      0.11      0.04

  Number of days with Delta-Deciview > 0.50:    26
  Number of days with Delta-Deciview > 1.00:    11
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        6.661      8.937      2.275     2000    47    97      79    2.90     92.31      7.54      0.11      0.04
  98th %tile Delta-DV     2.121      4.289      2.167     2000   216    95      77    2.40     69.11     30.68      0.18      0.03
  90th %tile Delta-DV     0.792      2.959      2.167     2000   215    91      73    2.40     73.19     26.21      0.44      0.16

  Number of days with Delta-Deciview > 0.50:    52
  Number of days with Delta-Deciview > 1.00:    31
  Max number of consecutive days with Delta-Deciview > 0.50:     5
```

Appendix A

NDDH PSD Class I Area Receptors

```
           NON-GRIDDED (DISCRETE) RECEPTOR DATA
           ------------------------------------

                    X UTM      Y UTM      Ground       Height
Receptor         Coordinate Coordinate  Elevation   Above Ground
  No.               (km)       (km)        (m)          (m)
--------         ---------- ----------  ---------   ------------
TRNP South Unit Receptors:
     1 ! X =     -120.0,      334.0,      801.5,       0.000!    !END!
     2 ! X =     -120.0,      336.0,      743.4,       0.000!    !END!
     3 ! X =     -118.0,      328.0,      737.9,       0.000!    !END!
     4 ! X =     -118.0,      330.0,      793.8,       0.000!    !END!
     5 ! X =     -118.0,      332.0,      757.7,       0.000!    !END!
     6 ! X =     -118.0,      334.0,      817.3,       0.000!    !END!
     7 ! X =     -118.0,      336.0,      782.7,       0.000!    !END!
     8 ! X =     -116.0,      328.0,      719.7,       0.000!    !END!
     9 ! X =     -116.0,      330.0,      715.9,       0.000!    !END!
    10 ! X =     -116.0,      332.0,      745.1,       0.000!    !END!
    11 ! X =     -116.0,      334.0,      764.1,       0.000!    !END!
    12 ! X =     -116.0,      336.0,      686.7,       0.000!    !END!
    13 ! X =     -114.0,      326.0,      767.7,       0.000!    !END!
    14 ! X =     -114.0,      328.0,      735.0,       0.000!    !END!
    15 ! X =     -114.0,      330.0,      683.9,       0.000!    !END!
    16 ! X =     -114.0,      332.0,      746.0,       0.000!    !END!
    17 ! X =     -114.0,      334.0,      685.3,       0.000!    !END!
    18 ! X =     -112.0,      326.0,      749.2,       0.000!    !END!
    19 ! X =     -112.0,      328.0,      728.1,       0.000!    !END!
    20 ! X =     -112.0,      330.0,      725.0,       0.000!    !END!
    21 ! X =     -112.0,      332.0,      707.9,       0.000!    !END!
    22 ! X =     -112.0,      334.0,      736.5,       0.000!    !END!
    23 ! X =     -110.0,      326.0,      794.3,       0.000!    !END!
    24 ! X =     -110.0,      328.0,      731.1,       0.000!    !END!
    25 ! X =     -110.0,      330.0,      758.7,       0.000!    !END!
    26 ! X =     -110.0,      332.0,      742.3,       0.000!    !END!
    27 ! X =     -110.0,      334.0,      767.4,       0.000!    !END!
    28 ! X =     -108.0,      324.0,      818.4,       0.000!    !END!
    29 ! X =     -108.0,      326.0,      740.2,       0.000!    !END!
    30 ! X =     -108.0,      328.0,      728.2,       0.000!    !END!
    31 ! X =     -108.0,      330.0,      760.7,       0.000!    !END!
    32 ! X =     -108.0,      332.0,      755.4,       0.000!    !END!
    33 ! X =     -106.0,      324.0,      790.0,       0.000!    !END!
    34 ! X =     -106.0,      326.0,      762.8,       0.000!    !END!
    35 ! X =     -106.0,      328.0,      733.4,       0.000!    !END!
    36 ! X =     -106.0,      330.0,      825.7,       0.000!    !END!
    37 ! X =     -106.0,      332.0,      772.3,       0.000!    !END!
    38 ! X =     -104.0,      324.0,      756  ,       0.000!    !END!
    39 ! X =     -104.0,      326.0,      761.3,       0.000!    !END!
    40 ! X =     -104.0,      328.0,      758.2,       0.000!    !END!
    41 ! X =     -104.0,      330.0,      771.0,       0.000!    !END!
    42 ! X =     -102.0,      324.0,      796.2,       0.000!    !END!
    43 ! X =     -102.0,      326.0,      774.3,       0.000!    !END!
    44 ! X =     -102.0,      328.0,      819.0,       0.000!    !END!
    45 ! X =     -100.0,      324.0,      839.3,       0.000!    !END!
    46 ! X =     -100.0,      326.0,      836.4,       0.000!    !END!
```

```
   101 ! X =    -121.608,    335.052,     777.3,        0.000!   !END!
   102 ! X =    -118.992,    337.441,     771.4,        0.000!   !END!
   103 ! X =    -116.945,    337.384,     734.8,        0.000!   !END!
   104 ! X =    -112.965,    335.621,     728.7,        0.000!   !END!
   105 ! X =    -107.051,    333.744,     746.3,        0.000!   !END!
   106 ! X =    -102.388,    329.593,     770.0,        0.000!   !END!
   107 ! X =    -100.852,    322.428,     853.9,        0.000!   !END!
   108 ! X =    -102.956,    322.371,     850.2,        0.000!   !END!
   109 ! X =    -110.918,    324.760,     750.5,        0.000!   !END!
   110 ! X =    -115.581,    326.352,     752.8,        0.000!   !END!
   111 ! X =    -119.447,    332.550,     765.9,        0.000!   !END!
```

TRNP North Unit Receptors:

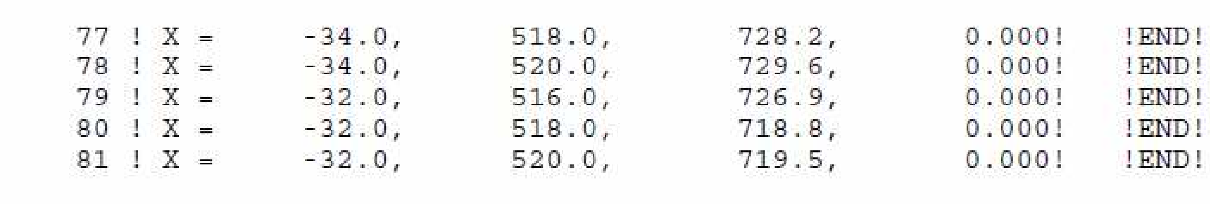
```
    47 ! X =    -108.0,      396.0,       608.7,        0.000!   !END!
    48 ! X =    -108.0,      398.0,       604.3,        0.000!   !END!
    49 ! X =    -108.0,      400.0,       614.6,        0.000!   !END!
    50 ! X =    -108.0,      402.0,       684.0,        0.000!   !END!
    51 ! X =    -106.0,      396.0,       621.5,        0.000!   !END!
    52 ! X =    -106.0,      398.0,       774.0,        0.000!   !END!
    53 ! X =    -106.0,      400.0,       598.2,        0.000!   !END!
    54 ! X =    -106.0,      402.0,       736.4,        0.000!   !END!
    55 ! X =    -106.0,      404.0,       690.9,        0.000!   !END!
    56 ! X =    -104.0,      396.0,       648.7,        0.000!   !END!
    57 ! X =    -104.0,      398.0,       768.0,        0.000!   !END!
    58 ! X =    -104.0,      400.0,       615.3,        0.000!   !END!
    59 ! X =    -104.0,      402.0,       622.0,        0.000!   !END!
    60 ! X =    -104.0,      404.0,       763.1,        0.000!   !END!
    61 ! X =    -102.0,      400.0,       671.9,        0.000!   !END!
    62 ! X =    -102.0,      402.0,       719.8,        0.000!   !END!
    63 ! X =    -102.0,      404.0,       629.9,        0.000!   !END!
    64 ! X =    -100.0,      400.0,       594.8,        0.000!   !END!
    65 ! X =    -100.0,      402.0,       624.6,        0.000!   !END!
    66 ! X =    -100.0,      404.0,       651.3,        0.000!   !END!
    67 ! X =     -98.0,      400.0,       593.7,        0.000!   !END!
    68 ! X =     -98.0,      402.0,       725.3,        0.000!   !END!
    69 ! X =     -96.0,      400.0,       591.2,        0.000!   !END!
    70 ! X =     -96.0,      402.0,       692.3,        0.000!   !END!
    71 ! X =     -94.0,      402.0,       677.4,        0.000!   !END!
   112 ! X =    -107.858,    404.020,     771.2,        0.000!   !END!
   113 ! X =     -98.243,    403.809,     687.9,        0.000!   !END!
   114 ! X =     -94.447,    400.520,     594.6,        0.000!   !END!
   115 ! X =     -98.960,    398.200,     712.1,        0.000!   !END!
   116 ! X =    -100.942,    398.243,     674.5,        0.000!   !END!
   117 ! X =    -109.587,    399.044,     677.7,        0.000!   !END!
   118 ! X =    -109.587,    401.026,     749.2,        0.000!   !END!
```

TRNP Elkhorn Ranch Receptor:

```
    72 ! X =    -122.581,    361.580,     647.7,        0.000!   !END!
```

Lostwood NWA Receptors:

```
    73 ! X =     -36.0,      516.0,       724.9,        0.000!   !END!
    74 ! X =     -36.0,      518.0,       724.4,        0.000!   !END!
    75 ! X =     -36.0,      520.0,       740.4,        0.000!   !END!
    76 ! X =     -34.0,      516.0,       725.0,        0.000!   !END!
```



```
77 ! X =     -34.0,      518.0,      728.2,      0.000!   !END!
78 ! X =     -34.0,      520.0,      729.6,      0.000!   !END!
79 ! X =     -32.0,      516.0,      726.9,      0.000!   !END!
80 ! X =     -32.0,      518.0,      718.8,      0.000!   !END!
81 ! X =     -32.0,      520.0,      719.5,      0.000!   !END!
```

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

June 9, 2006

JUN 2006
Received
Air Quality

Mr. Terry O'Clair, Director
Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, ND 58501-1947

Re: Heskett Unit 2 BART Modeling Refinements

Dear Mr. O'Clair:

This letter is in reference to your letter dated November 30, 2005, in which the Department states our Heskett Unit 2 is subject to BART. Since the modeling results for Unit 2 were under the "causes" impairment level of 1.0 dv, but over the "contributes to" impairment level of 0.5 dv, Montana-Dakota Utilities Co. retained ENSR to evaluate the previous modeling.

In conducting their review, ENSR determined it is appropriate to refine the grid size in the model from 3 km to 1 km and to use the average background visibility to determine the change caused by Unit 2, in accordance with the recently announced EPA court settlement. These changes, even when offset by using speciated particulate matter inputs, consistent with National Park Service guidance, provide model results that are less than the "contributes to" impairment level, thus indicating that Unit 2 does not contribute to visibility impairment and that it is not subject to BART. These model results were based on the currently authorized and permitted allowable emissions from Unit 2.

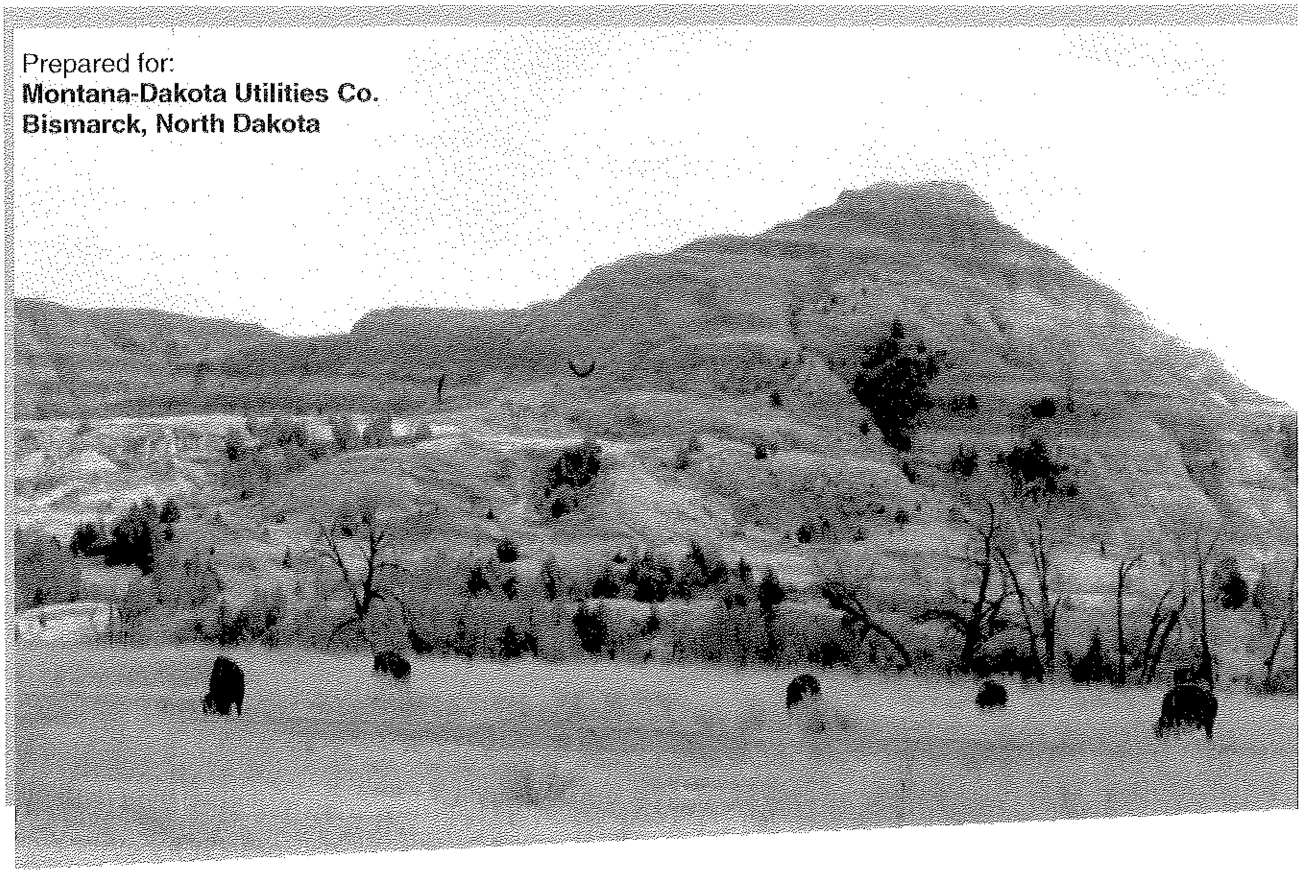
Separately, and as we have previously discussed, Montana-Dakota will nonetheless voluntarily commit to control SO_2 emissions by installing and operating the necessary equipment to use limestone as the bed material in the boiler. Montana-Dakota will agree to include a condition in our Title V permit implementing this change, including a permit shield pertaining to BART applicability. We will be in contact at a later date to discuss the details of the permit modification.

We look forward to your concurrence with the attached refined modeling report and determination that Heskett Unit 2 is not subject to BART. If you have any questions regarding this submittal, please contact Jay Skabo at 222-7835.

Sincerely,

Andrea Stomberg
Vice President – Electric Supply

Prepared for:
Montana-Dakota Utilities Co.
Bismarck, North Dakota

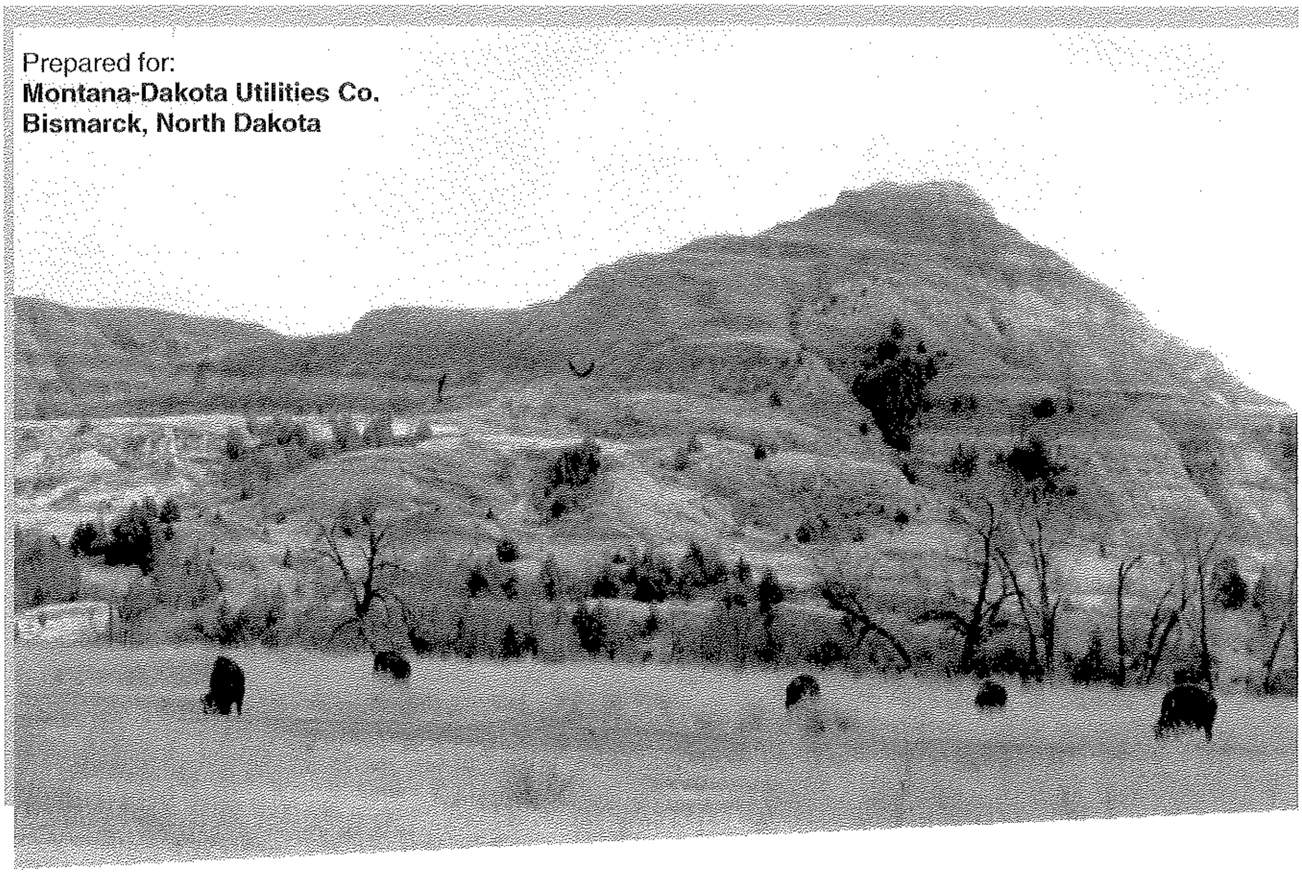


Refined BART CALPUFF Visibility Modeling Analysis for Montana-Dakota Utilities Heskett Station

ENSR Corporation
May 2006
Document No.: 04721-006-400

ENSR | AECOM

Prepared for:
Montana-Dakota Utilities Co.
Bismarck, North Dakota



Refined BART CALPUFF Visibility Modeling Analysis for Montana-Dakota Utilities Heskett Station

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May 2006
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1.0 Introduction

1.1 Background

The North Dakota Department of Health (NDDH) has conducted CALPUFF modeling for emission sources for all BART-eligible facilities in North Dakota. This study focuses upon CALPUFF modeling for one of these facilities, the Heskett Station (specifically, Unit 2). Heskett Unit 1, operational in 1954, has a capacity of 40 MW and is not BART-eligible since if was put into service before 1962. Unit 2, operational in 1963, has a capacity of 75 MW. Unit 2 was retrofitted to a fluidized-bed combustor in 1987.

The NDDH has provided information regarding CALPUFF modeling they conducted to determine whether the Unit 2 at the Heskett Station is subject to BART. Some of these predicted visibility impacts exceed the 0.5 deciview (dv) threshold for "contributing to impairment" at the Theodore Roosevelt National Park and the Lostwood Wilderness Area, as noted in EPA's final BART rule published on July 6, 2005. The results are discussed in Section 3.0 of this report.

Recently, EPA has announced a court settlement agreement regarding BART that allows each state to use the annual average background visibility instead of the best 20% days' background visibility. This change occurred because the actual BART rule (published in the July 6, 2005 *Federal Register*) stipulated that the annual average background visibility value should be used, while the preamble was inconsistent and mentioned that the 20% best days' background visibility should be used.

For this analysis, ENSR conducted additional CALPUFF modeling with three appropriate refinements to the analysis conducted by the NDDH, as described below. This report documents the results of this modeling analysis.

1.2 Elements of the Refined Analysis

The three refinements that ENSR has considered in this alternative modeling analysis are summarized below.

- In the generation of the wind field, we have increased the grid resolution by a factor of 3 in the x and y directions by reducing the grid size from 3 km to 1 km. To make the runs manageable, we have set the modeling domain extent to 50 km beyond the modeled source and PSD Class I areas.
- To be consistent with other refined BART analyses, we have used guidance from the National Park Service on the speciation of particulate matter emissions into several components that have different light scattering potential: coarse matter, inorganic fine matter, elemental carbon, sulfuric acid mist, and organic aerosol fine particulate.
- In accordance with a recent EPA announced court settlement, we used the annual average background visibility to determine the change in visibility caused by the BART-eligible source under consideration.

The BART analysis modeling refinements are discussed in more detail in Section 2. The results of the new modeling runs and conclusions are presented in Section 3. References are provided in Section 4.

2.0 BART Analysis Refinements

Three refinements have been made by ENSR to the CALMET/CALPUFF modeling conducted by the NDDH for the BART determination for the Heskett Station Unit 2. Otherwise, the same CALMET and CALPUFF model versions used by the NDDH have been used in this modeling. The first step in the ENSR modeling was to replicate the results obtained by the NDDH with the modeling files and executable files that were supplied to ENSR. This step was completed satisfactorily.

2.1 Meteorological Processing with CALMET

One of the ENSR refinements involves the use of a 1-km grid size instead of the 3 km used by the NDDH. The digital terrain data used for this analysis consisted of 1-degree data (90-meter resolution). This change has the effect of better terrain and land use resolution for the CALPUFF modeling. No other changes to the CALMET processing from that which the NDDH did were made, except that the total grid domain was slightly reduced (to save on disk space) to provide a 50-km buffer around the source modeled as well as the PSD Class I areas. Figure 2-1 shows the modeling domain that ENSR used.

2.2 Particulate Matter Speciation

The National Park Service has issued guidance on how to divide, or speciate, particulate matter emissions into different constituents that have different light scattering EPA potential: coarse matter, inorganic fine matter, elemental carbon, sulfuric acid mist, and organic aerosol fine particulate. The guidance is located at http://www.vistas-sesarm.org/BART/calpuff.asp on the VISTAS regional planning organization web site. While NDDH did not include this guidance in its BART screening protocol, ENSR believes it is obligatory it be included in this analysis, even though it results in modeling higher visibility impacts.

Engineers from Montana-Dakota Utilities reviewed these speciation profiles and selected the data for a dry bottom PC with FGD and ESP controls spreadsheet as the most representative of the emissions from Heskett Unit 2. A series of Method 8 stack tests conducted August 24 – 26, 2000 found an average H_2SO_4 rate of 9.0 lb/hr (2.9 ppm) at full load. The resulting emissions used in the CALPUFF regional haze modeling are listed in Table 2-1. To simplify the modeling, the coarse and fine inorganic matter were combined as fine matter, which has a slightly higher visibility extinction efficiency than coarse matter.

Table 2-1 Heskett Unit 2 emissions data for refined BART modeling

Component	Emission Rate (lb/hr)
SO_2	1475.5
NO_2	227.5
Coarse matter	8.2
Inorganic fine matter	6.3
Elemental carbon	0.2
H_2SO_4	9.0
Organic aerosols	2.0

ENSR input file shows 302.8 for NO_x emission rate, which is correct

2.3 Natural Background Determination

The EPA final BART rule is ambiguous regarding the appropriate statistic to be used for the natural background level in deciviews. While the BART rule text indicates that the average annual value should be used, the preamble to the rule indicates that the best 20% days' value should be used. After the rule was published, EPA tried to clarify this issue and state that the best 20% days' value was actually intended. However, the Utility Air Regulatory Group challenged this interpretation in court. EPA has proposed a settlement to the litigation that indicates that each state can select either option. The NDDH has indicated that it is permissible for sources to use the annual average background visibility. The concentrations used in the CALPUFF input for the speciated particulate that contribute to visibility impairment are listed in Table 2-2, consistent with Table 3-7 in the NDDH final BART modeling protocol.

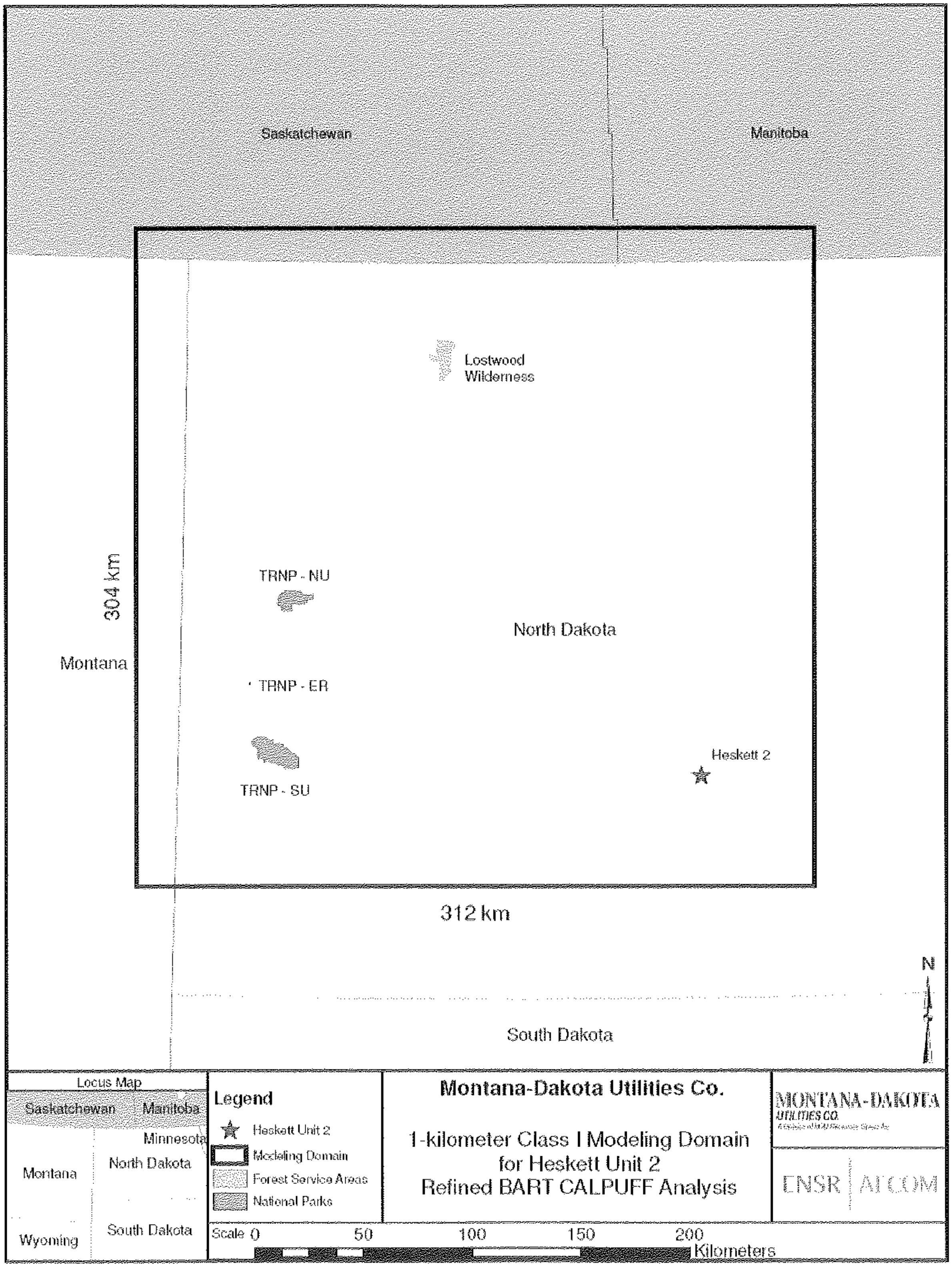
Table 2-2 Natural levels of aerosol components (μg/m³)

Component	Annual Average West Region(1)	20% Best Days Theodore Roosevelt NP	20% Best Days Lostwood NWA
Ammonium sulfate	0.12	0.048	0.049
Ammonium nitrate	0.10	0.040	0.041
Organic carbon mass	0.47	0.189	0.190
Elemental carbon	0.02	0.008	0.008
Soil	0.50	0.202	0.203
Coarse mass	3.00	1.209	1.215
Natural deciview(2)	-	2.19	2.21

(1) From "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" (EPA, 2003), Table 2-1.

(2) From "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" (EPA, 2003), Appendix B.

Figure 2-1 Modeling domain for 1 kilometer grid



3.0 Refined BART Analysis Results and Conclusions

A comparison of the NDDH and ENSR results are shown in Table 3-1. The results indicate that for all years tested, the ENSR refined BART modeling results indicate that all 98th percentile predictions of the change in visibility are below 0.5 deciviews.

Table 3-1 Comparison of NDDH BART results and ENSR BART results

NDDH BART Results (3-km grid, best 20% days' background, no PM speciation)	98th Percentile Change in Visibility			
	TRNP South	TRNP North	TRNP Elkhorn Ranch	Lostwood NWA
2000	0.350	0.355	0.381	0.346
2001	0.351	0.536	0.400	0.583
2002	0.822	0.496	0.606	0.457
ENSR BART Results (1-km Grid, annual average background, with PM speciation)	98th Percentile Change in Visibility			
	TRNP South	TRNP North	TRNP Elkhorn Ranch	Lostwood NWA
2000	0.201	0.267	0.217	0.278
2001	0.209	0.347	0.223	0.436
2002	0.428	0.397	0.388	0.224

Based upon these results, we conclude that upon verification of the modeling results by the NDDH, the Heskett Station Unit 2 does not cause or contribute to visibility impairment, and thus is not subject to BART.

4.0 References

Environmental Protection Agency, 2003b: Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule. EPA-454/B-03-005. U.S. Environmental Protection Agency, Research Triangle Park, NC.

North Dakota Department of Health. November 2005. Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final). North Dakota Department of Health, Division of Air Quality,1200 Missouri Avenue, Bismarck, ND

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May 8, 2007

FILE

Ms. Abbie Krebsbach
Environmental Manager
Montana Dakota Utilities
400 N Fourth Street
Bismarck, ND 58501

Re: Heskett Unit 2 BART Applicability

Dear Ms. Krebsbach:

The Department has reviewed the modeling analysis for the Heskett Station Unit 2 that was submitted June 9, 2006. The modeling analysis was conducted to determined the effect Unit 2 has on visibility in the Class I areas of North Dakota. This modeling analysis indicates that Unit 2 has an impact on visibility impairment of less than 0.5 deciviews.

On December 12, 2006, the Department and Montana Dakota Utilities (MDU) met to discuss the modeling analysis and proposed sulfur dioxide reductions at Heskett Unit 2. On December 27, 2006 we received a letter from MDU which outlined commitments stated at the December 12, 2006 meeting. From that meeting and the letter, it is the Department's understanding that MDU has committed to reduce sulfur dioxide emissions from Heskett Unit 2 by at least 70% on a 30-day rolling average basis (coal-to-stack) by the end of 2013. In addition, it is our understanding that Montana-Dakota Utilities has committed to conduct an optimization study to determine the removal efficiency due to limestone injection into the bed. The optimization study will be utilized to determine an enforceable reduction efficiency for Heskett Station Unit 2; however, removal efficiency shall not be less than 70%.

Based on the results of the modeling analysis and our understanding of Montana Dakota Utilities commitments regarding sulfur dioxide control from Heskett Unit 2, the Department has determined that Best Available Retrofit Technology (BART) requirements are not applicable to Heskett Unit 2.

If you have any questions, please feel free to contact me.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TAB:saj

Comments on EPA Region 8 and FLM Concerns Regarding BART Exemption Modeling for Montana-Dakota Utilities Company's R.M. Heskett Station Unit 2: August 2009 Update

Robert Paine
AECOM Environment (formerly ENSR)
Westford, MA
August 12, 2009

Introduction

In 2006, Montana Dakota Utilities Co. (Montana-Dakota) asked ENSR (now AECOM) to review the results of the North Dakota Department of Health (NDDH's) 2005 Best Available Retrofit Technology (BART) CALPUFF modeling analysis of Unit 2 at the R.M. Heskett Station to determine whether there were any aspects of the modeling procedures that should be refined to make the modeling results more accurate. In addition to utilizing annual average background visibility instead of the best 20% days' background visibility in the model, ENSR found two additional areas of refinement.

First, and in accordance with EPA's CALPUFF modeling "Frequently Asked Questions" and EPA guidance on resolving terrain features, ENSR decreased the horizontal grid spacing in the model from 3 km to 1 km. Use of the 1-km grid spacing for modeling the projected visibility impacts of Unit 2 is supported by both the intervening complex terrain and the proximity of R.M. Heskett Station to the Class I areas of concern. The effect of using the finer grid spacing over the three years modeled at the Class I areas ranged from a slight increase in visibility impacts to about a 40% decrease. Since the smaller grid size forces a smaller step change in the CALPUFF model and a better representation of causality effects, the 1-km grid size improved upon independent NDDH CALPUFF evaluations that show an overprediction tendency in the range of 50-70% relative to observed 24-hour concentrations in the Theodore Roosevelt National Park with the use of a 3-km grid spacing.

Second, since the NDDH modeling did not consider speciation of PM_{10} emissions, ENSR introduced a PM_{10} speciation input into the CALPUFF modeling in accordance with technical advice provided by other BART protocols, which had the effect of increasing the predicted impacts because the added species have a larger extinction efficiency than the model default for "soils" used by NDDH.

Application of the available refinements to the CALPUFF BART modeling for Heskett Unit 2 showed a worst-year 98th percentile deciview change from background of 0.421 at Theodore Roosevelt National Park and 0.399 at the Lostwood Wilderness Area. These values are below the 0.5 dv threshold which is used to determine if a BART-eligible source is contributing to regional haze at a Class I area. NDDH therefore concluded that Heskett Unit 2 is not a BART-subject source.

One additional area of refinement that was not available in the CALPUFF modeling system until 2008 was the ability to use the new IMPROVE equation, which is a more accurate method to convert the predicted particulate concentrations into visibility impairment. ENSR's experience with this new method is that it typically reduces the visibility impairment for emissions sources such as power plants in the range of 20-30%. The availability of this method would have further reduced the modeled visibility impact of Heskett Unit 2 over that which was reported to the NDDH in 2006. Therefore, the ENSR-reported visibility impact is overly conservative.

By letter to NDDH dated August 4, 2008, EPA Region 8 expressed concerns regarding the use of 1-km grid spacing in the Heskett Unit 2 BART exemption modeling analysis, although the ENSR modeling report did provide a discussion justifying the grid spacing selection. These comments provide an updated technical justification for the use of finer grid spacing.

Summary Background

In 2005, NDDH conducted CALPUFF modeling for emission sources at several BART-eligible facilities in North Dakota. One of these sources was Unit 2 at the R.M. Heskett Station (Heskett). This unit became operational in 1963 with a capacity of 75 MW, and was retrofitted to a fluidized-bed combustor in 1987.

The NDDH conducted initial CALPUFF modeling to determine whether Unit 2 at Heskett is subject to BART. The NDDH's CALPUFF modeling, which was provided to Montana-Dakota, indicated that baseline emissions impacts would result in a visibility impact of 0.82 deciviews (dv) at the Theodore Roosevelt National Park (TRNP) and 0.58 at the Lostwood Wilderness Area (LWA). These predicted visibility impacts exceed the 0.5 dv threshold for “contributing to impairment” as noted in the United States Environmental Protection Agency's (EPA's) final BART rule published on July 6, 2005 (70 Fed. Reg. 39104). This determination was based upon the use of the 20% best days' background visibility and the use of a 3-km grid spacing in CALMET and CALPUFF.

Subsequent to that modeling exercise, EPA announced a court settlement regarding BART that allows each state to use the annual average background visibility instead of the best 20% days' background visibility. This change occurred because the final July 6, 2005 BART rule stipulated that the annual average background visibility value should be used, while the preamble was inconsistent and mentioned that the 20% best days' background visibility should be used. NDDH elected to adopt a policy to use the annual average option for determining the results of BART exemption modeling analyses. This change alone resulted in a nearly 25% reduction of visibility impacts, adjusting the results at LWA to be below the 0.5 delta-dv threshold. The adjusted results at TRNP were also lower, but still above the 0.5 delta-dv threshold.

In 2006, Montana-Dakota asked ENSR to review the results of NDDH's CALPUFF modeling analysis and to determine whether there were any aspects of the modeling procedures that should be changed or refined to make the modeling results more accurate. ENSR found two areas for such refinement (in addition to the selection of the background metric mentioned above). These included the following:

1) In accordance with EPA's CALPUFF modeling “Frequently Asked Questions” and EPA guidance on resolving terrain features, ENSR decreased the horizontal grid spacing in the model from 3 km to 1 km. The effect of the finer grid spacing over the three years modeled at the various Class I areas (LWA and three units of TRNP) ranged from a slight increase in visibility impacts to about a 40% decrease in some cases.

2) Since the NDDH modeling did not consider speciation of PM_{10} emissions, ENSR introduced a PM_{10} speciation input into the CALPUFF modeling in accordance with technical advice provided by other BART protocols such as the VISTAS BART protocol, available at http://www.vistas-sesarm.org/documents/BARTModelingProtocol_rev3.2_31Aug06.pdf, and PM_{10} speciation guidance from the Federal Land Managers available at a link on the VISTAS web site (http://www.vistas-sesarm.org/BART/calpuff.asp). This change to the model increased the predicted impacts because the added species have a larger extinction efficiency than the “soils” used by NDDH.

The result of the refinements to the CALPUFF BART modeling for Heskett Unit 2 was a worst-year 98th percentile deciview change from background of 0.421 at TRNP and 0.399 at LWA. These values are below the 0.5 dv threshold which is used to determine if a BART-eligible source is contributing to regional haze at a Class I area. NDDH therefore concluded that Heskett Unit 2 is not a BART-subject source.

Since the selection of background visibility and a more conservative treatment of PM_{10} speciation are consistent with NDDH policy, the comments below relate to the selected grid spacing refinement ENSR employed.

It is noteworthy to consider that a third refinement, the use of the new IMPROVE equation, was not available to ENSR in 2006, but is now available as "Method 8" in CALPOST and is recognized now as an approved technique by the Federal Land Managers (see slide 4 of the presentation at http://www.cleanairinfo.com/regionalstatelocalmodelingworkshop/archive/2009/presentations/04%20Weds%20AM/RSL-FLM-05-13-09E.pdf). ENSR's experience with this more accurate method is an expected substantial decrease in the visibility impairment that is not reflected in the modeling analysis conducted in 2006.

EPA and FLM concerns with the CALPUFF Grid Spacing Issue

NDDH received a letter dated August 4, 2008 from EPA Region 8 in which the agency expressed some concern regarding the process for exempting Heskett Unit 2 from BART. In the letter, EPA stated:

> "We have concerns with ENSR's CALPUFF modeling. They reduce the CALMET/CALPUFF grid size from 3 km to 1 km. EPA has recently seen data indicating that CALPUFF may inappropriately reduce predicted concentrations with such grid size manipulation…Given that ENSR's refined results move Heskett from "subject-to-BART" to "exempt", a more robust discussion is necessary regarding why NDDH found ENSR's analysis "acceptable," including an explanation of why you think this approach will not lead to underestimates of visibility impacts."

EPA's statement that "grid size manipulation" may inappropriately reduce predicted concentrations is inaccurate. The grid size adjustment that ENSR employed follows EPA guidance regarding recommended resolution of terrain features, as noted below, and it improves CALPUFF's accuracy in addressing terrain feature interactions. The latter point is supported, in particular, by CALPUFF's developer as well as by Mr. Clint Bowman of the Washington Department of Ecology, each of whom conclude that grid size reductions are technically valid and improve the accuracy of CALPUFF modeling.

EPA Model Clearinghouse Memorandum

On May 15, 2009, EPA's Model Clearinghouse ruled on the Big Stone Unit 1 BART case (South Dakota) in which the use of a 1-km grid was questioned by EPA Region 8. In a February 24, 2009 letter to the Model Clearinghouse, EPA Region 8 questioned the use of a 1-km grid for a long distance plume travel (400 km) and relatively flat terrain. EPA Region 8 therein stated its support for the use of 1-km and even smaller grid spacing in areas where complex terrain would affect plume dispersion because the "higher resolution at these distances will better characterize terrain effects and local scale meteorology." However, for the Big Stone case under consideration which lacked complex terrain and which involved multiple-day transport, EPA Region 8 suggested that a 4-km grid spacing for a BART analysis would be supportable.

In their May 15, 2009 reply, the EPA Model Clearinghouse concurred with EPA Region 8's position on the grid spacing issue. The Model Clearinghouse noted that the modeling analysis documentation did not adequately justify the need for the finer grid resolution. They also recommended that prognostic meteorological data sets should have adequate evaluation.

The BART modeling for Heskett Unit 2 differs significantly from the Big Stone case because: (a) the Heskett case involves complex terrain with features that require a 1-km grid resolution (not flat terrain); and (b) plume travel distances from Heskett to the Class I areas at issue (LWA and three units at TRNP) are much less than 400 km, such that the plume-terrain interaction is more important to simulate correctly. Because the reduced grid size forces a smaller step change in the model and a better representation of causality effects, the 1-km grid improves on independent NDDH CALPUFF evaluations that show an overprediction tendency in the range of 50-70% relative to observed 24-hour concentrations from use of 3-km grid spacing. In addition, the NDDH has thoroughly researched and studied the Rapid Update Cycle (RUC) prognostic meteorological data being used for the BART analysis. This data set was also used previously for SO_2 increment modeling using CALPUFF and was accepted after a national review of this modeling application.

Appropriate CALMET/CALPUFF Grid Size: Response to Comments

EPA provides guidance for the selection of the CALPUFF grid size in the “Frequently Asked Questions” area on the TRC CALPUFF web site (available at http://www.src.com/calpuff/FAQ-answers.htm#2.1.4). The text of this guidance states the following:

> ***2.1.4 How will I know whether my terrain elevation data is sufficiently resolved (i.e., small enough grid size) for my specific application?***
>
> *In making CALMET and CALPUFF modeling runs, the goal is to find the optimum balance between the desire to make the grid size as large as feasible in order to reduce the run times and file sizes, and the desire to make the grid size small enough that CALMET can characterize the terrain effects on the wind field. The optimum grid spacing for a particular application will depend on the size of the modeling domain and the complexity of the terrain within the domain.*
>
> *There are some obvious checks one can make. For instance, if your application involves some terrain features (hills, valleys, etc.), CALMET needs to have as least 5 (preferably 10) grids to resolve each terrain feature. So if you have a valley of particular interest that is typically 5 km wide, one might like to have a grid spacing of 0.5 to 1-km terrain and land-use data.*
>
> *Graphical analyses may also prove helpful. Consider the following sequence to develop three graphical analyses: 1) contour the gridded data at what you think will be your final resolution, say 2-km; 2) shift the origin of the grid by ½ of the grid scale (left or right, up or down), re-grid the data using twice the original grid scale, and contour the terrain heights, and 3) using the same grid origin as in the second case, re-grid the data using ½ the original grid scale as in the first case, and contour the terrain heights. Compare the three plots to see how terrain features are 'appearing' and 'disappearing', and decide whether you are comfortable with your original grid scale. One could repeat these three steps using a different initial grid scale, but we should also remember that these results are subjective in nature, so try not to over-engineer this analysis. Common sense and experience should prevail.*

The key aspect of this guidance is that CALMET needs to have at least 5 grid elements to adequately resolve terrain features. The terrain features within the TRNP South Unit are depicted in Figures 1 and 2. Figure 1 is included since it better represents the actual terrain features of TRNP, while Figure 2 depicts the actual park boundaries more accurately. Two typical areas are circled in both figures as examples of terrain features that are on the order of 5 km or less in size. This implies that a grid spacing as large as 3 km would excessively smooth out these terrain features. In compliance with the guidance provided by EPA through the TRC website’s Frequently Asked Questions, ENSR used a 1-km grid spacing for the CALPUFF modeling to improve the accuracy of the model.

We also note that EPA Region 8 has indicated its support of the use of 1-km grid spacing or even smaller for applications with complex terrain and without long travel distances. In the case of Heskett Unit 2 and Theodore Roosevelt National Park (TRNP), virtually the entire North Unit has elevations above the Unit 2 stack top, and the terrain relief within the park exceeds 220 meters (720 feet). The distance to TRNP is less than 200 km, which is well within a distance that could be covered during nocturnal travel (12 hours at 5 m/s at plume level) in which the plume would stay relatively compact and significantly interact with the complex terrain at TRNP. The use of the 1-km grid spacing for the Heskett Unit 2 analysis therefore supplies higher resolution and better characterize terrain effects and local scale meteorology to improve the objective accuracy of the CALPUFF predictions.

In addition to this guidance, the following e-mail exchange between Robert Paine of ENSR and Joe Scire of TRC (the CALPUFF model developer) further establishes the scientific credibility of using the 1-km rather than the 3-km grid spacing.

> From: Scire, Joseph [mailto:JScire@TRCSOLUTIONS.com]
>
> Sent: Wednesday, January 10, 2007 2:32 PM
>
> To: Paine, Bob
>
> Subject: RE: issue of finer grid spacing in CALMET
>
> Bob,
>
> Generally, if CALMET is using a smaller grid spacing than MM5, it should be able to pick up terrain effects that MM5 does not see, and therefore improve the quality of the wind fields. The grid resolution of MM5 should not limit what is used in CALMET. This was tested in the Wyoming project and it was shown that the winds using CALMET at finer resolution produced the channeling that MM5 missed.
>
> Also, another advantage of finer grid resolution in CALMET is the ability to characterize the land use data in a more detailed way.
>
> Joe

Figure 1: Terrain Features within Theodore Roosevelt National Park, South Unit

Note: the southern boundary depicted on this figure may not be accurate, but the purpose of this map is to show the terrain features within the park.

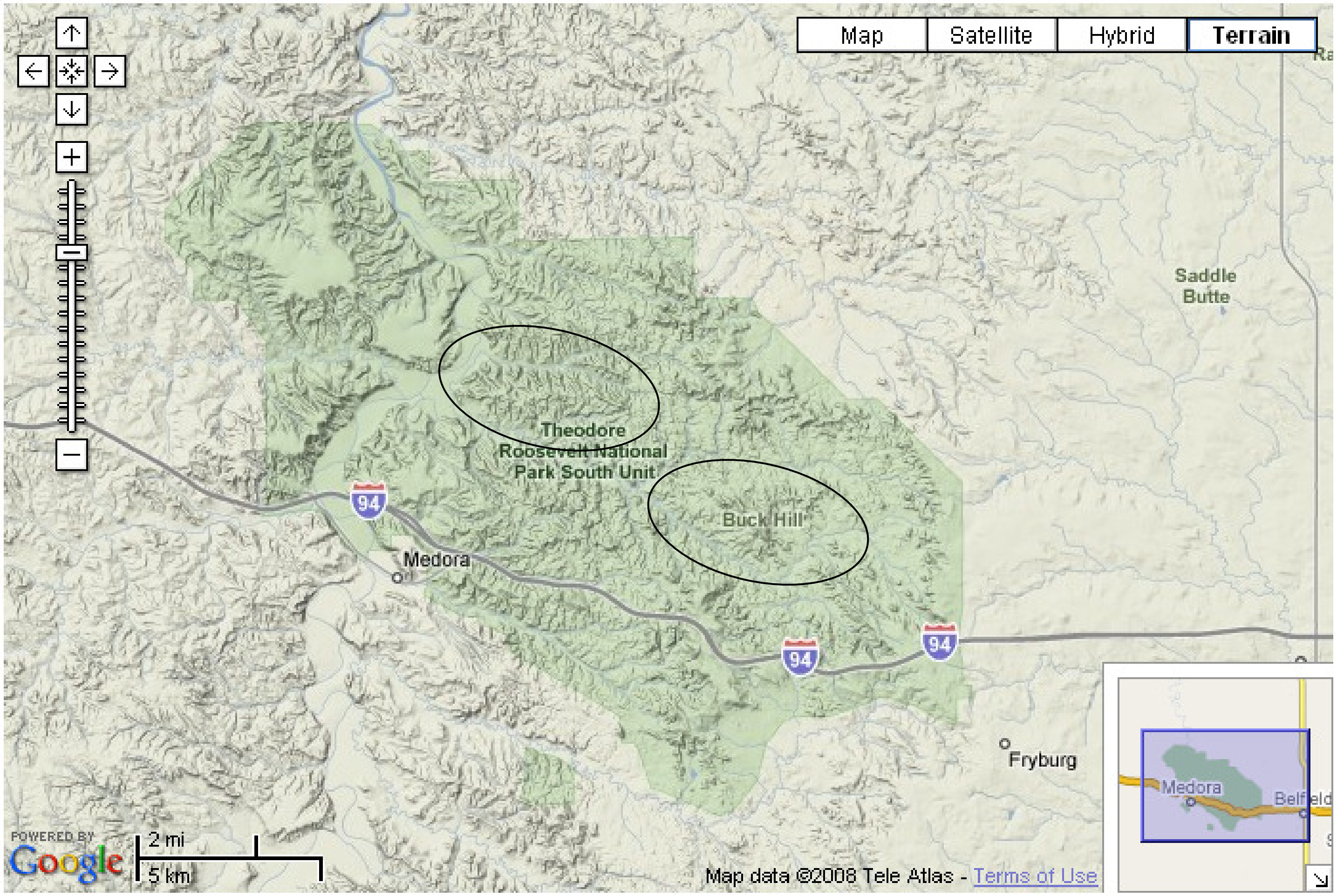
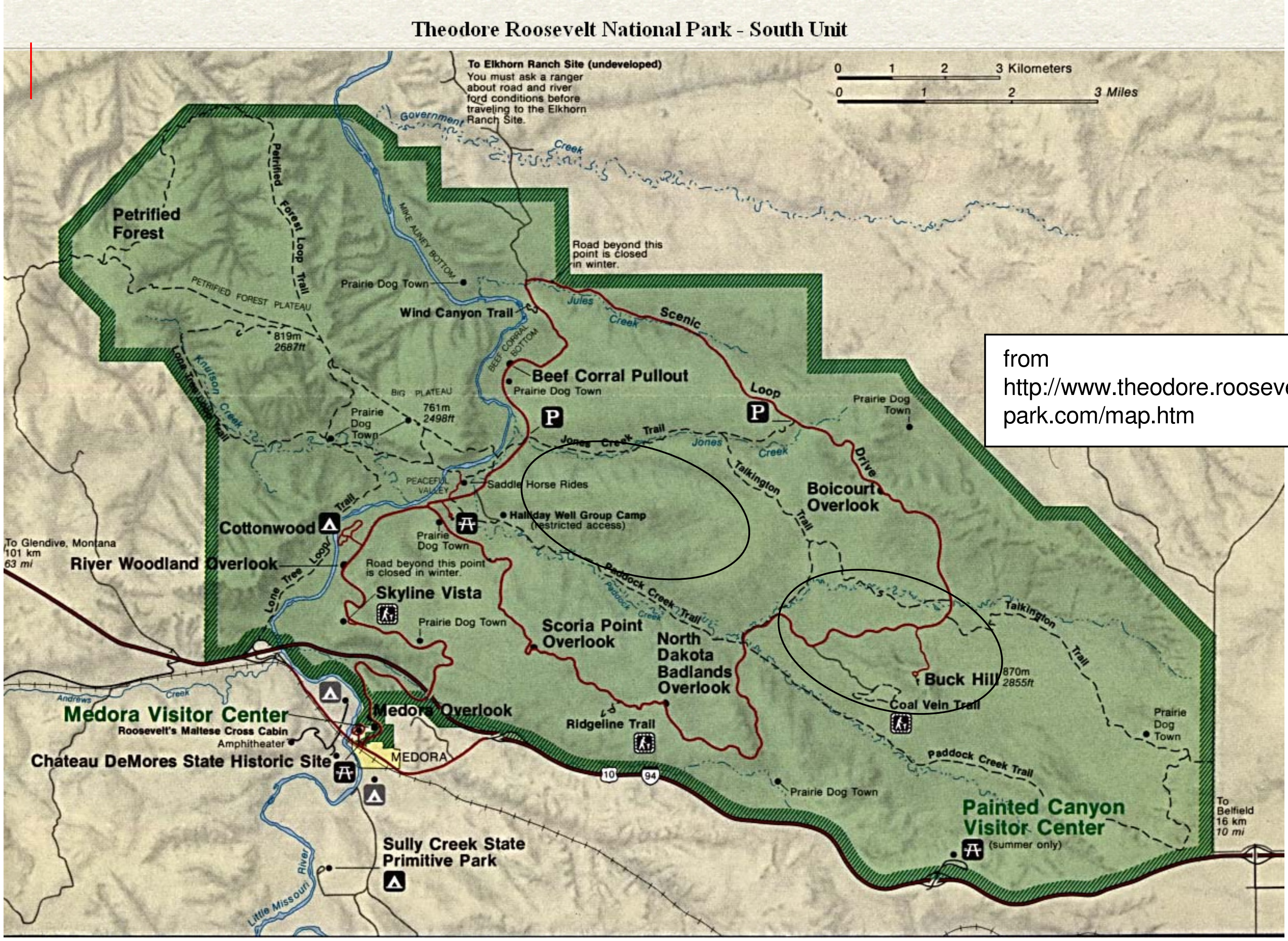


Figure 2: Terrain Features within Theodore Roosevelt National Park, South Unit (alternative map)



from http://www.theodore.roosevelt.national-park.com/map.htm

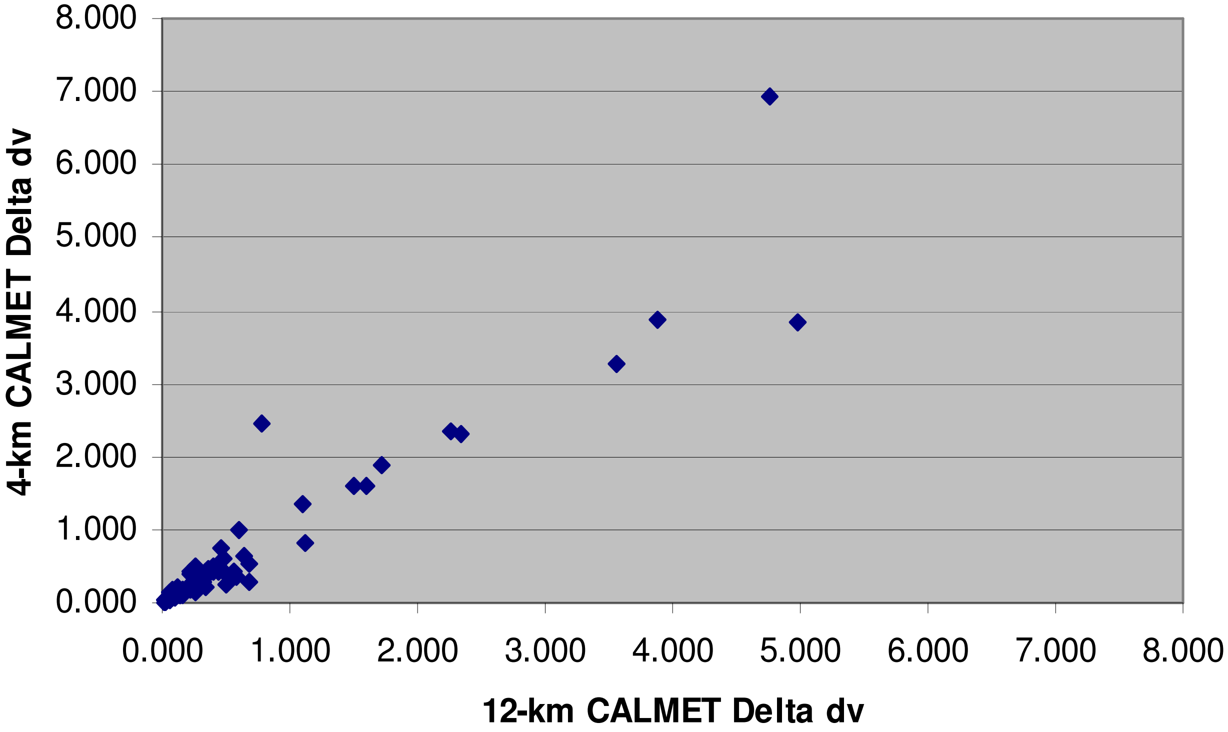
CALPUFF Modeling Bias Introduced by Smaller Grid Size?

Recently, the FLMs have suspected that lower CALPUFF predictions are routinely generated by smaller grid spacing. We surmise that this is why it is referred to in the August 4, 2008 EPA Region 8 letter to NDDH as a “grid size manipulation”. ENSR recently discussed this issue with Tim Allen of the Fish & Wildlife Service. According to Mr. Allen, his discussions in 2008 with Joe Scire indicated that the use of a finer grid spacing was neutrally biased in providing either lower or higher CALPUFF impacts.

A similar communication from Joe Scire on this issue, dated September 25, 2008, indicates that the smaller grid size would generally not be expected to introduce a routine bias in the modeling results for a large sample of modeling applications. Excerpts from Scire’s communication are provided below.

> *In CALPUFF, when using finer resolution, the model will provide a better representation of the terrain (higher peaks, lower valleys more closely representing the actual terrain), land use (higher resolution of land use variability), coastlines (a better representation of the actual land-water variation), wind flow adjustments caused by terrain (i.e., terrain channeling and slope flows) and other things too. A smaller grid size forces a smaller time step in the model and this can give a better representation of causality effects in the model.*
>
> *Regarding the issue that finer resolution always gives lower modeling predictions, this is clearly not the case. A summary of VISTAS modeling results for 26 sources at 90 source-Class I area combinations conducted previously by TRC shows this [see Figure 3]. Of the 90 cases, 47 cases showed higher max impact results with the finer grid resolution and 43 cases showed higher impacts with the coarse grid resolution. Given this result, using a fine resolution for selected Class I areas and coarse resolution for others (i.e., picking whichever produces the lower results) would probably not be deemed acceptable, since it is hard to argue the finer resolution result is better only in the cases when it produces lower impacts.*
>
> *In any given situation there may be valid reasons why the changes might be skewed more in one direction or the other, but the conclusion that finer grid resolution always decreases concentrations is not correct. As one example, coarse resolution that raises the valley floor in the model and lowers the peaks might make the flow at plume height completely different than a higher resolution run that lowers the stack base ground elevation and increases the peak elevations which may result in the plume being within the valley walls and thus subject to channeling effects. The higher resolution simulation might channel the plume into a Class I area, resulting in higher impacts, or transport it away from a Class I area and produce lower impacts (depending on where the source and Class I area are located). I’ve seen examples of both types of situations. In both cases, it could be argued the finer resolution results are more appropriate, whether they are higher or lower. But the details of the situation determine the nature of the response in the model and it will not always be the same.*

Figure 3: Comparison of Maximum Visibility Impact Predictions for Two CALPUFF Grid Sizes



In another study of the effects of grid spacing on CALPUFF results, Mr. Clint Bowman of the Washington Department of Ecology conducted a sensitivity study and presented it at EPA's 2008 modeling workshop. Bowman tested grid spacing ranging from 100 m to 12 km. He found that smaller grid size could lead to somewhat lower modeled impacts. His basic points were as follows:

- the primary effect of the finer grid spacing is to improve the terrain resolution, and this will improve the model accuracy;
- the finer grid spacing does not materially alter the peak impact location or time period;
- large grid spacing leads to artifacts in wind fields which will degrade model accuracy, while the accurate depiction of terrain-induced drainage flow is more realistic with small grid spacing; and
- the effect of slightly lower modeled impacts for a more accurate model setup with a smaller grid size is not confined to CALPUFF, but it is common to other models as well.

As ENSR has noted in various technical presentations, the issue of how grid spacing affects terrain resolution is important because there are model receptors on real terrain features (i.e., sharp peaks) that are not known to CALMET if the terrain is overly smoothed out with a coarse grid treatment. In the case of grid spacing less than the EPA recommendations noted above, the actual terrain height is provided to CALPUFF in the receptor information, but a lower hill height is presented to CALMET for the same area for purposes of wind flow adjustments. This can result in an incorrect depiction of the wind flow because it responds to the terrain information provided to CALMET. Therefore, with a smoothed version of the terrain, CALPUFF could inaccurately simulate artificial plume impacts for ground-level receptors that appear to be "flagpole" receptors relative to the terrain presented to CALMET if a coarse grid is used.

NDDH CALPUFF Evaluation

As part of the modeling analyses conducted by the NDDH on the SO_2 PSD increment question for Class I areas in North Dakota, the NDDH compared CALPUFF and available monitors with 2002 hourly emissions data from major EGUs, including Heskett Unit 2. The TRNP monitor available in 2002 was at the North Unit, for which a terrain map is shown in Figure 4. Terrain features of a size similar to that of the South Unit are present in the North Unit, justifying a grid spacing of 1 km as a more appropriate choice rather than 3 km.

The NDDH documentation of the CALPUFF model evaluation results are provided at http://www.ndhealth.gov/AQ/Dockets/Responses%20to%20Recuring%20PSD%20Issues/Responses%20to%20Recurring%20PSD%20Issues%20-%20Part%205.pdf, which involves a report of recurring issues involving the PSD increment modeling in PSD Class I areas. The NDDH analysis used more than one meteorological database, but the use of the Rapid Update Cycle (RUC) data is most closely related to the BART modeling. The results of the comparison of modeled to monitored (with a nominal background of 1.5 $\mu g/m^3$ added; Figure 23 of the NDDH report) are reproduced in Figure 5.

The relevant results, taken from the solid blue line labeled “RUC + 1.5”, indicate that the CALPUFF model as applied by the NDDH (which used a 3-km grid spacing) generally overpredicts the observed concentrations in a range of 50-70% for the peak few values. Since that margin is comparable to or exceeds the reduction in impacts obtained from reducing the grid size from 3 km to 1 km, we conclude that the smaller grid spacing would result in a better performing and more accurate CALPUFF model that still shows an overprediction tendency.

Conclusions

The initial BART modeling for Heskett Unit 2 was conducted by NDDH and it showed visibility impacts above the BART exemption threshold of 0.5 delta-dv. The EPA settlement with regard to the use of the annual average background resulted in one of the model refinements ENSR subsequently employed upon evaluation of the NDDH CALPUFF modeling. Further refinements that resulted in adjustments toward both higher and lower concentrations were applied by ENSR in two areas: (1) a finer grid spacing; and (2) the use of PM_{10} speciation, which NDDH did not use and which increased predicted visibility impacts. ENSR was not able to use a third refinement that later became available in 2008 (the new IMPROVE equation) which ENSR expects from nationwide modeling experience would have further reduced the predicted visibility impact of Heskett Unit 2.

Use of the finer grid spacing is technically justified by both the intervening complex terrain and the proximity of R.M. Heskett Station to the Class I areas. The finer 1-km grid spacing resulted in a change in impacts ranging from a slight increase to a reduction of about 40% from the 3-km spacing results. It also improved upon independent NDDH CALPUFF evaluations showing an overprediction tendency in the range of 50-70% relative to observed 24-hour concentrations with the use of 3-km grid spacing. It is evident that the use of a finer grid provides better CALPUFF accuracy and performance, still with an overall slight overprediction tendency.

For all of the reasons stated above, the concerns of the EPA and FLMs regarding the ENSR CALPUFF BART analysis have been addressed. The use of the 1-km grid will provide improved accuracy for the CALPUFF predictions. The BART exemption analysis shows that the Heskett Unit 2 regional haze impact would be below the BART contribution threshold of 0.5 delta-dv at TRNP and LWA even with the use of the old IMPROVE equation.

Figure 4: Terrain Features within Theodore Roosevelt National Park, North Unit

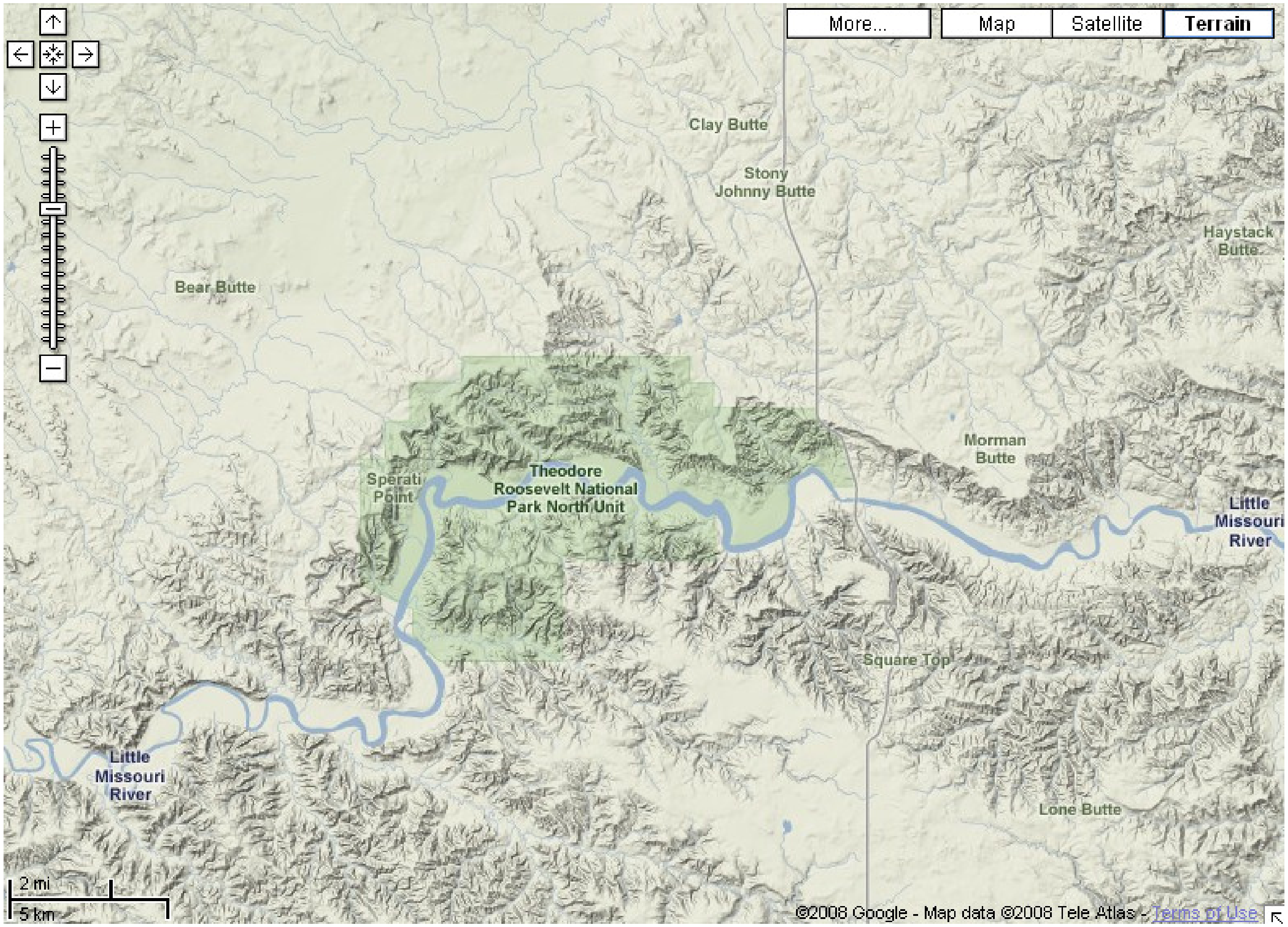
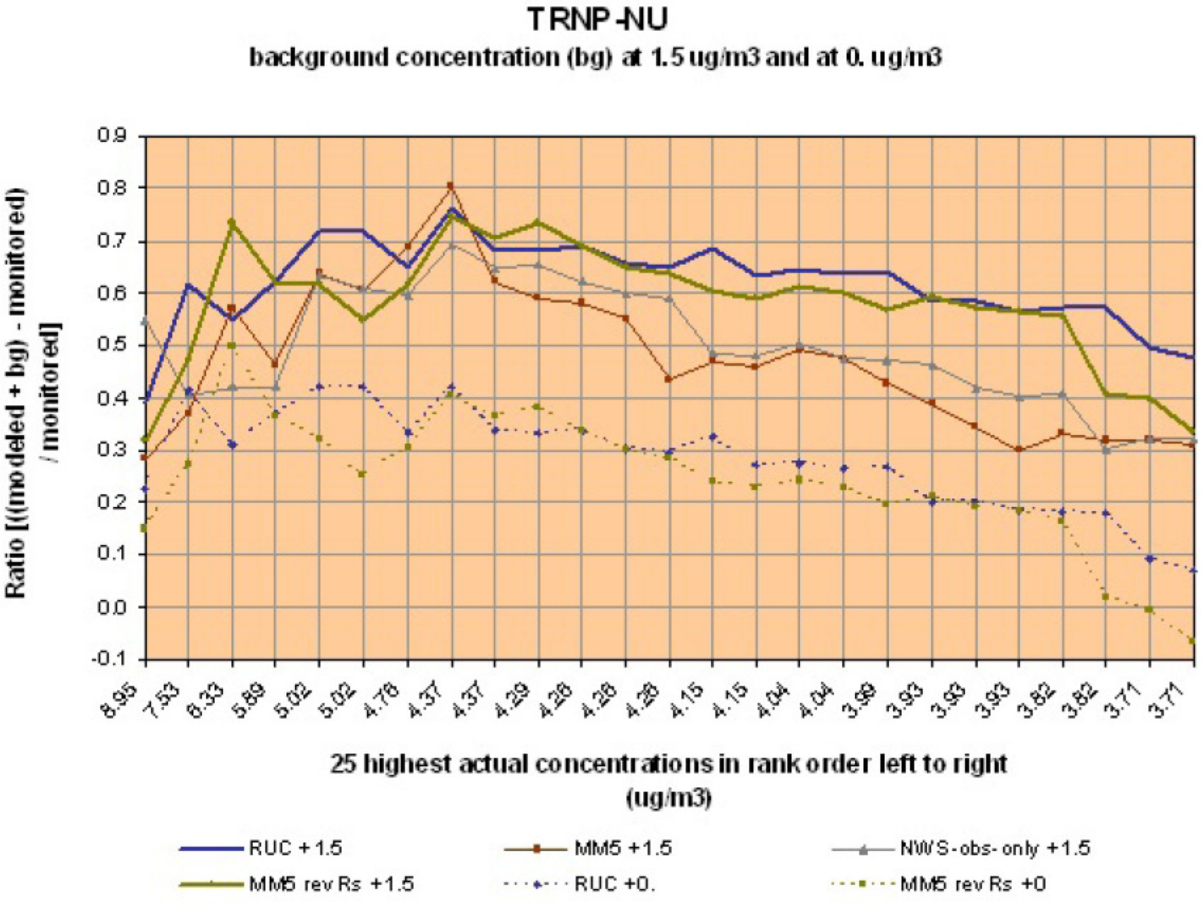


Figure 5: Normalized CALPUFF Bias from Normalized Rank-Order Pairs of SO_2 24-hour Concentrations at TRNP North Unit



AECOM

Environment

Submitted to:
Montana-Dakota Utilities Co.
Bismarck, North Dakota

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Westford, Massachusetts
60140139.0100
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CALPUFF Visibility Modeling Protocol: MDU Heskett Unit 2 BART Analysis

Prepared By Mary M. Kaplan

Robert J. Paine

Reviewed By Robert J. Paine

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1.0 Introduction

1.1 Background

The North Dakota Department of Health (NDDH) has conducted CALPUFF modeling for emission sources for all BART-eligible facilities in North Dakota. This study updates and refines the CALPUFF modeling for one of these facilities, Heskett Unit 2, which is owned and operated by Montana-Dakota Utilities Co. (MDU). Heskett Unit 1, operational in 1954, has a capacity of 40 MW and is not BART-eligible since it was put into service before 1962. Unit 2, operational in 1963, has a capacity of 75 MW. Unit 2 was retrofitted to a fluidized-bed combustor in 1987, thus making it BART eligible.

In 2006, MDU asked ENSR (now AECOM) to review the NDDH BART analysis for Heskett Unit 2 and to provide an analysis that considered updates to the November 2005 NDDH BART modeling protocol. The 2006 updates focused on the following three areas:

- US EPA had announced a court settlement regarding BART modeling that allowed each state to use the annual average background visibility instead of the best 20% days' background visibility for BART analyses. This development occurred because the actual BART rule (published in the July 6, 2005, 70 Fed. Reg. 39104) stipulated that the annual average background visibility value should be used, while the preamble was inconsistent and mentioned that the 20% best days' background visibility should be used. As a result of the settlement, the NDDH adopted the annual average background visibility for the BART analysis.

- ENSR considered a more complete speciation of particulate emissions consistent with guidance provided by the National Park Service.

- ENSR adopted a 1-km CALPUFF grid spacing consistent with EPA guidance as provided in the CALPUFF FAQs regarding the resolution of terrain features with at least 5 grid elements. Other reasons for the adoption of the 1-km grid spacing have been provided to US EPA in recent correspondence.

The results of the BART modeling analysis indicated that the 98th percentile daily regional haze impact of the peak baseline daily emissions from Heskett Unit 2 would not reach the NDDH-adopted contribution level of 0.5 delta-deciview. Therefore, Heskett Unit 2 was determined to be exempt from further BART review as NDDH confirmed in a May 8, 2007 letter to MDU.

On May 15, 2009, EPA issued a Clarification Memo on CALPUFF that challenged a BART exemption analysis for the Big Stone plant in South Dakota. The clarification recommended that the grid spacing to be used for CALMET/CALPUFF analyses should be no less than 4 km.

In a more recent Clarification Memo issued on August 31, 2009, EPA issued further guidance for running CALMET.

In its recent review of the draft North Dakota Regional Haze Rule State Implementation Plan (SIP) (August 21, 2009), EPA Region 8 stated that any updates to the procedures stated in the November 2005 NDDH BART modeling protocol would need to adopt current CALPUFF modeling guidance, including the procedures discussed in the 2009 Clarification memos cited above.

This EPA position was further discussed in a conference call held among EPA, the Federal Land Managers, NDDH, and MDU with AECOM on November 17, 2009. As a result of that conference call, MDU is providing this modeling protocol document to guide an update to BART CALPUFF modeling for Heskett Unit 2.

For this update AECOM will conduct CALPUFF modeling to assess the visibility impact of Heskett Unit 2 emissions with four general areas of change to the modeling approach specified in the November 2005 NDDH BART modeling protocol, as described in the next section.

1.2 Elements of the Updated BART Modeling Analysis

The updates from the November 2005 NDDH BART modeling protocol that AECOM proposes to implement in the updated BART modeling analyses for Heskett Unit 2 are summarized below.

- In the CALMET modeling, we will adopt the recent EPA recommendations by increasing the grid size from 3 km to 4 km, and set other CALMET technical options to those stated in recent EPA Clarification memos. We will continue to set the extent of the modeling domain to 50 km outside the area denoted by the modeled source and the boundaries of the PSD Class I areas.
- For national consistency with other BART analyses, we will continue to use guidance from the National Park Service on the speciation of particulate matter emissions into several components that have different light scattering potential: coarse matter, inorganic fine matter, elemental carbon, sulfuric acid mist, and organic aerosol fine particulate.
- As a result of the EPA settlement regarding the definition of the natural visibility background and the NDDH position on this issue, we will continue to use the annual average background visibility as input to CALPOST for determining the change in visibility caused by emissions from Heskett Unit 2.
- We will use CALMET and CALPUFF versions 5.8, with all technical options as noted in the 2009 EPA Clarification Memos, as well as any applicable guidance from the March 16, 2006 EPA memo from Dennis Atkinson regarding the preferred CALPUFF dispersion option. In addition (and to be consistent with the CALPOST methods used by NDDH in their Regional Haze Rule SIP modeling), we will use the recommended new IMPROVE equation application, also known as Method 8, in the approved version of CALPOST (Version 6.221) for processing the visibility impacts at the North Dakota Class I areas. We will use inputs to CALPOST as provided in the proposed FLAG 2008 guidelines.

These modeling procedures will first be used in a reassessment of the visibility impact of the peak daily baseline emissions for the modeling period of 2000-2002 (using NDDH's RUC data). In the event Heskett Unit 2 is found to be BART-subject, the same procedures will be used to determine the visibility improvement associated with each feasible BART control option.

The BART analysis modeling updates are discussed in more detail in Section 2 below, while the references for the same are provided in Section 3.

2.0 BART Analysis Updates

Updates to the modeling procedures described in Section 1.2 will be made by AECOM to the CALMET/CALPUFF modeling for Heskett Unit 2. More details regarding this process are provided in this section.

2.1 Meteorological Processing with CALMET

One of the updates will involve the use of a 4-km grid size instead of the 3-km grid size used by NDDH. The grid size adjustment is consistent with directives in the August 31, 2009 EPA Clarification Memo and comments made by EPA and the Federal Land Managers during the November 17, 2009 conference call. The digital terrain data that will be used for this analysis will consist of 1-degree data (90-meter resolution). With this CALMET remodeling, the total grid domain will be sized to provide a 50-km buffer around this specific source as well as the PSD Class I areas. Figure 2-1 shows the proposed modeling domain.

Another update will involve changing some of the CALMET switches from the values noted in the NDDH protocol (NDDH, 2005) to those provided in the EPA Clarification Memo released on August 31, 2009. This memorandum updates the draft Interagency Workgroup on Air Quality Modeling's (IWAQM) Phase 2 summary protocol (EPA, 2009). Table 2-1 shows the changes AECOM is proposing to make to the CALMET settings consistent with the August 31, 2009 EPA Clarification Memo.

Table 2-1 Comparison of CALMET Settings Used in NDDH 2005 Protocol and in Updated Modeling

Variable	Description	NDDH 2005 Values	Updated Values
DGRIDM	Grid spacing (km)	3	4
XORIGKM	Southwest grid cell X coordinate	-380	-175
YORIGKM	Southwest grid cell Y coordinate	140	268
NX	No. of X grid cells	213	79
NY	No. of Y grid cells	153	77
NZ	No. vertical layers	12	10
ZFACE	Cell face heights (m)	0.,20.,50.,90.,140.,200., 270.,370.,500.,1000., 1700.,2500.,4200.	0.,20.,40.,80.,160.,320., 640.,1200.,2000.,3000., 4000.
BIAS	Layer-dependent biases modifying the weights of surface and upper air stations (BIAS(NZ))	-1.0, -0.9, -0.7, -0.4, 0.0, 0.3, 0.7, 1.0, 1.0, 1.0, 1.0, 1.0	0,0,0,0,0,0,0,0,0,0
TERRAD	Radius of influence of terrain features (km)	10	15
R1	Distance from a surface observation station at which the wind observation and the first guess field are equally weighted (km)	10	50
R2	Distance from an upper-air observation station at which the wind observation and the first guess field are equally weighted (km)	10	100
ZUPWND	Bottom and top of layer through which the domain scale winds are computed (m)	1., 2500.	1., 1000.
MNMDAV	Max. search distance (in grid cells) for spatial averaging of mixing ht. and temperature	7	1
ILEVZI	Layer of winds used in upwind averaging of mixing heights	3	1
ZIMAX	Maximum over land mixing height (m)	4000	3000
ZIMAXW	Maximum over water mixing height (m)	4000	3000

* Values for years 2000, 2001, 2002

2.2 CALPUFF Modeling Options

As with the CALMET modeling, AECOM will change some of the switches in CALPUFF from the values noted in the November 2005 NDDH BART modeling protocol to those provided in the Dennis Atkinson Dispersion Coefficient memorandum released on March 16, 2006. At that time, Mr. Atkinson was the Model Clearinghouse Director of the EPA Office of Air Quality Planning and Standards (OAQPS). In 2006, he released a memo detailing the settings to be used in CALPUFF modeling. AECOM will follow Mr. Atkinson's recommendations with the exception of the CDIV value, which has been updated by the model developer (TRC) to be 0.0. Table 2-2 shows the changes AECOM is planning to make to the CALPUFF settings, consistent with Mr. Atkinson's EPA directives.

Table 2-2 Comparison of CALPUFF Settings Used in NDDH 2005 Protocol and in Updated Modeling

Variable	Description	NDDH 2005 Values	Updated Values
NSPEC	Number of chemical species	7	9
NSE	Number of chemical species emitted	4	7
MSPLIT	Allow puff splitting (1=yes)	1	0
MDISP	Method used to compute dispersion coefficients	2	3
MPDF	PDF used for dispersion under convective conditions (1=yes)	1	0
NX	No. of X grid cells	213	79
NY	No. of Y grid cells	153	77
NZ	No. vertical layers	12	10
DGRIDM	Grid spacing (km)	3	4
ZFACE	Cell face heights (m)	0.,20.,50.,90.,140.,200., 270.,370.,500.,1000.,1700., 2500.,4200.	0.,20.,40.,80.,160.,320., 640.,1200., 2000.,3000., 4000.
XORIGKM	Southwest grid cell X coordinate	-380	-175
YORIGKM	Southwest grid cell Y coordinate	140	268
IBCOMP	Southwest X-index of computational grid	20	2
JBCOMP	Southwest Y-index of computational grid	6	2
IECOMP	Northeast X-index of computational grid	213	78
JECOMP	Northeast Y-index of	153	76

Variable	Description	NDDH 2005 Values	Updated Values
	computational grid		
Dry Part. Dep.	Chemical parameters of particulate deposition species	Model defaults for which mean diameter = 6.25 m and standard deviation = 0.0 m for PMC	Model defaults for all but PMC for which mean diameter = 6.0 m and standard deviation = 2.0 m
XMAXZI	Maximum mixing height	4000	3000
IRESPLIT	Hours when puff is eligible for vertical split	Hours 0-4 and 19-23	Hour 17
ROLDMAX	Vertical puff split allowed only when the ratio of last hour's mixing height to max. mixing height experienced by the puff is smaller than this value	0.33	0.25
MDISP2	Backup method used to compute dispersion coefficients	1	3
MREG	Test options specified to see if they conform to regulatory values (1=yes)	0	1
CSPEC	Species modeled	SO2,SO4,NOX,HNO3,NO3, PMC,PMF	SO2,SO4,NOX,HNO3, NO3, EC,PMC,PMF,SOA
CDIV	Divergence criterion for dw/dz across puff used to initiate adjustment for horizontal convergence (1/s)	0.01, 0.01	0,0

2.3 Characterization of Baseline Emissions

The National Park Service has issued guidance on how to speciate particulate matter emissions into different constituents that have different light scattering EPA potential: coarse matter, inorganic fine matter, elemental carbon, sulfuric acid mist, and organic aerosol fine particulate. The guidance is located at http://www.vistas-sesarm.org/BART/calpuff.asp on the VISTAS regional planning organization web site. While NDDH did not include this guidance in its BART screening protocol, AECOM believes it should be included in this updated analysis.

Engineers from MDU have reviewed the speciation profiles and selected the data for a dry bottom PC with FGD and ESP controls spreadsheet as the most representative of the emissions from Heskett Unit 2. A series of Method 8 stack tests conducted August 24 – 26, 2000 found an average H_2SO_4 rate of 9.0 lb/hr (2.9 ppm) at full load. The resulting emissions that will be used in the CALPUFF regional haze modeling are listed in Table 2-3 (these values have not changed from the ENSR 2006 BART modeling). To simplify the modeling, the coarse and fine inorganic matter will be combined as fine matter, which has a slightly higher visibility extinction efficiency than coarse matter.

Table 2-3 Heskett Unit 2 emissions data for updated BART modeling

Component	Emission Rate (lb/hr)
SO_2	1475.5
NO_2	302.8
Coarse matter (PMC)	8.2
Inorganic fine matter (PMF)	6.3
Elemental carbon (EC)	0.2
H_2SO_4	9.0
Organic aerosols (SOA)	2.0

2.4 Natural Background Determination

Following the settlement of a court case involving how to determine natural background visibility for BART analyses, EPA determined that each state can select either the annual average or 20% best days' background. NDDH has adopted the annual average background visibility approach. The concentrations to be used in the CALPOST input for the particulate species that contribute to visibility impairment are listed in Table 2-4. In the post-processing, the various elements of the Theodore Roosevelt National Park will be considered as a single Class I area, departing from the treatment in the November 2005 NDDH BART modeling protocol. The bases for this change are reflected in EPA's comments 23, 39 and 53 pertaining to the August 21, 2009 draft NDDH Regional Haze SIP and comments provided by EPA and the Federal Land Managers during the November 17, 2009 conference call.

Table 2-4 Annual Average Natural Levels of Aerosol Components (µg/m³)

Component	Lostwood Wilderness(1)	Theodore Roosevelt NP(1)
Ammonium sulfate	0.12	0.12
Ammonium nitrate	0.10	0.10
Organic carbon mass	0.60	0.60
Elemental carbon	0.02	0.02
Soil	0.50	0.50
Coarse mass	3.00	3.00

(1) From "Federal Land Managers' Air Quality Related Values Workgroup" (FLAG, 2008), Appendix V-1, Table V.1-2.

2.5 Light Extinction and Haze Impact Calculations

The FLAG 2008 document (dated June 26, 2008) provides guidance on the recommended new IMPROVE equation application. CALPOST Version 6.221 defines this application as Method 8, Mode 5. The assessment of visibility impacts at the Class I areas will use CALPOST Method 8.

The CALPOST postprocessor will be used for the calculation of the impact of the modeled source's primary and secondary particulate matter concentrations on light extinction. In the new IMPROVE equation, the total sulfate, nitrate, and organic carbon compound concentrations are each split into two fractions, representing small and large size distributions of those components. New terms, such as sea salt (important for coastal locations), absorption by NO_2 (only used where NO_2 data are available), and site-specific Rayleigh scattering have been added to the equation. The new IMPROVE equation for calculating light extinction is shown below.

$$
\begin{aligned}
b_{ext} \quad = \quad & 2.2 \times f_S(RH) \times [\text{Small Sulfate}] + 4.8 \times f_L(RH) \times [\text{Large Sulfate}] \\
& + 2.4 \times f_S(RH) \times [\text{Small Nitrate}] + 5.1 \times f_L(RH) \times [\text{Large Nitrate}] \\
& + 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}] \\
& + 10 \times [\text{Elemental Carbon}] \\
& + 1 \times [\text{Fine Soil}] \\
& + 0.6 \times [\text{Coarse Mass}] \\
& + 1.7 \times f_{SS}(RH) \times [\text{Sea Salt}] \\
& + \text{Rayleigh Scattering (Site Specific)} \\
& + 0.33 \times [NO_2\ (\text{ppb})] \ \ \{\text{or as: } 0.1755 \times [NO_2\ (\mu g/m^3)]\}
\end{aligned}
$$

Where:

[ ] indicates concentrations in $\mu g/m^3$

$f_S(RH)$ = Relative humidity adjustment factor for small sulfate and nitrate

$f_L(RH)$ = Relative humidity adjustment factor for large sulfate and nitrate

$f_{SS}(RH)$ = Relative humidity adjustment factor for sea salt

For Total Sulfate $< 20\ \mu g/m^3$:

$$[\text{Large Sulfate}] = ([\text{Total Sulfate}] / 20\ \mu g/m^3) \times [\text{Total Sulfate}]$$

For Total Sulfate $\geq 20\ \mu g/m^3$:

$$[\text{Large Sulfate}] = [\text{Total Sulfate}]$$

And:

$$[\text{Small Sulfate}] = [\text{Total Sulfate}] - [\text{Large Sulfate}]$$

To calculate large and small nitrate and organic mass, substitute ({Large, Small, Total} {Nitrate, Organic Mass}) for Sulfate.

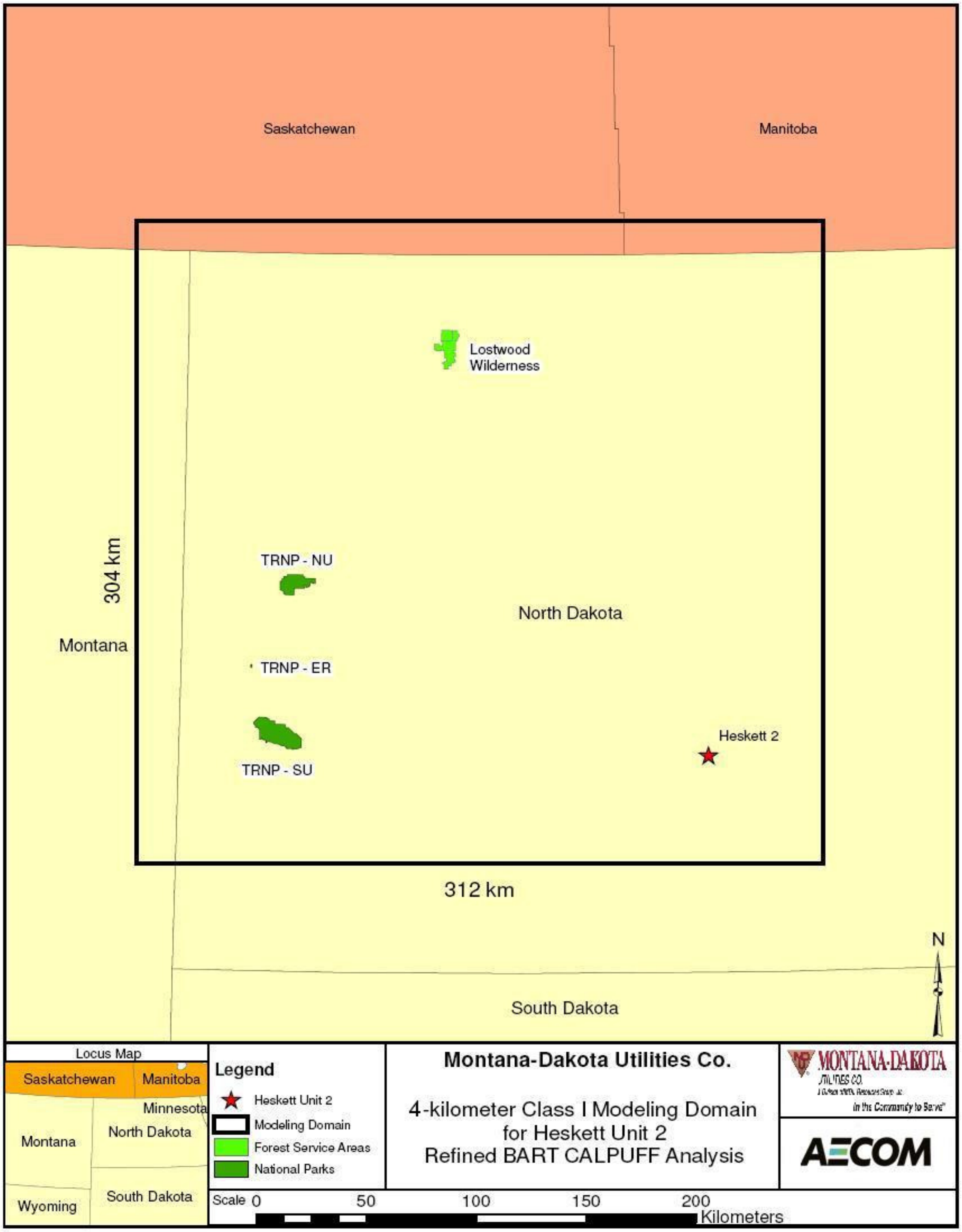
The FLAG 2008 document provides inputs to the new IMPROVE equation for the annual average natural conditions. Inputs to the CALPOST Method 8 calculations for each Class I area are listed in Table 2-5.

Table 2-5 New IMPROVE Equation CALPOST Inputs

Component	Lostwood Wilderness(1)	Theodore Roosevelt NP(1)
Sea salt concentration (µg/m^3)	0.03	0.01
Raleigh scattering (Mm^{-1})	11	11
Monthly f_L (RH)	2.51, 2.45, 2.54, 2.06, 2.03, 2.21, 2.23, 2.05, 2.02, 2.13, 2.69, 2.67	2.47, 2.42, 2.45, 2.12, 2.14, 2.21, 2.14, 1.99, 1.99, 2.10, 2.58, 2.57
Monthly f_S (RH)	3.21, 3.15, 3.36, 2.60, 2.54, 2.86, 2.89, 2.60, 2.53, 2.72, 3.60, 3.52	3.17, 3.11, 3.22, 2.71, 2.74, 2.85, 2.73, 2.49, 2.48, 2.66, 3.42, 3.37
Monthly f_{SS} (RH)	3.77, 3.66, 3.67, 2.86, 2.79, 3.07, 3.11, 2.82, 2.80, 2.99, 3.93, 3.95	3.67, 3.56, 3.51, 2.93, 2.97, 3.09, 2.96, 2.72, 2.72, 2.93, 3.75, 3.78

(1) From “Federal Land Managers’ Air Quality Related Values Workgroup” (FLAG, 2008), Appendix V-1, Tables V.1-2 to V.1-5.

Figure 2-1 Modeling domain for 4 kilometer grid



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AECOM Environment

Submitted to:
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Bismarck, North Dakota

Submitted by:
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Westford, Massachusetts
60140139.0100
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Updated BART CALPUFF Visibility Modeling Analysis for Montana-Dakota Utilities Heskett Station Unit 2

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Reviewed By Robert J. Paine

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1.0 Introduction

1.1 Background

The North Dakota Department of Health (NDDH) conducted CALPUFF modeling in 2005 for emission sources associated with all BART-eligible facilities in North Dakota. This study updates the CALPUFF modeling for one of these facilities, Heskett Unit 2, which is owned and operated by Montana-Dakota Utilities Co. (MDU). Heskett Unit 1, operational in 1954, has a capacity of 40 MW and is not BART-eligible since it was put into service before 1962. Unit 2, operational in 1963, has a capacity of 75 MW. Unit 2 was retrofitted to a fluidized-bed combustor in 1987, thus making it BART-eligible.

In 2006, MDU asked ENSR (now AECOM) to review the NDDH BART analysis for Heskett Unit 2 and to provide an analysis that considered updates to the November 2005 NDDH BART modeling protocol. The 2006 updates focused on the following three areas:

- US EPA had announced a court settlement regarding BART modeling that allowed each state to use the annual average background visibility instead of the best 20% days' background visibility for BART analyses. This development occurred because the actual BART rule (published in the Federal Register on July 6, 2005 at 70 Fed. Reg. 39104) stipulated that the annual average background visibility value should be used, while the preamble was inconsistent and mentioned that the 20% best days' background visibility should be used. As a result of the settlement, the NDDH adopted the annual average background visibility for the BART analysis.

- ENSR considered a more complete speciation of particulate emissions consistent with guidance provided by the National Park Service.

- ENSR adopted a 1-km CALPUFF grid spacing consistent with EPA guidance as provided in the CALPUFF FAQs regarding the resolution of terrain features with at least 5 grid elements. Support for use of 1-km grid spacing was provided to US EPA Region 8 and the Federal Land Managers in comments from AECOM dated August 12, 2009.

The results of the 2006 BART modeling analysis indicated that the 98th percentile daily regional haze impact of the peak baseline daily emissions from Heskett Unit 2 would not reach the NDDH-adopted contribution level of 0.5 delta-deciview. Therefore, Heskett Unit 2 was determined to be exempt from further BART review as NDDH confirmed in a May 8, 2007 letter to MDU.

The NDDH received EPA correspondence dated August 8, 2008 stating their concern in using a 1-km grid size and requesting a more robust discussion as to why the NDDH found the use of a 1-km grid size to be acceptable. Upon review of the EPA's comments, MDU requested AECOM develop responses to EPA's concerns. An AECOM response was filed with the NDDH on January 5, 2009.

On May 15, 2009, EPA issued a Clarification Memo on CALPUFF that challenged a BART exemption analysis for the Big Stone plant in South Dakota. The clarification recommended that the grid spacing to be used for CALMET/CALPUFF analyses should be no less than 4 km. MDU asked AECOM to update its January 5, 2009 document to take into account the issues raised in the EPA Clarification Memo. An updated AECOM response was provided to the NDDH on August 12, 2009 that included the rational for utilizing the 1-km grid size for Heskett Unit 2 in light of the May 15, 2009 EPA Clarification Memo. The

NDDH included the AECOM response as an attachment to the draft Regional Haze/BART SIP that was filed with the Federal Land Managers for review and comment in August 2009.

In a more recent Clarification Memo issued on August 31, 2009, EPA provided further guidance for running CALMET which was taken into account for recent modeling as described below.

In its recent review of the draft North Dakota Regional Haze Rule State Implementation Plan (SIP) (August 21, 2009), EPA Region 8 stated that any updates to the procedures stated in the November 2005 NDDH BART modeling protocol would need to adopt current CALPUFF modeling guidance, including the procedures discussed in the 2009 Clarification memos cited above.

This EPA position was further discussed in a conference call held among EPA, the Federal Land Managers, NDDH, and MDU with AECOM on November 17, 2009. On November 25, 2009, MDU provided NDDH a modeling protocol document to guide an update to BART CALPUFF modeling for Heskett Unit 2, consistent with both current EPA CALPUFF modeling guidance and directives provided by EPA during the November 17, 2009 conference call. The November 25, 2009 protocol was approved by the NDDH on December 1, 2009.

On December 10, 2009, EPA Region 8 also approved the November 25, 2009 protocol with the condition that one CALPUFF setting, CDIV, should be adjusted to (0.01, 0.01) instead of (0,0). While the CALPUFF model developer has advised AECOM that the setting of 0.01 is obsolete and it should be revised to be 0, the adjustment was made to demonstrate its effect upon the modeling results. To that end, the modeling results section of this report has been updated to provide predicted visibility impacts for both versions of the CALPUFF CDIV setting.

For this updated modeling analysis, AECOM conducted CALPUFF modeling in accordance with the approved protocol to assess the visibility impact of Heskett Unit 2 emissions with four general areas of change to the modeling approach specified in the November 2005 NDDH BART modeling protocol, as described in the next section.

1.2 Elements of the Refined Analysis

The updates from the November 2005 NDDH BART modeling protocol that AECOM implemented in the updated BART modeling analyses for Heskett Unit 2 are summarized below.

- In the CALMET modeling, we adopted the recent EPA recommendations by increasing the grid size from 3 km to 4 km, and set other CALMET technical options to those stated in recent EPA Clarification Memos. We set the extent of the modeling domain to 50 km outside the area denoted by the modeled source and the boundaries of the PSD Class I areas.
- For national consistency with other BART analyses, we continued to use guidance from the National Park Service on the speciation of particulate matter emissions into several components that have different light scattering potential: coarse matter, inorganic fine matter, elemental carbon, sulfuric acid mist, and organic aerosol fine particulate.
- As a result of the EPA settlement regarding the definition of the natural visibility background and the NDDH position on this issue, we used the annual average background visibility as input to CALPOST for determining the change in visibility caused by emissions from Heskett Unit 2.

- We used CALMET and CALPUFF versions 5.8, with all technical options as noted in the 2009 EPA Clarification Memos, as well as applicable guidance from the March 16, 2006 EPA memo from Dennis Atkinson regarding the preferred CALPUFF dispersion option. In addition (and to be consistent with the CALPOST methods used by NDDH in their Regional Haze Rule SIP modeling), we used the recommended new IMPROVE equation application, also known as Method 8, in the approved version of CALPOST (Version 6.221) for processing the visibility impacts at the North Dakota Class I areas. We used inputs to CALPOST as provided in the proposed FLAG 2008 guidelines.

These modeling procedures were first used in a reassessment of the visibility impact of the peak daily baseline emissions for the modeling period of 2000-2002 (using NDDH's RUC data). The results of this modeling analysis clarify whether Heskett Unit 2 is subject to BART.

The BART analysis modeling procedures are discussed in more detail in Section 2 below. Results of the modeling for baseline emissions are provided in Section 3. References are provided in Section 4.

2.0 BART Analysis Updates

Updates to the modeling procedures described in Section 1.2 were made by AECOM in the updated CALMET/CALPUFF modeling for Heskett Unit 2. More details regarding this process are provided in this section.

2.1 Meteorological Processing with CALMET

One of the updates involved the use of a 4-km grid size instead of the 3-km grid size used by NDDH. The grid size adjustment is consistent with directives in the August 31, 2009 EPA Clarification Memo and comments made by EPA and the Federal Land Managers during the November 17, 2009 conference call. The digital terrain data that was used for this analysis consisted of 1-degree data (90-meter resolution). With this CALMET remodeling, the total grid domain was sized to provide a 50-km buffer around this specific source as well as the PSD Class I areas. Figure 2-1 shows the modeling domain.

Another update involved changing some of the CALMET switches from the values noted in the NDDH protocol (NDDH, 2005) to those provided in the EPA Clarification Memo released on August 31, 2009. This memorandum updates the draft Interagency Workgroup on Air Quality Modeling's (IWAQM) Phase 2 summary protocol (EPA, 2009). Table 2-1 shows the changes AECOM applied to the CALMET settings consistent with the August 31, 2009 EPA Clarification Memo.

Table 2-1 Comparison of CALMET Settings Used in NDDH 2005 Protocol and in Updated Modeling

Variable	Description	NDDH 2005 Values	Updated Values
DGRIDM	Grid spacing (km)	3	4
XORIGKM	Southwest grid cell X coordinate	-380	-175
YORIGKM	Southwest grid cell Y coordinate	140	268
NX	No. of X grid cells	213	79
NY	No. of Y grid cells	153	77
NZ	No. vertical layers	12	10
ZFACE	Cell face heights (m)	0.,20.,50.,90.,140.,200.,270.,370.,500.,1000.,1700.,2500.,4200.	0.,20.,40.,80.,160.,320.,640.,1200.,2000.,3000.,4000.
BIAS	Layer-dependent biases modifying the weights of surface and upper air stations (BIAS(NZ))	-1.0, -0.9, -0.7, -0.4, 0.0, 0.3, 0.7, 1.0, 1.0, 1.0, 1.0, 1.0	0,0,0,0,0,0,0,0,0,0
TERRAD	Radius of influence of terrain features (km)	10	15
R1	Distance from a surface observation station at which the wind observation and the first guess field are equally weighted (km)	10	50
R2	Distance from an upper-air observation station at which the wind observation and the first guess field are equally weighted (km)	10	100
ZUPWND	Bottom and top of layer through which the domain scale winds are computed (m)	1., 2500.	1., 1000.
MNMDAV	Max. search distance (in grid cells) for spatial averaging of mixing ht. and temperature	7	1
ILEVZI	Layer of winds used in upwind averaging of mixing heights	3	1
ZIMAX	Maximum over land mixing height (m)	4000	3000
ZIMAXW	Maximum over water mixing height (m)	4000	3000

* Values for years 2000, 2001, 2002

2.2 CALPUFF Modeling Options

As with the CALMET modeling, AECOM changed some of the switches in CALPUFF from the values noted in the November 2005 NDDH BART modeling protocol to those provided in the Dennis Atkinson Dispersion Coefficient memorandum released on March 16, 2006. At that time, Mr. Atkinson was the Model Clearinghouse Director of the EPA Office of Air Quality Planning and Standards (OAQPS). In 2006, he released a memo detailing the settings to be used in CALPUFF modeling. AECOM followed Mr. Atkinson's recommendations with the exception of the CDIV value, which has been updated by the model developer (TRC) to be 0.0. Table 2-2 shows the changes AECOM made to the CALPUFF settings, consistent with Mr. Atkinson's EPA directives.

Table 2-2 Comparison of CALPUFF Settings Used in NDDH 2005 Protocol and in Updated Modeling

Variable	Description	NDDH 2005 Values	Updated Values
NSPEC	Number of chemical species	7	9
NSE	Number of chemical species emitted	4	7
MSPLIT	Allow puff splitting (1=yes)	1	0
MDISP	Method used to compute dispersion coefficients	2	3
MPDF	PDF used for dispersion under convective conditions (1=yes)	1	0
NX	No. of X grid cells	213	79
NY	No. of Y grid cells	153	77
NZ	No. vertical layers	12	10
DGRIDM	Grid spacing (km)	3	4
ZFACE	Cell face heights (m)	0.,20.,50.,90.,140.,200., 270.,370.,500.,1000.,1700., 2500.,4200.	0.,20.,40.,80.,160.,320., 640.,1200., 2000.,3000., 4000.
XORIGKM	Southwest grid cell X coordinate	-380	-175
YORIGKM	Southwest grid cell Y coordinate	140	268
IBCOMP	Southwest X-index of computational grid	20	1
JBCOMP	Southwest Y-index of computational grid	6	1
IECOMP	Northeast X-index of computational grid	213	79
JECOMP	Northeast Y-index of computational grid	153	77

Variable	Description	NDDH 2005 Values	Updated Values
Dry Part. Dep.	Chemical parameters of particulate deposition species	Model defaults for which mean diameter = 6.25 m and standard deviation = 0.0 m for PMC	Model defaults for all but PMC for which mean diameter = 6.0 m and standard deviation = 2.0 m
XMAXZI	Maximum mixing height	4000	3000
IRESPLIT	Hours when puff is eligible for vertical split	Hours 0-4 and 19-23	Hour 17
ROLDMAX	Vertical puff split allowed only when the ratio of last hour's mixing height to max. mixing height experienced by the puff is smaller than this value	0.33	0.25
MDISP2	Backup method used to compute dispersion coefficients	1	3
MREG	Test options specified to see if they conform to regulatory values (1=yes)	0	1
CSPEC	Species modeled	SO2,SO4,NOX,HNO3,NO3, PMC,PMF	SO2,SO4,NOX,HNO3, NO3, EC,PMC,PMF,SOA
CDIV	Divergence criterion for dw/dz across puff used to initiate adjustment for horizontal convergence (1/s)	0.01, 0.01	0,0

Note that CDIV was set to (0,0) because the CALPUFF model developer, Joe Scire, indicated in a December 22, 2006 e-mail to Robert Paine of AECOM (see below) that this setting is appropriate. However, EPA Region 8 has stated its preference that a CDIV of (0.01, 0.01) be used because that setting was specified in the March 16, 2006 EPA memo from Dennis Atkinson. To resolve this issue, we have conducted the modeling both ways and present two sets of results in Section 3 of this report.

From: Scire, Joseph [mailto:JScire@TRCSOLUTIONS.com]
Sent: Friday, December 22, 2006 9:11 AM
To: Paine, Bob
Subject: RE: CDIV question

Bob,

The default values for CDIV has been 0.0, 0.0 going back at least six years (i.e., 2000). We may have tested other values earlier than this, but using zero for the CDIV has been the default for quite a while.

The use of the smaller value gives better protection again mass accumulation within convergence zones by compensating with increased sigma z to account for vertical movement of the air.
Joe

Joseph S. Scire, CCM
TRC
Vice President, Atmospheric Studies Group,
Wannalancit Mills, 650 Suffolk Street, Suite 200,
Lowell, Massachusetts 01854

tel: (978) 656-3627
cell: (978) 697-0830
fax: (978) 453-1995

email: jscire@trcsolutions.com
or jscire@alum.mit.edu

2.3 Characterization of Baseline Emissions

The National Park Service has issued guidance on how to speciate particulate matter emissions into different constituents that have different light scattering EPA potential: coarse matter, inorganic fine matter, elemental carbon, sulfuric acid mist, and organic aerosol fine particulate. The guidance is located at http://www.vistas-sesarm.org/BART/calpuff.asp on the VISTAS regional planning organization web site. While NDDH did not include this guidance in its BART screening protocol, AECOM believes it should be included in this updated analysis.

Engineers from MDU have reviewed the speciation profiles and selected the data for a dry bottom PC with FGD and ESP controls spreadsheet as the most representative of the emissions from Heskett Unit 2. A series of Method 8 stack tests conducted August 24 – 26, 2000 found an average H_2SO_4 rate of 9.0 lb/hr (2.9 ppm) at full load. The resulting emissions that were used in the CALPUFF regional haze modeling are listed in Table 2-3 (these values have not changed from the ENSR 2006 BART modeling). To simplify the modeling, the coarse and fine inorganic matter were combined as fine matter, which has a slightly higher visibility extinction efficiency than coarse matter.

Table 2-3 Heskett Unit 2 emissions data for updated BART modeling

Component	Emission Rate (lb/hr)
SO_2	1475.5
NO_2	302.8
Coarse matter (PMC)	8.2
Inorganic fine matter (PMF)	6.3
Elemental carbon (EC)	0.2
H_2SO_4	9.0
Organic aerosols (SOA)	2.0

2.4 Natural Background Determination

Following the settlement of a court case involving how to determine natural background visibility for BART analyses, EPA determined that each state can select either the annual average or 20% best days' background. NDDH has adopted the annual average background visibility approach. The concentrations to be used in the CALPOST input for the particulate species that contribute to visibility impairment are listed in Table 2-4. In the post-processing, the various elements of the Theodore Roosevelt National Park were considered as a single Class I area, departing from the treatment in the November 2005 NDDH BART modeling protocol. The bases for this change are reflected in EPA's comments 23, 39 and 53 pertaining to the August 21, 2009 draft NDDH Regional Haze SIP and comments provided by EPA and the Federal Land Managers during the November 17, 2009 conference call.

Table 2-4 Annual Average Natural Levels of Aerosol Components (µg/m³)

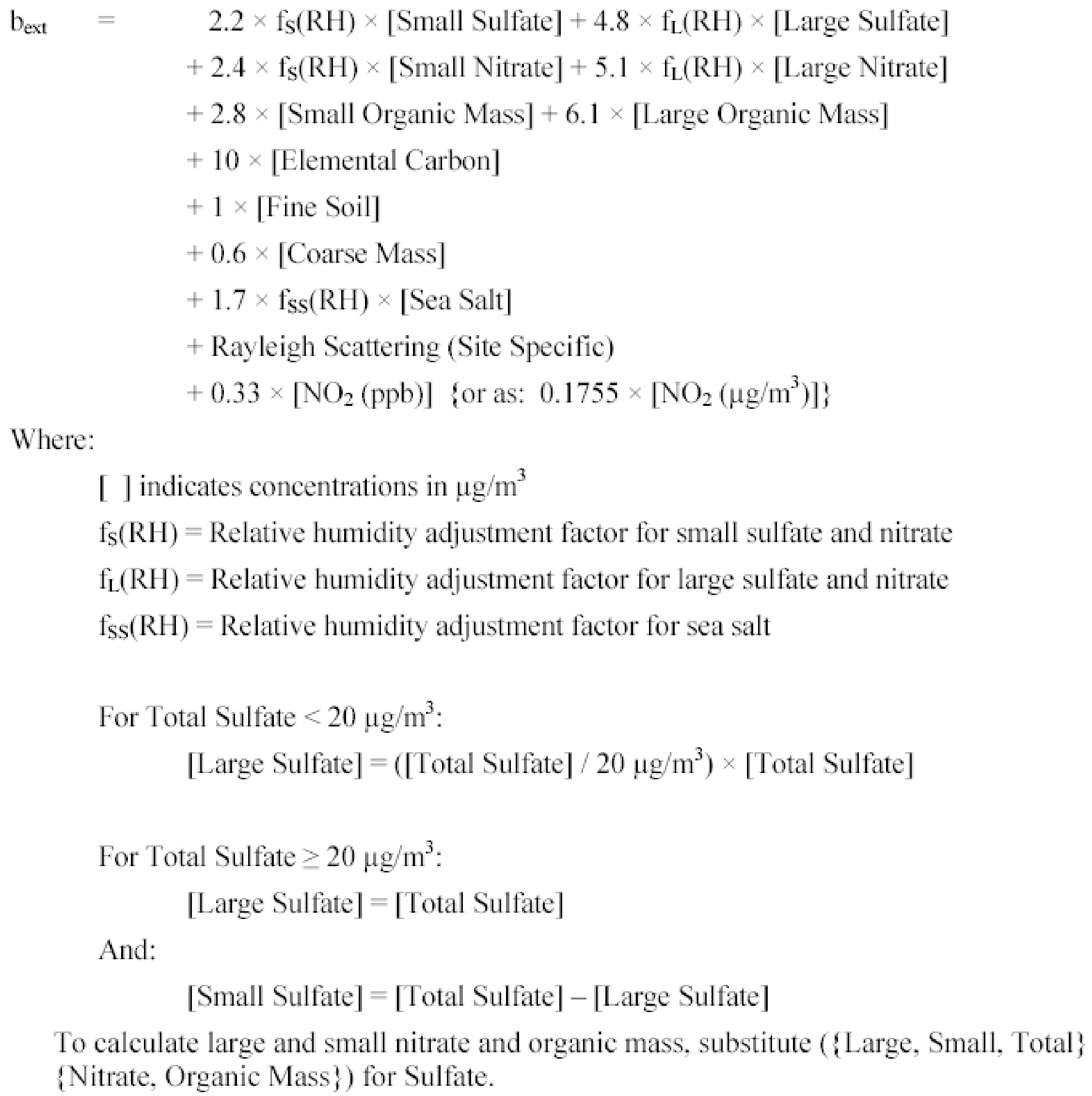
Component	Lostwood Wilderness(1)	Theodore Roosevelt NP(1)
Ammonium sulfate	0.12	0.12
Ammonium nitrate	0.10	0.10
Organic carbon mass	0.60	0.60
Elemental carbon	0.02	0.02
Soil	0.50	0.50
Coarse mass	3.00	3.00

(1) From "Federal Land Managers' Air Quality Related Values Workgroup" (FLAG, 2008), Appendix V-1, Table V.1-2.

2.5 Light Extinction and Haze Impact Calculations

The FLAG 2008 document (dated June 26, 2008) provides guidance on the recommended new IMPROVE equation application. CALPOST Version 6.221 defines this application as Method 8, Mode 5. The assessment of visibility impacts at the Class I areas will use CALPOST Method 8.

The CALPOST postprocessor will be used for the calculation of the impact of the modeled source's primary and secondary particulate matter concentrations on light extinction. In the new IMPROVE equation, the total sulfate, nitrate, and organic carbon compound concentrations are each split into two fractions, representing small and large size distributions of those components. New terms, such as sea salt (important for coastal locations), absorption by NO_2 (only used where NO_2 data are available), and site-specific Rayleigh scattering have been added to the equation. The new IMPROVE equation for calculating light extinction is shown below.



$$
\begin{aligned}
b_{ext} \quad = \quad & 2.2 \times f_S(RH) \times [\text{Small Sulfate}] + 4.8 \times f_L(RH) \times [\text{Large Sulfate}] \\
& + 2.4 \times f_S(RH) \times [\text{Small Nitrate}] + 5.1 \times f_L(RH) \times [\text{Large Nitrate}] \\
& + 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}] \\
& + 10 \times [\text{Elemental Carbon}] \\
& + 1 \times [\text{Fine Soil}] \\
& + 0.6 \times [\text{Coarse Mass}] \\
& + 1.7 \times f_{SS}(RH) \times [\text{Sea Salt}] \\
& + \text{Rayleigh Scattering (Site Specific)} \\
& + 0.33 \times [NO_2\ (\text{ppb})] \quad \{\text{or as: } 0.1755 \times [NO_2\ (\mu g/m^3)]\}
\end{aligned}
$$

Where:

[ ] indicates concentrations in $\mu g/m^3$

$f_S(RH)$ = Relative humidity adjustment factor for small sulfate and nitrate

$f_L(RH)$ = Relative humidity adjustment factor for large sulfate and nitrate

$f_{SS}(RH)$ = Relative humidity adjustment factor for sea salt

For Total Sulfate $< 20\ \mu g/m^3$:

$$[\text{Large Sulfate}] = ([\text{Total Sulfate}] / 20\ \mu g/m^3) \times [\text{Total Sulfate}]$$

For Total Sulfate $\geq 20\ \mu g/m^3$:

$$[\text{Large Sulfate}] = [\text{Total Sulfate}]$$

And:

$$[\text{Small Sulfate}] = [\text{Total Sulfate}] - [\text{Large Sulfate}]$$

To calculate large and small nitrate and organic mass, substitute ({Large, Small, Total} {Nitrate, Organic Mass}) for Sulfate.

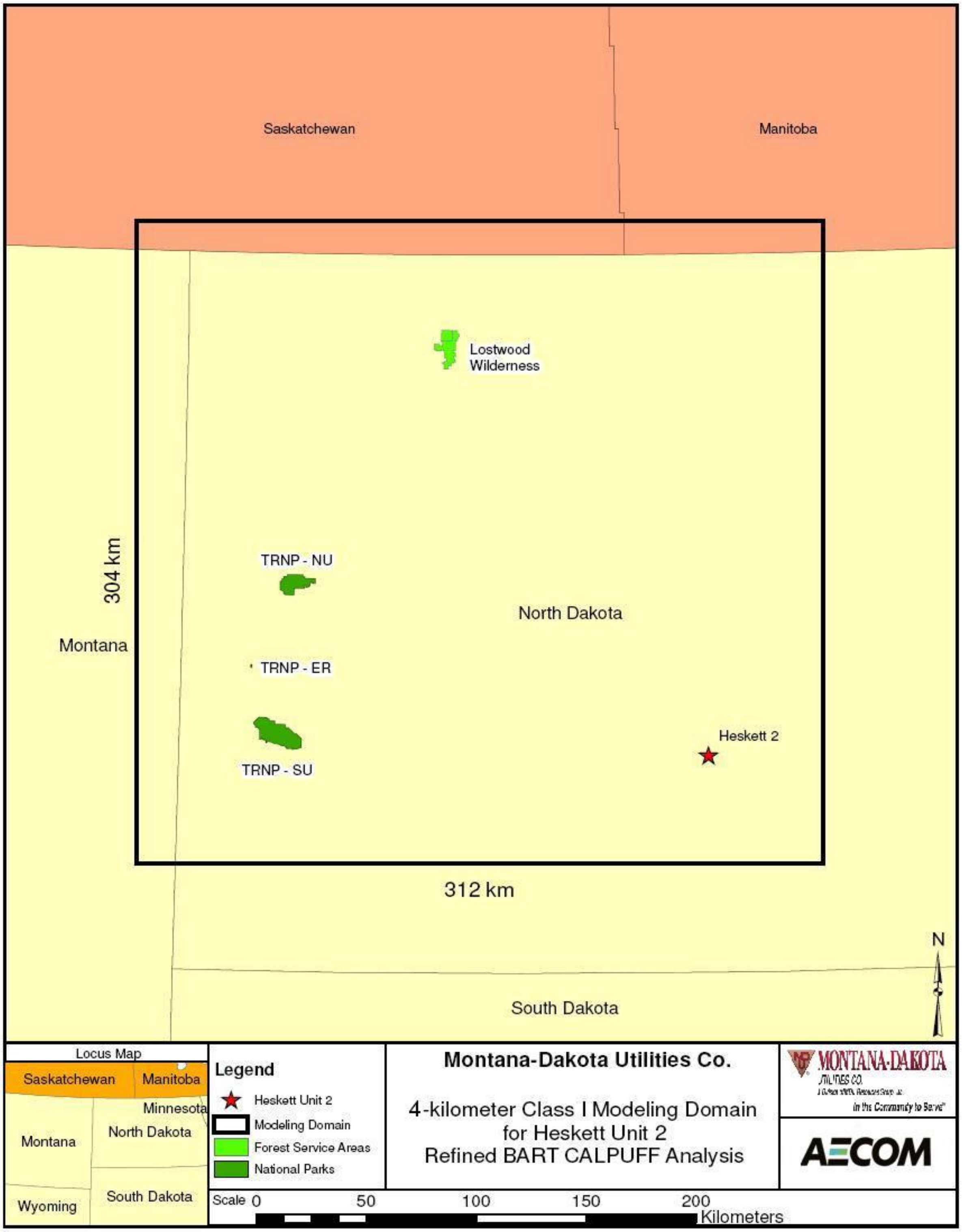
The FLAG 2008 document provides inputs to the new IMPROVE equation for the annual average natural conditions. Inputs to the CALPOST Method 8 calculations for each Class I area are listed in Table 2-5.

Table 2-5 New IMPROVE Equation CALPOST Inputs

Component	Lostwood Wilderness(1)	Theodore Roosevelt NP(1)
Sea salt concentration (µg/m^3)	0.03	0.01
Raleigh scattering (Mm^{-1})	11	11
Monthly f_L (RH)	2.51, 2.45, 2.54, 2.06, 2.03, 2.21, 2.23, 2.05, 2.02, 2.13, 2.69, 2.67	2.47, 2.42, 2.45, 2.12, 2.14, 2.21, 2.14, 1.99, 1.99, 2.10, 2.58, 2.57
Monthly f_S (RH)	3.21, 3.15, 3.36, 2.60, 2.54, 2.86, 2.89, 2.60, 2.53, 2.72, 3.60, 3.52	3.17, 3.11, 3.22, 2.71, 2.74, 2.85, 2.73, 2.49, 2.48, 2.66, 3.42, 3.37
Monthly f_{SS} (RH)	3.77, 3.66, 3.67, 2.86, 2.79, 3.07, 3.11, 2.82, 2.80, 2.99, 3.93, 3.95	3.67, 3.56, 3.51, 2.93, 2.97, 3.09, 2.96, 2.72, 2.72, 2.93, 3.75, 3.78

(1) From “Federal Land Managers’ Air Quality Related Values Workgroup” (FLAG, 2008), Appendix V-1, Tables V.1-2 to V.1-5.

Figure 2-1 Modeling domain for 4 kilometer grid



3.0 Updated BART Analysis Results and Conclusions

The results of the updated BART modeling for Heskett Unit 2 are provided in Table 3-1 with the use of CDIV = (0,0) and in Table 3-2 with the use of CDIV = (0.01, 0.01). The two sets of results are nearly the same, and they indicate that for the three years modeled all 98th percentile daily predictions of the change in visibility are below 0.5 deciview.

Table 3-1 Results of Updated BART Modeling with CDIV = (0, 0)

Class I Area	Met Year 2000				Met Year 2001				Met Year 2002				00-02 Peak
	Days above		MAX dv Δ B_{ext}	8th Highest Δ dv	Days above		MAX dv Δ B_{ext}	8th Highest Δ dv	Days above		MAX dv Δ B_{ext}	8th Highest Δ dv	8th Highest Δ dv
	0.5 dv Δ B_{ext}	1.0 dv Δ B_{ext}			0.5 dv Δ B_{ext}	1.0 dv Δ B_{ext}			0.5 dv Δ B_{ext}	1.0 dv Δ B_{ext}			
Lostwood W	1	0	0.69	0.19	0	0	0.38	0.23	0	0	0.31	0.11	0.23
T. Roosevelt NP	2	0	0.75	0.27	3	0	0.98	0.27	1	0	0.54	0.27	0.27

Table 3-2 Results of Updated BART Modeling with CDIV = (0.01, 0.01)

Class I Area	Met Year 2000				Met Year 2001				Met Year 2002				00-02 Peak
	Days above		MAX dv Δ B_{ext}	8th Highest Δ dv	Days above		MAX dv Δ B_{ext}	8th Highest Δ dv	Days above		MAX dv Δ B_{ext}	8th Highest Δ dv	8th Highest Δ dv
	0.5 dv Δ B_{ext}	1.0 dv Δ B_{ext}			0.5 dv Δ B_{ext}	1.0 dv Δ B_{ext}			0.5 dv Δ B_{ext}	1.0 dv Δ B_{ext}			
Lostwood W	1	0	0.82	0.20	0	0	0.40	0.23	0	0	0.32	0.11	0.23
T. Roosevelt NP	3	0	0.75	0.26	3	1	1.10	0.27	1	0	0.55	0.28	0.28

Based upon the predicted change in visibility in the two North Dakota Class I areas associated with the modeled peak daily baseline emissions reported above in either Table 3-1 or 3-2, Heskett Unit 2 is not subject to BART.

4.0 References

Environmental Protection Agency, 2009: Clarification on EPA-FLM Recommended Settings for CALMET. Memorandum. U.S. Environmental Protection Agency, Research Triangle Park, NC.

Environmental Protection Agency, 2009: DRAFT - Reassessment of the Interagency Workgroup on Air Quailty Modeling (IWAQM) Phase 2 Summary Report: Revisions to Phase 2 Recommendations. EPA-454/R-09-XXX. U.S. Environmental Protection Agency, Research Triangle Park, NC.

Environmental Protection Agency, 2003b: Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule. EPA-454/B-03-005. U.S. Environmental Protection Agency, Research Triangle Park, NC.

Environmental Protection Agency (EPA), Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, EPA-454/R-98-019, page 14, December, 1998

Federal Land Managers' Air Quality Related Values Workgroup (FLAG). Phase I Report Revised Draft, June 2008.

North Dakota Department of Health. November 2005. Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final). North Dakota Department of Health, Division of Air Quality,1200 Missouri Avenue, Bismarck, ND

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
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December 21, 2009

Ms. Callie Videtich (AP-AR)
Director, Air Programs
U.S. EPA, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Re: MDU Heskett Station Unit 2
BART Applicability

Dear ~~Ms. Videtich~~: Callie

On October 23, 2009, your staff provided comments on the draft North Dakota Regional Haze State Implementation Plan (SIP) revision. One of the comments concerned the exemption of Montana Dakota Utilities (MDU) Heskett Station Unit 2 from the BART requirements. EPA expressed concerns regarding the MDU modeling methodology, and requested that MDU remodel for BART applicability based on the latest EPA preferred model settings.

A conference call was held on November 17, 2009 with MDU, AECOM - MDU's consultant, EPA Region 8 representatives, FLM representatives and the Department to discuss the concerns. During the call, MDU agreed to remodel Heskett Unit 2 to determine BART applicability using preferred model settings identified by EPA and the FLMs. Although the Department does not necessarily agree with all of EPA's proposed model settings nor do we agree with treatment of combining the three units of TRNP as suggested by the FLMs, we did agree to allow the modeling to proceed in an effort to bring closure in addressing EPA's concerns and to meet the tight time constraints for submitting the State's RH SIP.

MDU has remodeled using the latest EPA preferred model settings and the FLMs treatment of Theodore Roosevelt National Park. The Department has reviewed MDU's updated analysis (attached) and has confirmed the modeling results. Based on the results of MDU's previous analysis and the updated analysis requested by EPA, the Department concludes MDU Heskett Station Unit 2 to be exempt from the BART requirements.

If you have any questions, please feel free to contact us.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:saj
Enc:
xc/enc: Abby Krebsbach, MDU
Tim Allen, U.S. Fish & Wildlife Service
John Notar, National Park Service
Trent Wickman, U.S. Forest Service
Amy Platt, EPA

FW BART CALPUFF Modeling Protocol for MDU Heskett

From: Weber, Steve F.
Sent: Friday, January 08, 2010 1:30 PM
To: Bachman, Tom A.
Subject: FW: BART CALPUFF Modeling Protocol for MDU Heskett
Attachments: MDU BART Modeling Protocol_AECOM page 2-3.pdf; MDU BART Modeling Protocol_AECOM.PDF

Tom,

As requested.

Note that MDU used the referenced default setting in their last submittal.

Steve

-----Original Message-----
From: Golden.Kevin@epamail.epa.gov [mailto:Golden.Kevin@epamail.epa.gov]
Sent: Thursday, December 10, 2009 9:14 AM
To: Weber, Steve F.
Cc: Abbie.Krebsbach@mdu.com; John_Notar@nps.gov; Tim Allen; O'Clair, Terry L.; Platt.Amy@epamail.epa.gov
Subject: Re: BART CALPUFF Modeling Protocol for MDU Heskett

With one exception the updated BART modeling protocol is acceptable to EPA.

The remaining issue is the CDIV switch in CALPUFF. The EPA regulatory default setting for
the Calpuff CDIV value is .01/.01 not 0/0 as the applicant has proposed.
The proposed setting should be submitted for review along with a specific request for a
regulatory change. The applicant did not give a technical reason for the setting change. If the
applicant decides to use the default setting EPA will accept the protocol.

On a non-technical issue, the narrative in the protocol describing the regulatory background
should be edited to note that EPA did not concur with the applicants 2006 exemption modeling
per a August 2008 letter from EPA.

From: "Weber, Steve F." <sweber@nd.gov>

To: Kevin Golden/R8/USEPA/US@EPA

Cc: Tim Allen <tim@den.nps.gov>, "John_Notar@nps.gov" <John_Notar@nps.gov>, "Abbie.Krebsbach@mdu.com" <Abbie.Krebsbach@mdu.com>, "O'Clair, Terry L." <toclair@nd.gov>

Date: 12/01/2009 09:24 AM

Subject: BART CALPUFF Modeling Protocol for MDU Heskett

Kevin,

Based on discussions among MDU, EPA, FLM, and NDDH (North Dakota Dept of Health) representatives during a conference call on November 17, 2009, MDU has provided the attached, updated BART modeling protocol for MDU Heskett Unit 2. The NDDH has reviewed the protocol and finds that it address all concerns expressed during the November 17 call, and is consistent with the latest modeling guidance from EPA and FLMs.

Note that the attachments include a corrected page 2-3.

If you have any questions regarding the proposed methodology, please let me know.

Steve

Steve Weber
Air Quality Division
ND Depth of Health
(701) 328-5188

(See attached file: MDU BART Modeling Protocol_AECOM page 2-3.pdf)(See attached file: MDU BART Modeling Protocol_AECOM.PDF)

From: Weber, Steve F.
Sent: Friday, February 05, 2010 9:07 AM
To: Bachman, Tom A.
Subject: FW: Heskett BART modeling protocol

From: Weber, Steve F.
Sent: Tuesday, December 01, 2009 9:33 AM
To: 'Paine, Bob'
Cc: O'Clair, Terry L.; 'Abbie.Krebsbach@mdu.com'
Subject: RE: Heskett BART modeling protocol

Bob,

The North Dakota Department of Health has reviewed your proposed BART CALPUFF modeling protocol for MDU Heskett Station Unit 2 titled, “CALPUFF Visibility Modeling Protocol: MDU Heskett Unit 2 BART Analysis” (November 2009). We have determined that this protocol is acceptable for BART CALPUFF modeling for Heskett Unit 2.

If you have any questions, please contact me.

Steve

Steve Weber
Air Quality Division
ND Dept of Health
(701) 328-5188

From: Paine, Bob [mailto:bob.paine@aecom.com]
Sent: Monday, November 30, 2009 2:31 PM
To: Weber, Steve F.
Subject: Heskett BART modeling protocol

Steve,

I hope that you have received our updated Heskett BART modeling protocol by now. We are hoping for a quick review (by you and by any EPA and FLM reviewers) so that we can quickly proceed with the modeling. If you have an approximate schedule for the review and approval (hopefully), let me know. We are hoping to be doing final modeling this week.

Regards,

Bob Paine, CCM, QEP
Technical Director
Environment
D 978.589.3164
bob.paine@aecom.com

AECOM
2 Technology Park Drive, Westford, MA 01886
T 978.589.3000 F 978.589.3100
www.aecom.com

From: Platt.Amy@epamail.epa.gov
Sent: Monday, February 08, 2010 9:51 AM
To: Bachman, Tom A.; Morales.Monica@epamail.epa.gov
Cc: Golden.Kevin@epamail.epa.gov
Subject: Re: Heskett Unit 2

Tom:

Based on our review of AECOM's December 17, 2009 "Updated BART Modeling Results for R.M. Heskett Station Unit 2," our preliminary conclusions are that an EPA-approved protocol was used, and the results indicate that Heskett Unit 2's impact was less than the subject-to-BART threshold of 0.5 deciviews. Therefore, it appears appropriate for the State to determine that the source is not subject to BART. However, the source may still qualify for potential emission reductions under the Reasonable Progress requirements of the Regional Haze Rule. In addition, please note that we can only reach a final decision regarding the modeling and its results, and any other aspect of the Regional Haze SIP, through our own notice and comment rulemaking.

Thanks for your follow-up on this one......Amy

Amy Platt, Environmental Scientist, 8P-AR
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NORTH DAKOTA
DEPARTMENT *of* HEALTH

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1200 Missouri Avenue, Bismarck, ND 58504-5264
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November 30, 2005

FILE

Cris Miller, P.E.
Environmental Coordinator
Basin Electric Power Cooperative
1717 E. Interstate Avenue
Bismarck, ND 58503

Dear Mr. Miller:

As specified in the June 15, 2005 final amendments to the EPA July, 1999 regional haze rule, the Department has completed visibility modeling to determine which North Dakota BART-eligible (Best Available Retrofit Technology) sources are subject to BART. The Department's visibility analysis for this BART screening followed the protocol outlined in "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota" (North Dakota Department of Health, November, 2005).

As you are aware, the Basin Electric Leland Olds Generating Station Units 1 and 2 are BART-eligible sources. Completed visibility modeling for the Leland Olds Station (Units 1 and 2 combined) indicates that the maximum 98th percentile delta-deciview prediction for the facility exceeds the BART screening threshold of 0.5 deciviews. Therefore, Leland Olds Units 1 and 2 are subject to BART.

Two summaries of modeling results are enclosed. Attachment A provides a summary of 98th percentile predictions for the worst-case meteorological year for all BART-eligible facilities. Attachment B provides more detailed results specific to the Leland Olds Generating Station. Included in Attachment B are results for all delta-deciview metrics recommended in the North Dakota protocol, for each year of meteorological data. Also provided are worst-case day and receptor, and the percent contribution for each species.

If you have any questions regarding these results, please contact Steve Weber or Rob White of my staff at (701)328-5188. We look forward to working with you to develop appropriate BART control strategies for Leland Olds Units 1 and 2.

Sincerely,

Steve Weber for
Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/SW:csc
Enc:

Environmental Health Section Chief's Office 701.328.5150
Air Quality 701.328.5188
Municipal Facilities 701.328.5211
Waste Management 701.328.5166
Water Quality 701.328.5210

Attachment A

Summary of BART Screening Results
98th Percentile Prediction for Worst-case Met. Year (2000-2002)
(24-hr Delta-Deciview)

	TRNP South	TRNP North	TRNP Elk. Ranch	Lostwood NWA
Leland Olds Station	6.22	5.32	4.49	5.42
Milton R Young Station	6.69	5.58	6.10	4.88
Coal Creek Station	4.48	3.56	3.04	4.04
Stanton Station Unit 1	1.68	1.54	1.43	1.35
Heskett Station Unit 2	0.82	0.54	0.61	0.58
Mandan Refinery	0.05	0.04	0.04	0.04

29-Nov-05

Attachment B

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Leland Olds Station (base case) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Leland Olds Station (Units 1+2) - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                              SEQ     ND          % of Modeled Extinction by Species
                       DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                       ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV       7.676     9.909     2.234   2000   74    49    103   2.80    89.58    10.24     0.11     0.07
  98th %tile Delta-DV    3.269     5.503     2.234   2000   71    45     45   2.80    72.73    26.87     0.31     0.10
  90th %tile Delta-DV    0.941     3.111     2.170   2000  161    53    107   2.50    95.82     3.74     0.27     0.17

  Number of days with Delta-Deciview > 0.50:    56
  Number of days with Delta-Deciview > 1.00:    35
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV       6.496     8.730     2.234   2000   72    82     71   2.80    77.67    22.01     0.26     0.07
  98th %tile Delta-DV    3.596     5.830     2.234   2000   44    83    112   2.80    62.20    37.34     0.34     0.11
  90th %tile Delta-DV    0.945     3.179     2.234   2000   48    82     71   2.80    79.57    20.37     0.02     0.03

  Number of days with Delta-Deciview > 0.50:    53
  Number of days with Delta-Deciview > 1.00:    34
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV       8.972    11.206     2.234   2000   74    90     72   2.80    98.74     1.08     0.10     0.07
  98th %tile Delta-DV    2.376     4.609     2.234   2000   54    90     72   2.80    83.67    16.04     0.21     0.07
  90th %tile Delta-DV    0.769     2.897     2.127   2000  101    90     72   2.30    62.90    36.48     0.44     0.17

  Number of days with Delta-Deciview > 0.50:    49
  Number of days with Delta-Deciview > 1.00:    28
  Max number of consecutive days with Delta-Deciview > 0.50:     3


LOSTWOOD NWA

  Largest Delta-DV      11.303    13.578     2.275   2000   47    99     81   2.90    98.80     0.98     0.16     0.06
  98th %tile Delta-DV    3.726     6.001     2.275   2000   48    99     81   2.90    80.59    19.28     0.09     0.04
  90th %tile Delta-DV    1.646     3.878     2.232   2000  209    99     81   2.70    80.47    18.08     1.09     0.36

  Number of days with Delta-Deciview > 0.50:    78
  Number of days with Delta-Deciview > 1.00:    56
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Leland Olds Station (base case) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Leland Olds Station (Units 1+2) - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                SEQ    ND            % of Modeled Extinction by Species
                        DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                        ----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV       10.896    13.129    2.234   2002   73    51    105   2.80    91.62    8.03    0.26    0.08
  98th %tile Delta-DV     6.222     8.455    2.234   2002   64     4      4   2.80    67.53   32.10    0.26    0.11
  90th %tile Delta-DV     1.617     3.766    2.149   2002  189    51    105   2.40    97.79    1.34    0.69    0.18

  Number of days with Delta-Deciview > 0.50:      63
  Number of days with Delta-Deciview > 1.00:      48
  Max number of consecutive days with Delta-Deciview > 0.50:     6


TRNP NORTH UNIT

  Largest Delta-DV       11.862    14.096    2.234   2002   73    89    118   2.80    80.01   19.53    0.37    0.09
  98th %tile Delta-DV     5.322     7.556    2.234   2002   50    83    112   2.80    62.02   37.50    0.36    0.11
  90th %tile Delta-DV     1.213     3.467    2.255   2002   30    82     71   2.90    79.74   20.18    0.05    0.03

  Number of days with Delta-Deciview > 0.50:      61
  Number of days with Delta-Deciview > 1.00:      41
  Max number of consecutive days with Delta-Deciview > 0.50:     5


TRNP ELKHORN RANCH

  Largest Delta-DV       11.392    13.625    2.234   2002   73    90     72   2.80    88.63   10.98    0.30    0.09
  98th %tile Delta-DV     4.490     6.617    2.127   2002  293    90     72   2.30    72.61   26.42    0.75    0.23
  90th %tile Delta-DV     0.858     2.964    2.106   2002  219    90     72   2.20    97.08    2.60    0.21    0.11

  Number of days with Delta-Deciview > 0.50:      56
  Number of days with Delta-Deciview > 1.00:      34
  Max number of consecutive days with Delta-Deciview > 0.50:     4


LOSTWOOD NWA

  Largest Delta-DV        8.315    10.591    2.275   2002   74    97     79   2.90    84.80   15.00    0.14    0.05
  98th %tile Delta-DV     4.762     7.102    2.340   2002  351    96     78   3.20    84.18   15.30    0.40    0.12
  90th %tile Delta-DV     1.125     3.271    2.145   2002  247    97     79   2.30    93.71    4.95    1.02    0.32

  Number of days with Delta-Deciview > 0.50:      61
  Number of days with Delta-Deciview > 1.00:      41
  Max number of consecutive days with Delta-Deciview > 0.50:     4
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Leland Olds Station (base case) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Leland Olds Station (Units 1+2) - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                SEQ     ND              % of Modeled Extinction by Species
                       DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                       ----------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV       6.997     9.230     2.234   2001   64    46     46   2.80    79.37    20.50     0.09     0.03
  98th %tile Delta-DV    3.187     5.315     2.127   2001   92    51    105   2.30    61.09    38.48     0.32     0.10
  90th %tile Delta-DV    0.869     2.996     2.127   2001   98    45     45   2.30    41.60    56.84     1.26     0.30

  Number of days with Delta-Deciview > 0.50:    50
  Number of days with Delta-Deciview > 1.00:    35
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP NORTH UNIT

  Largest Delta-DV       7.950    10.183     2.234   2001   64    82     71   2.80    85.72    14.11     0.13     0.04
  98th %tile Delta-DV    4.293     6.399     2.106   2001  261    89    118   2.20    96.58     3.15     0.19     0.08
  90th %tile Delta-DV    1.208     3.484     2.276   2001  339    63     52   3.00    48.01    51.03     0.79     0.17

  Number of days with Delta-Deciview > 0.50:    65
  Number of days with Delta-Deciview > 1.00:    44
  Max number of consecutive days with Delta-Deciview > 0.50:     6


TRNP ELKHORN RANCH

  Largest Delta-DV       6.835     9.069     2.234   2001   64    90     72   2.80    80.33    19.54     0.09     0.03
  98th %tile Delta-DV    3.070     5.304     2.234   2001   84    90     72   2.80    68.67    30.97     0.27     0.09
  90th %tile Delta-DV    0.633     2.761     2.127   2001  101    90     72   2.30    84.53    15.40     0.04     0.03

  Number of days with Delta-Deciview > 0.50:    44
  Number of days with Delta-Deciview > 1.00:    24
  Max number of consecutive days with Delta-Deciview > 0.50:     3


LOSTWOOD NWA

  Largest Delta-DV      12.197    14.536     2.340   2001  326    97     79   3.20    97.10     2.54     0.27     0.08
  98th %tile Delta-DV    5.419     7.564     2.145   2001  261    98     80   2.30    93.51     5.83     0.54     0.13
  90th %tile Delta-DV    1.541     3.686     2.145   2001  260    97     79   2.30    89.77    10.06     0.13     0.05

  Number of days with Delta-Deciview > 0.50:    80
  Number of days with Delta-Deciview > 1.00:    53
  Max number of consecutive days with Delta-Deciview > 0.50:     6
```

NORTH DAKOTA
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November 30, 2005

FILE

John Graves, P.E.
Environmental Manager
Minnkota Power Cooperative, Inc.
P.O. Box 13200
Grand Forks, ND 58208

Dear Mr. Graves:

As specified in the June 15, 2005 final amendments to the EPA July, 1999 regional haze rule, the Department has completed visibility modeling to determine which North Dakota BART-eligible (Best Available Retrofit Technology) sources are subject to BART. The Department's visibility analysis for this BART screening followed the protocol outlined in "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota" (North Dakota Department of Health, November, 2005).

As you are aware, the Minnkota Milton R. Young Generating Station Units 1 and 2 are BART-eligible sources. Completed visibility modeling for Milton R. Young Station (Units 1 and 2 combined) indicates that the maximum 98th percentile delta-deciview prediction for the facility exceeds the BART screening threshold of 0.5 deciviews. Therefore, Milton R. Young Units 1 and 2 are subject to BART.

Two summaries of modeling results are enclosed. Attachment A provides a summary of 98th percentile predictions for the worst-case meteorological year for all BART-eligible facilities. Attachment B provides more detailed results specific to the Milton R. Young Generating Station. Included in Attachment B are results for all delta-deciview metrics recommended in the North Dakota protocol, for each year of meteorological data. Also provided are worst-case day and receptor, and the percent contribution for each species.

If you have any questions regarding these results, please contact Steve Weber or Rob White of my staff at (701)328-5188. We look forward to working with you to develop appropriate BART control strategies for Milton R. Young Units 1 and 2.

Sincerely,

Steve Weber for

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/SW:csc
Enc:

Environmental Health Section Chief's Office 701.328.5150	Air Quality 701.328.5188	Municipal Facilities 701.328.5211	Waste Management 701.328.5166	Water Quality 701.328.5210

Attachment A

Summary of BART Screening Results
98th Percentile Prediction for Worst-case Met. Year (2000-2002)
(24-hr Delta-Deciview)

	TRNP South	TRNP North	TRNP Elk. Ranch	Lostwood NWA
Leland Olds Station	6.22	5.32	4.49	5.42
Milton R Young Station	6.69	5.58	6.10	4.88
Coal Creek Station	4.48	3.56	3.04	4.04
Stanton Station Unit 1	1.68	1.54	1.43	1.35
Heskett Station Unit 2	0.82	0.54	0.61	0.58
Mandan Refinery	0.05	0.04	0.04	0.04

29-Nov-05

Attachment B

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Milton R Young Station (base case) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Milton R Young Station (Units 1+2) - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                          SEQ    ND          % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV          8.396    10.630    2.234   2000   72    53    107   2.80    52.24   47.53    0.17    0.06
  98th %tile Delta-DV       2.813     5.088    2.276   2000  316    45     45   3.00    49.46   50.40    0.10    0.04
  90th %tile Delta-DV       1.010     3.158    2.149   2000  199    53    107   2.40    91.23    8.14    0.44    0.19

  Number of days with Delta-Deciview > 0.50:    57
  Number of days with Delta-Deciview > 1.00:    38
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP NORTH UNIT

  Largest Delta-DV          6.587     8.820    2.234   2000   66    71     60   2.80    63.04   36.71    0.19    0.07
  98th %tile Delta-DV       3.800     6.033    2.234   2000   74    67     56   2.80    60.75   39.18    0.03    0.04
  90th %tile Delta-DV       0.828     2.977    2.149   2000  190    67     56   2.40    80.73   18.89    0.30    0.08

  Number of days with Delta-Deciview > 0.50:    53
  Number of days with Delta-Deciview > 1.00:    32
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV          7.511     9.745    2.234   2000   74    90     72   2.80    87.78   12.12    0.04    0.05
  98th %tile Delta-DV       2.403     4.636    2.234   2000   69    90     72   2.80    44.55   55.23    0.15    0.07
  90th %tile Delta-DV       0.676     2.951    2.276   2000  336    90     72   3.00    36.33   63.43    0.18    0.06

  Number of days with Delta-Deciview > 0.50:    48
  Number of days with Delta-Deciview > 1.00:    27
  Max number of consecutive days with Delta-Deciview > 0.50:     3


LOSTWOOD NWA

  Largest Delta-DV          8.636    10.911    2.275   2000   47    97     79   2.90    96.21    3.64    0.10    0.05
  98th %tile Delta-DV       3.674     5.950    2.275   2000   70    93     75   2.90    40.63   59.17    0.13    0.07
  90th %tile Delta-DV       1.506     3.716    2.211   2000  158    93     75   2.60    48.18   50.90    0.67    0.25

  Number of days with Delta-Deciview > 0.50:    75
  Number of days with Delta-Deciview > 1.00:    53
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Milton R Young Station (base case) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Milton R Young Station (Units 1+2) - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                              SEQ     ND           % of Modeled Extinction by Species
                          DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                          ---------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV          5.982     8.216     2.234   2001   64    46     46   2.80   65.47    34.42     0.07     0.03
  98th %tile Delta-DV       3.284     5.390     2.106   2001  261    48    102   2.20   89.27    10.50     0.16     0.07
  90th %tile Delta-DV       0.794     2.900     2.106   2001  224    53    107   2.20   95.34     4.17     0.37     0.12

  Number of days with Delta-Deciview > 0.50:    47
  Number of days with Delta-Deciview > 1.00:    27
  Max number of consecutive days with Delta-Deciview > 0.50:      3


TRNP NORTH UNIT

  Largest Delta-DV          7.578     9.811     2.234   2001   64    82     71   2.80   66.87    33.02     0.08     0.03
  98th %tile Delta-DV       3.848     5.954     2.106   2001  260    85    114   2.20   93.69     6.09     0.16     0.06
  90th %tile Delta-DV       1.249     3.419     2.170   2001  175    82     71   2.50   97.03     2.23     0.57     0.18

  Number of days with Delta-Deciview > 0.50:    64
  Number of days with Delta-Deciview > 1.00:    45
  Max number of consecutive days with Delta-Deciview > 0.50:      5


TRNP ELKHORN RANCH

  Largest Delta-DV          5.707     7.941     2.234   2001   64    90     72   2.80   67.56    32.35     0.07     0.03
  98th %tile Delta-DV       3.543     5.818     2.276   2001  328    90     72   3.00   64.64    35.30     0.03     0.02
  90th %tile Delta-DV       0.590     2.865     2.276   2001  345    90     72   3.00   60.31    39.50     0.15     0.05

  Number of days with Delta-Deciview > 0.50:    41
  Number of days with Delta-Deciview > 1.00:    23
  Max number of consecutive days with Delta-Deciview > 0.50:      3


LOSTWOOD NWA

  Largest Delta-DV         12.974    15.313     2.340   2001  327    91     73   3.20   61.26    38.63     0.07     0.04
  98th %tile Delta-DV       4.875     7.151     2.275   2001   41    91     73   2.90   50.20    49.65     0.10     0.05
  90th %tile Delta-DV       1.586     3.926     2.340   2001  311    97     79   3.20   35.41    64.39     0.14     0.06

  Number of days with Delta-Deciview > 0.50:    77
  Number of days with Delta-Deciview > 1.00:    52
  Max number of consecutive days with Delta-Deciview > 0.50:      5
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Milton R Young Station (base case) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Milton R Young Station (Units 1+2) - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                             SEQ    ND             % of Modeled Extinction by Species
                     DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                     -------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV     11.011    13.245    2.234   2002   73    48    102   2.80    62.86    36.93     0.15     0.06
  98th %tile Delta-DV   6.693     8.926    2.234   2002   64    54    108   2.80    50.52    49.30     0.11     0.07
  90th %tile Delta-DV   1.394     3.628    2.234   2002   75    51    105   2.80    71.86    28.09     0.02     0.03

  Number of days with Delta-Deciview > 0.50:    66
  Number of days with Delta-Deciview > 1.00:    49
  Max number of consecutive days with Delta-Deciview > 0.50:     5


TRNP NORTH UNIT

  Largest Delta-DV     10.964    13.197    2.234   2002   73    58     47   2.80    55.28    44.49     0.17     0.06
  98th %tile Delta-DV   5.581     7.836    2.255   2002   26    63     52   2.90    48.31    51.36     0.26     0.08
  90th %tile Delta-DV   1.588     3.737    2.149   2002  184    82     71   2.40    97.43     2.05     0.38     0.14

  Number of days with Delta-Deciview > 0.50:    65
  Number of days with Delta-Deciview > 1.00:    45
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP ELKHORN RANCH

  Largest Delta-DV     11.808    14.042    2.234   2002   73    90     72   2.80    62.62    37.15     0.17     0.06
  98th %tile Delta-DV   6.103     8.378    2.276   2002  336    90     72   3.00    60.71    39.02     0.21     0.06
  90th %tile Delta-DV   0.950     3.077    2.127   2002  125    90     72   2.30    43.11    56.79     0.02     0.08

  Number of days with Delta-Deciview > 0.50:    53
  Number of days with Delta-Deciview > 1.00:    35
  Max number of consecutive days with Delta-Deciview > 0.50:     4


LOSTWOOD NWA

  Largest Delta-DV      7.423     9.698    2.275   2002   74    97     79   2.90    60.49    39.41     0.06     0.04
  98th %tile Delta-DV   4.112     6.387    2.275   2002   75    97     79   2.90    62.76    37.17     0.04     0.04
  90th %tile Delta-DV   1.219     3.364    2.145   2002   95    91     73   2.30    26.24    73.26     0.30     0.20

  Number of days with Delta-Deciview > 0.50:    61
  Number of days with Delta-Deciview > 1.00:    45
  Max number of consecutive days with Delta-Deciview > 0.50:     5
```

NORTH DAKOTA
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www.ndhealth.gov

November 30, 2005

FILE

Mr. Jay Skabo
Environmental Coordinator
Montana-Dakota Utilities
400 North Fourth Street
Bismarck, ND 58501

Dear Mr. Skabo:

As specified in the June 15, 2005 final amendments to the EPA July, 1999 regional haze rule, the Department has completed visibility modeling to determine which North Dakota BART-eligible (Best Available Retrofit Technology) sources are subject to BART. The Department's visibility analysis for this BART screening followed the protocol outlined in "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota" (North Dakota Department of Health, November, 2005).

As you are aware, the Montana-Dakota Utilities Heskett Unit 2 is a BART-eligible source. Completed visibility modeling for the Heskett Station Unit 2 indicates that the maximum 98th percentile delta-deciview prediction for the facility exceeds the BART screening threshold of 0.5 deciviews. Therefore, Heskett Unit 2 is subject to BART.

Two summaries of modeling results are enclosed. Attachment A provides a summary of 98th percentile predictions for the worst-case meteorological year for all BART-eligible facilities. Attachment B provides more detailed results specific to the Heskett Station Unit 2. Included in Attachment B are results for all delta-deciview metrics recommended in the North Dakota protocol, for each year of meteorological data. Also provided are worst-case day and receptor, and the percent contribution for each species.

If you have any questions regarding these results, please contact Steve Weber or Rob White of my staff at (701)328-5188. We look forward to working with you to develop an appropriate BART control strategy for Heskett Unit 2.

Sincerely,

Steve Weber for

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/SW:csc
Enc:

Attachment A

Summary of BART Screening Results
98th Percentile Prediction for Worst-case Met. Year (2000-2002)
(24-hr Delta-Deciview)

	TRNP South	TRNP North	TRNP Elk. Ranch	Lostwood NWA
Leland Olds Station	6.22	5.32	4.49	5.42
Milton R Young Station	6.69	5.58	6.10	4.88
Coal Creek Station	4.48	3.56	3.04	4.04
Stanton Station Unit 1	1.68	1.54	1.43	1.35
Heskett Station Unit 2	0.82	0.54	0.61	0.58
Mandan Refinery	0.05	0.04	0.04	0.04

29-Nov-05

Attachment B

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CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Heskett Station Unit 2 (base case) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Heskett Station (Unit 2) - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                 SEQ     ND              % of Modeled Extinction by Species
                       DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                       ---------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV       1.791     4.025     2.234   2000   74    46     46   2.80    82.01    17.62     0.01     0.36
  98th %tile Delta-DV    0.350     2.605     2.255   2000   11    52    106   2.90    73.39    25.94     0.02     0.66
  90th %tile Delta-DV    0.084     2.233     2.149   2000  199    51    105   2.40    95.76     3.40     0.04     0.79

  Number of days with Delta-Deciview > 0.50:      3
  Number of days with Delta-Deciview > 1.00:      1
  Max number of consecutive days with Delta-Deciview > 0.50:      1


TRNP NORTH UNIT

  Largest Delta-DV       1.120     3.353     2.234   2000   54    82     71   2.80    75.79    23.58     0.04     0.58
  98th %tile Delta-DV    0.355     2.631     2.276   2000  336    63     52   3.00    53.65    45.25     0.09     1.01
  90th %tile Delta-DV    0.102     2.208     2.106   2000  239    82     71   2.20    88.79    10.53     0.04     0.65

  Number of days with Delta-Deciview > 0.50:      6
  Number of days with Delta-Deciview > 1.00:      1
  Max number of consecutive days with Delta-Deciview > 0.50:      2


TRNP ELKHORN RANCH

  Largest Delta-DV       0.685     2.919     2.234   2000   74    90     72   2.80    82.49    17.16     0.01     0.34
  98th %tile Delta-DV    0.381     2.508     2.127   2000  106    90     72   2.30    70.64    28.49     0.06     0.80
  90th %tile Delta-DV    0.064     2.297     2.234   2000   37    90     72   2.80    66.93    32.38     0.03     0.66

  Number of days with Delta-Deciview > 0.50:      3
  Number of days with Delta-Deciview > 1.00:      0
  Max number of consecutive days with Delta-Deciview > 0.50:      1


LOSTWOOD NWA

  Largest Delta-DV       1.488     3.828     2.340   2000  349    99     81   3.20    73.22    26.34     0.01     0.43
  98th %tile Delta-DV    0.346     2.578     2.232   2000  209    99     81   2.70    82.84    15.72     0.08     1.36
  90th %tile Delta-DV    0.154     2.364     2.211   2000  158    91     73   2.60    69.46    28.04     0.09     2.41

  Number of days with Delta-Deciview > 0.50:      3
  Number of days with Delta-Deciview > 1.00:      1
  Max number of consecutive days with Delta-Deciview > 0.50:      2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Heskett Station Unit 2 (base case) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Heskett Station (Unit 2) - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                         SEQ    ND           % of Modeled Extinction by Species
                      DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3   %_PMC   %_PMF
                      ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV      0.719     2.973     2.255   2001   13    47    101   2.90    62.71    36.39    0.07    0.83
  98th %tile Delta-DV   0.351     2.478     2.127   2001  109    49    103   2.30    64.52    33.09    0.15    2.24
  90th %tile Delta-DV   0.069     2.196     2.127   2001   94    52    106   2.30    81.87    17.94    0.01    0.19

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1

TRNP NORTH UNIT

  Largest Delta-DV      2.349     4.603     2.255   2001   12    82     71   2.90    79.98    19.53    0.03    0.46
  98th %tile Delta-DV   0.536     2.812     2.276   2001  328    85    114   3.00    82.70    17.06    0.01    0.23
  90th %tile Delta-DV   0.110     2.216     2.106   2001  257    82     71   2.20    72.72    26.22    0.02    1.04

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2

TRNP ELKHORN RANCH

  Largest Delta-DV      0.884     3.139     2.255   2001   12    90     72   2.90    79.65    19.98    0.02    0.34
  98th %tile Delta-DV   0.400     2.675     2.276   2001  327    90     72   3.00    82.09    17.61    0.01    0.28
  90th %tile Delta-DV   0.052     2.158     2.106   2001  224    90     72   2.20    97.68     1.54    0.04    0.74

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2

LOSTWOOD NWA

  Largest Delta-DV      3.500     5.840     2.340   2001  327    93     75   3.20    78.40    21.23    0.02    0.35
  98th %tile Delta-DV   0.583     2.858     2.275   2001   89    99     81   2.90    73.25    26.20    0.02    0.53
  90th %tile Delta-DV   0.183     2.351     2.167   2001  233    99     81   2.40    89.27     9.66    0.07    0.99

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Heskett Station Unit 2 (base case) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Heskett Station (Unit 2) - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                SEQ     ND            % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)   DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                         -----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV         1.662     3.895      2.234   2002   73     47    101   2.80   74.31    25.21     0.04     0.44
  98th %tile Delta-DV      0.822     2.971      2.149   2002  199     28     28   2.40   79.43    18.89     0.12     1.56
  90th %tile Delta-DV      0.115     2.263      2.149   2002  198     54    108   2.40   91.94     7.02     0.06     0.98

  Number of days with Delta-Deciview > 0.50:    15
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV         2.116     4.350      2.234   2002   50     67     56   2.80   76.85    22.71     0.03     0.41
  98th %tile Delta-DV      0.496     2.666      2.170   2002  174     67     56   2.50   95.85     3.62     0.03     0.50
  90th %tile Delta-DV      0.142     2.375      2.234   2002   84     71     60   2.80   41.54    56.28     0.17     2.01

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV         1.673     3.906      2.234   2002   73     90     72   2.80   72.95    26.55     0.04     0.46
  98th %tile Delta-DV      0.606     2.839      2.234   2002   39     90     72   2.80   73.62    25.63     0.03     0.72
  90th %tile Delta-DV      0.090     2.217      2.127   2002  138     90     72   2.30   76.73    22.33     0.05     0.89

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV         0.677     2.953      2.275   2002   76     99     81   2.90   58.48    40.30     0.03     1.19
  98th %tile Delta-DV      0.457     2.797      2.340   2002  312     97     79   3.20   77.89    21.54     0.01     0.56
  90th %tile Delta-DV      0.102     2.269      2.167   2002  218     99     81   2.40   91.91     7.09     0.02     0.99

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

NORTH DAKOTA
DEPARTMENT of HEALTH

ENVIRONMENTAL HEALTH SECTION
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November 30, 2005

FILE

Ms. Dianne Stockdill
Environmental Coordinator
Great River Energy
2875 Third Street SW
Underwood, ND 58576

Dear Ms. Stockdill:

As specified in the June 15, 2005 final amendments to the EPA July, 1999 regional haze rule, the Department has completed visibility modeling to determine which North Dakota BART-eligible (Best Available Retrofit Technology) sources are subject to BART. The Department's visibility analysis for this BART screening followed the protocol outlined in "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota" (North Dakota Department of Health, November, 2005).

As you are aware, the Great River Energy Coal Creek Generating Station Units 1 and 2 are BART-eligible sources. Completed visibility modeling for the Coal Creek Station (Units 1 and 2 combined) indicates that the maximum 98th percentile delta-deciview prediction for the facility exceeds the BART screening threshold of 0.5 deciviews. Therefore, Coal Creek Units 1 and 2 are subject to BART.

Two summaries of modeling results are enclosed. Attachment A provides a summary of 98th percentile predictions for the worst-case meteorological year for all BART-eligible facilities. Attachment B provides more detailed results specific to the Coal Creek Generating Station. Included in Attachment B are results for all delta-deciview metrics recommended in the North Dakota protocol, for each year of meteorological data. Also provided are worst-case day and receptor, and the percent contribution for each species.

If you have any questions regarding these results, please contact Steve Weber or Rob White of my staff at (701)328-5188. We look forward to working with you to develop appropriate BART control strategies for Coal Creek Units 1 and 2.

Sincerely,

Steve Weber for

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/SW:csc
Enc:
xc/enc: Deb Nelson - Great River Energy

Attachment A

Summary of BART Screening Results
98th Percentile Prediction for Worst-case Met. Year (2000-2002)
(24-hr Delta-Deciview)

	TRNP South	TRNP North	TRNP Elk. Ranch	Lostwood NWA
Leland Olds Station	6.22	5.32	4.49	5.42
Milton R Young Station	6.69	5.58	6.10	4.88
Coal Creek Station	4.48	3.56	3.04	4.04
Stanton Station Unit 1	1.68	1.54	1.43	1.35
Heskett Station Unit 2	0.82	0.54	0.61	0.58
Mandan Refinery	0.05	0.04	0.04	0.04

29-Nov-05

Attachment B

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Coal Creek Station (base case) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Coal Creek Station (Units 1+2) - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                  SEQ    ND          % of Modeled Extinction by Species
                          DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                          -----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

   Largest Delta-DV         5.024     7.258     2.234   2000   72    53    107   2.80   66.43   32.84    0.25    0.48
   98th %tile Delta-DV      2.176     4.346     2.170   2000  164    51    105   2.50   97.09    1.47    0.53    0.92
   90th %tile Delta-DV      0.553     2.680     2.127   2000  100    51    105   2.30   63.30   35.11    0.55    1.04

   Number of days with Delta-Deciview > 0.50:    41
   Number of days with Delta-Deciview > 1.00:    22
   Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

   Largest Delta-DV         4.550     6.783     2.234   2000   74    67     56   2.80   82.48   17.04    0.06    0.42
   98th %tile Delta-DV      1.836     4.069     2.234   2000   36    82     71   2.80   58.41   40.68    0.25    0.66
   90th %tile Delta-DV      0.586     2.734     2.149   2000  183    82     71   2.40   93.83    4.90    0.41    0.86

   Number of days with Delta-Deciview > 0.50:    41
   Number of days with Delta-Deciview > 1.00:    19
   Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

   Largest Delta-DV         4.813     7.046     2.234   2000   74    90     72   2.80   78.69   20.85    0.07    0.40
   98th %tile Delta-DV      1.391     3.497     2.106   2000  265    90     72   2.20   87.87   11.21    0.28    0.64
   90th %tile Delta-DV      0.401     2.635     2.234   2000   56    90     72   2.80   74.35   24.92    0.22    0.51

   Number of days with Delta-Deciview > 0.50:    35
   Number of days with Delta-Deciview > 1.00:    15
   Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

   Largest Delta-DV         5.654     7.930     2.275   2000   47    99     81   2.90   86.27   13.15    0.19    0.39
   98th %tile Delta-DV      2.157     4.432     2.275   2000   72    97     79   2.90   69.75   29.78    0.16    0.30
   90th %tile Delta-DV      0.945     3.177     2.232   2000  204    96     78   2.70   66.55   32.48    0.34    0.63

   Number of days with Delta-Deciview > 0.50:    58
   Number of days with Delta-Deciview > 1.00:    33
   Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Coal Creek Station (base case) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Coal Creek Station (Units 1+2) - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                SEQ    ND              % of Modeled Extinction by Species
                          DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                          -----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV          5.001     7.235     2.234   2001   64    52    106   2.80    75.58    24.10     0.10     0.22
  98th %tile Delta-DV       2.181     4.287     2.106   2001  257    48    102   2.20    80.18    18.59     0.43     0.80
  90th %tile Delta-DV       0.466     2.572     2.106   2001  254    45     45   2.20    94.17     3.91     0.58     1.34

  Number of days with Delta-Deciview > 0.50:    34
  Number of days with Delta-Deciview > 1.00:    21
  Max number of consecutive days with Delta-Deciview > 0.50:      3


TRNP NORTH UNIT

  Largest Delta-DV          6.322     8.555     2.234   2001   64    82     71   2.80    75.32    24.29     0.13     0.26
  98th %tile Delta-DV       2.094     4.221     2.127   2001  100    82     71   2.30    76.82    22.82     0.07     0.29
  90th %tile Delta-DV       0.694     2.928     2.234   2001   62    82     71   2.80    80.07    19.61     0.08     0.24

  Number of days with Delta-Deciview > 0.50:    46
  Number of days with Delta-Deciview > 1.00:    25
  Max number of consecutive days with Delta-Deciview > 0.50:      4


TRNP ELKHORN RANCH

  Largest Delta-DV          5.006     7.240     2.234   2001   64    90     72   2.80    76.29    23.40     0.11     0.21
  98th %tile Delta-DV       1.949     4.076     2.127   2001   92    90     72   2.30    56.05    42.91     0.35     0.69
  90th %tile Delta-DV       0.365     2.493     2.127   2001  109    90     72   2.30    61.06    37.85     0.27     0.82

  Number of days with Delta-Deciview > 0.50:    27
  Number of days with Delta-Deciview > 1.00:    16
  Max number of consecutive days with Delta-Deciview > 0.50:      3


LOSTWOOD NWA

  Largest Delta-DV          6.517     8.793     2.275   2001   64    97     79   2.90    82.16    17.18     0.17     0.48
  98th %tile Delta-DV       4.038     6.313     2.275   2001   63    91     73   2.90    82.39    17.32     0.08     0.21
  90th %tile Delta-DV       0.984     3.151     2.167   2001  232    91     73   2.40    88.98     9.56     0.29     1.17

  Number of days with Delta-Deciview > 0.50:    56
  Number of days with Delta-Deciview > 1.00:    35
  Max number of consecutive days with Delta-Deciview > 0.50:      6
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Coal Creek Station (base case) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Coal Creek Station (Units 1+2) - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                SEQ     ND           % of Modeled Extinction by Species
                       DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                       -------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        6.675     8.908    2.234   2002   78    46     46   2.80    79.57    19.89    0.10     0.44
  98th %tile Delta-DV     4.475     6.730    2.255   2002   26    47    101   2.90    63.14    36.13    0.27     0.46
  90th %tile Delta-DV     0.971     3.077    2.106   2002  270    53    107   2.20    58.87    39.49    0.62     1.02

  Number of days with Delta-Deciview > 0.50:    50
  Number of days with Delta-Deciview > 1.00:    36
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP NORTH UNIT

  Largest Delta-DV       10.081    12.314    2.234   2002   73    89    118   2.80    65.93    33.24    0.33     0.49
  98th %tile Delta-DV     3.557     5.664    2.106   2002  250    82     71   2.20    89.34     9.05    0.68     0.93
  90th %tile Delta-DV     0.706     2.834    2.127   2002  152    85    114   2.30    92.23     6.33    0.38     1.06

  Number of days with Delta-Deciview > 0.50:    45
  Number of days with Delta-Deciview > 1.00:    27
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP ELKHORN RANCH

  Largest Delta-DV        8.644    10.878    2.234   2002   73    90     72   2.80    69.59    29.70    0.26     0.45
  98th %tile Delta-DV     3.039     5.315    2.276   2002  336    90     72   3.00    59.83    39.18    0.44     0.55
  90th %tile Delta-DV     0.581     2.708    2.127   2002   95    90     72   2.30    56.20    42.67    0.31     0.82

  Number of days with Delta-Deciview > 0.50:    42
  Number of days with Delta-Deciview > 1.00:    21
  Max number of consecutive days with Delta-Deciview > 0.50:     4


LOSTWOOD NWA

  Largest Delta-DV        6.332     8.608    2.275   2002   74    97     79   2.90    71.70    27.78    0.17     0.35
  98th %tile Delta-DV     3.190     5.487    2.297   2002   29    97     79   3.00    67.24    32.23    0.19     0.34
  90th %tile Delta-DV     0.707     2.852    2.145   2002  247    97     79   2.30    96.30     1.90    0.59     1.21

  Number of days with Delta-Deciview > 0.50:    45
  Number of days with Delta-Deciview > 1.00:    29
  Max number of consecutive days with Delta-Deciview > 0.50:     4
```

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
1200 Missouri Avenue, Bismarck, ND 58504-5264
P.O. Box 5520, Bismarck, ND 58506-5520
701.328.5200 (fax)
www.ndhealth.gov

November 30, 2005

FILE

Mr. Steve Smokey
Environmental Coordinator
Great River Energy
4001 Highway 200A
Stanton, ND 58571

Dear Mr. Smokey:

As specified in the June 15, 2005 final amendments to the EPA July, 1999 regional haze rule, the Department has completed visibility modeling to determine which North Dakota BART-eligible (Best Available Retrofit Technology) sources are subject to BART. The Department's visibility analysis for this BART screening followed the protocol outlined in "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota" (North Dakota Department of Health, November, 2005).

As you are aware, the Great River Energy Stanton Generating Station Unit 1 is a BART-eligible source. Completed visibility modeling for Stanton Station Unit 1 indicates that the maximum 98th percentile delta-deciview prediction for the facility exceeds the BART screening threshold of 0.5 deciviews. Therefore, Stanton Unit 1 is subject to BART.

Two summaries of modeling results are enclosed. Attachment A provides a summary of 98th percentile predictions for the worst-case meteorological year for all BART-eligible facilities. Attachment B provides more detailed results specific to the Stanton Station Unit 1. Included in Attachment B are results for all delta-deciview metrics recommended in the North Dakota protocol, for each year of meteorological data. Also provided are worst-case day and receptor, and the percent contribution for each species.

If you have any questions regarding these results, please contact Steve Weber or Rob White of my staff at (701)328-5188. We look forward to working with you to develop an appropriate BART control strategy for Stanton Station Unit 1.

Sincerely,

Steve Weber for

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/SW:csc
Enc:
xc/enc: Deb Nelson - Great River Energy

Attachment A

Summary of BART Screening Results
98th Percentile Prediction for Worst-case Met. Year (2000-2002)
(24-hr Delta-Deciview)

	TRNP South	TRNP North	TRNP Elk. Ranch	Lostwood NWA
Leland Olds Station	6.22	5.32	4.49	5.42
Milton R Young Station	6.69	5.58	6.10	4.88
Coal Creek Station	4.48	3.56	3.04	4.04
Stanton Station Unit 1	1.68	1.54	1.43	1.35
Heskett Station Unit 2	0.82	0.54	0.61	0.58
Mandan Refinery	0.05	0.04	0.04	0.04

29-Nov-05

Attachment B

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (base case) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station (Unit 1) - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                            SEQ     ND             % of Modeled Extinction by Species
                       DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                       ----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV      3.134     5.367     2.234    2000   74    48    102   2.80    82.39    17.54    0.05     0.01
  98th %tile Delta-DV   0.937     3.170     2.234    2000   71    45     45   2.80    73.49    26.34    0.14     0.02
  90th %tile Delta-DV   0.228     2.356     2.127    2000  110    49    103   2.30    52.31    46.77    0.79     0.13

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV      3.031     5.264     2.234    2000   36    82     71   2.80    70.43    29.39    0.15     0.03
  98th %tile Delta-DV   0.947     3.181     2.234    2000   44    83    112   2.80    62.34    37.42    0.20     0.04
  90th %tile Delta-DV   0.221     2.327     2.106    2000  261    83    112   2.20    91.67     7.86    0.41     0.07

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV      3.787     6.020     2.234    2000   74    90     72   2.80    83.38    16.56    0.05     0.01
  98th %tile Delta-DV   0.868     3.101     2.234    2000   44    90     72   2.80    66.10    33.73    0.14     0.03
  90th %tile Delta-DV   0.184     2.312     2.127    2000  100    90     72   2.30    80.07    19.68    0.21     0.04

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV      4.385     6.660     2.275    2000   47    97     79   2.90    86.50    13.42    0.06     0.01
  98th %tile Delta-DV   0.991     3.267     2.275    2000   72    97     79   2.90    80.71    19.22    0.06     0.01
  90th %tile Delta-DV   0.344     2.576     2.232    2000  212    99     81   2.70    98.41     1.47    0.09     0.03

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (base case) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station (Unit 1) - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                          SEQ     ND          % of Modeled Extinction by Species
                        DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                        ----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.736     3.970     2.234   2001   64    52    106   2.80    84.43    15.53     0.04     0.01
  98th %tile Delta-DV     0.901     3.177     2.276   2001  329    53    107   3.00    69.58    30.05     0.30     0.07
  90th %tile Delta-DV     0.214     2.447     2.234   2001   43    52    106   2.80    82.16    17.79     0.04     0.02

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:      2


TRNP NORTH UNIT

  Largest Delta-DV        4.052     6.307     2.255   2001   12    83    112   2.90    82.21    17.66     0.11     0.02
  98th %tile Delta-DV     1.205     3.438     2.234   2001   42    82     71   2.80    82.36    17.57     0.06     0.02
  90th %tile Delta-DV     0.319     2.467     2.149   2001  195    85    114   2.40    97.64     2.29     0.06     0.01

  Number of days with Delta-Deciview > 0.50:    21
  Number of days with Delta-Deciview > 1.00:    12
  Max number of consecutive days with Delta-Deciview > 0.50:      2


TRNP ELKHORN RANCH

  Largest Delta-DV        2.026     4.280     2.255   2001   12    90     72   2.90    81.37    18.57     0.05     0.01
  98th %tile Delta-DV     0.733     2.839     2.106   2001  261    90     72   2.20    93.65     6.27     0.07     0.02
  90th %tile Delta-DV     0.144     2.271     2.127   2001   94    90     72   2.30    82.66    17.29     0.04     0.01

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:      2


LOSTWOOD NWA

  Largest Delta-DV        4.914     7.254     2.340   2001  326    91     73   3.20    82.39    17.50     0.09     0.02
  98th %tile Delta-DV     1.351     3.626     2.275   2001   41    91     73   2.90    73.92    25.97     0.09     0.02
  90th %tile Delta-DV     0.386     2.596     2.211   2001  179    93     75   2.60    69.89    29.70     0.37     0.04

  Number of days with Delta-Deciview > 0.50:    30
  Number of days with Delta-Deciview > 1.00:    16
  Max number of consecutive days with Delta-Deciview > 0.50:      3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (base case) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station (Unit 1) - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                         SEQ     ND          % of Modeled Extinction by Species
                   DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                   ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV    3.841     6.074     2.234  2002   73    49    103   2.80    78.06   21.83    0.09    0.02
  98th %tile Delta-DV 1.675     3.781     2.106  2002  233    53    107   2.20    86.14   13.70    0.14    0.02
  90th %tile Delta-DV 0.310     2.416     2.106  2002  270    48    102   2.20    55.36   44.28    0.30    0.06

  Number of days with Delta-Deciview > 0.50:    29
  Number of days with Delta-Deciview > 1.00:    17
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV    4.809     7.042     2.234  2002   73    89    118   2.80    72.40   27.42    0.16    0.02
  98th %tile Delta-DV 1.540     3.774     2.234  2002   50    71     60   2.80    63.26   36.45    0.26    0.04
  90th %tile Delta-DV 0.312     2.546     2.234  2002   91    82     71   2.80    77.06   22.87    0.05    0.02

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:    14
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV    4.345     6.579     2.234  2002   73    90     72   2.80    76.06   23.81    0.11    0.02
  98th %tile Delta-DV 1.432     3.666     2.234  2002   39    90     72   2.80    78.88   20.97    0.12    0.03
  90th %tile Delta-DV 0.233     2.467     2.234  2002   83    90     72   2.80    51.30   48.24    0.41    0.05

  Number of days with Delta-Deciview > 0.50:    14
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV    2.442     4.717     2.275  2002   74    97     79   2.90    81.69   18.24    0.05    0.01
  98th %tile Delta-DV 1.150     3.489     2.340  2002  363    97     79   3.20    77.19   22.76    0.04    0.01
  90th %tile Delta-DV 0.308     2.541     2.232  2002  195    99     81   2.70    71.54   27.70    0.68    0.09

  Number of days with Delta-Deciview > 0.50:    25
  Number of days with Delta-Deciview > 1.00:    11
  Max number of consecutive days with Delta-Deciview > 0.50:     4
```

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
1200 Missouri Avenue, Bismarck, ND 58504-5264
P.O. Box 5520, Bismarck, ND 58506-5520
701.328.5200 (fax)
www.ndhealth.gov

November 30, 2005

FILE

Mr. Ron Day
Manager, Health, Safety & Environment
Tesoro Refinery & Marketing Co.
900 Old Red Trail NE
Mandan, ND 58554

Dear Mr. Day:

As specified in the June 15, 2005 final amendments to the EPA July, 1999 regional haze rule, the Department has completed visibility modeling to determine which North Dakota BART-eligible (Best Available Retrofit Technology) sources are subject to BART. The Department's visibility analysis for this BART screening followed the protocol outlined in "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota" (North Dakota Department of Health, November, 2005).

As you are aware, the Tesoro Mandan Refinery CO furnace is a BART-eligible source. Completed visibility modeling for the CO furnace indicates that the maximum 98th percentile delta-deciview prediction for the facility is below the BART screening threshold of 0.5 deciviews. Therefore, the CO furnace is not subject to BART.

Two summaries of modeling results are enclosed. Attachment A provides a summary of 98th percentile predictions for the worst-case meteorological year for all BART-eligible facilities. Attachment B provides more detailed results specific to the Mandan Refinery CO furnace. Included in Attachment B are results for all delta-deciview metrics recommended in the North Dakota protocol, for each year of meteorological data. Also provided are worst-case day and receptor, and the percent contribution for each species.

If you have any questions regarding these results, please contact Steve Weber or Rob White of my staff at (701)328-5188.

Sincerely,

Steve Weber for

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/SW:csc
Enc:

Environmental Health Section Chief's Office 701.328.5150
Air Quality 701.328.5188
Municipal Facilities 701.328.5211
Waste Management 701.328.5166
Water Quality 701.328.5210

Printed on recycled paper.

Attachment A

Summary of BART Screening Results
98th Percentile Prediction for Worst-case Met. Year (2000-2002)
(24-hr Delta-Deciview)

	TRNP South	TRNP North	TRNP Elk. Ranch	Lostwood NWA
Leland Olds Station	6.22	5.32	4.49	5.42
Milton R Young Station	6.69	5.58	6.10	4.88
Coal Creek Station	4.48	3.56	3.04	4.04
Stanton Station Unit 1	1.68	1.54	1.43	1.35
Heskett Station Unit 2	0.82	0.54	0.61	0.58
Mandan Refinery	0.05	0.04	0.04	0.04

29-Nov-05

Attachment B

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Mandan Refinery (base case) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Mandan Refinery (CO Furnace) - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND            % of Modeled Extinction by Species
                       DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY   RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                       ------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV      0.132     2.366     2.234   2000   74     52    106   2.80    50.86    45.06     0.00     4.08
  98th %tile Delta-DV   0.036     2.311     2.276   2000  336     45     45   3.00    17.08    75.03     0.00     7.89
  90th %tile Delta-DV   0.004     2.132     2.127   2000  105      3      3   2.30    43.33    51.14     0.00     5.53

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:      0


TRNP NORTH UNIT

  Largest Delta-DV      0.094     2.327     2.234   2000   54     82     71   2.80    41.67    52.99     0.00     5.34
  98th %tile Delta-DV   0.033     2.266     2.234   2000   55     82     71   2.80    16.77    73.56     0.00     9.67
  90th %tile Delta-DV   0.008     2.136     2.127   2000   97     82     71   2.30    29.69    62.52     0.00     7.79

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:      0


TRNP ELKHORN RANCH

  Largest Delta-DV      0.062     2.189     2.127   2000   98     90     72   2.30    21.36    69.04     0.00     9.60
  98th %tile Delta-DV   0.034     2.289     2.255   2000   11     90     72   2.90    32.88    59.71     0.00     7.41
  90th %tile Delta-DV   0.004     2.110     2.106   2000  261     90     72   2.20    60.10    20.63     0.00    19.27

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:      0


LOSTWOOD NWA

  Largest Delta-DV      0.108     2.448     2.340   2000  349     93     75   3.20    33.79    61.74     0.00     4.46
  98th %tile Delta-DV   0.024     2.300     2.275   2000   55     91     73   2.90    57.42    36.95     0.00     5.62
  90th %tile Delta-DV   0.009     2.242     2.232   2000  200     99     81   2.70    71.44    23.64     0.00     4.93

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:      0
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Mandan Refinery (base case) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Mandan Refinery (CO Furnace) - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                SEQ     ND              % of Modeled Extinction by Species
                        DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                        ---------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV       0.076     2.330     2.255   2001   13    45     45    2.90    15.62    74.72    0.00     9.66
  98th %tile Delta-DV    0.028     2.134     2.106   2001  260    46     46    2.20    77.10    17.67    0.00     5.23
  90th %tile Delta-DV    0.004     2.110     2.106   2001  257    53    107    2.20    68.00    25.65    0.00     6.36

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP NORTH UNIT

  Largest Delta-DV       0.155     2.410     2.255   2001   12    82     71    2.90    49.02    46.23    0.00     4.76
  98th %tile Delta-DV    0.036     2.270     2.234   2001   43    67     56    2.80    41.62    53.64    0.00     4.74
  90th %tile Delta-DV    0.007     2.156     2.149   2001  199    58     47    2.40    76.60    16.14    0.00     7.26

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP ELKHORN RANCH

  Largest Delta-DV       0.068     2.322     2.255   2001   12    90     72    2.90    47.16    49.02    0.00     3.82
  98th %tile Delta-DV    0.027     2.303     2.276   2001  328    90     72    3.00    52.10    44.85    0.00     3.05
  90th %tile Delta-DV    0.004     2.131     2.127   2001  100    90     72    2.30    60.48    37.06    0.00     2.46

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


LOSTWOOD NWA

  Largest Delta-DV       0.268     2.607     2.340   2001  327    91     73    3.20    44.63    51.28    0.00     4.09
  98th %tile Delta-DV    0.040     2.185     2.145   2001  269    99     81    2.30    16.76    67.08    0.00    16.16
  90th %tile Delta-DV    0.011     2.157     2.145   2001  262    97     79    2.30    32.66    53.46    0.00    13.88

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Mandan Refinery (base case) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Mandan Refinery (CO Furnace) - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND             % of Modeled Extinction by Species
                        DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                        ------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.119     2.246     2.127   2002  293    53    107   2.30    31.69    57.61    0.00    10.70
  98th %tile Delta-DV     0.054     2.288     2.234   2002   51    51    105   2.80    53.00    43.33    0.00     3.67
  90th %tile Delta-DV     0.008     2.241     2.234   2002   67    54    108   2.80    25.68    65.53    0.00     8.80

  Number of days with Delta-Deciview > 0.50:      0
  Number of days with Delta-Deciview > 1.00:      0
  Max number of consecutive days with Delta-Deciview > 0.50:      0


TRNP NORTH UNIT

  Largest Delta-DV        0.115     2.348     2.234   2002   50    67     56   2.80    41.88    53.56    0.00     4.56
  98th %tile Delta-DV     0.039     2.167     2.127   2002  301    82     71   2.30    25.65    66.52    0.00     7.83
  90th %tile Delta-DV     0.009     2.136     2.127   2002  116    58     47   2.30    24.56    66.44    0.00     9.00

  Number of days with Delta-Deciview > 0.50:      0
  Number of days with Delta-Deciview > 1.00:      0
  Max number of consecutive days with Delta-Deciview > 0.50:      0


TRNP ELKHORN RANCH

  Largest Delta-DV        0.089     2.323     2.234   2002   73    90     72   2.80    42.09    53.50    0.00     4.41
  98th %tile Delta-DV     0.042     2.276     2.234   2002   74    90     72   2.80    50.74    45.51    0.00     3.75
  90th %tile Delta-DV     0.006     2.133     2.127   2002  127    90     72   2.30    36.74    54.59    0.00     8.66

  Number of days with Delta-Deciview > 0.50:      0
  Number of days with Delta-Deciview > 1.00:      0
  Max number of consecutive days with Delta-Deciview > 0.50:      0


LOSTWOOD NWA

  Largest Delta-DV        0.059     2.335     2.275   2002   76    97     79   2.90    23.48    67.89    0.00     8.63
  98th %tile Delta-DV     0.027     2.302     2.275   2002   51    91     73   2.90    59.45    37.60    0.00     2.95
  90th %tile Delta-DV     0.006     2.217     2.211   2002  178    97     79   2.60    86.85     2.82    0.00    10.32

  Number of days with Delta-Deciview > 0.50:      0
  Number of days with Delta-Deciview > 1.00:      0
  Max number of consecutive days with Delta-Deciview > 0.50:      0
```

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

February 23, 2010

Mr. Terry Graumann
Manager, Environmental Services
OtterTail Power Company
P.O. Box 496
Fergus Falls, MN 56538-0496

Re: BART Permit to Construct

Dear Mr. Graumann:

The North Dakota Regional Haze State Implementation Plan (SIP) will require the OtterTail Power Company to reduce NO_x emissions at the Coyote Station, which is located near the City of Beulah in Mercer County. Enclosed is Permit to Construct No. 10008, which establishes the revised NO_x emission limit for the Coyote Station. A public comment period was held regarding the SIP from December 8, 2009 to January 8, 2010, during which comments were received by the Department and considered in our determination. Please note that Condition II.A.2 requires installation of the equipment necessary to meet the new NO_x limit by July 1, 2018 and compliance with the limit by July 1, 2019.

If you have any questions, please contact me at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/CDT:saj
Enc:
xc/enc: Gail Fallon, EPA - Region 8
Custer District Health Unit, Mandan

Environmental Health Section Chief's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality
701.328.5150	701.328.5188	701.328.5211	701.328.5166	701.328.5210

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
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AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT

Pursuant to Chapter 23-25 of the North Dakota Century Code, and the Air Pollution Control Rules of the State of North Dakota (Article 33-15 of the North Dakota Administrative Code), a Permit to Construct is hereby issued for modifications at the following source:

I. **General Information**:

A. **Permit to Construct Number**: PTC10008

B. **Source**:

1. **Name**: Coyote Station
2. **Location**: Sec. 10, S½ of S ½ of Sec. 3 and W½ of Sec. 11, T143N, R88W, North Dakota, Mercer County
3. **Source Type**: Fossil-fuel fired steam electric unit with a nominal heat input of 5,800 million British thermal units per hour (10^6 Btu/hr).

C. **Owner Names**:
Montana-Dakota Utilities Co.
NorthWestern Public Service Company
Northern Municipal Power Agency
(Minnkota Power Cooperative, Inc.)
Otter Tail Power Company

D. **Operator**:

1. **Name**: Otter Tail Power Company
2. **Address**:
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496

II. Permit Conditions:

This Permit to Construct establishes a revised nitrogen oxide (NO_x) emission limit for the main boiler at the Coyote Station (EUI 1) if, and when, EPA approves that limit as part of the Regional Haze SIP. The permit allows the construction and initial operation of new or modified air pollution control equipment and process modifications at the source to comply with the revised NO_x limit. If new emissions units are created, then a new Permit to Construct may be required in accordance with NDAC 33-15-14-02. The source shall be operated in accordance with the terms of this Permit to Construct and the Title V Permit to Operate until a revised Title V Permit to Operate is issued. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect to the North Dakota Department of Health and to the conditions specified below:

A. Special Conditions:

1. **Emission Limits**: The term "12-month rolling average," as used in this permit to demonstrate compliance with the limit in Condition II.A.1.a. shall be determined by calculating an arithmetic average of all operating hourly outlet NO_x emissions rates as measured and calculated by the CEMS for the current month and the previous 11 months. A new 12-month rolling average shall be calculated by the 30th day following the end of each month. Each 12-month rolling average rate shall include start-up, shutdown, emergency and malfunction periods unless those periods are exempt by this permit.

   a. The permittee shall not discharge or cause the discharge of nitrogen oxides (NO_x) into the atmosphere from EUI 1 (main boiler) in excess of 0.50 pounds per million British thermal units ($lb/10^6$ Btu) on a 12-month rolling average basis.

   b. The NO_x emission limit applies at all times including startup, shutdown, emergency and malfunction.

2. **Compliance Date**: Installation of the new or modified equipment shall be completed by July 1, 2018. Compliance with the revised NO_x emission limit shall begin by July 1, 2019.

3. **Continuous Emission Monitoring (CEM)**: The emissions from EUI 1 shall be measured by continuous emission monitors (CEM) for NO_x and CO_2, The monitoring requirements under Condition II.A.4 shall be the compliance determination method for NO_x.

4. **Monitoring Requirements and Conditions**:

a. Requirements:

Testing and monitoring protocols used to demonstrate compliance with the emission limits of Condition II.A.1 above shall be as follows:

Table 1
Monitoring Requirements by Pollutant/Parameter

Pollutant/Parameter	**Monitoring Requirement (Method)**	**Condition Number (II.A. ...)**
NO_x (lb/10^6 Btu)	CEM	4.b.(1), 4.b.(2), 4.b.(3) & 4.b.(4)
CO_2	CEM	4.b(1), 4.b.(2), 4.b.(3) & 4.b.(4)

b. Emission Monitoring Conditions:

(1) The monitoring shall be in accordance with the applicable requirements of the Acid Rain Program, 40 CFR 72 and 40 CFR 75. Emissions are calculated using 40 CFR Part 75.

(2) The Department may require additional performance audits of the CEM systems.

(3) When a failure of a continuous emission monitoring system occurs, an alternative method, acceptable to the Department, for measuring or estimating emissions must be undertaken as soon as possible. The procedures outlined in 40 CFR 75, Subpart D for substitution are considered an acceptable method for the emission rate limit. Timely repair of the emission monitoring system must be made.

(4) The permittee shall maintain and operate air pollution control monitoring equipment in a manner consistent with the manufacturer's recommended equipment in a manner consistent with the manufacturer's recommended procedures on a site-specific QA/QC Plan required by 40 CFR 75. The permittee shall have the QA/QC Plan available on-site and provide the Department with a copy when requested.

5. **Recordkeeping Requirements**: The permittee shall maintain compliance monitoring records for Unit 1 as outlined in Table 2 – Monitoring Records that includes the following information:

a. A copy of the sample analysis report(s), including the date that the sample analysis was performed; the company, entity, or person that performed the analysis; and the testing techniques or methods used.

b. The records of quality assurance for emissions measuring systems including but not limited to quality control activities, audits and calibration drifts as required by the applicable test method.

c. A copy of all field data sheets from the emissions testing.

d. A record shall be kept of all major maintenance activities conducted on the emissions units or air pollution control equipment.

Table 2
Monitoring Records

Pollutant/Parameter	**Compliance Monitoring Record**
NO_x (lb/10^6 Btu)	CEM Data
CO_2	CEM Data

e. In addition to requirements outlined in Condition II.A.5, recordkeeping for EUI 1 shall be in accordance with the applicable requirements of the North Dakota Air Pollution Control Rules and the Acid Rain Program, 40 CFR 72 and 40 CFR 75.

f. The permittee shall retain records of all required compliance monitoring data and support information for a period of at least five years from the date of the compliance monitoring sampling, measurement, report, or application. Support information includes all maintenance records of the emission units and all original strip-chart recordings/computer printouts and calibrations of the continuous compliance monitoring instrumentation, and copies of all reports required by the permit.

6. **Reporting**:

a. Reporting for Unit 1 shall be in accordance with the applicable requirements of the North Dakota Air Pollution Control Rules and the Acid Rain Program, 40 CFR 72 and 40 CFR 75.

b. Quarterly excess emissions reports for Unit 1 shall be submitted no later than the 30th day of the following the end of each calendar quarter. Excess emissions are defined as emissions which exceed the emission limit for EUI 1 as outlined in Condition II.A.1.a. Excess emissions shall be reported for the following:

Parameter	Reporting Period
NO_x lb/10^6 Btu	12-month rolling average

c. The permittee shall submit a semi-annual report for all monitoring records required under Condition II.A.5 on forms supplied or approved by the Department. All instances of deviations from the permit must be identified in the report. A monitoring report shall be submitted within 45 days after June 30 and December 31 of each year.

d. 1) The permittee shall submit an annual compliance certification report within 45 days after December 31 of each year on forms supplied or approved by the Department.

2) For emissions units where the method of compliance monitoring is demonstrated by either an EPA Test Method or portable analyzer, the test report shall be submitted to the Department within 60 days after completion of the test.

3) The permittee shall submit an annual emission inventory report on forms supplied or approved by the Department . This report shall be submitted by March 15 of each year. Insignificant units/activities listed in this permit do not need to be included in the report.

4) The permittee shall notify the Department within 15 days of the actual startup date of the equipment required to meet the NO_x permit limit.

B. **General Conditions**:

1. The permit shall in no way permit or authorize the maintenance of a public nuisance or danger to public health or safety.

2. The permittee shall comply with all State and Federal environmental laws and rules. In addition, the permittee shall comply with all local building, fire, zoning, and other applicable ordinances, codes, rules and regulations.

3. All reasonable precautions shall be taken by the permittee to prevent and/or minimize fugitive emissions during the construction period.

4. The permittee shall at all times, including periods of startup, shutdown, malfunction, maintain and operate EUI 1 and all other emission units including associated air pollution equipment and fugitive dust suppression

operations in a manner consistent with good air pollution control practices for minimizing emissions.

5. Any duly authorized officer, employee or agent of the North Dakota Department of Health may enter and inspect any property, premise or place at which the source listed in Item I.B. of this permit is or will be located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules and the conditions of this permit.

6. The conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23-25. Each and every condition of this permit is a material part thereof, and is not severable.

FOR THE NORTH DAKOTA
DEPARTMENT OF HEALTH

Date: 2/23/10

By: Terry O'Clair
Terry L. O'Clair, P.E., Director
Division of Air Quality

November 2006

2006 Report for the Western Regional Air Partnership (WRAP) Regional Modeling Center (RMC)

WGA Contract Number: 30203

Prepared for:

Western Regional Air Partnership
Western Governors' Association
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Denver, CO 80202

Prepared by:

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ENVIRON UNIVERSITY of CALIFORNIA Riverside UNC CAROLINA ENVIRONMENTAL PROGRAM

- It is acceptable to assume that all measured sulfate is in the form of ammonium sulfate [$(NH_4)_2SO_4$] and all particulate nitrate is in the form of ammonium nitrate [NH_4NO_3].

To facilitate tracking the progress toward visibility goals, two important visibility parameters are required for each Class I area:

- *Baseline Conditions:* "Baseline Conditions" represent visibility for the B20% and W20% days for the initial five-year baseline period of the regional haze program. Baseline Conditions are calculated using monitoring data collected during the 2000-2004 five-year period and are the starting point in 2004 for the uniform rate of progress (URP) glide path to Natural Conditions in 2064 (U.S. EPA, 2003b).
- *Natural Conditions:* "Natural Conditions," the RHR goal for 2064 for the Federally mandated Class I areas, represent estimates of natural visibility conditions for the B20% and W20% days at a given Class I area.

3.3.1 Calculation of Baseline Conditions

Baseline Conditions for Class I areas are calculated using fine and coarse PM concentrations measured at Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors (Malm et al., 2000). Each Class I area in the WRAP domain has an associated IMPROVE PM monitor. The IMPROVE monitors do not measure visibility directly, but instead measure speciated fine particulate ($PM_{2.5}$) and total $PM_{2.5}$ and PM_{10} mass concentrations from which visibility is calculated using the IMPROVE aerosol extinction equation, discussed later.

Visibility conditions are estimated starting with the IMPROVE 24-h average PM mass measurements related to six PM components of light extinction:

- Sulfate [$(NH_4)_2SO_4$]
- Particulate nitrate [NH_4NO_3]
- Organic matter [OMC]
- Light-absorbing carbon [LAC] or elemental carbon [EC]
- Soil
- Coarse matter [CM]

The IMPROVE monitors do not directly measure some of these species, so assumptions are made as to how the IMPROVE measurements can be adjusted and combined to obtain these six components. For example, sulfate and particulate nitrate are assumed to be completely neutralized by ammonium and only the fine mode ($PM_{2.5}$) is speciated to obtain sulfate and nitrate measurements (that is, any coarse-mode sulfate and nitrate in the real atmosphere may be present in the IMPROVE CM measurement). Concentrations for the above six components of light extinction in the IMPROVE aerosol extinction equation are obtained from the IMPROVE measured species using the formulas shown in Table 3-1.

Table 3-1. Definition of IMPROVE components from measured species.

IMPROVE Component	Calculation of Component from IMPROVE Measured Species
Sulfate	1.375 x (3 x S)
Nitrate	1.29 x NO_3^-
OMC	1.4 x OC
LAC	EC
Soil	(2.2 x Al) + (2.49 x Si) + (1.63 x Ca) + (2.42 x Fe) + (1.94 x Ti)
CM	MT – MF

where

- S is elemental sulfur as determined from proton-induced x-ray emissions (PIXE) analysis of the IMPROVE Module A. To estimate the mass of the sulfate ion ($SO_4^=$), S is multiplied by 3 to account for the presence of oxygen. If S is missing then the sulfate (SO_4) measured by ion chromatography analysis of Module B is used to replace (3 x S). For the IMPROVE aerosol extinction calculation, sulfate is assumed to be completely neutralized by ammonium (1.375 x SO_4).
- NO_3^- is the particulate nitrate measured by ion chromatography analysis of Module B. For the IMPROVE aerosol extinction calculation, it is assumed to be completely neutralized by ammonium (1.29 x NO_3).
- The IMPROVE organic carbon (OC) measurements are multiplied by 1.4 to obtain organic matter (OMC), which adjusts the OC mass for other elements assumed to be associated with OC.
- Elemental carbon (EC) is also referred to as light-absorbing carbon (LAC).
- Soil is determined as a sum of the masses of those elements (measured by PIXE) predominantly associated with soil (Al, Si, Ca, Fe, K, and Ti), adjusted to account for oxygen associated with the common oxide forms. Because K is also a product of the combustion of vegetation, it is represented in the formula by 0.6 x Fe and is not shown explicitly.
- MT and MF are total PM_{10} and $PM_{2.5}$ mass, respectively.

Associated with each PM species is an extinction efficiency that converts concentrations (in $\mu g/m^3$) to light extinction (in inverse megameters, Mm^{-1}), as listed below. Sulfate and nitrate are hygroscopic, so relative humidity (RH) adjustment factors, f(RH), are used to increase the particles' extinction efficiency with increasing RH; this accounts for the particles' taking on water and having greater light scattering. Note that some organic matter (OMC) compounds may also have hygroscopic properties, but the IMPROVE aerosol extinction equation assumes OMC is nonhygroscopic.

$$\beta_{Sulfate} = 3 \times f(RH) \times [sulfate]$$
$$\beta_{Nitrate} = 3 \times f(RH) \times [nitrate]$$
$$\beta_{OMC} = 4 \times [OMC]$$
$$\beta_{EC} = 10 \times [EC]$$
$$\beta_{Soil} = 1 \times [soil]$$
$$\beta_{CM} = 0.6 \times [CM]$$

The total light extinction (β_{ext}) is assumed to be the sum of the light extinctions due to the six PM species listed above plus Rayleigh (blue sky) background extinction (β_{Ray}), which is assumed to be 10 Mm^{-1}. This is reflected in the IMPROVE extinction equation:

$$\beta_{ext} = \beta_{Ray} + \beta_{Sulfate} + \beta_{Nitrate} + \beta_{EC} + \beta_{OMC} + \beta_{Soil} + \beta_{CM}$$

The total light extinction (β_{ext}) in Mm^{-1} is related to visual range (VR) in kilometers using the following relationship:

$$VR = 3912 / \beta_{ext}$$

The RHR requires that visibility be expressed in terms of a haze index (HI) in units of deciview (dv), which is calculated as follows:

$$HI = 10 \ln(\beta_{ext}/10)$$

The equations above, with measurements from the associated IMPROVE monitor, are used to estimate the daily average visibility at each Class I area for each IMPROVE monitored day. For each year from the 2000-2004 baseline period, these daily average visibility values are then ranked from highest to lowest. The "worst days" visibility for each of the five years in the baseline period is defined as the average visibility across the 20% worst-visibility days (highest deciview values); similarly, the "best days" visibility is defined as the average visibility across the 20% best-visibility days (lowest deciview values) for each year. The Baseline Conditions for the best and worst days are defined as the five-year average of the B20% visibility days and of the W20% visibility days, respectively, across the five-year baseline period.

The set of equations given above for relating measured PM species to visibility (light extinction) are referred to as the "Old IMPROVE" equation. The IMPROVE Steering Committee has developed a "New IMPROVE" equation that they believe better represents the fit between measured PM species concentrations and visibility impairment. Although conceptually similar to the Old IMPROVE equation, the New IMPROVE equation includes updates to many of the parameters and the addition of extinctions due to NO_2 absorption and sea salt. We performed 2018 visibility projections and comparisons with the URP glide path goals using both the New and Old IMPROVE equations. The reader is referred elsewhere for details on the New IMPROVE extinction equation (e.g., EPA, 2006a,b).

BART Determination
for
Leland Olds Station Units 1 and 2

I. Source Description

A. Owner/Operator: Basin Electric Power Cooperative
B. Source Type: Electric Utility Steam Generating Unit
C. BART Eligible Units

1. Unit 1 boiler
2. Unit 2 boiler
3. Auxiliary Boiler
4. Fire Pump
5. Materials Handling Equipment

   a. Unit 2 - coal bunkers and conveyors
   b. Unit 2 - transfer conveyors
   c. Main flyash silo
   d. 100 ton flyash silo
   e. Coal unloading facility
   f. Agglomerator
   g. Coal unloading silo

D. Unit Description

1. Unit 1:

Generator Nameplate Capacity: 216 MWe
Boiler Rating: 2622 x 10^6 Btu/hr
Startup: 1966
Fuel: North Dakota Lignite (80-100%)
: PRB Subbituminous (0-20%)
Firing Method: Wall-fired
Existing Air Pollution Control Equipment: Low NO_x burners (1995) and electrostatic precipitator

2. Unit 2:

Generator Nameplate Capacity: 440 MWe
Boiler Rating: 5130 x 10^6 Btu/hr
Startup: 1975
Fuel: North Dakota Lignite (80-100%)

: PRB Subbituminious (0-20%)
Firing Method: Cyclone
Existing Air Pollution Control Equipment: Electrostatic precipitator

3. Auxiliary Boiler:

   Boiler Rating: 51.6 x 10^6 Btu/hr
   Fuel: #2 fuel oil

4. Fire Pump:

   Rating: 200 Bhp
   Fuel: Diesel fuel

5. Materials Handling Equipment:

   a. Unit 2 coal bunkers and conveyors:
      Existing Air Pollution Control Equipment: Rotoclones

   b. Unit 2 transfer conveyors:
      Existing Air Pollution Control Equipment: Rotoclones

   c. Main Flyash Silo:
      Existing Air Pollution Control Equipment: Baghouse

   d. 100 Ton Flyash Silo:
      Existing Air Pollution Control Equipment: Baghouse
   e. Coal Unloading Facility:
      Existing Air Pollution Control Equipment: Baghouse

   f. Agglomerator:
      Existing Air Pollution Control Equipment: Baghouse

   g. Coal Unloading Silo:
      Existing Air Pollution Control Equipment: Baghouse

E. Emissions

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Avg.**
Unit 1 Boiler	SO_2 (tons)	16,864	13,237	16,655	19,125	15,448	16,666
	SO_2 (lb/10^6 Btu)	1.81	1.94	1.73	1.82	1.80	1.82
	NO_x (tons)	2,328	2,057	2,578	3,053	2,487	2,501
	NO_x (lb/10^6 Btu)	0.25	0.26	0.27	0.29	0.29	0.27

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Avg.**
	PM (tons) PM (lb/10^6 Btu)	104 0.011	480 0.061	184 0.019	280 0.027	46 0.005	219 0.025
Unit 2 Boiler	SO_2 (tons) SO_2 (lb/10^6 Btu)	28,587 1.85	36,319 1.91	30,744 1.73	25,598 1.79	32,990 1.85	30,828 1.83
	NO_x (tons) NO_x (lb/10^6 Btu)	9,330 0.60	12,608 0.66	11,068 0.62	8,695 0.61	10,410 0.58	10,422 0.61
	PM (tons) PM (lb/10^6 Btu)	274 0.018	755 0.040	499 0.028	415 0.029	175 0.010	424 0.025
Auxiliary Boiler	SO_2 (tons) NO_x (tons)						0.03 0.01
Fire Pump	SO_2 (tons) NO_x (tons)						<0.01 <0.01
Unit 2 Coal Bunkers/ Conveyors	PM (tons)						1.6
Unit 2 Transfer Conveyors	PM (tons)						1.6
Main Flyash Silo	PM (tons)						1.0
100 Ton Flyash Silo	PM (tons)						0.1
Coal Unloading Facility	PM (tons)						12.4
Agglomerator	PM (tons)						<0.1
Coal Unloading Silo	PM (tons)						0.2

II. Site Characteristics

The Leland Olds Station is located on the banks of the Missouri River in eastern Mercer county near the town of Stanton, North Dakota. The original design of Unit 1 only incorporated a multiclone for air pollution control, the electrostatic precipitator was added in the 1970's. Unit 2 was built with an electrostatic precipitator. Because of the original design and the close proximity of the Missouri River, there are some space constraints at the facility. Basin Electric has not indicated that the space constraints are insurmountable. Therefore, site constraints are an economic issue when evaluating the various control alternatives. Basin Electric has prepared a comprehensive BART analysis which can be found in Appendix C of the SIP.

III. BART Evaluation of Unit 1

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Wet Scrubber
Spray Dryer
Circulating Dry Scrubber
Flash Dryer Absorber
Powerspan ECO®
Fuel Switching
Coal Cleaning

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located on the banks of the Missouri River, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning. Therefore, these options were not considered further.

K-Fuel® is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels® process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from the Freedom Mine was tested. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. The use of the K-Fuel® process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel® process available or technically and economically feasible.

The Department considers the Powerspan ECO® technology not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on the information provided by Basin Electric, the Department has calculated the uncontrolled emission rate as follows:

Sulfur content = 1.13%
HHV = 6548 Btu/lb
Emission Factor = 35(s) lb/ton

The emission factor 35(s) is used to conservatively estimate the uncontrolled emission rate. During the Department's periodic review of SO_2 PSD increment consumption, emission factors for the Leland Olds Station were was extensively addressed[3]. Based on actual continuous emissions monitoring data an emission factor of 37.4(s) was established for Unit 1 and 38.7(s) for Unit 2. Using the lower emission factor of 35(s) results in a higher cost effectiveness and a lower controlled emission rate. As shown in Step 6, the emission factor does not affect the decision regarding the type of control technology selected since the most effective technology is selected as BART.

E = (35)(1.13%)(10^6)÷(2000 lb/ton)(6548 Btu/lb)
E = 3.02 lb/10^6 Btu
E = (2622 x 10^6 Btu/hr)(3.02 lb/10^6 Btu)
E = 7918.4 lb/hr
E = 34,683 tons/yr

Alternative	**Control Efficiency (%)**	**Inlet Loading (tons/yr)**	**Emissions**	
			(tons/yr)	**(lb/10^6 Btu)**
Wet Scrubber.	95	34,683	1734	0.15
Circulating Dry Scrubber	93	34,683	2428	0.21
Spray Dryer	90	34,683	3468	0.30
Flash Dryer Absorber	90	34,683	3468	0.30
Fuel Switching	≤77	34,683	7977	0.69

[a] New wet scrubbers generally achieve SO_2 removal efficiencies of 95%[4,5]. Higher efficiencies may be achieved with higher sulfur eastern coals, however, North Dakota (Fort Union) lignite is

much lower in sulfur content (1.13% for this analysis compared to 2.45% for interior bituminous coal[7]). EPA[6] indicates "Chlorine content improves the SO_2 removal ..." North Dakota lignite has some of the lowest chlorine levels of all the U.S. coals[7]. Based on the low chlorine content and lower sulfur content, lower SO_2 removal efficiencies would be expected on a power plant that burns North Dakota lignite than one that combusts eastern coal. In recent BACT assessments [8,9,10] for proposed power plants in North Dakota, the analyses indicated the efficiency of wet scrubbers would be 95% for North Dakota lignite. During three separate comment periods, no comments were received regarding the projected efficiency of a wet scrubber. The proposed BACT limits, and thus efficiency, will have to be met at all times including startup, shutdown and malfunction. The Department has determined that 95% removal efficiency is a reasonable upper limit that can be met on a continuous basis for a power plant combusting North Dakota lignite and using a wet scrubber.

Based on the future potential-to-emit, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	**Emissions Reduction (tons/yr)**	**Annualized Cost ($)***	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Wet FGD	32,949	19,310,000	586	353***
Circulating Dry Scrubber**	32,255	20,720,000	636	----
Spray Dryer	31,215	18,700,000	599	

Note: Flash Dryer Absorber not included since it costs more than a spray dryer with no additional emissions reduction.

* Costs provided by Basin Electric.
** Inferior option
*** Incremental cost from spray dryer to wet FGD.

Step 4: Evaluate Impacts and Document Results

Basin Electric has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of either a wet scrubber or spray dryer.

Step 5: Evaluate Visibility Results

The two primary alternatives are a wet scrubber operating at 95% removal efficiency and a spray dryer operating at 90% efficiency. The effects on visibility shown in the following tables are based on Basin Electric's estimate of SO_2 reductions. The Department estimates that the scrubbers will actually reduce emissions less than Basin Electric estimated since

Basin included SO_2 removed in the bottom ash in their calculation of emissions removed by the scrubber. The visibility impact results are therefore conservative (overestimate the improvement).

Unit 1 Delta Deciview 90th Percentile SO_2				
Year	**Unit**	**90% Reduction**	**95% Reduction**	**Difference**
2000	TRNP-SU	0.096	0.073	0.023
2001	TRNP-SU	0.091	0.060	0.031
2002	TRNP-SU	0.133	0.124	0.009
Average	TRNP-SU			0.021
2000	TRNP-NU	0.109	0.066	0.043
2001	TRNP-NU	0.110	0.085	0.025
2002	TRNP-NU	0.135	0.072	0.043
Average	TRNP-NU			0.037
2000	Elkhorn Ranch	0.087	0.062	0.025
2001	Elkhorn Ranch	0.059	0.034	0.025
2002	Elkhorn Ranch	0.094	0.066	0.028
Average	Elkhorn Ranch			0.026
2000	Lostwood W. A.	0.169	0.125	0.044
2001	Lostwood W. A.	0.218	0.136	0.082
2002	Lostwood W. A.	0.127	0.098	0.029
Average	Lostwood W. A.			0.052
Overall Average				0.034

Unit 1 Delta Deciview 98th Percentile SO_2				
Year	**Unit**	**90% Reduction**	**95% Reduction**	**Difference**
2000	TRNP-SU	0.401	0.298	0.103
2001	TRNP-SU	0.393	0.276	0.117
2002	TRNP-SU	0.832	0.627	0.205
Average	TRNP-SU			0.142
2000	TRNP-NU	0.563	0.309	0.254
2001	TRNP-NU	0.470	0.336	0.134
2002	TRNP-NU	0.720	0.569	0.151
Average	TRNP-NU			0.180
2000	Elkhorn Ranch	0.378	0.210	0.168
2001	Elkhorn Ranch	0.328	0.215	0.113

Unit 1 Delta Deciview 98th Percentile SO_2				
Year	**Unit**	**90% Reduction**	**95% Reduction**	**Difference**
2002	Elkhorn Ranch	0.670	0.472	0.198
Average	Elkhorn Ranch			0.160
2000	Lostwood W. A.	0.433	0.349	0.084
2001	Lostwood W. A.	0.650	0.511	0.139
2002	Lostwood W. A.	0.544	0.396	0.148
Average	Lostwood W. A.			0.124
Overall Average				0.151

Step 6: Select BART

The cost effectiveness is reasonable for all technologies evaluated and the incremental cost from one technology to another is not excessive. There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The unit has no existing air pollution control equipment for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. The degree of visibility improvement achieved by selecting a wet scrubber operating at 95% control efficiency versus a spray dryer operating at 90% control efficiency does not exceed 0.083 deciviews (90th percentile) or 0.198 deciviews (98% percentile) at any Class I area for the 2000-2002 time frame. Although the amount of visibility improvement achieved by selecting a wet scrubber versus a spray dryer or circulating dry scrubber is small, the Department believes the cost effectiveness and incremental cost of a new wet scrubber is very low. The Department has determined that BART is represented by the use of a wet scrubber. Based on an annual average controlled emission rate of 0.15 lb/10^6 Btu, the expected maximum 30-day rolling average emission rate is 0.19 lb/10^6 Btu. By allowing Basin Electric to comply with either the percent reduction requirement or the lb/10^6 Btu limitation, the presumptive levels for plants larger than 750 MWe can be established as the BART limit. BART is proposed as an emission reduction efficiency of 95% of the inlet sulfur dioxide concentration to the scrubber or 0.15 lb/10^6 Btu on a 30-day rolling average basis.

B. Filterable Particulate Matter

Step 1: Identify All Available Technologies

New Baghouse
New Electrostatic Precipitator
Compact Hybrid Particulate Collector (CoHPAC)
Existing Electrostatic Precipitator

Step 2: Eliminate Technically Infeasible Options

All technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

		Emissions	
Alternative	**Control Efficiency**	**(tons/yr)**	**(lb/106 Btu)**
Baghouse	99.7+	108	0.013
New ESP	99.7	125	0.015
CoHPAC	99.7	125	0.015
Baseline (Existing ESP)	≈99.2	332*	0.040

* Based on the Department’s estimate of baseline emissions (2001-2002).

Alternative	**Emissions* Reduction (tpy)**	**Annualized ** Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Baghouse	224	3,260,000	14,554	46,294***
New ESP	207	2,630,000	12,705	----
CoHPAC	207	2,473,000	11,947	----
Baseline (Existing ESP)	0	0	---	

* Reductions from the baseline emission rate.
** Costs provided by Basin Electric.
*** Baghouse compared to CoHPAC.

Step 4: Evaluate Impacts and Document the Results

Basin Electric has evaluated the energy and non-air quality effects of each option. The Department has determined that the effects will not preclude the selection of any of the options.

Step 5: Evaluate Visibility Impacts

The different alternatives were not modeled because of the high cost effectiveness. However, the baseline emission rate was modeled. The results are as follows:

Unit 1 Delta Deciview PM			
Year	**Unit**	**90th Percentile**	**98th Percentile**
2000	TRNP-SU	0.0037	0.0048
2001	TRNP-SU	0.0006	0.0103
2002	TRNP-SU	0.0046	0.0119
Average	TRNP-SU	0.0030	0.0090
2000	TRNP-NU	0.0010	0.0098
2001	TRNP-NU	0.0013	0.0068
2002	TRNP-NU	0.0021	0.0371
Average	TRNP-NU	0.0015	0.0179
2000	Elkhorn Ranch	0.0020	0.0118
2001	Elkhorn Ranch	0.0004	0.0015
2002	Elkhorn Ranch	0.0040	0.0102
Average	Elkhorn Ranch	0.0021	0.0078
200	Lostwood W.A	0.0071	0.0111
2001	Lostwood W.A.	0.0059	0.0211
2002	Lostwood W.A.	0.0001	0.0053
Average	Lostwood W.A.	0.0044	0.0125
Overall Average		0.0028	0.0118

Step 6: Select BART

The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate emissions is the CoHPAC system. This system has a cost effectiveness of $11,947 per ton of particulate when compared to the current emission control system (ESP operating at approximately 99.2% efficiency). The Department considers this cost to be excessive.

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The unit is equipped with an electrostatic precipitator that is achieving 99.2%, or greater, control efficiency. The plant is expected to have a remaining useful life of at least 20 years.

If all of the particulate emitted was eliminated, the most improvement in visibility at any Class I area would be approximately 0.0044 deciviews based on the three year average of the 90th percentile value (0.0125 deciviews based on the 98th percentile). The Department considers this amount of improvement to be negligible. Since none of the control technologies will eliminate all of the particulate matter emissions, the visibility improvement will be even less.

After considering all of the factors, the Department proposes that BART for filterable particulate matter is no additional controls. Since current actual emissions are less than the current allowable emissions, the Department proposes that BART is represented by an emission limit of 0.07 lb/10^6 Btu (average of 3 test runs).

C. Condensible Particulate Matter (PM_{10}).

Condensible particulate matter is made up of both organic and inorganic substances. Organic condensible particulate matter will be made up of organic substances, such as volatile organic compounds, which are in a gaseous state through the air pollution control devices but will eventually turn to a solid or liquid state. The primary inorganic substance expected from the boiler is sulfuric acid mist, with lesser amounts of hydrogen fluoride and ammonium sulfate.

Since sulfuric acid mist is the largest component of condensible particulate matter, controlling it will control most of the condensible particulate matter. The options for controlling sulfuric acid mist are the same options for controlling sulfur dioxide (see Section III.A.). Previously, BART for sulfur dioxide was determined to be represented by wet scrubber. This technology will achieve a 40-60% reduction as sulfuric acid mist emissions.

The control of volatile organic compounds at power plants is generally achieved through good combustion practices. The Department is not aware of any BACT determination at a power plant that resulted in any control technology being used. BACT has been found to be good combustion practices which are already in use since it minimizes the amount of fuel to generate electricity.

Basin Electric has indicated that the emission rate of condensible particulate matter could be as low as 0.0029 lb/10^6 Btu. AP-42, Compilation of Air Pollutant Emission Factors[2], suggests it could be as high as 0.02 lb/10^6 Btu. In either case, the emission rate is less than the current emissions of filterable particulate matter. The emissions of filterable particulate matter were determined to have a negligible impact on visibility.

Having considered all the factors, the Department has determined that BART for condensible particulate matter is represented by good sulfur dioxide control and good combustion control. Since the primary constituent of condensible particulate matter is sulfuric acid mist which is controlled proportionately to the sulfur dioxide controlled, the BART limit for sulfur dioxide can act as a surrogate for condensible particulate matter along with good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO)®
Selective Non-Catalytic Reduction (SNCR)
Hydrocarbon Enhanced SNCR (HE-SNCR)
Rich Reagent Injection (RRI)
Rotomix (ROFA + SNCR)
Conventional Gas Reburn (CGR)
CGR + SNCR w/separated overfire air (SOFA)
Coal Reburn
Coal Reburn + SNCR
Fuel-lean Gas Reburn (FLGR)
FLGR + SNCR
Rotating Overfire Air (ROFA)
Separated Overfire Air (SOFA)
New Low NO_x Burners (LNB)
Combustion Improvements

Step 2: Eliminate Technically Infeasible Options

The Department agrees with Basin Electric determination that high dust SCR is not technically feasible at this time. However, the Department believes low dust or tail end SCR has a good probability of successful application on Unit 1 (see discussion in Appendix B.5). ECO® and coal reburn plus SNCR have not been demonstrated on a pulverized coal-fired boiler and are considered technically infeasible. Rich reagent injection was developed for cyclone boilers and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Unit 1.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Based on the historic baseline emissions, the Department's estimated emissions using the various technologies would be as follows:

Alternative	Control Efficiency (%)*	Emissions**	
		(tons/yr)	$lb/10^6$ Btu)
SCR w/reheat	80	593	0.057
Coal Reburn + Boosted SOFA	48.7	1,522	0.146
Coal Reburn + SOFA	46.2	1,596	0.153
SNCR + Boosted SOFA	45.1	1,629	0.156
SNCR + Basic SOFA	42.0	1,721	0.165
SNCR + Close-coupled OFA	24.5	2,240	0.215
Boosted SOFA	24.3	2,246	0.216
SOFA	19.4	2,391	0.230
Baseline		2,967	0.285

* Control efficiency provided in Basin Electric's analysis except for SCR. In the ANPR for the Four Corners Power Plant, EPA noted that the Arizona DEQ had determined that an SCR efficiency of 75% was appropriate for a unit with LNB. Leland Olds Unit 1 is equipped with LNB. EPA also indicated they believed 80% for SCR was appropriate.

** Calculated from the historic baseline. The historic baseline was used since the increased sulfur in the coal will not affect NO_x emissions. The emission rate is an annual average rate.

The estimated costs for the various technologies are as follows:

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
SCR w/reheat (low dust)	2,225	19,797,000 - 28,431,000	8,339 - 12,397	13,741 - 23,034***
SCR w/reheat (tail-end)	2,374	21,517,000- 31,011,000*	9,061 - 13,628	15,592 - 25,812***
Coal Reburn + Boosted SOFA	1,445	7,032,000	4,866	14,176
Coal Reburn + SOFA	1,371	5,983,000	4,364	80,727
SNCR + Boosted SOFA	1,338	3,819,000	2,854	7,826

Alternative	**Emissions Reduction (tpy)**	**Annualized Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
SNCR + Basic SOFA	1,246	3,099,000	2,487	3,737*
SNCR + Close coupled OFA	727	3,361,000	4,623	
Boosted SOFA	721	1,137,000	1,577	6,848
SOFA	576	144,000	250	250

* Department estimate based on Unit 2 cost estimate.
** SNCR + Basic SOFA compared to Boasted SOFA.
*** Incremental cost of SCR versus coal reburn + boosted SOFA.

SCR technology has never been applied to a boiler that combusts North Dakota lignite There are many unknowns that will affect the cost of either LDSCR or TESCR at the Leland Olds Station including:

1) The catalyst deactivation rate
2) Catalyst volume required
3) Catalyst surface area required
4) Required reagent injection rate
5) Expected reagent slip
6) Whether formation of ammonium bisulfate and/or ammonium sulfate will be at an acceptable rate
7) An appropriate catalyst maintenance plan

All of these will affect either the initial construction cost and/or annual operation and maintenance costs. The amount of catalyst required will affect the initial capital cost as well as the replacement cost. The life of the catalyst and the amount of reagent required will have a large impact on the annual operating cost. If a wet electrostatic precipitator is required to control ammonium bisulfate/ammonium sulfate emissions, both the initial capital cost and operation and maintenance costs will rise dramatically. Given the many unknowns with North Dakota Lignite, estimating the cost of an SCR system is extremely difficult and subject to many different opinions regarding estimating procedures. The Department believes pilot scale testing would prove to be very beneficial in addressing the items of concern and provide a more detailed professionally reliable cost estimate. However, the BART process cannot mandate pilot testing be conducted to determine costs. The Department believes the cost estimate provided by Basin Electric for Unit 2 without pilot testing, although not ideal, will suffice based on the information that is available at the current time.

Step 4: Evaluate Impacts and Document Results

There are no energy or environmental impacts that would preclude the selection of any of the alternatives.

Step 5: Evaluate Visibility Impacts

The Department considers the cost effectiveness and/or incremental cost effectiveness of the top four alternatives to be excessive. Basin Electric has modeled a no controls option and the SNCR + Basic SOFA option. The results are as follows:

Unit 1
Delta Deciview
90th Percentile
NO_x

Year	**Unit**	**No Controls**	**SOFA + SNCR**	**Difference**
2000	TRNP-SU	0.241	0.228	0.013
2001	TRNP-SU	0.197	0.179	0.018
2002	TRNP-SU	0.360	0.321	0.039
Average	TRNP-SU	0.266	0.243	0.023
2000	TRNP-NU	0.212	0.180	0.032
2001	TRNP-NU	0.259	0.230	0.029
2002	TRNP-NU	0.295	0.273	0.022
Average	TRNP-NU	0.255	0.228	0.028
2000	Elkhorn Ranch	0.199	0.184	0.015
2001	Elkhorn Ranch	0.115	0.107	0.008
2002	Elkhorn Ranch	0.197	0.183	0.014
Average	Elkhorn Ranch	0.170	0.158	0.012
2000	Lostwood W.A.	0.412	0.366	0.046
2001	Lostwood W.A.	0.450	0.446	0.004
2002	Lostwood W.A.	0.303	0.276	0.027
Average	Lostwood W.A.	0.388	0.363	0.026
Overall Average		0.270	0.248	0.022

Unit 1
Delta deciviews
98th Percentile
NO_x

Year	**Unit**	**No Controls**	**SOFA + SNCR**	**Difference**
2000	TRNP-SU	0.897	0.819	0.078
2001	TRNP-SU	0.909	0.822	0.087
2002	TRNP-SU	1.756	1.610	0.146
Average	TRNP-SU	1.187	1.084	0.104

Unit 1 **Delta deciviews** **98th Percentile** **NO_x**				
Year	**Unit**	**No Controls**	**SOFA + SNCR**	**Difference**
2000	TRNP-NU	0.981	0.865	0.116
2001	TRNP-NU	1.090	1.025	0.065
2002	TRNP-NU	1.814	1.654	0.160
Average	TRNP-NU	1.295	1.181	0.114
2000	Elkhorn Ranch	0.669	0.570	0.099
2001	Elkhorn Ranch	0.745	0.709	0.036
2002	Elkhorn Ranch	1.433	1.309	0.124
Average	Elkhorn Ranch	0.949	0.863	0.086
2000	Lostwood W.A.	1.051	0.954	0.097
2001	Lostwood W.A.	1.610	1.466	0.144
2002	Lostwood W.A	1.081	0.979	0.102
Average	Lostwood W.A.	1.247	1.133	0.114
Overall Average		1.170	1.065	0.105

Step 6: Select BART

The Department considers the cost effectiveness and/or incremental cost of the top four options to be excessive. The Department proposes that BART is represented by SNCR plus basic SOFA. Basin Electric has indicated that Unit 1 can achieve an emission limit around 0.166-0.168 lb/10^6 Btu on an annual average basis. A thirty-day rolling average emission rate is expected to be at least 5-15% higher than the annual average emission rate. Unit 1 is a wall-fired unit fired primarily on lignite. In the BART Guideline (40 CFR 51, Appendix Y) EPA established a presumptive level for these units at 0.29 lb/10^6 Btu (30 d.r.a.). The Department proposes that BART is an emission limit of 0.19 lb/10^6 Btu on a 30-day rolling average basis.

V. BART Evaluation of Unit II

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Wet Scrubber
Spray Dryer
Circulating Dry Scrubber
Flash Dryer Absorber
Powerspan ECO

Fuel Switching
Coal Cleaning

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located on the banks of the Missouri River, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning.

K-Fuel® is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels® process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from the Freedom Mine was tested. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. The use of the K-Fuel® process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel® process available or technically and economically feasible.

The Department considers the Powerspan ECO technology not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on a potential-to-emit of 3.02 lb/10^6 Btu (see Section III.A.), the potential mass emission rate is:

E = $(3.02 \times 10^6$ lb/10^6 Btu$)(5130 \times 10^6$ Btu/hr$)$
E = 14592.6 lb/hr
E = 67,858 tons/yr

Alternative	Control Efficiency (%)	Inlet Loading (tons/yr)	Emissions	
			(tons/yr)	(lb/10^6 Btu)[a.]
Wet Scrubber	95	67,858	3,393	0.15
Circulating Dry Scrubber	93	67,858	4,750	0.21
Spray Dryer	90	67,858	6,786	0.30
Flash Dryer Absorber	90	67,858	6,786	0.30
Fuel Switching	≈77	67,858	15,607	0.69

[a.] Annual Average Emission Rate

Alternative	Emissions Reductions (tons/yr)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Wet Scrubber	64,465	29,840,000	463	1,099[a]
CDS	63,108	35,580,000	564	
Spray Dryer	61,072	32,890,000	539	
Flash Dryer	61.072	32,430,000	531	
Fuel Switching	<52,251	13,490,000	258	

[a.] Incremental cost difference between wet scrubbing and fuel switching. All other alternatives are inferior to the wet scrubber.

Step 4: Evaluate Impacts and Document Results

Basin Electric has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of any of the available options. Basin Electric has selected the wet scrubber alternative as BART for this unit. A wet scrubber is the most efficient control option. Therefore, no evaluation of costs is necessary.

Step 5: Evaluate Visibility Results

Basin Electric has selected a wet scrubber operating at 95% control efficiency as BART. The BART Guideline states that if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining steps. Basin has committed to the most stringent controls available and the lowest possible emission rate. Although modeling is not required, Basin Electric has modeled the use of a wet scrubber on Unit 2. The results are shown in the following table.

Unit 2
Delta Deciview
90th Percentile
SO_2

Year	**Unit**	**Uncontrolled**	**Wet Scrubber (95%)**	**Difference**
2000	TRNP-SU	0.674	0.178	0.496
2001	TRNP-SU	0.586	0.148	0.438
2002	TRNP-SU	1.161	0.336	0.825
Average	TRNP-SU	0.807	0.221	0.586
2000	TRNP-NU	0.681	0.146	0.535
2001	TRNP-NU	0.827	0.181	0.646
2002	TRNP-NU	0.761	0.212	0.549
Average	TRNP-NU	0.756	0.180	0.577
2000	Elkhorn Ranch	0.553	0.142	0.411
2001	Elkhorn Ranch	0.434	0.076	0.358
2002	Elkhorn Ranch	0.617	0.142	0.475
Average	Elkhorn Ranch	0.535	0.120	0.415
2000	Lostwood W.A.	1.109	0.307	0.802
2001	Lostwood W.A.	1.032	0.339	0.693
2002	Lostwood W.A.	0.796	0.209	0.587
Average	Lostwood W.A.	0.979	0.285	0.694
Overall Average		0.769	0.201	0.568

Unit 2
Delta Deciview
98th Percentile
SO_2

Year	**Unit**	**Uncontrolled**	**Wet Scrubber (95%)**	**Difference**
2000	TRNP-SU	2.340	0.728	1.612
2001	TRNP-SU	2.339	0.660	1.679
2002	TRNP-SU	4.924	1.445	3.479
Average	TRN-SU	3.201	0.944	2.257
2000	TRNP-NU	2.430	0.800	1.630
2001	TRNP-NU	2.954	0.877	2.077
2002	TRNP-NU	3.958	1.496	2.462
Average	TRNP-NU	3.114	1.058	2.056
2000	Elkhorn Ranch	1.581	0.471	1.110

Unit 2 Delta Deciview 98th Percentile SO_2				
Year	**Unit**	**Uncontrolled**	**Wet Scrubber (95%)**	**Difference**
2001	Elkhorn Ranch	2.288	0.477	1.811
2002	Elkhorn Ranch	3.450	1.134	2.316
Average	Elkhorn Ranch	2.440	0.694	1.746
2000	Lostwood W.A.	2.419	0.830	1.589
2001	Lostwood W.A.	4.158	1.391	2.767
2002	Lostwood W.A.	3.609	0.866	2.743
Average	Lostwood W.A.	3.395	1.029	2.366
Overall Average		3.038	0.931	2.106

Step 6: Select BART

After considering the cost of compliance, the energy and non-air quality environmental impacts, the remaining useful life (> 20 years) and the degree of visibility improvement, the Department proposes that BART is represented by a wet scrubber. Based on an annual controlled emission rate of 0.15 lb/10^6 Btu, a maximum 30-day rolling average emission rate of 0.19 lb/10^6 Btu is expected. By allowing Basin Electric to comply with either a percent reduction or a lb/10^6 Btu limitation, the presumptive emission limits for plants larger than 750 MWe can be established. The Department proposes that BART is 95% reduction efficiency from the inlet of the scrubber to the outlet of the scrubber, or 0.15 lb/10^6 Btu, on a 30-day rolling average basis.

B. Filterable Particulate Matter (PM/PM_{10})

Step 1: Identify All Available Technologies

New Baghouse
New Electrostatic Precipitator
Compact Hybrid Particulate Collector (CoHPAC)
Existing Electrostatic Precipitator

Step 2: Eliminate Technically Infeasible Options

All technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	Control Efficiency (%)	Emissions* (tons/yr)	Emissions* (lb/106 Btu)
Baghouse	99.7+	239	0.013
New ESP	99.7	277	0.015
CoHPAC	99.7	277	0.015
Baseline (Existing ESP)	≈ 99.3	627*	0.034

* Based on the Department's estimate of baseline emissions (2001-2002).

Alternative	Emissions* Reduction (tpy)	Annualized Cost** ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baghouse	388	5,892,000	15,186	44,265***
New ESP	350	4,948,000	14,137	
CoHPAC	350	4,210,000	12,029	
Baseline	0	0	---	

* Reductions from baseline emission rate.
** Costs provided by Basin Electric.
*** CoHPAC compared to a baghouse.

Step 4: Evaluate Impacts and Document Results

Basin Electric has evaluated the energy and non-air quality environmental impacts associated with each alternative and determined that these impacts would not prelude the selection of any of the alternatives as BART. The Department agrees with this determination.

Step 5: Evaluate Visibility Results

The different alternatives were not modeled because of the high cost effectiveness. However, the baseline emission rate was modeled. The results are as follows:

Unit 2 Delta Deciview PM			
Year	**Unit**	**90th Percentile**	**98th Percentile**
2000	TRNP-SU	0.0018	0.0070
2001	TRNP-SU	0.0013	0.0084
2002	TRNP-SU	0.0068	0.0158
Average	TRNP-SU	0.0033	0.0104
2000	TRNP-NU	0.0037	0.0053
2001	TRNP-NU	0.0007	0.0059
2002	TRNP-NU	0.0006	0.0293
Average	TRNP-NU	0.0017	0.0135
2000	Elkhorn Ranch	0.0028	0.0040
2001	Elkhorn Ranch	0.0055	0.0069
2002	Elkhorn Ranch	0.0048	0.0121
Average	Elkhorn Ranch	0.0044	0.0076
2000	Lostwood W. A.	0.0139	0.0249
2001	Lostwood W. A.	0.0015	0.0258
2001	Lostwood W. A.	0.0013	0.0274
Average	Lostwood W.A.	0.0056	0.0260
Overall Average		0.0038	0.0144

Step 6: Select BART

The alternative (excluding the baseline alternative) with the least cost for reducing filter particulate matter emissions is the CoHPAC system which has a cost effectiveness of $12,029 per ton when compared to the current emission control systems (ESP operating at 99.3% control efficiency). The Department considers this cost to be excessive. There are no energy or non-air quality impacts that would preclude the selection of any of the feasible control options.

The unit is equipped with an electrostatic precipitator that is achieving 99.3% control efficiency. The average emission rate for this unit for 2000-2004 was 0.025 lb/10^6 Btu. The plant is expected to have a remaining useful life of at least 20 years.

If all of the particulate matter emitted was eliminated, the most improvement in visibility at any Class I area would be 0.0056 deciviews based on the 90th percentile (0.0260 deciviews based on 98th percentile). The Department considers this amount of improvement to be negligible. Since none of the control alternatives will eliminate all of the particulate matter emissions, the visibility improvement will even be less.

After considering all of the factors, the Department proposes that BART for filterable particulate matter is no additional controls. Since the current actual emissions are less than the current allowable emissions, the Department proposes that BART is represented by an emission limit of 0.07 lb/10^6 Btu (average of three test runs).

C. Condensible Particulate Matter (PM_{10})

See the discussion for Unit 1 in Section III.C. Any additional control technology for controlling condensible particulate matter will result in less than a 0.0056 deciview improvement at any Class I area. The Department considers the use of a wet scrubber and good combustion practices to represent BART for condensible particulate matter from Unit 2. The BART limit for sulfur dioxide (95% reduction) and good combustion practices will act as a surrogate for condensible particulate matter.

D. Nitrogen Oxides

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO)®
Selective Non-Catalytic Reduction (SNCR)
Hydrocarbon Enhanced - SNCR with or without Advanced Separated Overfire Air (ASOFA)
Rich Reagent Injection (RRI) + SNCR + ASOFA
Rotomix (ROFA + SNCR)
Conventional Gas Reburn plus SNCR (CGB + SNCR)
Coal Reburn
Coal Reburn + SNCR
Fuel Lean Gas Reburn (FLGR)
Seperated Overfire Air (SOFA)
Advanced SOFA (ASOFA)
Rotating Overfire Air (ROFA)
Combustion Improvements
Oxygen Enhanced Combustion (OEC)

Step 2: Eliminate Technically Infeasible Options

The Department does not consider high dust SCR to be technically feasible at this time. However, the Department believes low dust or tail end SCR has a good probability of successful application on Unit 2 (see discussion in Appendix B.5). Basin Electric has determined the following technologies are also technically infeasible:

ECO
HE-SNCR
Rotamix
CGR + SNCR
Coal Reburn + SNCR
FLGR + SNCR
OEC

The Department agrees with Basin Electric's determination regarding technical feasibility. ROFA and SOFA are similar and only SOFA will be evaluated further.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on the historic baseline emissions, the expected emissions are as follows:

Alternative	**Control Efficiency* (%)**	**Emissions****	
		(tons/yr)	**(lb/10^6 Btu)**
SCR w/reheat + ASOFA	90	1,202	0.07
RRI + SNCR + ASOFA	60.3	4,773	0.266
SNCR + ASOFA	54.5	5,470	0.305
Coal Reburn + ASOFA	51.8	5,795	0.323
SNCR	37	7,574	0.422
ASOFA	28	8,657	0.482
SOFA/ROFA	<28	>8,657	>0.482
Baseline		12,023	0.67

*Control efficiency specified by Basin Electric in their analysis.
**Based on historic baseline emissions. The lb/10^6 Btu emission rate is an annual average.

The estimated costs for the most efficient alternatives are as follows:

Alternative	**Emissions Reduction (tons/yr)**	**Annualized Cost ($/ton)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Low Dust SCR + ASOFA	10,821	40,326,000 - 57,914,000	3,727 - 5,352	6,420 - 11,356
Tail-end SCR + ASOFA	10,821	43,830,000-63,170,000	4,050-5,838	7,401-12,817
RRI + SNCR + ASOFA	7,250	17,400,000	2,400	9,369
SNCR + ASOFA	6,553	10,870,000	1,659	3,021**
*Coal Reburn + ASOFA	6,228	14,860,000	2,386	
ASOFA	3,366	1,241,000	369	369

Note: See discussion for Unit 1 regarding the accuracy of the cost estimate for SCR.

* Inferior alternative since it costs more than SCNR + ASOFA with less emissions reduction.
** Incremental cost difference between SCNCR + ASOFA and ASOFA.

Step 4: Evaluate Impacts and Document Results

Basin Electric has not identified any environmental or energy impact that would preclude of the use of any of the previously evaluated emission control alternatives.

Step 5: Evaluate Visibility Impacts

The top three alternatives were evaluated with respect to the impact on visibility impairment. The results are as follows:

Unit 2
Delta Deciview
90th Percentile

Year	**Unit**	**SCR + ASOFA**	**ASOFA+RRI+SNCR**	**Difference**
2000	TRNP-SU	0.061	0.124	0.063
2001	TRNP-SU	0.060	0.104	0.044
2002	TRNP-SU	0.105	0.201	0.096
Average	TRNP-SU	0.075	0.143	0.068
2000	TRNP-NU	0.056	0.107	0.051
2001	TRNP-NU	0.073	0.132	0.059

Unit 2
Delta Deciview
90th Percentile

Year	Unit	SCR + ASOFA	ASOFA+RRI+SNCR	Difference
2002	TRNP-NU	0.082	0.147	0.065
Average	TRNP-NU	0.070	0.129	0.058
2000	Elkhorn Ranch	0.047	0.104	0.057
2001	Elkhorn Ranch	0.037	0.057	0.020
2002	Elkhorn Ranch	0.057	0.101	0.044
Average	Elkhorn Ranch	0.047	0.087	0.040
2000	Lostwood W.A.	0.114	0.215	0.101
2001	Lostwood W.A.	0.097	0.224	0.127
2002	Lostwood W.A.	0.074	0.135	0.061
Average	Lostwood W.A.	0.095	0.191	0.096
Overall Average		0.072	0.138	0.066

Unit 2
Delta Deciview
98th Percentile

Year	Unit	SCR + ASOFA	ASOFA+RRI+SNCR	Difference
2000	TRNP-SU	0.280	0.492	0.212
2001	TRNP-SU	0.217	0.484	0.267
2002	TRNP-SU	0.531	0.961	0.430
Average	TRNP-SU	0.343	0.646	0.303
2000	TRNP-NU	0.232	0.502	0.270
2001	TRNP-NU	0.303	0.609	0.306
2002	TRNP-NU	0.432	0.991	0.559
Average	TRNP-NU	0.322	0.701	0.378
2000	Elkhorn Ranch	0.154	0.334	0.180
2001	Elkhorn Ranch	0.218	0.317	0.099
2002	Elkhorn Ranch	0.385	0.767	0.382
Average	Elkhorn Ranch	0.252	0.473	0.220
2000	Lostwood W.A.	0.255	0.606	0.351
2001	Lostwood W.A.	0.399	0.909	0.510
2002	Lostwood W.A.	0.331	0.589	0.258
Average	Lostwood W.A.	0.328	0.701	0.373
Overall Average		0.311	0.630	0.319

Unit 2
Delta Deciview
90th Percentile

Year	Unit	SCR + ASOFA	SNCR + ASOFA	Difference
2000	TRNP-SU	0.061	0.135	0.074
2001	TRNP-SU	0.060	0.114	0.054
2002	TRNP-SU	0.105	0.225	0.120
Average	TRNP-SU	0.075	0.158	0.083
2000	TRNP-NU	0.056	0.121	0.065
2001	TRNP-NU	0.073	0.146	0.073
2002	TRNP-NU	0.082	0.151	0.069
Average	TRNP-NU	0.070	0.139	0.069
2000	Elkhorn Ranch	0.047	0.114	0.067
2001	Elkhorn Ranch	0.037	0.057	0.020
2002	Elkhorn Ranch	0.057	0.109	0.052
Average	Elkhorn Ranch	0.047	0.093	0.046
2000	Lostwood W.A.	0.114	0.238	0.124
2001	Lostwood W.A.	0.097	0.232	0.135
2002	Lostwood W.A.	0.074	0.149	0.075
Average	Lostwood W.A.	0.095	0.206	0.111
Overall Average		0.072	0.149	0.077

Unit 2
Delta Deciview
98th Percentile

Year	Unit	SCR + ASOFA	SNCR + ASOFA	Difference
2000	TRNP-SU	0.280	0.536	0.256
2001	TRNP-SU	0.217	0.526	0.309
2002	TRNP-SU	0.531	1.050	0.519
Average	TRNP-SU	0.343	0.70	0.361
2000	TRNP-NU	0.232	0.556	0.324
2001	TRNP-NU	0.303	0.658	0.355
2002	TRNP-NU	0.432	1.091	0.659
Average	TRNP-NU	0.322	0.768	0.446
2000	Elkhorn Ranch	0.154	0.372	0.218
2001	Elkhorn Ranch	0.218	0.346	0.128
2002	Elkhorn Ranch	0.385	0.836	0.451
Average	Elkhorn Ranch	0.252	0.518	0.266
2000	Lostwood W.A.	0.255	0.647	0.392

Unit 2
Delta Deciview
98th Percentile

Year	Unit	SCR + ASOFA	SNCR + ASOFA	Difference
2001	Lostwood W.A.	0.399	0.999	0.600
2002	Lostwood W.A.	0.331	0.643	0.312
Average	Lostwood W.A.	0.328	0.763	0.435
Overall Average		0.311	0.688	0.377

Unit 2
Delta Deciview
90th Percentile
NO_x

Year	Unit	ASOFA + RRI + SNCR	ASOFA + SNCR	Difference
2000	TRNP-SU	0.124	0.135	0.011
2001	TRNP-SU	0.104	0.114	0.010
2002	TRNP-SU	0.201	0.225	0.024
Average	TRNP-SU	0.143	0.158	0.015
2000	TRNP-NU	0.107	0.121	0.014
2001	TRNP-NU	0.132	0.146	0.014
2002	TRNP-NU	0.147	0.151	0.04
Average	TRNP-NU	0.129	0.139	0.011
2000	Elkhorn Ranch	0.104	0.114	0.010
2001	Elkhorn Ranch	0.057	0.057	0.000
2002	Elkhorn Ranch	0.101	0.109	0.008
Average	Elkhorn Ranch	0.087	0.093	0.006
2000	Lostwood W.A.	0.215	0.238	0.023
2001	Lostwood W.A.	0.224	0.232	0.008
2002	Lostwood W.A.	0.135	0.149	0.014
Average	Lostwood W.A.	0.191	0.206	0.015
Overall Average		0.138	0.149	0.012

Unit 2
Delta Deciview
98th Percentile
NO_x

Year	Unit	ASOFA + RRI + SNCR	ASOFA + SNCR	Difference
2000	TRNP-SU	0.492	0.536	0.044
2001	TRNP-SU	0.484	0.526	0.042
2002	TRNP-SU	0.961	1.050	0.089

Average	TRNP-SU	0.646	0.704	0.058
2000	TRNP-NU	0.502	0.556	0.054
2001	TRNP-NU	0.609	0.658	0.049
2002	TRNP-NU	0.991	1.091	0.100
Average	TRNP-NU	0.701	0.768	0.068
2000	Elkhorn` Ranch	0.334	0.372	0.038
2001	Elkhorn Ranch	0.317	0.346	0.029
2002	Elkhorn Ranch	0.767	0.836	0.069
Average	Elkhorn Ranch	0.473	0.518	0.045
2000	Lostwood W.A.	0.606	0.647	0.041
2001	Lostwood W.A.	0.909	0.999	0.090
2002	Lostwood W.A.	0.589	0.643	0.054
Average	Lostwood W.A.	0.701	0.763	0.062
Overall Average		0.630	0.688	0.058

Step 6: Select BART

The Department considers both the cost effectiveness and incremental cost of SCR to be excessive. SCR will only produce an average of 0.066 decivews improvement in the North Dakota Class I areas based on the 90th percentile (0.319 decivews based on the 98th percentile) versus RRI + ASOFA + SNCR. Because the single source modeling under the BART guidelines overestimates the visibility improvement in North Dakota by a factor of 5-7 (see Section 7.4.2 of SIP), the Department conducted modeling which included all sources of emissions in the modeling inventory to determine the true impact on visibility of SCR + ASOFA versus SNCR + ASOFA. The average improvement in visibility for the 20% worst days was only 0.01 decivews at both TRNP and LWA. The Department considers this amount of improvement to be negligible. Based on the excessive cost and negligible visibility improvement, SCR was eliminated as a BART alternative.

RRI + SNCR + ASOFA and SNCR + ASOFA are both considered to have reasonable cost effectiveness. However, the incremental cost ($9,369/ton) going from SNCR + ASOFA to RRI + SNCR + ASOFA is considered excessive. Use of RRI + SNCR + ASOFA will only increase visibility improvement by an average of 0.012 deciviews (90th percentile) or 0.058 deciviews (98th percentile) during the 2000-2002 time period. Given the high incremental cost and negligible visibility improvement, RRI + ASOFA + SNCR was eliminated as a BART alternative.

After considering all of the factors, the Department proposes that BACT is represented by SNCR + ASOFA. With SNCR + ASOFA, an emission rate of 0.305 lb/10^6 Btu on an annual average basis is expected. Basin

Electric believes that an emission rate of 0.35 lb/10^6 Btu is achievable based on a 30-day rolling average. The Department's experience with power plants suggest that the maximum 30-day rolling average NO_x emission rate is 5-15% higher than the annual average emission rate. Therefore, the Department proposes that BART is an emission limit of 0.35 lb/10^6 Btu on a 30-day rolling average basis.

V. BART Evaluation for Auxiliary Boiler

The auxiliary boiler is a #2 fuel-oil fired boiler with a nominal rating of 51.6 x 10^6 Btu/hr. The auxiliary boiler is only used when both units at the Leland Olds Station are down. During the baseline period (2000-2004), the unit was operated approximately 3.6 hours per year. The annual average emissions from the unit for this period were:

NO_x	0.01 tons
SO_2	0.03 tons
PM	0.001 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have a virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls. The current permit limits the fuel used in the boiler to #2 fuel oil. BART is the use of #2 fuel oil.

VI. BART Evaluation for Emergency Fire Pump

The emergency fire pump, is driven by a 200 horsepower diesel engine. The pump is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. During the baseline period (2000-2004), the engine operated 4.3 hours per year and the actual annual emissions were:

NO_x	0.0002 tons
SO_2	0.0003 tons
PM	0.00001 tons

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VII. BART Evaluation for Materials Handling Sources

The materials handling sources at Leland Olds Station that emit to the atmosphere are as follows:

EUI	Description	Existing Control Equipment	Current Emission Limit (lb/hr)	Baseline Emissions (tons/yr)
M7	Unit 2 East bunker conveyor	Rotoclone	1.0	0.82*
M8	Unit 2 West bunker conveyor	Rotoclone	1.0	0.82*
M9	Unit 2 Bunker house transfer conveyor (west)	Rotoclone	1.0	0.82*
M10	Unit 2 Bunker house transfer conveyor (east)	Rotoclone	1.0	0.82*
M11	Main flyash silo	Baghouse	0.26	1.0
M12	100 Ton flyash silo	Baghouse	0.1	0.01
M13	Coal unloading facility	Baghouse	16.97	12.4
M14	Agglomerator	Baghouse	0.06	0.04
M16	Coal unloading silo	Baghouse	0.26	0.19

*Department estimate

Based on the small quantity emissions from those sources that are controlled by rotoclones (M7-M10), it is apparent that no additional control equipment will be cost effective. The other materials handling units are controlled using a baghouse which is considered the most efficient control device. Therefore, the Department proposes that BART for the materials handling units is no additional controls and the current emission limit for the units is BART.

VIII. Summary

Source Unit	**Proposed* BART Limit/Work Practice**				**Emissions Reduction** (tons/yr)**		
	PM	**SO2**	**NOx**	**Units**	**PM**	**SO2**	**NOx**
Unit 1 Boiler	0.07	0.15 or 95% reduction	0.19	lb/106 Btu	0	15,290	757
Unit 2 Boiler	0.07	0.15 or 95% reduction	0.35	lb/106 Btu	0	28,297	4,519
Auxiliary Boiler	Use #2 Fuel Oil			N/A	0	0	0
Fire Pump	Use low sulfur diesel fuel			N/A	0	0	0
M7	1.0	---	---	lb/hr	0	---	---
M8	1.0	---	---	lb/hr	0	---	---

Source Unit	Proposed* BART Limit/Work Practice				Emissions Reduction** (tons/yr)		
	PM	**SO2**	**NOx**	**Units**	**PM**	**SO2**	**NOx**
M9	1.0	---	---	lb/hr	0	---	---
M10	1.0	---	---	lb/hr	0	---	---
M11	0.26	---	---	lb/hr	0	---	---
M12	0.1	---	---	lb/hr	0	---	---
M13	16.97	---	---	lb/hr	0	---	---
M14	0.06	---	---	lb/hr	0	---	---
M16	0.26	---	---	lb/hr	0	---	---
Total						43,587	5,276

* PM limit is the average of three 2-hour test runs. SO_2 and NO_x limits are a 30-day rolling average.

** Reductions from 2000-2004 average emission rate assuming 30-day rolling average equals the annual average emission rate.

IX. Permit to Construct

The emission limits, monitoring, recordkeeping and reporting requirements will be included in a federally enforceable Air Pollution Control Permit to Construct that will be issued to the owner/operator of the facility. The Permit to Construct is included in Appendix D.

A. Monitoring

1. Monitoring for SO_2 and NO_x will be accomplished using the continuous emission monitors required by 40 CFR 75 for the Acid Rain Program. Monitoring for particulate matter shall be in accordance with 40 CFR 64, Compliance Assurance Monitoring. If the owner/operator of the BART-eligible unit chooses to comply with the SO_2 percent reduction requirements, monitoring of the SO_2 inlet rate to the scrubber shall be accomplished by either:

   a. A continuous emission monitor that complies with the requirements of 40 CFR 75; or

   b. Coal sampling in accordance with Method 19 of 40 CFR 60, Appendix A plus development of an emission factor based on actual stack testing.

2. For purposes of determining compliance with the SO_2 reduction requirement, the reduction efficiency shall be determined as follows:

$$\% \text{ Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where:

Inlet SO_2 Rate is in units of lb/10^6 Btu, lb/hr or ppmvd @ 3% O_2.
Outlet SO_2 Rate is in the same units as the inlet SO_2 rate.

3. The owner/operator will be allowed to average emissions (bubble) for SO_2 and/or NO_x for the two units using the following formulas:

$$\text{Average AER} = \frac{[(AER_1)(HI_1)+(AER_2)(HI_2)]}{(HI_1 + HI_2)}$$

$$\text{Average ER} = \frac{[(ER_1)(HI_1)+(ER_2)(HI_2)]}{(HI_1 + HI_2)}$$

Where:

AER = Allowable Emission Rate (lb/MMBtu or % Reduction)

ER_1 = Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 1
ER_2 = Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 2
HI_1 = Actual Heat Input (MMBtu) of Unit 1
HI_2 = Actual Heat Input (MMBtu) of Unit 2

Notes: ER is a 30-day rolling average.
HI is a 30-day rolling average.
30-day rolling average for the 30 successive boiler operating days (must be on a consistent basis of lb/MMBtu or % reduction).

B. Recordkeeping and Reporting

The owner/operator will be required to conduct recordkeeping and reporting as required by NDAC 33-15-14-06, Title V Permit to Operate and NDAC 33-15-21, Acid Rain Program (40 CFR 72, 75 and 76).

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3. NDDH, 2005. A proposed alternative air quality modeling protocol to examine the status of attainment of PSD Class I increments. North Dakota Department of Health, Bismarck, ND 58506-5520.

4. Institute of Clean Air Components, 2008 Acid Gas/SO_2 Control Technologies www.icac.com

5. Federal Register Vol. 70, No. 28, P.9715

6. EPA, 2003, Air Pollution Control Technology Fact Sheet; EPA - 451/F-03-034.

7. Benson, Stephen A., Controlling Mercury Emissions for Utilities Firing Lignites from North America~~n~~, Summary Report. Energy and Environmental Research Center, University of North Dakota, Grand Forks, ND 58202.

8. NDDH, 2007. Air Quality Effects Analysis and Permit Application for Spiritwood Station, Stutsman County, North for Air Pollution Control Permit to Construct. North Dakota Department of Health, Bismarck, ND 58501.

9. NDDH, 2007. Air Quality Effects Analysis and Permit Application of Westmoreland Power, Inc., Electric Utility Steam Generating Station and Coal Mine; Bowman County, North Dakota for Air Pollution Control Permit to Construct. North Dakota Department of Health, Bismarck, ND 58501.

10. NDDH, 2005. Air Quality Effects Analysis and Permit Application of Montana Dakota Utilities Co. and Westmoreland Power, Inc. Electric Utility Steam Generating Station and Coal Mine, Bowman County, North Dakota for Air Pollution Control Permit to Construct. North Dakota Department of Health, Bismarck, ND 58501.

11. Basin Electric Power Cooperative, 2006. BART Determination for Leland Olds Station Unit 1 and 2; Basin Electric Power Cooperative; Final Draft; August 2006.

BART Determination
For
Coal Creek Station Units 1 and 2

12/1/09

I. Source Description

A. Owner/Operator: Great River Energy (GRE)

B. Source Type: Fossil-fuel fired steam electric plant of more than 250 million British thermal units (Btu) per hour heat input and having a total generating capacity in excess of 750 megawatts.

C. BART Eligible Units

1. EU 1 - Unit 1 boiler
2. EU 2 - Unit 2 boiler
3. EU 3 - Auxiliary boiler No. 91
4. EU 4 - Auxiliary boiler No. 92
5. EU 5 - Emergency generator
6. EU 6 - Fire pump engine
7. EU 7 through EU 26 material handling units, including coal and lime handling operations and flyash silos
    a. EU 7 - Lignite transfer house
    b. EU 8 - Lignite emergency reclaim system
    c. EU 9 - Lignite yard storage silos
    d. EU 10 - Lignite yard storage silos
    e. EU 11 - Crusher building (Two 1,500 ton per hour crushers)
    f. EU 12 - Generation building coal hopper
    g. EU 13 - Falkirk Mining Company mine silo base

      h. EU 14 - Generation building coal hopper

      i. EU 15 - Generation building coal hopper

      j. EU 16 - Generation building coal hopper

      k. EU 17 - Generation building coal hopper

      l. EU 19 - Scrubber building flyash silo

      m. EU 20 - Truck air slide flyash silo

      n. EU 21 - Truck air slide flyash silo

      o. EU 22 - Water treatment building

      p. EU 23 - Scrubber building lime handling system

      q. EU 24 - Scrubber building lime handling system

      r. EU 25 - Flyash railroad marketing silo

      s. EU 26 - Flyash dome

   8. FS 1 through FS 5 - Fugitive sources

      a. FS 1 - Cooling Towers No. 91, No. 92, and No. 93

      b. FS 2 - Boombelt conveyor (stackout)

      c. FS 3 - Conveyor 909 (stackout)

      d. FS 4 - Scrubber building flyash silo (stackout)

      e. FS 5 - Coal pile maintenance

D. Unit Description

   1. EU 1 - Unit 1 boiler:

      Generator Nameplate Capacity: 550 MWe

      Boiler Rating: 6,015 x 10^6 Btu/hour

      Startup: 1979

Fuel: North Dakota lignite

Firing Method: Tangential-fired pulverized coal (PC) unit

Existing Air Pollution Equipment:

Electrostatic precipitator (ESP)
Low NO_x burners (LNB) and separated over fire air (SOFA)
Wet scrubber

2. EU 2 - Unit 2 boiler

Generator Nameplate Capacity: 550 MWe

Boiler Rating: 6,022 x 10^6 Btu/hour

Startup: 1980

Fuel: North Dakota lignite

Firing method: Tangential-fired pulverized coal (PC) unit

Existing Air Pollution Equipment:

Electrostatic precipitator (ESP)
Low NO_x burners (LNB) and separated over fire air (SOFA)
Wet scrubber

3. EU 3 - Auxiliary boiler No. 91

Boiler rating: 172 x 10^6 Btu/hour

Fuel: Residual oil, distillate fuel oils, or any combination of these fuels

Existing air pollution equipment: None

4. EU 4 - Auxiliary boiler No. 92

Boiler rating: 172 x 10^6 Btu/hour

Fuel: Residual oil, distillate fuel oils, or any combination of these fuels

Existing air pollution equipment: None

5. EU 5 - Emergency generator

Rating: 3,500 bhp

Fuel: No. 2 fuel oil or a blend of No. 1 and No. 2 fuel oil

Existing air pollution equipment: None

6. EU 6 - Fire pump engine

Rating: 200 bhp

Fuel: No. 2 fuel oil or a blend of No. 1 and No. 2 fuel oil

Existing air pollution equipment: None

7. EU 7 through EU 26 - Material handling units, including lime handling operations and flyash silos

Existing air pollution equipment: Fabric filters/bag houses

8. FS 1 through FS 5 - Fugitive sources

Existing air pollution equipment: None - fugitive emissions

E. Emissions

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Ave.**
EU 1 - Unit 1 Boiler	SO_2 (tons)	14,332	14,630	11,910	13,817	15,742	14,086
	SO_2 (lb/10^6 Btu)	0.56	0.56	0.51	0.54	0.61	0.56
	NO_x (tons)	5,211	5,235	4,690	5,072	5,370	5,116
	NO_x (lb/10^6 Btu)	0.21	0.21	0.21	0.20	0.21	0.21
	PM (tons)	632	492	1,305	73	116	524
	PM (lb/10^6 Btu)	0.025	0.019	0.056	0.003	0.005	0.021

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Ave.**
EU 2 - Unit 2 Boiler	SO_2 (tons) SO_2 (lb/10^6 Btu)	12,817 0.53	11,683 0.51	12,518 0.49	13,547 0.54	11,469 0.50	12,407 0.51
	NO_x (tons) NO_x (lb/10^6 Btu)	5,324 0.22	5,190 0.23	5,454 0.22	5,558 0.22	5,429 0.24	5,391 0.23
	PM (tons) PM (lb/10^6 Btu)	827 0.034	649 0.028	1,268 0.050	121 0.005	80 0.003	589 0.024
EU 3 - Auxiliary boiler No. 91	PM (tons) SO_2 (tons) NO_x (tons)	0.10 0.30 0.10	0.00 0.00 0.10	0.10 0.00 0.10	0.00 0.00 0.00	0.00 0.00 0.10	0.02 0.06 0.10
EU 4 - Auxiliary boiler No. 92	PM (tons) SO_2 (tons) NO_x (tons)	0.10 0.30 0.10	0.60 1.30 0.40	0.00 0.00 0.00	0.00 0.00 0.00	0.00 0.00 0.00	0.14 0.32 0.10
EU 5 - Emergency generator	SO_2 (tons) NO_x (tons)	0.45 2.76	0.04 3.07	0.04 2.76	0.04 2.69	0.97 3.06	0.31 2.87
EU 6 - Fire pump engine	SO_2 (tons) NO_x (tons)	0.01 0.09	0.01 0.10	0.01 0.11	0.01 0.11	0.01 0.12	0.01 0.11
EU 7 - Lignite transfer house	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07
EU 8 - Lignite emergency reclaim system	PM (tons)	0.00	0.00	0.00	0.00	0.00	0.00
EU 9 - Lignite yard storage silos	PM (tons)	0.03	0.03	0.03	0.03	0.03	0.03
EU 10 - Lignite yard storage silos	PM (tons)	0.03	0.03	0.03	0.03	0.03	0.03
EU 11 - Crusher building	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07
EU 12 - Generation building coal hopper	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07
EU 13 - Falkirk mining Company mine silo base	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Ave.**
EU 14 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 15 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 16 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 17 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 19 - Scrubber building flyash silo	PM (tons)	0.01	0.02	0.02	0.03	0.03	0.02
EU 20 - Truck air slide flyash silo	PM (tons)	0.05	0.04	0.04	0.04	0.07	0.05
EU 21 Truck air slide flyash silo	PM (tons)	0.05	0.04	0.04	0.04	0.06	0.05
EU 22 - Water treatment building	PM (tons)	0.05	0.04	0.04	0.02	0.00	0.03
EU 23 - Scrubber building lime handling system	PM (tons)	0.03	0.03	0.02	0.02	0.01	0.02
EU 24 - Scrubber building lime handling system	PM (tons)	0.03	0.03	0.02	0.02	0.01	0.02
EU 25 - Flyash railroad marketing silo	PM (tons)	0.03	0.03	0.02	0.02	0.14	0.05
EU 26 - Flyash dome	PM (tons)	0.00	0.00	0.00	0.00	0.11	0.02
FS 1 - Cooling towers No. 91, No. 92 & No. 93	PM (tons)	0.02	0.02	0.01	0.02	0.02	0.02
FS 2 - Boombelt conveyor (stackout)	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
FS 3 - Conveyor 909 (stackout)	PM (tons)	0.02	0.03	0.04	0.05	0.05	0.04
FS 4 - Scrubber building flyash silo (stackout)	PM (tons)	0.02	0.03	0.04	0.05	0.05	0.04

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Ave.**
FS 5 - Coal pile maintenance	PM (tons)	3.77	3.77	3.77	3.77	3.77	3.77

II. Site Characteristics

The Coal Creek Station is a two-unit, 1,100 gross megawatt (MW) mine-to-mouth power plant consisting primarily of two steam generators and associated coal and ash handling systems. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially from a maximum of 64 firing points each. Unit 1 has a heat input capacity of 6,015 x 10^6 Btu/hr; Unit 2 is rated at 6,022 x 10^6 Btu/hr. Particulate matter from each boiler is controlled by a 99.5% efficient electrostatic precipitator (ESP) consisting of 48 transformer rectifier (TR) sets. A four-module flue gas desulfurization (FGD) system for each boiler removes approximately 90% of the sulfur dioxide from 60% of the flue gas. Each boiler is served by a 655 foot high stack.

Unit 1 began commercial operation in 1979 and Unit 2 in 1980. The facility is located in south central McLean County about five miles south of the town of Underwood, North Dakota and three miles west of US Highway 83. Coal Creek Station receives its lignite from the Falkirk Mine that is operated by the Falkirk Mining Company, a subsidiary of the North American Coal Corporation. Approximately 8,130,000 tons of lignite coal and approximately 165,000 gallons of oil were combusted in 2006.

III. BART Evaluation of Unit 1 and Unit 2

The BART guidelines apply to Units 1 and 2 because they are part of a fossil-fuel steam electric plant with a total generating capacity in excess of 750 megawatts, they are rated at more than 250 million Btu per hour heat input, and they have potential emissions of 250 tons or more per year of a visibility-impairing pollutant, specifically SO_2, NO_x and PM_{10}.

Since Units 1 and 2 are identical, the following evaluation will use values derived by averaging the historical data for each unit and then make a single BART determination that will be applicable to each unit.

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Coal Cleaning/Washing
K-Fuel®
TurboSorp®
Coal Drying
Dry Sorbent Injection
Spray Dryer

Wet Scrubber Modification
Wet Scrubber Replacement

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning/Washing: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that have required coal cleaning.

K-Fuel® is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from the Center Mine was tested. The use of the K-Fuel® process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel® and will be submitted to this Department at the end of the approved burn period process available or technically and economically feasible.

TurboSorp®: Although the GRE analysis concluded otherwise, the Department considers TurboSorp® dry flue gas desulfurization technology to be technically feasible because it employs the proven technology of circulating dry scrubbers. Additional information on this technology is found at:
http://www.eucetsa.net/eucetsa/webPages.do?pageID=200913.

Coal Drying: Coal drying of lignite has been demonstrated to be technically feasible through pilot projects at this facility. Furthermore, dried lignite is the primary fuel for another ND facility, the GRE Spiritwood Station, that received a permit to construct September 14, 2007.

In addition to coal drying, the remaining control technologies, dry sorbent injection, spray dryer, and wet scrubber (modification or replacement), are considered to be technically feasible. GRE has elected to install coal drying equipment independent of the SO_2 control chosen.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Baseline SO_2 Emissions Controlled (past): Based on average actual controlled annual emissions when combusting lignite (undried) for a 24 month period (2003-2004) with 27% bypass: (13,817 [Unit 1, 2003] + 13,547 [Unit 2, 2003] + 15,742 [Unit 1, 2004] + 11,469 [Unit 2, 2004])/4 = 13,644 ton/yr average baseline controlled SO_2 emissions with 27% bypass and undried coal.

Applying the 68% overall control efficiency of the existing scrubber yields: [(13,644 ton/yr)/(1-0.68)] = 42,638 ton/yr uncontrolled baseline SO_2 emissions.

The 42,638 ton/yr uncontrolled baseline SO_2 emissions are based on past undried coal with an average 2003-2004 sulfur content of 0.61%. The evaluation of alternative SO_2 cleaning equipment will be based on future undried coal with an expected worst case (98 percentile) sulfur content of 1.10%, as predicted for Falkirk coal and provided by GRE. Therefore, the uncontrolled baseline SO_2 emissions above must be adjusted to the future sulfur content so that an apples to apples comparison will correctly determine emission reductions expected to result from employing the alternative equipment. The 42,638 ton/yr uncontrolled baseline SO_2 emissions is adjusted as follows: (42,638 ton/yr)(1.1%/0.61%) = 76,888 ton/yr uncontrolled baseline SO_2 emissions for undried coal with future sulfur content.

For the purposes of this analysis, the adjustment to future coal was considered necessary only for SO_2 and the related condensible particulate matter and sulfuric acid mist emissions due to the increased sulfur content expected in future coal. For all other pollutants, this analysis does not adust to future coal due to the negligible impact on emissions. No adjustment to the baseline was made for coal drying because the Permit to Construct is not expected to require dried lignite or limit moisture content.

Note: TurboSorp® is a registered trademark for Babcock Power Environmental's circulating dry scrubber. The Department considers circulating dry scrubbers to be technically feasible. Circulating dry scrubbers will generally achieve SO_2 removal efficiencies similar to spray dryer absorbers but less than wet scrubbers. Other BART analyses projected a removal efficiency of 93% with higher costs than a new wet scrubber. Since a circulating dry scrubber will have a lower removal efficiency than a wet scrubber or upgrades to the existing wet scrubber (95% and 94%, respectively) and will cost more than a new wet scrubber or upgrades to the existing wet scrubber, a circulating dry scrubber is an inferior option and is not considered further.

Future Case

Alternative	**Control Efficiency (%)**	**Baseline Uncontrolled Emissions (tons/yr)***	**Controlled Emissions***	
			(tons/yr)	**(lb/10^6 Btu)****
Wet Scrubber Replacement***	95	76,888	3,844	0.146
Wet Scrubber Modification***	95	76,888	3,844	0.146
Spray Dryer***	90	76,888	7,689	0.292
Existing Scrubber & 0% Bypass	83.1	76,888	12,994	0.493
Dry Sorbent Injection***	70	76,888	23,066	0.875
Existing Scrubber & 27% Bypass	68****	76,888	24,604*****	--

*	Future lignite at 1.10% (GRE-predicted worst-case sulfur content for Falkirk Mine lignite. As a result, Department baseline future emission estimates are somewhat higher than GRE's estimates)
**	Annual
***	0% bypass
****	Current control rate
*****	Current controlled emissions = 76,888(1-0.68) = 24,604 tpy

Step 4: Evaluate Impacts and Document Results

Costs of Compliance: Based on the past emissions adjusted for the sulfur content of future coal, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	**Emissions Reduction (tons/yr)**	**Annualized Cost ($)***	**Cost Effectiveness($/ton)**	**Incremental Cost ($/ton)**
Wet Scrubber Replacement	20,760	30,760,000	1,482	24,987
Wet Scrubber Modification	20,760	11,520,000	555	--
Spray Dryer**	16,915	29,220,000	1,727	--
Existing Scrubber 0% Bypass	11,610	9,840,000	848	N/A
Dry Sorbent Injection**	1,538	12,520,000	8,140	N/A

*	Costs provided by GRE
**	Inferior option to wet scrubber modifications
N/A	Not applicable since the cost effectiveness of the less efficient alternative is more than the more efficient alternative

The incremental cost associated with wet scrubber replacement ($24,987/ton) as compared to wet scrubber modification represents an excessively high cost relative to the emission reduction obtained.

Energy and Non-air Quality Effects: GRE has evaluated the energy and non-air quality effects of each option. Although the Department has determined that the information presented by GRE concerning these effects does not appear to preclude the selection of any of the five alternatives above, the possible economic impacts due to extensive process downtime associated with scrubber replacement and dry sorbent injection may be significant negative factors for their selection.

Step 5: Evaluate Visibility Results

The three primary alternatives and associated removal efficiencies are a wet scrubber replacement (95%), wet scrubber modification (95%) and spray dryer (90%). GRE estimated the effects on visibility due to SO_2 reductions (GRE BART Analysis, pages 47-51). Although these estimates were based on 94% SO_2 control for the wet scrubber modification, GRE subsequently agreed to 95% control for that option.

Step 6: Select BART

While the cost effectiveness is reasonable for all technologies evaluated except dry sorbent injection, the incremental cost associated with wet scrubber replacement is excessive.

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The units have existing wet scrubbers for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. With identical levels of SO_2 control, wet scrubber replacement involves additional cost with no improvement in visibility at any Class I area when compared to wet scrubber modification.

The Department proposes that BART is scrubbing 100% of the flue gas stream, the use of wet scrubber modifications to achieve a minimum control efficiency of 95% (30-day rolling average) on the inlet sulfur dioxide concentration to the scrubber or 0.15 lb/10^6 Btu (30-day rolling average). Unit 1 and Unit 2 emissions may be averaged provided the average does not exceed the limit.

B. Filterable Particulate Matter

Step 1: Identify All Available Technologies

Multiclone
Replacement Dry Electrostatic Precipitator (ESP)
Polishing Wet ESP
Baghouse

Step 2: Eliminate Technically Infeasible Options

The multiclone is considered technically infeasible because it has not been successfully demonstrated at a similar plant. All remaining technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	**Control Efficiency**	**Emissions**	
		(tons/yr)	**(lb/10^6 Btu)***
Replacement Dry ESP	99.75	388	0.015
Polishing Wet ESP	99.75	388	0.015
Baghouse	99.75	388	0.015
Baseline (Existing ESP)	99.50	775	0.030

* Based on potential-to-emit (see page 15-16 of GRE's analysis).

Step 4: Evaluate Impacts and Document Results

Costs of Compliance: Based on historic baseline emissions, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	**Emissions Reduction* (tpy)**	**Annualized Cost** ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost*** ($/ton)**
Replacement Dry ESP	387	10,060,000	25,995	N/A
Polishing Wet ESP	387	1,920,000	4,961	N/A
Baghouse	387	7,670,000	19,819	N/A
Baseline (Existing ESP)	0	0	---	---

* Reductions from the baseline emission rate
** Costs provided by GRE
*** As compared to the baseline
N/A Not applicable since the all alternatives are equally efficient

Energy and Non-air Quality Effects: GRE has evaluated the energy and non-air quality effects of each option. The Department has determined that the information presented by GRE concerning these effects does not appear to preclude the selection of any of the alternatives above.

Step 5: Evaluate Visibility Impacts

The reduction in PM_{10} emissions that could be expected to be realized by implementing any of the three alternatives would produce a visibility improvement of less than 0.027 Δ-dV (98th percentile), a negligible improvement for the additional cost required.

Energy and Non-air Quality Effects: There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options.

Step 6: Select BART

The units have an existing dry ESP for removing filterable particulate matter and the plant is expected to have a remaining useful life of at least 20 years. Pre-BART modeling showed that PM from Units 1 and 2 contribute negligibly to visibility impairment as compared to sulfates and nitrates. The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate emissions is the polishing wet ESP. This system has a cost effectiveness of $4,961 per ton of particulate when compared to the current emission control system (ESP operating at 99.5% efficiency). Considering the negligible improvement in visibility that would be achieved by adding a polishing wet ESP, the Department considers this cost, as well as the costs of the more expensive options, to be excessive.

After considering all of the factors, the Department proposes that BART for filterable particulate matter is no additional controls. Current actual emissions are less than the current allowable emissions, and combusting dried lignite can be expected to further reduce particulate emissions. Based on past actual emissions and allowing for an additional margin of safety to provide a reasonable possibility for compliance, the Department proposes that BART is represented by an emission limit of 0.07 lb/10^6 Btu (average of 3 test runs).

C. Condensible Particulate Matter (PM_{10})

Condensible particulate matter is made up of both organic and inorganic substances. Organic condensible particulate matter will be made up of organic substances, such as volatile organic compounds, which are in a gaseous state through the air pollution control devices but will eventually turn to a solid or liquid state. The primary inorganic substance expected from the boiler is sulfuric acid mist, with lesser amounts of hydrogen fluoride and ammonium sulfate.

Since sulfuric acid mist is the largest component of condensible particulate matter, controlling it will control most of the condensible particulate matter. The options for controlling sulfuric acid mist are the same options for controlling sulfur dioxide (see Section III.A.). Previously, BART for sulfur dioxide was determined to be represented by the use of wet scrubber modifications to achieve a minimum SO_2 control efficiency of 95% and 100% of the flue gas stream. These changes are expected to reduce sulfuric acid mist emissions by approximately 90%. Changes that would provide additional reductions are economically infeasible considering the minimal improvement in visibility that could be achieved.

The control of volatile organic compounds at power plants is generally achieved through good combustion practices. The Department is not aware of any BACT determination at a power plant that resulted in any control technology being used. BACT has been found to be good combustion practices which are already in use since it minimizes the amount of fuel to generate electricity.

Both GRE and AP-42, Compilation of Air Pollutant Emission Factors[2], indicate the emission rate of condensible particulate matter could be expected to be 0.02 lb/10^6 Btu. This emission rate is less than the current emissions of filterable particulate matter and the emissions of filterable particulate matter were determined to have a negligible impact on visibility.

Having considered all the factors, the Department has determined that BART for condensible particulate matter is represented by good sulfur dioxide control and good combustion control. Since the primary constituent of condensible particulate matter is sulfuric acid mist which is controlled proportionately to the sulfur dioxide controlled, the BART limit for sulfur dioxide can act as a surrogate for condensible particulate matter along with a requirement for good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

External Flue Gas Recirculation
Selective Catalytic Reduction (SCR) High Dust
Electro-Catalytic Oxidation
Pahlman Process
SCR Low Dust
Low Temperature Oxidation (LTO), either Tri-No_x® or LoTOx
Selective Non-Catalytic Reduction (SNCR), No_xOut®
Modified and Additional Separated Overfire Air (SOFA)
Low NO_x Burners (LNB)

Step 2: Eliminate Technically Infeasible Options

Great River Energy has included a cost estimate for low-dust SCR, while high-dust SCR is listed as technically infeasible by GRE. The Department believes that low dust or tail end SCR has a good probability of successful application at Coal Creek and high dust SCR is technically infeasible (see discussion in Appendix B.5).

External Flue Gas Recirculation is technically infeasible due to limited space for ductwork and reduced flame temperature.

Electro-Catalytic Oxidation and the Pahlman Process considered technically infeasible because they are still in development and testing and have not been demonstrated to be commercially available. The remaining technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Based on the historic baseline emissions, the Department's estimated emissions using the various technologies are as follows:

Alternative	**Control* Efficiency (%)**	**Controlled Emissions****	
		(tons/yr)	**lb/10^6 Btu)**
LTO	90	536	0.022
SCR Low Dust	80	1,071	0.043
SNCR	50	2,679	0.108
SOFA/LNB Opt 1	30	3,750	0.15
SOFA/LNB Opt 2	21	4,232	0.17
Baseline	0	5,357	0.22

* Control efficiency provided in GRE's analysis.
** Calculated from the historic baseline (2003-2004). The emission rate is an annual average rate.

Step 4: Evaluate Impacts and Document Results

Costs of Compliance: Based on historic baseline emissions, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	**Emissions Reduction (tpy)**	**Annualized Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
LTO	4,821	58,070,000	12,045	3,589*
SCR Low Dust	4,286	56,150,000	13,101	20,678**
SNCR	2,678	22,900,000	8,551	20,766***
SOFA/LNB Opt 1	1,607	660,000	411	664****
SOFA/LNB Opt 2	1,125	340,000	302	---

* LTO compared to SCR Low Dust
** SCR Low Dust compared to SNCR
*** SNCR compared to SOFA/LNB Opt 1
**** SOFA/LNB Opt 1 compared to SOFA/LNB Opt 2

Note: SCR and SNCR estimates above include the costs associated with lost ash sales and increased landfilling requirements due to ammonia slip rendering the ash ineligible for beneficial use. Although they were included in the GRE analysis and the table above, if the sunk costs for the ash sales infrastructure are appropriately disregarded, then the annualized cost for SNCR would be $21,750,000, the cost effectiveness would be $8,122 per ton, and the incremental cost would be $19,692 per ton.

NDDAQ was unable to determine that SNCR and its associated use of ammonia will not negatively impact GRE's ash sales; in fact, there is evidence to the contrary. GRE emails dated 8/8/08 and 8/17/08 provide additional information on this issue, as does a summary of a University of Kentucky study on the matter. Furthermore, in a BART and PSD analysis for the Omaha Public Power District Nebraska City Station Unit #1 coal boiler (Construction Permit Number CP07-0049, 2/26/09 fact sheet, pg. 14), Nebraska DEQ determined SCR was not BART in part because . . ."ammonia used in the system would cause the ash to be contaminated, thereby jeopardizing the current beneficial reuse of a portion of the ash produced by NCS Unit 1."

After considering all the information available, NDDH reached the following conclusions.

- SCR and SNCR use at Coal Creek Station will likely result in ammonia in the fly ash.
- The level of ammonia in the fly ash cannot be predicted with a reasonable certainty.
- The maximum level of ammonia in fly ash that would still avoid negative impacts on the salability of the ash cannot be predicted. Levels as low as 100 ppm have made the fly ash unfit for use in concrete.[4]

The NDDH believes there is reasonable possibility that SCR or SNCR will result in a level of ammonia in the ash that could reduce or eliminate future ash sales. Lost ash sales will inflict a significant financial penalty on GRE and send ash to a landfill instead of it being used beneficially. If this ash is regulated as a hazardous waste, the financial burden will be even greater.

Energy and environmental impacts associated with the alternatives being considered include additional energy consumption (LTO, SCR), additional wastewater (LTO), ammonia slip (SCR, SNCR), potential to require ash to be landfilled (SNCR). The Department encourages the beneficial use of fly ash for making concrete. Ammonia slip associated with SNCR and SCR would preclude this beneficial use.

Step 5: Evaluate Visibility Impacts

The Department considers the incremental cost effectiveness of LTO, SCR Low Dust and SNCR to be excessive. GRE estimated the effects on visibility due to NO_x reductions (GRE BART Analysis, pages 47-51).

The following tables show the visibility impacts of the SOFA/LNB Options 1 and 2, and SNCR.

Coal Creek Station Unit 1 or 2 Delta Deciview 90th Percentile – NO_x				
Year	Unit	SOFA/LNB Option 1 30% Reduction	SNCR 50% Reduction	Difference
2000	TRNP-SU	0.119	0.106	0.013
2001	TRNP-SU	0.108	0.096	0.012
2002	TRNP-SU	0.207	0.186	0.021
Average	TRNP-SU	0.145	0.129	0.015
2000	TRNP-NU	0.118	0.105	0.013
2001	TRNP-NU	0.136	0.127	0.009
2002	TRNP-NU	0.151	0.131	0.020
Average	TRNP-NU	0.135	0.121	0.014
2000	Elkhorn Ranch	0.082	0.072	0.010
2001	Elkhorn Ranch	0.076	0.069	0.007
2002	Elkhorn Ranch	0.129	0.118	0.011
Average	Elkhorn Ranch	0.096	0.086	0.009
2000	Lostwood W.A.	0.207	0.180	0.027
2001	Lostwood W.A.	0.207	0.180	0.027
2002	Lostwood W.A.	0.165	0.141	0.024
Average	Lostwood W.A.	0.193	0.167	0.026
Overall Average		0.142	0.126	0.016

Coal Creek Station Unit 1 or 2 Delta Deciview 98th Percentile – NO_x				
Year	Unit	SOFA/LNB Option 1 30% Reduction	SNCR 50% Reduction	Difference
2000	TRNP-SU	0.467	0.410	0.057
2001	TRNP-SU	0.482	0.437	0.045
2002	TRNP-SU	1.140	1.052	0.088
Average	TRNP-SU	0.696	0.633	0.063
2000	TRNP-NU	0.416	0.352	0.064
2001	TRNP-NU	0.512	0.436	0.076
2002	TRNP-NU	0.918	0.813	0.105
Average	TRNP-NU	0.615	0.534	0.082
2000	Elkhorn Ranch	0.300	0.270	0.030
2001	Elkhorn Ranch	0.473	0.405	0.068
2002	Elkhorn Ranch	0.746	0.654	0.092
Average	Elkhorn Ranch	0.506	0.443	0.063
2000	Lostwood W.A.	0.469	0.417	0.052
2001	Lostwood W.A.	0.469	0.417	0.052
2002	Lostwood W.A.	0.783	0.680	0.103
Average	Lostwood W.A.	0.574	0.505	0.069
Overall Average		0.598	0.529	0.069

Coal Creek Station Unit 1 or 2 Delta Deciview 90th Percentile – NO_x				
Year	Unit	SOFA/LNB Option 1 30% Reduction	SOFA/LNB Option 2 21% Reduction	Difference
2000	TRNP-SU	0.119	0.125	0.006
2001	TRNP-SU	0.108	0.116	0.008
2002	TRNP-SU	0.207	0.219	0.012
Average	TRNP-SU	0.145	0.153	0.009
2000	TRNP-NU	0.118	0.124	0.006
2001	TRNP-NU	0.136	0.142	0.006
2002	TRNP-NU	0.151	0.158	0.007
Average	TRNP-NU	0.135	0.141	0.006
2000	Elkhorn Ranch	0.082	0.088	0.006
2001	Elkhorn Ranch	0.076	0.076	0.000
2002	Elkhorn Ranch	0.129	0.136	0.007
Average	Elkhorn Ranch	0.096	0.100	0.004
2000	Lostwood W.A.	0.207	0.215	0.008
2001	Lostwood W.A.	0.207	0.215	0.008
2002	Lostwood W.A.	0.165	0.178	0.013
Average	Lostwood W.A.	0.193	0.203	0.010
Overall Average		0.142	0.149	0.007

Coal Creek Station Unit 1 or 2 Delta Deciview 98th Percentile – NO_x				
Year	Unit	SOFA/LNB Option 1 30% Reduction	SOFA/LNB Option 2 21% Reduction	Difference
2000	TRNP-SU	0.467	0.494	0.027
2001	TRNP-SU	0.482	0.509	0.027
2002	TRNP-SU	1.140	1.181	0.041
Average	TRNP-SU	0.696	0.728	0.032
2000	TRNP-NU	0.416	0.446	0.030
2001	TRNP-NU	0.512	0.547	0.035
2002	TRNP-NU	0.918	0.987	0.069
Average	TRNP-NU	0.615	0.660	0.045
2000	Elkhorn Ranch	0.300	0.314	0.014
2001	Elkhorn Ranch	0.473	0.505	0.032
2002	Elkhorn Ranch	0.746	0.789	0.043
Average	Elkhorn Ranch	0.506	0.536	0.030
2000	Lostwood W.A.	0.469	0.499	0.030
2001	Lostwood W.A.	0.469	0.499	0.030
2002	Lostwood W.A.	0.783	0.832	0.049
Average	Lostwood W.A.	0.574	0.610	0.036
Overall Average		0.598	0.634	0.036

Step 6: Select BART

The units have existing low NO_x burners and SOFA for removing nitrogen oxides and the plant is expected to have a remaining useful life of at least 20 years. The Department considers the incremental cost of the top three options to be excessive. If fly ash sales are not lost due to the use of SNCR, the cost for this alternative is not considered excessive. However, the maximum improvement in visibility for SNCR versus SOFA/LNB Option 1 is 0.105 deciviews based on the 98th percentile (0.027 deciviews based on the 90th percentile). The Department has found that the single source BART modeling overpredicts the amount of visibility improvement by a factor of 5-7 (see Section 7.4.2 of SIP). The Department considers the amount of visibility improvement from the use of SCNR versus SOFA/LNB Option 1 to be inconsequential. Because of the potential for lost sales of fly ash, the negative environmental effects of having to dispose of the fly ash instead of recycling it into concrete, and the very small amount of visibility improvement from the use of SNCR, this option is rejected as BART. The Department proposes that BART is represented by modified and additional SOFA plus LNB (Option 1). GRE has indicated the feasibility of, and the manufacturer has guaranteed, an emission limit of 0.15 $lb/10^6$ Btu on an annual average basis. An achievable thirty-day rolling average emission rate is expected to be slightly higher at 0.17 $lb/10^6$ Btu. The Department proposes that BART is 0.17 $lb/10^6$ Btu on a 30-day rolling average basis. Unit 1 and Unit 2 emissions may be averaged provided the average does not exceed the limit.

IV. BART Evaluation for Auxiliary Boilers No. 91 and No. 92

Auxiliary boilers No. 91 and No. 92 are distillate and residual oil-fired boilers with a nominal rating of 172 x 10^6 Btu/hr. The auxiliary boilers are only used when both units at the Coal Creek Station are down. During the baseline period (2000-2004), the auxiliary boilers were operated an average of 11.2 hours per unit per year. The annual average emissions per unit for this period were:

NO_x	0.09 tons
SO_2	0.19 tons
PM	0.08 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have a virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls and the currently permitted fuel limitation of distillate oil, residual oil or any combination of the two.

V. BART Evaluation of Emergency Generator

The emergency generator is driven by a 3,500 horsepower diesel engine. The generator is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. During the baseline period (2000-2004), the engine operated an average of 94.9 hours per year and the average annual emissions were:

PM	0.07 tons
NO_x	2.87 tons
SO_2	0.31 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have a virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VI. BART Evaluation for Emergency Fire Pump

The emergency fire pump is driven by a 200 horsepower diesel engine. The pump is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. During the baseline period (2000-2004), the engine operated an average of 14.0 hours per year and the actual annual emissions were:

PM	0.01 tons
NO_x	0.11 tons
SO_2	0.01 tons

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VII. BART Evaluation for Materials Handling Sources

The materials handling sources at Coal Creek Station that emit to the atmosphere are as follows:

EU – Description	Existing Control Equipment	Current PM Emission Limit (lb/hr)	Baseline PM Emissions (tons/yr)
EU 7 - Lignite transfer house	Bagfilter	3	0.07
EU 8 - Lignite emergency reclaim system	Bagfilter	3	0.00
EU 9 - Lignite yard storage silos	Bagfilter	3	0.03
EU 10 - Lignite yard storage silos	Bagfilter	3	0.03
EU 11 - Crusher building	Bagfilter	3	0.07
EU 12 - Generation building coal hopper	Bagfilter	3	0.07
EU 13 - Falkirk mining Company mine silo base	Bagfilter	3	0.07

EU – Description	**Existing Control Equipment**	**Current PM Emission Limit (lb/hr)**	**Baseline PM Emissions (tons/yr)**
EU 14 - Generation building coal hopper	Bagfilter	3	0.02
EU 15 - Generation building coal hopper	Bagfilter	3	0.02
EU 16 - Generation building coal hopper	Bagfilter	3	0.02
EU 17 - Generation building coal hopper	Bagfilter	3	0.02
EU 19 - Scrubber building flyash silo	Bagfilter	3	0.02
EU 20 - Truck air slide flyash silo	Bagfilter	3	0.05
EU 21 - Truck air slide flyash silo	Bagfilter	3	0.05
EU 22 - Water treatment building	Bagfilter	3	0.03
EU 23 - Scrubber building lime handling system	Bagfilter	3	0.02
EU 24 - Scrubber building lime handling system	Bagfilter	3	0.02
EU 25 - Flyash railroad marketing silo	Bagfilter	3	0.05
EU 26 - Flyash dome	Bagfilter	0.4 (EP 26a-26b), 0.09 (EP 26e)	0.02
EU 27 - Coal Dryer	Bagfilter	3.1	0.3*
FS 1 - Cooling towers No. 91, No. 92, and No. 93	Fugitive	--	0.02
FS 2 - Boombelt conveyor (stackout)	Fugitive	--	0.02
FS 3 - Conveyor 909 (stackout)	Fugitive	--	0.04
FS 4 - Scrubber building flyash silo (stackout)	Fugitive	--	0.04
FS 5 - Coal pile maintenance	Fugitive	--	3.77

* Department estimate based on 2005 emissions

Based on the small quantity emissions from those sources (EU 7-27) that are controlled by bagfilters, which are considered the most efficient control devices, it is apparent that no additional control equipment will be cost effective. Materials handling units (FS 1-5) are uncontrolled sources of fugitive emissions. Based on the small quantity of emissions from those sources, it is apparent that no additional control equipment will be cost effective. Any additional controls would have a neglible effect on visibility impairment. Therefore, the Department proposes that BART for the materials handling units is no additional controls and the current emission limits for the units is BART.

VIII. Summary

Source Unit	**Proposed BART Limit/Work Practice**				**Emissions Reduction (tons/yr)**		
	PM	**SO_2**	**NO_x**	**Units**	**PM**	**SO_2**	**NO_x**
Unit 1 Boiler	0.07	0.15 (30-dra) or 94% reduction	0.17 (30-dra)	$lb/10^6$ Btu	0	19,990*	1,607
Unit 2 Boiler	0.07	0.15 (30-dra) or 94% reduction	0.17 (30-dra)	$lb/10^6$ Btu	0	19,990*	1,607
Auxiliary Boiler No. 91	Continue current practices			N/A	0	0	0
Auxiliary Boiler No. 92	Continue current practices			N/A	0	0	0
Emerg. Gen.	Continue current practices			N/A	0	0	0
Fire Pump	Continue current practices			N/A	0	0	0
Material Handling EU 7-25	3	---	---	lb/hr	0	---	---
Flyash Dome EU 26	0.4 (EP 26a-26b), 0.09 (EP 26e)	---	---	lb/hr	0	---	---

Source Unit	Proposed BART Limit/Work Practice				Emissions Reduction (tons/yr)		
	PM	SO_2	NO_x	Units	PM	SO_2	NO_x
Coal Dryer EU 27	3.1	---	---	---	0	---	---
Fugitive FS 1-5	---	---	---	---	0	---	---
Total:						39,980*	3,214

* Reductions from 2000-2004 average emission rate adjusted for future fuel (dried lignite).

IX. Permit to Construct

The emission limits, monitoring, recordkeeping and reporting requirements will be included in a federally enforceable Air Pollution Control Permit to Construct that will be issued to the owner/operator of the facility. The Permit to Construct is included in Appendix D.

A. Monitoring

1. Monitoring for SO_2 and NO_x will be accomplished using the continuous emission monitors required by 40 CFR 75 for the Acid Rain Program. Monitoring for particulate matter shall be in accordance with 40 CFR 64, Compliance Assurance Monitoring. If the owner/operator of the BART-eligible unit chooses to comply with the SO_2 percent reduction requirements, monitoring of the SO_2 inlet rate loading to the scrubber shall be accomplished by either:

    a. A continuous emission monitor that complies with the requirements of 40 CFR 75; or

    b. Coal sampling in accordance with Method 19 of 40 CFR 60, Appendix A plus development of an emission factor based on actual stack testing.

2. For purposes of determining compliance with the SO_2 reduction requirement, the reduction efficiency shall be determined as follows:

$$\% \text{ Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where:

Inlet SO_2 Rate is in units of lb/10^6 Btu, lb/hr or ppmvd @ 3% O_2.

Outlet SO_2 Rate is in the same units as the inlet SO_2 rate.

3. The owner/operator will be allowed to average emissions (bubble) for SO_2 and/or NO_x for the two units using the following formulas:

$$\text{Average AER} = \frac{[(AER_1)(HI_1)+(AER_2)(HI_2)]}{(HI_1 + HI_2)}$$

$$\text{Average ER} = \frac{[(ER_1)(HI_1)+(ER_2)(HI_2)]}{(HI_1 + HI_2)}$$

Where:

AER = Allowable Emission Rate (lb/MMBtu or % Reduction)
ER_1 = Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 1
ER_2 = Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 2
HI_1 = Actual Heat Input (MMBtu) of Unit 1
HI_2 = Actual Heat Input (MMBtu) of Unit 2

Notes: ER is a 30-day rolling average.
HI is a 30-day rolling average.
30-day rolling average is determined in accordance with 40 CFR 60, Subpart Da, for the 30 successive boiler operating days (must be on a consistent basis of lb/MMBtu or % reduction).

B. Recordkeeping and Reporting

The owner/operator will be required to conduct recordkeeping and reporting as required by NDAC 33-15-14-06, Title V Permit to Operate and NDAC 33-15-21, Acid Rain Program (40 CFR 72, 75 and 76).

References

1. K-fuels® website, 2007. www.evgenergy.com

2. EPA, 1995. Compilation of Air Pollutant Emission Factors Volume 1: Stationary Point and Area Sources. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711

3. Great River Energy, 2007. Coal Creek Station Units 1 and 2 BART Analysis; Revised December 12, 2007.

4. Bittner, James D.; Gasiorowski, Stephen A.; Hrach, Frank J.; Fly Ash Separation and Ammonia Removal at Tampa Electric Big Bend. Separation Technologies, LLC, Needham, MA 02492.

BART Determination
For
Coal Creek Station Units 1 and 2

2/10/10

I. Source Description

A. Owner/Operator: Great River Energy (GRE)

B. Source Type: Fossil-fuel fired steam electric plant of more than 250 million British thermal units (Btu) per hour heat input and having a total generating capacity in excess of 750 megawatts.

C. BART Eligible Units

1. EU 1 - Unit 1 boiler
2. EU 2 - Unit 2 boiler
3. EU 3 - Auxiliary boiler No. 91
4. EU 4 - Auxiliary boiler No. 92
5. EU 5 - Emergency generator
6. EU 6 - Fire pump engine
7. EU 7 through EU 26 material handling units, including coal and lime handling operations and flyash silos
    a. EU 7 - Lignite transfer house
    b. EU 8 - Lignite emergency reclaim system
    c. EU 9 - Lignite yard storage silos
    d. EU 10 - Lignite yard storage silos
    e. EU 11 - Crusher building (Two 1,500 ton per hour crushers)
    f. EU 12 - Generation building coal hopper
    g. EU 13 - Falkirk Mining Company mine silo base

h. EU 14 - Generation building coal hopper

i. EU 15 - Generation building coal hopper

j. EU 16 - Generation building coal hopper

k. EU 17 - Generation building coal hopper

l. EU 19 - Scrubber building flyash silo

m. EU 20 - Truck air slide flyash silo

n. EU 21 - Truck air slide flyash silo

o. EU 22 - Water treatment building

p. EU 23 - Scrubber building lime handling system

q. EU 24 - Scrubber building lime handling system

r. EU 25 - Flyash railroad marketing silo

s. EU 26 - Flyash dome

8. FS 1 through FS 5 - Fugitive sources

a. FS 1 - Cooling Towers No. 91, No. 92, and No. 93

b. FS 2 - Boombelt conveyor (stackout)

c. FS 3 - Conveyor 909 (stackout)

d. FS 4 - Scrubber building flyash silo (stackout)

e. FS 5 - Coal pile maintenance

D. Unit Description

1. EU 1 - Unit 1 boiler:

Generator Nameplate Capacity: 550 MWe

Boiler Rating: 6,015 x 10^6 Btu/hour

Startup: 1979

Fuel: North Dakota lignite

Firing Method: Tangential-fired pulverized coal (PC) unit

Existing Air Pollution Equipment:

Electrostatic precipitator (ESP)
Low NO_x burners (LNB) and separated over fire air (SOFA)
Wet scrubber

2. EU 2 - Unit 2 boiler

   Generator Nameplate Capacity: 550 MWe

   Boiler Rating: 6,022 x 10^6 Btu/hour

   Startup: 1980

   Fuel: North Dakota lignite

   Firing method: Tangential-fired pulverized coal (PC) unit

   Existing Air Pollution Equipment:

   Electrostatic precipitator (ESP)
   Low NO_x burners (LNB) and separated over fire air (SOFA)
   Wet scrubber

3. EU 3 - Auxiliary boiler No. 91

   Boiler rating: 172 x 10^6 Btu/hour

   Fuel: Residual oil, distillate fuel oils, or any combination of these fuels

   Existing air pollution equipment: None

4. EU 4 - Auxiliary boiler No. 92

   Boiler rating: 172 x 10^6 Btu/hour

   Fuel: Residual oil, distillate fuel oils, or any combination of these fuels

   Existing air pollution equipment: None

5. EU 5 - Emergency generator

Rating: 3,500 bhp

Fuel: No. 2 fuel oil or a blend of No. 1 and No. 2 fuel oil

Existing air pollution equipment: None

6. EU 6 - Fire pump engine

   Rating: 200 bhp

   Fuel: No. 2 fuel oil or a blend of No. 1 and No. 2 fuel oil

   Existing air pollution equipment: None

7. EU 7 through EU 26 - Material handling units, including lime handling operations and flyash silos

   Existing air pollution equipment: Fabric filters/bag houses

8. FS 1 through FS 5 - Fugitive sources

   Existing air pollution equipment: None - fugitive emissions

E. Emissions

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Ave.**
EU 1 - Unit 1 Boiler	SO_2 (tons) SO_2 (lb/10^6 Btu)	14,332 0.56	14,630 0.56	11,910 0.51	13,817 0.54	15,742 0.61	14,086 0.56
	NO_x (tons) NO_x (lb/10^6 Btu)	5,211 0.21	5,235 0.21	4,690 0.21	5,072 0.20	5,370 0.21	5,116 0.21
	PM (tons) PM (lb/10^6 Btu)	632 0.025	492 0.019	1,305 0.056	73 0.003	116 0.005	524 0.021

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Ave.**
EU 2 - Unit 2 Boiler	SO_2 (tons)	12,817	11,683	12,518	13,547	11,469	12,407
	SO_2 (lb/10^6 Btu)	0.53	0.51	0.49	0.54	0.50	0.51
	NO_x (tons)	5,324	5,190	5,454	5,558	5,429	5,391
	NO_x (lb/10^6 Btu)	0.22	0.23	0.22	0.22	0.24	0.23
	PM (tons)	827	649	1,268	121	80	589
	PM (lb/10^6 Btu)	0.034	0.028	0.050	0.005	0.003	0.024
EU 3 - Auxiliary boiler No. 91	PM (tons)	0.10	0.00	0.10	0.00	0.00	0.02
	SO_2 (tons)	0.30	0.00	0.00	0.00	0.00	0.06
	NO_x (tons)	0.10	0.10	0.10	0.00	0.10	0.10
EU 4 - Auxiliary boiler No. 92	PM (tons)	0.10	0.60	0.00	0.00	0.00	0.14
	SO_2 (tons)	0.30	1.30	0.00	0.00	0.00	0.32
	NO_x (tons)	0.10	0.40	0.00	0.00	0.00	0.10
EU 5 - Emergency generator	SO_2 (tons)	0.45	0.04	0.04	0.04	0.97	0.31
	NO_x (tons)	2.76	3.07	2.76	2.69	3.06	2.87
EU 6 - Fire pump engine	SO_2 (tons)	0.01	0.01	0.01	0.01	0.01	0.01
	NO_x (tons)	0.09	0.10	0.11	0.11	0.12	0.11
EU 7 - Lignite transfer house	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07
EU 8 - Lignite emergency reclaim system	PM (tons)	0.00	0.00	0.00	0.00	0.00	0.00
EU 9 - Lignite yard storage silos	PM (tons)	0.03	0.03	0.03	0.03	0.03	0.03
EU 10 - Lignite yard storage silos	PM (tons)	0.03	0.03	0.03	0.03	0.03	0.03
EU 11 - Crusher building	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07
EU 12 - Generation building coal hopper	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07
EU 13 - Falkirk mining Company mine silo base	PM (tons)	0.07	0.07	0.07	0.07	0.07	0.07

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Ave.**
EU 14 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 15 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 16 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 17 - Generation building coal hopper	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
EU 19 - Scrubber building flyash silo	PM (tons)	0.01	0.02	0.02	0.03	0.03	0.02
EU 20 - Truck air slide flyash silo	PM (tons)	0.05	0.04	0.04	0.04	0.07	0.05
EU 21 Truck air slide flyash silo	PM (tons)	0.05	0.04	0.04	0.04	0.06	0.05
EU 22 - Water treatment building	PM (tons)	0.05	0.04	0.04	0.02	0.00	0.03
EU 23 - Scrubber building lime handling system	PM (tons)	0.03	0.03	0.02	0.02	0.01	0.02
EU 24 - Scrubber building lime handling system	PM (tons)	0.03	0.03	0.02	0.02	0.01	0.02
EU 25 - Flyash railroad marketing silo	PM (tons)	0.03	0.03	0.02	0.02	0.14	0.05
EU 26 - Flyash dome	PM (tons)	0.00	0.00	0.00	0.00	0.11	0.02
FS 1 - Cooling towers No. 91, No. 92 & No. 93	PM (tons)	0.02	0.02	0.01	0.02	0.02	0.02
FS 2 - Boombelt conveyor (stackout)	PM (tons)	0.02	0.02	0.02	0.02	0.02	0.02
FS 3 - Conveyor 909 (stackout)	PM (tons)	0.02	0.03	0.04	0.05	0.05	0.04
FS 4 - Scrubber building flyash silo (stackout)	PM (tons)	0.02	0.03	0.04	0.05	0.05	0.04

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Ave.**
FS 5 - Coal pile maintenance	PM (tons)	3.77	3.77	3.77	3.77	3.77	3.77

II. Site Characteristics

The Coal Creek Station is a two-unit, 1,100 gross megawatt (MW) mine-to-mouth power plant consisting primarily of two steam generators and associated coal and ash handling systems. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially from a maximum of 64 firing points each. Unit 1 has a heat input capacity of 6,015 x 10^6 Btu/hr; Unit 2 is rated at 6,022 x 10^6 Btu/hr. Particulate matter from each boiler is controlled by a 99.5% efficient electrostatic precipitator (ESP) consisting of 48 transformer rectifier (TR) sets. A four-module flue gas desulfurization (FGD) system for each boiler removes approximately 90% of the sulfur dioxide from 60% of the flue gas. Each boiler is served by a 655 foot high stack.

Unit 1 began commercial operation in 1979 and Unit 2 in 1980. The facility is located in south central McLean County about five miles south of the town of Underwood, North Dakota and three miles west of US Highway 83. Coal Creek Station receives its lignite from the Falkirk Mine that is operated by the Falkirk Mining Company, a subsidiary of the North American Coal Corporation. Approximately 8,130,000 tons of lignite coal and approximately 165,000 gallons of oil were combusted in 2006.

III. BART Evaluation of Unit 1 and Unit 2

The BART guidelines apply to Units 1 and 2 because they are part of a fossil-fuel steam electric plant with a total generating capacity in excess of 750 megawatts, they are rated at more than 250 million Btu per hour heat input, and they have potential emissions of 250 tons or more per year of a visibility-impairing pollutant, specifically SO_2, NO_x and PM_{10}.

Since Units 1 and 2 are identical, the following evaluation will use values derived by averaging the historical data for each unit and then make a single BART determination that will be applicable to each unit.

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Coal Cleaning/Washing
K-Fuel[7]
TurboSorp[7]
Coal Drying
Dry Sorbent Injection
Spray Dryer

Wet Scrubber Modification
Wet Scrubber Replacement

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning/Washing: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that have required coal cleaning.

K-Fuel^7 is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Evergreen=s website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from the Falkirk Mine was tested. The use of the K-Fuel^7 process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel^7 and will be submitted to this Department at the end of the approved burn period process available or technically and economically feasible.

TurboSorp^7: Although the GRE analysis concluded otherwise, the Department considers TurboSorp^7 dry flue gas desulfurization technology to be technically feasible because it employs the proven technology of circulating dry scrubbers. Additional information on this technology is found at:
http://www.eucetsa.net/eucetsa/webPages.do?pageID=200913.

Coal Drying: Coal drying of lignite has been demonstrated to be technically feasible through pilot projects at this facility. Furthermore, dried lignite is the primary fuel for another ND facility, the GRE Spiritwood Station, that received a permit to construct September 14, 2007.

In addition to coal drying, the remaining control technologies, dry sorbent injection, spray dryer, and wet scrubber (modification or replacement), are considered to be technically feasible. GRE has elected to install coal drying equipment independent of the SO_2 control chosen.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Baseline SO_2 Emissions Controlled (past): Based on average actual controlled annual emissions when combusting lignite (undried) for a 24 month period (2003-2004) with 27% bypass: (13,817 [Unit 1, 2003] + 13,547 [Unit 2, 2003] + 15,742 [Unit 1, 2004] + 11,469 [Unit 2, 2004])/4 = 13,644 ton/yr average baseline controlled SO_2 emissions with 27% bypass and undried coal.

Applying the 68% overall control efficiency of the existing scrubber yields: [(13,644 ton/yr)/(1-0.68)] = 42,638 ton/yr uncontrolled baseline SO_2 emissions.

The 42,638 ton/yr uncontrolled baseline SO_2 emissions are based on past undried coal with an average 2003-2004 sulfur content of 0.61%. The evaluation of alternative SO_2 cleaning equipment will be based on future undried coal with an expected worst case (98 percentile) sulfur content of 1.10%, as predicted for Falkirk coal and provided by GRE. Therefore, the uncontrolled baseline SO_2 emissions above must be adjusted to the future sulfur content so that an apples to apples comparison will correctly determine emission reductions expected to result from employing the alternative equipment. The 42,638 ton/yr uncontrolled baseline SO_2 emissions is adjusted as follows: (42,638 ton/yr)(1.1%/0.61%) = 76,888 ton/yr uncontrolled baseline SO_2 emissions for undried coal with future sulfur content.

For the purposes of this analysis, the adjustment to future coal was considered necessary only for SO_2 and the related condensible particulate matter and sulfuric acid mist emissions due to the increased sulfur content expected in future coal. For all other pollutants, this analysis does not adjust to future coal due to the negligible impact on emissions. No adjustment to the baseline was made for coal drying because the Permit to Construct is not expected to require dried lignite or limit moisture content.

Note: TurboSorp[7] is a registered trademark for Babcock Power Environmental=s circulating dry scrubber. The Department considers circulating dry scrubbers to be technically feasible. Circulating dry scrubbers will generally achieve SO_2 removal efficiencies similar to spray dryer absorbers but less than wet scrubbers. Other BART analyses projected a removal efficiency of 93% with higher costs than a new wet scrubber. Since a circulating dry scrubber will have a lower removal efficiency than a wet scrubber or upgrades to the existing wet scrubber (95% and 94%, respectively) and will cost more than a new wet scrubber or upgrades to the existing wet scrubber, a circulating dry scrubber is an inferior option and is not considered further.

Future Case

Alternative	**Control Efficiency (%)**	**Baseline Uncontrolled Emissions (tons/yr)***	**Controlled Emissions***	
			(tons/yr)	**(lb/10^6 Btu)****
Wet Scrubber Replacement***	95	76,888	3,844	0.146
Wet Scrubber Modification***	95	76,888	3,844	0.146
Spray Dryer***	90	76,888	7,689	0.292
Existing Scrubber & 0% Bypass	83.1	76,888	12,994	0.493
Dry Sorbent Injection***	70	76,888	23,066	0.875
Existing Scrubber & 27% Bypass	68****	76,888	24,604*****	--

*	Future lignite at 1.10% (GRE-predicted worst-case sulfur content for Falkirk Mine lignite. As a result, Department baseline future emission estimates are somewhat higher than GRE=s estimates)
**	Annual
***	0% bypass
****	Current control rate
*****	Current controlled emissions = 76,888(1-0.68) = 24,604 tpy

Step 4: Evaluate Impacts and Document Results

Costs of Compliance: Based on the past emissions adjusted for the sulfur content of future coal, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	**Emissions Reduction (tons/yr)**	**Annualized Cost ($)***	**Cost Effectiveness($/ton)**	**Incremental Cost ($/ton)**
Wet Scrubber Replacement	20,760	30,760,000	1,482	24,987
Wet Scrubber Modification	20,760	11,520,000	555	--
Spray Dryer**	16,915	29,220,000	1,727	--
Existing Scrubber 0% Bypass	11,610	9,840,000	848	N/A
Dry Sorbent Injection**	1,538	12,520,000	8,140	N/A

*	Costs provided by GRE
**	Inferior option to wet scrubber modifications
N/A	Not applicable since the cost effectiveness of the less efficient alternative is more than the more efficient alternative

The incremental cost associated with wet scrubber replacement ($24,987/ton) as compared to wet scrubber modification represents an excessively high cost relative to the emission reduction obtained.

Energy and Non-air Quality Effects: GRE has evaluated the energy and non-air quality effects of each option. Although the Department has determined that the information presented by GRE concerning these effects does not appear to preclude the selection of any of the five alternatives above, the possible economic impacts due to extensive process downtime associated with scrubber replacement and dry sorbent injection may be significant negative factors for their selection.

Step 5: Evaluate Visibility Results

The three primary alternatives and associated removal efficiencies are a wet scrubber replacement (95%), wet scrubber modification (95%) and spray dryer (90%). GRE estimated the effects on visibility due to SO_2 reductions (GRE BART Analysis, pages 47-51). Although these estimates were based on 94% SO_2 control for the wet scrubber modification, GRE subsequently agreed to 95% control for that option.

Step 6: Select BART

While the cost effectiveness is reasonable for all technologies evaluated except dry sorbent injection, the incremental cost associated with wet scrubber replacement is excessive.

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The units have existing wet scrubbers for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. With identical levels of SO_2 control, wet scrubber replacement involves additional cost with no improvement in visibility at any Class I area when compared to wet scrubber modification.

The Department proposes that BART is scrubbing 100% of the flue gas stream, the use of wet scrubber modifications to achieve a minimum control efficiency of 95% (30-day rolling average) on the inlet sulfur dioxide concentration to the scrubber or 0.15 lb/10^6 Btu (30-day rolling average). Unit 1 and Unit 2 emissions may be averaged provided the average does not exceed the limit.

B. Filterable Particulate Matter

Step 1: Identify All Available Technologies

Multiclone
Replacement Dry Electrostatic Precipitator (ESP)
Polishing Wet ESP
Baghouse

Step 2: Eliminate Technically Infeasible Options

The multiclone is considered technically infeasible because it has not been successfully demonstrated at a similar plant. All remaining technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	**Control Efficiency**	**Emissions**	
		(tons/yr)	**(lb/10^6 Btu)***
Replacement Dry ESP	99.75	388	0.015
Polishing Wet ESP	99.75	388	0.015
Baghouse	99.75	388	0.015
Baseline (Existing ESP)	99.50	775	0.030

* Based on potential-to-emit (see page 15-16 of GRE's analysis).

Step 4: Evaluate Impacts and Document Results

Costs of Compliance: Based on historic baseline emissions, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	**Emissions Reduction* (tpy)**	**Annualized Cost** ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost*** ($/ton)**
Replacement Dry ESP	387	10,060,000	25,995	N/A
Polishing Wet ESP	387	1,920,000	4,961	N/A
Baghouse	387	7,670,000	19,819	N/A
Baseline (Existing ESP)	0	0	---	---

* Reductions from the baseline emission rate
** Costs provided by GRE
*** As compared to the baseline
N/A Not applicable since the all alternatives are equally efficient

Energy and Non-air Quality Effects: GRE has evaluated the energy and non-air quality effects of each option. The Department has determined that the information presented by GRE concerning these effects does not appear to preclude the selection of any of the alternatives above.

Step 5: Evaluate Visibility Impacts

The reduction in PM_{10} emissions that could be expected to be realized by implementing any of the three alternatives would produce a visibility improvement of less than 0.027 Δ-dV (98th percentile), a negligible improvement for the additional cost required.

Energy and Non-air Quality Effects: There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options.

Step 6: Select BART

The units have an existing dry ESP for removing filterable particulate matter and the plant is expected to have a remaining useful life of at least 20 years. Pre-BART modeling showed that PM from Units 1 and 2 contribute negligibly to visibility impairment as compared to sulfates and nitrates. The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate emissions is the polishing wet ESP. This system has a cost effectiveness of $4,961 per ton of particulate when compared to the current emission control system (ESP operating at 99.5% efficiency). Considering the negligible improvement in visibility that would be achieved by adding a polishing wet ESP, the Department considers this cost, as well as the costs of the more expensive options, to be excessive.

After considering all of the factors, the Department proposes that BART for filterable particulate matter is no additional controls. Current actual emissions are less than the current allowable emissions, and combusting dried lignite can be expected to further reduce particulate emissions. Based on past actual emissions and allowing for an additional margin of safety to provide a reasonable possibility for compliance, the Department proposes that BART is represented by an emission limit of 0.07 lb/10^6 Btu (average of 3 test runs).

C. Condensible Particulate Matter (PM_{10})

Condensible particulate matter is made up of both organic and inorganic substances. Organic condensible particulate matter will be made up of organic substances, such as volatile organic compounds, which are in a gaseous state through the air pollution control devices but will eventually turn to a solid or liquid state. The primary inorganic substance expected from the boiler is sulfuric acid mist, with lesser amounts of hydrogen fluoride and ammonium sulfate.

Since sulfuric acid mist is the largest component of condensible particulate matter, controlling it will control most of the condensible particulate matter. The options for controlling sulfuric acid mist are the same options for controlling sulfur dioxide (see Section III.A.). Previously, BART for sulfur dioxide was determined to be represented by the use of wet scrubber modifications to achieve a minimum SO_2 control efficiency of 95% and 100% of the flue gas stream. These changes are expected to reduce sulfuric acid mist emissions by approximately 90%. Changes that would provide additional reductions are economically infeasible considering the minimal improvement in visibility that could be achieved.

The control of volatile organic compounds at power plants is generally achieved through good combustion practices. The Department is not aware of any BACT determination at a power plant that resulted in any control technology being used. BACT has been found to be good combustion practices which are already in use since it minimizes the amount of fuel to generate electricity.

Both GRE and AP-42, Compilation of Air Pollutant Emission Factors[2], indicate the emission rate of condensible particulate matter could be expected to be 0.02 lb/10^6 Btu. This emission rate is less than the current emissions of filterable particulate matter and the emissions of filterable particulate matter were determined to have a negligible impact on visibility.

Having considered all the factors, the Department has determined that BART for condensible particulate matter is represented by good sulfur dioxide control and good combustion control. Since the primary constituent of condensible particulate matter is sulfuric acid mist which is controlled proportionately to the sulfur dioxide controlled, the BART limit for sulfur dioxide can act as a surrogate for condensible particulate matter along with a requirement for good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

External Flue Gas Recirculation
Selective Catalytic Reduction (SCR) High Dust
Electro-Catalytic Oxidation
Pahlman Process
SCR Low Dust
Low Temperature Oxidation (LTO), either Tri-No_x[7] or LoTOx
Selective Non-Catalytic Reduction (SNCR), No_xOut[7]
Modified and Additional Separated Overfire Air (SOFA)
Low NO_x Burners (LNB)

Step 2: Eliminate Technically Infeasible Options

Great River Energy has included a cost estimate for low-dust SCR, while high-dust SCR is listed as technically infeasible by GRE. The Department believes that low dust or tail end SCR has a good probability of successful application at Coal Creek and high dust SCR is technically infeasible (see discussion in Appendix B.5).

External Flue Gas Recirculation is technically infeasible due to limited space for ductwork and reduced flame temperature.

Electro-Catalytic Oxidation and the Pahlman Process considered technically infeasible because they are still in development and testing and have not been demonstrated to be commercially available. The remaining technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Based on the historic baseline emissions, the Department's estimated emissions using the various technologies are as follows:

Alternative	**Control* Efficiency (%)**	**Controlled Emissions****	
		(tons/yr)	**lb/10^6 Btu)**
LTO	90	536	0.022
SCR Low Dust	80	1,071	0.043
SNCR	50	2,679	0.108
SOFA/LNB Opt 1	30	3,750	0.15
SOFA/LNB Opt 2	21	4,232	0.17
Baseline	0	5,357	0.22

* Control efficiency provided in GRE's analysis.
** Calculated from the historic baseline (2003-2004). The emission rate is an annual average rate.

Step 4: Evaluate Impacts and Document Results

Costs of Compliance: Based on historic baseline emissions, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	**Emissions Reduction (tpy)**	**Annualized Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
LTO	4,821	58,070,000	12,045	3,589*
SCR Low Dust	4,286	56,150,000	13,101	20,678**
SNCR	2,678	22,900,000	8,551	20,766***
SOFA/LNB Opt 1	1,607	660,000	411	664****
SOFA/LNB Opt 2	1,125	340,000	302	---

* LTO compared to SCR Low Dust
** SCR Low Dust compared to SNCR
*** SNCR compared to SOFA/LNB Opt 1
**** SOFA/LNB Opt 1 compared to SOFA/LNB Opt 2

Note: SCR and SNCR estimates above include the costs associated with lost ash sales and increased landfilling requirements due to ammonia slip rendering the ash ineligible for beneficial use. Although they were included in the GRE analysis and the table above, if the sunk costs for the ash sales infrastructure are appropriately disregarded, then the annualized cost for SNCR would be $21,750,000, the cost effectiveness would be $8,122 per ton, and the incremental cost would be $19,692 per ton.

NDDH was unable to determine that SNCR and its associated use of ammonia will not negatively impact GRE's ash sales; in fact, there is considerable evidence to the contrary. GRE emails dated 8/8/08, 8/17/08 and 2/9/10 provide additional information on this issue, as does a summary of a University of Kentucky study on the matter. The 2/9/10 GRE email contains testimonials from ash marketers, buyers and end product users that provide clear evidence of actual negative impact on ash sales and use when the ash is contaminated with ammonia by SCR and SNCR systems. Furthermore, in a BART and PSD analysis for the Omaha Public Power District Nebraska City Station Unit #1 coal boiler (Construction Permit Number CP07-0049, 2/26/09 fact sheet, pg. 14), Nebraska DEQ determined SCR was not BART in part because . . ."ammonia used in the system would cause the ash to be contaminated, thereby jeopardizing the current beneficial reuse of a portion of the ash produced by NCS Unit 1."

After considering all the information available, NDDH reached the following conclusions.

- SCR and SNCR use at Coal Creek Station will likely result in ammonia in the fly ash.
- The level of ammonia in the fly ash cannot be predicted with a reasonable certainty.
- The maximum level of ammonia in fly ash that would still avoid negative impacts on the salability of the ash cannot be predicted. Levels as low as 100 ppm have made the fly ash unfit for use in concrete.[4]

The NDDH believes there is reasonable possibility that SCR or SNCR will result in a level of ammonia in the ash that could reduce or eliminate future ash sales. Lost ash sales will inflict a significant financial penalty on GRE and send ash to a landfill instead of it being used beneficially. If this ash is regulated as a hazardous waste, the financial burden will be even greater.

Energy and environmental impacts associated with the alternatives being considered include additional energy consumption (LTO, SCR), additional wastewater (LTO), ammonia slip (SCR, SNCR), potential to require ash to be landfilled (SNCR). The Department encourages the beneficial use of fly ash for making concrete. Ammonia slip associated with SNCR and SCR would preclude this beneficial use.

Step 5: Evaluate Visibility Impacts

The Department considers the incremental cost effectiveness of LTO, SCR Low Dust and SNCR to be excessive. GRE estimated the effects on visibility due to NO_x reductions (GRE BART Analysis, pages 47-51).

The following tables show the visibility impacts of the SOFA/LNB Options 1 and 2, and SNCR.

Coal Creek Station Unit 1 or 2
Delta Deciview
90th Percentile – NO_x

Year	Unit	SOFA/LNB Option 1 30% Reduction	SNCR 50% Reduction	Difference
2000	TRNP-SU	0.119	0.106	0.013
2001	TRNP-SU	0.108	0.096	0.012
2002	TRNP-SU	0.207	0.186	0.021
Average	TRNP-SU	0.145	0.129	0.015
2000	TRNP-NU	0.118	0.105	0.013
2001	TRNP-NU	0.136	0.127	0.009
2002	TRNP-NU	0.151	0.131	0.020
Average	TRNP-NU	0.135	0.121	0.014
2000	Elkhorn Ranch	0.082	0.072	0.010
2001	Elkhorn Ranch	0.076	0.069	0.007
2002	Elkhorn Ranch	0.129	0.118	0.011
Average	Elkhorn Ranch	0.096	0.086	0.009
2000	Lostwood W.A.	0.207	0.180	0.027
2001	Lostwood W.A.	0.207	0.180	0.027
2002	Lostwood W.A.	0.165	0.141	0.024
Average	Lostwood W.A.	0.193	0.167	0.026
Overall Average		0.142	0.126	0.016

Coal Creek Station Unit 1 or 2
Delta Deciview
98th Percentile – NO_x

Year	Unit	SOFA/LNB Option 1 30% Reduction	SNCR 50% Reduction	Difference
2000	TRNP-SU	0.467	0.410	0.057
2001	TRNP-SU	0.482	0.437	0.045
2002	TRNP-SU	1.140	1.052	0.088
Average	TRNP-SU	0.696	0.633	0.063
2000	TRNP-NU	0.416	0.352	0.064
2001	TRNP-NU	0.512	0.436	0.076
2002	TRNP-NU	0.918	0.813	0.105
Average	TRNP-NU	0.615	0.534	0.082
2000	Elkhorn Ranch	0.300	0.270	0.030
2001	Elkhorn Ranch	0.473	0.405	0.068
2002	Elkhorn Ranch	0.746	0.654	0.092
Average	Elkhorn Ranch	0.506	0.443	0.063
2000	Lostwood W.A.	0.469	0.417	0.052
2001	Lostwood W.A.	0.469	0.417	0.052
2002	Lostwood W.A.	0.783	0.680	0.103
Average	Lostwood W.A.	0.574	0.505	0.069
Overall Average		0.598	0.529	0.069

Coal Creek Station Unit 1 or 2 Delta Deciview 90th Percentile – NO_x				
Year	Unit	SOFA/LNB Option 1 30% Reduction	SOFA/LNB Option 2 21% Reduction	Difference
2000	TRNP-SU	0.119	0.125	0.006
2001	TRNP-SU	0.108	0.116	0.008
2002	TRNP-SU	0.207	0.219	0.012
Average	TRNP-SU	0.145	0.153	0.009
2000	TRNP-NU	0.118	0.124	0.006
2001	TRNP-NU	0.136	0.142	0.006
2002	TRNP-NU	0.151	0.158	0.007
Average	TRNP-NU	0.135	0.141	0.006
2000	Elkhorn Ranch	0.082	0.088	0.006
2001	Elkhorn Ranch	0.076	0.076	0.000
2002	Elkhorn Ranch	0.129	0.136	0.007
Average	Elkhorn Ranch	0.096	0.100	0.004
2000	Lostwood W.A.	0.207	0.215	0.008
2001	Lostwood W.A.	0.207	0.215	0.008
2002	Lostwood W.A.	0.165	0.178	0.013
Average	Lostwood W.A.	0.193	0.203	0.010
Overall Average		0.142	0.149	0.007

Coal Creek Station Unit 1 or 2 Delta Deciview 98th Percentile – NO_x				
Year	Unit	SOFA/LNB Option 1 30% Reduction	SOFA/LNB Option 2 21% Reduction	Difference
2000	TRNP-SU	0.467	0.494	0.027
2001	TRNP-SU	0.482	0.509	0.027
2002	TRNP-SU	1.140	1.181	0.041
Average	TRNP-SU	0.696	0.728	0.032
2000	TRNP-NU	0.416	0.446	0.030
2001	TRNP-NU	0.512	0.547	0.035
2002	TRNP-NU	0.918	0.987	0.069
Average	TRNP-NU	0.615	0.660	0.045
2000	Elkhorn Ranch	0.300	0.314	0.014
2001	Elkhorn Ranch	0.473	0.505	0.032
2002	Elkhorn Ranch	0.746	0.789	0.043
Average	Elkhorn Ranch	0.506	0.536	0.030
2000	Lostwood W.A.	0.469	0.499	0.030
2001	Lostwood W.A.	0.469	0.499	0.030
2002	Lostwood W.A.	0.783	0.832	0.049
Average	Lostwood W.A.	0.574	0.610	0.036
Overall Average		0.598	0.634	0.036

Step 6: Select BART

The units have existing low NO_x burners and SOFA for removing nitrogen oxides and the plant is expected to have a remaining useful life of at least 20 years. The Department considers the incremental cost of the top three options to be excessive. If fly ash sales are not lost due to the use of SNCR, the cost for this alternative is not considered excessive. However, the maximum improvement in visibility for SNCR versus SOFA/LNB Option 1 is 0.105 deciviews based on the 98th percentile (0.027 deciviews based on the 90th percentile). The Department has found that the single source BART modeling overpredicts the amount of visibility improvement by a factor of 5-7 (see Section 7.4.2 of SIP). The Department considers the amount of visibility improvement from the use of SCNR versus SOFA/LNB Option 1 to be inconsequential. Because of the potential for lost sales of fly ash, the negative environmental effects of having to dispose of the fly ash instead of recycling it into concrete, and the very small amount of visibility improvement from the use of SNCR, this option is rejected as BART. The Department proposes that BART is represented by modified and additional SOFA plus LNB (Option 1). GRE has indicated the feasibility of, and the manufacturer has guaranteed, an emission limit of 0.15 lb/10^6 Btu on an annual average basis. An achievable thirty-day rolling average emission rate is expected to be slightly higher at 0.17 lb/10^6 Btu. The Department proposes that BART is 0.17 lb/10^6 Btu on a 30-day rolling average basis. Unit 1 and Unit 2 emissions may be averaged provided the average does not exceed the limit.

IV. BART Evaluation for Auxiliary Boilers No. 91 and No. 92

Auxiliary boilers No. 91 and No. 92 are distillate and residual oil-fired boilers with a nominal rating of 172 x 10^6 Btu/hr. The auxiliary boilers are only used when both units at the Coal Creek Station are down. During the baseline period (2000-2004), the auxiliary boilers were operated an average of 11.2 hours per unit per year. The annual average emissions per unit for this period were:

NO_x	0.09 tons
SO_2	0.19 tons
PM	0.08 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have a virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls and the currently permitted fuel limitation of distillate oil, residual oil or any combination of the two.

V. BART Evaluation of Emergency Generator

The emergency generator is driven by a 3,500 horsepower diesel engine. The generator is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. During the baseline period (2000-2004), the engine operated an average of 94.9 hours per year and the average annual emissions were:

PM	0.07 tons
NO_x	2.87 tons
SO_2	0.31 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have a virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VI. BART Evaluation for Emergency Fire Pump

The emergency fire pump is driven by a 200 horsepower diesel engine. The pump is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. During the baseline period (2000-2004), the engine operated an average of 14.0 hours per year and the actual annual emissions were:

PM	0.01 tons
NO_x	0.11 tons
SO_2	0.01 tons

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VII. BART Evaluation for Materials Handling Sources

The materials handling sources at Coal Creek Station that emit to the atmosphere are as follows:

EU – Description	Existing Control Equipment	Current PM Emission Limit (lb/hr)	Baseline PM Emissions (tons/yr)
EU 7 - Lignite transfer house	Bagfilter	3	0.07
EU 8 - Lignite emergency reclaim system	Bagfilter	3	0.00
EU 9 - Lignite yard storage silos	Bagfilter	3	0.03
EU 10 - Lignite yard storage silos	Bagfilter	3	0.03
EU 11 - Crusher building	Bagfilter	3	0.07
EU 12 - Generation building coal hopper	Bagfilter	3	0.07
EU 13 - Falkirk mining Company mine silo base	Bagfilter	3	0.07

EU – Description	Existing Control Equipment	Current PM Emission Limit (lb/hr)	Baseline PM Emissions (tons/yr)
EU 14 - Generation building coal hopper	Bagfilter	3	0.02
EU 15 - Generation building coal hopper	Bagfilter	3	0.02
EU 16 - Generation building coal hopper	Bagfilter	3	0.02
EU 17 - Generation building coal hopper	Bagfilter	3	0.02
EU 19 - Scrubber building flyash silo	Bagfilter	3	0.02
EU 20 - Truck air slide flyash silo	Bagfilter	3	0.05
EU 21 - Truck air slide flyash silo	Bagfilter	3	0.05
EU 22 - Water treatment building	Bagfilter	3	0.03
EU 23 - Scrubber building lime handling system	Bagfilter	3	0.02
EU 24 - Scrubber building lime handling system	Bagfilter	3	0.02
EU 25 - Flyash railroad marketing silo	Bagfilter	3	0.05
EU 26 - Flyash dome	Bagfilter	0.4 (EP 26a-26b), 0.09 (EP 26e)	0.02
EU 27 - Coal Dryer	Bagfilter	3.1	0.3*
FS 1 - Cooling towers No. 91, No. 92, and No. 93	Fugitive	--	0.02
FS 2 - Boombelt conveyor (stackout)	Fugitive	--	0.02
FS 3 - Conveyor 909 (stackout)	Fugitive	--	0.04
FS 4 - Scrubber building flyash silo (stackout)	Fugitive	--	0.04
FS 5 - Coal pile maintenance	Fugitive	--	3.77

* Department estimate based on 2005 emissions

Based on the small quantity emissions from those sources (EU 7-27) that are controlled by bagfilters, which are considered the most efficient control devices, it is apparent that no additional control equipment will be cost effective. Materials handling units (FS 1-5) are uncontrolled sources of fugitive emissions. Based on the small quantity of emissions from those sources, it is apparent that no additional control equipment will be cost effective. Any additional controls would have a neglible effect on visibility impairment. Therefore, the Department proposes that BART for the materials handling units is no additional controls and the current emission limits for the units is BART.

VIII. Summary

Source Unit	**Proposed BART Limit/Work Practice**				**Emissions Reduction (tons/yr)**		
	PM	**SO_2**	**NO_x**	**Units**	**PM**	**SO_2**	**NO_x**
Unit 1 Boiler	0.07	0.15 (30-dra) or 95% reduction	0.17 (30-dra)	lb/10^6 Btu	0	19,990*	1,607
Unit 2 Boiler	0.07	0.15 (30-dra) or 95% reduction	0.17 (30-dra)	lb/10^6 Btu	0	19,990*	1,607
Auxiliary Boiler No. 91	Continue current practices			N/A	0	0	0
Auxiliary Boiler No. 92	Continue current practices			N/A	0	0	0
Emerg. Gen.	Continue current practices			N/A	0	0	0
Fire Pump	Continue current practices			N/A	0	0	0
Material Handling EU 7-25	3	---	---	lb/hr	0	---	---
Flyash Dome EU 26	0.4 (EP 26a-26b), 0.09 (EP 26e)	---	---	lb/hr	0	---	---

Source Unit	Proposed BART Limit/Work Practice				Emissions Reduction (tons/yr)		
	PM	SO_2	NO_x	Units	PM	SO_2	NO_x
Coal Dryer EU 27	3.1	---	---	---	0	---	---
Fugitive FS 1-5	---	---	---	---	0	---	---
Total:						39,980*	3,214

* Reductions from 2000-2004 average emission rate adjusted for future fuel (dried lignite).

IX. Permit to Construct

The emission limits, monitoring, recordkeeping and reporting requirements will be included in a federally enforceable Air Pollution Control Permit to Construct that will be issued to the owner/operator of the facility. The Permit to Construct is included in Appendix D.

A. Monitoring

1. Monitoring for SO_2 and NO_x will be accomplished using the continuous emission monitors required by 40 CFR 75 for the Acid Rain Program. Monitoring for particulate matter shall be in accordance with 40 CFR 64, Compliance Assurance Monitoring. If the owner/operator of the BART-eligible unit chooses to comply with the SO_2 percent reduction requirements, monitoring of the SO_2 inlet rate loading to the scrubber shall be accomplished by either:

   a. A continuous emission monitor that complies with the requirements of 40 CFR 75; or

   b. Coal sampling in accordance with Method 19 of 40 CFR 60, Appendix A plus development of an emission factor based on actual stack testing.

2. For purposes of determining compliance with the SO_2 reduction requirement, the reduction efficiency shall be determined as follows:

$$\% \text{ Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where:

Inlet SO_2 Rate is in units of lb/10^6 Btu, lb/hr or ppmvd @ 3% O_2.

Outlet SO_2 Rate is in the same units as the inlet SO_2 rate.

3. The owner/operator will be allowed to average emissions (bubble) for SO_2 and/or NO_x for the two units using the following formulas:

$$\text{Average AER} = \frac{[(AER_1)(HI_1)+(AER_2)(HI_2)]}{(HI_1 + HI_2)}$$

$$\text{Average ER} = \frac{[(ER_1)(HI_1)+(ER_2)(HI_2)]}{(HI_1 + HI_2)}$$

Where:

AER = Allowable Emission Rate (lb/MMBtu or % Reduction)
ER_1 = Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 1
ER_2 = Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 2
HI_1 = Actual Heat Input (MMBtu) of Unit 1
HI_2 = Actual Heat Input (MMBtu) of Unit 2

Notes: ER is a 30-day rolling average.
HI is a 30-day rolling average.
30-day rolling average is determined in accordance with 40 CFR 60, Subpart Da, for the 30 successive boiler operating days (must be on a consistent basis of lb/MMBtu or % reduction).

B. Recordkeeping and Reporting

The owner/operator will be required to conduct recordkeeping and reporting as required by NDAC 33-15-14-06, Title V Permit to Operate and NDAC 33-15-21, Acid Rain Program (40 CFR 72, 75 and 76).

References

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2. EPA, 1995. Compilation of Air Pollutant Emission Factors Volume 1: Stationary Point and Area Sources. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711

3. Great River Energy, 2007. Coal Creek Station Units 1 and 2 BART Analysis; Revised December 12, 2007.

4. Bittner, James D.; Gasiorowski, Stephen A.; Hrach, Frank J.; Fly Ash Separation and Ammonia Removal at Tampa Electric Big Bend. Separation Technologies, LLC, Needham, MA 02492.

BART Determination
for
Stanton Station Unit 1

11/18/09

I. <u>Source Description</u>

A. Owner/Operator: Great River Energy

B. Source Type: Electric Utility Steam Generating Unit

C. BART Eligible Units
  1. Unit 1 boiler
  2. Auxiliary Boiler
  3. Emergency Diesel Generator
  4. Emergency Fire Pump Engine
  5. Materials Handling Equipment
    a. Unit 1 coal bunker
    b. Flyash silo

D. Unit Description

  1. Unit 1:
     Generator Nameplate Capacity: 188 MWe
     Boiler Rating: 1,800 x 10^6 Btu/hr
     Startup: 1966
     Fuel: North Dakota Lignite, PRB Subbituminous
     Firing Method: Wall-fired
     Existing Air Pollution Control Equipment: Low NO_x burners and an electrostatic precipitator

  2. Auxiliary Boiler:
     Boiler Rating: 38 x 10^6 Btu/hr
     Fuel: #2 fuel oil

  3. Emergency Diesel Generator
     Rating: 10.35 x 10^6 Btu/hr
     Fuel: #2 fuel oil

  4. Emergency Fire Pump Engine:
     Rating: 370 horsepower
     Fuel: #2 fuel oil

  5. Materials Handling Equipment:

    a. Unit 1 coal bunker
       Existing Air Pollution Control Equipment: Baghouse

b. Flyash Silo:
Existing Air Pollution Control Equipment: Baghouse

E. Emissions

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Avg.**
Unit 1 Boiler (lignite coal)	SO_2 (tons)	7,660	9,046	8,548	8,084	7,871	8,242
	SO_2 (lb/10^6 Btu)	1.70	1.82	1.59	1.81	1.52	1.70
	NO_x (tons)	1,849	2,044	2,312	1,961	2,073	2,048
	NO_x (lb/10^6 Btu)	0.41	0.41	0.43	0.44	0.40	0.42
	PM (tons)	86	95	70	53	63	73.4
	PM (lb/10^6 Btu)	0.019	0.019	0.013	0.012	0.012	0.016
Unit 1 Boiler (PRB coal)	SO_2 (tons)	*	*	*	*	*	6,216**
	SO_2 (lb/10^6 Btu)	*	*	*	*	*	1.2**
	NO_x (tons)	*	*	*	*	*	1,740**
	NO_x (lb/10^6 Btu)	*	*	*	*	*	0.36**
	PM (tons)	*	*	*	*	*	91**
	PM (lb/10^6 Btu)	*	*	*	*	*	0.019**
Auxiliary Boiler	SO_2 (tons)	*	*	*	*	*	0.36
	NO_x (tons)	*	*	*	*	*	0.14
	PM (tons)	*	*	*	*	*	0.02
Emergency Diesel Generator	SO_2 (tons)	*	*	*	*	*	1.3***
	NO_x (tons)	*	*	*	*	*	8.0***
	PM (tons)	*	*	*	*	*	0.2***
Emergency Fire Pump Engine	SO_2 (tons)	*	*	*	*	*	0.19***
	NO_x (tons)	*	*	*	*	*	2.76***
	PM (tons)	*	*	*	*	*	0.2***
Unit 1 Coal Bunker	PM (tons)	*	*	*	*	*	0.6****
Flyash Silo	PM (tons)	*	*	*	*	*	18.3****

* See A2000-2004 Avg.@ column.

** Projected emission rates when burning PRB coal (see discussion in Section IV.A. of this analysis for sulfur dioxide and Section IV.D. of this analysis for nitrogen oxides). For PM, it is assumed that PM emissions from the combustion of PRB coal are the same as for lignite coal.

*** Based on 500 hours per year of operation.

**** Department estimate.

II. Site Characteristics

The Stanton Station is located on the banks of the Missouri River in eastern Mercer County near the town of Stanton, North Dakota.

III. BART Evaluation of Unit 1 When Combusting Lignite Coal

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

- Wet Scrubber
- Spray Dryer / Fabric Filter (SD/FF)
- Circulating Dry Scrubber
- Wet Scrubber with a 10% bypass
- Dry Sorbent Injection / Fabric Filter (DSI/FF)
- Dry Sorbent Injection / Existing ESP (DSI/ESP)
- Powerspan ECO7
- Coal Cleaning
- Pahlman Process^{TM}
- K-Fuel7

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located on the banks of the Missouri River, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning.

K-Fuel7 is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from North Dakota was tested. The use of the K-Fuel process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel process available or technically and economically feasible.

A circulating dry scrubber is not considered commercially available by Great River Energy. However, the Department is including this as an available technology. Costs for a circulating dry scrubber are estimated based on cost estimates included in other BART analyses.

The Department considers the Powerspan ECO technology and the Pahlman Process not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

The Department has calculated the baseline SO_2 emission rate when burning lignite by utilizing the highest calendar year average SO_2 emission rate of 1.81 lb/million Btu from 2000-2004 and multiplying this value by the highest heat input for any two consecutive years for the 2000-2004 period. This results in a baseline SO_2 emission rate as follows:

Heat input (2001) = 9.965×10^{12} Btu

Heat input (2002) = 1.075×10^{13} Btu

Average heat input = $(9.965 \times 10^{12} + 1.075 \times 10^{13}) / 2$
= 1.036×10^{13} Btu

Baseline SO_2 emission rate when combusting lignite coal
= 1.036×10^{13} Btu (1.81 lb/million Btu)(1 ton/2000 lb) = 9,376 tons/year

The control effectiveness of all remaining control technologies are shown in the following table.

Alternative	**Control Efficiency (%)**	**Inlet Loading (tons/yr)**	**Controlled Emissions**	
			(tons/yr)	**(lb/10^6 Btu)**
Wet Scrubber	95	9,376	469	0.091
Circulating Dry Scrubber	93	9,376	656	0.127
SD/FF	90	9,376	938	0.181
Flash Dryer Absorber	90	9,376	938	0.181

Alternative	**Control Efficiency (%)**	**Inlet Loading (tons/yr)**	**Controlled Emissions**	
			(tons/yr)	**(lb/10^6 Btu)**
Wet Scrubber with 10% bypass	86	9,376	1,313	0.263
DSI/FF	55	9,376	4,219	0.817
DSI/ESP	35	9,376	6,094	1.18

The cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	**Emissions Reduction (tons/yr)**	**Annualized Cost ($)***	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Wet Scrubber	8,907	13,180,000	1,480	4,179****
Circulating Dry Scrubber	8,720	14,220,000***	1,631	10,638
SD/FF	8,438	11,220,000	1,330	850**
Wet Scrubber with 10% bypass	8,063	9,490,000	1,177	365
DSI/FF	5,157	8,430,000	1,635	2,789
DSI/ESP	3,282	3,200,000	975	---

Note: Flash Dryer Absorber not included since it costs more than a spray dryer with no additional emissions reduction.

* Costs provided by Great River Energy (except as noted).
** The incremental cost shown is the incremental cost of SD/FF compared to DSI/FF.
*** The cost is estimated based on other BART analyses.
**** The incremental cost shown is the incremental cost of a wet scrubber compared to SD/FF.

Step 4: Evaluate Impacts and Document Results

Great River Energy has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of any of the control equipment.

Step 5: Evaluate Visibility Results

The two primary alternatives are a wet scrubber operating at 95% removal efficiency and a spray dryer operating at 90% efficiency. The effects on visibility for each of these two control options at the Theodore Roosevelt National Park, South Unit (TRNP-SU), Theodore Roosevelt National Park, North Unit (TRNP-NU), Theodore Roosevelt National Park, Elkhorn Ranch (TRNP-Elkhorn Ranch) and the Lostwood Wilderness Area (Lostwood WA) are shown in the following tables.

Unit 1 - Lignite Coal Combustion
Delta Deciview
90th Percentile
SO_2

Year	**Unit**	**90% Reduction**	**95% Reduction**	**Difference**
2000	TRNP-SU	0.066	0.048	0.018
2001	TRNP-SU	0.061	0.043	0.018
2002	TRNP-SU	0.096	0.089	0.007
Average	TRNP-SU			0.014
2000	TRNP-NU	0.080	0.062	0.018
2001	TRNP-NU	0.089	0.061	0.028
2002	TRNP-NU	0.097	0.072	0.025
Average	TRNP-NU			0.024
2000	TRNP-Elkhorn Ranch	0.054	0.040	0.014
2001	TRNP-Elkhorn Ranch	0.036	0.024	0.012
2002	TRNP-Elkhorn Ranch	0.074	0.050	0.024
Average	TRNP-Elkhorn Ranch			0.017
2000	Lostwood WA	0.118	0.094	0.024
2001	Lostwood WA	0.160	0.139	0.021
2002	Lostwood WA	0.088	0.078	0.01
Average	Lostwood WA			0.019
	Overall Average			0.019

Unit 1 - Lignite Coal Combustion
Delta Deciview
98th Percentile
SO_2

Year	Unit	90% Reduction	95% Reduction	Difference
2000	TRNP-SU	0.320	0.290	0.03
2001	TRNP-SU	0.322	0.270	0.052
2002	TRNP-SU	0.668	0.556	0.112
Average	TRNP-SU			0.065
2000	TRNP-NU	0.458	0.369	0.089
2001	TRNP-NU	0.385	0.334	0.051
2002	TRNP-NU	0.595	0.516	0.079
Average	TRNP-NU			0.073
2000	TRNP-Elkhorn Ranch	0.224	0.183	0.041
2001	TRNP-Elkhorn Ranch	0.241	0.178	0.063
2002	TRNP-Elkhorn Ranch	0.517	0.429	0.088
Average	TRNP-Elkhorn Ranch			0.064
2000	Lostwood WA	0.340	0.320	0.02
2001	Lostwood WA	0.526	0.449	0.077
2002	Lostwood WA	0.410	0.341	0.069
Average	Lostwood WA			0.055
	Overall Average			0.064

Step 6: Select BART

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The incremental cost of greater than $10,600 per ton of sulfur dioxide removed for a circulating dry scrubber compared to a spray dryer is considered excessive and a circulating dry scrubber is removed from further consideration as BART.

The unit has no existing air pollution control equipment for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. The degree of visibility improvement achieved by selecting a wet scrubber operating at 95% control efficiency versus a spray dryer operating at 90% control efficiency does not exceed 0.028 deciviews (90th percentile) or 0.112 deciviews (98% percentile) at any Class I area for the 2000-2002 time frame. Although the amount of visibility improvement achieved by selecting a wet scrubber versus a spray dryer is small, the Department has placed the primary emphasis on the cost of each option. The incremental cost from a spray dryer to a wet scrubber is $4,179 per ton of SO_2 removed. The Department does not consider this incremental cost to be excessive. However, wet scrubbing does have additional environmental impacts when compared to a spray dryer with a fabric filter as outlined below:

- A wet scrubber is estimated by GRE to use as much as 20% more water or approximately 15 million gallons per year of additional water.
- It is assumed that a wet scrubber system will require additional on-site ponding. GRE has identified two potential areas on site that could be used for the additional ponding. The areas include the existing ash pile, which would have to be excavated and moved, or the abandoned ash disposal area adjacent to the river, which reportedly has geotechnical deficiencies.
- Dry scrubbers are purported to achieve a higher mercury control efficiency on lignite and PRB as compared to a wet scrubber. In addition, future mercury control requirements could result in high concentrations of mercury in the ponds and prove problematic to discharge.

Based upon the additional environmental impacts and the fact that a wet scrubber will remove at best an additional 469 tons/year of SO_2 (with a small corresponding visibility improvement) beyond the control achieved by a spray dryer, the Department proposes BART as a spray dryer with a fabric filter.

The highest calendar year average SO_2 emission rate is approximately 1.81 lb/MM Btu for the 2000-2004 period when combusting lignite at Stanton Station Unit 1. Utilizing a 90% control efficiency for the spray dryer and fabric filter results in an annual average controlled emission rate of approximately 0.181 lb/MM Btu. Based upon historical SO_2 emissions data for spray dryers and fabric filters at North Dakota facilities, the Department has determined that an increase of 33% is warranted to adjust from an annual average SO_2 emission rate to a 30-day rolling average SO_2 emission rate. Multiplying the annual average emission rate of 0.181 lb/MM Btu by a factor of 1.33 (an increase of 33%) yields a 30-day rolling average SO_2 emission rate of 0.24 lb/MM Btu. Therefore, BART for SO_2 when combusting lignite coal is an SO_2 emission limit of 0.24 lb/million Btu heat input (on a 30 day rolling average) or a reduction efficiency of 90% (on a 30 day rolling average) on the inlet SO_2 concentration to the pollution control equipment.

B. Filterable Particulate Matter

Step 1: Identify All Available Technologies

New Baghouse
New Electrostatic Precipitator (ESP)
New Wet ESP
Existing ESP

Step 2: Eliminate Technically Infeasible Options

All technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	Control Efficiency	Emissions (tons/yr)	Emissions (lb/10^6 Btu)
Baghouse	99.7+	72.5	0.015
New ESP	99.7	72.5	0.015
Wet ESP	99.7	72.5	0.015
Baseline (Existing ESP)*	.99.5	90.5	0.019

* Based on the average of 2000 and 2001 emissions.

Alternative	Emissions Reduction (tpy)*	Annualized Cost ($)**	Cost Effectiveness ($/ton)
Baghouse	18	4,980,000	276,670
New ESP	18	5,800,000	322,220
Wet ESP	18	2,030,000	112,780
Baseline (Existing ESP)	0	0	---

* Reductions from the baseline emission rate.
** Costs provided by Great River Energy.

Step 4: Evaluate Impacts and Document the Results

Great River Energy has evaluated the energy and non-air quality effects of each option. The Department has determined that the effects will not preclude the selection of any of the options.

Step 5: Evaluate Visibility Impacts

Modeling was conducted to determine the visibility impairment at the PM emission limit of 0.1 lb/million Btu and an emission limit of 0.015 lb/million Btu. The visibility improvement in deciviews which results from reducing PM emissions from 0.1 lb/million Btu to 0.015 lb/million Btu is shown in the following table.

Unit 1 - Lignite Coal Combustion PM Delta Deciview			
Year	**Unit**	**90th Percentile**	**98th Percentile**
2000	TRNP-SU	0.005	0.008
2001	TRNP-SU	0.001	0.002
2002	TRNP-SU	0.006	0.021
Average		0.004	0.01
2000	TRNP-NU	0.001	0.011
2001	TRNP-NU	0.005	0.006
2002	TRNP-NU	0.001	0.019
Average		0.002	0.012
2000	TRNP-Elkhorn Ranch	0.001	0.013
2001	TRNP-Elkhorn Ranch	<0.001	0.002
2002	TRNP-Elkhorn Ranch	0.001	0.01
Average		<0.001	0.008
2000	LWA	0.005	0.011
2001	LWA	0.007	0.007
2002	LWA	0.005	0.003
Average		0.006	0.007
Overall Average		0.003	0.009

Step 6: Select BART

The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate emissions is a wet ESP. This system has a cost effectiveness of approximately $113,000 per ton of particulate when compared to the current emission control system (ESP operating at 99.5% efficiency). The Department considers this cost to be excessive.

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The unit is equipped with an electrostatic precipitator that is achieving 99.5% Control efficiency. The plant is expected to have a remaining useful life of at least 20 years.

If the particulate emitted was reduced from the allowable emission limit of 0.1 lb/million Btu to 0.015 lb/million Btu, the most improvement in visibility at any Class I area would be approximately 0.006 deciviews (90th percentile) based on the three year average (0.008 deciviews based on the 98th percentile). The Department considers this amount of improvement to be insignificant.

After considering all of the factors, the Department proposes that BART for filterable particulate matter when combusting lignite coal is no additional controls. Since current actual emissions are less than the current allowable emissions and emissions lower than the current allowable can be achieved by the existing control equipment, the Department proposes that BART is represented by an emission limit of 0.07 lb/10^6 Btu.

C. Condensible Particulate Matter (PM_{10}).

Condensible particulate matter is made up of both organic and inorganic substances. Organic condensible particulate matter will be made up of organic substances, such as volatile organic compounds, which are in a gaseous state through the air pollution control devices but will eventually turn to a solid or liquid state. The primary inorganic substance expected from the boiler is sulfuric acid mist, with lesser amounts of hydrogen fluoride and ammonium sulfate.

Since sulfuric acid mist is the largest component of condensible particulate matter, controlling it will control most of the condensible particulate matter. The options for controlling sulfuric acid mist are the same options for controlling sulfur dioxide (see Section III.A.). Previously, BART for sulfur dioxide was determined to be represented by a spray dryer.

The control of volatile organic compounds at power plants is generally achieved through good combustion practices. The Department is not aware of any BACT determination at a power plant that resulted in any control technology being used. BACT has been found to be good combustion practices which are already in use since it minimizes the amount of fuel to generate electricity.

AP-42, Compilation of Air Pollutant Emission Factors[2], suggests that the emission rate of condensible PM could be as high as 0.02 lb/10^6 Btu. This emission rate is approximately equal to the current emissions of filterable particulate matter. The emissions of filterable particulate matter were determined to have a negligible impact on visibility.

Having considered all the factors, the Department has determined that BART for condensible particulate matter when combusting lignite coal is represented by good sulfur dioxide control and good combustion control. Since the primary constituent of condensible particulate matter is sulfuric acid mist which is controlled proportionately to the sulfur dioxide controlled, the BART limit for sulfur dioxide can act as a surrogate for condensible particulate matter along with a requirement for good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Low Temperature Oxidation (LTO)
Non Selective Catalytic Reduction (NSCR)
Electro-Catalytic Oxidation (ECO)
Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
Flue Gas Recirculation (FGR)
Overfire Air (OFA)
Low NO_x Burners (LNB)
Pahlman Process

Step 2: Eliminate Technically Infeasible Options

After significant review, it is the Department=s position that high-dust SCR for control of emissions from the combustion of North Dakota lignite at electric utility steam generating units is not technically feasible at this time (see discussion in Appendix B.5). Great River Energy has included a cost estimate for low-dust SCR, while high-dust SCR is listed as technically infeasible by GRE.

ECO, NSCR and the Pahlman Process have not been demonstrated on a pulverized coal-fired boiler and are considered technically infeasible.

Rich reagent injection was developed for cyclone boilers and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Unit 1 since it is not a cyclone boiler.

Flue gas recirculation is not considered a technically feasible control option due to the space constraints at the facility. The space constraints do not allow for the additional ductwork and blower required to recirculate the flue gas.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Based on the historic baseline emissions, the Department=s estimated emissions using the various technologies would be as follows:

Alternative	**Control Efficiency (%)***	**Emissions**	
		(tons/yr)	**(lb/10^6 Btu)**
SCR with reheat	90	210	0.044
LTO	90	210	0.044
LNB + OFA + SNCR	45	1,156	0.239
SNCR	33	1,401	0.29
LNB + OFA	26	1,546	0.32
Baseline**	---	2,137	0.44

* Control efficiency provided in Great River Energy=s analysis.
** Based on the average of 2002 and 2003 emissions.

The estimated costs for the various technologies are as follows:

Alternative	**Emissions Reduction (tpy)**	**Annualized Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
SCR with reheat	1,929	12,490,000	6,475	10,032*
LTO	1,929	44,780,000	23,217	45,439
LNB + OFA + SNCR	983	3,000,000	3,052	6,923**
SNCR	738	2,700,000	3,658	16,551
LNB + OFA	593	300,000	504	---
Baseline	2,137	---	---	---

* The incremental cost shown is the incremental cost of SCR with reheat as compared to LNB + OFA + SNCR.
** The incremental cost show is the incremental cost of LNB + OFA + SNCR as compared to LNB + OFA.

Step 4: Evaluate Impacts and Document Results

There are no energy or environmental impacts that would preclude the selection of any of the alternatives.

Step 5: Evaluate Visibility Impacts

The Department considers the incremental cost effectiveness of the top two alternatives to be excessive. Modeling has been conducted assuming control with a spray dryer and LNB (current control for NO_x) and additional modeling has been conducted assuming control with OFA and SNCR in addition to the spray dryer and LNB. The difference in visibility impact between the two control scenarios is shown in the following tables.

Unit 1 - Lignite Coal Combustion Delta Deciview 90th Percentile				
Year	**Unit**	**LNB**	**LNB + OFA + SNCR**	**Difference**
2000	TRNP-SU	0.066	0.055	0.011
2001	TRNP-SU	0.061	0.054	0.007
2002	TRNP-SU	0.096	0.080	0.016
Average	*TRNP-SU*	0.074	0.063	0.011
2000	TRNP-NU	0.080	0.065	0.015
2001	TRNP-NU	0.089	0.073	0.016
2002	TRNP-NU	0.097	0.083	0.014
Average	*TRNP-NU*	0.089	0.074	0.015
2000	Elkhorn Ranch	0.054	0.049	0.005
2001	Elkhorn Ranch	0.036	0.034	0.002
2002	Elkhorn Ranch	0.074	0.060	0.014
Average	*Elkhorn Ranch*	0.055	0.048	0.007
2000	Lostwood W.A.	0.118	0.096	0.022
2001	Lostwood W.A.	0.160	0.133	0.027
2002	Lostwood W.A.	0.088	0.073	0.015
Average	*Lostwood W.A.*	0.122	0.101	0.021
Overall Average		0.085	0.0715	0.0135

Unit 1 - Lignite Coal Combustion
Delta Deciview
98th Percentile

Year	**Unit**	**LNB**	**LNB + OFA + SNCR**	**Difference**
2000	TRNP-SU	0.320	0.253	0.067
2001	TRNP-SU	0.322	0.261	0.061
2002	TRNP-SU	0.668	0.565	0.103
Average		0.437	0.360	0.077
2000	TRNP-NU	0.458	0.356	0.102
2001	TRNP-NU	0.385	0.318	0.067
2002	TRNP-NU	0.595	0.460	0.135
Average		0.479	0.378	0.101
2000	Elkhorn Ranch	0.224	0.215	0.009
2001	Elkhorn Ranch	0.241	0.203	0.038
2002	Elkhorn Ranch	0.517	0.426	0.091
Average		0.327	0.281	0.046
2000	Lostwood W.A.	0.340	0.260	0.08
2001	Lostwood W.A.	0.526	0.422	0.104
2002	Lostwood W.A.	0.410	0.334	0.076
Average		0.425	0.339	0.086
Overall Average		0.417	0.340	0.077

Step 6: Select BART

The Department considered the incremental cost of the top two options to be excessive. The Department proposes that BART is represented by low-NO_x burners (LNB) plus over-fire air (OFA) plus selective non-catalytic reduction (SNCR). The Department proposes that BART for NO_x when combusting lignite coal is an emission limit of 0.29 lb/million Btu on a 30-day rolling average basis.

IV. BART Evaluation of Unit 1 when Burning PRB

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Wet Scrubber
Spray Dryer / Fabric Filter (SD/FF)
Circulating Dry Scrubber
Flash Dryer Absorber
Wet Scrubber with a 10% bypass
Dry Sorbent Injection / Fabric Filter (DSI/FF)
Dry Sorbent Injection / Existing ESP (DSI/ESP)
Powerspan ECO
Coal Cleaning
Pahlman Process

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located on the banks of the Missouri River, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning.

K-Fuel is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. The use of the K-Fuel process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Based upon the above, the Department does not consider coal cleaning or the K-Fuel process available or technically and economically feasible.

A circulating dry scrubber is not considered commercially available by Great River Energy. However, the Department is including this as an available technology. Costs for a circulating dry scrubber are estimated based on cost estimates included another BART analysis.

The Department considers the Powerspan ECO technology and the Pahlman Process not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Actual SO_2 emissions from Unit 1 at the Stanton Station were approximately 0.44 lb/million Btu heat input for calendar year 2006. However, Great River Energy has indicated that the mine from which the current PRB coal is received has a contractual arrangement with Great River to supply coal with a sulfur content which equates to an SO_2 emission limit no greater than 0.8 lb/million Btu heat input with a financial penalty if the sulfur content is greater than this amount. The mine uses a sulfur reject value of 1.2 lb/million Btu heat input.

Great River Energy has indicated that the contract for PRB coal from the existing mine expires in 2009 and has indicated that other potential PRB coal mines have PRB coal average sulfur contents of 0.34% sulfur, 0.64% sulfur and 0.80% sulfur, which equates to the following SO_2 emission rates:

SO_2 emission rate = 35S lb/ton*

* From EPA Publication AP-42, Section 1.1, Table 1.1-3, where S is the coal sulfur content.

SO_2 emission rate (at 0.34% sulfur PRB coal)
= 35 (0.34) lb/ton (1 ton/2,000 lb)(l lb / 9,350 Btu)
= 0.64 lb/million Btu heat input

SO_2 emission rate (at 0.64% sulfur PRB coal)
= 35 (0.64) lb/ton (1 ton/2,000 lb)(l lb / 8,750 Btu)
= 1.28 lb/million Btu heat input

SO_2 emission rate (at 0.80% sulfur PRB coal)
= 35 (0.80) lb/ton (1 ton/2,000 lb)(l lb / 8,750 Btu)
= 1.60 lb/million Btu heat input

For purposes of this analysis, an SO_2 emission rate of 1.2 lb/million Btu will be used to calculate uncontrolled emissions when combusting PRB coal. Baseline SO_2 emissions when combusting PRB coal are calculated using the heat inputs for calendar years 2001 and 2002, which are the same calendar years which were used to establish the baseline emission rate for SO_2 when combusting lignite coal. Baseline SO_2 emissions when combusting PRB coal assuming an SO_2 emission rate of 1.2 lb/million Btu are calculated as follows:

Heat input (2001) = 9.965×10^{12} Btu

Heat input (2002) = 1.075×10^{13} Btu

Average heat input = $(9.965 \times 10^{12} + 1.075 \times 10^{13}) / 2$
= 1.036×10^{13} Btu

Baseline SO_2 emission rate when combusting PRB coal
= 1.036×10^{13} Btu (1.2 lb/million Btu)(1 ton/2000 lb)
= <u>6,216 tons/year</u>

The control effectiveness of all remaining control technologies assuming an SO_2 emission rate of 1.2 lb/million Btu are shown in the following table.

Alternative	Control Efficiency (%)	Inlet Loading (tons/yr)	Controlled Emissions	
			(tons/yr)	(lb/10^6 Btu)
Wet Scrubber	95	6,216	311	0.06
Circulating Dry Scrubber	93	6,216	435	0.084
SD/FF	90	6,216	622	0.12
Flash Dryer Absorber	90	6,216	622	0.12
Wet Scrubber with 10% bypass	86	6,216	870	0.168
DSI/FF	55	6,216	2,797	0.54
DSI/ESP	35	6,216	4,040	0.78

The cost effectiveness and incremental costs for the various alternatives assuming an SO_2 emission rate of 1.2 lb/million Btu are shown in the following table.

Alternative	**Emissions Reduction (tons/yr)**	**Annualized Cost ($)***	**Cost Effectiveness($/ton)**	**Incremental Cost ($/ton)**
Wet Scrubber	5,905	13,180,000	2,232	6,302****
Circulating Dry Scrubber	5,781	14,220,000***	2,460	16,043
SD/FF	5,594	11,220,000	2,006	1,283**
Wet Scrubber with 10% bypass	5,346	9,490,000	1,775	550
DSI/FF	3,419	8,430,000	2,466	4,208
DSI/ESP	2,176	3,200,000	1,471	---

Note: Flash Dryer Absorber is not included since it costs more than a spray dryer with no additional emissions reduction.

* Costs provided by Great River Energy

** The incremental cost shown is the incremental cost of SD/FF compared to DSI/FF.

*** The cost is estimated based on costs included in the BART analysis for the Leland Olds Station.

**** The incremental cost shown is the incremental cost of a wet scrubber compared to SD/FF.

Given that a lower SO_2 emission rate of 0.64 lb/million Btu is possible in the future, baseline SO_2 emissions at this emission rate are calculated as follows:

Baseline SO_2 emission rate when combusting PRB coal
= 1.036 x 10^{13} Btu (0.64 lb/million Btu)(1 ton/2000 lb)
= <u>3,315 tons/year</u>

The control effectiveness of all remaining control technologies assuming an SO_2 emission rate of 0.64 lb/million Btu are shown in the following table.

Alternative	**Control Efficiency (%)**	**Inlet Loading (tons/yr)**	**Controlled Emissions**	
			(tons/yr)	**(lb/10^6 Btu)**
Wet Scrubber	95	3,315	166	0.032
Circulating Dry Scrubber	93	3,315	232	0.045
SD/FF	90	3,315	332	0.064

Alternative	**Control Efficiency (%)**	**Inlet Loading (tons/yr)**	**Controlled Emissions**	
			(tons/yr)	**($lb/10^6$ Btu)**
Flash Dryer Absorber	90	3,315	332	0.064
Wet Scrubber with 10% bypass	86	3,315	464	0.090
DSI/FF	55	3,315	1,492	0.288
DSI/ESP	35	2,215	2,155	0.416

The cost effectiveness and incremental costs for the various alternatives assuming an SO_2 emission rate of 0.64 lb/million Btu are shown in the following table.

Alternative	**Emissions Reduction (tons/yr)**	**Annualized Cost ($)***	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Wet Scrubber	3,149	13,180,000	4,185	11,807****
Circulating Dry Scrubber	3,083	14,220,000***	4,612	30,000
SD/FF	2,983	11,220,000	3,761	2,405**
Wet Scrubber with 10% bypass	2,851	9,490,000	3,329	1,031
DSI/FF	1,823	8,430,000	4,624	7,888
DSI/ESP	1,160	3,200,000	2,759	---

Note: Flash Dryer Absorber is not included since it costs more than a spray dryer with no additional emissions reduction.

* Costs provided by Great River Energy

** The incremental cost shown is the incremental cost of SD/FF compared to DSI/FF.

*** The cost is estimated based on costs included in the BART analysis for the Leland Olds Station.

**** The incremental cost shown is the incremental cost of a wet scrubber compared to SD/FF.

Step 4: Evaluate Impacts and Document Results

Great River Energy has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of any of the control equipment.

Step 5: Evaluate Visibility Results

The two primary alternatives are a wet scrubber operating at 95% removal efficiency and a spray dryer operating at 90% efficiency. The effects on visibility for each of these two control options at the Theodore Roosevelt National Park, South Unit (TRNP-SU), Theodore Roosevelt National Park, North Unit (TRNP-NU), Theodore Roosevelt National Park, Elkhorn Ranch (TRNP-Elkhorn Ranch) and the Lostwood Wilderness Area (Lostwood WA) were modeled when combusting lignite but not PRB. The degree of visibility improvement achieved by selecting a wet scrubber versus a spray dryer when combusting lignite does not exceed 0.028 deciviews (90th percentile) or 0.112 deciviews (98th percentile). The degree of incremental visibility improvement when combusting PRB is expected to be less than the incremental improvement when combusting lignite due to the lower SO_2 emission rates expected when combusting PRB.

Step 6: Select BART

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The incremental cost of greater than $16,000 per ton of SO_2 removed for a circulating dry scrubber compared to a spray dryer is considered excessive and a circulating dry scrubber is removed from further consideration as BART.

The unit has no existing air pollution control equipment for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. The degree of visibility improvement achieved by selecting a wet scrubber operating at 95% control efficiency versus a spray dryer operating at 90% control efficiency is expected to be minimal. Although the amount of visibility improvement achieved by selecting a wet scrubber versus a spray dryer is small, the Department has placed the primary emphasis on the cost of each option. The incremental cost from a spray dryer to a wet scrubber is $6,302 per ton of SO_2 removed (assuming an uncontrolled emission rate of 1.2 lb/million Btu) and $11,807 per ton of SO_2 removed (assuming an uncontrolled emission rate of 0.64 lb/million Btu). The Department does not consider the incremental cost of $6,302 per ton to be excessive but does consider the incremental cost of $11,807 per ton to be excessive. Wet scrubbing does have additional environmental impacts as outlined below:

- A wet scrubber is estimated by GRE to use as much as 20% more water or approximately 15 million gallons per year of additional water.
- It is assumed that a wet scrubber system will require additional on-site ponding. GRE has identified two potential areas on site that could be used for the additional ponding. The areas include the existing ash pile, which would have to be

excavated and moved, or the abandoned ash disposal area adjacent to the river, which reportedly has geotechnical deficiencies.

- Dry scrubbers are purported to achieve a higher mercury control efficiency on lignite and PRB as compared to a wet scrubber. In addition, future mercury control requirements could result in high concentrations of mercury in the ponds and prove problematic to discharge.

Based upon the additional environmental impacts and the fact that a wet scrubber will only remove at best an additional 311 tons/year of SO_2 (with a small corresponding visibility improvement) beyond the control achieved by a spray dryer, the Department proposes BART as a spray dryer with a fabric filter.

The calendar year average SO_2 emission rate used in the analysis is 1.2 lb/MM Btu when combusting PRB at Stanton Station Unit 1. As indicated previously, this is considered to be a reasonable estimate of the future annual average SO_2 emission rate when combusting PRB coal at Stanton Station Unit 1. Utilizing a 90% control efficiency for the spray dryer and fabric filter results in an annual average controlled SO_2 emission rate of approximately 0.12 lb/MM Btu. Based upon historical SO_2 emissions data for spray dryers and fabric filters at North Dakota facilities, the Department has determined that an increase of 33% is warranted to adjust from an annual average SO_2 emission rate to a 30-day rolling average SO_2 emission rate. Multiplying the annual average emission rate of 0.12 lb/MM Btu by a factor of 1.33 (an increase of 33%) yields a 30-day rolling average SO_2 emission rate of 0.16 lb/MM Btu. Therefore, BART for SO_2 when combusting PRB coal is an SO_2 emission limit of 0.16 lb/million Btu heat input on a 30 day rolling average basis or a reduction efficiency of 90% (on a 30-day rolling average basis) on the inlet SO_2 concentration to the pollution control equipment.

B. Filterable Particulate Matter

Section III.B. of this analysis proposes BART for filterable particulate matter (PM) when combusting lignite coal as no additional controls with an emission limit of 0.07 lb/million Btu heat input. Given that the available pollution control equipment is expected to control emissions from both lignite coal and PRB coal to similar expected emission rates, a BART analysis for filterable particulate matter when combusting PRB coal is expected to yield essentially the same results as the BART analysis for filterable PM when combusting lignite coal.

The Department has proposed BART for filterable PM when combusting lignite coal as no additional controls. The Department proposes that BART for filterable PM when combusting PRB coal is also no additional controls and proposes that BART is represented by an emission limit of 0.07 lb/million Btu (average of 3 test runs).

C. Condensible Particulate Matter (PM_{10})

Section III.C. of this analysis proposes BART for condensible particulate matter (PM) when combusting lignite coal is represented by sulfur dioxide control and good combustion control. For the same reasons outlined in Section III.C. for the selection of BART for condensible PM when combusting lignite coal, the Department proposes that the BART limit for sulfur dioxide when combusting PRB coal can act as a surrogate for condensible particulate matter along with a requirement for good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Low Temperature Oxidation (LTO)
Non Selective Catalytic Reduction (NSCR)
Electro-Catalytic Oxidation (ECO)
Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
Flue Gas Recirculation (FGR)
Overfire Air (OFA)
Low NO_x Burners (LNB)
Pahlman Process

Step 2: Eliminate Technically Infeasible Options

After significant review, it is the Department=s position that high-dust SCR for control of emissions from the combustion of North Dakota lignite at electric utility steam generating units is not technically feasible at this time (see discussion in Appendix B.5). Great River Energy has included a cost estimate for low-dust SCR, while high-dust SCR is listed as technically infeasible by GRE. Although high-dust SCR is considered technically feasible by the Department when combusting PRB coal, the fact that lignite coal will be allowed to be combusted in the future in Unit 1 does not allow for the installation of a high-dust SCR system; therefore, a high-dust SCR system remains technically infeasible for Unit 1.

ECO, NSCR and the Pahlman Process have not been demonstrated on a pulverized coal-fired boiler and are considered technically infeasible.

Rich reagent injection was developed for cyclone boilers and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Unit 1 since it is not a cyclone boiler.

Flue gas recirculation is not considered a technically feasible control option due to the space constraints at the facility. The space constraints do not allow for the additional ductwork and blower required to recirculate the flue gas.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Great River Energy calculated the baseline emission rate for NO_x when combusting PRB coal using an emission rate of 0.36 lb/million Btu (as compared to the baseline emission rate when burning lignite of 0.435 lb/million Btu), resulting in a baseline emission rate when combusting PRB coal of 1,740 tons/year. The Department=s estimated emissions using the various technologies would be as follows:

Alternative	**Control Efficiency (%)***	**Emissions**	
		(tons/yr)	**(lb/10^6 Btu)****
SCR with reheat	88	210	0.044
LTO	88	210	0.044
LNB + OFA + SNCR	45	946	0.196
SNCR	36	1,111	0.230
LNB + OFA	21	1,382	0.286
Baseline	---	1,740	0.36

* Control efficiencies calculated based upon the lb/million Btu emission rates provided by Great River Energy.

** Provided by Great River Energy.

The estimated costs for the various technologies are as follows:

Alternative	**Emissions Reduction (tpy)**	**Annualized Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
SCR with reheat	1,530	12,490,000	8,163	12,894*
LTO	1,530	44,780,000	29,268	60,842
LNB + OFA + SNCR	794	3,000,000	3,778	6,193**
SNCR	629	2,700,000	4,293	8,856
LNB + OFA	358	300,000	838	---
Baseline	1,740	---	---	---

* The incremental cost shown is the incremental cost of SCR with reheat as compared to LNB + OFA + SNCR.

** The incremental cost show is the incremental cost of LNB + OFA + SNCR as compared to LNB + OFA.

Step 4: Evaluate Impacts and Document Results

There are no energy or environmental impacts that would preclude the selection of any of the alternatives.

Step 5: Evaluate Visibility Impacts

The Department considers the incremental cost effectiveness of the top two alternatives to be excessive. Modeling has been conducted to estimate visibility impacts when combusting lignite but not PRB. When combusting lignite, the degree of visibility improvement achieved by selecting a low-NO_x burner plus over-fire air and SNCR over a low NO_x burner plus over-fire air was shown to be no greater than 0.027 deciviews (90th percentile) and 0.135 deciviews (98th percentile). The degree of incremental visibility improvement when combusting PRB is expected to be less than the incremental improvement when combusting lignite due to the lower NO_x emission rates expected when combusting PRB.

Step 6: Select BART

The Department considers the cost effectiveness and the incremental cost of the top two options to be excessive. The cost for the third option (LNB + OFA + SNCR) is not considered to be excessive. The Department proposes that BART is represented by low-NO_x burners (LNB) plus over-fire air (OFA) plus selective non-catalytic reduction (SNCR). The Department proposes that BART when combusting PRB coal is an emission limit of 0.23 lb/10^6 Btu on a 30-day rolling average basis.

V. BART Evaluation for Auxiliary Boiler

The auxiliary boiler is a #2 fuel-oil fired boiler with a nominal rating of 38 x 10^6 Btu/hr. The auxiliary boiler is only used when both units at the Stanton Station are down. During the baseline period (2000-2004), the unit was operated a total of 93 hours. The annual average emissions from the unit for this period were:

NO_x	0.14 tons
SO_2	0.36 tons
PM	0.02 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have a virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls. The current permit limits the fuel used in the boiler to #2 fuel oil. BART is the use of #2 fuel oil.

VI. BART Evaluation for Emergency Diesel Generator

The emergency diesel generator has a rated heat input of 10.35 million Btu/hr. The generator is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. Assuming 500 hours/year of operation, emissions from the unit would be as follows.

NO_x	8.0 tons
SO_2	1.3 tons
PM	0.2 tons

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VII. BART Evaluation for Emergency Fire Pump

The emergency fire pump is driven by a 370 horsepower diesel engine. The pump is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. Assuming a maximum of 500 hours of operation per year, emissions would be as follows:

NO_x	2.76 tons
SO_2	0.19 tons
PM	0.2 tons

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VIII. BART Evaluation for Materials Handling Sources

The materials handling sources at the Stanton Station that emit to the atmosphere are as follows:

EUI	Description	Existing Control Equipment	Current Emission Limit (lb/hr)	Baseline Emissions (tons/yr)
M1	Unit 1 Coal Bunker	Baghouse	5.0*	0.6**
M3	Unit 2 West bunker conveyor	Baghouse	5.0	18.3**

* The emission limit of 5.0 lb/hr is for combined emissions from the Unit 1 and Unit 10 coal bunkers.

** Department estimate.

The materials handling units are controlled using a baghouse which is considered the most efficient control device. Therefore, the Department proposes that BART for the materials handling units is no additional controls and the current emission limit for the units is BART.

IX. Summary

The proposed BART limits and the effect on emissions is shown in the following table.

Source Unit	**Proposed BART Limit/Work Practice**				**Emissions Reduction (tons/yr)**		
	PM	**SO_2**	**NO_x**	**Units**	**PM**	**SO_2**	**NO_x**
Unit 1 Boiler (lignite)	0.07	0.24	0.29	lb/10^6 Btu	0	7,715	983
Unit 1 Boiler (PRB)	0.07	0.16	0.23	lb/10^6 Btu	0	5,594	794
Auxiliary Boiler	Use #2 Fuel Oil			N/A	0	0	0
Emergency Diesel Generator	Use #2 Fuel Oil			N/A	0	0	0
Fire Pump	Use #2 Fuel Oil			N/A	0	0	0
M1	5.0	---	---	lb/hr	0	---	---
M3	5.0	---	---	lb/hr	0	---	---
Total (lignite)					0	7,715	983
Total (PRB)					0	5,594	794

The BART analyses for SO_2 and NO_x were conducted assuming 100% lignite combustion and 100% PRB coal combustion. Since the same technologies were chosen for both fuels, any BART analysis conducted assuming a blending of lignite and PRB coal would result in the choice of the same control technologies as BART. For this reason, separate BART analyses conducted assuming a blending of coals were not necessary and were not conducted. However, to account for the scenario when both lignite coal and subbituminous coal are burned together in a 30-day averaging period, SO_2 and NO_x emissions will be limited by a weighted average emission limit when burning a combination of lignite and subbituminous coal. It should be noted that lignite and PRB coal will likely only be burned in the same 30-day averaging period during a switch from one coal to another (i.e., fuel blending is not likely to occur on an extended basis).

The modeled visibility impacts of Unit 1 when combusting lignite coal are shown in the following tables. As can be seen from the tables below, the proposed BART limits will result in average modeled visibility improvements ranging from 69-75% in the Class I areas when combusting lignite coal. The overall average improvement (90th percentile) for all Class I areas is approximately 0.2 deciviews, which equates to a 73% improvement. The overall average improvement (98th percentile) for all Class I areas is approximately 0.8 deciviews, which equates to a 70% improvement.

Modeling was not conducted to determine the visibility impacts when combusting PRB coal; however, since the proposed BART limits are lower for PRB (when compared to lignite), the visibility improvement when combusting PRB coal is expected to be greater than the visibility improvement when combusting lignite.

Unit 1 - Lignite Coal Combustion
Delta Deciview
90th Percentile

Year	**Unit**	**Existing Impact**	**BART Controls**	**Difference**	**Percent Improvement**
2000	TRNP-SU	0.228	0.055	0.173	76
2001	TRNP-SU	0.214	0.054	0.160	75
2002	TRNP-SU	0.310	0.080	0.230	74
Average	*TRNP-SU*	*0.251*	*0.063*	*0.188*	*75*
2000	TRNP-NU	0.221	0.065	0.156	71
2001	TRNP-NU	0.319	0.073	0.246	77
2002	TRNP-NU	0.312	0.083	0.229	73
Average	*TRNP-NU*	*0.284*	*0.074*	*0.210*	*74*
2000	Elkhorn Ranch	0.184	0.049	0.135	73
2001	Elkhorn Ranch	0.144	0.034	0.110	76
2002	Elkhorn Ranch	0.233	0.060	0.173	74
Average	*Elkhorn Ranch*	*0.187*	*0.048*	*0.139*	*74*
2000	Lostwood W.A.	0.344	0.096	0.248	72
2001	Lostwood W.A.	0.386	0.133	0.253	66
2002	Lostwood W.A.	0.308	0.073	0.235	76
Average	*Lostwood W.A.*	*0.346*	*0.101*	*0.245*	*71*
Overall Average		**0.267**	**0.072**	**0.196**	**73**

Unit 1 - Lignite Coal Combustion
Delta Deciview
98th Percentile

Year	**Unit**	**Existing Impact**	**BART Controls**	**Difference**	**Percent Improvement**
2000	TRNP-SU	0.937	0.253	0.684	73
2001	TRNP-SU	0.901	0.261	0.640	71
2002	TRNP-SU	1.675	0.565	1.110	66
Average	*TRNP-SU*	*1.171*	*0.360*	*0.811*	*70*
2000	TRNP-NU	0.947	0.356	0.591	62
2001	TRNP-NU	1.205	0.318	0.887	74
2002	TRNP-NU	1.540	0.460	1.080	70
Average	*TRNP-NU*	*1.231*	*0.378*	*0.853*	*69*
2000	Elkhorn Ranch	0.868	0.215	0.653	75
2001	Elkhorn Ranch	0.733	0.203	0.530	72
2002	Elkhorn Ranch	1.432	0.426	1.006	70
Average	*Elkhorn Ranch*	*1.011*	*0.281*	*0.730*	*72*
2000	Lostwood W.A.	0.991	0.260	0.731	74
2001	Lostwood W.A.	1.351	0.422	0.929	69
2002	Lostwood W.A.	1.150	0.334	0.816	71
Average	*Lostwood W.A.*	*1.164*	*0.339*	*0.825*	*71*
Overall Average		**1.144**	**0.340**	**0.805**	**70**

X. Permit to Construct

The emission limits, monitoring, recordkeeping and reporting requirements will be included in a federally enforceable Air Pollution Control Permit to Construct that will be issued to the owner/operator of the facility. The Permit to Construct is included in Appendix D.

A. Monitoring

1. Monitoring for SO_2 and NO_x will be accomplished using the continuous emission monitors required by 40 CFR 75 for the Acid Rain Program. Monitoring for particulate matter shall be in accordance with 40 CFR 64, Compliance Assurance Monitoring. If the owner/operator of the BART-eligible unit chooses to comply with the SO_2 percent reduction requirements, monitoring of the SO_2 inlet rate loading to the scrubber shall be accomplished by either:

    a. A continuous emission monitor that complies with the requirements of 40 CFR 75; or

b. Coal sampling in accordance with Method 19 of 40 CFR 60, Appendix A plus development of an emission factor based on actual stack testing.

2. For purposes of determining compliance with the SO_2 reduction requirement, the reduction efficiency shall be determined as follows:

$$\%\ \text{Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate - Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where:

Inlet SO_2 Rate is in units of lb/10^6 Btu, lb/hr or ppmvd @ 3% O_2.

Outlet SO_2 Rate is in the same units as the inlet SO_2 rate.

B. Recordkeeping and Reporting

The owner/operator will be required to conduct recordkeeping and reporting as required by NDAC 33-15-14-06, Title V Permit to Operate and NDAC 33-15-21, Acid Rain Program (40 CFR 72, 75 and 76).

References

1. K-fuels website, 2007. www.evgenergy.com

2. EPA, 1995. Compilation of Air Pollutant Emission Factors Volume 1: Stationary Point and Area Sources. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.

3. Great River Energy, 2008. Stanton Station Unit 1 BART Analysis; Revised January 2008.

BART Determination
for
Milton R. Young Station Units 1 and 2

I. Source Description

A Owner Unit 1: Minnkota Power Cooperative, Inc.
B. Owner Unit 2: Square Butte Electric Cooperative
C. Operator Units 1 & 2: Minnkota Power Cooperative, Inc.
D. Source Type: Electric Utility Steam Generating Unit
E. BART Eligible Units

1. Unit 1 Boiler
2. Unit 2 Boiler
3. Auxiliary Boiler
4. Unit 1 Fire Pump
5. Unit 2 Fire Pump
6. Emergency Generator
7. Materials Handling Equipment
    a. Unit 1 - Crusher House and Conveyer 1C
    b. Unit 1 - Coal Silos
    c. Unit 2 - Crusher House
    d. Unit 2 - Coal Silos
    e. Unit 1 - Flyash Silo Vent
    f. Unit 1 - Flyash Silo (rotary unloader)
    g. Unit 2 - Flyash Silo Vent
    h. Unit 2 - Flyash Ash Silo (rotary unloader)
    i. Unit 1 - Truck Dump
    j. Unit 2 - Truck Dump
    k. Water Treatment Plant Lime Storage Silo

D. Unit Description

1. Unit 1:

Generator Nameplate Capacity: 257 MWe
Boiler Rating: 3200 x 10^6 Btu/hr
Startup: 1970
Fuel: North Dakota Lignite Firing Method: Cyclone
Existing Air Pollution Control Equipment: Electrostatic Precipitator

2. Unit 2:

   Generator Nameplate Capacity: 477 MWe
   Boiler Rating: 6300 x 10^6 Btu/hr
   Startup: 1975
   Fuel: North Dakota Lignite
   Firing Method: Cyclone
   Existing Air Pollution Control Equipment: Electrostatic precipitator and wet scrubber

3. Auxiliary Boiler:

   Boiler Rating: 78 x 10^6 Btu/hr
   Fuel: #1 or #2 fuel oil

4. Unit 1 Fire Pump:
   Rating: 237 Bhp

5. Unit 2 Fire Pump:
   Rating: 190 Bhp
   Fuel: Diesel fuel

6. Emergency Generator:
   Rating: 355 Bhp
   Fuel: Diesel fuel

7. Materials Handling Equipment:

   a. Unit 1 Crusher House and Conveyer 1C:
      Existing Air Pollution Control Equipment: Rotoclone

   b. Unit 1 Coal Silo:
      Existing Air Pollution Control Equipment: Rotoclone

   c. Unit 2 Crusher House:
      Existing Air Pollution Control Equipment: Rotoclone

   d. Unit 2 Coal Silos:
      Existing Air Pollution Control Equipment: Rotoclone

   e. Unit 1 Flyash Vent:
      Existing Air Pollution Control Equipment: Electrostatic Precipitator

f. Unit 1 Flyash Silo (rotary unloader):
Existing Air Pollution Control Equipment: None - fugitive emissions

g. Unit 2 Flyash Silo Vent:
Existing Air Pollution Control Equipment: Fabric Filter/Electrostatic Precipitator

h. Unit 2 Flyash Silo (rotary unloader)
Existing Air Pollution Control Equipment: None - fugitive emissions

i. Unit 1 Truck Dump:
Existing Air Pollution Control Equipment: None

j. Unit 2 Truck Dump:
Existing Air Pollution Control Equipment: None

k. Unit 2 Lime Storage Silo Vent:
Existing Air Pollution Control Equipment: Bin vent filter

E. Emissions

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Avg.**
Unit 1 Boiler	SO_2 (tons)	18,095	23,179	19,958	18,020	21,586	20,148
	SO_2 (lb/10^6 Btu)	1.91	2.00	1.85	1.77	1.87	1.88
	NO_x (tons)	7,584	9,220	8,459	8,325	9,738	8,665
	NO_x (lb/10^6 Btu)	0.80	0.78	0.79	0.82	0.84	0.81
	PM (tons)	213	238	205	330	103	218
	PM (lb/10^6 Btu)	0.023	0.021	0.019	0.032	0.009	0.021
Unit 2 Boiler	SO_2 (tons)	21,078	12,377	8,707	10,064	9,795	12,404
	SO_2 (lb/10^6 Btu)	0.98	0.78	0.49	0.52	0.58	0.67
	NO_x (tons)	17,727	13,287	14,278	14,578	13,655	14,705
	NO_x (lb/10^6 Btu)	0.84	0.83	0.81	0.77	0.81	0.81
	PM (tons)	164	131	385	1885	109	535
	PM (lb/10^6 Btu)	0.008	0.008	0.022	0.097	0.006	0.028

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Avg.**
Auxiliary Boiler	SO_2 (tons) NO_x (tons)	<2 <1	<2 <1	<2 <1	<2 <1	<2 <1	<2 <1
Unit 1 Fire Pump	SO_2 (tons) NO_x (tons)	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1
Unit 2 Fire Pump	SO_2 (tons) NO_x (tons)	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1
Emergency Generator	SO_2 (tons) NO_x (tons)	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1
Unit 1 Crusher House	PM (tons)	0.4	0.4	0.4	0.4	0.4	0.4
Unit 1 Coal Silo	PM (tons)	0.5	0.6	0.5	0.5	0.6	0.4
Unit 2 Crusher House	PM (tons)	0.2	0.1	0.1	0.1	0.1	0.1
Unit 2 Coal Silo	PM (tons)	2.4	2.0	2.4	2.3	2.0	2.2
Unit 2 Flyash Silo Vent	PM (tons)	<1	<1	<1	<1	<1	<1
Unit 1 Truck Dump	PM (tons)	10.0	11.1	10.6	8.9	11.2	10.4
Unit 2 Truck Dump	PM (tons)	20.4	16.7	20.1	19.8	17.1	18.8
Unit 2 Lime Storage Silo Vent	PM (tons)	<1	<1	<1	<1	<1	<1
Unit 1 Flyash Silo Vent	PM (tons)	<1	<1	<1	<1	<1	<1
Lime Storage Silo	PM (tons)	<1	<1	<1	<1	<1	<1

II. Site Characteristics

The M.R. Young Station is located in east central Oliver County near the town of Center, North Dakota. The facility receives its lignite from BNI Coal Ltd.'s Center Mine which is located immediately adjacent to the plant. The original design of Unit 1 only incorporated a multiclone for air pollution control, the electrostatic precipitator was added in the 1970s. Unit 2 was built with an electrostatic precipitator and a wet scrubber. Because of the original design and the close proximity to Nelson Lake, there are some space constraints at the facility. Minnkota has not indicated that the space constraints are insurmountable. Therefore, site constraints are an economic issue when evaluating the various control alternatives.

III. BART Evaluation of Unit 1

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Wet Scrubber
Spray Dryer
Circulating Dry Scrubber
Powerspan ECO®
Fuel Switching
Coal Cleaning

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located near Nelson Lake, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning.

K-Fuel® is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels® process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from the Center Mine was tested. The use of the K-Fuel® process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel® process available or technically and economically feasible.

A recent decision by the Seventh Circuit Court of Appeals on a BACT for Prairie Generating Company, LLC indicated that fuel switching was not required for mine mouth coal generating facilities. The Department believes the decision would also apply to BART determinations. Therefore, the Department did not consider coal switching.

The Department considers the Powerspan ECO® technology not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on the information provided by Minnkota Power Coop. in their Annual Emission Inventory Reports, the Department has calculated the baseline emission rate (2001-2002) at 21,519 tons per year.

Alternative	**Control Efficiency (%)**	**Baseline Emissions (tons/yr)**	**Emissions***	
			(tons/yr)	**(lb/106 Btu)**
Wet Scrubber	95	21,519	1,076	0.10
Circulating Dry Scrubber	93	21,519	1,506	0.14
Spray Dryer	90	21,519	2,152	0.20

* Emission rate (lb/10^6 Btu) is an annual average rate. Future coal is expected to have higher sulfur content and a higher emission rate.

The cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	**Emissions Reduction (tons/yr)**	**Annualized Cost ($)***	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Wet Scrubber	20,443	22,584,000	1,105	N/A
Circulating Dry Scrubber	20,013	24,650,000	1,232	N/A
Spray Dryer	19,367	23,676,000	1,222	N/A

* Costs for wet scrubber and spray dryer provided by Minnkota. Circulating Dry Scrubber costs are the Department's estimate based on costs provided by Basin Electric for Leland Olds Unit 2.

Step 4: Evaluate Impacts and Document Results

Minnkota has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of either a wet scrubber or spray dryer.

Step 5: Evaluate Visibility Results

The alternatives are a wet scrubber operating at 95% removal efficiency, a circulating dry scrubber at 93% control and a spray dryer operating at 90% efficiency. Minnkota has proposed to install a wet scrubber operating at 95% removal efficiency. Since this is the most efficient technology, an evaluation of the impact on visibility for each alternative was not necessary. However, Minnkota did evaluate the impact on visibility for the 95% and 90% control options. The results based on the 90th and 98th percentile value are shown in the following tables.

Unit 1
Delta Deciview
90th Percentile
SO_2

Year	Unit	90% Control	95% Control	Difference
2000	TRNP-SU	0.200	0.167	0.033
2001	TRNP-SU	0.302	0.095	0.207
2002	TRNP-SU	0.258	0.247	0.011
Average	TRNP-SU	0.253	0.170	0.084
2000	TRNP-NU	0.157	0.144	0.013
2001	TRNP-NU	0.419	0.117	0.302
2002	TRNP-NU	0.244	0.222	0.022
Average	TRNP-NU	0.273	0.161	0.112
2000	Elkhorn Ranch	0.122	0.109	0.013
2001	Elkhorn Ranch	0.209	0.068	0.141
2002	Elkhorn Ranch	0.155	0.148	0.007
Average	Elkhorn Ranch	0.162	0.108	0.054
2000	Lostwood W.A.	0.277	0.274	0.003
2001	Lostwood W.A.	0.488	0.280	0.208
2002	Lostwood W.A.	0.201	0.189	0.012
Average	Lostwood W.A.	0.322	0.248	0.074
Overall Average		0.253	0.172	0.081

Unit 1
Delta Deciview
98th Percentile
SO_2

Year	Unit	90% Control	95% Control	Difference
2000	TRNP-SU	0.594	0.583	0.011
2001	TRNP-SU	1.219	0.635	0.584
2002	TRNP-SU	1.768	1.694	0.074
Average	TRNP-SU	1.194	0.971	0.223
2000	TRNP-NU	1.097	0.762	0.335
2001	TRNP-NU	1.833	0.837	0.996
2002	TRNP-NU	1.594	1.522	0.072
Average	TRNP-NU	1.508	1.040	0.468
2000	Elkhorn Ranch	0.528	0.482	0.046
2001	Elkhorn Ranch	1.049	0.525	0.524
2002	Elkhorn Ranch	1.589	1.533	0.056
Average	Elkhorn Ranch	1.055	0.847	0.209
2000	Lostwood W.A.	0.870	0.820	0.050
2001	Lostwood W.A.	2.003	1.194	0.809
2002	Lostwood W.A.	0.899	0.839	0.060
Average	Lostwood W.A.	1.257	0.951	0.306
Overall Average		1.254	0.952	0.301

Step 6: Select BART

The cost effectiveness is reasonable for all technologies evaluated and the incremental cost from one technology to another is not excessive. There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The unit has no existing air pollution control equipment for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. Minnkota has proposed that BART is a wet scrubber operating at 95% control efficiency. The Department concurs with the use of a wet scrubber achieving a 95% reduction efficiency. Minnkota is a party to a Consent Decree which resolved alleged New Source Review violations at the M.R. Young Station. The Consent Decree states that if Minnkota installs a wet scrubber, they must comply with a 95% reduction requirement with no alternative emission rate (lb/10^6 Btu) limit. Therefore, the Department proposes that BART is a reduction efficiency of 95% of the inlet sulfur dioxide concentration to the scrubber on a 30-day rolling average basis (30 d.r.a.).

B. Filterable Particulate Matter

Step 1: Identify All Available Technologies

New Baghouse
New Electrostatic Precipitator
Compact Hybrid Particulate Collector (CoHPAC)
Existing Electrostatic Precipitator (Upgrade)

Step 2: Eliminate Technically Infeasible Options

All technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

The baseline emission rate from Unit 1 was calculated by the Department at 268 tons per year based on data for 2002-2003.

Alternative	**Control Efficiency**	**Emissions**	
		(tons/yr)	**(lb/10^6 Btu)**
Baghouse	99.7+	134	0.013
New ESP	99.7	158	0.015
CoHPAC	99.7	158	0.015
Baseline (Existing ESP)	99.0	268	0.026

Alternative	**Emissions* Reduction (tpy)**	**Annualized** Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Baghouse	134	5,284,000	39,433	37,545***
New ESP	90	4,643,000	51,589	N/A
CoHPAC	90	3,632,000	40,355	40,355
Baseline (Existing ESP)	0	1,822,000	---	

* Reductions from the baseline emission rate.
** Costs provided by Minnkota.
*** Incremental cost between baghouse and CoHPAC. New ESP is an inferior option since it costs more than CoHPAC with no additional emissions reductions.

Step 4: Evaluate Impacts and Document the Results

Minnkota has evaluated the energy and non-air quality effects of each option. The Department has determined that the effects will not preclude the selection of any of the options.

Step 5: Evaluate Visibility Impacts

The different alternatives were not modeled because of the high cost effectiveness. However, the maximum 24-hour emission rate during the baseline period was modeled. The results are as follows:

Unit 1 Delta Deciview PM			
Year	Unit	90th Percentile	98th Percentile
2000	TRNP-SU	0.0004	0.0015
2001	TRNP-SU	0.0006	0.0048
2002	TRNP-SU	0.0016	0.0023
Average	TRNP-SU	0.0007	0.0029
2000	TRNP-NU	0.0002	0.0004
2001	TRNP-NU	0.0011	0.0007
2002	TRNP-NU	0.0004	0.0059
Average	TRNP-NU	0.0006	0.0023
2000	TRNP-Elkhorn Ranch	0.0003	0.0010
2001	TRNP-Elkhorn Ranch	0.0002	0.0031
2002	TRNP-Elkhorn Ranch	0.0004	0.0020
Average	TRNP-Elkhorn Ranch	0.0003	0.0020
2000	Lostwood W. A.	0.0018	0.0007
2001	Lostwood W.A.	0.0013	0.0058
2002	Lostwood W. A.	0.0015	0.0007
Average	Lostwood W. A.	0.0015	0.0024
Overall Average		0.0013	0.0024

Step 6: Select BART

The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate emissions is the new baghouse. This system has a cost effectiveness of $39,433 per ton of particulate when compared to the current emission control system (ESP operating at 99.0% efficiency). The Department considers this cost to be excessive.

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The unit is equipped with an electrostatic precipitator that is achieving 99.0% Control efficiency. The plant is expected to have a remaining useful life of at least 20 years.

If all of the particulate emitted was eliminated, the most improvement in visibility at any Class I area would be approximately 0.0015 deciviews based on the 3-year average of the 90th percentile (0.0024 deciviews based on the 98th percentile). The Department considers this amount of improvement to be insignificant. Since none of the control alternatives will eliminate all of the particulate matter emissions, the visibility improvement will be even less.

After considering all of the factors, the Department proposes that BART for filterable particulate matter is no additional controls. Minnkota is under a Consent Decree which limits particulate emissions to 0.030 lb/10^6 Btu if they install a wet scrubber or 0.015 lb/10^6 if they install a dry scrubber with baghouse. Since Minnkota will install a wet scrubber, the Department proposes that BART is represented by an emission limit of 0.030 lb/10^6 Btu (average of 3 test runs).

C. Condensible Particulate Matter (PM_{10})

Condensible particulate matter is made up of both organic and inorganic substances. Organic condensible particulate matter will be made up of organic substances, such as volatile organic compounds, which are in a gaseous state through the air pollution control devices but will eventually turn to a solid or liquid state. The primary inorganic substance expected from the boiler is sulfuric acid mist, with lesser amounts of hydrogen fluoride and ammonium sulfate.

Since sulfuric acid mist is the largest component of condensible particulate matter, controlling it will control most of the condensible particulate matter. The options for controlling sulfuric acid mist are the same options for controlling sulfur dioxide (see Section III.A.). Previously, BART for sulfur dioxide was determined to be represented by a wet scrubber. This technology will achieve a 40-60% reduction as sulfuric acid mist emissions.

The control of volatile organic compounds at power plants is generally achieved through good combustion practices. The Department is not aware of any BACT determination at a power plant that resulted in any control technology being used. BACT has been found to be good combustion practices which are already in use since it minimizes the amount of fuel to generate electricity.

AP-42, Compilation of Air Pollutant Emission Factors[2], suggests the condensible particulate matter emission rate could be as high as 0.02 lb/10^6 Btu. This emission rate is less than the current emissions of filterable particulate matter. The emissions of filterable particulate matter were determined to have a negligible impact on visibility.

Having considered all the factors, the Department has determined that BART for condensible particulate matter is represented by good sulfur dioxide control and good combustion control. Since the primary constituent of condensible particulate matter is sulfuric acid mist which is controlled proportionately to the sulfur dioxide controlled, the BART limit for sulfur dioxide can act as a surrogate for condensible particulate matter along with good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO)
Selective Non-Catalytic Reduction (SNCR)
Hydrocarbon Enhanced SNCR (HE-SNCR)
Rich Reagent Injection (RRI)
Rotomix® (ROFA + SNCR)
Conventional Gas Reburn (CGR)
CGR + SNCR w/separated overfire air (SOFA)
Coal Reburn
Coal Reburn + SNCR
Fuel Lean Gas Reburn (FLGR™)
FLGR™ + SOFA
Rotating Overfire Air (ROFA)
Separated Overfire Air (SOFA)
Advanced SOFA (ASOFA)
Combustion Improvements (Included with SOFA and ASOFA)
Oxygen Enhanced Combustion (OEC)

Step 2: Eliminate Technically Infeasible Options

Minnkota believes SCR is not technically feasible at the M.R. Young Station. The Department does not consider high dust SCR to be technically feasible at this time. However, the Department believes low dust and tail end and SCR have a good probability of successful application at M.R. Young Station (see discussion in Appendix B.5). Minnkota has determined the following technologies are also technically infeasible:

ECO®
HE-SNCR
RRI
Rotomix® (ASOFA + SNCR evaluated)
CGR + SNCR
Coal Reburn + SNCR
FLGR™ + SNCR
OEC®

The Department agrees with Minnkota's determination regarding technical feasibility, except for LDSCR and TESCR. ROFA, SOFA, and ASOFA are similar and only ASOFA will be evaluated further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Alternative	Control Efficiency* (%)	Emissions (tons/yr)	Emissions ($lb/10^6$ Btu)
SCR w/reheat + ASOFA	90	903	0.085
SNCR + ASOFA	58.1	3,784	0.355
Gas Reburn + ASOFA	56.0	3,974	0.374
Coal Reburn + ASOFA	54.6	4,100	0.385
FLGR + ASOFA	45.9	4,886	0.460
ASOFA	39.5	5,464	0.513
SNCR	37	5,690	0.535
SOFA/ROFA	<28	6,503	0.611
Baseline	0	9,032	0.849

* Control efficiency specified by Minnkota in their analysis except for SCR. The Department believes a reduction effiency of 90% for ASOFA and SCR is more appropriate on a long-term basis.

** Based on the Department's calculation of baseline emissions. The $lb/10^6$ Btu emission rate is an annual average rate.

The estimated costs for the most efficient alternatives are as follows:

Alternative	Emissions Reduction (tpy)	Annualized Cost ($/ton)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Low Dust SCR + ASOFA	8,129	33,526,000/ 52,193,000	4,124/6,421	9,043/15,523
Tail End SCR + ASOFA*	8,129	39,307,000/ 56,095,000	4,835/6,901	11,050/16,877
SNCR + ASOFA	5,248	7,472,000	1,424	2,966***
Gas Reburn + ASOFA**	5,058	37,334,000	7,381	
Coal Reburn + ASOFA**	4,931	11,388,000	2,309	
FLGR + ASOFA	4,146	16,990,000	4,098	
ASOFA	3,568	2,489,000	698	

* Two different cost estimates are provided for SCR. This represents the range of costs provided by Minnkota for two different catalyst replacement scenarios and two different cost

bases – stand alone SCR systems for each unit and shared facilities.
** Inferior options to SNCR + ASOFA
*** Incremental cost for SNCR + ASOFA versus ASOFA

Minnkota has provided calculations of cost effectiveness and incremental cost effectiveness based on an NO_x removal efficiency of 93.8% and a baseline emission rate that is more reflective of potential emissions (the Department used 90% efficiency and historical data to calculate baseline emission rate). Minnkota used the most optimistic projections of efficiency and baseline emissions to show that LDSCR and TESCR are not cost effective even under those conditions. Minnkota's estimated costs are:

Alternative	**Emissions Reduction (tons)**	**Annualized Cost ($)***	**Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**
Low Dust SCR + ASOFA	9,348/9,401	33,526,000/ 52,193,000	3,586/5,552	7,575/12,806
Tail End SCR + ASOFA	9,345/9,398	39,307,000/ 56,095,000	4,206/5,969	9,264/13,936
SNCR + ASOFA	4,025	7,472,000	1,265	---
Coal Reburn + ASOFA	4,275	11,388,000	2,037	---
FLGR + ASOFA	4,343	16,990,000	3,635	---
ASOFA	5,260	2,489,000	613	---

*Range of costs using two different catalyst replacement schedules and two different cost bases – stand alone SCR systems and shared facilities between M.R. Young 1 and 2.

SCR technology has never been applied to a boiler that combusts North Dakota lignite. There are many unknowns that will affect the cost of either LDSCR or TESCR at the M.R. Young Station including:

1) The catalyst deactivation rate
2) Catalyst volume required
3) Catalyst surface area required
4) Required reagent injection rate
5) Expected reagent slip
6) Whether formation of ammonium bisulfate and/or ammonium sulfate will be at an acceptable rate
7) An appropriate catalyst maintenance plan

All of these will affect either the initial construction cost and/or annual operation and maintenance costs. The amount of catalyst required will affect the initial capital cost as well as the replacement cost. The life of the catalyst and the amount of reagent required will have a large impact on the annual operating cost. If a wet electrostatic precipitator is required to control ammonium bisulfate/ammonium sulfate emissions, both the initial capital cost and operation and maintenance costs will rise dramatically. Given the many unknowns with North Dakota lignite, estimating the cost of an SCR system is extremely difficult and subject to many different opinions regarding estimating procedures. The Department believes pilot scale testing would prove to be very beneficial in addressing the items of concern and provide a more detailed professionally reliable cost estimate; however, the BART process cannot mandate that pilot testing be conducted to determine costs. The Department believes the cost estimate without pilot testing, although not ideal, will suffice based on the information that is available at the current time.

Step 4: Evaluate Impacts and Document Results

Minnkota has not identified any environmental impacts or energy impacts that would preclude of the use of any of the previously evaluated emission control alternatives.

Step 5: Evaluate Visibility Impacts

The Department has conducted modeling to determine the improvement in visibility for SCR + ASOFA versus SNCR + ASOFA. The results, based on the BART modeling guidelines, are as follows:

Unit 1
Delta Deciview
90th Percentile

Year	**Unit**	**SCR + ASOFA**	**SNCR + ASOFA**	**Difference**
2000	TRNP-SU	0.032	0.094	0.062
2001	TRNP-SU	0.023	0.060	0.037
2002	TRNP-SU	0.044	0.118	0.074
Average	TRNP-SU	0.033	0.091	0.058
2000	TRNP-NU	0.025	0.068	0.043
2001	TRNP-NU	0.034	0.079	0.045
2002	TRNP-NU	0.046	0.131	0.085
Average	TRNP-NU	0.035	0.093	0.058
2000	Elkhorn Ranch	0.021	0.059	0.038
2001	Elkhorn Ranch	0.018	0.041	0.023
2002	Elkhorn Ranch	0.026	0.071	0.045
Average	Elkhorn Ranch	0.022	0.057	0.035
2000	Lostwood W.A.	0.045	0.139	0.094
2001	Lostwood W.A.	0.047	0.141	0.094
2002	Lostwood W.A.	0.037	0.102	0.065
Average	Lostwood W.A.	0.043	0.127	0.084
Overall Average		0.033	0.092	0.059

Unit 1 Delta Deciview 98th Percentile				
Year	**Unit**	**SCR + ASOFA**	**SNCR + ASOFA**	**Difference**
2000	TRNP-SU	0.098	0.265	0.167
2001	TRNP-SU	0.116	0.344	0.228
2002	TRNP-SU	0.294	0.847	0.553
Average	TRNP-SU	0.169	0.485	0.316
2000	TRNP-NU	0.118	0.342	0.224
2001	TRNP-NU	0.134	0.385	0.251
2002	TRNP-NU	0.263	0.734	0.471
Average	TRNP-NU	0.172	0.487	0.315
2000	Elkhorn Ranch	0.082	0.246	0.164
2001	Elkhorn Ranch	0.101	0.304	0.203
2002	Elkhorn Ranch	0.288	0.790	0.502
Average	Elkhorn Ranch	0.157	0.447	0.290
2000	Lostwood W.A.	0.134	0.421	0.287
2001	Lostwood W.A.	0.175	0.517	0.342
2002	Lostwood W.A.	0.148	0.435	0.287
Average	Lostwood W.A.	0.152	0.458	0.305
Overall Average		0.163	0.469	0.307

Step 6: Select BART

The cost effectiveness and incremental cost of LDSCR and TESCR is considered excessive or unreasonable. The visibility modeling results indicated only a 0.059 deciview (90th percentile) average improvement for SCR + ASOFA versus SNCR + ASOFA (0.307 deciviews based on 98th percentile). Because modeling based on the BART Guidelines (40 CFR 51, Appendix Y) overpredicts the visibility improvement in North Dakota (see Section 7.4.2), the Department conducted a modeling analysis to determine the amount of improvement when all sources are considered (cumulative analysis). The visibility will only improve 0.01 deciviews on average for the 20% worst days when SCR + ASOFA is compared to SNCR + ASOFA. The Department considers 0.01 deciviews improvement to be negligible.

The Department also considered the cost effectiveness and incremental costs of LDSCR and TESCR calculated by Minnkota. Both of these cost metrics are considered excessive over the entire range. The Department conducted dispersion modeling to determine the visibility improvement if SCR did achieve 93.8% reduction efficiency. The results indicate only a 0.011 deciview improvement in visibility on average for the 20% worst days when SCR + ASOFA is compared to SNCR + ASOFA. The amount of improvement is still negligible. Given the excessive cost and negligible visibility improvement, SCR + ASOFA is not considered BART for Unit 1.

Minnkota has proposed SNCR + ASOFA as BART. SNCR + ASOFA will achieve an emission rate of 0.355 lb/10^6 Btu on an annual average basis. The Department has determined that BART, during normal operations, is a limit of 0.36 lb/10^6 Btu on a 30-day rolling average basis.

Minnkota has requested a different limit during startup of the boiler. Minnkota's justification for the startup units is found in Section 3.5.2 of their BART analysis. Minnkota is under a Consent Decree which requires a BACT determination for nitrogen oxides. The Consent Decree (Paragraph 66) requires Minnkota to address specific limits during unit startups. Therefore, the proposed BACT and BART limit (which are identical) do not account for startups of the units. If it did, the proposed limit would be substantially higher. In order to harmonize the BACT limits with the BART limits, the Department is proposing separate BART emissions limits for NO_x during startup of Units 1 and 2.

The EPA Air Pollution Control Cost Manual[3] states "The NO_x reduction reaction occurs within a specific temperature range where adequate heat is available to drive the reaction. At lower temperatures the reaction kinetics are slow and ammonia passes through the boiler (ammonia slip). At higher temperatures the reagent oxidizes and additional NO_x is generated. The temperature window is dependent on the reagent utilized. Figure 1.3 shows the NO_x reduction efficiency for urea and ammonia SNCR at various boiler temperatures. For ammonia, the optimum temperature is from 870°C to 1100°C (1600°F to 2000°F)."

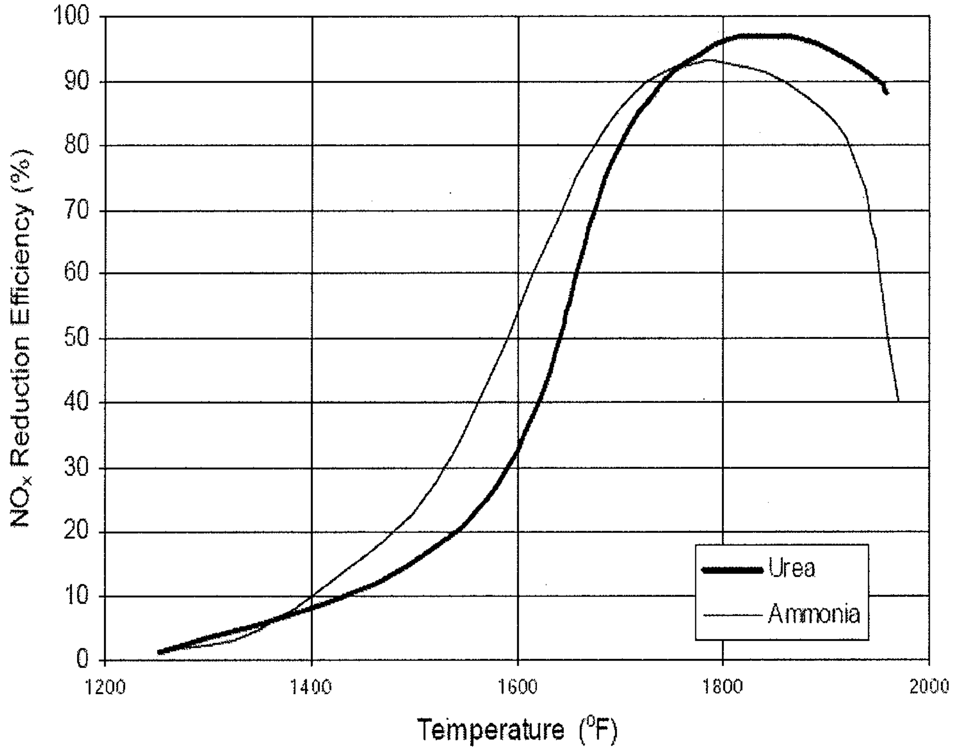

Figure 1.3: Effect of Temperature on NO_x Reduction

“ Flue gas temperature within the boiler depends on the boiler design and operating conditions. These are generally set to meet steam generation requirements and are not always ideal for the SNCR process. Flue gas temperatures in the upper furnace through the convective pass may vary by ±150°C (300°F) from one boiler to the next [1]. In addition, fluctuations in the boiler load profile affect the temperature within the boiler. At lower load profiles, the temperature within the boiler is lower. Variations in the flue gas temperature make the design and operation of an SNCR system more difficult.”

It is clear to the Department that startup of the boiler will affect the SNCR system and perhaps the overfire system also (see p. 3-42 to p. 3-42 of Minnkota’s BART analysis). Minnkota has stated that startup has lasted up to 61 hours (2.54 days) for Unit 1. Including 2.54 days of noncompliance within a 30-day rolling average emission rate calculation will make compliance extremely difficult. In recent PSD application reviews for power plants, the Department has found sufficient cause to provide alternative limits under BACT for periods of startup and shutdown. The State of Montana in the permit for the Highwood Generating Station, EPA Region 9 in the permit for the Desert Rock Energy Center and the State of Nebraska in the Ag Soy Processing plant permit also included alternative limits for NO_x during startup and shutdown.

Minnkota has recommended in the October 2006 BACT submittal an emission limit of 0.98 lb/10^6 Btu (24-hr rolling average) for periods of startup. This value is based on historical data for startups from 2001 - 2005. Based on a rated heat input of 3200 x 10^6 Btu/hr, this equates to 3136 lb/hr. The rated heat input will generally not be achieved during a startup and a lower emission limit for startup is warranted. Minnkota has proposed a reduced startup limit of 2070.2 lb/hr on a 24-hour rolling average basis (see November 11, 2007 submittal). The Department proposes that NO_x emissions be limited to 2070.2 lb/hr on a 24-hour rolling average basis during startup. The normal BART limit of 0.36 lb/10^6 Btu will apply during all other periods including malfunctions.

IV. BART Evaluation of Unit II

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

New Wet Scrubber
Spray Dryer
Circulating Dry Scrubber
Flash Dryer Absorber
Powerspan ECO®

Fuel Switching
Coal Cleaning
Upgrade Existing Scrubber

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located near Nelson lake, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning.

K-Fuel® is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels® process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Although Evergreen Energy indicates the technology has been tested on lignite, there is no indication that lignite from the Freedom Mine was tested. The use of the K-Fuel® process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel® process available or technically and economically feasible.

The Department considers the Powerspan ECO® technology not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	Control Efficiency (%)	Baseline Emissions (tons/yr)**	Emissions	
			(tons/yr)	($lb/10^6$ Btu)*
New Wet Scrubber	95	18,090	1,964	0.11
Upgrade Existing Scrubber	95	18,090	1,964	0.11
Circulating Dry Scrubber	93	18,090	2,749	0.16
Upgrade Existing	90	18,090	3,928	0.23

Alternative	Control Efficiency (%)	Baseline Emissions (tons/yr)**	Emissions	
			(tons/yr)	(lb/10^6 Btu)*
Scrubber				
Spray Dryer	90	18,090	3.928	0.23
Flash Dryer Absorber	90	18,090	3,928	0.23

* Annual average emission rate.
** Based on an annual average sulfur content of 0.93% and 2000-2001 operating data.

Unit 2 is equipped with a lime/flyash scrubber that achieved an average SO_2 reduction efficiency (inlet to outlet) of approximately 65% for the period 2000-2004. It is obvious that upgrading the existing scrubber to either 90% or 95% control efficiency will be the most cost effective alternative.

Alternative	Emissions Reduction (tpy)	Annualized Cost ($/ton)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Upgrade existing scrubber to 95%	16,126	8,414,000	522	550
Upgrade existing scrubber to 90%	14,162	7,333,000	518	N/A

Step 4: Evaluate Impacts and Document Results

Minnkota has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of any of the available options.

Step 5: Evaluate Visibility Results

The two primary alternatives are upgrading the existing scrubber to achieve a reduction efficiency of 90% or 95%. The effects on visibility shown below are based on Minnkota's estimate of SO_2 reductions.

Unit 2
Delta Deciview
90th Percentile
SO_2

Year	Unit	95% Reduction	90% Reduction	Difference
2000	TRNP-SU	0.317	0.340	0.023
2001	TRNP-SU	0.154	0.332	0.178
2002	TRNP-SU	0.442	0.497	0.055
Average	TRNP-SU	0.304	0.390	0.085
2000	TRNP-NU	0.241	0.257	0.016
2001	TRNP-NU	0.214	0.442	0.228
2002	TRNP-NU	0.359	0.419	0.051
Average	TRNP-NU	0.271	0.370	0.098
2000	Elkhorn Ranch	0.175	0.201	0.026
2001	Elkhorn Ranch	0.119	0.215	0.096
2002	Elkhorn Ranch	0.219	0.259	0.040
Average	Elkhorn Ranch	0.171	0.225	0.054
2000	Lostwood W.A.	0.421	0.494	0.073
2001	Lostwood W.A.	0.450	0.580	0130
2002	Lostwood W.A.	0.344	0.405	0.061
Average	Lostwood W.A.	0.405	0.493	0.081
Overall Average				0.081

Unit 2
Delta Deciview
98th Percentile
SO_2

Year	Unit	95% Reduction	90% Reduction	Difference
2000	TRNP-SU	1.096	1.159	0.063
2001	TRNP-SU	1.095	1.476	0.381
2002	TRNP-SU	2.876	3.080	0.204
Average	TRNP-SU	1.689	1.905	0.216
2000	TRNP-NU	1.199	1.332	0.133
2001	TRNP-NU	1.314	1.793	0.479
2002	TRNP-NU	2.464	2.666	0.202
Average	TRNP-NU	1.659	1.930	0.271
2000	Elkhorn Ranch	0.827	1.068	0.241
2001	Elkhorn Ranch	0.863	1.310	0.447
2002	Elkhorn Ranch	2.601	2.789	0.188
Average	Elkhorn Ranch	1.430	1.722	0.292
2000	Lostwood W.A.	1.311	1.443	0.132
2001	Lostwood W.A.	1.654	2.042	0.388
2002	Lostwood W.A.	1.343	1.486	0.143
Average	Lostwood W.A.	1.436	1.657	0.221
Overall Average				0.250

Step 6: Select BART

The Consent Decree that covers M.R. Young Station Unit 2 only requires 90% reduction of SO_2 emissions by the scrubber. Minnkota has proposed that BART is represented by improvements to the existing scrubber such that a 90% reduction efficiency will be achieved on a 30-day rolling average basis. Minnkota states that the costs associated with each alternative (90% or 95% reduction) are reasonable based on other regulatory analysis. The Department believes the costs are quite low and very reasonable. Minnkota has not identified any energy or non-air quality impacts that would preclude either alternative. Minnkota's choice of 90% reduction as BART is based on the visibility modeling results. The difference, according to Minnkota's results, indicate an average visibility impact reduction of only 0.082 deciviews based on the 90th percentile value (0.250 dv based on 98th percentile). However, the difference in visibility impact between the two alternatives will be as much as 0.228 deciviews based on the 90th percentile (0.479 deciviews based on 98th percentile) for year 2001 in TRNP-NU. Although the average visibility improvement is small, this factor must be considered with the other four factors.

The cost of upgrading the existing wet scrubber to achieve 95% control is very reasonable. There are no unacceptable energy and non-air quality environmental impacts, the remaining useful life is greater than 20 years, and there is a small degree of visibility improvement. The Department proposes that BART is represented by improvements to the existing wet scrubber which will achieve approximately 95% reduction in SO_2 emissions. BART is 95% reduction efficiency from the inlet of the scrubber to the outlet of the scrubber.

Data on future coal sulfur content was submitted by Minnkota in an April 18, 2007 response to comments (Table C.11). The core sample data indicates a maximum sulfur content of 5.6%, an average sulfur content of 0.93% and a standard deviation of 0.53%. Based on an average sulfur content of 0.93%, the uncontrolled emission rate would be approximately 2.26 lb/10^6 Btu. However, the unit will have to comply with the BART emission limit at all times on a 30-day rolling average basis. Adding one standard deviation to the average sulfur content yields a design sulfur content of 1.46% or an uncontrolled emission rate of 3.48 lb/10^6 Btu.

A scrubber operating at 95% removal efficiency will achieve an annual average emission rate of 0.11 lb/10^6 Btu based on average coal or 0.17 lb/10^6 Btu based on a design sulfur content of 1.46%. This is equivalent to approximately 0.15 lb/10^6 Btu to 0.23 lb/10^6 Btu on a 30-day rolling average basis. The existing scrubber is a mid 1970s design and maintaining 95% reduction continuously will be more difficult than with new designs that are 30 years more advanced. Because of the age of the scrubber and some uncertainty in the future coal sulfur content, the Department has determined that an alternative limit be incorporated into the BART limit. Minnkota has agreed to limit SO_2 emissions to no more than 0.15 $lb/10^6$ Btu. The Department has determined that BART is 95% reduction or 0.15 $lb/10^6$ Btu on a 30-day rolling average basis. This is the same as the presumptive BART level listed in 40 CFR 51, Appendix Y even though the unit is not subject to the presumptive level (i.e., plant is less than 750 MWe and existing SO_2 controls achieve greater than 50% efficiency). However, the Consent Decree requires a minimum of 90% reduction. This requirement will also be incorporated into the BART limit.

B. Filterable Particulate Matter (PM/PM_{10})

Step 1: Identify All Available Technologies

New Baghouse
New Electrostatic Precipitator
Compact Hybrid Particulate Collector (CoHPAC)
Existing Electrostatic Precipitator

Step 2: Eliminate Technically Infeasible Options

All technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	**Control Efficiency (%)**	**Emissions***	
		(tons/yr)	**($lb/10^6$ Btu)**
Baghouse	99.7+	248	0.013
New ESP	99.7	286	0.015
CoHPAC	99.7	286	0.015
Baseline (Existing ESP)	≈99.0	1,135	0.060

* Based on the Department's estimate of baseline emissions.

Alternative	**Emissions* Reduction (tpy)**	**Annualized** Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Baghouse	887	8,249,000	9,300	67,553***
New ESP	849	7,520,000	8,857	---
CoHPAC	849	5,682,000	6,693	9,472
Baseline (Existing ESP)	0	2,973,000	-	-

* Reductions from baseline emission rate.
** Costs provided by Minnkota.
*** Baghouse compared to CoHPAC.

Step 4: Evaluate Impacts and Document Results

Minnkota has evaluated the energy and non-air quality environmental impacts associated with each alternative and determined that these impacts would not prelude the selection of any of the alternatives as BART. The Department agrees with this determination.

Step 5: Evaluate Visibility Results

The different alternatives were not modeled because of the high cost effectiveness. However, the maximum 24-hour average emission rate from the baseline period was modeled. The results are as follows:

Unit 2
Delta Deciview
PM

Year	**Unit**	**90th Percentile**	**98th Percentile**
2000	TRNP-SU	0.0054	0.0151
2001	TRNP-SU	0.0037	0.0068
2002	TRNP-SU	0.0100	0.0090
Average	TRNP-SU	0.0064	0.0103
2000	TRNP-NU	0.0034	0.0024
2001	TRNP-NU	0.0042	0.0093
2002	TRNP-NU	0.0073	0.0106
Average	TRNP-NU	0.0050	0.0074
2000	Elkhorn Ranch	0.0013	0.0046
2001	Elkhorn Ranch	0.0006	0.0054
2002	Elkhorn Ranch	0.0005	0.0082
Average	Elkhorn Ranch	0.0008	0.0061
2000	Lostwood W.A.	0.0009	0.0032
2001	Lostwood W.A.	0.0040	0.0165
2002	Lostwood W.A.	0.0009	0.0123
Average	Lostwood W.A.	0.0019	0.0107
Overall Average		0.0035	0.0086

Step 6: Select BART

The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate matter emissions is CoHPAC, which has a cost effectiveness of $6,693 per ton. The Department considers this cost to be excessive. There are no energy or non-air quality impacts that would preclude the selection of any of the feasible control options.

The unit is equipped with an electrostatic precipitator that is achieving at least 99.0% control efficiency. The baseline emission rate is 0.06 lb/10^6 Btu; however, the average emission rate for this unit for 2000-2004 was 0.028 lb/10^6 Btu. The plant is expected to have a remaining useful life of at least 20 years.

If all of the particulate matter emitted was eliminated, the most improvement in visibility at any Class I area would be 0.0064 deciviews based on the 90th percentile (0.0103 deciviews based on 98th percentile). The Department considers this amount of improvement to be negligible. Since none of the control alternatives will eliminate all of the particulate matter emissions, the visibility improvement will even be less.

Minnkota is currently under a Consent Decree (CD) which limits particulate emissions to 0.030 lb/10^6 Btu. After considering all of the factors, the Department proposes that BART for filterable particulate matter is no additional controls. Since the CD requires a lower limit, the Department proposes that BART is represented by an emission limit of 0.030 lb/10^6 Btu (average of three test runs).

C. Condensible Particulate Matter (PM_{10})

See the discussion for Unit 1 in Section III.C. Any additional control technology for controlling condensible particulate matter will result in less than a 0.0064 deciview (90th percentile) improvement at any Class I area. The Department considers the use of a wet scrubber and good combustion practices to represent BART for condensible particulate matter from Unit 2. The BART limit for sulfur dioxide (95% reduction) and good combustion practices will act as a surrogate for condensible particulate matter.

D. Nitrogen Oxides

Introduction – See discussion in Appendix B.5 and Section III.D. The rationale will apply to Unit 2 that applies to Unit 1.

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO®)
Selective Non-Catalytic Reduction (SNCR)
Hydrocarbon Enhanced -SNCR with or without Advanced Separated Overfire Air (ASOFA)
Rich Reagent Injection (RRI) + SNCR + ASOFA

Rotomix® (ROFA + SNCR)
Conventional Gas Reburn plus SNCR (CGB + SNCR)
Coal Reburn
Coal Reburn + SNCR
Fuel Lean Gas Reburn (FLGR™)
FLGR™ + SOFA
SOFA or Advanced SOFA (ASOFA)
Rotating Overfire Air (ROFA)
Combustion Improvements (Included with ASOFA)
Oxygen Enhanced Combustion (OEC)

Step 2: Eliminate Technically Infeasible Options

Minnkota considers SCR to be technically infeasible at the M.R. Young Station. The Department does not consider high SCR to be technically feasible at this time. However, LDSCR and TESCR are considered technically feasible (see discussion in Appendix B.5 and III.D. of this analysis). Minnkota has determined the following technologies are also technically infeasible:

LDSCR
TESCR
ECO®
HE-SNCR
RRI
Rotomix® (ASOFA + SNCR evaluated)
CGR + SNCR
Coal Reburn + SNCR
FLGR™ + SNCR
OEC®

The Department agrees with Minnkota's determination regarding technical feasibility except for LDSCR and TESCR. ROFA, SOFA, and ASOFA are similar and only ASOFA will be evaluated further.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on the historic baseline emissions, the expected emissions are as follows:

Alternative	**Control Efficiency * (%)**	**Emissions****	
		(tons/yr)	**(lb/10^6 Btu)**
SCR w/reheat + ASOFA	90	1,551	0.079
SNCR + ASOFA	58.0	6,513	0.330
Gas Reburn +	55.4	6,916	0.350

Alternative	Control Efficiency * (%)	Emissions**	
		(tons/yr)	($lb/10^6$ Btu)
ASOFA			
Coal Reburn + ASOFA	54.2	7,102	0.360
FLGR + ASOFA	45.0	8,529	0.432
ASOFA	37.7	9,661	0.489
Baseline	---	15,507	---

*Control efficiency specified by Minnkota in their analysis except for SCR.
**Based on the Department's estimate of baseline emissions. The $lb/10^6$ Btu emission rate is an annual average rate.

The estimated costs for the most efficient alternatives are as follows:

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Low Dust SCR + ASOFA	13,956	57,351,000/ 89,072,000	4,109/ 6,382	9,260/ 15,652
Tail End SCR + ASOFA*	13,956	66,506,000/ 98,818,000	4,765/7,081	11,105/17,616
SNCR + ASOFA	8,994	11,405,000	1,268	N/A
Gas Reburn + ASOFA**	8,591	63,883,000	7,436	N/A
Coal Reburn + ASOFA**	8,405	19,475,000	2,317	N/A
FLGR + ASOFA	6,978	29,313,000	4,201	N/A
ASOFA	5,846	4,376,000	749	

* Two different estimates of cost are provided for SCR. These represent the range of costs provided by Minnkota based on two catalyst replacement scenarios and two cost bases – stand along SCR systems or shared facilities.
** Inferior options to SNCR + ASOFA

Minnkota has calculated the cost effectiveness and incremental cost effectiveness based on 93.8% removal efficiency and a baseline emission rate that is more reflective of potential emissions instead on historical emissions. This represents the costs under the most optimistic conditions. The Minnkota calculations are:

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($)*	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Low Dust SCR + ASOFA	14,862/14,980	57,351,000/ 89,072,000	3,859/5,946	8,331/13,812
Tail End SCR + ASOFA	14,857/14,980	66,506,000/ 98,818,000	4,477/6,597	10,007/15,550
SNCR + ASOFA	9,372	11,618,000	1,240	2,263
ASOFA	6,172	4,376,000	709	---

** Range of costs using two different catalyst replacement schedules and two different cost bases – standalone SCR systems and shared facilities between Unit 1 and 2.

Step 4: Evaluate Impacts and Document Results

Minnkota has not identified any environmental or energy impact that would preclude of the use of any of the previously evaluated emission control alternatives.

Step 5: Evaluate Visibility Impacts

The following tables show the visibility improvement of SCR + ASFOA versus SNCR + ASOFA.

Unit 2
Delta Deciview
90th Percentile
NO_x

Year	Unit	SCR + ASOFA	ASOFA+SNCR	Difference
2000	TRNP-SU	0.057	0.127	0.070
2001	TRNP-SU	0.047	0.066	0.019
2002	TRNP-SU	0.087	0.186	0.099
Average	TRNP-SU	0.064	0.126	0.063
2000	TRNP-NU	0.049	0.090	0.041
2001	TRNP-SU	0.061	0.098	0.037
2002	TRNP-SU	0.088	0.158	0.070
Average	TRNP-SU	0.066	0.115	0.049
2000	Elkhorn Ranch	0.040	0.069	0.029
2001	Elkhorn Ranch	0.030	0.056	0.026
2002	Elkhorn Ranch	0.049	0.096	0.047
Average	Elkhorn Ranch	0.040	0.074	0.034
2000	Lostwood W.A.	0.092	0.190	0.098
2001	Lostwood W.A.	0.087	0.193	0.096
2002	Lostwood W.A.	0.066	0.134	0.068
Average	Lostwood W.A.	0.082	0.169	0.087
Overall Average		0.063	0.121	0.058

Unit 2 Delta Deciview 98th Percentile NO_x				
Year	**Unit**	**SCR + ASOFA**	**ASOFA+SNCR**	**Difference**
2000	TRNP-SU	0.214	0.464	0.250
2001	TRNP-SU	0.225	0.498	0.273
2002	TRNP-SU	0.558	1.124	0.566
Average	TRNP-SU	0.332	0.695	0.363
2000	TRNP-NU	0.200	0.455	0.255
2001	TRNP-NU	0.259	0.556	0.297
2002	TRNP-NU	0.466	1.088	0.622
Average	TRNP-NU	0.308	0.700	0.391
2000	Elkhorn Ranch	0.163	0.425	0.262
2001	Elkhorn Ranch	0.197	0.429	0.232
2002	Elkhorn Ranch	0.432	1.025	0.593
Average	Elkhorn Ranch	0.264	0.626	0.362
2000	Lostwood W.A.	0.230	0.524	0.294
2001	Lostwood W.A.	0.336	0.636	0.320
2002	Lostwood W.A.	0.295	0.566	0.271
Average	Lostwood W.A.	0.287	0.582	0.295
Overall Average		0.298	0.651	0.353

Because the BART modeling guidance (40 CFR 61, Appendix Y) uses single source modeling, the modeling overpredicts the amount of improvement for North Dakota (see Section 7.4.2 of SIP). The Department has conducted modeling with all sources included in the inventory. The results of this modeling indicates that visibility at TRNP will only improve 0.02 deciviews on average for the 20% worst days when SCR + ASOFA is utilized versus SNCR + ASOFA. At LWA, the visibility will only improve 0.01 deciviews.

Step 6: Select BART

The cost effectiveness of SCR (LDSCR and TESCR) + ASOFA is considered excessive over the entire range of costs. The Department considers the incremental cost over the entire range of costs to be excessive for SCR + ASOFA when compared to SNCR + ASOFA. The BART type modeling predicts an average improvement of 0.058 deciviews based on the 90th percentile (0.353 deciviews based on the 98th percentile); but overpredicts the amount of improvement (see Section 7.4.2 of SIP). The Department's cumulative modeling predicts a 0.02 deciview improvement at TRNP and 0.01 deciview improvement at LWA for the most impaired days when compared to SNCR + ASOFA. There are no environmental or energy impacts that would preclude the selection of any of the control alternatives as BART and the unit is expected to have greater than a 20 year remaining life.

The Department has also considered the cost effectiveness and incremental costs provided by Minnkota. The costs calculated by Minnkota are also considered excessive. The Department also conducted modeling to determine the amount of visibility improvement if SCR did achieve 93.8% NO_x removal. The results indicated a 0.021 deciview improvement for SCR + ASOFA versus SNCR + ASOFA at TRNP and a 0.011 deciview improvement of LWA during the most impaired days.

Because of the excessive cost effectiveness and incremental cost and negligible visibility improvement, SCR + ASOFA is eliminated as a BART alternative. The Department has determined that BART is represented by SNCR + ASOFA. This technology will achieve an annual average emission rate of 0.33 lb/10^6 Btu. Based on a 30-day rolling average basis, an emission rate of 0.35 lb/10^6 Btu is achievable and is proposed as BART for normal operating conditions.

Minnkota has requested an alternative BART limit during startup. Minnkota's justification is found in Section 3.5.2 of their BART analysis. The Department believes an alternative limit is justified (see discussion in Section III.D. Step 6). Therefore, the Department proposes a limit of 3,995.6 lb/hr on a 24-hour rolling average basis during startup.

V. BART Evaluation for Auxiliary Boiler

The auxiliary boiler is a #1 or #2 fuel-oil fired boiler with a nominal rating of 78 x 10^6 Btu/hr. The auxiliary boiler is normally only used when both units at the M.R. Young Station are down. During cold weather, the auxiliary boiler may be used if one unit is off line. During the baseline period (2000-2004), the auxiliary boiler was operated approximately 100 hours per year. Based on the estimated 100 hours per year of operation, the annual emissions from the unit were:

NO_x	0.56 tons
SO_2	1.2 tons
PM	0.06 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls. The current permit limits the fuel used in the boiler to #1 or #2 fuel oil. BART is the use of #1 or #2 fuel oil.

VI. BART Evaluation for Emergency Fire Pump and Diesel Generator

The fire pumps and emergency generator are powered by diesel engines and are used for emergency purposes only. Most of the emissions generated are due to testing and maintenance activities. During the baseline period (2000-2004), the fire pumps operated approximately 1.2 hours per year and the emergency generator operated approximately 30 hours per year.

Based on this utilization the estimated annual emissions are as follows:

Pollutant	Unit 1 Fire Pump (tons/yr)	Unit 2 Fire Pump (tons/yr)	Emergency Generator (tons/yr)
NO_x	0.04	0.03	0.17
SO_2	0.003	0.002	0.01
PM	0.003	0.002	0.01

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VII. BART Evaluation for Materials Handling Sources

The materials handling sources at the M.R. Young Station that emit to the atmosphere are as follows:

EUI	**Description**	**Existing Control Equipment**	**Baseline Emissions (tons/yr)**
M1	Unit 1 crusher house and conveyor 1C	Rotoclone	0.4
M2	Unit 1 Coal Silos	Rotoclone	0.5
M3	Unit 2 Crusher House	Rotoclone	0.1
M4	Unit 2 Coal Silos	Rotoclone	2.2
M5	Unit 1 Flyash Silo	ESP	<1
M6	Unit 2 Flyash Silo	ESP	<1
M7	Unit 2 Lime Storage Silo	Bin Vent Filter	<1
M8	Unit 1 Truck Dump	None	10.4
M9	Unit 2 Truck Dump	None	18.8
M12	Lime Storage Silo	Baghouse	<1

Based on the small quantity emissions from the sources, it is apparent that no additional control equipment will be cost effective and will have very little impact on visibility in the Class I areas. Therefore, the Department proposes that BART for the materials handling units is no additional controls and the current emission limits for the units are BART.

VIII. Summary

	Proposed* BART Limit/Work Practice				Emissions Reduction** (tons/yr)		
Source Unit	**PM**	**SO_2**	**NO_x**	**Units**	**PM**	**SO_2**	**NO_x**
Unit 1 Boiler	0.030	95% reduction	0.36	lb/10^6 Btu	0	19,140	4,808
Unit 2 Boiler	0.030	0.15 and 90% reduction or 95% reduction	0.35	lb/10^6 Btu	0	9,665	8,313
Auxiliary Boiler	Use #2 Fuel Oil			N/A	0	0	0
Fire Pumps and Diesel Generator	Use low sulfur diesel fuel			N/A	0	0	0
M1	---	---	---	lb/hr	0	---	---
M2	---	---	---	lb/hr	0	---	---
M3	---	---	---	lb/hr	0	---	---
M4	---	---	---	lb/hr	0	---	---
M5	---	---	---	lb/hr	0	---	---
M6	---	---	---	lb/hr	0	---	---
M7	---	---	---	lb/hr	0	---	---
M8	---	---	---	lb/hr	0	---	---
M9	---C	---	---	lb/hr	0	---	---
Total						28,805	13,121

* Emission limits for PM are a 3-hour average. The limits for SO_2 and NO_x are on a 30-day rolling average basis.

** Reductions from 2000-2004 average emission rate.

IX. Permit to Construct

The emission limits, monitoring, recordkeeping and reporting requirements will be included in a federally enforceable Air Pollution Control Permit to Construct that will be issued to the owner/operator of the facility. The Permit to Construct is included in Appendix D.

A. Monitoring

1. Monitoring for SO_2 and NO_x will be accomplished using continuous emission monitors which are installed and maintained as required by 40 CFR 75.

Monitoring for particulate matter shall be in accordance with 40 CFR 64, Compliance Assurance Monitoring.

2. For purposes of determining compliance with the SO_2 reduction requirement, the reduction efficiency shall be determined as follows:

$$\% \text{ Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where:

Inlet SO_2 Rate is in units of lb/10^6 Btu.

Outlet SO_2 Rate is in the same units as the inlet SO_2 rate.

3. If Minnkota chooses to comply with the 95% reduction requirement at Unit 2, Minnkota may average the % reduction from Unit 1 and Unit 2 provided:

   A) The average reduction is at least 95% as determined in accordance with the following formula:

$$\text{Average ER} = \frac{[(ER_1)(HI_1)+(ER_2)(HI_2)]}{(HI_1 + HI_2)}$$

Where:

AER = Allowable Emission Rate (% reduction)
ER_1 = Actual Emission Rate (% reduction) of Unit 1 based on lb/10^6 Btu
ER_2 = Actual Emissions Rate (% reduction) of Unit 2 based on lb/10^6 Btu
HI_1 = Actual Heat Input (MMBtu) of Unit 1
HI_2 = Actual Heat Input (MMBtu) of Unit 2

Notes:
ER is a 30-day rolling average.
HI is a 30-day rolling average.
30-day rolling average is determined for the 30 successive boiler operating days (must be on a % reduction basis).

   B) The reduction by Unit 1 is at least 95%, and

   C) The reduction by Unit 2 is at least 90%.

B. Recordkeeping and Reporting

The owner/operator will be required to conduct recordkeeping and reporting as required by NDAC 33-15-14-06, Title V Permit to Operate and NDAC 33-15-21, Acid Rain Program (40 CFR 72, 75 and 76).

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Best Available Retrofit Technology

Selective Catalytic Reduction
Technical Feasibility Analysis

for

North Dakota Lignite

July 2009

Division of Air Quality
ND Department of Health
918 E. Divide Avenue
Bismarck, ND

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Attachment I - Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2

Part I: **High Dust SCR**

A. Technical Review

The SCR process is based on the chemical reduction of the NO_x molecule using a metal based catalyst with activated sites to increase the rate of the reduction reaction. A nitrogen based reducing agent (reagent), such as ammonia or urea, is injected into the post combustion flue gas. The reagent reacts selectively with the flue gas NO_x within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_x molecule into molecular nitrogen and water vapor.[2]

The BART Guidelines[1] state that in order for SCR to be technically feasible, it must be both "available" and "applicable". SCR has been applied to the many different types of coal throughout the world. Based on its widespread usage, it would initially appear to be available for use at North Dakota power plants.

The BART Guidelines[1] also state that decisions regarding technical feasibility are made by comparing the physical and chemical characteristics of the exhaust gas stream from the unit under review to those of the unit from which the technology is being transferred. Unless significant differences between the source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible. In order to compare the flue gas streams where SCR has been successfully applied to the flue gas from units burning North Dakota (Fort Union) lignite, a comparison of the fuel (coal) characteristics is necessary.

EPA's Air Pollution Control Cost Manual[2] states: "Certain fuel constituents which are released during combustion act as catalyst poisons. Catalyst poisons include calcium oxide and magnesium oxide, potassium, sodium, arsenic, chlorine, fluorine, and lead. These constituents deactivate the catalyst by diffusing into active pore sites and occupying them irreversibly. Catalyst poisoning represents the main cause of catalyst deactivation.

Ammonia-sulfur salts, fly ash, and other particulate matter in the flue gas cause blinding, plugging or fouling of the catalyst. The particulate matter deposits on the surface and in the active pore sites of the catalyst. This results in a decrease of the number of sites available for NO_x reduction and an increase in flue gas pressure loss across the catalyst.

Impingement of particulate matter and high interstitial gas velocities erode the catalyst material. Catalysts with hardened leading edges or increased structural strength are less susceptible to erosion. Increasing catalyst strength through hardening, however, reduces the number of active pore sites."

The most significant problem for the successful operation of SCR catalysts on units that fire North Dakota lignite is the formation of low temperature sodium-potassium-calcium-magnesium sulfates and phosphates. Sodium is a significant contributor to the "stickiness" of the ash produced from firing North Dakota lignite. The sodium content of North Dakota lignite ash ranges from 2-13% with an average of approximately 4% for lignite combusted in North Dakota power plants from 2002-2006. Powder River Basin (PRB) coal from Wyoming typically averages around 1.5% sodium[3].

A review was conducted to compare the constituents of fuels for which SCR has been successfully applied to that of North Dakota lignite. Data was obtained from the U.S. Geological Survey's U.S. Coal Quality Database[3]. The results are shown in Table 1.

Table 1
COAL CHARACTERISTICS
COMPARISON

	ND Lignite[a]	Texas Lignite[a]	Wyoming PRB[a]	PA Bituminous[a]
Avg. Heat Value (10^6 Btu/ton)	13.0[b]	15.2	17.0[c]	25.5
Avg. Ash Content	9.5[b]	12.6	5.0[c]	13.0
Avg. Na$_2$0 (% of Ash) Std. Deviation	3.60[b] 1.24[b]	0.54 0.58	1.58 1.26	0.28 0.20
Avg. Ca0 (% of Ash) Std. Deviation	15.44 6.45	13.18 5.16	17.31 7.39	1.69 1.64
Avg. Mg0 (% of Ash) Std. Deviation	5.47 2.04	2.28 1.05	3.82 2.12	0.64 0.34
Avg. K$_2$0 (% of Ash) Std. Deviation	0.49 0.44	0.52 0.31	0.53 0.42	1.87 0.77
Na$_2$0+Ca0+Mg0+K$_2$0 (% of Ash)	25.00	16.52	23.24	4.48

[a] Heating values, ash content and ash constituents from the USGS National Coal Database except as noted.

[b] From 2002-2006 Annual Emission Inventory Reports.

[c] From University of Wyoming.

In order to properly compare flue gas conditions, an estimate of the total emission rate of the deactivation (fouling and poisoning) constituents can be made. Although the catalyst deactivation rate may not be directly proportional to the emission rates of the various constituents, it does provide a means of comparison of the flue gas characteristics.

AP-42, Compilation of Air Pollutant Emission Factors[4], lists the following particulate matter emission factors as shown in Table 2.

Table 2 AP-42 EMISSION FACTORS		
Combustion Unit Type	**Fuel**	**Emission Factor**
Cyclone	Lignite	6.7A[a]
Cyclone	Bit./Subbit.	2.0A
Wall/Tangential	Bit./Subbit.	10.0A
Wall	Lignite	6.5A
Tangential	Lignite	5.1A

A = Ash content of the coal (%)

[a] 9.4A based on stack testing data from Minnkota Power Cooperative

To assess whether the flue gas characteristics at the North Dakota electric generating facilities are different from characteristics at other generating stations where SCR has been successfully applied, the emission rate, or loading, of the various deactivation constituents and the chemical form (organic or inorganic) of these constituents must be evaluated. Using the coal characteristics data from Table 1, the emission factors from Table 2, the emission rate of the deactivation constituents were calculated. Emphasis was given to the sodium oxide (Na_2O) emission rate because North Dakota lignite generally contains more Na_2O than bituminous or subbituminous coal. Since cyclone boilers firing North Dakota lignite partition the ash, the sodium is concentrated in the ash leaving the boiler. The results of the following calculation will underestimate the amount of sodium in the flue gas for a cyclone boiler firing North Dakota lignite; however, it does provide a conservative comparison. The results of the calculation are provided in Table 3:

Table 3
Emission Rate Comparison

	ND LIGNITE[a]	TEXAS LIGNITE[b]	WYOMING PRB[b]	PA BITUMINOUS[b]
Na_2O (% of Ash)	3.60	0.54	1.58	0.28
CaO (% of Ash)	15.44	13.18	17.31	1.69
MgO (% of ash)	5.47	2.28	3.82	0.64
K_2O (% of Ash)	0.49	0.52	0.53	1.87
$Na_2O+CaO+MgO+K_2O$	25.00	16.52	23.24	4.48
Ash Content	9.5	12.6	5.0	13.0
Heat Value (10^6 Btu/ton)	13.00	15.20	17.00	25.50
PM Emission Factor (lb/ton/1% Ash)[c,d]				
Cyclone Boiler	9.4	6.7	2.0	2.0
Wall/Tangentially-fired Boiler (Pulverized)	5.8	5.8	10.0	10.0
PM Emissions (lb/10^6 Btu)				
Cyclone Boiler	6.86	5.55	0.59	1.02
Wall/Tangentially-fired Boiler (Pulverized)	4.23	4.81	2.94	5.10
Na_2O Cyclone Boiler Emissions				
lb/ton	3.21	0.46	0.16	0.07
lb/10^6 Btu	0.2470	0.0300	0.0093	0.0029

Table 3
Emission Rate Comparison

	ND LIGNITE[a]	**TEXAS LIGNITE**[b]	**WYOMING PRB**[b]	**PA BITUMINOUS**[b]
lb/dscf	2.5054E-05	3.0417E-06	9.5032E-07	2.9191E-07
lb/wscf	2.0672E-05	2.5097E-06	8.7351E-07	2.6832E-07
Na_2O+CaO+MgO+K_2O Cyclone Boiler Emissions				
lb/ton	22.30	13.95	2.32	1.16
lb/10^6 Btu	1.72	0.92	0.14	0.05
lb/dscf	1.7399E-04	9.3054E-05	1.3978E-05	4.6706E-06
lb/wscf	1.4356E-04	7.6779E-05	1.2848E-05	4.2931E-06
Ratio of ND Lignite Cyclone Emissions to Other Cyclones				
Na_2O				
lb/ton		7.04	20.33	44.11
lb/10^6 Btu		8.24	26.58	86.53
lb/dscf		8.24	26.36	85.83
lb/wscf		8.24	23.67	77.04
Na_2O+CaO+MgO+K_2O				
lb/ton		1.60	9.60	19.15
lb/10^6 Btu		1.87	12.55	37.56
lb/dscf		1.87	12.45	37.25
lb/wscf		1.87	11.17	33.44
Comparison of ND Lignite Cyclone Emissions to Pulverized Units				
Na_2O Emissions				
lb/ton	3.21	0.39	0.79	0.36

Table 3
Emission Rate Comparison

	ND LIGNITE[a]	**TEXAS LIGNITE[b]**	**WYOMING PRB[b]**	**PA BITUMINOUS[b]**
lb/10^6 Btu	0.2470	0.0260	0.0465	0.0143
lb/dscf	2.5054E-05	2.6331E-06	4.7516E-06	1.4596E-06
lb/wscf	2.0672E-05	2.1726E-06	4.3675E-06	1.3416E-06
$Na_2O+CaO+MgO+K_2O$ Emissions				
lb/ton	22.30	12.07	11.62	5.82
lb/10^6 Btu	1.7155	0.7943	0.6835	0.2284
lb/dscf	1.7399E-04	8.0554E-05	6.9891E-05	2.3353E-05
lb/wscf	1.4356E-04	6.6466E-05	6.42415E-05	2.14654E-05
Ratio ND Lignite Cyclone Emissions to Pulverized Units				
Na_2O				
lb/ton		8.14	4.07	8.82
lb/10^6 Btu		9.51	5.32	17.31
lb/dscf		9.51	5.27	17.17
lb/wscf		9.51	4.73	15.41
$Na_2O+CaO+MgO+K_2O$				
lb/ton		1.85	1.92	3.83
lb/10^6 Btu		2.16	2.51	7.51
lb/dscf		2.16	2.49	7.45
lb/wscf		2.16	2.23	6.69
Comparison of ND Pulverized Units to Other Pulverized Units				
Na_2O Emissions				
lb/ton	1.981512	0.394632	0.79	0.364
lb/10^6 Btu	0.152424	0.025962632	0.046470588	0.01427451

Table 3
Emission Rate Comparison

	ND LIGNITE[a]	**TEXAS LIGNITE[b]**	**WYOMING PRB[b]**	**PA BITUMINOUS[b]**
lb/dscf	1.54588E-05	2.63313E-06	4.7516E-06	1.4596E-06
lb/wscf	1.27551E-05	2.17261E-06	4.3675E-06	1.3416E-06
$Na_2O+CaO+MgO+K_2O$ Emissions				
lb/ton	13.7605	12.072816	11.62	5.824
lb/10^6 Btu	1.0585	0.7943	0.6835	0.2284
lb/dscf	1.073529E-04	8.0554E-05	6.9891E-05	2.3353E-05
lb/wscf	8.85774E-05	6.6466E-05	6.42415E-05	2.14654E-05
Ratio ND Pulverized Unit Emissions to Other Pulverized Units				
Na_2O		5.02	2.51	5.44
lb/ton		5.87	3.28	10.68
lb/10^6 Btu		5.87	3.25	10.59
lb/dscf		5.87	2.92	9.51
lb/wscf				
$Na_2O+CaO+MgO+K_2O$				
lb/ton		1.14	1.18	2.36
lb/10^6 Btu		1.33	1.55	4.63
lb/dscf		1.33	1.54	4.60
lb/wscf		1.33	1.38	4.13

[a] Source: Annual Emission Inventory Reports 2002-2006 (weighted average).

[b] Source: USGS National Coal Database and University of Wyoming.

[c] Source: AP-42, Compilation of Air Pollutant Emission Factors except for cyclone units burning ND lignite; factor is based on stack test data.

[d] Emission factor for wall-fired and tangentially fired units combusting lignite is the average of the AP-42 emissions factors.

The most useful emission rate calculation is that in terms of pounds per wet standard cubic foot (lb/wscf). This estimated emission rate represents the actual concentration of the constituents in the ductwork leaving the boiler at standard temperature and pressure. However, most laboratory and pilot scale testing report the results in lb/dscf or mg/Nm^3. Table 3 shows that the potential for deactivation of the SCR catalyst is much greater for a boiler combusting North Dakota lignite.

The Energy & Environmental Research Center (EERC) at the University of North Dakota is recognized as one of the world's leading coal research facilities. Since 1951, the EERC has focused on research and development, technology demonstration and technology commercialization. As part of the BART assessment for Minnkota Power Cooperative and Basin Electric Power Cooperative, a report by the EERC titled Ash Impacts on SCR Catalyst Performance[5] was included. In that report, it is stated: "The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be plagued with problems." The report further states: "Alkali and alkaline earth sulfates are enhanced by cyclone-fired systems. The cyclone firing results in partitioning of the ash between bottom slag and the body of the boiler. The sulfate forming materials are more concentrated in the fly ash as a result of cyclone firing."

In reviewing the flue gas characteristics of plants firing coal types where SCR has been applied with those firing North Dakota lignite, it appears comparison of the characteristics for cyclone fired units combusting North Dakota lignite to cyclone units firing other types of coal alone is more appropriate because of the enhanced sulfates formation in cyclone units. Likewise, it is appropriate to compare pulverized lignite fired units to pulverized units firing different types of coal. The Department's review indicates that the sodium oxide loading in the flue gas for the North Dakota lignite-fired unit would be nearly 24 times (on a lb/wscf basis) that of a cyclone unit burning PRB subbituminous coal. This ratio is actually conservative (expected to higher) because of the partitioning of the ash that occurs in a cyclone boiler firing North Dakota lignite. The estimated combined loading of catalyst deactivation constituents sodium oxide, calcium oxide, magnesium oxide and potassium oxide is more than eleven times that of PRB subbituminous coal-fired cyclone units. For pulverized units, a unit firing North Dakota lignite is expected to emit three times as much sodium oxide as a unit firing PRB subbituminous coal. Although the deactivation of the SCR catalyst may not be directly proportional to the emission rate, it is evident that the concentration of various SCR deactivation chemical constituents in the flue gas of a North Dakota lignite-fired power plant is much different from a unit firing PRB subbituminous coal or other types of coal.

Gutberlet[6] in his technical paper on deactivation of SCR catalyst states: "Alkaline metals chemically attach to active catalyst pore sites and cause blinding. Sodium (Na) and potassium (K) are of prime concern especially in their water soluble forms which are mobile and penetrate into the catalyst pores." Minnkota, in its March 19, 2007 response to questions indicates that most sodium in North Dakota lignite is organically associated. Combustion of the organically associated sodium produces soluble sodium compounds that are readily available for reactions with catalysts and flue gas species. Minnkota also stated that in a conversation with Fleming Hansen of Haldor Topsoe (see Minnkota's November 9, 2007 response to comments[10]), Mr. Hansen indicated that sodium was a major concern and that it causes deactivation, especially in the organically associated form. It is evident to the Department that the form (soluble) of sodium present in the ash from the combustion of North Dakota lignite will deactivate an SCR much more quickly than the other types of coals where SCR has been successful.

The next issue to address is whether the difference in these characteristics would preclude the successful use or reasonable operation of SCR technology on units fired on North Dakota lignite.

The BART Guidelines[1] state: "In Step 2, you evaluate the technical feasibility of the control options you identified in Step 1. You should document a demonstration of technical infeasibility and should explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option on the emissions unit under review." "An available technology is applicable if it can reasonably be installed and operated on the source type under consideration." The BART Guideline[1] does not define successful use of the control option or reasonably be installed and operated.

The EERC, several utilities and catalyst vendors conducted pilot scale testing at the Coyote Station, which is a cyclone fired unit that combusts North Dakota lignite. The pilot scale SCR deployed at the Coyote Station was plugged and the catalyst pores deactivated after 2 months (approx. 1430 hours). The Department believes "successful use or reasonably operated" is considerably more than a few thousand hours of operation. For example, the EPA Air Pollution Control Cost Manual[2] states: "For coal-fired boiler applications, SCR catalyst vendors typically guarantee that catalyst for an operating life ranging between 10,000 hours to 30,000 hours." In the technical paper Nitrogen Oxides Emission Control Options for Coal Fired Electric Utility Boilers,[9] it is stated: "On dry-bottom, coal-fired U.S. boilers equipped with full SCR, the planned time between catalyst changes on a typical unit is typically > 24,000 operating hours or ≥ 3 years of operations." The paper also indicated that Merrimack 2, a cyclone boiler with 100% flyash reinjection, the expected time between the replacement of layers is 14,000 operating hours. It appears that 10,000 hours of operation would be a minimum time for successful use or reasonable operation.

Pritchard[7] states in his paper on optimizing SCR catalyst design: "Our experience show that coal-fired SCRs are successful when the system impact and catalyst deterioration factors are understood and specific counter measures are implemented in system and catalyst design." The Coyote pilot test may not have provided much useful data for designing an SCR system for plants firing North Dakota lignite; however, it did indicate a difference between lignite and subbituminous coal. The pilot scale testing protocol was the same for the Coyote Station, Columbia Station and Baldwin Station; however, the test at the Columbia Station used a different catalyst. The Coyote Station combusts lignite while the Columbia Station and Baldwin Station fire subbituminous coal. The EERC has described the blinding and plugging (deactivation) at the Coyote Station as extremely rapid and severe as compared to testing at the Columbia and Baldwin Stations. This indicates to the Department that design of an SCR system for North Dakota lignite would be different from a unit burning subbituminous coal. Because of the lack of deactivation data from the pilot test at the Coyote Station, it would appear to be extremely difficult to design an SCR system that could be successfully used or reasonably operated. Proceeding with installation of such a design without engineering data collected during appropriate pilot testing is subject to an extreme risk. This suggests to the Department that additional research and testing on the effects of the flue gas constituents are required to design a high dust SCR system.

Kling et. al.[11] conducted pilot and bench sale testing of SCR catalysts when subjected to the flue gas from the combustion of biomass. The testing was conducted using three different types of catalyst. Catalyst Type A was typical of that use for coal-fired boilers, Type B was a "bio-optimized" catalyst with an increased vanadium content and Type C has a very high vanadium content. Kling[11] and later Zheng et. al[12] have concluded that it is the alkali aerosols that are less than or equal to 0.1 micrometers that cause most of the catalyst deactivation. In North Dakota lignite, the alkali metals are generally associated with the organic matter of the lignite while in other coals the alkaline constituents are associated with the inorganic portion of the coal (e.g. clays). The combustion of the organically associated alkaline elements causes them to vaporize; when they condense they form submicron aerosols. The combustion of inorganically associated alkalis causes only a small portion to vaporize. Minnkota has supplied information that indicates these condensed alkali aerosols have a mass mean diameter of approximately 0.1 micrometers. Therefore, 50% of the aerosols would be less than 0.1 micrometers in size on a mass basis. The mass of sodium oxide and potassium oxide leaving a pulverized boiler combusting North Dakota lignite would average 1.55×10^{-5} lb/dscf (266 mg/Nm^3) and 2.11×10^{-6} lb/dscf (36 mg/Nm^3), respectively. This value would be higher for cyclone boilers (431 and 59 mg/Nm^3 respectively).

Crespi[13] has provided data that suggests potassium oxide is approximately twice as potent catalyst deactivation chemical on a molar basis (1.3 times on a mass basis) than sodium oxide. The equivalent potassium oxide emission rate for a pulverized boiler based on this data would be 241 mg/Nm^3. The aerosols are most likely in the sulfate form. This would lead to an equivalent potassium sulfate emission rate of 446 mg/Nm^3.

Kling[11] found a deactivation rate of 21-52% over 1500 hours for fuel made up of tree bark and 30% demolition wood waste. This fuel had a potassium chloride loading of 16.7 mg/Nm^3 and a sodium chloride loading of 5.8 mg/Nm^3. The Kling results were for aerosols with an aerodynamic diameter of less than 0.1 micrometers. If all of the sodium and potassium in lignite vaporizes, 50% of the total loading would be less than or equal to 0.1 micrometers or 223 mg/Nm^3 for a pulverized unit. Zheng[12] has suggested that potassium chloride is two and one half times more potent catalyst poison than potassium sulfate (0.4% per day versus 1% per day). An equivalent loading of sodium and potassium for North Dakota lignite as potassium chloride would be 89 mg/Nm^3. This loading is more than four times that of the Kling[11] testing. For a cyclone boiler it would be approximately seven times as much loading. The Kling[11] results suggest 2,885-7,140 hours until 100% deactivation. The higher loading at the North Dakota facilities suggests a much shorter catalyst life.

Zheng et. al.[11] found a catalyst deactivation rate of 0.4% per day for a potassium sulfate. The testing was conducted using a concentration of 20-30 mg/Nm^3 of potassium sulfate with a mass mean diameter of 0.55 micrometers. Although data is not available to determine the loading of aerosols with a diameter less than 0.55 micrometers for all boilers burning North Dakota lignite, a comparison to the fraction less than 0.1 micrometers indicates a concentration is 7-11 times larger than the concentration in Zheng's tests. The 0.4% deactivation rate per day is equivalent to 6000 hours at 100% deactivation. Flue gas from the combustion of North Dakota lignite in a pulverized boiler would likely produce a much higher deactivation rate. A cyclone boiler would probably deactivate an SCR catalyst even faster.

The recent testing by Kling[11] and Zheng[12] indicate that it is unlikely to achieve 10,000 hours of catalyst life when combusting North Dakota lignite. In fact, the catalyst life could be only a few thousand hours as suggested by the pilot scale testing at the Coyote Station.

Besides catalyst deactivation, a high-dust SCR would experience plugging problems due to ash deposition and the carryover of "popcorn ash" from the boiler. Ash deposition is a problem for all units firing North Dakota lignite. Sodium is a significant contributor to the "stickiness" of the ash. Since the ash of North Dakota lignite contains much more sodium than other types of coal where SCR has been applied, deposition problems will be greatly increased. Since this sticky ash is not easily removed, the catalyst life could be severely reduced.

The flue gas temperature variation at the location a high dust SCR would be placed is also a concern for cyclone units. Minnkota indicates that the temperature generally ranges from approximately 430°F to 960°F for Unit 1 depending on the unit's load. For Unit 2, it could vary from 430-880°F. However, temperatures as high as 1050°F at Unit 1 and 990°F at Unit 2 have been measured. Basin Electric has indicated that the Unit 2 temperature can be significantly higher than 750°F.

The <u>EPA Air Pollution Control Cost Manual</u>[2] states:
"The NO_x reduction reaction is effective only within a given temperature range. The use of a catalyst in the SCR process lowers the temperature range required to maximize the NO_x reduction reaction. At temperatures below the specified range, the reaction kinetics decrease and ammonia passes through the boiler (ammonia slip). At temperatures above the specified range, nitrous oxide (N_2O) forms and catalyst sintering and deactivation occurs.

In an SCR system, the optimum temperature depends on both the type of catalyst utilized in the process and the flue gas composition. For the majority of commercial catalysts (metal oxides), the optimum temperatures for the SCR process range from 480°F to 800°F (250°C to 427°C). The figure shows that the rate of the NO_x removal increases with temperatures up to a maximum between 700°F to 750°F (370°C to 400°C)" (figure omitted here).

The Control Cost Manual[2] goes on to state: "The relationships between flue gas temperature, catalyst volume, and NO_x removal are complicated functions of the catalyst formulation and configuration. The physical and chemical properties of each catalyst are optimized for different operating conditions. For a given catalyst formulation, the required catalyst volume and/or temperature range can even change from one manufacturer of the catalyst to another. The selection of catalyst, therefore, is critical to the operation and performance of the SCR system."

This complicated relationship suggests that additional research, design and testing may be required before the temperature problem could be overcome for cyclone units.

The final reason for technical infeasibility is erosion of the catalyst. Because of the high ash content and frequent cleaning cycles due to the deposition characteristics of North Dakota lignite ash, erosion may be more of a concern than with a bituminous or subbituminous coal-fired unit.

The BART assessments for Minnkota and Basin Electric were prepared by Burns and McDonnell, which has considerable experience with SCR systems, and the EERC, which has extensive experience with North Dakota lignite. Sargent and Lundy, LLC (S&L), another consulting firm acting on behalf of Basin Electric Power Cooperative, also made two presentations to the Department on the application of SCR technology to North Dakota lignite. S&L indicated it had designed 46% of the SCR systems in the United States. Of the SCR systems, 39 were for coal-fired units with 10 designed for Powder River Basin subbituminous coal. S&L listed[8] their "Keys to Achieving Success" as:

- Understand deactivation mechanisms
- Understand ash behavior
- The "Understanding" establishes:
  - Catalyst formulation
  - Catalyst pitch
  - Reactor velocity
  - Catalyst surface and volume
- Results in reactor size and shape to match catalyst management plan
- Physical model for:
  - NH_3 and NO_x mixing
  - Gas distribution and velocity profile
- CFD modeling:
  - Identify and mitigate areas of potential ash deposits
  - Mixing gases of different temperatures

S&L also provided possible solutions for deactivation of the catalyst. However, they indicated there was no known solution for deactivation due to soluble alkalis such as the soluble sodium compounds generated by the combustion of North Dakota lignite. S&L speculated that more catalyst and a larger reactor may be possible solutions; however, how much more catalyst or how much larger the reactor would have to be to solve the problem was unknown. S&L also pointed out that some design issues for North Dakota have not been addressed by Powder River Basin experience. Some of these issues include:

- The high level of soluble alkali in North Dakota lignite
- The particle size and sticky nature of high alkaline North Dakota lignite
- Potential abrasive qualities of North Dakota lignite ash

S&L concluded their presentation with the following statement about North Dakota lignite: "There are attributes of this fuel in an SCR environment that are not well understood today and need more investigation to predict its performance." S&L recommendations included a parametric pilot test program to:

Answer questions on:

- soluble alkalis
- ash characteristics
- size
- stickiness
- abrasive qualities
- Compare findings with PRB experience.

The BART Guidelines[1] describe the process commonly used for bringing a control technology concept to reality as a commercial product as follows:

- concept stage
- research and patenting
- bench scale or laboratory testing
- pilot scale testing
- licensing and commercial demonstration
- commercial sales

The BART Guidelines[1] go on to state "A control technique is considered available within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review."

"Commercial availability by itself, however is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration."

B. Summary:

The characteristics of the exhaust, or flue gas stream, after combustion of fuel by a boiler are governed by the design and operating characteristics of the boiler and the characteristics of the fuel. In this scenario, the fuel is North Dakota (Fort Union) lignite. The BART applicants concluded in their BART analyses that available SCR catalysts are not applicable for their unit(s).

One foremost issue in the NO_x BART analyses is whether any unique characteristics due to lignite fired by the boilers are cause for doubt that known SCR technology is not applicable and technically infeasible. We note that plugging of a catalyst on its face due to deposition of particles larger than the pitch of a catalyst (a.k.a. catalyst channel blockage) and plugging of pores on surfaces of a catalyst are generally different physical interactions. Our review of the supplemental information (see Minnkota BACT analysis[10]) concludes that the following facts are not disputed by EPA.

1) In cyclone firing of Fort Union lignite, about 45 - 50% of the ash forming components of the coal end up as flue-gas ash. For wall-fired and tangentially fired units, 25 - 35% of the ash ends up in the flue gas. Unburned or partially burned organic fraction of the Fort Union lignite, which contains more sodium than other coals, reacts with silicate particles causing a "stickiness" quality of flue gas ash, which results in ash deposits on heat transfer surfaces. And larger particles fracture from heat-transfer surfaces (a.k.a. popcorn ash) and enter the flue gas stream. Consequently, deposition on surfaces of catalytic reactors occurs and rates of deposition are higher.

2) Fort Union lignite has a higher moisture content and is oxygen rich compared to other coal types. This lignite also has a higher sulfur content compared to PRB coal. Consequently, the flue gas stream is rich in sulfur dioxide (SO_2) and sulfate (SO_4) compared to other coal types.

3) Fort Union lignite has a higher organic matter content. This lignite contains a higher proportion of alkali metal constituents, especially sodium (Na). Cyclone combustion of the coal produces ash, which is partitioned as slag on high temperature boiler surfaces and as flue gas vapor and fine particles (less than 15 micrometers (microns)). About 75% of total sodium in the lignite is associated with the organic fraction of the lignite; so very little of the sodium is associated with the mineral fraction of the lignite such as clays. During combustion, organic and water-soluble sodium vaporizes. Consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.

4) Alkali vapors condense (homogeneous nucleation) due to flue-gas cooling or react (heterogeneous nucleation) with other flue gas constituents, e.g., mineral silicates and sulfate. The size distribution of flue gas particles is bi-modal, relating to organically associated inorganics in coal and coalesced minerals and inorganics in flue gas; the size distribution varies by coal type and combustion method.

5) NO_x reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NO_x. Residual alkali vapors, Na, potassium (K) and calcium (Ca) displace hydrogen (H) on fresh catalyst, which prevents catalytic reaction with NO_x (a.k.a poisoning) and reacts with sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging, which requires more frequent catalyst maintenance.

6) There are no SCR systems planned, constructed or operating in the flue gas stream of boilers fired with Fort Union lignite. Fort Union lignite has some coal characteristics that are uniquely different than Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, sodium specifically, with that organic matter.

7) Slipstream SCR reactors of the same design were installed at three power plants to test SCR for NO_x emissions control. One of the plants was cyclone fired with Fort Union lignite and the others with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium and sulfur. The tests confirmed catalyst blinding and plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to PRB coal.

8) There may be an engineering solution to reduce deposition on the surface of catalytic reactors. But there is no known in-reactor engineering solution to:

(a) reduce deactivation rates caused by heterogeneous reactions that form the particles that cause pore blinding and plugging, or

(b) to restore the catalytic reactions by removing particles from catalyst pores.

9) There are no usable data for rates of deactivation of SCR catalyst in the flue gas from combustion of Fort Union lignite. Catalyst pitch is the only apparent catalyst geometric affecting ash deposition; but pitch also affects flue gas velocity through the reactor and, thus, times of exposure of NO_x for reduction to nitrogen (N_2) and water (H_20).

10) The BART Guidelines[1] do not provide specific numeric performance measures that an SCR NO_x control technology must achieve to satisfy the guideline's applicable (technically feasible) criteria.

11) The State of Louisiana recently determined that high dust SCR was not technically feasible for an activated carbon plant which utilizes lignite in the process because of the flue gas characteristics (high alkaline compounds) that will deactivate the catalyst.

Companion issues including ammonia slip and pyrosulfates emitted from a high-dust SCR will exaggerate flue-gas particulate (ash) deposits on low-temperature convective pass surfaces in the economizer and the primary air pre-heaters.

C. Conclusions:

The Department has completed an extensive review of all aspects of the application of SCR technology to the North Dakota power plants. Whether the problems associated with adapting SCR technology to a unit firing North Dakota lignite can be overcome is highly speculative.

The Department makes the following conclusions:

1) North Dakota lignite is extremely variable in heat content, ash content, and in the constituents that make up the ash. This variability will affect the design and operation of an SCR system.

2) The only pilot scale testing that has ever been conducted on a unit firing North Dakota lignite was at the Coyote Station. The pilot scale SCR plugged after only 2 months and little useful data was obtained. However, the testing used the same protocol as testing at the Columbia and Baldwin Station which had fewer problems. The Columbia and Baldwin Stations burn subbituminous coal. The Coyote testing demonstrates to the Department that North Dakota lignite firing will have more severe effects (plugging and catalyst deactivation) than units firing subbituminous coal when the same design is employed. Operation of an SCR

system for only 2 months between catalyst change out is much less time than is normally expected (at least 10,000 hours or 13.7 months) for power plants. Operation of an SCR system for only 2 months between catalyst replacement is not considered successful use or reasonable operation of SCR technology.

3) North Dakota lignite contains primarily organic sodium compounds. The combustion of the lignite produces soluble sodium compounds which causes more severe catalyst deactivation problems than insoluble sodium compounds.

4) The flue gas constituents that cause SCR catalyst deactivation at North Dakota power plants are significantly different from Texas lignite, Wyoming PRB subbituminous coal, and Pennsylvania bituminous coal. When cyclone boilers combusting North Dakota lignite are compared to any other type of combustion unit burning the other types of coal, the concentration of sodium compounds in the flue gas is at nearly five times greater (based on average coal and lb/wscf basis) than the other types of fuel and the total primary alkali constituents (CaO, Na_2O, MgO and K_2O) are approximately double. When pulverized units firing North Dakota lignite are compared to pulverized units firing other coals, the sodium ratio is approximately three times and the total primary alkali constituents ratio is approximately 1.4. The flue gas generated at North Dakota power plants is different from the flue gas at any plant where SCR technology has been applied, primarily due to the high concentration of soluble sodium compounds and the total flue gas loading of catalyst deactivation chemicals. Recent testing by Kling[11] and Zheng[12] suggest that it may not be possible to obtain 10,000 hours of catalyst life and probably much less than 10,000 hours. This difference in flue gas characteristics will preclude the successful use or reasonable operation of existing SCR technology at these units. Additional pilot scale testing is necessary to learn if the technology can be adapted.

5) Both Burns and McDonnell and Sargent and Lundy have extensive experience with the design and operation of SCR systems. Burns and McDonnell has expressed concerns whether an SCR system can be successfully designed and operated at a boiler combusting North Dakota lignite. S&L has indicated that certain design issues have not been addressed by PRB (subbituminous coal) experience. They have also indicated that some important unanswered questions pose significant risks for an SCR design engineer and recommended pilot scale testing before design takes place. The questions left unanswered include:

- High level of soluble alkali in North Dakota lignite
- Particle size and sticky nature of high alkaline North Dakota lignite ash
- Potential abrasive qualities of North Dakota lignite ash

6) The BART Guidelines[1] list the stages in the development of a commercial control system from concept stage to commercial sales. Experimentation with the SCR system takes place during the bench scale/laboratory testing or pilot scale testing stages. Although adjustments of full scale (commercial product) units is often necessary, the source operator should not be required at this stage to conduct

experimentation in order to make the equipment work. This could cause extended time delays and resource penalties for the source operator. To design and install an SCR system for a unit firing North Dakota lignite without obtaining additional data from bench scale or pilot scale testing would be experimentation.

7) The temperature variation of the flue gas at cyclone units entering the SCR will adversely affect performance and must be resolved for successful application of this technology. Engineering studies will be required to determine if this problem can be resolved. Minnkota and Basin Electric are not required to experience extended time delays or resource penalties to allow research to be conducted. Neither are they required to experience extended trials to learn how to apply a technology. The temperature problems for the SCR will require extensive, and correspondingly expensive, engineering studies to determine if this problem can be resolved.

8) There are unresolved issues regarding catalyst erosion from the ash. Recent pilot scale testing will have to be evaluated to determine if the erosion problems are resolvable.

9) Poisoning, blinding and plugging of a catalyst are affected by the geometries and properties of the catalyst. Firing of Fort Union lignite results in a flue gas stream that highly accelerates poisoning, blinding and plugging (of pores) due to the rich sodium and potassium vapors, particles and ammonium sulfates (due to ammonia injection) in lignite-fired flue gas. The engineering solutions of a larger SCR reactor, more catalyst and larger pitch do not resolve the rapid plugging of catalyst pores, at least with some certainty to assure a predictable useful life of catalyst before change out. There is no catalyst vendor solution to reduce or eliminate catalyst pore plugging. The chemical and physical process of pore plugging cannot be reversed, which dictates catalyst change out.

10) Without pilot scale testing, the long term NO_x reduction efficiency, the volume of the reactor, the catalyst pitch, life of the catalyst, or even the type of catalyst to be used cannot be predicted with a high degree of confidence. Sargent and Lundy has pointed out that to design an SCR system for a plant burning North Dakota lignite without pilot scale testing would present significant risks for the SCR design engineer. Without these design factors determined, any cost estimate would be conjecture and any evaluation of cost effectiveness or incremental cost in Step 4 of the BART analysis would be meaningless. The BART sources are not required to conduct pilot testing to obtain this data.

Therefore, the Department has determined, based on guidance in 40 CFR 51, Appendix Y[1], that high dust SCR technology is not available and thus not technically feasible at this time for units combusting North Dakota lignite.

Part II. **Low Dust and Tail Gas SCR**

A. Introduction

Selective catalytic reduction (SCR) systems that are placed downstream of the particulate matter (PM) and sulfur dioxide (SO_2) central systems are generally referred to as tail end SCR. Tail end SCR systems have been used on coal-fired and biomass fired boilers in the United States as well as other countries. However, no SCR system including a tail end SCR, has ever been operated on a boiler firing North Dakota lignite. The flue gas produced by the combustion of North Dakota lignite contains high concentrations of alkali aerosols (primarily sodium and potassium). Cyclone boilers, such as the two units at the M.R. Young Station, produce higher concentrations of submicron aerosols than conventional pulverized or fluidized bed boilers. The higher temperature in the cyclone boilers vaporizes the organically associated sodium and potassium in North Dakota lignite. When these elements condense, they form submicron aerosols. Minnkota[14] (page 12) has indicated that the condensed vapors have a mean diameter of approximately 0.1 micrometers. Papers by Kling[11] and Zheng[12] have indicated that the aerosols with a diameter less than or equal to 0.1 micrometers cause the greatest catalyst deactivation.

The NSR Manual[1] states that decisions regarding technically feasibility are made by comparing the physical and chemical characteristics of the exhaust gas stream from the unit under review to those of the unit from which the technology is being transferred. Unless significant differences between the source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible unless the source can present information to the contrary.

Since no low dust or tail end SCR system has even been applied to a boiler that combusts North Dakota lignite, an evaluation of the flue gas characteristics was made to determine if they were substantially different from facilities that have successfully applied SCR technology or to determine if empirical data would indicate whether LDSCR or TESCR can be successfully applied.

B. Flue Gas Characteristics

The Minnkota lignite represents the worst-cast for the evaluation of low dust or tail SCR application to a unit combusting North Dakota lignite. At the M.R. Young Station, both units use an electrostatic precipitator (ESP) to control PM emissions. Unit 2 is equipped with a wet scrubber to control SO_2 emissions while a wet scrubber will be constructed for Unit 1. Minnkota[15] (p. 20) as part of their BACT analysis has provided an analysis of the particulate matter emitted from Unit 2. The analysis indicated the PM was 6.56% sodium (Na), 2.26% potassium (K), 5.71% sulfur (S), 57.52% oxygen (O) and the remaining other elements.

The form of the sodium and potassium is most likely in sulfate form[16] (p. 32). If all of the sodium and potassium are in the sulfate form, sodium sulfate and potassium sulfate would compromise approximately 25% of the total particulate matter emitted from Unit 2. Minnkota has indicated that the sample of the particulate matter that was analyzed was obtained while some flue gas was bypassing the SO_2 scrubber. The amount of sodium, potassium and/or sulfur in the sample could be biased high when compared to a sample when all flue gas passes through the wet scrubber.

A review of the latest PM stack tests at M.R. Young Unit 2 (8/07 and 5/08) indicated an average PM emission rate of 10.61 milligrams per normal cubic meter (mg/Nm^3). Based on 25% of the PM being sodium and potassium sulfate, the combined emission rate of these two compounds is approximately 2.7 mg/Nm^3. This indicates a sodium and potassium removal efficiency of greater than 99% by the ESP and wet scrubber.

Minnkota has submitted data from a study by Markowski[16] (p. 31) which indicated that approximately 81% of the sulfate emitted is less than 1.1 micrometers in size and approximately 36% is less than 0.26 micrometers in size. Based on the latest stack tests and the Markowski data, the submicron sodium sulfate plus potassium sulfate emission rate would be less than 2.2 mg/Nm^3 and the emission rate of sodium and potassium sulfate less than 0.26 micrometers in size would be approximately 1.0 mg/Nm^3. These values are similar to those Markowski reported which were 1.335 mg/m^3 and 0.602 mg/m^3 respectively.

C. Catalyst Deactivation

The two primary flue gas constituents that will cause SCR catalyst deactivation in a tail end configuration are sodium and potassium, most likely in sulfate form[16] (p.32-35). Crespi[17] (et.al.), in their paper regarding the Amager Station, presented a graph which shows the effect of various poisons on the activity of vanadia – titania catalysts. Minnkota[14] (page 21) provided similar information that indicates that potassium oxide is a more potent catalyst poison on a molar basis than sodium oxide. Although no actual data is supplied, analysis of the graph indicates that potassium oxide is 1.7[17] – 2.0[18] times more potent catalyst poison than sodium oxide (on a molar basis) up to a vanadium/titanium to poison ratio of 0.6. Because potassium oxide has a larger molecular weight than sodium oxide, the poisoning ratio is 1.1 – 1.3 on a mass basis.

As indicated earlier, Kling[11] and Zheng[12] have indicated that the aerosols less than or equal to 0.1 micrometers cause the catalyst deactivation. Data are not available to calculate the portions of the PM emissions from Unit 2 that would be less than or equal to 0.1 micrometers. A conservative assumption is that all of the sodium and potassium sulfate less than 0.26 micrometers is less than or equal to 0.1 micrometers. The total emission rate for sodium and potassium sulfate combined is estimated at less than 1.0 mg/Nm^3 of which 0.78 mg/Nm^3 is sodium sulfate and 0.20 mg/Nm^3 is potassium sulfate based on the filter analysis submitted by Minnkota[15].

Kling[11] has provided catalyst deactivation rates for varies biomass fuels which produce a flue gas that contains sodium and potassium aerosols. The testing was conducted using different types of honeycomb W_2O_5/TiO_2 SCR catalyst. Type A catalyst was catalyst typically applied at coal-fired power plants, Type B was a "bio-optimized" catalyst with increased vanadium content, and Type C had an even higher vanadium content.

For a mixture of peat and 15% wood, the flue gas contained 4.4 mg/Nm^3 of potassium chloride and 0.8 mg/Nm^3 of sodium chloride aerosols with an aerodynamic particle diameter less than 0.1 micrometers.

	Peat + 15% Wood*	Center Lignite**
Potassium (mg/Nm^3)	4.4	0.20
Sodium (mg/Nm^3)	0.8	0.78

*As chloride
**As sulfate

The maximum deactivation rate was 12% in 768 hours using Type A catalyst. Another result indicated 15% deactivation in 1488 hours using Type B catalyst. The shorter test on peat plus 15% wood indicates 6400 hours to 100% deactivation while the longer test indicates 9920 hours to 100% deactivation. Regarding the deactivation rates, Kling[11] et.al stated "Exposure of this kind of short samples gives a larger deactivation compared to a full-length catalyst [1,4] that is mainly a consequence of turbulence of the inlet of the catalyst, before laminar flow is attained."

The flue gas concentration of sodium from Center lignite is similar to that of the peat plus 15% wood; however, the potassium content is approximately 17 times lower. Zheng[12] has reported that potassium chloride has an SCR catalyst deactivation rate of 1% per day versus 0.4% per day for potassium sulfate, or 2½ times more. It appears the catalyst life for an SCR at M.R. Young Station would be substantially longer than that estimated for peat plus 15% wood.

Zheng et.al.[12] found a deactivation rate of 0.4% per day for potassium sulfate or 6,000 hours to 100% deactivation. The testing was conducted at a loading of 20-30 mg/Nm^3. The aerosols varied in size from 0.07 micrometers to 1.05 micrometers with a mass mean diameter of 0.55 micrometers. The Markowski data indicates that approximately 53% of outlet sulfate was less than or equal to 0.52 micrometers. Based on the latest stack tests at M.R. Young Unit 2, this equates to an emission rate of approximately 1.4 mg/Nm^3 for those sodium and potassium sulfate aerosols less than 0.52 micrometers. The Minnkota emission rate is substantially less (14-21 times) than the Zheng testing. Again, this does not consider the fact that potassium sulfate is a more potent catalyst poison than sodium sulfate. This suggests that a much longer catalyst life is possible for North Dakota lignite.

For a LDSCR application, the only air pollution control device prior to SCR will be a dry electrostatic precipitator (ESP). Stack test results from the FINE Particles – Technology, Environmental and Health Technology Programme[20] suggests that an ESP on a biomass boiler will have a control efficiency of greater than 90% for submicron particles and can achieve greater than 96% for particles less than 0.1 micrometers in size. This is consistent with AP-42[4] data for Kraft recovery boilers which indicates an ESP can remove more than 98% of the submicron particulate matter in the flue gas which is primarily sodium sulfate[21]. Similar results are reported for coal-fired/biomass boilers by Mohr[22], Lind[23] and the Power Station Emissions Hanbook[24]. This indicates that most of the submicron sodium and potassium aerosols, including those aerosols less than 0.1 micrometers in size, will be removed by electrostatic precipitators.

Minnkota has submitted data on the ash composition that accumulate on the electrodes of the Power Span ECO electrodes during a pilot test[14] (p. 26). The data suggests that the sodium and potassium concentration in the particulate matter downstream of the Unit I ESP is higher than the concentration in the particulate matter downstream of the Unit II wet scrubber. However, the concentration is less than a factor of two higher. The total loading of sodium and potassium, as indicated by the data submitted by Minnkota, would still be considerably less than the loadings in the Kling[11] and Zheng[12] tests. This suggests that the catalyze deactivation rate of LDSCR and MRYS should be lower than in the referenced tests.

D. Vendor Information

The U.S. Department of Justice, through their contractor Mr. Hans Hartenstein, has provided emails from various catalyst and SCR system providers[19] as part of Minnkota BACT process. Each of the responses from the vendors indicated that tail end SCR is technically feasible for the Milton R. Young Station.

The Department contacted three of the vendors, Ceram Environmental, Haldor Topsoe and Babcock Power. The companies generally confirmed the information in the emails to Mr. Hartenstein. Babcock Power indicated they had no worries about getting 10,000 hours of catalyst life at the M.R. Young Station. However, they recommended “coupon” testing prior to design of the SCR. Ceram was convinced it was technically feasible; however, their representative did acknowledge that if the sodium and potassium aerosols are making it through the ESP and wet scrubber, catalyst deactivation could be a problem. Haldor Topsoe indicated that the catalyst deactivation at M.R. Young would be manageable if the catalyst is kept dry during outages. Although no written guarantees have been provided by the vendors, it appears that vendors are willing to provide them for a tail end SCR at the M.R. Young Station.

E. Similar Facilities using SCR

There are no boilers that combust North Dakota lignite and are equipped with SCR technology. In general, other U.S. coals are much lower in the organically associated alkalis that cause SCR catalyst deactivation. Biomass fired boilers would have flue gas characteristics that more closely approximate those from North Dakota lignite. At least four biomass boilers that are equipped with tail end or low dust SCR are currently in operation.

These include:

- Whitefield Power & Light, New Hampshire – Boiler uses whole tree chips and has operated since October 2004.

- Bridgewater Power, New Hampshire – Boiler uses whole tree chips and has operated since October 2007.

- Pine Tree Power, New Hampshire.
- Boralex Stratton, Main – Boiler was whole tree chips, waste wood, and construction and demolition waste. The boiler has operated since December 2004.

The Department is also aware of proposed installation at the Burlington Electric Plant in Vermont, Synterprise Global Solutions in Tennessee and the Amager Heat and Power Plant near Copenhagen, Denmark. The Amager Station is also allowed to burn coal and may not be required to operate the SCR when combusting biomass.

Although there are boilers that combust 100% biomass and utilize SCR for NO_x control, there is very little information about the actual loading of potassium and sodium aerosols at the inlet to the SCR. The New Hampshire Department of Environmental Services (NHDES) was contacted regarding the biomass boilers that use low dust/tail end SCR. The Whitefield Power Plant is a 16 MWe spreader stoker that is equipped with a multiclone and electrostatic precipitator for particulate matter control. The NHDES confirmed the boiler had been operating for approximately four years. NHDES was not aware of any catalyst deactivation problems at this facility. The plant has a NO_x emission limit of 0.075 lb/10^6 Btu. The other facilities in New Hampshire are similar; however, they are not operated as long. No data was available regarding the loading of potassium and sodium at the inlet of the SCR.

F. Conclusions

The Department has concluded that an SCR system must have a catalyst life of at least 10,000 before SCR technology could be deemed successfully applied to the source. No data has been found from an actual operating facility which has similar flue gas characteristics to M.R. Young Station for applying high dust, low dust or tail end SCR. However, experimental and pilot scale testing by Kling[11] provides a good comparison for a low dust or tail end SCR. The total sodium and potassium loading of aerosols less than 0.1 micrometers expected at the inlet of a tail end SCR at M.R. Young Station is expected to be at least 5 times less than found is Kling tests on peat plus 15% wood. Kling's data indicated up to 9920 hours of catalyst life for catalyst type B. Zheng's[12] data suggested 6,000 hours of catalyst life when exposed to potassium sulfate at a concentration (0.55 micrometer aerosols) which is 14-21 times higher than the concentration of sodium and potassium sulfate aerosols of this size expected after a wet scrubber at M.R. Young Station. Kling[11] also pointed out that the testing probably over estimates the deactivation rate because of turbulence in the pilot scale inlet of the catalyst which would be more laminar in a full scale SCR.

Existing biomass boilers are using tail end SCR successfully. Although the boilers are not cyclone fired units, the new Hampshire units use similar PM control devices as M.R. Young Station (i.e. ESP). The Whitefield Plant has operated for more than four years without deactivation problems. Kling[11] has referred to "bio-optimized" catalyst and higher vanadium catalysts that appear to have a longer life than the typical coal-fired boiler SCR catalyst for a given concentration of sodium and potassium aerosols. A "bio-optimized" catalyst will be installed at the Amager Station[13]. Vendors believe that tail end SCR is technically feasible and can be successfully applied at M.R. Young Station.

The Minnkota situation represents the worst-case scenario for boilers burning North Dakota lignite that are subject to BART. Based on the experimental data available, the use of tail end SCR on biomass fired boilers, and vendor information that tail end SCR is feasible at the M.R. Young Station, the Department concludes that tail end and low dust SCR are technically feasible for boilers combusting North Dakota lignite that are subject to BART requirements.

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Selective Catalytic Reduction (SCR)
Technical Feasibility
For
M.R. Young Station

I. Introduction

On July 27, 2006 a Consent Decree was entered by the United States District Court for the District of North Dakota for Civil Action No. 1:06-CV-034, United States of America and the State of North Dakota versus Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative. The Consent Decree resolved alleged violations of the Federal Clean Air Act and the North Dakota Air Pollution Control Rules (NDAC 33-15) including the Prevention of Significant Deterioration Rules (NDAC 33-15-15). Section V, Paragraph 65, of the Consent Decree required Minnkota Power Cooperative and Square Butte Power Cooperative (hereafter Minnkota) to submit to the Department for review and approval, a nitrogen oxides (NO_x) top-down Best Available Control Technology (BACT) analysis for the two existing units at the M.R. Young Station. The Consent Decree required Minnkota to evaluate various technologies including selective catalytic reduction (SCR), selective noncatalytic reduction (SNCR), over-fire air (OFA) and rich reagent injection (RRI). Minnkota must also submit any additional information requested by the Department or the U.S. Environmental Protection Agency (hereafter EPA) which is pertinent to the BACT determination. On October 9, 2006, the Department received the required BACT analyses.

Under Section III, paragraphs 23 and 24 of the Consent Decree, the BACT analysis must be made in accordance with the provisions of Chapter B of EPA's New Source Review Workshop Manual[9] (hereafter NSR Manual). As discussed in the NSR Manual, the steps for conducting a BACT analysis using the "top down" approach are as follows:

Step 1: Identify All Control Technologies.

- List is comprehensive.

Potentially applicable control alternatives can be categorized in three ways.

- Inherently Lower-Emitting Processes/Practices, including the use of materials and production processes and work practices that prevent emissions and result in lower "production-specific" emissions; and
- Add-on Controls, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced.
- Combinations of Inherently Lower Emitting Processes and Add-on Controls. For example, the application of combustion and post-combustion controls to reduce NO_x emissions at a gas-fired turbine.

The top-down BACT analysis should consider potentially applicable control techniques from all three categories. Lower-polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review.

Step 2: Eliminate Technically Infeasible Options.

- A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

The NSR Manual[9] provides guidance for determining whether a control option is technically infeasible. Two concepts are important in making this determination, "availability" and "applicability". A technology is considered "available" if it can be obtained through commercial channels or is otherwise available within the common sense meaning of the word. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is considered technically feasible.

Regarding "availability" the NSR Manual[9] states:

> "A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in a pilot scale testing stages of development would not be considered available for BACT review."

With respect to "applicability" the NSR Manual[9] states:

> "Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.

For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible.

In practice, decisions about technical feasibility are within the purview of the review authority. Further, a presumption of technical feasibility may be made by the review authority based solely on technology transfer. For example, in the case of add-on controls, decisions of this type would be made by comparing the physical and chemical characteristics of the exhaust gas stream from the unit under review to those of the unit from which the technology is to be transferred. Unless significant differences between source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible unless the source can present information to the contrary."

Step 3: Rank Remaining Control Technologies By Control Effectiveness

This includes:

- control effectiveness (percent pollutant removed);
- expected emission rate (tons per year);

- expected emission reduction (tons per year);
- energy impacts (Btu, KW-hr);
- environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
- economic impacts (total cost effectiveness and incremental cost effectiveness).

Step 4: Evaluate Most Effective Controls and Document Results

- Case-by-case consideration of energy, environmental, and economic impacts.
- If the most effective option is not selected as BACT, evaluate next most effective control option.

Step 5: Select BACT

- Most effective option not rejected is BACT and establish emission limit or work practice standard.

The Department solicited public comments on its preliminary BACT determination for nitrogen oxides (NO_x) controls at the M.R. Young Station (MRYS). Comments from the Environmental Protection Agency and several environmental groups disagreed with the conclusion that high dust SCR (HDSCR), low dust SCR (LDSCR) and tail end SCR (TESCR) were technically infeasible. Comments from other parties agreed with the Department's preliminary determination. The Department has evaluated the comments and has reaffirmed its preliminary determination that HDSCR is technically infeasible. However, the Department now believes LDSCR and TESCR are technically feasible.

This document explains the Department's current views on technical feasibility. This document does not represent a final Department action. The Department will make its final BACT determination after the remaining steps for conducting a BACT analysis have been completed. Minnkota will be required to submit additional information necessary for the Department to make its final BACT determination including an evaluation of the cost of LDSCR and TESCR.

II. High Dust Selective Catalytic Reduction (HDSCR)

HDSCR, or conventional SCR, refers to an SCR system that is installed prior to any air pollution control equipment and usually between the economizer outlet and air heater inlet. HDSCR has been installed on many pulverized coal and cyclone boilers firing bituminous and subbitiminous coal in the United States.

A. Public Comments

1. NDDH's Technical Feasibility Analysis of High Dust SCR is Incorrect and Based Upon Flawed Data

The NSR Manual states "A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles, and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique."

The Department asked EPA's consultant, Mr. Roger Christmann, if he was aware of any installation in the world where HDSCR had been applied to a facility with as high of sodium loading as at MRYS. Mr. Christmann indicated no. This indicates that there has never been a design established for a flue gas with the chemical characteristics found at MRYS. Simple mathematics prepared by the Department shows that the flue gas at MRYS is much higher in sodium and other catalyst deactivation chemicals than other power plant flue gases. EPA seems to ignore the fact that the sodium at MRYS is the soluble form (organically associated) which is a more potent catalyst deactivation chemical than the insoluble (inorganically associated) form found in other coals. EPA tries to dismiss this showing by ratioing the loading of Powder River Basin (PRB) subbituminous coal to bituminous coal without indicating the actual loading. The Department showed the actual loading (lb/dscf and lb/wscf) as well as the ratio to other facilities. When you start out with a very small loading, as is the case with bituminous coal, a large ratio for subbituminous coal also gives you small loading. As EPA's own consultant points out, SCR has never been applied to sodium loading as high as at MRYS.

Minnkota and its consultants have documented very well the effect of soluble sodium on an SCR catalyst. Although the Coyote testing did not provide any deactivation rate data for high soluble sodium North Dakota lignite, it did show that an HDSCR design for subbituminous coal will probably not work successfully with North Dakota lignite. As Sargent and Lundy pointed out, there is no known solution for the soluble alkalis such as the soluble sodium and potassium found in North Dakota lignite. EPA ignores the chemical differences between Texas lignite and North Dakota lignite.

With respect to the catalyst vendor "guarantees", all of the vendors that Minnkota contacted indicated that pilot scale testing was either required or should be done prior to applying high dust SCR technology to a North Dakota lignite-fired boiler. Minnkota has provided information that indicates the potential for greatly reduced catalyst life due to the chemical characteristics of the flue gas. Although two vendors indicated a catalyst life which the Department would consider as a "successful application" of HDSCR technology at MRYS, others did not give such an indication. All vendors indicated the flue gas temperature problems (too hot or too cold) must be resolved for the application of HDSCR to be successful. No solution to this problem has been found at this time. EPA has indicated that some of the vendors may have been prompted by Minnkota, or its consultants, to indicate that pilot testing should be done. Even if some vendors may have been "prompted" to make these statements, it is irrelevant since the vendors could have chosen not to make the statement.

Although the Texas CEQ has determined that HDSCR is technically feasible for Texas lignite, the chemical constituents of North Dakota lignite that affect the feasibility of HDSCR are quite different. The State of Louisiana recently determined that HDSCR was not technically feasible for an activated carbon plant because of the flue gas characteristics of the lignite used in the process.

The NSR Manual[9] indicates that an add-on control technology is only technically feasible if it can lead to "successful operation" or "successful deployment." The Department has indicated that anything less than 10,000 hours of catalyst life would not be successful operation of the SCR system and thus technically infeasible. Kling et. al.[2] conducted pilot and bench sale testing of SCR catalysts when subjected to flue gas from the combustion of biomass. The testing was conducted using three different types of catalyst. Catalyst Type A was typical of that used for coal-fired boilers, Type B was a "bio-optimized" catalyst with an increased vanadium content and Type C had a very high vanadium content. Kling[2], and later Zheng et. al[3], have concluded that it is the alkali aerosols that are less than or equal to 0.1 micrometers that cause most of the catalyst deactivation. In North Dakota lignite, the alkali metals are generally associated with the organic matter of the lignite while in other coals the alkaline constituents are associated with the inorganic portion of the coal (e.g. clays). The combustion of the organically associated alkaline elements causes them to vaporize; when they condense, they form submicron aerosols. The combustion of inorganically associated alkalis causes only a small portion to vaporize. Minnkota has supplied information that indicates these condensed alkali aerosols have a mass mean diameter of approximately 0.1 micrometers. Therefore, 50% of the aerosols would be less than 0.1 micrometers in size on a mass basis. The average mass of sodium oxide and potassium oxide emitted from the MRYS boilers was calculated at 3.05 x 10^{-5} lb/dscf (524 mg/Nm^3) and 9.01 x 10^{-6} lb/dscf (155 mg/Nm^3), respectively.

Crespi[6] has provided data that suggests potassium oxide is approximately twice as potent a catalyst deactivation chemical on a molar basis (1.3 times on a mass basis) than sodium oxide. The equivalent potassium oxide emission rate for MRYS based on this data would be 558 mg/Nm^3. The aerosols are most likely in the sulfate form.[5] This would lead to an equivalent potassium sulfate emission rate of 1034 mg/Nm^3.

Kling[2] found a deactivation rate of 21-52% over 1500 hours for fuel made up of tree bark and 30% demolition wood waste. This fuel has a potassium chloride loading of 16.7 mg/Nm^3 and a sodium chloride loading of 5.8 mg/Nm^3. The Kling[2] results were for aerosols with an aerodynamic diameter of less than 0.1 micrometers. If all of the sodium and potassium in lignite vaporizes, 50% of the total loading would be less than or equal to 0.1 micrometers or 517 mg/Nm^3 of equivalent potassium sulfate. Zheng[3] has suggested that potassium chloride is two and one half times more potent catalyst poison than potassium sulfate (0.4%

per day versus 1% per day). An equivalent loading of sodium and potassium for a HDSCR at MRYS as potassium chloride would be 207 mg/Nm^3. This loading is nearly 10 times that of the Kling[2] testing. The Kling[2] results suggest 2,885-7,140 hours until 100% deactivation. The higher loading at the North Dakota facilities suggests a much higher deactivation rate and a shorter catalyst life.

Zheng et. al.[3] found a catalyst deactivation rate of 0.4% per day for a potassium sulfate. The testing was conducted using a concentration of 20-30 mg/Nm^3 of potassium sulfate with a mass mean diameter of 0.55 micrometers. Although data is not available to determine the loading of aerosols with a diameter less than 0.55 micrometers, a comparison to the fraction less than 0.1 micrometers indicates a concentration 17-26 times larger than the concentration in Zheng's tests. The 0.4% deactivation rate per day is equivalent to 6000 hours at 100% deactivation. For a HDSCR, the flue gas from the MRYS would likely produce a higher deactivation rate.

The recent testing by Kling[2] and Zheng[3] indicate that it is unlikely that a HDSCR will achieve 10,000 hours of catalyst life when combusting Center lignite at MRYS. In fact, the catalyst life could be only a few thousand hours as suggested by the pilot scale testing at the Coyote Station.

2. MRYS Temperature Variation Issue Related to HDSCR

EPA has indicated the temperature problems with HDSCR can be resolved.

Mr. Steve Moorman of Babcock and Wilcox in a July 18, 2007 email stated the resolution of the temperature problem would require a technical feasibility analysis of a "very complex nature" to determine if boiler modifications could bring furnace exit gas temperatures into the range needed for compatibility with operation of HDSCR. Modifications outside of the boiler may solve the temperature problem; however, a study would be required. EPA's statement that the technical issues with the temperature issue can be resolved appears to be premature.

The email also states "Our budget estimate to complete this study is $275,000 to $400,000 including the performance test, project management costs and travel expenses. We project the study will require 20 to 24 weeks to complete including the time to run the performance tests." The NSR Manual[9] states: "A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review." The Department considers the time and money necessary to determine if the temperature problems can be overcome to be excessive.

3. EPA's Conclusion on HDSCR

When considering application of HDSCR to a cyclone boiler burning North Dakota lignite, the MRYS is considered a new source type. In the past, EPA has recognized cyclone boilers, and more generally slag tap furnaces, that burn lignite from North Dakota, South Dakota and Montana as a separate source category for NO_x emissions in the New Source Performance Standards, Subparts D and Da. This separate category was established primarily based on the use of high sodium lignite. Not until EPA developed a fuel and furnace neutral standard was this category replaced. The replacement of this category was apparently done without an evaluation of the flue gas characteristics of North Dakota lignite. The NSR Manual[9] states "Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emission unit undergoing BACT review." (NSR Manual, Chapter B, Section IV.A).

Minnkota has demonstrated that the flue gas characteristics at MRYS are different from other coal-fired boilers where HDSCR has been applied. The NSR Manual states "A source would not be required to experience time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type." (Chapter B, Section IV.B). Minnkota is not required to conduct extensive and expensive feasibility analyses for modifying the boiler to correct temperature problems that make HDSCR infeasible.

EPA has indicated that catalyst regeneration is a viable option (that is currently used in practice) for restoring catalyst life either in-situ, on-site, or off-site water washing. EPA cites a PowerPoint presentation at the 2007 NO_x Round Table and Expo by Reinhold Environmental Limited as evidence that this technique is available. DOJ's consultant, Mr. Hans Hartenstein, also made a presentation at the referenced Expo. In Mr. Hartenstein's presentation the following statement is made "Regeneration = Removal of catalyst poisons plus restoration of catalytically active ingredients - can typically not be done in-situ or on-site, but should be done off-site to ensure required close process control." EPA may be referring to "rejuvenation" of a catalyst for which Mr. Hartenstein states "Removal of catalyst poisons without the need for replenishing catalytically active compounds - can **sometimes** [emphasis added] be done in-situ, but is most commonly done either on-site or off-site." These statements were also made by

Ehrnschwender and Holsccher at the February 2008 Expo (Considerations for Catalyst Deactivation and Regeneration When Firing Biomass). Minnkota and its consultants have addressed this issue by stating "Regarding the contention of Hartenstein, there is extremely limited experience with in-situ catalyst cleaning on coal-fired units. ENBW in Germany developed this technique, but it has never had a commercial success. It has also never been used for blinded or chemically poisoned catalyst, but only for mechanically plugged catalyst." There is no evidence regarding the effectiveness of washing to rejuvenate an SCR catalyst on the MRYS. Pilot scale testing would be necessary to determine the feasibility of this catalyst maintenance technique.

4. The NDDH BACT Determination Incorrectly Applies the Concept of Pilot Testing in EPA's NSR Manual to Conclude that SCR is not Technically Feasible

EPA states that "For determining whether a control option is available, EPA's NSR Manual does not describe the comparison of gas stream characteristics between the source under review and other sources."

There has never been SCR technology applied to a boiler that combusts North Dakota lignite. EPA has recognized in the past, that cyclone boilers, such as those at Minnkota, that burn lignite from North Dakota is a separate source category for NO_x emission limits under the New Source Performance Standards, Subpart D and Da. Chapter B, Section IV.A, Identify Alternative Emission

Control Techniques **(Step 1)** [emphasis added] states "The top-down BACT analysis should consider potentially applicable control techniques from all three categories. Lower polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. **Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review.**" [emphasis added] Clearly, identification of control options under Step 1 must take into account the flue gas characteristics. If the flue gas characteristics can be shown to prevent successful application of the technology to the source under view, the technology is not identified as "potentially applicable" to the source in Step 1 and is therefore not commercially available under Step 2. Minnkota has shown that the flue gas characteristics for a HDSCR at MRYS are different from that at any other coal-fired power plant where SCR has been installed. Mr. Roger Christmann, EPA consultant, stated that he was not aware of any power plant where HDSCR had been applied with as high of sodium loading as MRYS.

HDSCR technology designed for other coal-fired power plants is not applicable to a North Dakota lignite-fired unit and there is no commercially available design. Pilot scale testing would be necessary to show whether HDSCR can work successfully. As Sargent and Lundy (S&L) pointed out, there are no known solutions for the catalyst surface masking and catalyst deactivation caused by the soluble alkalis (Na_2O and K_2O) found in North Dakota lignite. S&L indicated that some thresholds or limits are yet to be defined for HDSCR involving ash with greater than 2% Na_2O and greater than 1% K_2O. Ash from MRYS contains an average 4.4% Na_2O and 1.3% K_2O. The Na_2O can be as high as 13% and K_2O as high as 7%. Any pilot scale testing would be used to obtain data on the soluble alkalis and ash characteristics and compare the findings with experience on Powder River Basin Coal.

The pilot scale testing for a HDSCR would not be for optimizing an existing applicable control technology. It would be for researching solutions for the high soluble alkalis and possibly designing a new SCR system for a new and dissimilar source category.

5. <u>The NDDH BACT Determination Frustrates the Technology Forcing Function of the BACT that was Intended by Congress.</u>

MRYS is a different source category based on its flue gas characteristics at a HDSCR location. The Department has taken the position that the flue gas characteristics at the MRYS would preclude the successful application of existing HDSCR technology. Decisions regarding technical feasibility are based on the flue gas characteristics, not whether it has been applied to a coal-fired boiler or some other general source category. We believe Congress never intended forcing a technology on a source when there is a low probability of successful deployment of that technology.

B. Conclusions

Recent testing by Kling[2] and Zheng[3] suggest a low probability of achieving successful application of HDSCR technology by MRYS. The high concentration of sodium and potassium in the flue gas will rapidly deactivate the catalyst. The results suggest much less than 10,000 hours of catalyst life which the Department believes is necessary for successful application of HDSCR.

Minnkota has supplied data indicating temperature problems (both too high and too low) at the location of HDSCR which will affect the catalyst life. Babcock and Wilcox has estimated that a study of the temperature problems could take up to 24 weeks and cost up to $400,000. The NSR manual indicates that a company is not expected to experience extended trials to learn how to apply a technology.

Based on the flue gas characteristics at the location of the high dust SCR and the temperature problems (both too high and too low), the Department does not consider HDSCR to be technically feasible for MRYS.

III. Tail End SCR and Low Dust SCR

A. Introduction

SCR systems placed between the particulate control device and sulfur dioxide control equipment are called low dust SCR (LDSCR). Systems that are placed downstream of the particulate matter (PM) and sulfur dioxide (SO_2) control systems are generally referred to as tail end SCR (TESCR). This is in contrast to a HDSCR location where none of the particulate matter and sulfur dioxide has been removed from the flue gas. LDSCR and TESCR systems have been used on coal-fired and biomass fired boilers in the United States as well as other countries. However, no SCR system including a low dust or tail end SCR has ever been operated on a boiler firing North Dakota lignite. The flue gas produced by the combustion of North Dakota lignite contains high concentrations of alkali aerosols (primarily sodium and potassium). Cyclone boilers, such as the two units at the M.R. Young Station, produce higher concentrations of submicron aerosols than conventional pulverized or fluidized bed boilers. The higher temperature in the cyclone boilers vaporizes the organically associated sodium and potassium in North Dakota lignite. When these elements condense, they form submicron aerosols. Minnkota[1] (p. 12) has indicated that the condensed vapors have a mean diameter of approximately 0.1 micrometers. Papers by Kling[2] and Zheng[3] have indicated that the aerosols with a diameter less than or equal to 0.1 micrometers cause the greatest catalyst deactivation.

The NSR Manual[9] states that decisions regarding technically feasibility are made by comparing the physical and chemical characteristics of the exhaust gas stream from the unit under review to those of the unit from which the technology is being transferred. Unless significant differences between the source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible unless the source can present information to the contrary.

Since no LDSCR or TESCR system has ever been applied to a boiler that combusts North Dakota lignite, an evaluation of the flue gas characteristics was made to determine if they were substantially different from facilities that have successfully applied SCR technology or to determine if empirical data would indicate whether low dust or tail end SCR can be successfully applied.

B. Flue Gas Characteristics

At the MRYS, both units use an electrostatic precipitator (ESP) to control PM emissions. Unit 2 is equipped with a wet scrubber to control SO_2 emissions while a wet scrubber will be constructed for Unit 1. Minnkota[4] (p.20) has provided an analysis of the particulate matter emitted from Unit 2 which can be used for evaluation of TESCR. The analysis indicated the PM was 6.56% sodium (Na), 2.26% potassium (K), 5.71% sulfur (S), 57.52% oxygen (O) and the remaining other elements.

The sodium and potassium after the ESP and wet scrubber is most likely in sulfate form[5] (p.32). If all of the sodium and potassium is in the sulfate form, sodium sulfate and potassium sulfate would comprise approximately 25% of the total particulate matter emitted from Unit 2 (see Appendix A). Minnkota has indicated that the sample of the particulate matter that was analyzed was obtained while some flue gas was bypassing the SO_2 scrubber. The amount of sodium, potassium and/or sulfur in the sample could be biased high when compared to a sample when all flue gas passes through the wet scrubber.

A review of the latest PM stack tests at M.R. Young Unit 2 (8/07 and 5/08) indicated an average PM emission rate of 10.61 milligrams per normal cubic meter (mg/Nm^3 at 6% O_2 – see Appendix B). Based on 25% of the PM being sodium and potassium sulfate, the combined emission rate of these two compounds is approximately 2.7 mg/Nm^3. This indicates a sodium and potassium removal efficiency of greater than 99% by the ESP and wet scrubber.

Minnkota has submitted data from a study by Markowski[5] (p.31) which indicated that approximately 81% of the sulfate emitted after the Unit 2 wet scrubber is less than 1.1 micrometers in size and approximately 36% is less than 0.26 micrometers in size. Based on the latest stack tests and the Markowski data, the submicron sodium sulfate plus potassium sulfate emission rate would be less than 2.2 mg/Nm^3 and the emission rate of sodium and potassium sulfate less than 0.26 micrometers in size would be approximately

1.0 mg/Nm^3. These values are similar to those Markowski reported which were 1.335 mg/m^3 and 0.602 mg/m^3 respectively.

C. Catalyst Deactivation

The two primary flue gas constituents that will cause SCR catalyst deactivation in a low dust or tail end configuration are sodium and potassium, most likely in sulfate form[5] (p.32-35). Crespi et.al.[6], in their paper regarding the Amager Station, presented a graph which shows the effect of various poisons on the activity of vanadia – titania catalysts. Minnkota[1] (page 21) provided similar information that indicates that potassium oxide is a more potent catalyst poison on a molar basis than sodium oxide. Although no actual data is supplied, analysis of the graph indicates that potassium oxide is 1.7[7] – 2.0[8] times more potent catalyst poison than sodium oxide (on a molar basis) up to a poison to vanadium/titanium ratio of 0.5 (see Appendix C). Because potassium oxide has a larger molecular weight than sodium oxide, the poisoning ratio is 1.1 – 1.3 on a mass basis.

As indicated earlier, Kling[2] and Zheng[3] have indicated that the aerosols less than or equal to 0.1 micrometers cause the catalyst deactivation. Data are not available to calculate the portions of the PM emissions from Unit 2 that would be less than or equal to 0.1 micrometers. A conservative assumption is that all of the sodium and potassium sulfate less than 0.26 micrometers is less than or equal to 0.1 micrometers. Based on this assumption and the PM analysis data, the total emission rate for sodium and potassium sulfate combined that is less than or equal to 0.1 micrometers is size is estimated at 0.98 mg/Nm^3 of which 0.78 mg/Nm^3 is sodium sulfate.

Kling[2] has provided catalyst deactivation rates for various biomass fuels which produce a flue gas that contains sodium and potassium aerosols. The testing was conducted using different types of honeycomb W_2O_5/TiO_2 SCR catalyst. Type A catalyst was catalyst typically applied at coal-fired power plants, Type B was a "bio-optimized" catalyst with increased vanadium content, and Type C had an even higher vanadium content.

For a mixture of peat and 15% wood, the flue gas contained 4.4 mg/Nm^3 of potassium and 0.8 mg/Nm^3 of sodium aerosols with an aerodynamic particle diameter less than 0.1 micrometers.

	Peat + 15% Wood[a]	Center Lignite[b]
Potassium (mg/Nm^3)	4.4	0.20
Sodium (mg/Nm^3)	0.8	0.78

[a] As chloride

[b] As sulfate

The maximum deactivation rate was 12% in 768 hours using Type A catalyst. Another result indicated 15% deactivation in 1488 hours using Type B catalyst. The shorter test result on peat plus 15% wood indicates 6400 hours to 100% deactivation while the longer test result indicates 9920 hours to 100% deactivation. Regarding the deactivation rates, Kling et.al[2] stated "Exposure of this kind of short samples gives a larger deactivation compared to a full-length catalyst [1, 4] that is mainly a consequence of turbulence of the inlet of the catalyst, before laminar flow is attained."

The sodium concentration in the flue gas after the wet scrubber from Center lignite is similar to that of the peat plus 15% wood; however, the potassium content is approximately 17 times lower. It appears the catalyst life for an SCR at M.R. Young Station should be substantially longer than that estimated for peat plus 15% wood.

Zheng et.al.[3] found a deactivation rate of 0.4% per day for potassium sulfate or 6000 hours to 100% deactivation. The testing was conducted at a loading of 20-30 mg/Nm^3. The aerosols varied in size from 0.07 micrometers to 1.05 micrometers with a mass mean diameter of 0.55 micrometers. The Markowski data indicates that approximately 53% of outlet sulfate was less than or equal to 0.52 micrometers. Based on the latest stack tests at M.R. Young Unit 2, this equates to a total emission rate of approximately 1.4 mg/Nm^3 for those sodium and potassium sulfate aerosols less than 0.52 micrometers. The Minnkota emission rate is substantially less (14-21 times) than the Zheng testing.

The above results do not consider the fact that potassium is a more potent catalyst poison than sodium and chlorides are more potent than sulfates. These facts make it even more likely that the catalyst life will be longer than the testing indicated by Kling[2] and Zheng[3] since Center lignite combustion at MRYS produces primarily sodium sulfate aerosols while biomass combustion produces primarily potassium chloride aerosols.

For a LDSCR application, the only air pollution control device prior to SCR will be a dry electrostatic precipitator (ESP). Stack test results from the FINE Particles – Technology, Environmental and Health Technology Programme[13] suggests that an ESP on a biomass boiler will have a control efficiency of greater than 90% for submicron particles and can achieve greater than 96% for particles less than 0.1 micrometers in size. This is consistent with AP-42[12] data for Kraft recovery boilers which indicates an ESP can remove more than 98% of the submicron particulate matter in the flue gas which is primarily sodium sulfate[14]. Similar results are reported for coal-fired/biomass boilers by Mohr[15], Lind[16] and the Power Station Emissions Handbook[17]. This indicates that most of the submicron sodium and potassium aerosols, including those aerosols less than 0.1 micrometers in size, will be removed by the electrostatic precipitators at MRYS.

Minnkota has submitted data on the ash composition that accumulated on the electrodes of the Power Span ECO electrodes during a pilot test[11] (p. 26). The data suggests that the sodium and potassium concentration in the particulate matter downstream of the Unit I ESP is higher than the concentration in the particulate matter downstream of the Unit II wet scrubber. However, the concentration is less than a factor of two higher. The total loading of sodium and potassium, as indicated by the data submitted by Minnkota, would still be considerably less than the loadings in the Kling[2] and Zheng[3] tests. This suggests that the catalyst deactivation rate of a LDSCR at MRYS should be lower than in the referenced tests.

D. Vendor Information

The U.S. Department of Justice, through their contractor Mr. Hans Hartenstein, has provided emails from various catalyst and SCR system providers[10] (Appendix D). Each of the responses from the vendors indicated that tail end SCR is technically feasible for the Milton R. Young Station.

The Department contacted three of the vendors, Ceram Environmental, Haldor Topsoe and Babcock Power. The companies generally confirmed the information in the emails to Mr. Hartenstein. Babcock Power indicated they had no worries about getting 10,000 hours of catalyst life at the M.R. Young Station. However, they recommended "coupon" testing prior to design of the SCR. Ceram was convinced it was technically feasible; however, their representative did acknowledge that if the sodium and potassium aerosols are making it through the ESP and wet scrubber, catalyst deactivation could be a problem. Haldor Topsoe indicated that the catalyst deactivation at M.R. Young would be manageable if the catalyst is kept dry during outages. Although no written guarantees have been provided by the vendors, it appears that vendors are willing to provide them for a tail end SCR at the M.R. Young Station.

E. Biomass Facilities using LDSCR/TESCR

There are no boilers that combust North Dakota lignite and are equipped with SCR technology. LDSCR and TESCR has been applied to coal-fired boilers in Europe, Asia and the United States. However, in general, other U.S. coals are much lower in the organically associated alkalis that cause SCR catalyst deactivation. Biomass fired boilers have flue gas characteristics that more closely approximate those from North Dakota lignite. At least four biomass boilers that are equipped with tail end or low dust SCR are currently in operation in the United States. The boilers are spreader stoker design and use an electrostatic precipitator as the primary particulate matter control device. These include:

- Whitefield Power & Light, New Hampshire – Boiler uses whole tree chips and has operated since October 2004.
- Bridgewater Power, New Hampshire – Boiler uses whole tree chips and has operated since October 2007.
- Pine Tree Power, New Hampshire – Biomass combustion.
- Boralex Stratton, Maine – Boiler uses whole tree chips, waste wood, and construction and demolition waste. The boiler has operated since December 2004.

The Department is also aware of proposed TESCR or LDSCR installations at the Burlington Electric Plant in Vermont, Synterprise Global Solutions in Tennessee and the Amager Heat and Power Plant near Copenhagen, Denmark. The Amager Station is also allowed to burn coal and may not be required to operate the TESCR when combusting biomass.

Although there are boilers that combust 100% biomass and utilize LDSCR for NO_x control, there is no information about the actual loading of potassium and sodium aerosols at the inlet to the SCR. The New Hampshire Department of Environmental Services (NHDES) was contacted regarding the biomass boilers that use LDSCR. The Whitefield Power Plant is a 16 MWe spreader stoker that is equipped with a multiclone and electrostatic precipitator for particulate matter control. The NHDES confirmed the boiler had been operating for approximately four years. NHDES was not aware of any catalyst deactivation problems at this facility. The plant has a NO_x emission limit of 0.075 $lb/10^6$ Btu. The other facilities in New Hampshire are similar; however, they have not operated as long. No data was available regarding the loading of potassium and sodium at the inlet of the SCR.

F. Conclusions

In the June 2008 Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, the Department concluded that an SCR system must have a catalyst life of at least 10,000 hours before SCR technology could be deemed successfully applied to the source. The life of the catalyst will depend on many factors including the reduction efficiency required, the allowable ammonia slip, the volume of catalyst used, the plant load variability, the coal flue gas characteristics, the makeup of the catalyst (e.g. high vanadium catalyst will last longer than a catalyst with a lower vanadium content), the design of the reactor system, the number of catalyst layers, the catalyst management plan, and other factors. The catalyst could be replaced when deactivation has reached 50% or less or it could be replaced at a higher deactivation point depending on the system's ability to meet the regulatory requirements for the NO_x emission rate and/or ammonia slip rate.

No data has been found from an actual operating facility which has similar flue gas characteristics to M.R. Young Station that use high dust, low dust or tail end SCR. However, experimental and pilot scale testing by Kling[2] and Zheng[3] provides empirical data for comparison. The total sodium and potassium loading of aerosols less than 0.1 micrometers expected at the inlet of a TESCR at M.R. Young Station is expected to be at least 5 times less than found in the Kling tests on peat plus 15% wood. Kling's data indicated up to 9920 hours before 100% deactivation for catalyst type B. Zheng's[3] data suggested 6,000 hours before 100% deactivation when exposed to potassium sulfate aerosols with an mean diameter of 0.55 micrometers at a concentration which is 14-21 times higher than the concentration of sodium and potassium aerosols of this size expected after a wet scrubber at M.R. Young Station. The loading at a low dust location would also be substantially less than the loading in the Kling or Zheng tests. Kling[2] also pointed out that the testing probably over estimates the deactivation rate because of turbulence in the pilot scale inlet of the catalyst which would be more laminar in a full scale SCR.

Existing biomass boilers are using LDSCR successfully. Although the boilers are not cyclone fired units, the New Hampshire units use similar PM control devices as M.R. Young Station (i.e. ESP). The potassium chloride emitted from the biomass boilers is a much more potent catalyst poison than the sodium sulfate emitted at the MRYS. The Whitefield Plant has operated for more than four years without deactivation problems. Kling[2] has referred to "bio-optimized" catalyst and higher vanadium catalysts that appears to have a longer life than the typical coal-fired boiler SCR catalyst for a given concentration of sodium and potassium aerosols. A bio-optimized catalyst (high vanadium content) will be installed at the Amager Station[6] (p. 13). Vendors believe that TESCR is technically feasible and can be successfully applied at M.R. Young Station.

Based on the empirical data available at that time, vendor information that TESCR is feasible at the M.R. Young Station and the use of low dust SCR on biomass fired boilers, the Department concludes that tail end and low dust SCR appear to be technically feasible at M.R. Young Station.

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Appendix A

Analysis of Unit II
Stack Test Filter

MINNKOTA UNIT 2
FILTER ANALYSIS

ELEMENT	% OF ELEMENT ON FILTER	MOLECULAR WEIGHT	MOLES [a]
Na	6.56	23.0	0.285
K	2.26	39.1	0.058
S	5.71	32.1	0.178
O	57.52	16.0	3.595

[a] *BASED ON 100 GRAMS OF PM*

2 Na + 1 S + 4 O --> Na_2SO_4

0.285 MOLES OF SODIUM AVAILABLE
NEED (0.285/2)*(1) MOLES OF SULFUR = 0.142 MOLES
NEED (0.285/2)*(4) MOLES OF OXYGEN = 0.570 MOLES

TOTAL WT. Na_2SO_4 = (23)(0.285) + (32.1)(.142) + (16)(.570) = 20.2 grams
POTENTIAL Na_2SO_4 = 20.2 g/100 g *100% = 20.2%

2 K +1 S + 4 O --> K_2SO_4

0.058 MOLES OF POTASSIUM AVAILABLE
NEED (0.058/2)(1) MOLES OF SULFUR = 0.029 MOLES
NEED (0.058/2)(4) MOLES OF OXYGEN = 0.116 MOLES

TOTAL WEIGHT K_2SO_4 = (39.1)(.058) + (0.029)(32.1) + (16)(.116) = 5.05 grams
POTENTIAL K_2SO_4 = 5.05%

the strands. These particles are rich in sodium and sulfur as compared to the filter materials. Figure 18 shows a region of the filter that was not exposed to flue gas and the fiber stands do not have particles bonded to the surfaces.

Table 5. Morphological analysis results for filter sample 001. Results expressed as weight percent on an elemental basis.

Fig.	Pt/Area	Description	Na	Mg	Al	Si	S	Cl	K	Ca	Ti	Fe	Ba	O
14	1*	Overall area - 100x	5.98	1.83	2.62	10.85	3.80	0.00	2.29	11.10	0.00	2.31	0.00	59.21
	2*	Overall area - 100x	5.95	2.40	2.82	10.93	5.42	0.00	2.25	11.30	0.40	2.46	0.00	56.07
	3*	Overall area - 100x	7.31	1.99	2.23	8.73	7.38	0.00	2.28	9.86	0.00	1.11	0.00	59.10
	4*	Overall area - 100x	5.66	2.54	2.20	9.47	5.27	0.00	2.54	10.08	0.00	3.05	1.65	57.56
	5	Light particle	1.21	3.33	5.47	7.65	1.38	0.00	1.40	13.44	0.00	6.76	1.85	57.52
	6	Dark particle	6.40	9.79	1.47	10.75	6.24	0.00	3.76	7.84	0.00	1.06	0.00	52.68
	7	Light particle	0.57	3.99	7.49	8.94	1.74	0.19	1.15	15.67	0.43	3.83	0.00	56.01
	8	Overall area - 100x	8.50	2.62	2.45	10.04	6.81	0.00	2.12	9.26	0.50	2.40	0.00	55.30
	9	Overall area - 100x	5.95	1.97	2.64	11.03	5.58	0.00	2.09	10.21	0.86	1.78	0.00	57.90
	10	Light particle	0.78	4.20	6.78	11.26	0.00	0.00	1.24	15.37	0.00	3.70	5.10	51.56
	11*	Blank edge of filter	0.00	0.93	5.11	20.20	0.00	0.00	0.93	13.83	0.00	0.00	0.00	59.00
	12*	Blank edge of filter	0.00	1.19	4.95	19.69	0.00	0.00	1.16	16.52	0.00	0.59	0.00	55.91
15	13	Small, light particles	3.00	3.30	3.10	7.72	2.91	0.00	1.40	11.02	0.00	3.49	1.89	62.18
	14	Small bonded particles	2.93	1.25	1.02	10.04	6.99	0.00	4.06	29.33	0.00	5.38	2.93	36.08
	15	Large dark particle	10.25	9.68	0.00	1.41	22.60	0.00	3.74	2.16	0.00	0.00	0.00	50.15
	16	Large dark particles	13.40	11.82	0.00	1.30	10.30	0.00	2.28	0.96	0.00	2.17	0.00	57.78
	17	Small bonded particles	4.39	3.56	2.17	10.95	6.88	0.00	2.77	14.02	0.51	2.83	0.00	51.92
	18	Small bonded particles	1.49	2.82	5.86	10.45	4.93	0.00	3.19	26.01	1.19	8.23	0.00	35.84
Average		**Overall areas**	**6.56**	**2.23**	**2.49**	**10.17**	**5.71**	**0.00**	**2.26**	**10.30**	**0.29**	**2.18**	**0.27**	**57.52**
		Light particles	**1.39**	**3.71**	**5.71**	**8.89**	**1.51**	**0.05**	**1.30**	**13.88**	**0.11**	**4.44**	**2.21**	**56.82**
		Dark particles	**10.02**	**10.43**	**0.49**	**4.49**	**13.05**	**0.00**	**3.26**	**3.65**	**0.00**	**1.08**	**0.00**	**53.54**
		Small bonded particles	**2.94**	**2.54**	**3.02**	**10.48**	**6.27**	**0.00**	**3.34**	**23.12**	**0.57**	**5.48**	**0.98**	**41.28**
		Filter edge	**0.00**	**1.06**	**5.03**	**19.94**	**0.00**	**0.00**	**1.04**	**15.18**	**0.00**	**0.30**	**0.00**	**57.46**

* = areas not specifically noted or shown in electron micrograph Figure 14.

Appendix B

Calculation of Emissions Rate
For
M.R. Young Station

MINNKOTA
STACK TEST RESULTS

UNIT	DATE OF TEST	PM EMISSION RATE (gr/dscf)	OXYGEN CONTENT (%)	PM EMISSION RATE (mg/m^3)	PM EMISSION RATE (mg/Nm^3) [a]	PM EMISSION RATE (mg/Nm^3) at 6% O_2
1	6/9/2008	0.0026	8.6	5.95	6.39	7.74
1	8/29/2007	0.0031	5.9	7.09	7.61	7.56
	AVERAGE	0.00285	7.25	6.52	7.00	7.65
2	5/7/2008	0.0042	7.4	9.61	10.32	11.38
2	08/28/2007	0.0039	6.4	8.92	9.58	9.84
	AVERAGE	0.00405	6.9	9.27	9.95	10.61

[a] ***ADJUSTED TO 0 °C***

TAIL END SCR

FROM FILTER ANALYSIS Na = 6.56% OF PM AND K = 2.26%.
IF ALL Na AND K IS SULFATE FORM, Na_2SO_4 = 20.2% AND K_2SO_4 = 5.05% OF PM.

UNIT	DATE OF TEST	POTENTIAL Na_2SO4 EMISSION RATE (mg/Nm^3)	POTENTIAL K_2SO_4 EMISSION RATE (mg/Nm^3)	EQ. K_2SO_4 [b] EMISSION RATE (mg/Nm^3)	EQ. K_2SO_4 [b,c] EMISSION RATE < 0.52 um (mg/Nm^3)	EQ. KCl [c,d] EMISSION RATE < 0.26 um (mg/Nm^3)
1	6/9/2008	1.56	0.39	1.59	0.85	0.23
1	8/29/2007	1.53	0.38	1.56	0.83	0.23
AVG.		***1.55***	***0.39***	***1.57***	***0.84***	***0.23***
2	5/7/2008	2.30	0.57	2.34	1.24	0.34
2	08/28/2007	1.99	0.50	2.03	1.08	0.30
AVG.		***2.14***	***0.54***	***2.19***	***1.16***	***0.32***

[b] ***BASED ON CRESPI DATA INDICATING POTASSIUM IS 1.3 TIMES MORE POTENT CATALYST POISON THAN SODIUM ON A MASS BASIS.***

[c] ***BASED ON MARKOWSKI DATA THAT INDICATES 53.1% OF SULFATE IS LESS THAN 0.52 um AND 36.5% IS LESS THAN 0.26 um.***

[d] ***BASED ON ZHENG'S DATA THAT INDICATED A DEACTIVATION RATE OF 1% PER DAY FOR KCl AND 0.4% PER DAY FOR K_2SO_4.***

ZHENG TO MINNKOTA LOADING RATIO = (20-30 mg/Nm^3)/(1.16 mg/Nm^3) = <u>17.2 TO 25.9</u>

KLING (PEAT + 15% WOOD) TO MINNKOTA LOADING RATIO = (4.4 + 0.8/1.3 mg/Nm^3)/(0.32 mg/Nm^3) = <u>15.7</u>
NOTE: THIS IS CONSERVATIVE SINCE LESS THAN 36.5% OF SULFATE AT MINNKOTA WILL PROBABLY HAVE A DIAMETER OF 0.1 um OR LESS.

MINNKOTA POWER COOP.
UNIT 2
HIGH DUST SCR

	Na_2O	K_2O	EQ. K_2O [a]	EQ. K_2SO_4 [b]	EQ. KCl [c]	EQ. KCL [d] (< 0.1 um)
AVG. EMISSION RATE (lb/dscf)	3.051E-05	9.014E-06	3.248E-05	6.013E-05	2.405E-05	1.203E-05
AVG. EMISSION RATE (mg/Nm^3)	524	155	558	1034	413	207

[a] *BASED ON CRESPI DATA WHICH INDICATES $K_2 0$ IS 1.3 TIMES MORE POTENT CATALYST POISON THAT Na_2O ON A MASS BASIS.*

[b] *BASED ON A MOLECULAR WEIGHT OF 94 FOR $K_2 0$ AND 174 FOR K_2SO_4 AND ASSUMING ALL Na & K IS IN SULFATE FORM .*

[c] *BASED ON ZHENG'S DATA THAT INDICATED A DEACTIVATION RATE OF 1% PER FOR DAY FOR KCl AND 0.4% PER DAY FOR K_2SO_4.*

[d] *BASED O0N 50% OF AEROSOLS LESS THAN 0.1 MICRONS IN SIZE.*

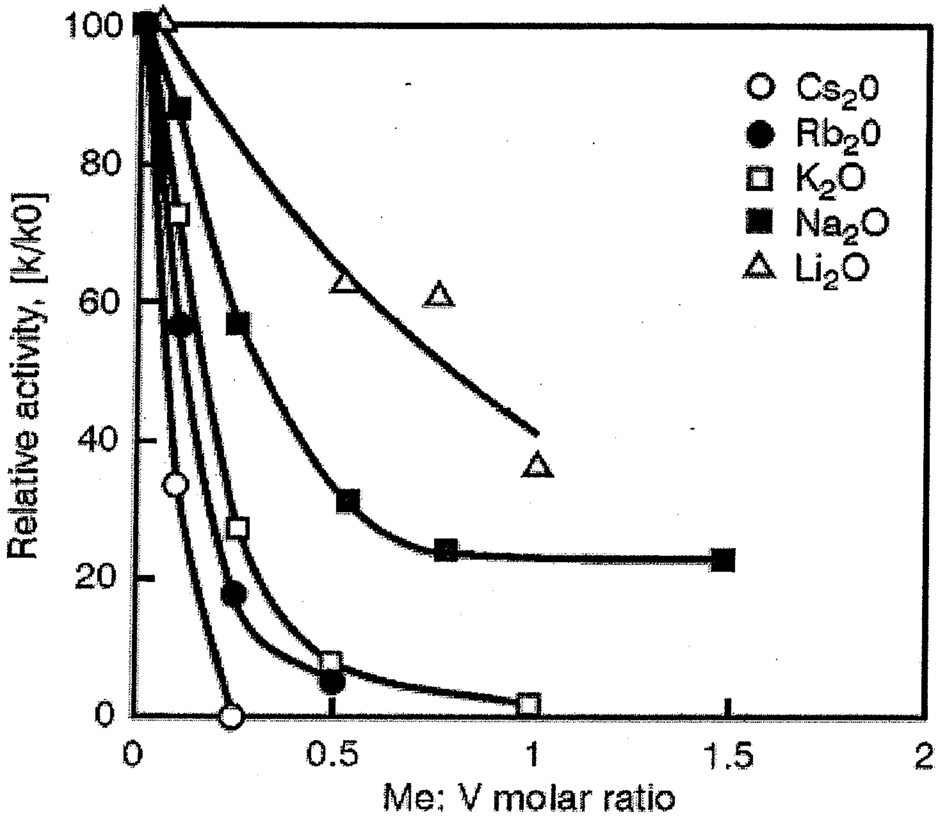
*MINNKOTA TO ZHENG LOADING RATIO = (1034 mg/Nm^3)*0.50 / (20-30 mg/Nm^3) = <u>25.9 TO 17.2</u>*

MINNKOTA TO KLING LOADING RATIO (BARK + 30% DEMOLITION WOOD) = (207 mg/Nm^3) / (16.7 + 5.8/1.3) = <u>9.8</u>

Appendix C

Analysis of Na_2O and K_2O Poisoning Potency

DEPARTMENT ANALYSIS
Na_2O and K_2O DEACTIVATION POTENCY



CONTAMINANT	**RELATIVE ACTIVITY**	**MOLAR RATIO**	**Na_2O/K_2O MOLAR RATIO**
Na_2O	30%	0.55	2.20
K_2O	30%	0.25	
Na_2O	40%	0.42	2.00
K_2O	40%	0.21	
Na_2O	60%	0.25	1.79
K_2O	60%	0.14	
AVERAGE			***2.00***

Appendix D

Vendor Information
Tail End SCR

Appendix B: SCR Vendor Query Correspondence

1. Vendor Correspondence with SCR system suppliers

1.1 E-Mail correspondence with Clay Erickson, Babcock Power (SCR System Vendor – extensive tail-end SCR experience)

From: cerickson@babcockpower.com [mailto:cerickson@babcockpower.com]
Sent: Thursday, June 19, 2008 15:59
To: Hans Hartenstein
Cc: jlangone@babcockpower.com; tlicata@babcockpower.com
Subject: Re: Tail-end SCR

Hans,

Babcock Power has reviewed the Milton Young plant in the past, based on these reviews Babcock Power finds

- A tail-end SCR is technically and commercial feasible
- Babcock Power does not recommend or require additional pilot testing only proper flue gas characterization as with any SCR system per performed
- Will provide commercial guarantees for the SCR and catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime

Babcock Power has the largest SCR experience list in the world; from this experience we are completely confident in the application of a tail end system at Milton Young. If you have further questions please let me know.

With best regards,
Clay

Clayton Erickson, PhD
Director, Process Engineering
Babcock Power Inc.
5 Neponset Street
Worcester, MA 01606

T: 508-854-4039 F: 508-854-1177
M: 508-245-2383

From: "HansHartenstein"<Hans.Hartenstein@Evonik-EnergyServices.us>
Sent: 06/18/2008 12:16
To: <cerickson@babcockpower.com>
Subject: Tail-end SCR

Clay,

As discussed during our phone conversation today, during which you stated that Babcock Power considers a high-dust SCR principally, technically feasible even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in Babcock Power's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat) Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Babcock Power:

- Consider a tail-end SCR technically feasible?
- Recommend or require additional pilot testing?
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Given the fact that tail-end SCRs in Germany including the ones built by your licensor Fisia Babcock (most of which are on wet bottom boilers) went into operation in the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that Babcock Power / Fisia Babcock has sufficient confidence in your tail-end SCR experience to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

1.2 E-Mail Correspondence with Don Tonn, Babcock & Wilcox (SCR System Vendor – no tail-end SCR experience)

From: Tonn, Donald P [mailto:dptonn@babcock.com]
Sent: Monday, June 23, 2008 16:06
To: Hans Hartenstein
Subject: RE: Tail-end SCR

Hans:

Please note my responses to your questions in the referenced email below.

Regards,
Donald P. Tonn
Babcock & Wilcox Power Generation Group
AQCS Technology
Phone 330-860-1986
Cell 330-289-7795

From: Hans Hartenstein [mailto:Hans.Hartenstein@Evonik-EnergyServices.us]
Sent: Wednesday, June 18, 2008 13:25
To: Tonn, Donald P
Subject: Tail-end SCR

Don,

As discussed during our phone conversation today, during which you stated that Babcock & Wilcox considers a tail-end SCR (downstream of a wet scrubber including flue gas reheat) principally technically feasible for Minnkota's Milton R. Young Station, I would be interested in Babcock & Wilcox's position on the following questions. Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Babcock & Wilcox:

- Consider a tail-end SCR technically feasible? Yes
- Recommend or require additional pilot testing? Requires further discussion with catalyst suppliers.

- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be? While B&W has considered tail-end SCR systems on other projects we have not had these commercial guarantee discussions with the catalyst suppliers for the North Dakota lignite application. Before consideration of providing these guarantees a comfort level would be required after obtaining guarantees from catalyst suppliers.

Given the fact that tail-end SCRs in Germany went into operation in the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that Babcock & Wilcox has sufficient confidence in tail-end SCR systems to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

2. Vendor Correspondence with SCR Catalyst Manufacturers

2.1 E-Mail Correspondence with Cindy Khalaf, Argillon (Catalyst Manufacturer – extensive tail-end SCR experience)

From: Khalaf Cindy R [mailto:cindy.khalaf@argillon.com]
Sent: Tuesday, June 24 2008 14:15
To: Hans Hartenstein
Subject: Re: Argillon Tail-end SCR

No problem.
Regards,
Cindy

From: Hans Hartenstein <Hans.Hartenstein@Evonik-EnergyServices.us>
Sent: Tuesday, June 24, 2008, 16:45
To: Khalaf Cindy R
Subject: RE: Argillon Tail-end SCR

Cindy,

Thanks a bunch for taking the time to respond. I greatly appreciate your answer. I'll keep you posted where this thing is going.

Best regards,
Hans Hartenstein
http://www.evonik-energyservices.us

From: Sadler Randy [mailto:randy.sadler@argillon.com]
Sent: Tuesday, June 24, 2008 08:15 AM

To: Hans Hartenstein
Cc: Khalaf Cindy R
Subject: Argillon Tail-end SCR
Importance: High

On behalf of Cindy Khalaf -

Hans,

Further to our phone call, as far as I know, Argillon has more tail end experience than any other SCR catalyst manufacturer and, as you noted, we also have experience with high dust, German lignite SCRs. Argillon also won the first US lignite SCR catalyst project (Luminant Oak Grove 1 & 2) and provided commercial guarantees. These units are not in service yet. So, yes, we consider ourselves able to answer these questions competently.

Consider a tail-end SCR technically feasible?

Yes, we consider this configuration to be technically feasible. As you know, tail end SCRs are often used when there are significant catalyst poisons in a flue gas stream. A wet scrubber can remove most of these poisons, resulting in very low catalyst deactivation.

Recommend or require additional pilot testing?

For a high dust configuration, we would say definitely. For a tail-end configuration, we would say no. We would only like to see a flue gas analysis for conditions at the inlet to the SCR in order to predict deactivation rate.

Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Generally speaking, yes, we would provide guarantees for DeNOx & slip as specified (not to exceed 90% or 2 ppm), 24k hours life, SO_2 conversion rate - low but value TBD, pressure drop - value TBD. Of course we would have to see the technical specifications before being more specific. In addition, tail-end SCRs perform much longer, so depending on the application specifics, customer, etc., we may decide to extend the operating life guarantees. This is a commercial decision and will be reviewed on a case-by case basis.

If you have any more questions, please let me know.

Regards,
Cindy

Cindy R. Khalaf
Argillon LLC
President
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Email: cindy.khalaf@argillon.com
5895 Shiloh Road, Ste. 101
Alpharetta, GA 30005

From: Hans Hartenstein [mailto:Hans.Hartenstein@Evonik-EnergyServices.us]
Sent: Thursday, June 19, 2008 16:29

To: Khalaf Cindy R
Subject: Tail-end SCR

Cindy,

As discussed during our phone conversation today, during which you stated that Argillon considers a high-dust SCR principally technically, feasible based on your high-dust SCR experience with lignite fired units in Europe even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in Argillon's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat). Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Argillon:

- Consider a tail-end SCR technically feasible?
- Recommend or require additional pilot testing?
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Given the fact that tail-end SCRs in Germany including the ones equipped with Argillon catalyst went into operation in the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that Argillon has sufficient confidence in your tail-end SCR experience to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

2.2 E-Mail Correspondence with John Cochran, CERAM Environmental (Catalyst Manufacturer – extensive tail-end SCR experience)

From: John Cochran [mailto:John.Cochran@ceram-usa.com]
Sent: Wednesday, June 25, 2008 15:14
To: Hans Hartenstein
Cc: Greg Holscher; Noel Rosha; Orehovsky Kurt
Subject: RE: Request for Information

Hans,

CERAM certainly considers the use of a tail-end SCR on applications such as the Milton R. Young Station as technically feasible provided a proper design approach is used. CERAM has the experience from more than 100 tail-end and low dust applications dating from 1988 that would substantiate our opinion. For a tail-end approach we see no need for additional pilot testing. As such, we can provide full commercial guarantees for catalyst performance (activity or lifetime, conversion rate, pressure drop, etc.).

The choice between high dust and tail-end processes certainly should consider capital costs, operating costs and process risk. Based on our experience certainly process risk would favor a tail-end approach, but albeit for most circumstances at a higher "all-in" cost. Should very high retrofit factors be present for a high dust arrangement then the relative economic factors may even favor a tail-end approach.

I hope this information is useful to your evaluation. Please advise should you have any further questions or information needs. Thanks.

Best Regards,
John Cochran

CERAM Environmental, Inc.
www.frauenthal.net
913.239.9896 (phone)
913.205.5615 (cell)

From: Hans Hartenstein [mailto:Hans.Hartenstein@Evonik-EnergyServices.us]
Sent: Tuesday, June 17, 2008 7:20
To: John Cochran
Subject: Request for Information

John,

As discussed during our phone conversation today, during which you stated that CERAM considers a high-dust SCR principally technically, feasible even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in CERAM's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat) Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would CERAM:

- Consider a tail-end SCR technically feasible?
- Recommend or require additional pilot testing?
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Given the fact that tail-end SCRs in Germany including the ones equipped with CERAM catalyst (Herne 1, 2 and 3, Voerde (West) 1 and 2, Lünen 10 and 11 – all of which are wet bottom boilers) went into operation in the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that CERAM has sufficient confidence in your tail-end SCR experience to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

2.3 E-Mail Correspondence with Scot Pritchard, Cormetech (Catalyst Manufacturer – no tail-end SCR experience)

From: Pritchard, Scot G. [mailto:PritchardSG@Cormetech.com]
Sent: Thursday, June 19, 2008 17:41
To: Hans Hartenstein
Subject: RE: Tail-end SCR

Hans,

I was thinking of if you put a coupon in the tailend location and it showed something weird then you would have to do something more elaborate i.e. A slipstream with longer hours, etc. We do not anticipate this - in fact you could probably do without the coupon test as well since I don't see any reason why this system would be any different the primary tail end experience i.e. Unlikely any nasties make it through the lower temperature environment and scrubber process. The coupon is OK but I really don't expect to see much. Finally, we have not done any specific coupon tests (because slipstream has been the primary way to evaluate) so we would need to think through the best way to do it - i.e. holder, mounting arrangement, test method, hours of exposure, etc. If you already have something in mind please let us know.
Hope that helps with the clarification.

Scot

From: "Hans Hartenstein" <Hans.Hartenstein@Evonik-EnergyServices.us>
Sent: Thursday, 6/19/08 4:26 pm
To: "Pritchard, Scot G." <PritchardSG@Cormetech.com>
Subject: RE: Tail-end SCR

Scot,

Thanks for the input from Cormetech, which is greatly valued. One question for clarification purposes only, though. Coupon tests and/or flue gas analysis would only be performed in order to characterize the flue gas going into the tail-end SCR as is needed for the design of any APC equipment. Obviously, nobody could offer any performance guarantees concerning what's coming out of a tail-end SCR without knowing what's going into it. You state that in case coupon tests would show a significant accumulation of catalyst poisons, a subsequent slip stream test, which is unquestionably more accurate and representative of a full scale - in this case tail-end - SCR, would be recommended. Stating this, do I understand you right that you would recommend this slip stream testing mainly for the purpose of properly characterizing the flue gas composition at the inlet to the tail-end SCR in order to provide a reliable basis for correct catalyst design? Do I assume correctly, that you would not require extensive and long-term (12 - 24 months) pilot testing with a slip stream reactor because you have serious doubts about the principal technical feasibility of a tail-end SCR for this application? Please clarify. Thanks.

Best regards,
Hans Hartenstein

From: Pritchard, Scot G. [mailto:PritchardSG@Cormetech.com]
Sent: Thursday, June 19, 2008 12:15
To: Hans Hartenstein
Subject: RE: Tail-end SCR

Hans,

Please see my input below.

As discussed during our phone conversation today, during which you stated that Cormetech considers a high-dust SCR principally technically, feasible even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in Cormetech's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat) Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Cormetech:

- Consider a tail-end SCR technically feasible? - yes

- Recommend or require additional pilot testing? - We generally do not consider coupon testing an accurate representation of an SCR, however in order to minimize cost and provide basic screening information we would suggest the potential use of a coupon sample test. If the coupon shows significant accumulation of catalyst poisons, a subsequent slipstream type test which is more representative of a full scale SCR i.e match velocity, AVs, etc. would be recommended.
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be? Presuming the coupon test does not show anything unusual (which we do not expect to see anything unusual) we would be willing to provide commercial guarantees for a low dust application. Basic guarantees would be associated with life (this would not include specific Ko and K/Ko as guarantees - the guarantee would be an efficiency and slip guarantee at a certain number of operating hours), SO2 conversion, pressure loss.

As discussed, the high dust application needs additional due diligence testing (slipstream, ash testing, etc.) as well as the practicality of the applicable operating temperature to establish the commercial stance for a high dust application on North Dakota Lignite. We have done such work for Texas lignite as well as other coal sources and other fuels/applications in the past and would expect to be able to achieve the same for this application. The economics for any given application would be considered on a case by case basis.
Let me know if you have any questions. Also I would appreciate anything of the final document that you can share.

Thank you and regards,

Scot Pritchard
VP, Sales & Marketing
Cormetech
919-595-8708 o
919-815-2380 c

From: Hans Hartenstein [mailto:Hans.Hartenstein@Evonik-EnergyServices.us]
Sent: Thursday, June 19, 2008 11:35 AM
To: Pritchard, Scot G.
Subject: Tail-end SCR

Scot,

As discussed during our phone conversation today, during which you stated that Cormetech considers a high-dust SCR principally technically, feasible even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in Cormetech's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat) Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Cormetech:
- Consider a tail-end SCR technically feasible?
- Recommend or require additional pilot testing?
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Given the fact that tail-end SCRs in Germany (most of which are on wet bottom boilers) went into operation in the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that Cormetech has sufficient confidence in tail-end SCR systems to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

2.4 E-Mail Correspondence with Flemming Hansen, Haldor Topsoe (Catalyst Manufacturer – extensive tail-end SCR experience)

From: Flemming Hansen [mailto:FGH@topsoe.com]
Sent: Friday, June 27, 2008 12:56
To: Hans Hartenstein
Subject: RE: Tail-end SCR

Hans,
Your understanding is what I meant to say.

Thanks

Flemming G. Hansen
Manager SCR DeNOx Catalyst
Haldor Topsoe, Inc.
281-228-5120 (office)
281-228-5129 (fax)
281-684-8820 (cell)
FGH@Topsoe.com
www.topsoe.com

"Hans Hartenstein" <Hans.Hartenstein@Evonik-EnergyServices.us>
06/24/2008 04:16 PM

To "Flemming Hansen" <FGH@topsoe.com>
cc

Subject RE: Tail-end SCR

Flemming,

Thanks for your note. Just to make sure that I understand you correctly. Is it correct to state that Haldor Topsoe feels fully confident that a tail-end SCR is technically feasible and would not experience any accelerated catalyst deactivation? Therefore, you would be willing to guarantee catalyst performance (NOx removal efficiency, pressure drop, SO_2/SO_3 conversion rate and catalyst lifetime) without any need for further pilot testing. Please confirm. Thanks.

Best regards,
Hans Hartenstein

From: Flemming Hansen [mailto:FGH@topsoe.com]
Sent: Dienstag, 24. Juni 2008 16:44
To: Hans Hartenstein

Subject: Re: Tail-end SCR

Hans,

Like you describe we have had very good operating experience with SCR in the clean environment after a scrubber or bag filter. There appears to be practically no catalyst deactivation and with the low amount of particulate the catalyst pitch can be small, which both leads to a compact SCR as compared to a high dust SCR.

Based on the clean flue gas after the FGD we would not require any further testing in order to guarantee a catalyst performance.

The actual guarantees would be as normally applied in a high dust installation and depend on the catalyst volume and operating conditions. At the low operating temperature expected at the tail-end position the SO_2 oxidation will be negligible.

I hope this confirmation will have your approval.

Flemming G. Hansen
Manager SCR DeNOx Catalyst
Haldor Topsoe, Inc.
281-228-5120 (office)
281-228-5129 (fax)
281-684-8820 (cell)
FGH@Topsoe.com
www.topsoe.com

"Hans Hartenstein" <Hans.Hartenstein@Evonik-EnergyServices.us>
06/24/2008 10:24 AM

To <fgh@topsoe.com>
cc
Subject Tail-end SCR

Flemming,

As discussed during our phone conversation today, during which you stated that Haldor Topsoe considers a high-dust SCR principally technically, feasible even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in Haldor Topsoe's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat) Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Haldor Topsoe:

- Consider a tail-end SCR technically feasible?
- Recommend or require additional pilot testing?
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Given the fact that tail-end SCRs in Germany including the ones equipped with your catalyst have been in operation since the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that Haldor Topsoe has sufficient confidence in your tail-end SCR experience to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

BART DETERMINATION STUDY

for

Leland Olds Station Unit 1 and 2

Basin Electric Power Cooperative

Final Draft

August 2006

37640

BASIN ELECTRIC
POWER COOPERATIVE

Burns & McDonnell
SINCE 1898

Basin Electric Power Cooperative
Leland Olds Station
Units 1 and 2
Best Available Retrofit Technology Analysis

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EXECUTIVE SUMMARY

On July 6, 2005, the U.S. EPA finalized the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations. The final regulations require eligible sources to be analyzed to determine a BART emission limit for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). The North Dakota Department of Health (NDDH) reviewed the operational history of North Dakota sources and determined which sources were BART eligible and provided a state specific modeling protocol for use in the analysis. Basin Electric Power Cooperative's (BEPC's) Units 1 and 2 at the Leland Olds Station (LOS) were determined to be BART eligible by the NDDH. As discussed in the analysis, small emission units at LOS produce emissions in levels anticipated to be too small to affect visibility in Class 1 areas and were excluded from further consideration in the study. This BART determination was conducted in accordance with the eligibility conclusion made by NDDH and follows the steps outlined in the guidelines and the NDDH protocol.

The BART determination process has five predefined steps. Steps 1 through 3 include identifying and evaluating feasible control technologies. Steps 4 and 5 involve a technical evaluation of the impacts related to each control technology. The evaluation reviews multiple impacts including economics and visibility impairment in Class 1 areas. The result of conducting this five step analysis is a list of control technologies for regulated pollutants that provides a cost effective system of emission reduction and visibility impact reduction. This technology list, including control efficiencies, is then translated into an emission rate constituting BART that must be achieved by the eligible source. Although the impacts requiring analysis are explicitly stated within the guideline, no methodology is provided for using the impacts to select a control technology. Thus, every BART analysis will have a certain level of subjectivity based upon source characteristics, reviewed technologies, and background information used to perform the evaluation.

This analysis used several reference works, including the RACT/BACT/LAER Clearinghouse (RBLC), to identify which control technologies to evaluate. The technologies were then reviewed for feasibility and systematically eliminated by analyzing the impacts provided in the guidelines. Specifically, the control technologies were ranked by control efficiency and removed from the list based upon the cost per ton of removal and the reduction in visibility impairment impact. Based upon that evaluation, the BART recommendations are made for each pollutant and are summarized in the tables below.

Leland Olds Station Unit 1 Recommended BART

Pollutant	Percent Removal %	Emission Rate lb/MMBtu
SO_2	90	0.34
NO_X	-	0.29
PM(1)	NA	0.10

(1) - Filterable PM only.

Leland Olds Station Unit 2 Recommended BART

Pollutant	Percent Removal %	Emission Rate lb/MMBtu
SO_2	95	0.17
NO_X	54.5	0.304
PM(1)	NA	0.10

(1) - Filterable PM only.

The rates provided in these tables are based upon the control efficiency of a recommended BART control technology applied to each unit at the Maximum Continuous Rating (MCR) burning 100% lignite fuel. However, because the accuracy of the cost estimate is ± 30% and in some cases is greater than the differences between the estimated costs of feasible control alternatives, the technology used to meet the BART recommendation may change. These rates are not provided as recommended permit conditions. The guidelines suggest that emission limits be developed on a 30-day rolling average for Electric Generating Units (EGUs). Unfortunately, the guidelines do not provide a methodology to calculate the limit for permitting purposes and only state that an enforceable limit that reflects BART requirements must be established.

To develop recommended permit conditions for each pollutant, emissions calculations were performed using an increased Boiler Heat Input and coal sulfur content. Historical variability in plant operations show that the boiler design capacity Heat Input rate was exceeded 10.6% and 7.6% of the operating time for Unit 1 and Unit 2 respectively. Normal plant operation includes exceeding the original boiler design capacity Heat Input rate, which has an impact on hourly emissions variability. Short-term increases of heat input can raise hourly emissions, which can have a significant impact on short-term emission averages. To take into account the influence that an average heat input rate higher-than-nameplate boiler design heat input capacity rating would have on baseline emissions over a 30-day averaging period, a 5% increase in heat input was used for developing a recommended 30-day emission limit for each pollutant for permitting purposes.

Sulfur content of the coal was the primary constituent of concern because SO_2 emissions are directly related to the amount of sulfur in the coal and are not as related to equipment design. A forty year mining plan was analyzed to determine the future maximum annual sulfur content to be used in the BART analysis. The results indicated that future delivered coal will have a maximum annual average sulfur content of approximately 1.13% with a standard deviation of 0.12%. A 30-day rolling average SO_2 emission rate was calculated using the maximum sulfur content plus 1 standard deviation (i.e., 1.25% S).

As previously stated, selection of BART for control of the major pollutants of interest needs to be translated into an emission rate limit, which is not a fixed percent reduction from baseline. The post-control emission rate is influenced by the unit pre-control baseline emission rate and the effectiveness of BART selected for the particular pollutant. Boiler Heat Input is the single most important variable affecting the NO_X emissions rate. The pre-control baseline NO_X emission rate is influenced by the variability of the hourly boiler heat input rate over the duration of the averaging period selected. For LOS Unit 1, the recommended BART 30-day rolling average unit NO_X emission rate is 0.29 lb/mmBtu (presumptive level). A recommended BART 30-day rolling average unit NO_X emission rate of 0.35 lb/mmBtu for LOS Unit 2 results from applying a 54.5 percent reduction to the unit NO_X pre-control baseline emission rate of 0.77 lb/mmBtu that reflects the higher Boiler Heat Input rate. A provisional operating period of one year of operational experience is recommended in conjunction with the recommended BART 30-day rolling average NO_X permit emission rate to allow BEPC to demonstrate the actual control system capabilities of Unit 2's boiler. At the end of that period, it is recommended that the NO_X BART permit limits be reviewed considering the demonstrated operating history.

To account for the higher heat input and higher future sulfur content, a representative SO_2 emission rate was calculated based upon a 5% higher heat input and the maximum annual average sulfur content plus 1 standard deviation (i.e., 1.25% S). The resulting recommended 30-day rolling average SO_2 permit limit for LOS Unit 1 is 0.39 lb SO_2/mmBtu. Similarly, the resulting SO_2 permit limit for LOS Unit 2 is 0.19 lb SO_2/mmBtu.

Emission evaluated rates for particulate matter are based upon the design of the existing electrostatic precipitator and the heat input. The resulting recommended 30-day rolling average PM permit limits for both Unit 1 and 2 are 0.10 lb PM/mmBtu. Using the methodologies discussed for each pollutant, recommended emission limits for each pollutant are tabulated below.

Recommended 30-Day Rolling Average BART Emission Limits for LOS Unit 1

Pollutant	Emission Rate(1) lb/MMBtu
SO_2	0.39
NO_X	0.29
PM	0.10

(1) - 30-day rolling average, based upon an average boiler heat input rate of 2,622 * 1.05 = 2,753 mmBtu/hr and percent removal compared to pre-control baseline emission levels. NO_X pre-control baseline emission rate for this recommended limit is 0.29 lb/mmBtu. Note that the recommended PM emissions are not a 30-day rolling average.

Recommended 30-Day Rolling Average BART Emission Limits for LOS Unit 2

Pollutant	Emission Rate(1) lb/MMBtu
SO_2	0.19
NO_X	0.35
PM	0.10

(1) - 30-day rolling average, based upon an average boiler heat input rate of 5,130 * 1.05 = 5,387 mmBtu/hr and percent removal compared to pre-control baseline emission levels. NO_X pre-control baseline emission rate for this recommended limit is 0.77 lb/mmBtu. Note that the recommended PM emissions are not a 30-day rolling average.

Although the emission limits presented above for each unit are recommended for permitting purposes, this analysis also recommends discussing an alternative compliance method as suggested in the BART Guidelines. The guidelines provide that states, "should consider allowing sources to ''average'' emissions across any set of BART-eligible emission units within a fenceline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible units that constitute a BART-eligible source." (70 FR 39172) During the process of developing enforceable permit conditions, the opportunity to apply a plant-wide limit using an "averaging" or "bubbling" strategy should be considered.

1.0 INTRODUCTION

The U.S. EPA finalized the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations[1] in the Federal Register on July 6, 2005 (70 FR 39104). BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). This document presents the BART analysis for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Basin Electric Power Cooperative's (BEPC's) Leland Olds Station (LOS) Units 1 and 2 located in Stanton, North Dakota.

A BART eligible source is one that meets three criteria identified by EPA in the guidelines for the determination of BART. A source is BART eligible if operations fall within one of 26 specifically listed source categories (70 FR 39158), the source entered into service between August 7, 1962 and August 7, 1977, and the source has the potential to emit 250 tons per year or more of a visibility-impairing air pollutant (SO_2, NO_X or PM). The North Dakota Department of Health (NDDH) reviewed the operational history of sources within North Dakota and independently determined which sources are BART eligible. The NDDH classified the electric generating units (EGUs) at Leland Olds Station as BART eligible. For the purposes of this report, the NDDH's determination will be used and Units 1 and 2 at LOS are assumed to be subject to a BART analysis.

Where a particular source is determined to be eligible, the general steps for determining BART for each pollutant are as follows (70 FR 39164):

STEP 1 - Identify all available retrofit control technologies (within the BART Guidelines).
STEP 2 - Eliminate technically infeasible options.
STEP 3 - Evaluate control effectiveness of remaining control technologies.

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[1] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations"; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.

STEP 4 - Evaluate the following impacts for each feasible control technology and document results: (70 FR 39166).

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

STEP 5 – Evaluate the visibility impacts.

Basin Electric Power Cooperative retained Burns & McDonnell to assist in the completion of the Best Available Retrofit Technology analysis for Leland Olds Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services to the power industry since the 1970s. As a result of their long history providing these services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies and control technology analysis.

This report includes steps 1 through 5 of the BART Determination for emissions from Units 1 and 2 at LOS. Section 1 of the report quickly summarizes the plant conditions, provides the parameters used in the analysis and discusses the approach to the BART Determination. The true BART analysis begins with Sections 2 through 5. Each section contains the analysis for each major pollutant (NO_X, SO_2 and PM). Within the section for each pollutant, the results of each step of the BART analysis are summarized for each unit. Separate summaries for each unit are provided at the end of the report to communicate the results of each step in the analyses, combine results obtained for each pollutant and develop permit limit recommendations based upon a 30 day rolling average.

1.1 BACKGROUND

Basin Electric Power Cooperative operates the Leland Olds Station in Stanton, North Dakota. Leland Olds Station is a steam electric generating plant with two units. Unit No. 1 is a Babcock & Wilcox (B&W) wall-fired, dry-bottom, pulverized coal-fired boiler serving a turbine generator with a nameplate rating of 220 MW. Particulate control is provided by a Research Cottrell electrostatic precipitator (ESP) rated at 99.5% control. Unit 1 has no sulfur dioxide (SO_2) control system and exhausts to a 350 foot tall, concrete stack with a brick liner. Unit No. 2 is a B&W cyclone-fired unit burning crushed coal, with a turbine-generator name plate rating of 440 MW. Particulate control for

Unit 2 is provided by two parallel Joy Manufacturing precipitators rated at 99.1% control. Unit 2 does not have a flue gas desulfurization system and exhausts to a 500 foot tall, concrete stack with a brick liner. Unit 1 began commercial operation in 1966 and Unit 2 in 1976. Due to their designation by the NDDH, both units are subject to the requirements for BART analysis under the Regional Haze Rule.

1.2 BART ANALYSIS PARAMETERS

Table 1.2-1 contains the design parameters for LOS Unit 1 and Unit 2 used in the analysis. Typical coal parameters used in the BART analysis are provided in Table 1.2-2. The economic factors were specified by BEPC for this study and are presented in Table 1.2-3.

Table 1.2-1 – Unit Design and Operating Parameters

Design Unit Operating Characteristics[(1)]	**Unit 1 Design**	**Unit 2 Design**
Boiler Type	Wall-Fired	Cyclone
Boiler Manufacturer	B&W	B&W
Boiler Design Heat Input Capacity (nameplate), mmBtu/hr	2,622	5,130
Unit Nameplate Generator Output Capacity, MW_g (gross)	216	440
Unit Nominal Full Load (NFL) Output, MW_g (gross)	220	440
Boiler Heat Input for Unit NFL Output, mmBtu/hr	2,468	4,846
Boiler Excess O_2, % (all cases)	3	3
Boiler Excess Air, % (all cases)	20	20
Fly Ash Portion of Total Ash, % (all cases)	70	30
Air Heater Leakage, % (all cases)	5	12
Average Boiler Heat Input for NO_X period, mmBtu/hr	2,443	4,478
Average Gross Unit Output for NO_X period, MW_g	217.8	406.5
Average Capacity Factor for NO_X period, % of Unit NFL	99	92.4
NO_X Concentrations at the air heater outlet	**Typical**	**Typical**
lb/mmBtu	0.29	0.67
lb/hr	697	2,987
Average Boiler Heat Input for SO_2 period, mmBtu/hr	2,468	4,846
Average Capacity Factor for SO_2 period, % of Unit NFL	90	85
Coal Flow Rate for Historic SO_2 Case, lb/hr	352,375	691,900
Flue Gas Conditions at the air heater outlet		
Flue Gas Temperature, F	375	395
Flue Gas Pressure, in. wg	-14.80	-14.80
Flue Gas Mass Flow Rate, lb/hr	2,670,000	5,590,000
Flue Gas Volumetric Flow Rate, acfm	972,600	2,085,000
SO_2 Concentrations at the air heater outlet	**Typical**	**Typical**
lb/mmBtu	2.76	2.76
lb/hr	6,817	13,380

Table 1.2-1 – Unit Design and Operating Parameters (cont.)

Design Unit Operating Characteristics	**Unit 1 Design**	**Unit 2 Design**
Future Potential-to-Emit (PTE) Conditions	**Design**	**Design**
Capacity Factor, %	100	100
PTE Case Boiler Heat Input, mmBtu/hr	2,622	5,130
NO_X Concentrations at the air heater outlet	**Typical**	**Typical**
lb/mmBtu	0.29	0.67
lb/hr	760	3,422
Coal Flow Rate for PTE Case , lb/hr	398,700	780,000
Flue Gas Conditions at the air heater outlet		
Flue Gas Temperature, F	375	395
Flue Gas Pressure, in. wg	-14.80	-14.80
Flue Gas Mass Flow Rate, lb/hr	2,838,000	5,921,000
Flue Gas Volumetric Flow Rate, acfm	1,034,000	2,210,000
SO_2 Concentrations at the air heater outlet	**Typical**	**Typical**
lb/mmBtu	3.43	3.43
lb/hr	9,001	17,609

(1) – Averages based upon highest actual 24-month rolling summation for each specific pollutant, years 2000-2004. Boiler heat input and unit generating output are specific to the actual 24-month period for each specific pollutant.

Table 1.2-2 – Coal Parameters

Ultimate Coal Analysis (% by mass):	**PRB Typical**	**Lignite Typical**	**Typical Blended Coal[(1)]**	**Future Coal Case (Lignite)[(2)]**
Moisture	32.00	37.25	36.88	37.25
Carbon	47.88	38.26	38.93	38.26
Hydrogen	3.10	2.69	2.72	2.69
Nitrogen	0.70	0.67	0.67	0.67
Chlorine	0.01	0.01	0.01	0.01
Sulfur	0.43	0.96	0.92	1.13
Ash	5.20	8.45	8.22	8.45
Oxygen	10.69	11.70	11.63	11.70
Total	100.01	99.99	99.99	100.16
Higher Heating Value, Btu/lb	8,000	6,577	6,677	6,548
Ash Mineral Analysis (% by mass):				
Silica	28.11	29.09		29.09
Alumina	15.57	13.06		13.06
Titania	1.31	0.51		0.51
Calcium Oxide	24.60	21.14		21.14
Magnesium Oxide	6.53	7.39		7.39
Sodium Oxide	1.60	7.55		7.55
Iron Oxide	6.01	4.96		4.96
Sulfur Trioxide	12.22	6.20		6.20
Potassium Oxide	0.23	1.20		1.20
Phosphorus Pentoxide	0.60	0.21		0.21
Strontium Oxide	not reported	not reported		not reported
Barium Oxide	not reported	1.49		1.49
Manganese Oxide	not reported	not reported		not reported
Total	96.78	92.80		92.80

(1) - Typical blend of 93% North Dakota lignite and 7% Powder River Basin (PRB) subbituminous coal on an annual basis.

(2) - A forty year mining plan was analyzed to determine the future maximum annual sulfur content to be used in the BART analysis. The mining plan data used in the analysis is presented in Appendix B2.

Table 1.2-3 – Economic Factors[(1), (2)]

Total Possible Operating Hours per Year	8,760
Amortization Life, Years	20
Cost of Money	6%
Property Taxes, Insurance, %	NA
Conversion Tax (in lieu of property tax)	(see footnote 3)
Amortization Rate for APC Capital Costs	6%
Interest During Construction (IDC)	6%
Discount Rate	6%
Construction Cost Escalation	3%
Non-Fuel O&M Escalation	2%
Fuel (coal and natural gas) Escalation	2%
Auxiliary Electric Power Cost, $/MW-hr	$38.00
Fly Ash Disposal Cost ($/ton)	$5.51
Bottom Ash Disposal ($/ton)	$2.10
Operating Labor Rate (fully burdened), $/hr	$40.60
Administrative or Supervisory Overheads	30%
Lime Cost ($/ton delivered) (4)	$60.50
Limestone Cost ($/ton delivered) (4)	$25.00
Urea Cost, ($/ton delivered)	$380.00
Ammonia Cost ($/ton delivered)	$304.45
Natural Gas ($/mmBtu)	$7.98

(1) - All costs in the table were provided by BEPC.
(2) - All costs are in 2005 dollars unless noted otherwise.
(3) - Conversion tax is provided in the economics for each pollutant control technology.
(4) - Lime and limestone costs are in 2006 dollars.

1.3 APPROACH

The purpose of the Regional Haze Rule is to address visibility impairment in mandatory Class 1 areas that results from the emission of SO_2, NO_X, PM, Volatile Organic Compounds (VOCs) and ammonia from certain major sources. The visibility impact of VOCs and ammonia are considered negligible for a BART analysis, according to the NDDH's November 2005 modeling protocol[2], and are not addressed further in this report. Before the actual BART analysis can begin, a basis must be defined for establishing emission rates to be used by eligible sources. The NDDH requested companies use the same basis that is used for the Prevention of Significant Deterioration (PSD) program which is to determine the hourly averages from the highest 24-month rolling summation emissions within the

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[2] "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota"; North Dakota Department of Health, Division of Air Quality; November, 2005.

previous 5-year operating period. BEPC reviewed its operating data for 2000 through 2004 to obtain historical emission rates presented in Table 1.3-1.

Table 1.3-1 – Leland Olds Station Historical Emissions for BART Analysis

Pollutant	Unit 1		Unit 2	
	lb/h(1)	tpy(2)	lb/h(1)	tpy(2)
SO_2	4,280	18,749	7,899	34,596
NO_X	697	2,967	2,987	12,023
PM (3)	68.68	263.9	153.32	577.2

(1) - Pounds per hour (lb/h) for SO_2 and NO_X for these historic pre-control baseline emission rates determined as actual 24-month highest rolling summation tons x 2000 lb/ton divided by actual 24-month operating hours for the same time period.

(2) - Tons per year (tpy) for SO_2 and NO_X calculated as the 24 month highest rolling summation tons divided by 2.

(3) - PM emissions calculated from actual 24-month highest rolling summation heat input (mmBtu) divided by actual 24-month operating hours for the same time period multiplied by the average PM total lb/mmBtu from particulate matter tests performed annually.

The historical emission rates are averages based upon operating at partial capacity and burning specific types of coal. Due to the narrow operational characteristics that are a result of past coal quality from which these emission rates were obtained, they are considered not representative for performing a BART analysis at LOS that accurately reflects future coal quality. BEPC discussed an alternative method to obtain acceptable emission rates with the NDDH and obtained approval to use different rates in the LOS BART analysis. The alternative rates are based upon each unit operating at 100% capacity and burning lignite with higher sulfur content. A forty year mining plan was analyzed to determine the future annual average lignite sulfur content used in the BART analysis. The alternative baseline emission rates for the future coal case scenario are labeled “PTE Emissions” and are presented in Table 1.3-2.

Table 1.3-2 – Leland Olds Station Future PTE Emissions for BART Analysis

Pollutant	Unit 1		Unit 2	
	lb/h(1)	tpy(2)	lb/h(1)	tpy(2)
SO_2	9,001	39,424	17,610	77,132
NO_X	760	3,330	3,422	14,989
PM	73	320	169	740

(1) - Pounds per hour (lb/h) for these future PTE pre-control baseline emission rates determined from assumed unit emission rates (lb/mmBtu) multiplied by boiler design capacity heat input rating (mmBtu/hr) provided in Table 1.2-1.

(2) - Tons per year (tpy) calculated from the average hourly unit emission rates multiplied by 8,760 hours per year of possible operation.

In Part IV of the Guidelines for BART Determination, and discussed in Section 1.0 of this report, the EPA provides five basic steps for a case-by-case BART analysis. The format of this report follows these basic steps. The approach used to complete each step is summarized below.

1.3.1 IDENTIFICATION OF RETROFIT CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit control technologies. In order to identify the applicable control technologies, several reference works are consulted. A preliminary list of control technologies and their estimated capabilities is developed.

1.3.2 FEASIBILITY ANALYSIS

The second step of the BART process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the "availability" and "applicability" of each control technology.

A control technology is considered available, "if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term" or "if it has reached the stage of licensing and commercial availability." On the contrary, a control technology is not considered available, "in the pilot scale testing stages of development." (70 FR 39165) When considering a source's applicability, technical judgment must be exercised to determine "if it can reasonably be installed and operated on the source type." The EPA also does not "expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type." (70 FR 39165) "A technology that is available and applicable is technically feasible." (70 FR 39165)

1.3.3 EVALUATE TECHNICALLY FEASIBLE CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the BART analysis, the control efficiency is reviewed and presented with the description of each technology. The evaluation of the technically feasible BART alternatives concludes with the alternatives ranked in descending order of control effectiveness.

1.3.4 IMPACT ANALYSIS

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis. The BART Determination will consider the following four factors in the impact analysis:

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

The first three of the four factors considered in the impact analysis are discussed in the associated pollutant section. The remaining useful life of the source is included as part of the cost of compliance. Due to the complexity involved with estimating costs, additional discussion is provided below.

1.3.5 METHODOLOGY FOR ESTIMATED COSTS

The economic evaluations of each control alternative are presented together for each pollutant in the respective sections of the report. Capital and O&M cost estimates for each control alternative are presented. The Levelized Total Annual Cost (LTAC) and Unit Control Costs for the control alternatives are calculated and presented. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 20 year design life, again in current (2005) dollars. As a minimum, the design life for any alternative was taken to be that recommended by “The EPA Air Pollution Control Cost Manual”, Sixth Edition, January 2002, EPA/452/B-02-001.

The LTAC is also used to calculate the average annual and incremental cost effectiveness of each alternative. The LTAC represents an annual payment in current day dollars sufficient to finance the project over its entire life.

In determining the LTAC a Capital Recovery Factor and an O&M Levelization Factor were calculated from the project economic conditions and then applied separately to the estimated capital and O&M costs. The equation used is shown below.

$$LACC/NPV = \left(\frac{i(1+i)^n}{(1+i)^n - 1} \right) = CRF$$

Where,
LACC = Levelized Annual Capital Cost
NPV = Net Present Value of the capital investments required.
i = discount rate
n = design life in years
CRF = Capital Recovery Factor

Therefore:

LACC = CRF x NPV

For the economic conditions described in Table 1.2-3 the Capital Recovery Factor was calculated to be 0.08718.

In determining the levelized annual O&M cost the estimated annual O&M cost, the inflation rate, the discount rate, and the equipment life are taken into account. The O&M Levelization Factor (OMLF) was calculated as follows.

$$LAOMC/A_1 = \left(\frac{1+i_d}{1+i_i} - 1 \right) \left(\frac{i_d (1+i_d)^n}{(1+i_d)^n - 1} \right) = OMLF$$

Where,
A = Levelized Annual O&M Cost (LAOMC)
A_1 = Total annual O&M cost in current dollars
i_d = discount rate
i_i = inflation rate
n = design life in years

Therefore:

LAOMC = OMLF x A_1

For the economic conditions described in Table 1.2-3 the Operating and Maintenance Levelization Factor was calculated to be 1.19314.

The Levelized Total Annual Cost, or LTAC is the sum of the levelized capital cost and the levelized O&M cost. Therefore:

$$\text{LTAC} = \text{LACC} + \text{LAOMC} = (\text{CRF x NPV}) + (\text{OMLF x } A_1) = 0.08718 \text{ x P} + 1.19314 \text{ x } A_1$$

The differences between alternatives are also presented graphically in the form of a plot of the LTAC versus the annual emissions reduction (tpy) for each alternative. This form of plot graphically depicts the cost effectiveness (in $/ton of pollutant reduction) of each alternative relative to all of the others. The cost effectiveness is also referred to as the Unit Control Cost and defined as the LTAC divided by the annual emissions reduction (ton/yr). The area on the plot indicated by the various data points represents the cost effectiveness envelope for the alternatives under consideration. A smooth line is drawn on this plot connecting the rightmost points (those with the lowest cost for a given level of emissions reduction). This line is referred to as the Dominant Control Curve (DCC). The DCC defines the right hand boundary of the envelope encompassing all of the alternatives considered. The DCC is used as a screening tool between considered alternatives. Those alternatives whose plotted position is above and/or to the left of the DCC are not as cost effective as those forming the line and thus can be eliminated from further analysis if desired.

In order to compare various pollutant control alternatives, the Unit Control Cost and the incremental Unit Control Cost of each alternative were also calculated and tabulated for comparison purposes. The Unit Control Cost compares control technologies on a basis of dollars expended per ton of pollutant reduced ($/ton). This relationship is graphically depicted in the DCC chart.

To more accurately compare between alternatives with different costs and control efficiencies, the incremental cost effectiveness is also determined for those alternatives on the DCC. The incremental cost effectiveness is defined as the LTAC of a given control option minus the LTAC of an alternative, divided by the difference between the annual emissions reduction (tpy) of the given control option and the alternative being evaluated. The combination of these two economic analyses can be used as an argument for the elimination of control technologies with significantly greater marginal control costs than the given case. The equation used for the incremental cost effectiveness is shown below.

$$ICF = \frac{(LTAC_1 - LTAC_2)}{(AE_1 - AE_2)}$$

Where,

ICF = Incremental cost effectiveness ($/incremental ton removed)
$LTAC_1$ = Levelized Total Annual Cost of control alternative No. 1 ($/yr)
$LTAC_2$ = Levelized Total Annual Cost of control alternative No. 2 ($/yr)
AE_1 = Control option No. 1 Annual Emissions Reduction (ton/yr)
AE_2 = Control option No. 2 Annual Emissions Reduction (ton/yr)
(The higher cost, more effective control option is subscript 1 in this equation.)

The economic analyses presented in this report not only include the estimated capital and O&M costs for each alternative, but also the LTAC for economic comparison of the various alternatives. In addition, the Unit Control Cost or cost effectiveness is presented for each alternative. Finally, a comparison between alternatives, in the form of the incremental cost effectiveness, is presented in both numerical and graphical form. Thus a comprehensive comparison of the economic impacts of each alternative, as well as the differences in economic impact between alternatives is clearly presented.

1.3.6 METHODOLOGY FOR VISIBILITY IMPACTS DETERMINATION

In the BART Determination Guidelines, and discussed in Section 1.0 of this report, the EPA provides five basic steps for a case-by-case BART analysis. The fifth step involves evaluating visibility impacts utilizing dispersion modeling. Visibility impairment impacts for modeled pre-control and post-control emission levels and visibility improvements are to be assessed in deciViews (dV). The BART guidelines describe the thresholds for visibility impairment as:

> "A single source that is responsible for a 1.0 dV change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 dV change may still contribute to visibility impairment..... any threshold that you (the States) use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 dV." (70 FR 39161)

The NDDH BART protocol does not distinguish between a source that "causes" or "contributes" to visibility impairment but follows the EPA's Regional Haze Rule threshold recommendations. Thus, 0.5 dV is the deminimis threshold level of visibility impairment impact for an otherwise BART-eligible source under the NDDH BART protocol. In other words, a BART-eligible source for which modeling predicts a visibility impairment impact of greater than 0.5 dV is deemed to have a visibility impairment impact and thus is subject to a BART analysis under this the NDDH BART protocol. A BART-eligible source for which the modeling predicts less than a 0.5 dV impact would be deemed to not have a visibility impairment impact, and thus could be exempted from BART on that basis. Most noticeably, the EPA refrains from addressing the question of whether or not a difference in visibility impairment impact improvement of less than 0.5 dV between two BART alternatives would constitute equivalency under the visibility analysis, or if any difference in the model results, no matter how slight, should be interpreted as ranking one solution over the other.

The approach taken in the BART analysis for LOS incorporates the visibility analysis results as part of the decision making process. Thus, when ranking a particular BART alternative during the selection process, the visibility improvement associated with the implementation of that particular alternative is included in the ranking. If two alternatives have an identical potential for visibility improvement, the remaining criteria identified for consideration as part of the impact analysis are then used to differentiate between the two alternatives. Where similar visibility improvement potentials are identified for two or more alternatives, the incremental cost to achieve the slightly greater visibility improvement is determined and evaluated against incremental costs for the next most stringent alternative. This approach identifies the more effective BART alternative in terms of regional haze considerations, not in terms of the most stringent control alternative, as would happen if a strictly top-down approach had been implemented.

1.3.7 ADDITIONAL APPROACH METHODS

In addition to the steps discussed above, there are two subjects within the guidelines which warrant mention due to their effects on the contents of the report. The first subject deals with the presumptive limits and their application to power plants smaller than 750 MW in size. The Guidelines for BART Determination include the following statement with regard to presumptive BART for SO_2 (70 FR 39171):

> "You (meaning States) must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lbs/MMBtu, for each EGU greater than 200 MW that is currently uncontrolled unless you determine that an alternative control level is justified based on a careful consideration of the statutory factors. For a currently uncontrolled EGU

> greater than 200 MW in size, but located at a power plant smaller than 750 MW in size, such controls are generally cost effective and could be used in your BART determination….."

Similarly for NO_X, the EPA states (70 FR 39171):

> "For coal-fired EGUs greater than 200 MW located at greater than 750 MW power plants and operating without post-combustion controls, we have provided presumptive NO_X limits differentiated by boiler design and type of coal burned. You may determine that an alternative control level is appropriate based on a careful consideration of the statutory factors. For coal-fired EGUs greater than 200 MW located at power plants 750 MW or less in size and operating without post-combustion controls, you should likewise presume that these same levels are cost-effective."

For power plants greater than 750 MW in size, the EPA requires state agencies to apply the presumptive limits for BART as a floor for NO_X control. However, for power plants smaller than 750 MW in size, the presumptive limits are described as being "cost-effective" but not set as a minimum performance requirement. Thus, BART for EGUs at power plants smaller than 750 MW in size, like LOS, is not required to meet the presumptive limits. This BART analysis for LOS will evaluate potential control options that can attain presumptive limits on typical EGUs. Consequently, based upon the feasibility analysis, the recommended control options may not achieve the EPA's presumptive BART limits for specific pollutants from certain units.

The second part of the guideline that should be addressed relates to which emission units are subject to BART for a particular pollutant. The guideline states that:

> "Once you determine that a source is subject to BART for a particular pollutant, you must establish BART for that pollutant. The BART determination must address air pollution control measures for each emissions unit or pollutant emitting activity subject to review." (70 FR 39163)

According to this statement, the BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2, PM) regardless of size. The BART analysis for LOS will review control options for the main boilers for Unit 1 and Unit 2. However, smaller emissions sources at the facility are anticipated to provide negligible contribution to visibility impacts from LOS in Class 1 areas. Smaller sources at LOS are discussed in Section 1.3.8 through 1.3.10.

1.3.8 SMALL SOURCE EMISSION UNITS

The BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2, PM) regardless of size. However, smaller emissions sources at the facility are anticipated to provide negligible contributions to visibility impairment in Class 1 areas. The nearest Class 1 area is Theodore Roosevelt National Park located approximately 145 km to the west. Although technically eligible, smaller source emissions units were not reviewed because they have limited hours of operation and consequentially their emissions are too small to affect visibility in Class 1 areas. Table 1.3-3 lists emission units at Leland Olds Station that have very low operating hours due to the function of the equipment.

Table 1.3-3 – Leland Olds Station Limited Operation Emissions Units(1)

Emission Unit	Fuel	Rating	Operating Hours	NO_X (tons/yr)	SO_2 (tons/yr)	PM (tons/yr)
Auxiliary Boiler	Fuel Oil	51.6 mmBtu/hr	3.6	0.0128	0.0257	0.0013
Emergency Fire Pump	Fuel Oil	255 hp	4.3	0.00015	0.00030	0.00001

(1) - Emissions are based upon amount of fuel used, sulfur content of the fuel oil, AP-42 emission factors and actual average plant operations for the period of 2000 – 2004.

1.3.9 MATERIAL HANDLING EMISSIONS

Table 1.3-4 lists the emission rates for the material handling units at Leland Olds Station. The majority of the material handling units are associated with the totally enclosed coal delivery system. Since the system is totally enclosed, there would normally be no emissions associated with the equipment. However, the original equipment included air handling systems to reduce fire and explosions hazards caused by build-up of coal dust. The air handling systems used either rotoclones or baghouses for particulate control.

Table 1.3-4 – Leland Olds Station Material Handling Emissions Units

Emission Unit	Unit ID	PM Emissions (tons/yr) (1)
Rotoclone Transfer Tower G	M1	0(2)
Rotoclone Reclaim Tunnel	M2	0(2)
Rotoclone Crusher House (E)	M3	0(2)
Rotoclone Crusher House (W)	M4	0(2)
Rotoclone Transfer Tower	M5	0(2)
Rotoclone Unit 1 Bunker House	M6	0(2)
Rotoclone Unit 2 E. Bunker	M7	4.38
Rotoclone Unit 2 W. Bunker	M8	4.38
Rotoclone Unit 2 W. Trans. Conveyor	M9	4.38
Rotoclone E. Trans. Conveyor	M10	4.38
Baghouse Fabric Filter Main Fly Ash Silo	M11	0.95
Baghouse Fabric Filter 100 Ton Fly Ash Silo	M12	0.01
Baghouse Fabric Filter Coal Unloading	M13	12.39
Baghouse Fabric Filter Agglomerator	M14	0.04
Rotoclone Unit 1 Coal Bunker	M15	0(2)
Baghouse Fabric Filter Coal Unloading Silo	M16	0.19

(1) - Emissions are based upon manufacturers design emission rate and Units 1 and 2 operating at 100% capacity for 8760 hours. Hours of operation were maximized to account for variations in service and resulting annual emissions variation.

(2) - A fogging system was installed in 2003 to replace rotoclones used for fire suppression. The system uses totally enclosed transfer points and does not have any emissions.

In 2003, a water based fogging system was installed in the coal delivery system to provide a higher level of coal dust suppression inside the enclosed system. The existing air handling equipment with the rotoclones were placed in a stand-by mode thereby eliminating associated emissions. As shown in Table 1.3-4, the emission points currently using the fogging system do not have emissions. A search of the RACT/BACT/LAER database for coal handling sources showed that baghouses are currently recognized as the most effective control available for material handling sources emitting PM. No further BART analysis was conducted for baghouse controlled sources listed in Table 1.3-4 because the most effective control technology is already in use on these sources. Materials handling units at LOS using controls produce emissions in levels anticipated to be too small to affect visibility in the nearest Class 1 area located approximately 145 km away and were excluded from further consideration in the study.

1.3.10 FUGITIVE DUST

The primary source of fugitive dust is from the outside coal storage area and other plant activities normally found at a coal-fired electrical generating facility. The coal stockpile, access roads and plant activities are performed and maintained with good operating practices. On the coal stockpile and on other applicable fugitive sources, dust suppression is achieved through the use of water sprays or surfactants.

The level of fugitive PM emissions are not expected to affect the visibility in Class 1 areas based upon the approximate 145 km distance to the nearest Class 1 area, the large particle size and relatively small emission rates. As such, fugitive sources were not evaluated in this BART analysis for LOS.

1.4 THE ROLE OF MODELING AND CALPUFF IN A BART ANALYSIS

The proposed BART guidelines list visibility impact at a Class I area as one of the factors in a BART determination. The EPA interpreted the statutory provision of Section 169A of the Clean Air Act to require that a BART-eligible source is one that is “reasonably anticipated to cause or contribute” to regional haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area (70 FR 39161). A Class I area, as listed by the EPA, is an area of the country with pristine air quality that is sensitive to changes in visibility. For Class I areas more than 50 km from a source, the EPA has identified CALPUFF as a guideline model for long-range transport that is suitable for predicting potential changes in visibility. CALPUFF is a non-steady-state meteorological and air quality dispersion modeling system used to access long-range transport of pollutants. Two Class 1 areas have been identified for inclusion in the visibility analysis for LOS. These are the Theodore Roosevelt National Park (TRNP), and the Lostwood National Wildlife Refuge (Lostwood NWR), which are approximately 145 and 160 km (90 and 100 miles), from Leland Olds Station, respectively.

The NDDH modeling protocol confirmed that the two Class I areas to be considered for visibility impairment analysis are the TRNP and Lostwood NWR. However, the three units or areas of the TRNP are to be treated as separate Class I areas for the analysis.

1.4.1 CALPUFF MODELING METHODOLOGY

Visibility impairment is caused by a combination of particles and gases in the atmosphere. Some particles and gases scatter light, others absorb light. The combined effect of scattering and absorption is called “light extinction” which is most commonly seen as haze. This haziness is measured in deciView (dV) units, and is related to light extinction coefficient by the following equation:

$$dV = 10 \ln(b_{ext}/10)$$

Where b_{ext} is light extinction coefficient in inverse megameters.

Visibility impairment is a function of light extinction. Light extinction occurs when light energy is either scattered or absorbed by particles in the air. The amount of moisture in the air also plays a role in light extinction. Certain gases combine with moisture in the air to form small light scattering particles. These gases, most notably SO_2 and NO_X, are significant components of coal-fired power plant emissions. Particulate Matter (PM) also contributes to light extinction. In the BART Determination Guidelines, the EPA states that "You may use PM_{10} as an indicator for particulate matter. We do not recommend the use of Total Suspended Particulates (TSP). As emissions of PM_{10} include the components of $PM_{2.5}$ as a subset, there is no need to have separate 250 ton thresholds for PM_{10} and $PM_{2.5}$; 250 tons of PM_{10} represents at most 250 tons of $PM_{2.5}$, and at most 250 tons of any individual particulate species such as elemental carbon, crustal material, etc." (70 FR 39160). The NDDH modeling protocol states that particulate matter emissions should be specified as either course (PM_{10} minus $PM_{2.5}$) or fine ($PM_{2.5}$). The distinction between course and fine particulate occurs in the modeling.

The NDDH modeling protocol recommends a specific version of the CALPUFF modeling system as modified by the NDDH to specifically address terrain, climate, and emission characteristics of LOS. (CALMET and CALPUFF were recompiled by the NDDH while the CALPOST executable used for this visibility analysis was the EPA guideline executable). Along with the CALPUFF modeling system, the NDDH also provided the RUC2-MM5 gridded wind field data (2000-2002), surface, upper air, and precipitation files, and CALMET and CALPUFF input files. The input files contained the specific coordinate grid points, wind field options, terrain, dispersion options, receptor coordinates and plume characteristics and other model parameters that the NDDH has determined best represents the region. The NDDH version of CALPUFF was used for modeling.

In order to predict the change in light extinction at TRNP and Lostwood NWR areas, SO_2, NO_X, and PM were modeled with CALPUFF using pre-control and post-control emission scenarios. A variety of post-control scenarios were used to determine the reduction in visibility impact for each control technology. The NDDH identified 104 receptors allocated over both TRNP and Lostwood NWR. These receptors are location points for which CALPUFF was used to perform a visibility calculation.

The BART guideline states that a visibility improvement is based upon the modeled change in visibility impacts, measured in deciViews, for the pre-control and post-control emission scenarios.

The comparison should be made for the 98th percent days (70 FR 39170). The NDDH modeling protocol provides additional clarification about BART applicability by stating, "…the context of the 98th percentile 24-hour delta-deciView prediction is with respect to days of the year, and is not receptor specific. A 24-hour prediction greater than 0.5 delta-deciView at any receptor in a Class I area would constitute a day of exceedance, and up to 7 days of exceedance would be allowed per year per Class I area (i.e., the 98th percentile is approximated by the eighth-highest daily prediction)." In other words, visibility impacts should be compared on an annual basis using the eighth highest day for comparison (365 * (1-.98) ~ 7 days of acceptable exceedance). However, NDDH subsequently advised that the delta-deciView comparison should be made at the 90th percentile to be consistent with the Western Regional Air Partnership (WRAP) protocol. Therefore, the visibility impairment impact reduction presented for each control scenario in this section is based on the 90th percentile value.

1.4.2 MODELING SCENARIOS

Since a BART analysis is based on the degree of reduction achieved by the application of control technologies, the CALPUFF analysis examined multiple operating scenarios based upon the feasible control technologies identified for each pollutant. These scenarios represent the emissions of SO_2, NO_X, and PM under the following conditions:

- Pre-Control NDDH BART Modeling Protocol historical emissions
- Post-Control emissions based upon future coal data, PTE conditions and control technologies

The removal efficiencies modeled in each scenario are presented in Table 1.4-1.

Table 1.4-1 – Leland Olds Station Emissions Modeling Scenarios

Scenario	**Unit 1**		**Unit 2**	
	NO_X	**SO_2**	**NO_X**	**SO_2**
Screening	Uncontrolled	Uncontrolled	Uncontrolled	Uncontrolled
1(1)	Presumptive(2)	90.0%	60.3%	95.0%(3)
2(1)	Presumptive(2)	93.0%	54.5%	95.0%(3)
3(1)	Presumptive(2)	95.0%(3)	28.0%	95.0%(3)
4(1)	20.7%	90.0%		
5(1)	20.7%	93.0%		
6(1)	20.7%	95.0%(3)		

(1) - Percentages for emission reductions for future PTE post-control (future coal scenario) cases were applied to future PTE baseline average hourly unit emission rates and correspond to control options evaluated in this analysis.

(2) - Presumptive BART NO_X emissions for dry-bottom, wall-fired boilers burning lignite for LOS Unit 1.

(3) - Presumptive BART SO_2 emissions.

These scenarios represent the range of emissions evaluated to date for consideration in making a BART analysis. The removal efficiencies presented in Table 1.4-1 correspond to control options evaluated in this analysis. The pre-control scenario from the NDDH BART modeling protocol is based on the historical, maximum 24-hour emission rates for LOS between 2000 and 2002. These rates were supplied to the NDDH by BEPC, but were based upon emissions from burning specific types of coal. Due to analyses performed on future coal reserves, BEPC has determined that these historic rates are not representative of future maximum 24-hour emissions and has requested NDDH to allow the use of an alternative baseline. NDDH agreed to the alternative baseline. The alternative baseline and post-control scenarios are based upon various control technology emission reductions being applied to emissions from burning future coal at a heat input equal to the 100% of the boiler design capacity rating. Due to the number of variations involved for each pollutant, the scenarios are discussed in the section related to the controlled pollutant.

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2.0 NO_X BART EVALUATION

A summary of the BART analysis, steps 1 through 5, for NO_X emissions from Leland Olds Station Unit 1 and Unit 2 are described in this section. A review and discussion of the EPA's presumptive BART NO_X emission limits for dry bottom, wall-fired boilers and cyclone-fired boilers burning lignite is presented. Technical descriptions of LOS Unit 1 and Unit 2 boilers and existing air pollution control equipment are provided. NO_X control technologies are identified, evaluated for feasibility and control capability, then ranked according to effectiveness. The impacts analysis for cost of compliance are summarized, with the estimated capital costs, and operating and maintenance (O&M) costs, for remaining feasible NO_X control alternatives. Remaining useful life impact analysis is included in the calculations for estimated annual costs of the feasible alternatives. Following the cost estimates, the cost effectiveness for selected feasible NO_X control technologies are plotted, and those that comprise the Dominant Control Curve are identified. The energy, non-air quality environmental, and visibility impacts are developed and summarized.

The NO_X BART evaluations for LOS Units 1 and 2 were combined for this part of the BART analysis due to similar control technologies (e.g., both EGUs include coal-fired boilers burning North Dakota lignite), with unit-specific cost-effectiveness and impacts analysis developed for each boiler.

Leland Olds Unit 1 is a Babcock and Wilcox pulverized coal-fired steam generator installed in 1966 (RB-412). The unit includes a pulverized coal-fired subcritical steam-generating boiler using balanced-draft and natural circulation. Original unit design steam generating capacity is 1.570 million lbs/hr at 2,475 psi. The boiler is fired by 20 second-generation low-NO_x burners, consisting of two rows of four burners each arranged within compartmented windboxes across the back wall, and opposed by three rows of four burners across the front wall of the furnace. Four close-coupled, windbox/register-style overfire air ports are arranged across each of the front and rear walls of the furnace just above the top rows of burners. The unit has a tubular air heater installed between the boiler and the ductwork leading to the electrostatic precipitator (ESP) for preheating primary air to promote coal drying and conveying through the ten pulverizers to the burners. Compartmented windboxes are supplied with main combustion air (secondary air) preheated by two rotary regenerative (Ljungstrom) air heaters arranged in parallel. These secondary combustion air heaters (SCAHs) cool the flue gases prior to admission to the ESP. Exhaust gases leave the air heaters and pass through an ESP for particulate collection and removal prior to the two induced draft (ID) fans (installed in parallel) which discharge to the stack. Design nameplate output rating is 216 MW.

LOS Unit 1 does not currently employ post-combustion NO_X emission reduction technology. A summary of the identified NO_X emission control technologies is summarized in Section 2.1.

Leland Olds Station Unit 2 is a Babcock and Wilcox cyclone-fired steam generator first placed into commercial operation in 1975 (RB-489). The unit includes a subcritical steam-generating boiler using balanced-draft and assisted natural circulation. Original unit design steam generating capacity is 3.075 million lbs/hr at 2,620 psi. The boiler is fired by twelve 10-foot diameter cyclone burners, arranged "3 over 3" on front and rear walls of the lower furnace. The unit has a tubular air heater, installed for preheating primary air for coal drying and conveying, and secondary combustion air. The air preheater is located between the boiler and the flue gas ductwork leading to the pair of electrostatic precipitators (ESPs) installed in parallel. Exhaust gases leave the air heater and pass through the two parallel ESPs for particulate collection and removal prior to the two induced draft fans (installed in parallel) which discharge to the stack. Design nameplate output rating is 440 MW.

LOS Unit 2 does not currently employ post-combustion NO_X emission reduction technology. A summary of the identified NO_X emission control technologies is discussed in Section 2.1.

2.0.1 DISCUSSION OF BART GUIDELINES FOR NO_X BART CONTROL ALTERNATIVES AT LELAND OLDS STATION

EPA's final Guidelines for BART Determinations (BART Guidelines), and the Preamble to the final rule, established presumptive emission limits for nitrogen oxides for coal-fired electric generating units (EGUs), including wall-fired dry bottom, pulverized coal boilers burning lignite[1] [70 FR 39172, 39135]. According to the final BART Guidelines, "States, as a general matter, must require owners and operators of greater than 750 MW power plants to meet these BART emission limits" [70 FR 39131]. However, the EPA also recognized that:

> "A State may establish different requirements if the State can demonstrate that an alternative determination is justified based on a consideration of the five statutory factors. In addition, while States are not required to follow these guidelines for EGUs located at power plants with a generating capacity less than 750 MW, based on our analysis…the States will find these same presumptive controls to be highly cost-effective, and to result in a significant degree of visibility improvement, for most EGUs greater than 200 MW, regardless of the size of the plant at which they are located. A State is free to reach a different conclusion if the State

> believes that an alternative determination is justified based on a consideration of the five statutory factors" [70 FR 39131].

The EPA further states in the BART Guidelines that:

> "For sources without post-combustion controls (i.e. SCRs and SNCRs), we [the EPA] are establishing a presumption as to the appropriate BART limits for coal-fired units based on boiler design and coal type. These presumptions apply to EGUs greater than 200 MW at power plants with the generating capacity greater than 750 MW and are based on control strategies that are generally cost-effective for all such units" [70 FR 39134].

Also in the BART Guidelines is the statement:

> "both cost effectiveness and post-control rates for NO_X do depend largely on boiler design and type of coal burned. Based on these analyses, we [the EPA] believe that States should carefully consider the specific NO_X rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits" [70 FR 39134].

2.0.1.1 PRESUMPTIVE BART NO_X LIMITS FOR PULVERIZED COAL-FIRED BOILERS

According to the BART Guidelines, there are a total of 491 BART-eligible coal-fired EGUs. Of those EGUs, 121 are dry-bottom, wall-fired units greater than 200 MW output. There are 44 dry-bottom, wall-fired units greater than 200 MW output located at power plants with less than 750 MW total output capacity [70 FR 39134, Table 1]. Unit 1 at Leland Olds Station satisfies this criterion.

According to the EPA, for "all types of boilers other than cyclone units, the limits … are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs" [70 FR 39134]. Also, "the types of current combustion control technology options assumed [in the EPA's analysis] include low NO_X burners, over-fire air, and coal reburning" [70 FR 39134]. Furthermore, the EPA "assumed that coal-fired EGUs would have the space available to install separated over-fire air" [70 FR 39134].

In the BART Guidelines, the EPA lists the presumptive NO_X emission limits for BART-eligible coal-fired units, distinguished by unit type, and coal type. For dry-bottom, wall-fired EGUs burning lignite coal, the NO_X presumptive limit is 0.29 lb/mmBtu [70 FR 39135, Table 2]. The analysis performed by the EPA for establishing the presumptive limits for NO_X emissions from pulverized coal-fired EGUs assumed only the application of low-NOx burners and overfire air combustion controls.

The actual highest 24-month rolling NO_X summation total from 2000-2004 divided by the actual 24-month rolling summation unit heat input for the same time period for Unit 1 at Leland Olds Station meets the presumptive BART NO_X emission limits stated above. The future PTE case also meets presumptive BART NO_X emission limits. The requirements of performing a NO_X BART analysis on a BART-eligible coal-fired unit with a nameplate capacity greater than 200 MW at a powerplant less than 750 MW that has a unit NO_X emission rate that meets the EPA's presumptive BART NO_X emission limit is not apparent in the BART Guidelines. However, this BART analysis presents a NO_X control technology feasibility evaluation, with impact analysis for NO_X control alternatives. This includes the four prescribed impact criteria plus the impact assessment for visibility impairment improvement for a separated overfire air alternative following the general procedures of the BART Guideline.

2.0.1.2 PRESUMPTIVE BART NO_X LIMITS FOR CYCLONE-FIRED BOILERS

EPA's presumptive limit for emissions of nitrogen oxides from cyclone-fired boilers was established in the final BART Guidelines and the Preamble to the final rule [70 FR 39172]. In discussing NO_X controls for EGUs, there are two somewhat distinct approaches to reducing NO_X at existing sources. One approach is to use combustion controls. The other approach is removal technology applied to the flue gas stream (such as SCRs and SNCRs).

For NO_X emissions control, the EPA analyzed:

> "the installation of SCRs at BART-eligible EGUs, applying SCR to each unit and fuel type. The cost-effectiveness was generally higher than for current combustion control technology except for one unit type, cyclone units. Because of the relatively high NO_X emission rates of cyclone units, SCR is more cost-effective than the use of current combustion control technology for these units. The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and lignite should enable the units to cost-effectively meet NO_X rates of 0.10 lbs/mmBtu. As a result, [the EPA] are establishing a presumptive NO_x limit of 0.10 lbs/mmBtu based on the use of SCR for coal-fired cyclone units greater than 200 MW located at 750 MW power plants. As with other presumptive limits established in this guideline, [the

> States] may determine that an alternative level of control is appropriate based on [the States'] consideration of the relevant statutory factors. For other cyclone units, [the States] should review the use of SCR and consider whether these post-combustion controls should be required as BART"[1] [70 FR 39172].

Also, for cyclone boilers,

> "SCRs were found to be more cost-effective than current combustion control technology [which the EPA established in their analysis as coal reburning]; thus the NO_X limits for cyclone units are set based on using SCRs" [70 FR 39134].

The EPA identified a population of 56 BART-eligible coal-fired cyclone boilers used in their cost-effectiveness analysis for applying SCRs for NO_X control [70 FR 39134 Table 1]. Of the 56 cyclones, 35 are units larger than 200 MW, and 19 are units larger than 200 MW located at 750 MW plants [70 FR 39134]. Conversely, there are 16 cyclone-fired units greater than 200 MW output located at power plants with less than 750 MW total output capacity. Unit 2 at Leland Olds Station fits this criterion.

The EPA's Technical Support Document[2] published in the Edocket (EPA's internet website) for the BART Guidelines describes the cost-effectiveness analysis that resulted in the establishment of SCR as the presumptive NO_X control technology for BART-eligible cyclone-fired coal EGUs. For such cyclone EGUs, the analysis assumed that the unit capacity capital cost factor was $100/kW and 90 percent of the boiler outlet NO_X concentration was removed by SCR technology. The EPA's cost-effectiveness analysis assumed presumptive BART emission rates for the cyclone-fired EGU at Leland Olds Station as 0.07 lb/mmBtu, based on a pre-control emission rate of 0.7 lb/mmBtu. This is approximately 60 percent lower than the lowest BART NO_X presumptive limit (0.17 lb/mmBtu) for dry-bottom, tangentially-fired boilers that burn pulverized lignite coal.

In the EPA's setting of presumptive NO_X limits for coal-fired EGUs larger than 200 MW at power plants greater than 750 MW total gross output rating, the EPA also recognizes that:

> "because of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective…As noted, the NO_X limits set forth here today are presumptions only; in making a BART determination, States have the ability to consider specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source" [70 FR 39134].

This BART analysis presents a NO_X control technology feasibility evaluation of pre-combustion, combustion, and post-combustion controls, including SCR, separated overfire air, SNCR, and coal reburn for Leland Olds Station Unit 2. This includes the four prescribed impact criteria plus the impact assessment for visibility impairment improvement following the general procedures of the BART Guideline.

2.0.1.3 TECHNOLOGY AVAILABILITY AND APPLICABILITY FOR EMISSION CONTROLS

The second step of the BART process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The final BART Guidelines states that "two key concepts [are] important in determining whether a technology could be applied: "availability" and "applicability" [70 FR 39165].

As explained in more detail in the final BART Guidelines:

> "a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term" [70 FR 39165].

For the purposes of this analysis, the term "commercial" is further defined to mean "capable of establishing a full contractual agreement with commercial and performance guarantees supported by appropriate financial backing" for the implementation of full-scale, full-time systems of the technique or technology application.

Also per the BART Guidelines:

> "An available technology is "applicable" if it can be reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible" [70 FR 39165].

A control technique is considered available "if it has reached the stage of licensing and commercial availability" [70 FR 39165]. "Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible" [70 FR 39165]. Also, "vendor guarantees may provide an indication of commercial availability and technical feasibility of a control technique and contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances" [70 FR 39165]. Furthermore, the EPA does "not consider a vendor guarantee alone as sufficient justification that a control option will work.

Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option is technically infeasible" [70 FR 39165]. [A State agency] "should make decisions about technical feasibility based on chemical, and engineering analyses, as discussed above, in conjunction with information about vendor guarantees" [70 FR 39165]. The EPA also does not "expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently [a State agency] would not consider technologies in the pilot scale stages of development as "available" for the purposes of a BART review" [70 FR 39165]. This would appear to apply to many emerging technologies in the bench, pilot-scale, or "proof-of-concept" testing phases of development, so these were eliminated from the list of potential controls included in subsequent sections of this analysis.

Also in the EPA's final BART Rule is a qualification of "applicability" for technical feasibility, as described by the statement:

> "[a State agency] need[s] to exercise technical judgment in determining whether a control alternative is applicable to the source type under consideration. Where [a State agency] conclude[s] that a control option identified in Step 1 is technically infeasible, [the State agency] should demonstrate that the option is either commercially unavailable, or that specific circumstances preclude its application to a particular emission unit. Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g. size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility)" [70 FR 39165].

2.0.1.4 TECHNOLOGY EVALUATION FOR CONTROL EFFECTIVENESS

The third step in a BART evaluation is to evaluate the remaining control technologies for control effectiveness. The purpose is to establish a level of control effectiveness of the remaining feasible control technologies compared to baseline emission levels so that a suitable basis for estimating cost effectiveness can be determined. In order to determine control and cost effectiveness, "the degree of control using a metric [units] that ensures an "apples to apples" comparison of emissions performance levels among options" [70 FR 39166] is one of the two key issues that must be addressed in a BART analysis. For fossil fuel-fired boilers associated with steam-electric generating units, pounds of nitrogen oxides per unit of fuel heat input (i.e. lb/mmBtu), is a common means of comparing and calculating NO_X emissions.

The second key issue in the evaluation of technically feasible control alternatives is giving appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels. Many control techniques, including both add-on controls and inherently lower polluting processes, can perform over a wide range of levels. To clarify this concept:

> "It is not the [EPA's] intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options. It is important, however, that in analyzing a technology [the States] take into account the most stringent emission control level that the technology is capable of achieving. [The States] should consider recent regulatory decisions and performance data (e.g. manufacturer's data, engineering estimates, and the experience of other sources) when identifying emissions performance level or levels to evaluate" [70 FR 39166].

2.0.1.5 IMPACT EVALUATION FOR FEASIBLE CONTROLS

The fourth step in a BART evaluation is to evaluate BART-specific impacts of remaining feasible control technologies. This consists of four parts:

- Impact analysis part 1: Costs of compliance.
- Impact analysis part 2: Energy impacts.
- Impact analysis part 3: Non-air quality environmental impacts.
- Impact analysis part 4: Remaining useful life of the source.

The purpose of the impacts evaluation is to determine if the remaining useful life of the source or any energy, economic, and non-air quality environmental reasons would eliminate the remaining control technologies from consideration.

Section 1.2 includes information pertinent to the cost analysis for part 1 of the impacts, involving several basic subtasks as prescribed by the BART Guidelines:

1. Identify the emissions units being controlled;
2. Identify design parameters for emissions controls; and
3. Develop cost estimates based upon those design parameters.

According to the BART Guidelines:

> "The part of the plant being evaluated for control costs must be clearly identified and well defined. The analysis should provide a clear summary list of equipment and the associated control costs. Specifying the control system design parameters, and the values selected for those parameters, should ensure that the control option will achieve the level of emission control being evaluated. Once the control technology alternatives and achievable emissions performance levels have been identified, estimated capital and annual costs are developed. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor or by a referenced source (such as the OAQPS Control Cost Manual, latest edition), with the latter preferred where possible. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option" [70 FR 39166].

2.0.1.6 VISIBILITY IMPACT EVALUATION FOR FEASIBLE CONTROLS

The fifth step in a BART analysis is to conduct a visibility improvement determination for the source. In order to predict the change in light extinction at the nearest Class 1 areas (TRNP and LNWR), hourly average SO_2, NO_X, and particulate matter emission rates were modeled with CALPUFF using pre-control baselines and different emission control scenarios. Other pollutants are emitted during coal combustion, but the BART guidelines focus on these three. The BART visibility impairment impact analysis was based on:

- NDDH BART protocol screening analysis emission rates (historic highest 24-hour pre-control average)[3]; and
- Potential-To-Emit (PTE) emission rates for the future PTE case (post-control).

A BART visibility impact analysis calculates the change in modeled visibility impairment predicted for the pre-control emissions rates (baseline) compared to the visibility impairment predicted from modeled post-control emissions rates over the days with the highest 90% and 98% visibility impacts above natural background levels at each receptor. Since visibility is a 24-hour averaged analysis, each receptor was tabulated for each day and the visibility impairment impact predicted for the worst 7 days (98th percentile) or worst 36 days (90th percentile). Results from the three-year modeling period included the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area (100th percentile). The visibility impairment impact (dVs) predicted for the 98th percentile and 90th percentile levels were also included with model results. This data is shown in Section 2.4 for LOS Unit 1, and Section 2.5 for LOS Unit 2, with additional details in Appendix D1.

The modeled visibility impact scenarios represent the range of emissions evaluated for consideration in making a BART analysis. The LOS boilers' heat inputs for the future PTE case are from the current NDDH Title V operating permit for LOS dated 7/27/98. The BART guidelines specify "presumptive BART" as 95% SO_2 control and NO_X levels of 0.29 lb/mmBtu for dry-bottom, wall-fired boilers burning pulverized lignite. These conditions were applied to the emissions for one run of visibility modeling of the post-control future PTE case for LOS Unit 1. Additional modeling runs for LOS Unit 1 were performed for various high levels of SO_2 control with a NO_X emission level expected to result from the next highest cost NO_X control alternative, i.e. achieving below the presumptive BART NO_X level using separated overfire air. The emissions for the post-control future PTE case for LOS Unit 2 include a presumptive BART level of 95% SO_2 control along with various alternative levels of NO_X control presented in Table 1.4-1.

2.0.1.7 BASIS FOR NO_X BART ANALYSIS AT LOS - UNIT 1

For LOS Unit 1, control and cost-effectiveness were evaluated at the historic highest 24-consecutive month average NO_X emission rate during the calendar years 2000-2004. This pre-control NO_X emission rate averaged 247 tons per month for the period ending on the last day of August 2004. This is equivalent to 2,967 tons of NO_X per year, and corresponds to an average hourly NO_X emission rate of 697 lbs per hour of actual operation. The historic 24-month average hourly NO_X emission rate for LOS Unit 1 is based upon an annual average unit operation of 8,510 hrs/yr corresponding to the same time period. This annual unit operation is equivalent to a 97.2% plant availability factor relative to 8,760 hrs/yr. An equivalent 24-month average NO_X emission rate of 0.285 lb/mmBtu was derived for this period of operation. An average gross unit output of 217.8 MW and average gross fuel heat input rate of 2,443 mmBtu/hr correspond to this same historic 24-month operating period. Compared to an average gross fuel heat input rate of 2,468 mmBtu/hr corresponding to a nominal 220 MW gross unit output, this historic highest 24-month operation resulted in an average running plant capacity factor (RPCF) of 99.0 percent during this same time period. The availability factor of 97.2% and the running plant capacity factor were used to calculate an overall capacity factor of 96.2 percent. LOS Unit 1's nameplate capacity of 216 MW (gross) output was used for the basis of controls design for BART determination purposes according to the EPA's Technical Support Document – Methodology for Developing BART NO_X Presumptive Limits[2]. This nameplate capacity also served as the assumed number for calculating capital costs based on $/kW unit capacity capital cost factors.

For LOS Unit 1, control and cost-effectiveness were also evaluated at the post-control basis for the maximum future PTE case. This analysis assumed an hourly average gross fuel heat input rate equal to the boiler design capacity rating of 2,622 mmBtu/hr for 8,760 hours per year of operation for LOS Unit 1's boiler.

The BART Guidelines specify presumptive BART levels for NO_X emissions from a dry bottom, wall-fired EGU burning pulverized lignite as 0.29 lb NO_X/mmBtu. The equivalent 24-month highest historic average NO_X emission rate was 0.285 lb /mmBtu during the calendar years 2000-2004. If the EPA's presumptive BART level were applied to LOS Unit 1's NO_X emissions, this would indicate that LOS Unit 1 already complies on a historic long-term average basis. Maintaining an average NO_X emission rate of 0.29 lb /mmBtu for the future PTE case for LOS Unit 1 also complies with the EPA's presumptive BART NO_X emission level for dry-bottom wall-fired boilers burning pulverized lignite in power plants greater than 750 MW.

2.0.1.8 BASIS FOR NO_X BART ANALYSIS AT LOS - UNIT 2

For LOS Unit 2, the highest 24-consecutive month average NO_X emission rate during the calendar years 2000-2004 averaged 1,002 tons per month, for the period ending on the last day of February 2003. This pre-control NO_X emission rate is equivalent to 12,023 tons/yr, and corresponds with an average NO_X emission rate of 2,987 lbs per hour of actual operation. The historic 24-month average hourly NO_X emission rate for LOS Unit 2 is based upon an annual average unit operation of 8,050 hrs/yr corresponding to the same time period. This annual unit operation is equivalent to a 91.9% plant availability factor relative to 8,760 hrs/yr. An equivalent 24-month average NO_X emission rate of 0.667 lb /mmBtu was derived for this period of operation. An average gross unit output of 406.5 MW and average gross fuel heat input rate of 4,478 mmBtu/hr correspond to this same historic 24-month operating period. Compared to an average gross fuel heat input rate of 4,846 mmBtu/hr corresponding to a nominal 440 MW gross unit output, this historic highest 24-month operation resulted in an average running plant capacity factor (RPCF) of 92.4% during this same time period. LOS Unit 2's nameplate capacity of 440 MW (gross) output was used for the basis of controls design for BART determination purposes according to the EPA's Technical Support Document –

Methodology for Developing BART NO_X Presumptive Limits[2]. This nameplate capacity also served as the assumed number for calculating capital costs based on $/kW unit capacity capital cost factors.

For LOS Unit 2, control and cost-effectiveness were also evaluated at the post-control basis for the future PTE case. This analysis assumed an hourly average gross fuel heat input rate equal to the boiler design capacity rating of 5,130 mmBtu/hr for 8,760 hours per year of operation for LOS Unit 2's boiler.

2.1 IDENTIFICATION OF RETROFIT NO_X CONTROL TECHNOLOGIES

The first step in the BART evaluation for nitrogen oxides emissions following determination of BART eligibility is to identify potentially applicable retrofit control alternatives. A comprehensive literature search was performed, with sources including technical papers and presentations made by parties involved with design, construction, and testing of NO_X control techniques at conferences sponsored by nationally-recognized technical organizations, plus hardware supplier experience lists.

Uncontrolled NO_X emissions from a coal-fired electric generating unit are highly dependent on type of firing method, amount of solid fuel fired per unit time and furnace volume, and the fuel's basic combustion properties and elemental composition. The methods for reduction of such emissions:

- either prevent pollution, i.e. use inherently lower-emitting processes/practices which produce fewer NO_X emissions during the power generation process; or
- involve improvements to, or provide new add-on controls that, reduce emissions after they are produced before they are emitted from the facility; or
- are combinations of inherently lower-emitting processes and add-on controls.

There are three basic categories of NO_X emission control alternatives:

- Pre-combustion controls;
- Combustion controls; and
- Post-Combustion controls.

A significant number of the identified control options have been commercially-available, installed, and operating in many full-scale, permanent installations i the United States for five years or more.

A summary of the potentially available alternatives identified for NO_X emissions control on coal-fired steam-electric generating units is shown in Table 2.1-1.

TABLE 2.1-1 – Potentially Available NO_X Control Alternatives Identified for BART Analysis

Control Technology
Pre-Combustion Controls
Fuel Blending/Switching/Cleaning
Combustion Controls
Basic Combustion Control Improvements
Low NO_X Burners (LNB)
Separated Overfire Air (SOFA) / Boosted SOFA
Flue Gas Recirculation
Fuel Reburn
Oxygen-enhanced Combustion (OEC)
Water/steam Injection (Combustion Tempering)
Post-Combustion Controls
Selective Non-Catalytic Reduction (SNCR)(1)
Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO®)(2)

Notes: these are basic forms of the identified techniques.
Not all variations or combinations are included.
(1) – SNCR technologies include Rich Reagent Injection, and Hydrocarbon-enhanced SNCR, commercially available as "NO_XStar™".
(2) – Multi-pollutant control technology currently under commercial development by Powerspan Corp.

Pre-combustion controls, such as fuel switching, fuel blending, and fuel cleaning, have been practiced and performed at numerous utility power plants, typically for sulfur dioxide and nitrogen oxide emissions control reasons.

Combustion controls, such as low-NO_X burners (LNBs) and overfire air systems, are very commonly applied to pulverized coal and gaseous or liquid fuel-fired boilers. Flue gas recirculation (FGR) has been applied and practiced at numerous natural gas and fuel oil-fired utility and industrial power plants for NO_X emissions control. FGR has been applied to large coal-fired utility boilers, primarily for steam temperature control purposes, not for emissions control. Conventional Gas Reburn (CGR) with overfire air has been placed in commercial operation on several cyclone-fired boilers, primarily in the eastern region of the United States. Coal Reburn (CR) with overfire air has been successfully demonstrated on two cyclone-fired boilers and commercially installed on three pulverized coal-fired boilers in the United States.

Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) are post-combustion technologies that have been applied mostly on eastern or midwestern bituminous coal-fired boilers. Others, mostly comprised of a combination of available control technologies, are often referred to as "hybrid" or "layered" control technologies. Variations of SNCR, such as recently developed "Rich Reagent Injection" (RRI) technology with and without SNCR, have only been demonstrated on a limited number of cyclone-fired boilers. Other layered NO_X emission control technologies, such as Fuel Lean Gas Reburn with SNCR, hydrocarbon-enhanced SNCR (commercially available as NO_XStar™), and oxygen-enhanced combustion have only been demonstrated and/or installed on a limited number of pulverized coal-fired power plants.

Emerging post-combustion multi-pollutant control technologies, such as Powerspan's Electro-Catalytic Oxidation (ECO®), which include NO_X control, were also identified. These are typically in the pilot-scale commercial development phase, and have not been successfully demonstrated on a full scale basis on any pulverized coal, cyclone, or circulating fluidized bed boilers.

In most of the "layered" control combination and emerging control cases, the NO_X control technology has been demonstrated to be capable of controlling the targeted pollutant(s) on either:

- a full-scale basis, but only with temporary equipment; or
- a full-scale basis, with permanent equipment but in a limited number of installations; or
- a commercial development basis with less than full-scale and full-time application.

The predominant method employed for control of NO_X emissions on dry bottom, wall-fired pulverized coal boilers is the application of low-NO_X burners (LNBs) and separated overfire air systems. Section 2.2 includes a summary of these control technologies available for potential use on LOS Unit 1, which uses existing low-NO_X burners and close-coupled overfire air. LOS Unit 1 appears to meet the current EPA BART presumptive NO_X emission level for dry bottom, wall-fired boilers burning pulverized lignite.

There are a number of coal-fired cyclone boilers around the country that have implemented or are planning to implement modifications to reduce NO_X emissions. Table 2.1-2 summarizes the various NO_X emission control system installations currently installed, or that have been demonstrated on a full-scale, short-term basis, in response to Acid Rain requirements, EPA's NO_X SIP call and local regulations, or a utility investigating the technology. The following section also includes a summary of these control technologies potentially available and applicable for use on LOS Unit 1 and Unit 2

TABLE 2.1-2 – Identified NO_X Control System Retrofits on Pulverized Coal and Cyclone Coal-Fired Boilers

No. of Units[1]	NO_X Control Technology Description[1]
	Pulverized Coal-Fired Boiler NO_X Control Technology Description
100+	Pulverized coal Low-NO_X Burners, w/ and w/o Separated Overfire Air (SOFA)
28	Selective Non-Catalytic Reduction, w/ and w/o Low NO_X Burners & SOFA
50+[2],[3]	High-dust or low-dust SCR, with or without other technologies
0[3]	Tail-gas SCR, with or without other technologies
8	Conventional fuel reburn (coal, gas, oil, orimulsion), w/ and w/o Low- NO_X Burners
1	Fuel lean gas reburn (FLGR), w/ and w/o Low- NO_X Burners
5	Amine-enhanced FLGR, w/ and w/o Low- NO_X Burners
2	Oxygen-enhanced combustion, w/ and w/o Low- NO_X Burners
	Cyclone Coal-Fired Boiler NO_X Control Technology Description
39[4]	Separated Overfire Air (SOFA)
22[3]	High-dust or low-dust SCR, with or without other technologies
1[3]	Tail-gas SCR, with or without other technologies
7[5]	Conventional fuel reburn (pulverized or micronized coal, gas), w/ SOFA
1[6]	Fuel lean gas reburn, with or without SOFA
2	Selective Non-Catalytic Reduction, with or without SOFA
2[7]	Rich Reagent Injection, with SOFA

(1) – This list of known NO_X control retrofit installations is primarily focused on units in the United States. There may be other installations that are similar but were not identified. Includes boilers retrofit for full-scale temporary demonstration testing and permanent installations. Does not include Powerspan's ECO™ multi-pollutant control pilot plant (commercial demonstration unit, or CDU) at FirstEnergy's R.E. Burger Station Units 4&5.

(2) – At least 85 existing SCRs have been installed on BART-eligible EGUs in the US, mostly on coal-fired boilers burning eastern bituminous fuels. No examples of boilers located in the United States that were retrofit for full-scale, permanent TG SCR installations were found. PSE&G's Mercer Station Units 1 & 2 have low-dust SCRs with flue gas reheat, but they do not have flue gas desulfurization systems upstream of the SCR reactor inlets. See Technical Literature Reference list and Appendix A for further details

(3) – High-dust SCR technology has been retrofitted on sixteen U.S. cyclone-fired boilers, all believed to have SOFA. Low-dust SCRs in U.S. have only been installed on pulverized coal-fired boilers, none on cyclones. One tail-gas SCR installation on a coal-fired cyclone boiler found in Germany; none in the U.S. See technical literature references in Appendix A1 and A3 for details.

(4) – Installed for NO_X control without fuel reburn. A list of known cyclone boiler SOFA installations is included in Appendix A3.

(5) – Several conventional coal and gas reburn retrofits have discontinued reburn demonstration or routine operation. See Technical Literature Reference list and Appendix A3 for further details.

(6) – Only one example of fuel lean gas reburn retrofit (without OFA) on a cyclone-fired boiler has been demonstrated. This system was installed for short-term reburn testing and has since been removed.

(7) – RRI has only been demonstrated with temporary equipment for testing. See Technical Literature Reference List and Appendix A3 for further details.

A more detailed description of the various NO_X control technology retrofits and their technical feasibility is included in Appendix A1, with the associated references for technical literature. A summary of several U.S. NO_X retrofit projects and their claimed emission control effectiveness are included in Appendix A3, with the associated technical literature references for the selected NO_X control projects' listed in Appendix A4.

2.2 TECHNICAL DESCRIPTIONS AND FEASIBILITY ANALYSIS OF NO_X CONTROL TECHNOLOGIES

The second step of the BART process is to evaluate the control processes that have been identified. The following paragraphs summarize the evaluation of the processes for technical feasibility for Leland Olds Station Unit 1 and Unit 2 NO_X controls.

2.2.1 FEASIBILITY OF PRE-COMBUSTION NO_X CONTROLS

Pre-combustion controls involve technologies that are usually applied to the fuel and occur prior to entering the boiler. Pre-combustion controls include:

- Fuel switching,
- Fuel blending, and
- Fuel cleaning.

These techniques have been practiced and performed at numerous utility power plants, typically for operational and sulfur emissions control reasons. These methods are feasible, but considering the current use of lower cost lignite fuel and approximately equal combustion performance, they are not expected to produce lower NO_X emissions, and were eliminated from further consideration for NO_X control at Leland Olds Station. These techniques were not included in the NO_X control cost-effectiveness analysis. For more details, refer to the technical feasibility description included in Appendix A1.

2.2.2 FEASIBILITY OF COMBUSTION NO_X CONTROLS AT LOS

2.2.2.1 COMBUSTION NO_X CONTROLS - UNIT 1

Combustion controls include technologies that are applied to a pulverized fuel-fired boiler. These are summarized as follows:

- Basic combustion control improvements such as low-NO_X burners and separated overfire air are feasible, primarily involving improvements to measuring and controlling fuel feed and combustion air distribution. Basic combustion control improvements and improved operating techniques have already been implemented on the Unit 1 boiler to lower NO_X emissions, so no significant further reductions are expected without being incorporated into another feasible alternative, such as separated overfire air. Basic combustion control improvements alone were eliminated from consideration for additional NO_X reduction at Leland Olds Station.
- Low-NO_X burners (LNBs) are commonly installed in place of original equipment provided prior to 1990. These are often, but not always, installed with some form of overfire air to allow for air-staged or "starved air" combustion to lower NO_X emissions. LOS Unit 1 already has second-generation replacement low NO_X burners suitable for good combustion performance and low NO_X emissions with pulverized lignite fuel. Installing the latest multi-zone LNBs would not significantly lower NO_X emissions without adverse operational consequences, such as unstable flame patterns and raising unburned carbon levels in the emitted flyash. Using the latest LNB technology was eliminated from consideration for additional NO_X reduction at LOS for Unit 1.
- Separated overfire air (SOFA) systems are very commonly applied to pulverized coal-fired boilers for combustion NO_X control. SOFA systems typically divert approximately 15-20% of the hot secondary combustion air admitted to the boiler through the burners to dedicated ports located at higher elevations of the furnace, above the top row of burners. The overall amount of excess air admitted to the boiler is not substantially different than prior to implementation of a SOFA system. SOFA systems are often installed and operated with low-NO_X burners to provide lower carbon monoxide (CO) emissions and unburned carbon (UBC) levels in flyash during air-staged burner operation for effective NO_X emissions control. Booster fans may use ambient or hot secondary combustion air to supply the SOFA ports for higher velocity air injection, which promotes better mixing with the furnace gases for lower CO emissions and flyash UBC content than may be achieved with diverted secondary air on boilers with low windbox air pressure.

  - Unit 1 at LOS already has close-coupled overfire air (CCOFA) and is capable of modest levels of additional NO_X emissions reduction by eliminating CCOFA and adding SOFA. Using SOFA was included in the control effectiveness analysis for additional NO_X reduction at LOS for Unit 1.
  - "Rotating Opposed Fired Air" (ROFA) is feasible for dry-bottom, wall-fired pulverized coal boilers such as LOS Unit 1. It is different than basic SOFA in that it includes a hot air booster fan and injects the high-pressure overfire air into the boiler in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row[9].
    - ROFA does not offer a significantly greater NO_X control reduction advantage compared with conventional SOFA to compensate for the higher costs of supplying, installing, and operating the booster fan for LOS Unit 1. This technology is subject to the same operating limitations as conventional air-staged or fuel-staged pulverized coal burners burning North Dakota lignite. (See Appendix A1 for details).
    - Alternatives with boosted overfire assume the installation of ROFA in the control effectiveness and cost evaluation for the Unit 1 boiler at Leland Olds Station.
- Fuel reburn, with and without overfire air:
  - Conventional gas reburn (CGR) and conventional pulverized or micronized coal reburn (PCR or MCR) have been installed and demonstrated as effective for NO_X control on pulverized coal boilers [10,11,12,13,15,16]. CGR or PCR/MCR replaces around 15-30% of total boiler fuel heat input with reburn fuel injected downstream of burners and upstream of SOFA, with or without air-staging the burners. CGR or PCR/MCR would likely involve operation with fewer active pulverized coal main burners.
    - Although LOS currently has no direct high volume supply of gaseous fossil fuels, conventional gas reburn is otherwise considered technically feasible for NO_X control at LOS. Compared with other similarly-effective NO_X controls, conventional gas reburn's expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make gas-consuming alternatives economically unattractive for application at LOS. Conventional gas reburn alternatives were not evaluated further for consideration as NO_X control options for LOS Unit 1.
    - Powerhouse site space constraints would require dedicated buildings and grinding equipment for coal reburn fuel preparation for LOS Unit 1. PCR/MCR would require improvements to increase PM collection efficiency for LOS Unit 1 to prevent higher particulate matter emissions (described in more detail in Appendix A1).

    - Conventional pulverized/micronized coal reburn alternatives were included in the control effectiveness and cost evaluation for the Unit 1 boiler at Leland Olds Station.
  - Fuel-lean gas reburn (FLGR™) has been permanently installed on only a few dry-bottom, pulverized coal-fired boilers. FLGR™ replaces around 6-7% of total boiler fuel heat input with natural gas injection downstream of burners and overfire air, with or without air-staging the burners below stoichiometric ratio.
    - FLGR™ is considered technically feasible for application on LOS Unit 1, but compared with other equally-effective NO_X controls, the expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make this alternative economically unattractive for application at LOS.
    - With much higher installation and operating costs compared with SOFA, FLGR™ alternatives were not evaluated further for consideration as NO_X control options for LOS Unit 1.
- Oxygen-enhanced combustion (OEC) has only been demonstrated and/or installed on a limited number of small pulverized coal-fired power plants[19,20].
  - OEC has not been demonstrated and does not have permanently installed experience on pulverized coal boilers in the same output range as LOS Unit 1. Compared with other equally-effective NO_X controls, expected high on-going oxygen costs make this alternative economically unattractive for application at LOS.
  - OEC was considered infeasible for NO_X control application at LOS on Unit 1.
- Flue gas recirculation (FGR) has been applied and practiced at numerous natural gas and fuel oil-fired utility and industrial power plants for NO_X emissions control. No examples of flue gas recirculation applied to dry-bottom wall-fired pulverized coal boilers for NO_X control were found. FGR has been applied to large coal-fired utility boilers, primarily for steam temperature control purposes, but not for emissions control. Lacking demonstrated experience on pulverized coal boilers for NO_X control purposes, FGR was considered infeasible for application at LOS on Unit 1
- Water/steam injection has been retrofit and intermittently practiced on older natural gas and oil-burning wall-fired utility boilers. This technique was not found to be permanently installed and continuously practiced on dry-bottom wall-fired pulverized coal boilers, especially those that fire high-moisture lignite or western subbituminous coals. Thus, water/steam injection was considered infeasible for permanent, full-time, long-term application for NO_X control on Unit 1.

2.2.2.2 COMBUSTION NO$_X$ CONTROLS - UNIT 2

Combustion controls include technologies that are applied to a cyclone-fired boiler. These are summarized as follows:

- Basic combustion control improvements and improved operating techniques have already been implemented on the Unit 2 boiler to lower NO$_X$ emissions, so no significant further reductions are expected without being incorporated into another feasible alternative, such as separated overfire air. Basic combustion control improvements were eliminated from consideration for additional NO$_X$ reduction at LOS for the Unit 2 boiler.
- Low-NO$_X$ burners (LNBs) are not applicable as replacements of cyclones for combustion NO$_X$ control[4]. This alternative was considered infeasible for application at LOS for the Unit 2 boiler.
- Separated overfire air (SOFA) systems have been retrofit to many cyclone boilers[4,5,6,7,8] for combustion NO$_X$ control. The amount of secondary combustion air diverted from the burners and function of a SOFA system applied to a cyclone boiler is generally the same as for a pulverized coal boiler. Supplying a booster fan for raising the pressure of the separated overfire air on a cyclone boiler is unnecessary, since cyclone boilers inherently require higher pressure combustion air than pulverized coal boilers.
  - "Advanced" SOFA (ASOFA) offers the highest performing version of this technology for lignite-fired cyclone boilers, and includes relocating lignite drying system vent ports and flue gas recirculation ports. Using ASOFA was included in the control effectiveness analysis for additional NO$_X$ reduction at LOS for Unit 2. Such NO$_X$ control improvements at LOS Unit 2 will be limited by potential adverse impacts on cyclone operation associated with air-staged (sub-stoichiometric air/fuel) cyclone operation, which are described in Appendix A1.
  - ROFA has not been demonstrated or permanently installed and operated on any cyclone boiler.
    - ROFA is subject to the same operating limitations as conventional air-staged or fuel-staged cyclones burning North Dakota lignite. (See Appendix A1).
    - Since a booster fan typically supplied with this technology is not necessary for cyclone boilers, ROFA does not appear to offer significant advantages for improved NO$_X$ control performance on LOS Unit 2 compared to conventional SOFA.
    - Although it may be possible to install some aspects of ROFA on a cyclone boiler, such as high-velocity offset overfire air ports without a booster fan, the lack of experience on cyclone boiler applications makes this alternative infeasible for LOS Unit 2. ROFA was not evaluated further for the Unit 2 boiler at Leland Olds Station.

- Fuel reburn, with and without overfire air:
  - Conventional gas reburn (CGR) and conventional pulverized or micronized coal reburn (PCR or MCR) have been installed and demonstrated as effective for NO_X control on cyclone boilers[10,11,12,13,14,15,16].
    - CGR or PCR/MCR replaces around 15-30% of total boiler fuel heat input with reburn fuel injected downstream of the cyclones and upstream of SOFA, with or without air-staging the cyclones.
    - CGR or PCR/MCR would likely involve operation with fewer active cyclones.
    - Operation of CGR or PCR/MCR with fewer active cyclones with limited use of advanced SOFA on LOS Unit 2 potentially avoids some adverse operational impacts and impairments associated with fuel- and air-staging cyclones burning North Dakota lignite.
    - Compared with other similarly-effective NO_X controls, conventional gas reburn's expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make gas-consuming alternatives economically unattractive for application at LOS. CGR with ASOFA was not evaluated further for LOS Unit 2.
    - Powerhouse site space constraints would require dedicated buildings and grinding equipment for coal reburn fuel preparation for LOS Unit 2. PCR/MCR would require improvements to increase PM collection capacity additions for LOS Unit 2, for preventing higher particulate matter emissions (described in more detail in Appendix A1).
    - These conditions will make conventional PCR/MCR with basic or advanced versions of SOFA more expensive to install, operate, and maintain at LOS compared to previous retrofit coal reburn applications on existing cyclone-fired boilers. The conventional PCR/MCR with ASOFA alternative is the highest performing version considered technically feasible for NO_X control at Leland Olds Station, and was evaluated for LOS Unit 2.
  - Fuel-lean gas reburn (FLGR™) has not been permanently installed and operated on any cyclone-fired boilers. FLGR™ replaces around 6-7% of total boiler fuel heat input with natural gas injection downstream of cyclones and overfire air, with or without air-staging the cyclones below stoichiometric ratio.
    - For cyclone boilers, FLGR™ has only been demonstrated during a single short-term test[17,18] on a cyclone boiler without a SOFA system. This technology appears to offer limited NO_X control potential on cyclone boilers burning North Dakota lignite, especially for the current configuration of lignite drying system vent ports and flue gas recirculation

    ports in the lower furnace where the gas injectors would be located (described in more detail in Appendix A1).
    - FLGR™ may be technically feasible to be installed with an advanced form of SOFA on cyclone boilers designed to burn North Dakota lignite, however the expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make this alternative economically unattractive for application at LOS. FLGR™ was not evaluated further as a combustion control option for LOS Unit 2 NO_X reduction.
- Oxygen-enhanced combustion (OEC) has not been demonstrated and/or installed on a cyclone-fired boiler. Lacking demonstrated experience on cyclone boilers, OEC was considered infeasible for NO_X control application at LOS on Unit 2.
- Flue gas recirculation (FGR) has been applied and practiced at numerous natural gas and fuel oil-fired utility and industrial power plants for NO_X emissions control. No examples of flue gas recirculation applied to coal-fired cyclone boilers for NO_X control were found. FGR has been applied to large coal-fired utility boilers, primarily for steam temperature control purposes, not for emissions control.
    - FGR is installed and practiced at LOS on Unit 2 for operational reasons, not for NO_X control. However, the advanced version of SOFA applied to cyclone boilers designed to burn North Dakota lignite using lignite drying systems would relocate the existing lower furnace FGR ports to minimize disruption of the in-furnace NO_X reduction process (described in more detail in Appendix A1). Due to the lack of use on cyclone boilers, using FGR alone for NO_X control at LOS Unit 2 was eliminated from further consideration.
- Water/steam injection has been retrofit and intermittently practiced on older natural gas wall-fired utility boilers, and at one natural gas-fired cyclone boiler[21]. Although it has been tested on eastern or midwestern bituminous coal-fired cyclone boilers[4], this technique was not found to be permanently installed and continuously practiced on coal-fired cyclone boilers, especially those that fire high-moisture lignite or western subbituminous coals. Thus, water/steam injection was considered infeasible for permanent, full-time, long-term application for NO_X control on lignite-fired boilers at LOS.

2.2.3 FEASIBILITY OF POST-COMBUSTION NO_X CONTROLS

2.2.3.1 POST-COMBUSTION NO_X CONTROLS - UNIT 1

Post-combustion controls involve technologies that are usually applied to the flue gas exiting the boiler. These are summarized as follows:

- Selective Non-Catalytic Reduction (SNCR) and variations for NO_X control at LOS Unit 1:
  - Injects ammonia or urea reagent into the upper furnace zone with suitable temperature conditions.
  - Chemical reactions of amine and NO_X are insensitive to fuel and boiler type; excess unreacted reagent is emitted from the boiler as "ammonia slip" and can contribute to fouling of air heaters when combined with sulfates.
  - SNCR can be implemented with or without other combustion and in-furnace and downstream post-combustion controls.
  - SNCR has been applied and practiced on numerous pulverized coal utility boilers.
  - SNCR, in combination with the existing close-coupled overfire air (CCOFA), is considered feasible for modest NO_X control on the Unit 1 pulverized coal boiler at LOS.
  - Hydrocarbon-enhanced SNCR (commercially available as NO_XStar^{TM}) uses high temperature steam and ammonia vapor with small quantities of gaseous hydrocarbon fuel (natural gas or propane) and offers potentially higher NO_X control performance than conventional SNCR. NO_XStar^{TM} has been demonstrated with the initial installation on one pulverized coal-fired boiler burning eastern coal, and commercially installed on another PC boiler burning eastern coal[25,26].
    - NO_XStar^{TM} is susceptible to major impairment of permanently-installed injection lances attached to convective heat transfer surfaces of the boiler due to severe fouling expected from lignite ash deposits.
    - NO_XStar^{TM} may be feasible for NO_X control on lignite-fired dry-bottom pulverized coal boilers such as LOS Unit 1. However, with much higher installation and operating costs compared with SOFA, and the lack of a experience on dry-bottom PC-fired boilers burning high fouling coals such as lignite, this alternative was considered infeasible as a NO_X control option for LOS Unit 1.
  - Rich Reagent Injection (RRI) injects aqueous urea into the high-temperature lower furnace zone and requires an "air-starved" atmosphere to avoid creating instead of reducing NO_X. RRI has not been developed nor demonstrated for NO_X control application on pulverized coal-fired boilers. This alternative is considered infeasible for LOS Unit 1.
- Selective Catalytic Reduction (SCR):
  - Injects ammonia reagent into the flue gas in a zone with suitable temperature conditions.
  - Chemical reactions of ammonia and NO_X in the presence of a catalyst are effective at much lower temperatures than SNCR, typically 600°F to 750°F. Very high NO_X control efficiencies are possible, with lower reagent consumption per ton of NO_X emission reduction

compared to SNCR. This technology has been applied to a variety of fuels and boiler types. Excess unreacted reagent is emitted from the boiler as "ammonia slip" and can contribute to fouling of air heaters when combined with sulfates.

  - Conventional SCR technology has been widely applied to pulverized coal fired boilers in the United States for NO_X control, primarily in a "hot-side, high-dust" arrangement.
    - There have been no installations of SCR systems (full-scale) on units that fire North Dakota lignite.
    - An evaluation of impacts of ash on SCR plugging and blinding was performed, which included the use of SCR slipstream testing on a North Dakota lignite-fired powerplant. This slipstream SCR testing examined the significance of ash accumulations on SCR catalyst on both the macroscopic and microscopic levels.
    - North Dakota lignite produces ash with severe deposition characteristics that are not typical with other fuels. These deposition characteristics will result in deposits and pluggage of the catalyst. SCR performance and catalyst life will be severely impacted.
    - Success of SCR technology on an EGU firing North Dakota lignite is considered technically infeasible. This is explained in more detail in Appendix A1 and A5.
    - SCR alternatives were not evaluated further for consideration as options for LOS Unit 1.
- Electro-Catalytic Oxidation (ECO®) is an emerging multi-pollutant control technology for coal-fired boilers that uses a barrier reactor for NO_X control upstream of an ammonia scrubber. A slip-stream pilot-scale commercial demonstration of ECO® is currently undergoing field development on a pulverized coal-fired power plant in Ohio. ECO® has not been installed on a full-scale, full-time basis on any coal-fired EGU, and has no commercial demonstration experience on western subbituminous or lignite coals. Thus, ECO® was considered commercially unavailable and technically infeasible for NO_X control at LOS. For more details, refer to the technical feasibility evaluation included in Appendix A1.

2.2.3.2 POST-COMBUSTION NO_X CONTROLS - UNIT 2

Post-combustion controls involve technologies that are usually applied to the flue gas exiting the boiler. These are summarized as follows:

- Selective Non-Catalytic Reduction (SNCR) and variations for NO_X control at LOS Unit 2:
  - SNCR has been applied and practiced on several cyclone-fired boilers[22,23,24] since 1995.
  - SNCR is considered feasible for modest NO_X control on the Unit 2 cyclone boiler at LOS.

  - SNCR without SOFA, with much higher installation and operating costs compared with SOFA alone, is not economically attractive for application at LOS Unit 2 and was eliminated from further consideration for control and cost-effectiveness.
  - Hydrocarbon-enhanced SNCR (commercially available as NO_XStar^{TM}) has not been demonstrated on any cyclone-fired boilers. It is susceptible to major impairment of permanently-installed injection lances attached to convective heat transfer surfaces of the boiler due to severe fouling expected from lignite ash deposits. NO_XStar^{TM} was considered infeasible for application on North Dakota lignite-fired cyclone boilers for NO_X control.
  - Rich Reagent Injection (RRI) injects aqueous urea into the high-temperature lower furnace zone and requires an "air-starved" atmosphere to avoid creating instead of reducing NO_X. RRI has been developed and demonstrated with application intended only on cyclone boilers[27,28,29,30]. RRI but has not been permanently installed but is commercially available from two sub-licensees (Fuel Tech and Combustion Components Associates) of the technology licensed by EPRI to Reaction Engineering International, Inc..
    - RRI is susceptible to impairment due to fouling by ash slag deposits and heat-related damage of injection nozzles, located near the cyclones in the lower furnace.
    - RRI may be feasible for application at LOS for Unit 2's cyclone-fired boiler operating under substoichiometric conditions with modest air-staged cyclones using ASOFA for limited NO_X control. Because RRI in combination with ASOFA without SNCR is expected to be less effective for NO_X reduction and have higher reagent consumption than SNCR with ASOFA, RRI+ASOFA was not included in the control and cost effectiveness analysis in this evaluation for LOS Unit 2. (see Section 2.2.4)
    - Basic SOFA for North Dakota lignite cyclone boilers is incompatible with Rich Reagent Injection. Such combinations are technically infeasible, and thus were eliminated from further consideration for LOS Unit 2. For more details, refer to the technical feasibility evaluation included in Appendix A1.
- Selective Catalytic Reduction (SCR):
  - SCR technology has been installed on 22 cyclone-fired boilers in the U.S.[34], mostly applied in conventional "hot-side, high-dust" arrangements.
  - Catalyst is susceptible to fouling and deactivation from sodium and sulfur deposits, which are expected to be severe from the firing of North Dakota lignite in the LOS Unit 2 cyclone boiler. This conventional arrangement of SCR technology is considered technically infeasible for application at LOS for the Unit 2 cyclone boiler. For more details, refer to the technical feasibility evaluation included in Appendix A1.

- "Low-dust" SCR (LD-SCR) technology (hot-side or cold-side) has been installed on 10 pulverized coal-fired boilers, but no cyclone boilers, in the U.S.[34]. LD-SCRs are typically located downstream of a hot-side electrostatic precipitator. LD-SCR in a cold-side application requires flue gas reheat prior to the catalyst reactor, typically involving supplemental gaseous fuel firing and large regenerative gas-to-gas heat exchanger equipment. LD-SCR is also susceptible to catalyst fouling and deactivation from sodium and sulfur deposits not removed by the particulate matter control device upstream. This fouling is expected to be sufficient to cause significant impairment on ND lignite-fired cyclone boilers. LD-SCR was considered technically infeasible for application at LOS Unit 2. For more details, refer to the technical feasibility evaluation included in Appendix A1.
- "Tail gas" SCR (TG-SCR) technology has been installed on several coal-fired boilers in Europe, but not in the United States[34]. In such cases, TG-SCRs are located downstream of the air preheater, particulate matter control device and flue gas desulfurization (FGD) scrubber. This requires supplemental fuel or steam heat with a large gas-to-gas heat exchanger to reheat the flue gas to an appropriate temperature prior to the SCR reactor. There are serious concerns about the susceptibility of TG-SCR catalyst to fouling from sodium and sulfur deposits not removed by the particulate matter control device and FGD scrubber sufficient to cause significant impairment on ND lignite-fired cyclone boilers. TG-SCR technology was considered technically infeasible for application on Unit 2 at LOS. For more details, refer to the technical feasibility evaluation included in Appendix A1.

2.2.4 FEASIBILITY OF COMBINATIONS OF COMBUSTION AND POST-COMBUSTION NO_X CONTROLS

2.2.4.1 COMBUSTION AND POST-COMBUSTION NO_X CONTROLS - UNIT 1

Combination controls involve simultaneous use of multiple types of technologies that were described in Section 2.2.2 above. These are briefly summarized as follows:

- Separated Overfire Air + Selective Non-Catalytic Reduction (SNCR) and variations:
  - Basic or boosted SOFA + SNCR combinations are technically feasible for application on pulverized coal-fired boilers for NO_X control, and were included in the control and cost effectiveness analysis for LOS Unit 1.
  - Basic and boosted SOFA + Hydrocarbon-enhanced SNCR (commercially available as NO_XStar^{TM}) may be capable of NO_X control on lignite-fired dry-bottom pulverized coal boilers such as LOS Unit 1. However, with much higher installation and operating costs

compared with conventional SNCR, and the lack of a experience on dry-bottom PC-fired boilers burning high fouling coals such as lignite, this alternative was considered infeasible as a NO_X control option for LOS Unit 1.

  - A version of SNCR combined with a boosted form of separated overfire air is currently being marketed commercially as "Rotating Mixing" (Rotamix, using ROFA or Rotating Opposed Fired Air). This has been applied only to pulverized coal-fired boilers. It is different than basic SOFA + SNCR in that it includes a hot air booster fan and a small ambient air fan, and injects ammonia (or urea) reagent into the high-pressure overfire air stream which is introduced into the boiler in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. At least eight tangentially-fired and five wall-fired pulverized coal utility boilers have been retrofitted with Rotamix, with results published for three "T"-fired boilers burning eastern bituminous coal or Illinois bituminous coal [31,32,33].
    - Since it uses ROFA, Rotamix technology is subject to the same operating limitations as conventional air-staged or fuel-staged pulverized coal burners firing North Dakota lignite. (See Appendix A1).
    - Use of Rotamix on some coal-fired boilers may not produce the levels of NO_X control capable of being achieved with separate SNCR and SOFA injection ports located to optimize each individual technique's performance. This applies to the Unit 1 boiler at LOS.
    - Rotamix is generally considered feasible for NO_X control on small to medium-sized dry-bottom wall-fired pulverized coal boilers.
    - The boosted overfire and SNCR NO_X control alternative assumes the installation of Rotamix in the control effectiveness and cost evaluations for the Unit 1 boiler at Leland Olds Station.
- Fuel Reburn + Selective Non-Catalytic Reduction (SNCR) and variations:
  - Fuel-lean gas reburn + SNCR with basic or boosted SOFA is considered technically feasible on dry-bottom, wall-fired pulverized coal boilers. However, with much higher installation and operating costs compared to other options with similar control effectiveness, such combinations of technologies were not evaluated for consideration as NO_X control options for LOS Unit 1.
  - Conventional Gas Reburn (CGR) + SNCR with basic SOFA combination has only been installed on one tangentially-fired pulverized coal boiler in the United States. This combination of technologies may be technically feasible for LOS Unit 1, but there have been

no commercial installations on dry-bottom, wall-fired pulverized coal boilers. Also, with much higher installation and operating costs compared to other options with similar control effectiveness, this alternative was not evaluated for consideration as a layered controls option for LOS Unit 1.

- Conventional pulverized / micronized coal reburn (PCR or MCR) + SNCR with basic or boosted SOFA combination may be technically feasible for LOS Unit 1, but has not been demonstration tested or commercially sold for a dry-bottom, wall-fired pulverized coal boiler application in the United States. A dedicated building with grinding equipment for coal reburn fuel preparation, and the need to control higher particulate matter emissions through increased collection efficiency improvements would be required to implement this alternative on LOS Unit 1. With a lack of demonstrated success and much higher installation and operating costs compared with other demonstrated combinations of NOx control technologies with similar control effectiveness, this option was eliminated from further consideration for NO_X control on LOS Unit 1.

The results of Step 2 of the NO_X BART Analysis for determining the technical feasibility of NO_X emission control technologies potentially applicable to lignite-fired pulverized coal-fired boilers are summarized in Table 2.2-1, and for cyclone boilers in Table 2.2-2 located in the following report section. Every possible combination of all the various techniques, i.e. "layered technologies", is not listed, in keeping with the EPA's BART Guidelines that they do not "expect a source owner to conduct extended trials to learn how to apply a technology" and "would not consider technologies in the pilot scale stages of development as "available" for the purposes of a BART review" [70 FR 39165]. Also, it "is not the [EPA's] intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options" and [the States] "should consider recent regulatory decisions and performance data (e.g. manufacturer's data, engineering estimates, and the experience of other sources) when identifying emissions performance level or levels to evaluate" [70 FR 39166].

TABLE 2.2-1 – Technical Feasibility of Potential NO_X Control Technologies for Leland Olds Station Unit 1

Control Technology(1)	**In Permanent, Full-Scale Service on Existing Pulverized Coal-Fired Utility Boilers?**	**Technically Feasible on Leland Olds Station Unit 1 boiler?**
Selective Catalytic Reduction (SCR) (high dust); Low-dust SCR; Tail-gas SCR	Yes(2) / Yes / Yes(3)	No. See discussion in text and footnote
Electro-Catalytic Oxidation (ECO®)	No	No; has not been demonstrated full-scale; See discussion in text and footnote(3).
SNCR	Yes(2)	Yes; can be combined w/ other technologies.
HE-SNCR (NO_XStar™)	Yes(4)	No(4). See discussion in text and footnote(5).
Rich Reagent Injection (RRI)	No(6)	No(6). Not applicable to pulverized coal-firing.
Rotamix (ROFA + SNCR)	Yes	Yes. See discussion in text and footnote.
Conventional Gas Reburn (CGR)	Yes(7)	Yes(7); Requires SOFA. See discussion in text and footnote(5).
Conventional Gas Reburn + SNCR w/ SOFA	Yes(7)	Yes. Only one CGR w/ SNCR application on PC firing. See discussion in text and footnote(5).
Coal Reburn	Yes(8)	Yes(8); Requires SOFA.
Coal Reburn + SNCR	No	No. Has not been demonstrated on PC-firing.
FLGR™	No(7)	Yes[7] (w/ or w/out SOFA). See discussion in text and footnote[5].
Fuel Lean Gas Reburn + SNCR (AEFLGR™)	Yes[7]	Yes. Five installations in PC-fired U.S. boilers. See discussion in text and footnote(5).
Boosted SOFA (or ROFA)	Yes(9),(10)	Yes(9). See discussion in text and footnote.
Separated OFA (SOFA)	Yes(10)	Yes, commonly applied with LNBs.
Low NO_X Burners (LNBs)(latest technology)	Yes	Yes, commonly applied with CCOFA or SOFA. See discussion in text.
Combustion Improvements	Yes	Yes(11); typically included with separated OFA.
OEC	No(12)	No(12). See discussion in text and footnote.
Water Injection	No(13)	No(13)
Flue Gas Recirculation	Not for NO_X control	No(14)
Fuel Switching (from lignite to 100% PRB)	Yes	Yes(15) (not expected to reduce NO_X further)

See technical feasibility details in Appendix A1 and literature References in Appendix A3 for details.

1 – All potential combinations of technologies not listed. See discussion of "layered" technologies.

2 – Limited number of active installations on pulverized-fired boilers burning western subbituminous coal.

3 – No identified full-scale permanent installations operating continuously on coal-fired boilers in the United States.

4 – Hydrocarbon-enhanced SNCR has been demonstrated on two pulverized coal-fired boilers, but not on any boiler firing western subbituminous coal or lignite with severe fouling characteristics.

5 – Much higher installation and operation costs expected compared with other options with similar control effectiveness, this alternative was not evaluated for consideration as a NO_X control option for LOS Unit 1.

6 – Rich Reagent Injection has only been successfully demonstrated for brief periods with SOFA+SNCR at two cyclone power plants. It is not intended nor has it been successfully demonstrated on pulverized coal-fired boilers.

7 – No conventional gas reburn (CGR) demonstrations or installations on pulverized coal-fired boilers burning western subbituminous coal or lignite. No demonstrations or installations of FLGR™ have been performed on a pulverized coal-fired boiler burning western subbituminous coal or lignite. Only one installation of conventional gas reburn with SNCR on PC-fired boiler burning eastern bituminous coal. Several installations of FLGR™ with and without SNCR on PC-fired boilers burning eastern bituminous coal. Most conventional gas reburn and FLGR™ systems are not currently active.

8 – No conventional pulverized or micronized coal reburn (PCR/MCR) demonstrations or installations on pulverized coal-fired boilers burning western subbituminous coal or lignite. Three active coal reburn systems on PC-fired boilers burning eastern bituminous coal.
9 – Several active commercial installations of boosted SOFA on pulverized coal-fired boilers.
10 –No wall-fired PC boilers burning North Dakota lignite have installed separated OFA or boosted OFA.
11 –Considered part of SOFA installation for coal boilers without improved combustion controls for NO_X reduction.
12 – Oxygen-enhanced combustion has been applied on two modestly-sized pulverized coal-fired boilers firing bituminous coal, but has not been demonstrated on 100% western subbituminous coal or lignite-fired boilers.
13 – No permanently installed examples of using this technique continuously on coal-fired boilers were found in available technical literature. Not suitable for high-moisture lignite fuels.
14 – No examples of using recirculated flue gas on coal-fired boilers for NO_X emissions control were found in available technical literature. Zero additional NO_X reduction potential expected from this technique alone for LOS Unit 1.
15 – Zero additional NO_X reduction potential expected from this technique alone for LOS Unit 1.

2.2.4.2 COMBUSTION AND POST-COMBUSTION NO_X CONTROLS - UNIT 2

Combination controls involve simultaneous use of multiple types of technologies that were described in Section 2.2.3 above. These are briefly summarized as follows:

- Separated Overfire Air + Selective Non-Catalytic Reduction (SNCR) and variations:
  - Because advanced SOFA + SNCR is the highest performing feasible form of this post-combustion NO_X control combination for North Dakota lignite cyclone boilers, it was evaluated for control and cost effectiveness on LOS Unit 2. Basic SOFA + SNCR together is a feasible combination but is not the highest performing version, and thus was eliminated from further consideration for LOS Unit 2.
  - Basic or advanced SOFA + Hydrocarbon-enhanced SNCR (commercially available as NO_XStar^{TM}) alternatives lack demonstrated experience on cyclone boilers. These combinations are susceptible to major impairment of permanently-installed reagent injection lances attached to convective heat transfer surfaces of the boiler due to severe fouling expected from lignite ash deposits. NO_XStar^{TM} with basic or advanced SOFA combinations were considered infeasible for application on North Dakota lignite-fired cyclone boilers such as LOS Unit 2 for NO_X control.
  - Rich Reagent Injection may be technically feasible for application with and without SNCR combinations at LOS for Unit 2's cyclone-fired boiler operating under substoichiometric conditions with ASOFA, although the expected modest amount of cyclone air-staging will substantially reduce the NO_X control potential of RRI at LOS Unit 2. Because RRI + SNCR with advanced SOFA is the highest performing form of this post-combustion NO_X control combination, it was evaluated for control and cost effectiveness on LOS Unit 2.
  - RRI with advanced SOFA (without SNCR) is not the highest performing version, and thus was eliminated from further consideration for LOS Unit 2.

  - Basic SOFA for North Dakota lignite cyclone boilers is incompatible with Rich Reagent Injection with SNCR, so this combination is technically infeasible, and thus was eliminated from further consideration for LOS Unit 2. For more details, refer to the technical feasibility evaluation included in Appendix A1.
  - SNCR combined with a boosted form of separated overfire air is currently being marketed commercially as "Rotating Mixing" (Rotamix, using ROFA or Rotating Opposed Fired Air). This has been applied only to pulverized coal-fired boilers[31,32,33].
    - Since it uses ROFA, Rotamix technology is subject to the same operating limitations as conventional air-staged or fuel-staged cyclones burning North Dakota lignite. (See Appendix A1).
    - Use of Rotamix on some coal-fired boilers may not produce the levels of NO_X control capable of being achieved with separate SNCR and SOFA injection ports located to optimize each individual technique's performance. This applies to the LOS Unit 2 boiler.
    - There has been no Rotamix experience on cyclone-fired boilers. Rotamix also does not offer a significant performance advantage for cyclone NO_X control at LOS for Unit 2 compared to the levels of NO_X control capable of being achieved with separate SNCR and SOFA injection ports located to optimize each individual technique's performance. Although it may be possible to install some aspects of Rotamix on a cyclone boiler, such as high-velocity offset overfire air ports with SNCR but without a booster fan, the lack of experience on cyclone boiler applications makes this alternative infeasible for LOS Unit 2. Rotamix was not evaluated further for the LOS Unit 2 boiler.
- Fuel Reburn + Selective Non-Catalytic Reduction (SNCR) and variations:
  - FLGR™ + SNCR (with basic or advanced SOFA) has not been demonstrated or permanently installed and operated on a coal-fired cyclone boiler. This combination may be technically feasible but would appear to offer limited NO_X control potential on cyclone boilers burning North Dakota lignite (see Appendix A1). FLGR™'s expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make this alternative economically unattractive for application at LOS. FLGR™ + SNCR (with basic or advanced SOFA) were eliminated from further consideration for NO_X control on LOS Unit 2.
  - Conventional Gas Reburn (CGR) + SNCR with basic or advanced SOFA may be technically feasible for LOS Unit 2, but there have been no successfully demonstrated or commercial installations on cyclone boilers. This combination of technologies lacks

experience. Expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make this alternative economically unattractive compared with similar NO_X reduction available with other demonstrated or commercially available controls. This combination was eliminated from further consideration on LOS Unit 2.

- Conventional pulverized / micronized coal reburn (PCR or MCR) + SNCR with basic or advanced SOFA combination may be technically feasible for LOS Unit 2, but has not been demonstration tested or commercially sold for a cyclone boiler application. A dedicated building with grinding equipment for coal reburn fuel preparation, and the need to control higher particulate matter emissions through increased PM collection capacity with flyash handling and storage capacity additions would be required to implement this alternative on LOS Unit 2. Since this combination of technologies lacks experience, PCR or MCR + SNCR with basic or advanced SOFA were eliminated from further consideration for NO_X control on LOS Unit 2.

TABLE 2.2-2 – Technical Feasibility of Potential NO_X Control Technologies for Leland Olds Station Unit 2

Control Technology(1)	In Permanent, Full-Scale Service on Existing Coal-Fired Cyclone Utility Boilers?	Technically Feasible on Leland Olds Station Unit 2 boiler?
Selective Catalytic Reduction (SCR) (high dust); Low-dust SCR; Tail-gas SCR	Yes(2) / No / Yes(3)	No - Unresolvable fouling and catalyst deactivation problems expected. See discussion of SCR feasibility for ND lignite.
Electro-Catalytic Oxidation (ECO®)	No	No, has not been demonstrated full-scale; commercial availability not confirmed
SNCR	Yes(2)	Yes; can be combined with other technologies
HE-SNCR (NO_XStar™)(with or without SOFA or ASOFA)	No(4)	No(4). Has not been demonstrated on cyclone.
Rich Reagent Injection (RRI) with ASOFA	No(5)	Yes(5). Requires Advanced SOFA for lignite, can be combined w/ SNCR.
Rotamix (ROFA + SNCR)	No	No. Has not been demonstrated on cyclone.
Conventional Gas Reburn (ACGR) + SNCR	No(6)	No. Has not been demonstrated on cyclone. Would require ASOFA.
Conventional Gas Reburn	Yes(6)	Yes(7); Requires ASOFA
Coal Reburn	Yes(8)	Yes(8); Requires ASOFA
Coal Reburn + SNCR	No	No. Has not been demonstrated on cyclone.
FLGR™	No(6)	Yes(7) (w/ or w/out SOFA or ASOFA)
Fuel Lean Gas Reburn + SNCR (AEFLGR™)	No(6)	No. Has not been demonstrated on cyclone.
Advanced SOFA	No(9)	Yes(9)
Separated OFA (SOFA)	Yes(9)	Yes(9)
ROFA	No(10)	No(10). No significant advantages over SOFA.
Combustion Improvements	Yes	Yes(11) ; typically included with separated OFA
OEC[12]	No(12)	No - has not been demonstrated on cyclone boiler
Water Injection	No(13)	No(13)
Flue Gas Recirculation	Not for NO_X control	Yes(14) (not expected to reduce NO_X further)
Fuel Switching (from lignite to 100% PRB)	Yes	Yes(15) (not expected to reduce NO_X further)
Low NO_X Burners	No	No – Not Feasible

See technical feasibility details in Appendix A1 and literature References in Appendix A3 for details.

1 – All potential combinations of technologies not listed. See discussion of "layered" technologies.

2 – Limited number of active installations on cyclone-fired boilers burning western subbituminous coal.

3 – No identified full-scale permanent installations operating continuously on coal-fired boilers in the United States.

4 – Hydrocarbon-enhanced SNCR has been demonstrated on two pulverized coal-fired boilers, but not on any boiler, including cyclones, firing western subbituminous coal or lignite with severe fouling characteristics.

5 – Rich Reagent Injection has only been successfully demonstrated for brief periods with SOFA+SNCR at two cyclone power plants. It is not intended nor has it been successfully demonstrated on pulverized coal-fired boilers.

6 – Limited number of conventional gas reburn (CGR) demonstrations or installations on cyclone-fired boilers burning western subbituminous coal. One demonstrations (no permanent installations) of FLGR™ have been performed on a cyclone-fired boiler. Only one installation of conventional gas reburn with SNCR on PC-fired boiler burning eastern bituminous coal. Several installations of FLGR™ with and without SNCR on PC-fired boilers burning eastern bituminous coal. Most conventional gas reburn and FLGR™ systems are not currently active.

7 – Much higher installation and operation costs expected compared with other options with similar control effectiveness, this alternative was not evaluated for consideration as a NO_X control option for LOS Unit 2.

8 – One conventional pulverized (PCR/MCR) demonstration on cyclone-fired boilers burning western subbituminous coal has been discontinued. Only one active micronized coal reburn system on cyclone boiler burning eastern bituminous coal. Three active coal reburn systems on PC-fired boilers burning eastern bituminous coal.

9 – No cyclone or wall-fired PC boilers burning North Dakota lignite have installed separated OFA or boosted OFA.

10 – Several active commercial installations of boosted SOFA (or ROFA) on pulverized coal-fired boilers, none on cyclone boilers.

11 –Considered part of SOFA installation for coal boilers without improved combustion controls for NO_X reduction.

12 – Oxygen-enhanced combustion has been applied on two modestly-sized pulverized coal-fired boilers firing bituminous coal, but has not been demonstrated on any cyclone boilers or 100% western subbituminous coal or lignite-fired PC boilers.

13 – This technique has been demonstrated but no permanently installed examples of using this technique continuously on cyclone coal-fired boilers were found in available technical literature. Not suitable for high-moisture lignite fuels.

14 – No examples of using recirculated flue gas on coal-fired boilers for NO_X emissions control were found in available technical literature. Zero additional NO_X reduction potential expected from this technique alone for LOS Unit 2. Potential NO_X reduction improvement on LOS Unit 2 considered part of “advanced” SOFA.

15 – Zero additional NO_X reduction potential expected from this technique alone for LOS Unit 2.

2.3 CONTROL EFFECTIVENESS EVALUATION OF NO_X CONTROL TECHNOLOGIES

Several feasible NO_X control alternatives previously listed in Tables 2.2-1 and 2.2-2 have been removed from the control effectiveness ranking in Tables 2.3-1 and 2.3-2 for LOS Unit 1, and Tables 2.3-3 and 2.3-4 for LOS Unit 2. This control option ranking approach recognizes that those feasible alternatives that appear to offer zero or very small control performance for a significant cost impact (e.g. fuel switching), should not be included in the control and cost effectiveness impact analysis. Alternatives that include natural gas firing, or are similar in predicted emission reduction percentage but are more expensive to install and operate, or have more substantial operational limitations compared to other feasible alternatives were also eliminated from further analysis.

The emission reduction (control effectiveness) percentages developed for ranking the feasible alternatives shown for LOS Unit 1 and LOS Unit 2 are estimates based upon engineering judgments with considerations of:

- the general combustion properties of North Dakota lignite;
- published and available emission reduction performance achieved at other similar utility power plants (dry-bottom pulverized coal and wet-bottom cyclone-fired boilers);
- computer-derived predictions; and
- inclusion of performance margins to allow for variations in fuel, weather, equipment condition, and other factors that prevent the ultimate peak short-term performance from being reliably sustained over the course of long-term operation.

These NO_X emission level and percent reduction estimates include adjustments of previously demonstrated or predicted performance that reflect differences between North Dakota lignite and eastern or midwestern bituminous and western subbituminous coals. The numbers assume the maximum short-term potential capability of the employed technique, demonstrated or installed elsewhere, is not achievable or sustainable long-term. As such, the expressed control percentages reflect the use of engineering judgment, based on the listed technique or technology application.

2.3.1 CONTROL EFFECTIVENESS OF COMBUSTION NO_X CONTROLS – LOS UNIT 1

Only close-coupled overfire air with low NO_X burners have been previously installed for reducing NO_X emissions from the LOS Unit 1 boiler. NO_X emission control options considered feasible were evaluated for the LOS Unit 1 boiler, are listed in Table 2.3-1 and Table 2.3-2. The existing LNBs with a retrofit of separated overfire air in place of CCOFA were estimated to produce a modest NO_X control reduction for LOS Unit 1 beyond the presumptive BART NO_X level. Pre-retrofit levels of NO_X emissions for Leland Olds Station's Unit 1 boiler in Table 2.3-1 are relative to an equivalent unit emission baseline rate of 0.285 lb/mmBtu (historic highest 24-month average rate, years 2000-2004), with a corresponding average heat input rate of 2,443 mmBtu/hr for 8,510 hours per year. This is compared to the estimated post-control equivalent average NO_X unit emission rates (lb/mmBtu) for a boiler design capacity heat input rate of 2,622 mmBtu/hr for 8,760 hrs/yr operation under the future Potential To Emit (PTE) scenario.

Feasible, demonstrated pulverized coal-fired boiler NO_X controls which allow or enhance further reductions when separated overfire air is combined with other combustion or post-combustion control alternatives that did not involve gas-consuming technologies were evaluated.

Based upon Burns & McDonnell's experience, applying SOFA technology to LOS Unit 1 boiler is expected to produce a reduction percentage from the pre-control baseline NO_X emission rate approximately half as great as is typically achieved when PC-fired boilers burning western subbituminous coal implement SOFA and operate low-NO_X burners at fairly low burner air/fuel ratios (around 0.90). This reduction estimate relates to the pre-control baseline NO_X emission rate which reflects the modest amount of burner air-staging that is believed can be sustained when firing lignite at full unit output capacity when operating existing low-NO_X burners with SOFA.

Predictions of NO_X emission reduction percentages for incremental NO_X emission reductions from CCOFA-, and basic and boosted SOFA-controlled levels for SNCR alternatives were estimated from a vendor proposal of Selective Non-Catalytic Reduction[46].

Coal reburn with basic and boosted SOFA is estimated to reduce NO_X emissions around 60 percent, based upon estimated uncontrolled baseline NO_X levels and demonstrated coal-reburn retrofits on PC-fired boilers. The reduction estimates from pre-retrofit baseline levels of NO_X emissions for Leland Olds Station's Unit 1 boiler in Tables 2.3-1 and 2.3-2 reflect the modest amount of burner air-staging with existing LNBs and CCOFA that can be sustained when firing lignite at full unit output capacity.

TABLE 2.3-1 – Historic Baseline and Estimated Control Options' PTE NO_X Emission Rates Evaluated for LOS Unit 1 Boiler

Alt. No.(1)	NO_X Control Technique	LOS Unit 1 Emission Rate(2) (lb/mmBtu)	Control Percentage(2)	LOS Unit 1 Hourly Emission(2) (lb/hr)	LOS Unit 1 Annual Emission(2) (tons/yr)
G	Coal Reburn with boosted SOFA (future PTE case)	0.147	48.7	384	1,666
F	Coal Reburn with basic SOFA (future PTE case)	0.154	46.2	403	1,746
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	0.157	45.1	411	1,782
D	SNCR with basic SOFA (future PTE case)	0.166	42.0	434	1,883
C	SNCR with Close-Coupled OFA (future PTE case)	0.216	24.5	565	2,450
B	Boosted Separated Overfire Air (ROFA), (future PTE case)	0.216	24.3	567	2,483
A	Separated Overfire Air (SOFA, basic), (future PTE case)	0.230	19.4	603	2,642
--	Baseline, based on annual operation at highest historic 24-mo average pre-control NO_X emission rate	0.285	--	697	2,967

1 – Alternative designation has been assigned from highest to lowest annual NO_X emissions.

2 – Emissions are calculated from unit emission rates, control percentage, 2,443 mmBtu/hr hourly heat input rate, and 8,510 annual hrs/yr of operation at future PTE conditions compared to historic pre-control baseline.

Table 2.3-2 shows an average pre-control equivalent NO_X baseline unit emission rate of 0.29 lb/mmBtu and post-control unit emission rates (lb/mmBtu), each applied to the LOS Unit 1 boiler at a fuel heat input rate of 2,622 mmBtu/hr (boiler design capacity rating) for 8,760 hrs/yr of operation under steady-state operating conditions relative to the future PTE case. Note that the order of SNCR with CCOFA and Boosted SOFA (ROFA) are switched in the latter case versus historic baseline.

TABLE 2.3-2 – Pre-Control Presumptive BART Baseline and Estimated Control Options' NO_X Emission Rates Evaluated for Future PTE Scenario, LOS Unit 1 Boiler

Alt. No.(1)	NO_X Control Technique	LOS Unit 1 Emission Rate(2) (lb/mmBtu)	Control Percentage(2)	LOS Unit 1 Hourly Emission(2) (lb/hr)	LOS Unit 1 Annual Emission(2) (tons/yr)
G	Coal Reburn with boosted SOFA (future PTE case)	0.149	48.7	390	1,693
F	Coal Reburn with basic SOFA (future PTE case)	0.156	46.2	409	1,774
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	0.159	45.1	418	1,811
D	SNCR with basic SOFA (future PTE case)	0.168	42.0	441	1,913
C	Boosted Separated Overfire Air (ROFA), (future PTE case)	0.215	25.9	564	2,469
B	SNCR with Close-Coupled OFA (future PTE case)	0.219	24.5	574	2,490
A	Separated Overfire Air (SOFA, basic), (future PTE case)	0.230	20.7	603	2,641
--	Baseline, based on annual operation at presumptive BART NO_X pre-control emission rate for future PTE scenario	0.290	--	760	3,330

1 – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

2 – Emissions are calculated from unit emission rates, control percentage, 2,622 mmBtu/hr hourly heat input rate, and 8,760 annual hrs/yr of operation at future PTE conditions compared to presumptive BART NO_X pre-control baseline.

2.3.2 CONTROL EFFECTIVENESS OF COMBUSTION AND POST-COMBUSTION NO_X CONTROLS – LOS UNIT 2

None of the remaining control options have been installed on cyclone-fired boilers burning North Dakota lignite. This is particularly pertinent to all control options that involve air-staged combustion associated with advanced forms of separated overfire air, reburn, and Rich Reagent Injection. RRI requires the hot furnace environment where the reagent is injected to be essentially devoid of free oxygen. Alternatives with the advanced form of SOFA are estimated to reduce NO_X emission levels more effectively from the LOS Unit 2 pre-control baselines than those which do not employ the use of cyclone air-staging and overfire air. Feasible, demonstrated cyclone boiler NO_X controls which allow or enhance further reductions when ASOFA is combined with other combustion or post-combustion control alternatives that did not involve gas-consuming technologies were evaluated.

Based upon Burns & McDonnell's experience, applying the advanced version of SOFA to the LOS Unit 2 cyclone boiler's pre-control baseline NO_X emission rate is estimated to produce a reduction percentage approximately half as great as is typically achieved when cyclone-fired boilers burning western subbituminous coal implement SOFA and operate at fairly low cyclone air/fuel ratios (around 0.90). This reduction estimate relates to the pre-control baseline NO_X emission rate which reflects the modest amount of cyclone air-staging that is believed can be sustained when firing lignite at full unit output capacity, and the additional amount of control potential available from operating with relocated lignite drying system vent ports and FGR ports associated with ASOFA.

Prediction of NO_X emission reduction percentage for Rich Reagent Injection (RRI) is based on engineering judgment with consideration of a recent demonstration testing performed at Ameren's Sioux Unit 1 cyclone boiler, and published computational fluid dynamics (CFD) modeling of the Sioux Unit 1 cyclones and furnace zones. A 2002 technical paper by Reaction Engineering International[28] showing the results of CFD modeling and field demonstration testing of RRI at the Sioux Unit 1 boiler with modest cyclone air/fuel ratios (close to 0.95 to 0.99) was used as guidance for estimating the NO_X emission reduction percentages assumed for LOS Unit 2.

Incremental NO_X emission reductions from ASOFA-controlled levels for SNCR, and SNCR+RRI alternatives were estimated from a vendor proposal of Selective Non-Catalytic Reduction[46] and information in a 2002 technical paper by Reaction Engineering International[28] for RRI testing and CFD modeling of the Sioux Unit 1 boiler.

Coal reburn with ASOFA is estimated to reduce NO_X emissions slightly more than 50 percent, based upon control levels demonstrated by previous coal-reburn retrofits on cyclone-fired boilers. This reduction estimate relates to the pre-control baseline NO_X emission rate which reflects the modest amount of cyclone air-staging that is believed can be sustained when firing lignite at full unit output capacity, and the additional amount of control potential available from operating with relocated lignite drying system vent ports and FGR ports associated with ASOFA.

The potential operational limitations mentioned in the detailed feasibility discussions included in Appendix A1 for deeply air-staged cyclones associated with separated overfire air and Rich Reagent

Injection or coal reburn alternatives are expected to limit the amount of NO_X control potential possible from successful practice of the technique or technology.

A ranking of available NO_X emission control options considered feasible for Leland Olds Station Unit 2 boiler are listed in Table 2.3-3 and Table 2.3-4. Ranking of the alternatives in Table 2.3-4 assumes that the pre-retrofit level of NO_X emissions for the Leland Olds Station Unit 2 boiler is associated with the equivalent average unit emission rate of 0.67 lb/mmBtu. This baseline is based on the historic highest twenty-four consecutive months' summation between years 2000 and 2004, with a corresponding average heat input rate of 4,478 mmBtu/hr for 8,050 hours per year. The annual post-control estimated NO_X emissions are based on the stated percent reduction applied to the pre-control unit baseline emission rate (0.67 lb/mmBtu) and fuel heat input rate of 5,130 mmBtu/hr (boiler design capacity rating) for 8,760 hrs/yr operation for the future PTE scenario.

TABLE 2.3-3 – Historic Baseline and Estimated Control Options' NO_X Emission Rates Evaluated for Future PTE Scenario, LOS Unit 2 Boiler

Alt. No.[(1)]	NO_X Control Technique	LOS Unit 2 Emission Rate (lb/mmBtu)	Control Percentage[(1)]	LOS Unit 2 Hourly Emission[(1)] (lb/hr)	LOS Unit 2 Annual Emission[(1)] (tons/yr)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	0.265	60.3	1,359	5,895
C	SNCR (using urea) w/ ASOFA	0.304	54.5	1,557	6,762
B	Coal Reburn (conventional, pulverized) w/ ASOFA	0.32	51.8	1,649	7,115
A	Advanced Separated Overfire Air (ASOFA)	0.48	28	2,465	10,796
--	Baseline, based on annual operation at historic highest 24-month average pre-control NO_X emission rate	0.67	--	2,987	12,023

1 - Alternative designation assigned from highest to lowest unit NO_X emission rate. Emissions are calculated from unit emission rates, control percentage, hourly heat input rate of 4,478 mmBtu/hr, and 8,050 annual hrs/yr operation compared to pre-control baseline.

Table 2.3-4 shows NO_X emissions for a different pre-control baseline. The annual post-control maximum NO_X emissions are based on the stated percent reduction applied to the LOS Unit 2 boiler pre-control unit emission rate (0.67 lb/mmBtu) and 5,130 mmBtu/hr for 8,760 hrs/yr operation for the future PTE case.

TABLE 2.3-4 – Pre-Control Baseline and Estimated Control Options' NO_X Emission Rates Evaluated for Future PTE Scenario LOS Unit 2 Boiler

Alt. No.[(1)]	**NO_X Control Technique**	**LOS Unit 2 Emission Rate (lb/mmBtu)**	**Control Percentage**[(1)]	**LOS Unit 2 Hourly Emission**[(1)] **(lb/hr)**	**LOS Unit 2 Annual Emission**[(1)] **(tons/yr)**
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	0.265	60.3	1,359	5,895
C	SNCR (using urea) w/ ASOFA	0.304	54.5	1,557	6,762
B	Coal Reburn (conventional, pulverized) w/ ASOFA	0.32	51.8	1,649	7,115
A	Advanced Separated Overfire Air (ASOFA)	0.48	28	2,465	10,796
--	Baseline, based on annual operation at future PTE scenario pre-control emission rate	0.67	--	3,422	14,989

1 - Alternative designation assigned from highest to lowest unit NO_X emission rate. Emissions are calculated from unit emission rates, control percentage, hourly heat input of 5,130 mmBtu/hr, and 8,760 annual hrs/yr operation compared to pre-control baseline.

Combinations of individual technologies for most alternatives in Tables 2.3-3 and 2.3-4 apply "advanced" SOFA, which is expected to have significantly lower NO_X emissions than a typical SOFA system as applied to the LOS Unit 2 cyclone boiler. The distinction that "advanced" separated overfire air has drastically different expected NO_X emissions than a typical SOFA system affects the NO_X emissions predicted from application of the highest performing form of overfire air combined with other various combustion-related and post-combustion techniques and technologies. These figures indicate the expected additional NO_X emission reduction potential from installation of various forms of SNCR, or coal reburn, in combination with existing cyclones and advanced separated overfire air systems for modest levels of "starved air" substoichiometric cyclone combustion.

2.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS – LOS UNIT 1

The fourth step of a BART analysis is to evaluate the following impacts of feasible emission controls:

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

The purpose of the impacts evaluation is to determine if there are any energy, economic, non-air quality environmental reasons, or aspects of the remaining useful life of the source, which would eliminate the remaining control technologies from consideration for LOS Unit 1.

2.4.1 COST IMPACTS OF NO_X CONTROLS – LOS UNIT 1

An evaluation was performed to determine the compliance costs of installing various feasible NO_X control alternatives on LOS Unit 1 boiler. This evaluation included estimates for:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, procure, construct, install, startup, test, and place into commercial operation a particular control technology. The results of this evaluation are summarized in Tables 2.4-1 through 2.4-6.

2.4.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROLS – LOS UNIT 1

The capital costs to implement the various NO_X control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

A review of the unit capital cost factor range and single point unit capital cost factor for the feasible NO_X emission reduction technologies evaluated for LOS Unit 1 is presented in Table 2.4-1.

TABLE 2.4-1 – Unit Capital Cost Factors of NO_X Control Options for LOS Unit 1

NO_X Control Technique	**Range ($/kW)(1),(2)**	**Single Point Unit Capital Cost Factor(2), ($/kW) LOS Unit 1**
SNCR (using urea) w/ boosted SOFA (Rotamix)	27-45(3),(4)	43.3(5)
SNCR (using urea) w/ basic SOFA	15-30(4)	28.9(5),(6)
SNCR (using urea) w/ CCOFA	10-20(4)	22.6(5)
Coal Reburn (conventional, pulverized) w/ boosted SOFA	42-75(3)	178.8(3),(7)
Coal Reburn (conventional, pulverized) w/ basic SOFA	30-60(3)	164.4(6),(7)
Boosted Separated Overfire Air (ROFA)	17-25(3)	20.7(4)
Separated Overfire Air (SOFA, basic)	5-10(4)	6.3(6)

(1) – Range based on published values or vendor proposals. Single point cost factor is a reasonable estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on MCR rating. In several cases, additional capital costs will be incurred that were not included in the published unit cost factors.
(2) – Unit capital cost factors of these individual technologies combined by simple addition. Actual costs may differ this due to positive or negative synergistic effects.
(3) – ROFA capital cost range from the 2005 WRAP Draft Report[44], posted at their website. See Appendix A for reference details
(4) – SNCR capital cost range from NESCAUM 2005 Technical Paper[43], posted at their website. See Appendix A for reference details.
(5) – Estimated capital cost for SNCR point estimate derived from December 2004 budgetary proposal by Fuel Tech.
(6) – Burns & McDonnell internal database was used for the point capital cost estimates of basic SOFA.
(7) – The single point unit capital cost factor shown for a coal reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper[43]; the single point cost estimate is based on the same factor assumed for cyclone boilers included in the 2005 WRAP Draft Report[44], posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in coal reburn options is 72.9 $/kW. See Appendix A for reference details.

Annualized capital cost, which includes the time value of capital monies and its recovery, is determined from the estimated capital cost and the methodology described in Section 1. Table 2.4-2 shows the estimated installed capital cost and annualized capital cost values for the NO_X emission reduction technologies evaluated for LOS Unit 1. These were developed from multiplying the unit capital cost single point factor for the control option by the nameplate output capacity rating of the respective unit.

TABLE 2.4-2 – Installed and Annualized Capital Costs Estimated for NO_X Control Options - LOS Unit 1

NO_X Control Alternative	Installed Capital Cost(1) ($1,000)	Annualized Capital Cost(2) ($1,000)
SNCR (using urea) w/ boosted SOFA (Rotamix)	9,342	814
SNCR (using urea) w/ basic SOFA	6,234	544
SNCR (using urea) w/ CCOFA	4,871	425
Coal Reburn (conventional, pulverized) w/ boosted SOFA	38,617(3)	3,367(3)
Coal Reburn (conventional, pulverized) w/ basic SOFA	35,509	3,096
Boosted Separated Overfire Air (ROFA)	4,471	390
Separated Overfire Air (SOFA, basic)	1,363	119

(1) – Installed capital cost is estimated for determination of total capital cost for a control technology, based on nameplate unit output capacity rating of 216,000 kW. Installed capital cost figures in 2005 dollars.

(2) – Annualized capital cost = Installed capital cost x 0.08718 capital recovery factor.

(3) – Costs for increased PM collection capacity included in coal reburn option are $15,740,000 for installed capital cost, and $1,372,000/yr annualized capital cost.

2.4.1.2 OPERATING AND MAINTENANCE COST ESTIMATES FOR NO_X CONTROLS – LOS UNIT 1

The operation and maintenance costs to implement the NO_X control technologies evaluated for LOS Unit 1 were largely estimated from cost factors established in the EPA's Air Pollution Control Cost Manual (OAQPS), and from engineering judgment applied to that control technology. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's Levelized Total Annual Costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR alternatives; and
- Reagent dilution water consumption and unit cost for SNCR alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.

- Reductions in revenue expected to result from loss of unit availability, i.e. outages attributable to the control option, which reduce annual net electrical generation available for sale (revenue).

Table 2.4-3 and Table 2.4-4 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the NO_X control options evaluated for LOS Unit 1. The cost methodology summarized in Section 1.3.5 provides more details for the levelized annual O&M cost calculations and cost factors. The annual operating and maintenance costs of the control options in Table 2.4-3 is based on LOS Unit 1 operation with the control options at 2,622 mmBtu/hr heat input and 8,760 hrs/yr operation. These O&M costs are relative to unit pre-control baseline operation at 0.285 lb/mmBtu for the highest 24-month NOx emission summation at 2,443 mmBtu/hr heat input for 8,510 hrs/yr operation of LOS Unit 1 with existing close-coupled overfire air and low-NO_X burners.

TABLE 2.4-3 – Estimated O&M Costs for NO_X Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

NO_X Control Alternative	**Annual O&M Cost$^{(1)}$ ($1,000)**	**Levelized Annual O&M Cost$^{(2)}$ ($1,000)**
SNCR (using urea) w/ boosted SOFA (Rotamix)	2,157	2,574
SNCR (using urea) w/ basic SOFA	1,702	2,030
SNCR (using urea) w/ CCOFA	1,195	1,426
Coal Reburn (conventional, pulverized) w/ boosted SOFA	3,072$^{(3)}$	3,665$^{(3)}$
Coal Reburn (conventional, pulverized) w/ basic SOFA	2,420$^{(3)}$	2,887$^{(3)}$
Boosted Separated Overfire Air (ROFA)	626	747
Separated Overfire Air (SOFA, basic)	21	25
Baseline, based on annual operation at historic 24-mo average pre-control emission rate	0	0

(1) – Annual O&M cost figures in 2005 dollars.

(2) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.

(3) – Costs for increased PM collection capacity included in coal reburn option are $901,000 for annual O&M cost, and $1,074,000/yr levelized annual O&M cost.

The annual operating and maintenance costs of the control options in Table 2.4-4 are based on LOS Unit 1 operation with the control option at 2,622 mmBtu/hr heat input and 8,760 hrs/yr operation. These O&M costs are relative to unit baseline operation at 0.29 lb/mmBtu for the highest 24-month

NO_X emission summation at 2,622 mmBtu/hr heat input for 8,760 hrs/yr operation of LOS Unit 1 with existing close-coupled overfire air and low-NO_X burners.

TABLE 2.4-4 – Estimated O&M Costs for NO_X Control Options (Relative to Presumptive BART Annual Emission Baseline – Future PTE Case) LOS Unit 1

NO_X Control Alternative	**Annual O&M Cost[(1)] ($1,000)**	**Levelized Annual O&M Cost[(2)] ($1,000)**
SNCR (using urea) w/ boosted SOFA (Rotamix)	2,157	2,574
SNCR (using urea) w/ basic SOFA	1,701	2,030
SNCR (using urea) w/ CCOFA	1,197	1,428
Coal Reburn (conventional, pulverized) w/ boosted SOFA	3,072(3)	3,665(3)
Coal Reburn (conventional, pulverized) w/ basic SOFA	2,420(3)	2,887(3)
Boosted Separated Overfire Air (ROFA)	626	747
Separated Overfire Air (SOFA, basic)	21	25
Baseline, based on annual operation at future PTE case pre-control emission rate	0	0

(1) – Annual O&M cost figures in 2005 dollars.
(2) – Levelized annual O&M cost = Annual O&M cost x 1.19314 O&M cost factor.
(3) – Costs for increased PM collection capacity included in coal reburn option are $901,000 for annual O&M cost, and $1,074,000/yr levelized annual O&M cost.

2.4.1.3 COST EFFECTIVENESS FOR NO_X CONTROLS – LOS UNIT 1

In order to compare a particular NO_X emission reduction alternative during the cost of compliance impact analysis portion of the BART determination process, the basic methodology defined in the BART Guidelines was followed [70 FR 39167-39168]. The sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which is referred to as "Levelized Total Annual Cost" (LTAC) of each alternative, was calculated. The LTAC for all NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Section 1.3.5 for cost methodology details).

The Average Cost Effectiveness (also called Unit Control Cost) was then determined as the LTAC divided by annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. There are two different NO_X emission baselines; the first assumes the highest historic 24-month average NO_X emission rate expressed in tons per year. The second baseline derives tons per year from the maximum future PTE case average NO_X emission rate. This approach results in two different average cost effectiveness values for the control options evaluated for LOS Unit 1. The annual NO_X emission reduction is the difference between the pre-control baseline and post-control emissions in tons per year. Average control cost for a particular technology is LTAC divided by annual tons of expected emission reduction. A summary of the annual emissions, reductions, control and levelized annual costs for the two LOS Unit 1 baselines are presented in Table 2.4-5 and 2.4-6.

TABLE 2.4-5 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

Alt. No.(1)	**NO_X Control Alternative**	**Annual NO_X Emissions**(2) **(Tons/yr)**	**Annual NO_X Emissions Reduction**(2) **(Tons/yr)**	**Levelized Total Annual Cost**(3),(4) **($1,000)**	**Average Control Cost**(4) **($/ton)**
G	Coal Reburn with boosted SOFA (future PTE case)	1,666	1,301	7,032(5)	5,404(5)
F	Coal Reburn with basic SOFA (future PTE case)	1,746	1,221	5,983(5)	4,898(5)
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	1,782	1,185	3,388	2,860
D	SNCR with basic SOFA (future PTE case)	1,883	1,084	2,574	2,373
C	SNCR with Close-Coupled OFA (future PTE case)	2,450	517	1,851	3,582
B	Boosted Separated Overfire Air (ROFA), (future PTE case)	2,483	484	1,137	2,347
A	Separated Overfire Air (SOFA, basic)	2,642	325	144	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	2,967	0	0	

(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.

(2) – NO_X emissions and control level reductions relative to the highest historic 24-month average pre-control annual baseline for LOS Unit 1.

(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #2 for Tables 2.4-2 and 2.4-3 for annualized cost factors.

(4) – Annualized cost figures in 2005 dollars.

(5) – LTAC for increased PM collection capacity included in coal reburn option are $1,372,000 for annualized capital cost plus $1,074,000 for annualized O&M cost, for a total of $2,446,000/yr. This results in an average control cost of $1,762/ton with boosted SOFA and $1,870/ton with basic SOFA.

TABLE 2.4-6 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Presumptive BART Annual Emission Baseline – Future PTE Case)

LOS Unit 1

Alt. No.[1]	NO_X Control Alternative	Annual NO_X Emissions[2] Tons/yr	Annual NO_X Emissions Reduction[2] Tons/yr	Levelized Total Annual Cost[3],[4] $1,000	Average Control Cost[4] $/ton
G	Coal Reburn with boosted SOFA (future PTE case)	1,693	1,638	7,032[5]	4,293[5]
F	Coal Reburn with basic SOFA (future PTE case)	1,774	1,557	5,983[5]	3,844[5]
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	1,811	1,519	3,388	2,230
D	SNCR with basic SOFA (future PTE case)	1,913	1,417	2,574	1,816
C	Boosted Separated Overfire Air (ROFA), (future PTE case)	2,469	862	1,137	1,298
B	SNCR with Close-Coupled OFA (future PTE case)	2,490	841	1,853	2,204
A	Separated Overfire Air (SOFA, basic)	2,641	689	144	208
	Baseline, based on annual operation at future PTE scenario pre-control emission rate	3,330	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

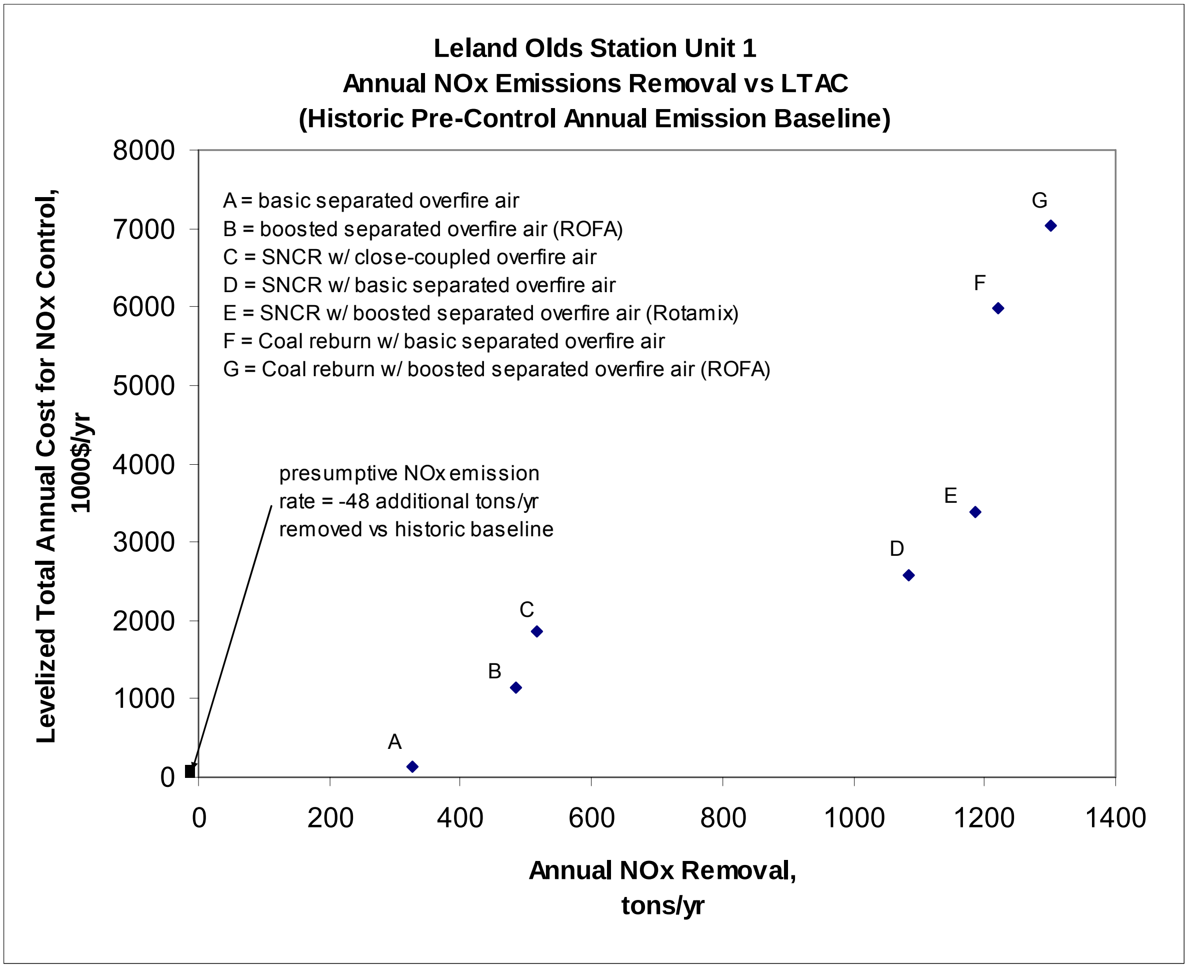
(2) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE scenario applied to LOS Unit 1.

(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #2 for Tables 2.4-2 and 2.4-4 for annualized cost factors.

(4) – Annualized cost figures in 2005 dollars.

(5) – LTAC for increased PM collection capacity included in coal reburn option are $1,372,000 for annualized capital cost plus $1,074,000 for annualized O&M cost, for a total of $2,446,000/yr. This results in an average control cost of $1,493/ton with boosted SOFA and $1,571/ton with basic SOFA.

Figure 2.4-1 – NO_X Control Cost Effectiveness – LOS Unit 1 (Historic Pre-Control Annual Emission Baseline)(1)



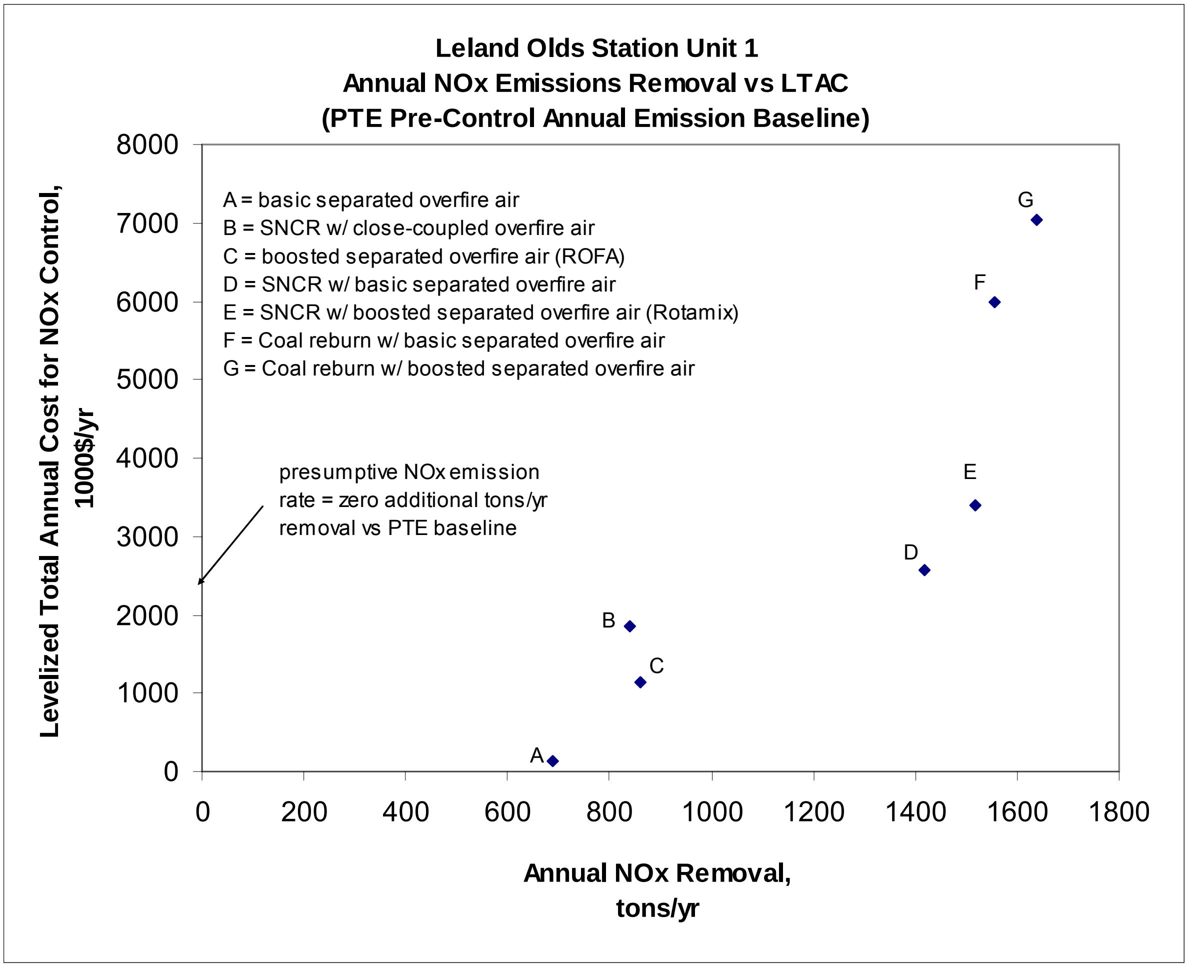
(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-5.

The comparison of the cost-effectiveness of the control options evaluated for LOS Unit 1 relative to two different NO_X emission baselines was made and is shown in Figures 2.4-1 and 2.4-2. The estimated annual amount of NO_X removal (emission reduction) in tons per year is plotted on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis).

Figure 2.4-1 is for the control options evaluated relative to the baseline historic pre-control annual baseline, compared to the post-control maximum annual NO_X emissions for operation of LOS Unit 1 under the future PTE case.

Figure 2.4-2 plots estimated levelized total annual costs versus estimated annual amount of NO_X removal (emission reduction) for the control options evaluated relative to the maximum pre-control annual baseline and future potential-to-emit post-control NO_X emissions for operation of LOS Unit ` under the future PTE case.

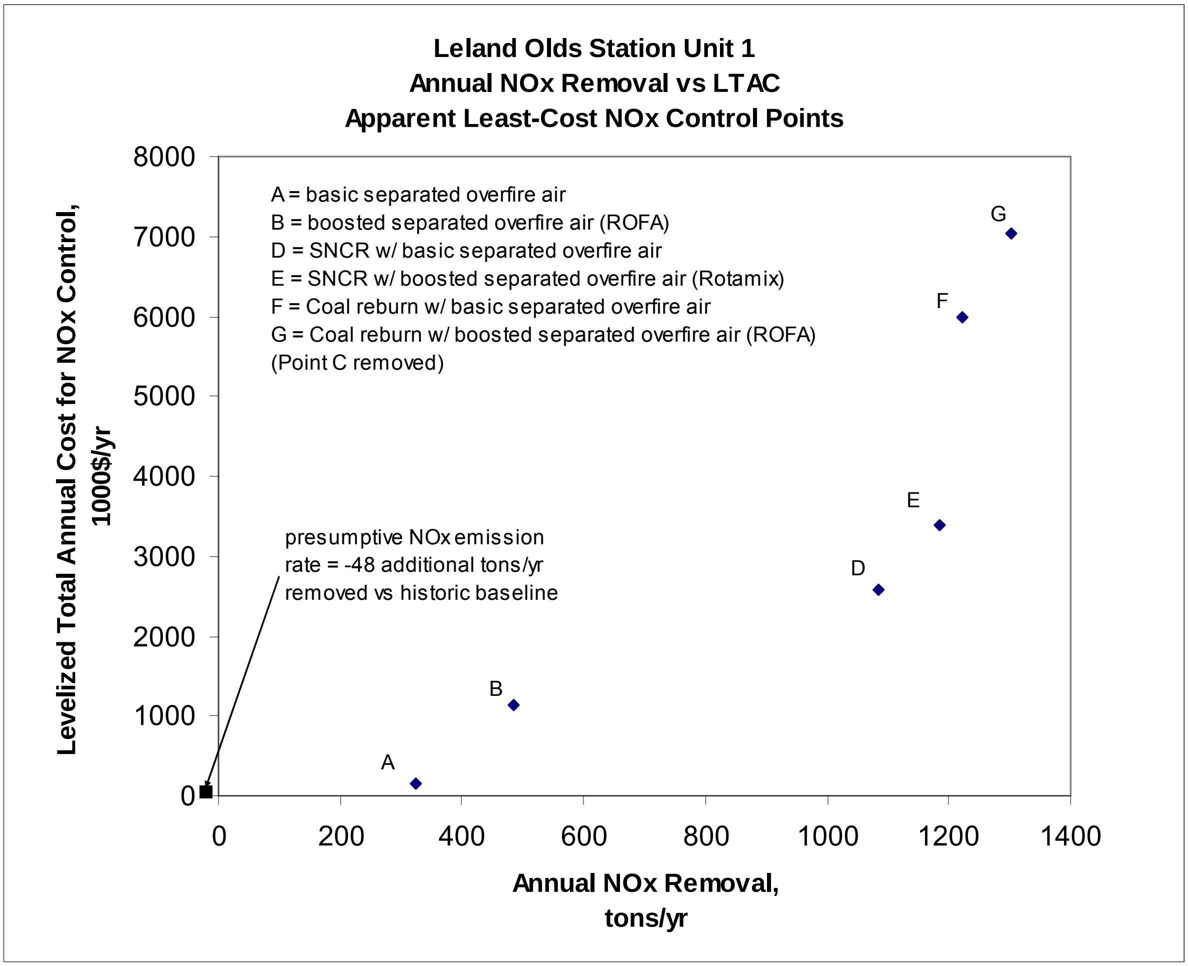
Figure 2.4-2 – NO_X Control Cost Effectiveness – LOS Unit 1 (PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-6.

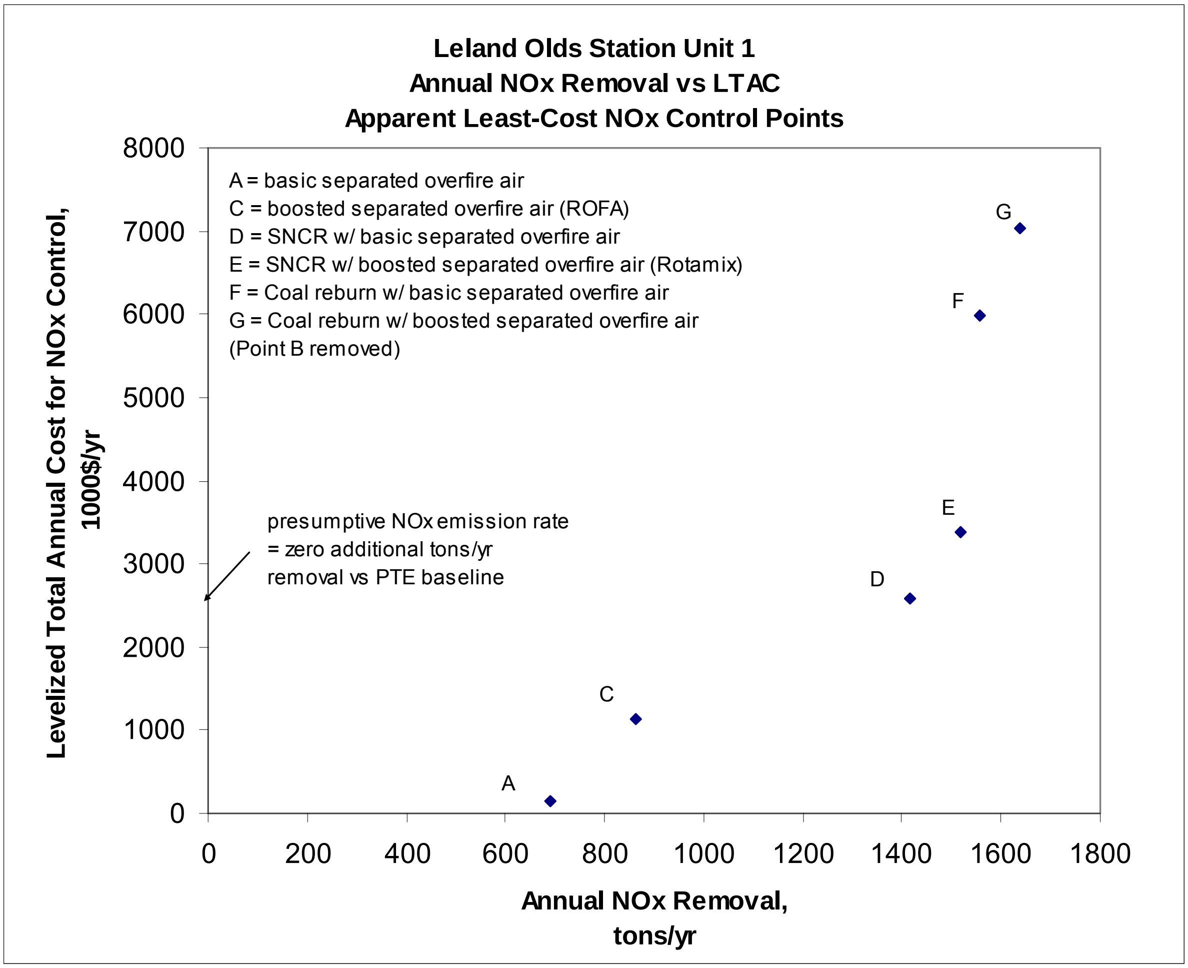
The purpose of Figures 2.4-1 and 2.4-2 is to show the range of control and cost for the evaluated NO_X reduction alternatives and identify the least-cost controls so that the Dominant Controls Curve can be created. The Dominant Controls Curve is the best fit line through the points forming the lower rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual NO_X removal tonnage for the various remaining BART alternatives. Points distinctly to the left of and above this curve are inferior control alternatives per the BART Guidelines and BART Guidelines on a cost effectiveness basis. Following a "bottom-up" graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope should be excluded from further analysis on a cost efficiency basis. Of the highest-performing versions of the technically feasible LOS Unit 1 NO_X control alternatives evaluated for cost-effectiveness, the data point for SNCR with close-coupled OFA is seen to be more costly for fewer tons of NO_X removed than for boosted separated overfire air (ROFA). SNCR with CCOFA appears to be an inferior control, and thus should not be included on the least cost and Dominant Controls Curve boundary. Note that cost-effectiveness points for conventional gas reburn and fuel-lean gas reburn alternatives would be distinctly left and significantly above the least cost-control envelope, so these options were not included in the cost-effectiveness analysis. Figures 2.4-3 and 2.4-4 show the revised least-cost control points without SNCR with CCOFA.

Figure 2.4-3 – NO_X Control Cost Effectiveness – LOS Unit 1
Apparent Least-Cost NOx Control Points
(Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-5.

Figure 2.4-4 – NO_X Control Cost Effectiveness – LOS Unit 1
Apparent Least-Cost NOx Control Points
(PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



1 - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-6.

The next step in the cost effectiveness analysis for the BART NO_X control alternatives is to review the incremental cost effectiveness between remaining least-cost alternatives. Figure 2.4-5 and Figure 2.4-6 contain a repetition of the levelized total annual cost and NO_X control information from Figure 2.4-3 and Figure 2.4-4 with SNCR with CCOFA removed (Point C in Figure 2.4-1, and Point B in Figure 2.4-2), and shows the incremental cost effectiveness between each successive set of least-cost NO_X control alternatives. The incremental NO_X control tons per year, divided by the incremental levelized annual cost, yields an incremental average unit cost ($/ton). This represents the slope of a line, if drawn, from one least-cost point as compared with another least-cost point.

TABLE 2.4-7 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,301	1,049	80	13,130
F	Coal Reburn with basic SOFA (future PTE case)	5,983	1,221	2,594	37	70,697
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,388	1,185	815	100	8,124
D	SNCR with basic SOFA (future PTE case)	2,574	1,084	1,437	600	2,394
B	Boosted Separated Overfire Air (ROFA), (future PTE case)	1,137	484	993	159	6,249
A	Separated Overfire Air (SOFA, basic)	144	325	144	325	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	0	0			

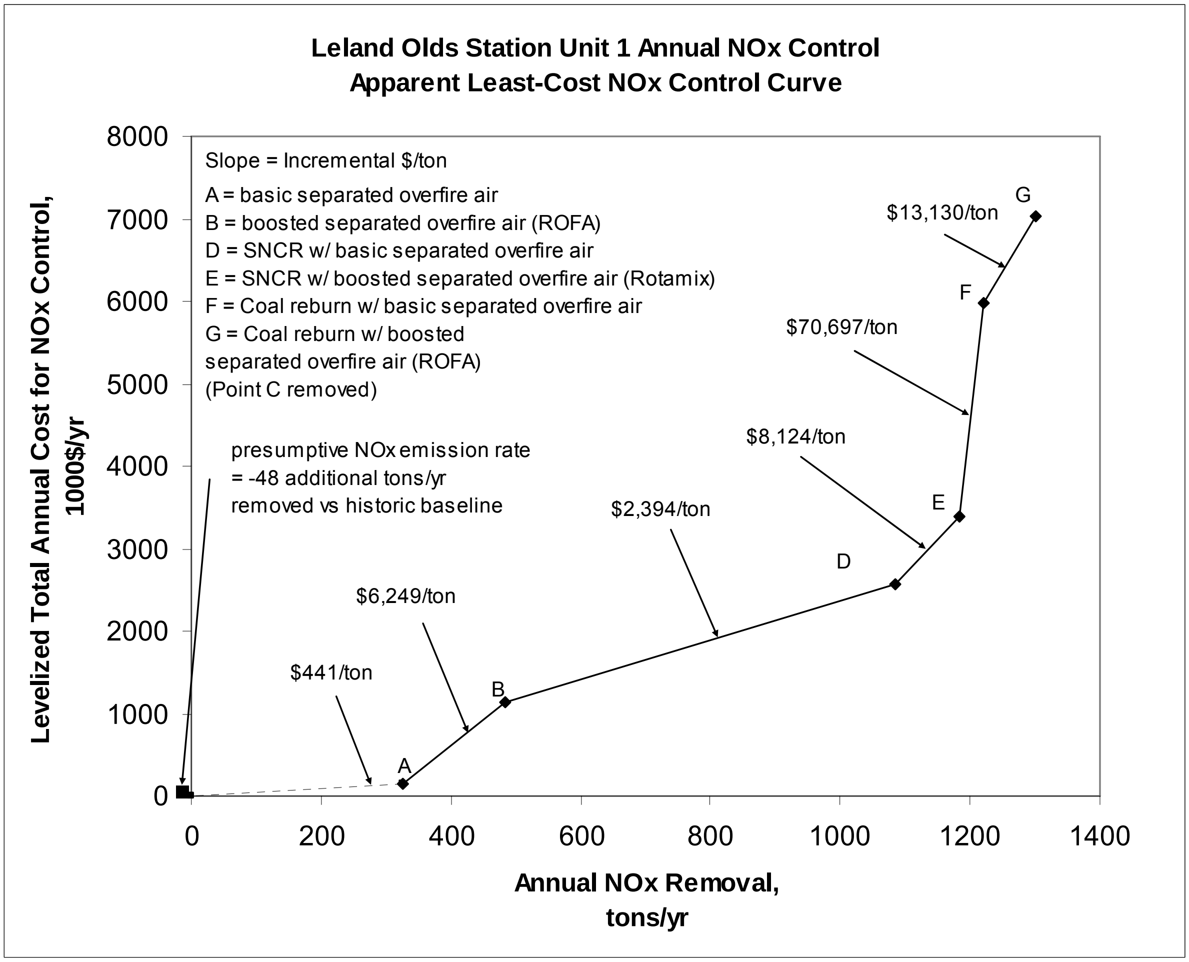
(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection efficiency are included in coal reburn options.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

TABLE 2.4-8 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) LOS Unit 1

Alt. No.(1)	**NO_X Control Technique**	**Levelized Total Annual Cost**(2),(3) **($1,000)**	**Annual Emission Reduction**(4) **(Tons/yr)**	**Incremental Levelized Total Annual Cost**(3),(5) **($1,000)**	**Incremental Annual Emission Reduction**(4),(5) **(Tons/yr)**	**Incremental Control Cost Effectiveness ($/ton)**(3),(6)
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,638	1,049	81	12,921
F	Coal Reburn with basic SOFA (future PTE case)	5,983	1,557	2,594	37	69,573
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,388	1,519	815	102	7,994
D	SNCR with basic SOFA (future PTE case)	2,574	1,417	1,437	556	2,586
C	Boosted Separated Overfire Air (ROFA), (future PTE case)	1,137	862	993	172	5,763
A	Separated Overfire Air (SOFA, basic)	144	689	144	689	208
--	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

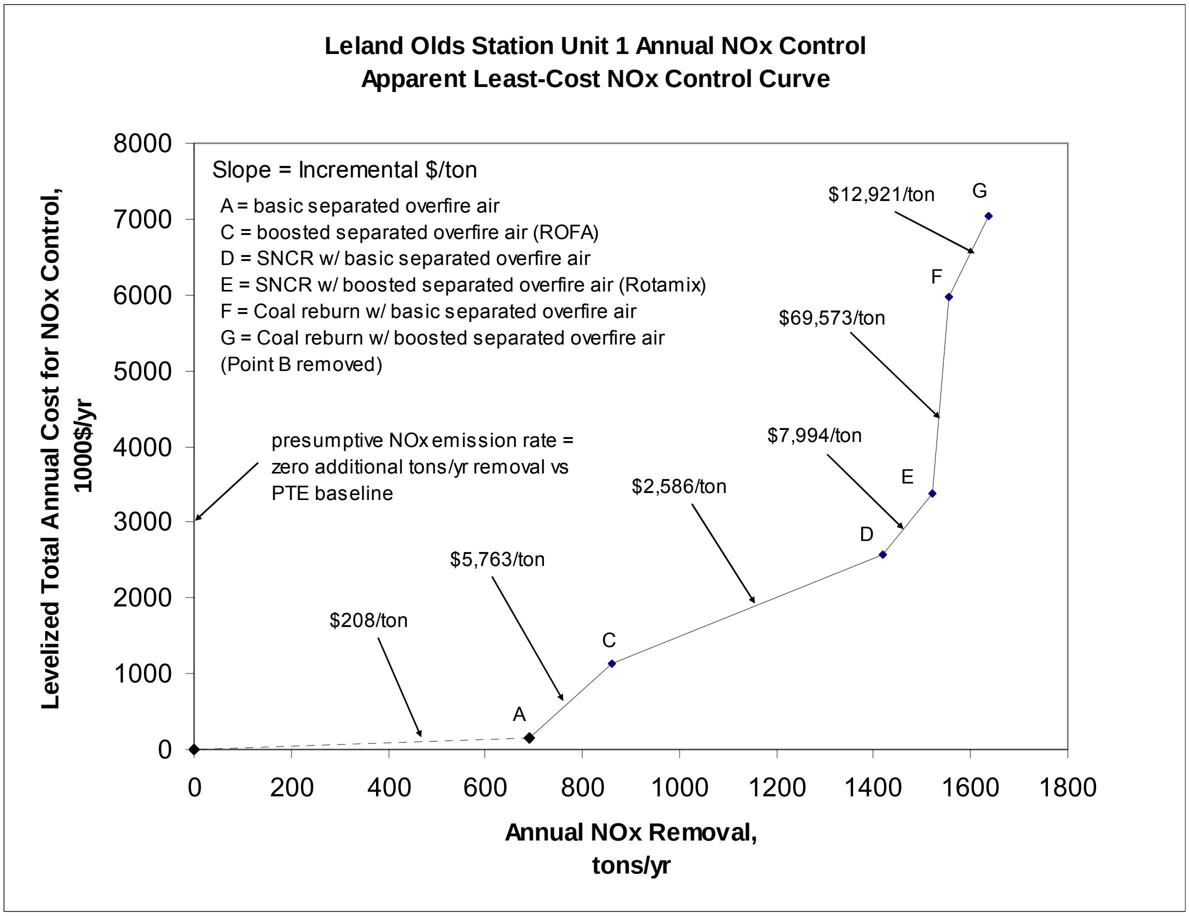
(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection capacity are included in coal reburn options.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

Figure 2.4-5 – NO_X Control Cost Effectiveness – LOS Unit 1 Apparent Least-Cost Controls Curve (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-7.

Figure 2.4-6 – NO_X Control Cost Effectiveness – LOS Unit 1 Apparent Least-Cost Controls Curve (PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)

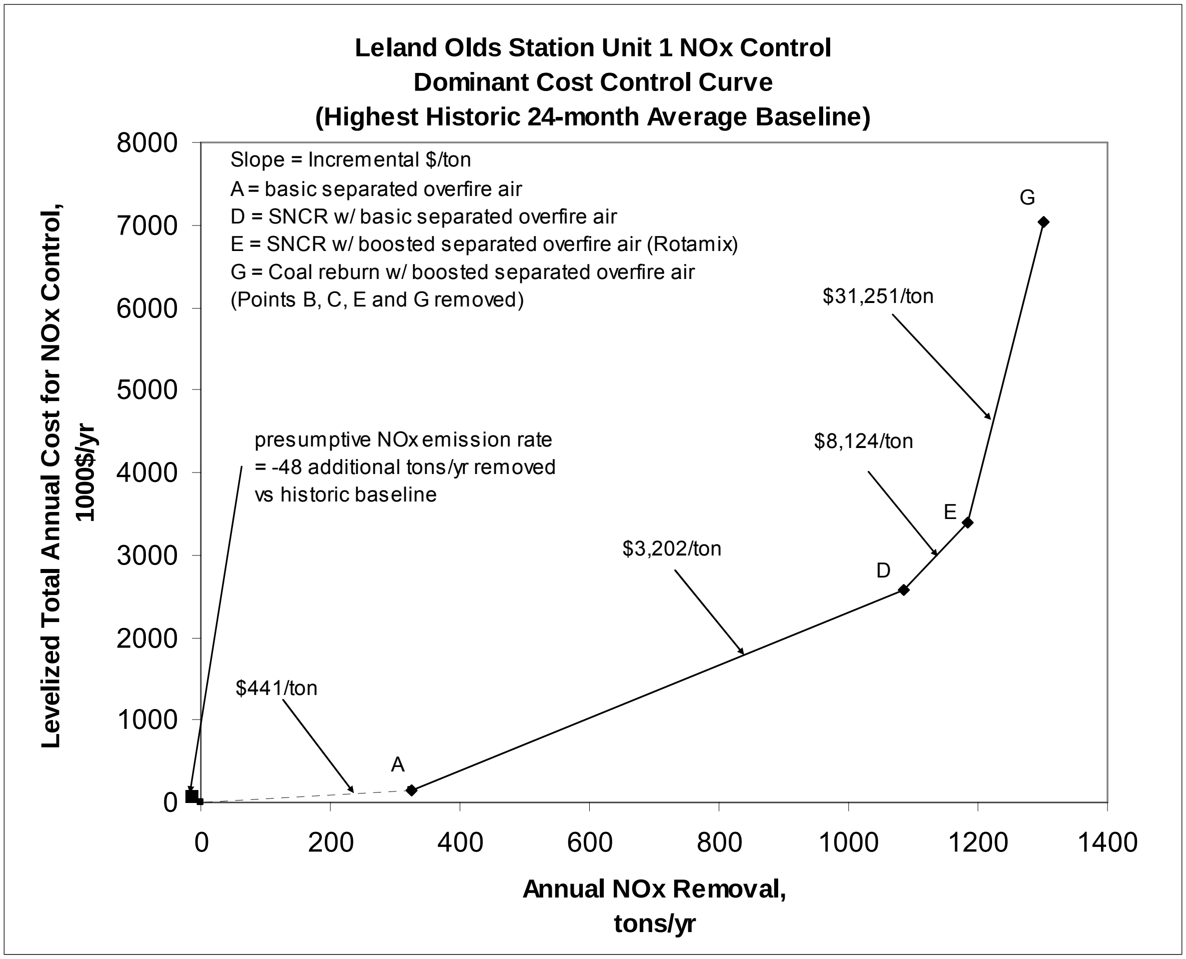


(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-8.

In the comparison displayed in Figure 2.4-5 and Figure 2.4-6, for the data shown in Table 2.4-7 and Table 2.4-8, the boosted SOFA (ROFA) NO_X control alternative (Point B in Figure 2.4-5, Point C in Figure 2.4-6) had a significantly higher incremental unit NO_X control cost (slope, $6,249/ton and $5,763/ton, respectively) compared against basic SOFA alternative (Point A) versus SNCR with basic SOFA (Points D) compared against ROFA. Also, Coal Reburn with basic SOFA (Points F) was significantly more incrementally expensive ($70,697/ton and $69,573/ton) compared against SNCR with boosted SOFA (Points E) versus Coal Reburn with boosted SOFA (Points G) compared against Coal Reburn with basic SOFA alternatives (Point F) ($13,130/ton and $12,921/ton). This indicates that Points C and Points F are inferior controls and do not occupy the Dominant Cost Control Curves.

After removal of Points C and F, the modified least-cost controls curve is the Dominant Cost Control Curve for NO_X emissions alternatives for each of the LOS Unit 1 pre-control baselines evaluated.

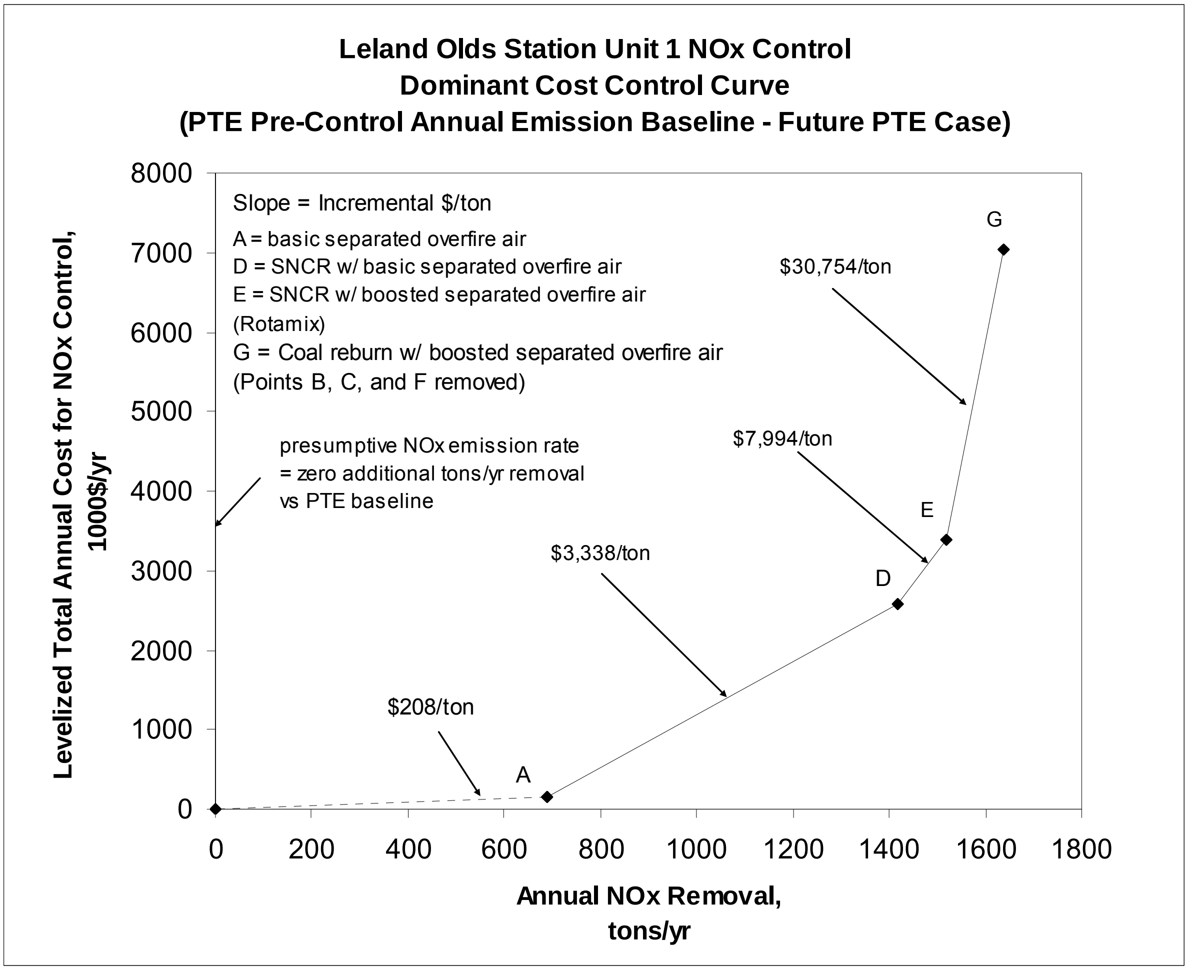
Figure 2.4-7 – NO_X Control Cost Effectiveness – LOS Unit 1 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-9.

Figure 2.4-8 – NO_X Control Cost Effectiveness – LOS Unit 1 Dominant Cost Control Curve(1)

(PTE Pre-Control Annual Emission Baseline – Future PTE Case)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-10.

TABLE 2.4-9 – Estimated Incremental Annual Emissions and LTAC for Dominant Cost Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1 NO_X Control

Alt. No.(1)	**NO_X Control Technique**	**Levelized Total Annual Cost**(2),(3) **($1,000)**	**Annual Emission Reduction**(4) **(Tons/yr)**	**Incremental Levelized Total Annual Cost**(3),(5) **($1,000)**	**Incremental Annual Emission Reduction**(4),(5) **(Tons/yr)**	**Incremental Control Cost Effectiveness ($/ton)**(3),(6)
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,301	3,643	117	31,251
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,388	1,185	815	100	8,124
D	SNCR with basic SOFA (future PTE case)	2,574	1,084	2,430	759	3,202
A	Separated Overfire Air (SOFA, basic)	144	235	144	325	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.

(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection efficiency are included in coal reburn option.

(3) – Annualized cost figures in 2005 dollars.

(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 1.

(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

TABLE 2.4-10 – Estimated Incremental Annual Emissions and LTAC for Dominant Cost Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) – LOS Unit 1 NO_X Control

Alt. No.[1]	NO_X Control Technique	Levelized Total Annual Cost[2],[3] ($1,000)	Annual Emission Reduction[4] (Tons/yr)	Incremental Levelized Total Annual Cost[3],[5] ($1,000)	Incremental Annual Emission Reduction[4],[5] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[3],[6]
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,638	3,643	118	30,754
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,388	1,519	815	102	7,994
D	SNCR with basic SOFA (future PTE case)	2,574	1,417	2,430	728	3,338
A	Separated Overfire Air (SOFA, basic)	144	689	144	689	208
--	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection capacity are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

The cost impact analysis for historic and PTE baseline conditions identifies those control alternatives that are on the Dominant Controls Cost Curve. Those alternatives are scrutinized for cost-effectiveness on both relative and absolute bases. In the comparison displayed in Figure 2.4-7 and Figure 2.4-8, for the data shown in Table 2.5-9 and Table 2.5-10, the SNCR with basic SOFA NO_X control alternative (Points D) had a significantly higher incremental unit NO_X control cost (slope, $3,202/ton and $3,338/ton, respectively, for historic and PTE baseline conditions) compared against basic SOFA alternative (Point A) versus baseline ($441/ton and $208/ton, respectively). The incremental cost-effectiveness of the least-cost SNCR alternative on the Dominant Cost Control Curve is on the order of seven to sixteen times the magnitude of basic SOFA. SNCR with boosted SOFA (Point E) had a significantly higher incremental unit NO_X control cost compared against the

SNCR with basic SOFA alternative (Point D) ($8,124/ton and $7,994/ton, vs $3,202/ton and $3,338/ton respectively). Coal Reburn with boosted SOFA was even more incrementally costly.
In the final BART Guidelines, the EPA neither proposes hard definitions for reasonable or unreasonable Unit Control Costs nor for incremental cost effectiveness values. As can be seen from a review of Table 2.4-5, the average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the highest 24-hour historic baseline NO_X emission ranges from $441/ton to $5,404/ton. Table 2.4-6 shows average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the presumptive NO_X emission level ranges from $208/ton to $4,293/ton. The latter has lower costs per ton of NO_X emission removal due to the higher number of tons removed for the maximum emissions for pre-control baseline and additional controls under the future PTE case.

Various combinations of NO_X control technologies evaluated for control and cost-effectiveness are considered to be technically feasible for LOS Unit 1, but have much higher installation and operating costs compared with basic SOFA alone. This confirms the analysis performed by the EPA for establishing the presumptive limits for BART NO_X emissions from pulverized coal-fired EGUs: that the application of current combustion control technology, [primarily low-NOx burners and overfire air] is generally, but not always, more cost-effective than post-combustion controls. Based on the cost impact analysis and the premise that LOS Unit 1's historic and PTE annual average baseline emissions already meet the presumptive BART NO_X level of 0.29 lb/mmBtu, only the least-cost alternative of basic separated overfire air was considered for further impact and visibility impairment evaluations for LOS Unit 1 NO_X emissions control.

The other elements of the fourth step of a BART analysis after the cost impact analysis include evaluating the following impacts:

- Energy impacts.
- Non-air quality environmental impacts.
- Remaining useful life of the source.

For the purposes of this BART analysis, the remaining useful life of the source was assumed to exceed the 20-year project life utilized in the levelized annual cost impact estimates. The other impacts for the single LOS Unit 1 NO_X emissions control alternative chosen to be evaluated further are discussed in Section 2.4.2 and Section 2.4.3. Visibility impairment impacts for the single LOS Unit 1 NO_X emissions control are summarized in Section 2.4.4.

2.4.2 ENERGY IMPACTS OF NO_X CONTROL ALTERNATIVES – LOS UNIT 1

The single feasible NO_X control alternative was reviewed for significant or unusual energy penalties or benefits associated with its use. There are several basic kinds of energy impacts for NO_X emissions controls:

- Potential increase or decrease in power plant energy consumption resulting from a change in thermal (heat) energy to net electrical output conversion efficiency of the unit, usually expressed as an hourly unit heat rate (Btu/kW-hr) or the inverse of pounds of pollutant per unit electrical power output (MW-hr). This may or may not change the net electrical output (MW) capacity of the EGU, depending on if there are physical or imposed limits on the total heat input to the boiler or electrical power output.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in physical operational limitations imposed on the ability to sustain a fuel heat input rate (mmBtu/hr) which results in a potentially lower or higher unit net electrical output (MW) capacity. This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in auxiliary electrical power demand and usage (kW, kW-hrs). This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in reliability and availability to generate electrical power. This results in a change to the number of hours of annual operation, not necessarily a change in net electrical output (MW) capacity of the EGU.

Separated overfire air was the only NOX control technology evaluated further for LOS Unit 1. SOFA does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. To provide effective volumes and velocities of separated overfire air at the injection ports may require slightly higher forced draft fan power consumption resulting from higher fan discharge pressure. Combustion air damper actuators' electrical power demand would be an insignificant (+ 1 kW) change in net electrical power consumption from LOS Unit 1. Higher windbox pressure and ductwork pressure drop impacts of the SOFA system on the forced draft fans' and induced draft fans' auxiliary electrical power consumption are expected to be negligible (less than 1% of the annual auxiliary power consumed by these fans) so that unit net electrical output (MW) capacity is essentially the same as the current nameplate rating.

Operation of a SOFA system may cause a small increase in levels of unburned carbon in the flyash emitted from the boiler compared with current operation. This represents a slight amount of lost potential electrical power generation from the incompletely burned fuel, so this inefficiency could have a small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr). This impact was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

Boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures may be slightly elevated during air-staged burner operation with SOFA. This impact on the boiler's operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr) was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

SOFA is not expected to significantly reduce unit reliability and availability to generate electrical power. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion of the steel waterwall tubes by sulfur compounds in the furnace gases being created above the burners and below the SOFA injection ports. Due to the moderate sulfur content in the lignite and modest amount of air-staging during firing of the existing low-NO_X burners expected during SOFA operation, this potential change in corrosion rate of the boiler tubes is expected to be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube failures and changeouts is difficult to estimate, and has not been quantified.

Table 2.4-11 summarizes the gross demand and usage of auxiliary electrical power estimated for the single NO_X control alternative evaluated for LOS Unit 1. This assumes annual operation for 8,760 hours at a heat input rate of 2,622 mmBtu/hr at the future PTE case conditions.

TABLE 2.4-11 – Expected Auxiliary Electrical Power Impacts for NO_X Controls – LOS Unit 1

Alt. No.	NO_X Control Technique	NO_X Control Equipment Estimated Annual Average Auxiliary Electrical Power Demand and Usage		
		Aux. Power Demand (1) (kW)	Generation Reduction from Aux. Power Demand(2) (kW-hrs/yr)	Generation Reduction from Reduced Unit Availability(3) (kW-hrs/yr)
A	Separated OFA	1	8,760	0

(1) – The NO_X control equipment gross auxiliary electrical power demand is estimated.

(2) – The annual change in NO_X equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.

(3) – The estimated total hours per year of unit unavailability multiplied by average gross generation multiplied by annual running plant capacity factor for the particular control alternative. For this analysis, SOFA was not expected to reduce annual hours of possible operation.

2.4.3 NON AIR QUALITY AND OTHER ENVIRONMENTAL IMPACTS OF NO_X CONTROL ALTERNATIVES – LOS UNIT 1

Nitrogen oxides react with oxygen in the atmosphere to produce elemental nitrogen and ozone (O_3). This is one of the common causes of visible pollution in the atmosphere referred to as “smog”. Operation of the various NO_X control technologies considered for potential application at the Leland Olds Station impose direct and indirect impacts on the environment. The most pronounced environmental impact expected from operation of any of the NO_X control options considered is the reduction of ozone and improvement in atmospheric visibility (i.e. reduced visibility impairment) downwind of the facility. This is discussed in detail in the Visibility Impacts section.

2.4.3.1 ENVIRONMENTAL IMPACTS OF SOFA

The amount of unburned carbon in the flyash produced by the boiler, collected for disposal or potentially emitted to the atmosphere, may increase by small increments due to operation of LOS Unit 1 using separated overfire air for NO_X emissions control. The potential changes in the annual amounts of flyash emissions and disposal rates are expected to be inconsequential, and have not been quantified.

The operation of a system using a basic form of separated overfire air for NO_X emissions control may increase carbon monoxide concentrations in the stack flue gas emitted from the LOS Unit 1 boiler.

This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

There were no other adverse or significant changes in non-air quality or other environmental impacts identified for LOS Unit 1 as a result of using separated overfire air for NO_X emissions control. Predicted visibility impacts are discussed in the next section.

2.4.4 VISIBILITY IMPAIRMENT IMPACTS OF LELAND OLDS STATION NO_X CONTROLS – UNIT 1

The fifth step in a BART analysis is to conduct a visibility improvement determination for the source.

For this BART analysis, there were two baseline NO_X emission rates modeled for LOS Unit 1 – one for the historic pre-control NO_X emission rate listed in the NDDH BART protocol[3], and one applying the presumptive BART NO_X emission rate. The historic pre-control emission baseline was the 24-hour average actual NO_X emission rate from the highest emitting day of the years 2000-2002 (meteorological period modeled per the NDDH BART protocol[3]). The historic (protocol) NO_X baseline condition emission rate was modeled simultaneously with the highest 24-hour average SO_2 emission rate, and the highest 24-hour average PM emission rate of the 2000-2002 time period.

The historic (protocol) baseline hourly NO_X emission rate used for modeling visibility impacts due to LOS Unit 1 under the conditions stated above was 813 lb/hr. Visibility impact modeling was performed using the CALPUFF model with the difference between the impacts from historic pre-control baseline and post-control average hourly NO_X emission rates representing the visibility impairment impact reduction. Three CALPUFF model runs were conducted with the same presumptive BART NO_X emission baseline rate, constant PM emissions, and various levels of SO_2 control assuming the Potential-To-Emit (PTE) boiler design rating for heat input (2,622 mmBtu/hr). The presumptive BART unit NO_X emission baseline rate of 0.29 lb/mmBtu multiplied by the boiler PTE heat input rating of 2,622 mmBtu/hr yields 760 lb/hr for LOS Unit 1 under the future PTE case. The model used an average unit NO_X emission rate of 0.23 lb/mmBtu with the PTE boiler heat input rating to yield 603 lb/hr. This was the post-control hourly NO_X emission rate representing basic SOFA applied to the future PTE case for LOS Unit 1.

In keeping with the NDDH BART visibility impairment impact modeling protocol, the BART NO_X presumptive emission rate (760 lb/hr) and SOFA alternative both have a different boiler heat input basis than the historic highest 24-hour pre-control NO_X emission baseline (813 lb/hr). The post-control conditions both assume operation at the boiler PTE capacity rating (future PTE case).

The results of the historic pre-control baseline presumptive BART NO_X PTE baseline emission rate, and post-control SOFA-enhanced PTE NO_X emission rate, modeled with the PTE 90% sulfur emission control rate for LOS Unit 1 are shown in Table 2.4-12. The results of the visibility impairment modeling at the pre-control (protocol) baseline emission rate for LOS Unit 1 showed that Lostwood National Wildlife Refuge exceeded 0.5 deciView for the highest predicted visibility impairment impact (90th percentile, averaged for 2000-2002). Average predicted visibility impairment impacts decreased significantly for the presumptive BART NO_X PTE baseline emission rate, and slightly more with post-control SOFA-enhanced PTE NO_X emission rates, modeled with any of the three PTE sulfur emission control rates for LOS Unit 1. The comparison of the incremental average visibility impairment impacts that are predicted for the three PTE sulfur emission control rates for LOS Unit 1 is shown in Section 3.4.4.

TABLE 2.4-12 – Average Visibility Impairment Impacts from NO_X Controls – LOS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts(1)		
	Historic Pre-Control (Protocol) Baseline (dV)	Presumptive BART NO_X PTE Baseline(2) (dV)	PTE Emissions with SOFA NO_X Control(2) (dV)
TRNP-South Unit	0.423	0.107	0.099
TRNP-North Unit	0.450	0.118	0.111
TRNP-Elkhorn Ranch	0.287	0.080	0.073
Lostwood NWR	0.639	0.171	0.153

(1) - Average predicted visibility impairment impacts (90th percentile) relative to background for years 2000-2002. Pre-control baseline impacts are from highest historic 24-hour NO_X, SO_2, and PM emission rates (NDDH BART protocol). Presumptive BART NO_X and SOFA NO_X impacts are from PTE heat input emission rates. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case.

The results of the visibility impairment modeling at the presumptive BART NO_X PTE emission rate (760 lb/hr) with the PTE 90% sulfur emission control rate for LOS Unit 1 again showed that Lostwood National Wildlife Refuge had the highest predicted improvement in visibility impairment compared to the pre-control (protocol) baseline levels. Average predicted visibility impairment reduction also increased with SOFA-enhanced post-control NO_X PTE emission rate from LOS Unit 1 for Lostwood NWR (approximately 0.5 deciView reduction). This is shown in Table 2.4-13.

TABLE 2.4-13 – Average Visibility Impairment Impact Reductions from NO_X Controls – LOS Unit 1 (Post-Control PTE Emissions vs Historic Baseline)

	Visibility Impairment Reductions(1)	
Federal Class 1 Area	**Presumptive BART NO_X PTE Baseline(2) (dV)**	**PTE Emissions, SOFA NO_X Control(2) (dV)**
TRNP-South Unit	0.316	0.323
TRNP-North Unit	0.332	0.339
TRNP-Elkhorn Ranch	0.207	0.214
Lostwood NWR	0.467	0.486

(1) - Average predicted visibility impairment impact reductions (90th percentile) relative to historic pre-control emission rates (NDDH BART protocol) for years 2000-2002. Presumptive BART NO_X and SOFA NO_X impacts are from PTE heat input emission rates.

(2) - SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case scenario.

This analysis includes a determination of the incremental control effectiveness of reducing the predicted visibility impairment impact for presumptive BART NO_X and SOFA alternatives' PTE emission levels evaluated for the future PTE case operation of LOS Unit 1. The average predicted visibility impairment reduction resulting from LOS Unit 1 NO_X PTE emissions expected to result from separated overfire air (SOFA) emissions versus presumptive BART NO_X levels for the future PTE case are shown in Table 2.4-14.

TABLE 2.4-14 –Visibility Impairment Reduction from NO_X Controls (vs Presumptive BART NO_X Baseline Emissions) – LOS Unit 1

Federal Class 1 Area	Incremental Visibility Impairment Reduction(1) PTE Emissions, SOFA NO_X Control(2) (dV)
TRNP-South Unit	0.00733
TRNP-North Unit	0.00733
TRNP-Elkhorn Ranch	0.00733
Lostwood NWR	0.0183

(1) - Incremental average predicted visibility impairment impact reductions (90th percentile) relative to presumptive BART NO_X PTE baseline emission rates for years 2000-2002. SOFA NO_X impacts are from PTE heat input emission rates.

(2) - SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case.

Table 2.4-14 shows that incremental visibility impairment improvements predicted to result from applying the SOFA alternative to the presumptive BART NO_X PTE emission rate for LOS Unit 1 are very small. The amount of visibility impairment predicted for natural background conditions is much greater in magnitude than the amount predicted from LOS Unit 1's contribution alone. The data also shows that reductions in predicted visibility impairment impacts that result from a combination of presumptive BART NO_X PTE emissions and SO_2 PTE emissions at the 90 percent (or better) control levels compared to the pre-control (protocol) emission conditions are much greater in significance than the incremental improvements of predicted visibility impairment from additional reductions in NO_X emissions.

This analysis also includes a determination of the incremental cost-effectiveness of reducing predicted visibility impairment impact for the SOFA alternative evaluated for LOS Unit 1. The estimated LTAC for reducing NO_X emissions from LOS Unit 1 expected to result from separated overfire air (SOFA) for the future PTE case are shown in Table 2.4-6. The comparison in Table 2.4-15 shows that the ratio of the estimated additional annualized costs of installing and operating SOFA with the future PTE case to the average predicted visibility impairment improvement relative to the presumptive BART NO_X PTE baseline emission rate for the future PTE case applied to LOS Unit 1 would result in millions of dollars per deciView of visibility impairment improvement.

TABLE 2.4-15 – Cost Effectiveness of Visibility Impairment Reduction from NO_X Controls (vs Presumptive NO_X Baseline Emissions) – LOS Unit 1

Federal Class 1 Area	Incremental Visibility Impairment Reduction Unit Cost PTE Emissions, SOFA NO_X Control(1),(2) ($/dV-yr)
TRNP-South Unit	19,640,000
TRNP-North Unit	19,640,000
TRNP-Elkhorn Ranch	19,640,000
Lostwood NWR	7,860,000

(1) - Average predicted visibility impairment impact reductions (90th percentile) relative to presumptive BART NO_X PTE baseline emission rates for years 2000-2002. SOFA NO_X impacts are from PTE heat input emission rates. Control costs are levelized annual values for installed capital + O&M for SOFA NO_X control. All cost figures in 2005 dollars. See Table 2.4-6 for details.

(2) - SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case.

The number of days predicted to have visibility impairment due to LOS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the historic pre-control (protocol) hourly NO_X, SO_2, and PM emission rates described previously in this Section. The results are summarized and presented in Table 3.4-15. Similarly, the same information for the post-control SO_2 and PM alternatives with presumptive BART NO_X PTE emission rates was summarized and is shown in Table 3.5-16. The differences in average visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between presumptive BART NO_X emission rates versus SOFA-controlled NO_X emission rates with post-control SO_2 and PM alternatives are summarized and shown in Table 2.4-16.

The magnitude of predicted visibility impairment impacts and number of days predicted to have visibility impairment impact greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 area. The highest number of days in which the predicted visibility impairment impact above background exceeded 0.5 deciViews was for the pre-control (protocol) emission case in year 2000 for Lostwood NWR. A series of bar charts showing the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for both the pre-control and post-control model results is included in Section 3.4.

The post-control SO_2 and PM alternatives with SOFA for NO_X control were only slightly lower for the predicted visibility impairment impacts and number of days predicted to have visibility impairment impacts greater than 0.50 and 1.00 deciViews compared to the same post-control SO_2 and PM conditions with presumptive BART NO_X PTE emission rates. The number of days are presented in Appendix D. A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the SOFA-controlled PTE emission rates compared to presumptive BART NO_X PTE emission rates with post-control SO_2 and PM alternatives is included in Figures 2.4-9, 2.4-10, and 2.4-11.

2.4.5 SUMMARY OF IMPACTS OF LOS NO_X CONTROLS – UNIT 1

Table 2.4-17 summarizes the various quantifiable impacts discussed in Sections 2.4.1 through 2.4.4 for the single BART NO_X alternative evaluated for LOS Unit 1.

Table 2.4-16 – Visibility Impairment Reductions – SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

Class 1 Area	NO_X Control Technique(1)	Visibility Impairment Reduction(2) (ΔdV)	ΔDays(3) Exceeding 0.5 dV in 2000	ΔDays(3) Exceeding 0.5 dV in 2001	ΔDays(3) Exceeding 0.5 dV in 2002	ΔDays(3) Exceeding 1.0 dV in 2000	ΔDays(3) Exceeding 1.0 dV in 2001	ΔDays(3) Exceeding 1.0 dV in 2002	ΔConsecutive Days(3) Exceeding 0.5 dV 2000	ΔConsecutive Days(3) Exceeding 0.5 dV 2001	ΔConsecutive Days(3) Exceeding 0.5 dV 2002
TRNP South	SOFA	0.00733	1	0	0	0	0	0	0	0	0
TRNP North	SOFA	0.00733	2	3	2	0	0	0	0	1	0
TRNP Elkhorn	SOFA	0.00733	1	0	1	1	0	1	0	0	0
Lostwood NWR	SOFA	0.0183	0	0	2	0	2	0	0	0	0

1 - SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

2 - Average predicted visibility impairment reductions (90th percentile) from all PTE emissions for SO_2 and PM post-control alternatives with SOFA NO_X control at 0.23 lb/mmBtu relative to presumptive NO_X emission level of 0.29 lb/mmBtu with PTE heat input emission rates (future PTE case), years 2000-2002.

3 - Difference in number of days is 100th percentile level for predicted visibility impacts in Table 3.4-15.

Figure 2.4-9 – Days of Visibility Impairment Reductions – 0.5 dV
SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

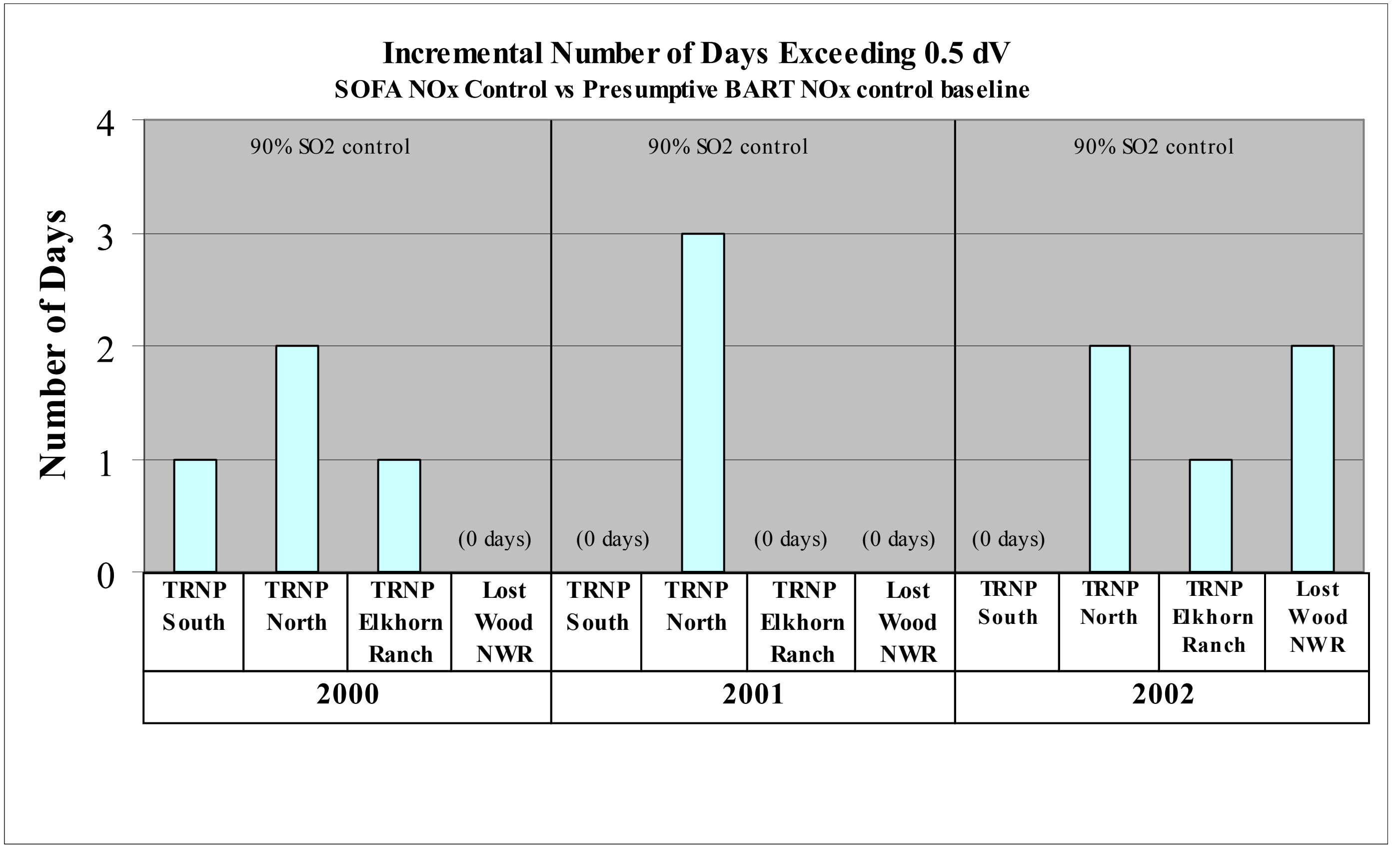


Figure 2.4-10 – Days of Visibility Impairment Reductions – 1.0 dV
SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

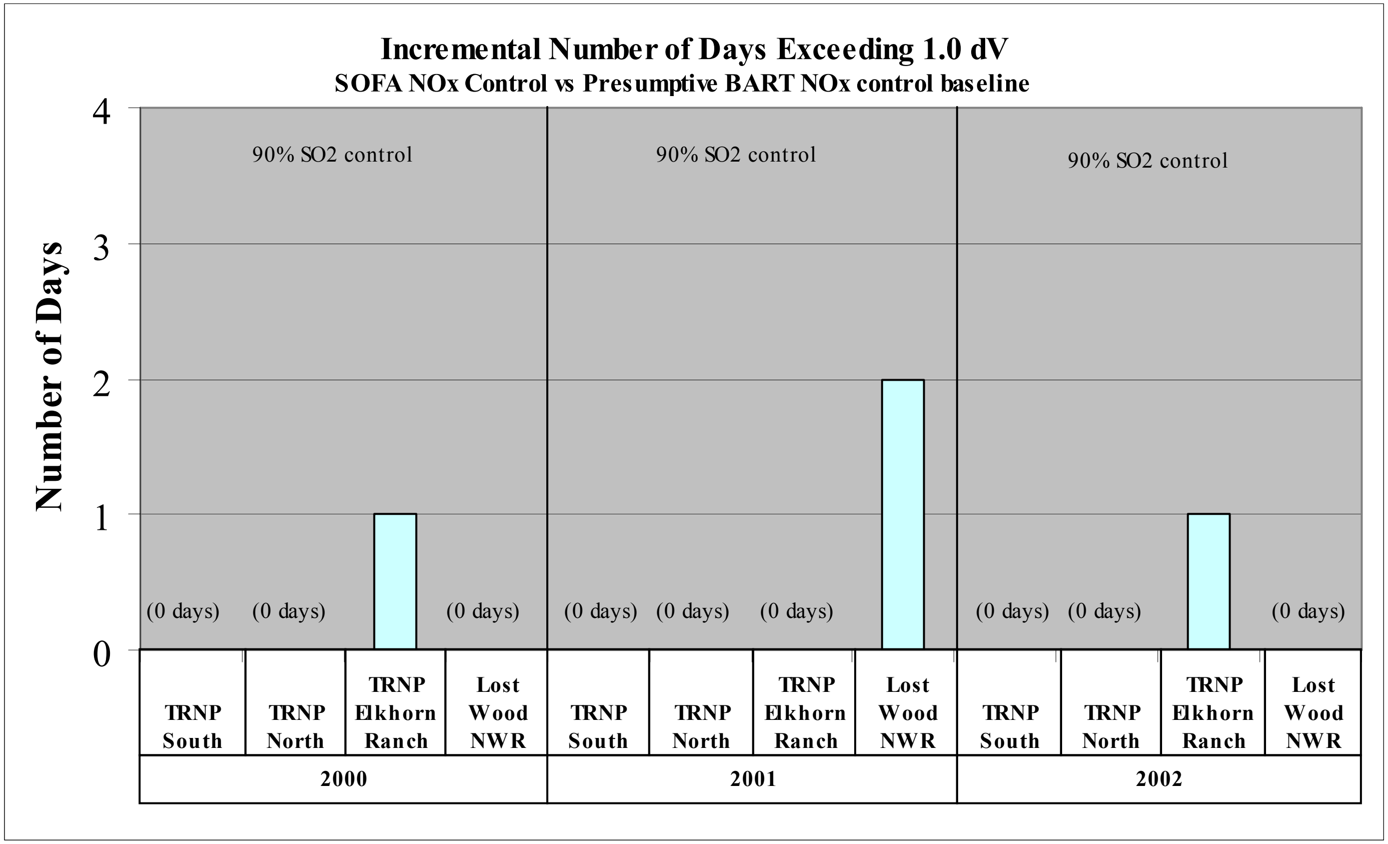


Figure 2.4-11 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV
SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

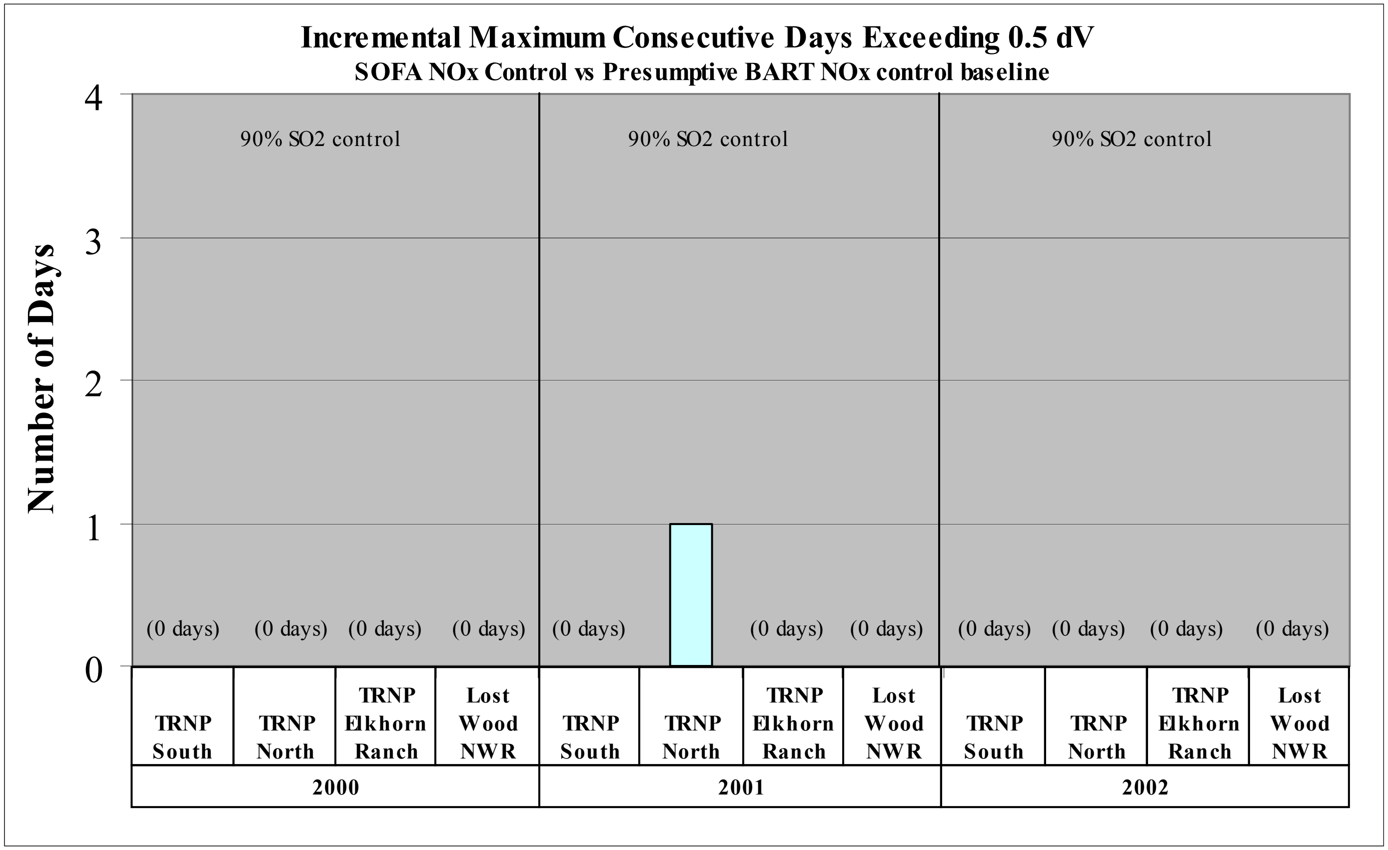


Table 2.4-17 – Impacts Summary for LOS Unit 1 NO_X Controls (vs Presumptive BART NO_X PTE Emissions)

NO_X Control Technique w/ SO_2 Control Level	NO_X Control Efficiency (%)	Annual NO_X Emissions Reduction (tpy)	Levelized Total Annual Cost(1) ($)	Unit Control Cost ($/ton)	Visibility Impairment Impact Reduction		Incremental Visibility Impairment Reduction Unit Cost(1),(3) ($/dV)	Energy Impact (kW)	Non Air Quality Impacts
					Class 1 Area	Incremental(2) ΔdV			
SOFA w/ 90% SO_2 Control	20.7%	689	$144,000	$289	TRNP-S	0.00733	$19,640,000	1	Flyash unburned carbon increase
					TRNP-N	0.00733	$19,640,000		
					TRNP-Elk	0.00733	$19,640,000		
					LNWR	0.0183	$7,860,000		

(1) - All cost figures in 2005 dollars. See Table 2.4-6 for details.

(2) - Average predicted visibility impairment impact improvements (incremental, 90th percentile) for years 2000-2002 relative to presumptive BART NO_X emission level of 0.29 lb/mmBtu for all SO_2 and PM post-control alternatives at PTE heat input emission rates (future PTE case). This case assumes 90% SO_2 control over pre-control baseline.

(3) - LTAC for SOFA NO_X control divided by Incremental ΔdV.

2.5 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS – LOS UNIT 2

The fourth step of a BART analysis is to evaluate the following impacts of feasible emission controls:

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

The purpose of the impacts evaluation is to determine if there are any energy, economic, non-air quality environmental reasons, or aspects of the remaining useful life of the source, which would eliminate the control technologies from consideration for Leland Olds Station Unit 2.

2.5.1 COST IMPACTS OF NO_X CONTROLS – LOS UNIT 2

An evaluation was performed to determine the compliance costs of installing various feasible NO_X control alternatives on LOS Unit 2 boiler. This evaluation included estimates for:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 2.5-1 through 2.5-8. From Step 3 of the BART analysis, compared with other similarly-effective NO_X controls, conventional gas reburn alternatives would have high expected capital costs for a natural gas supply pipeline and on-going natural gas costs. Thus, otherwise technically feasible gas-consuming alternatives are considered economically unattractive for application at LOS on the Unit 2 boiler.

Although the BART Guidelines prescribes following a "top down" analysis approach for BART determination, the development of a least cost envelope with dominant controls[1] [70 FR 39168] clearly labels points with lower emissions reductions and total annual costs first, i.e. "A", "B", etc. then proceeding with labeling and connecting points plotted further away from the zero emission reduction point. This "bottom-up" approach is for plotting the least-cost (dominant) control curve. The labeling of each unit's NO_X control technique alternative has followed this approach.

2.5.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROLS - LOS UNIT 2

The capital costs to implement the various NO_X control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. In the cases involving SNCR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

A review of the unit capital cost factor range and single point unit capital cost factor for the feasible NO_X emission reduction technology evaluated for LOS Unit 2 are presented in Table 2.5-1.

TABLE 2.5-1 – Unit Capital Cost Factors of Feasible NO_X Control Options for LOS Unit 2

Alt. No. (1)	NO_X Control Technique	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3), ($/kW) LOS Unit 2
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	20 + ?(4)	46(4),(5),(6)
C	SNCR (using urea) w/ ASOFA	20-35(7)	38(5),(6)
B	Coal Reburn (conventional, pulverized) w/ ASOFA	30-60(7)	153(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	23(6)

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) – Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on existing nameplate rating. Single point cost figures in 2005 dollars.
(4) – No published RRI unit capital cost factor was found in available technical literature. The installed capital costs for RRI are expected to be similar to SNCR. If both RRI and SNCR are installed together, capital cost of the RRI+SNCR portion was assumed to be 1.5x the capital cost of SNCR alone, due to commonality between the two systems sharing certain equipment and systems.
(5) – Estimated capital cost for SNCR point estimate derived from December 2004 budgetary proposal by Fuel Tech. See Appendix A for details.
(6) – The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
(7) – NESCAUM 2005 Technical Paper, posted at their website for basic SOFA. See Appendix A for details.
(8) – The single point unit capital cost factor shown for a coal reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report, posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in coal reburn options is 57.5 $/kW. See Appendix A for details.

Annualized capital cost, which includes the time value of capital monies and its recovery, is determined from the estimated capital cost and the methodology described in Section 1. Table 2.5-2 shows the estimated installed capital cost and annualized capital cost values for the highest-performing form of the various feasible NO_X emission reduction technologies applied to LOS Unit 2. These were developed by multiplying the unit capital cost single point factors for the control option by the nameplate output capacity rating of the respective unit. These are listed in order of control effectiveness, with the highest ranked options at the top.

TABLE 2.5-2 – Installed and Annualized Capital Costs Estimated for NO_X Control Alternatives - LOS Unit 2

Alt. No. (1)	**NO_X Control Alternative**	**Installed Capital Cost(2) ($1,000)**	**Annualized Capital Cost(3) ($1,000)**
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	20,200	1,760
C	SNCR (using urea) w/ ASOFA	16,800	1,470
B	Coal Reburn (conventional, pulverized) w/ ASOFA	67,400(4)	5,880(4)
A	Advanced Separated Overfire Air (ASOFA)	10,100	883
	Baseline	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – Installed capital cost is estimated for determination of total capital cost for a control technology, assuming maximum unit output capacity is based on existing nameplate rating of 440,000 kW. Installed capital cost figures in 2005 dollars.

(3) – Annualized capital cost = Installed capital cost x 0.08718 Capital Recovery Factor.

(4) – Costs for increased PM collection capacity included in coal reburn option are $25,300,000 for installed capital cost, and $2,200,000/yr annualized capital cost.

2.5.1.2 OPERATING AND MAINTENANCE COST ESTIMATES FOR NO_X CONTROLS – LOS UNIT 2

The operation and maintenance costs to implement the various NO_X control technologies were largely estimated from cost factors (percentages of installed capital costs) established in the EPA's Air Pollution Control Cost Manual (OAQPS), and from engineering judgment applied to that control technology. In the cases including various forms of SNCR, preliminary vendor quotes were obtained and used in place of, or to adjust the OAQPS cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's Levelized Total Annual Costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR and RRI alternatives; and
- Reagent dilution water consumption and unit cost for SNCR and RRI alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.
- Reductions in revenue expected to result from loss of unit availability, i.e. outages attributable to the control option, which reduce annual net electrical generation available for sale (revenue).

Table 2.5-3 and Table 2.5-4 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the highest-performing form of the various feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Section 1.3.5 provides more details for the levelized annual O&M cost calculations and cost factors.

TABLE 2.5-3 – Estimated O&M Costs for NO_X Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual O&M Cost(2) ($1,000)	Levelized Annual O&M Cost(3) ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	11,000	13,100
C	SNCR (using urea) w/ ASOFA	6,570	7,830
B	Coal Reburn (conventional, pulverized) w/ ASOFA	5,730(4)	6,830(4)
A	Advanced Separated Overfire Air (ASOFA)	152	182
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Annual O&M cost figures in 2005 dollars.
(3) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $1,740,000 for annual O&M cost, and $2,080,000/yr levelized annual O&M cost.

Annual operating and maintenance costs of the NO_X control options in Table 2.5-3 and Table 2.5-4 are based on LOS Unit 2 operation with the control option at 5,130 mmBtu/hr heat input and 8,760 hrs/yr operation. The Table 2.5-3 O&M costs are relative to unit pre-control baseline operation at 0.667 lb/mmBtu for the highest 24-month NO_X emission summation at 4,478 mmBtu/hr heat input for 8,050 hrs/yr operation of LOS Unit 2. The Table 2.5-4 O&M costs are relative to unit pre-control baseline operation at 0.667 lb/mmBtu for the maximum NO_X emissions associated with the future PTE case at 5,130 mmBtu/hr heat input for 8,760 hrs/yr operation of LOS Unit 2.

TABLE 2.5-4 – Estimated O&M Costs for NO_X Control Options (Relative to PTE Pre-Control Annual Emission Baseline – Future PTE Case) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual O&M Cost(2) ($1,000)	Levelized Annual O&M Cost(3) ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	11,000	13,100
C	SNCR (using urea) w/ ASOFA	6,580	7,830
B	Coal Reburn (conventional, pulverized) w/ ASOFA	5,730(4)	6,830(4)
A	Advanced Separated Overfire Air (ASOFA)	152	182
	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Annual O&M cost figures in 2005 dollars.
(3) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $1,740,000 for annual O&M cost, and $2,080,000/yr levelized annual O&M cost.

The majority of the annual operating and maintenance costs for the alternatives using chemical reagent injection (urea) for NO_X emissions control are for the delivered reagent and dilution water. Both RRI and SNCR are assumed to dilute the 50% aqueous urea solution as-received to a 10% aqueous urea concentration for direct injection into the targeted furnace areas. Higher than theoretical normalized (molar) stoichiometric ratios (NSRs) for the moles of equivalent reagent injected (urea) per mole of inlet NO_X emission were assumed for SNCR with ASOFA, and for RRI+SNCR with ASOFA due to inefficiencies inherent in their use. These annual costs reflect a significant increase in reagent consumption above the theoretical rates based on expected amounts of reagent utilization.

In order to compare a particular NO_X emission reduction alternative during the cost of compliance impact analysis portion of the BART selection process, the basic methodology defined in the BART

Guidelines was followed [70 FR 39167-39168]. The sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which in this analysis is referred to as "Levelized Total Annual Cost" (LTAC) of expected pollutant removal incurred by implementing that alternative, was calculated. The LTAC for these NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Section 1.3.5 of this BART evaluation for methodology details).

The Average Cost Effectiveness (also called Unit Control Cost) was then determined as the LTAC divided by baseline annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. The feasible control alternatives were also compared by calculating the change in LTAC per incremental ton of pollutant removed for the next most stringent alternative (incremental cost effectiveness). This identified which alternatives produced the highest increment of expected pollutant reduction for the estimated lowest average LTAC increment compared with the pre-control baseline emission rate. The expected annual number of tons of pollutant removed versus estimated LTAC for each remaining control alternative was then plotted. These incremental and average control costs relative to the historic pre-control annual NO_X emission baseline for LOS Unit 2 are shown in Table 2.5-5. The incremental and average control costs relative to the PTE pre-control annual NO_X emission baseline for LOS Unit 2 are shown in Table 2.5-6.

TABLE 2.5-5 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	5,895	6,128	14,900	2,430
C	SNCR (using urea) w/ ASOFA	6,762	5,261	9,300	1,770
B	Coal Reburn (conventional, pulverized) w/ ASOFA	7,115	4,908	12,700^5	2,590^5
A	Advanced Separated Overfire Air (ASOFA)	10,796	1,227	1,060	867
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	12,023	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.

(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.

(4) – Annualized cost figures in 2005 dollars.

(5) – LTAC for increased PM collection capacity included in coal reburn option are $2,200,000 for annualized capital cost plus $2,080,000 for annualized O&M cost, for a total of $4,280,000/yr. This results in an average control cost of $873 per ton of NO_X removed.

TABLE 2.5-6 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case)
LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	5,895	9,094	14,900	1,640
C	SNCR (using urea) w/ ASOFA	6,762	8,226	9,300	1,130
B	Coal Reburn (conventional, pulverized) w/ ASOFA	7,115	7,873	12,700[5]	1,610[5]
A	Advanced Separated Overfire Air (ASOFA)	10,796	4,193	1,060	254
	Baseline, based on annual operation at future PTE case pre-control emission rate	14,989	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 2.

(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-4 for annualized cost factors.

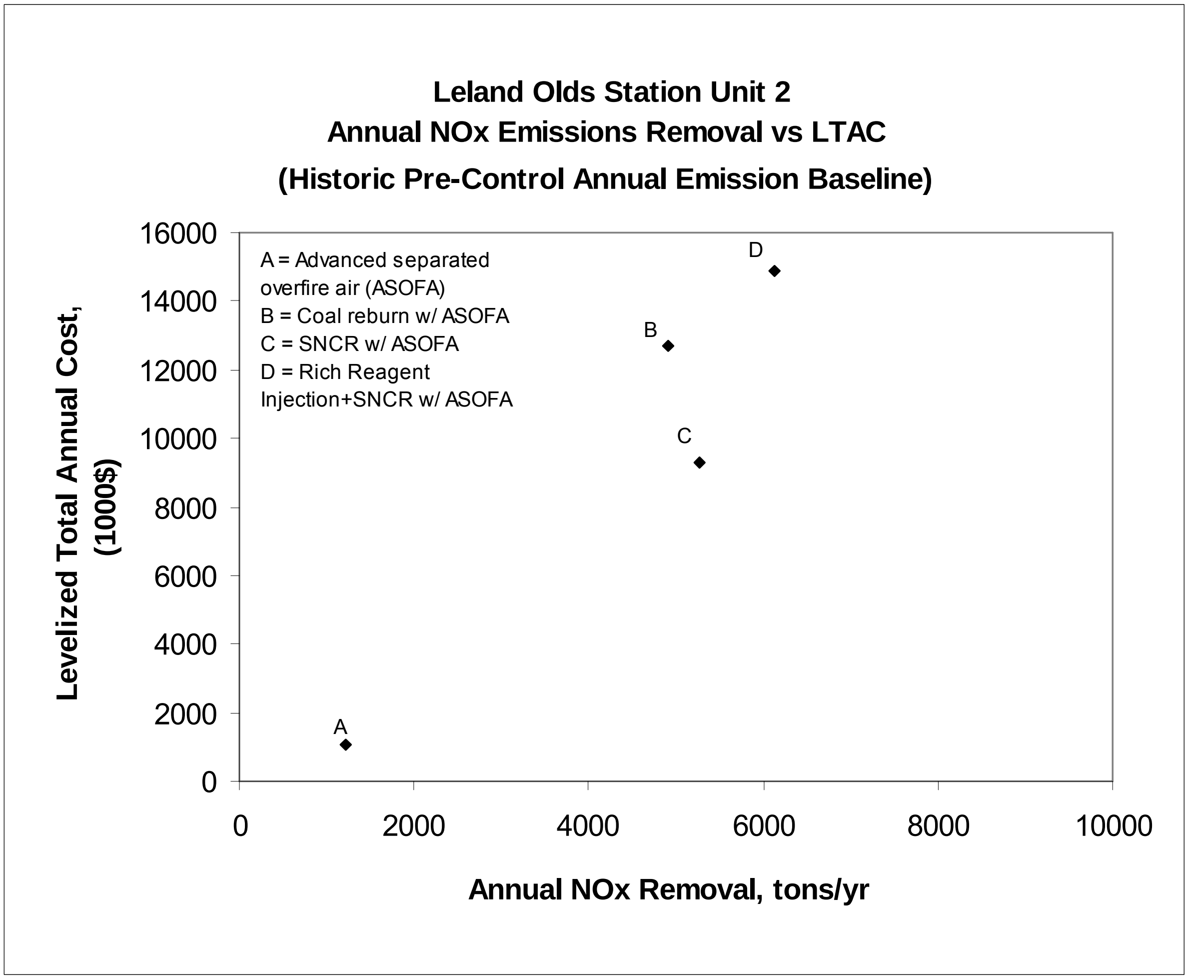
(4) – Annualized cost figures in 2005 dollars.

(5) – LTAC for increased PM collection capacity included in coal reburn option are $2,200,000 for annualized capital cost plus $2,080,000 for annualized O&M cost, for a total of $4,280,000/yr. This results in a average control cost of $544 per ton of NO_X removed.

The comparison of the cost-effectiveness of the control options evaluated for LOS Unit 2 relative to two different NO_X emission baselines was made and is shown in Figures 2.5-1 and 2.5-2. The estimated annual amount of NO_X removal (emission reduction) in tons per year is plotted on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis).

Figure 2.5-1 is for the control options evaluated relative to the baseline historic pre-control annual baseline, compared to the post-control maximum annual NO_X emissions for operation of LOS Unit 2 under the future PTE case.

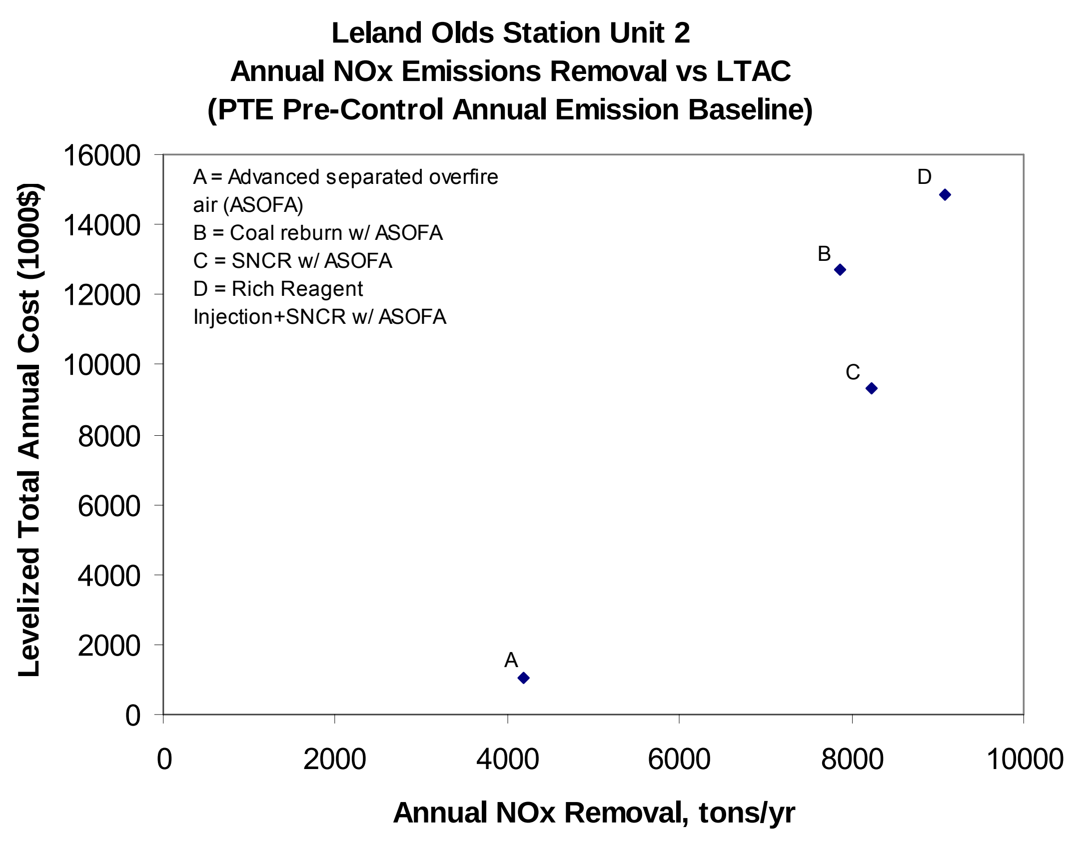
Figure 2.5-1 – NO_X Control Cost Effectiveness – LOS Unit 2 (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-5.

Figure 2.5-2 plots estimated levelized total annual costs versus estimated annual amount of NO_X removal (emission reduction) for the control options evaluated relative to the maximum pre-control annual baseline and future potential-to-emit post-control NO_X emissions for operation of LOS Unit 2 under the future PTE case.

Figure 2.5-2 – NO_X Control Cost Effectiveness – LOS Unit 2 (PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-6.

The purpose of Figures 2.5-1 and 2.5-2 is to show the range of control and cost for the evaluated NO_X reduction alternatives and identify the least-cost controls so that the Dominant Controls Curve can be created. The Dominant Controls Curve is the best fit line through the points forming the lower rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual NO_X removal tonnage for the various remaining BART alternatives. Points distinctly to the left of and above this curve are inferior control alternatives per the BART Guidelines and BART Guidelines on a cost effectiveness basis. Following a "bottom-up" graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope should be excluded from further analysis on a cost efficiency basis. Of the highest-performing versions of the technically feasible LOS Unit 2 NO_X control alternatives evaluated for cost-effectiveness, the data point for coal reburn with ASOFA is seen to be more costly for fewer tons of NO_X removed than for SNCR with ASOFA. This appears to be an inferior control, and thus should not be included on the least cost and Dominant Controls Curve boundary. Note that cost-effectiveness points for conventional gas reburn and fuel-lean gas reburn alternatives would be distinctly left and significantly above the least cost-control envelope, so these options were not included in the cost-effectiveness analysis.

The next step in the cost effectiveness analysis for the BART NO_X control alternatives is to review the incremental cost effectiveness between remaining least-cost alternatives. Figure 2.5-3 and Figure 2.5-4 contains a repetition of the levelized total annual cost and NO_X control information from Figure 2.5-1 and Figure 2.5-2 with Point B removed, and shows the incremental cost effectiveness between each successive set of least-cost NO_X control alternatives. The incremental NO_X control tons per year, divided by the incremental levelized annual cost, yields an incremental average unit cost ($/ton). This represents the slope of a line, if drawn, from one least-cost point as compared with another least-cost point. This modified least-cost controls curve is the Dominant Controls Cost Curve for NO_X emissions alternatives for each of the LOS Unit 2 pre-control baselines evaluated.

TABLE 2.5-7 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	14,900	6,128	5,570	867	6,420
C	SNCR (using urea) w/ ASOFA	9,300	5,261	8,240	4,034	2,040
A	Advanced SOFA (ASOFA)	1,060	1,227	1,060	1,227	867
	Baseline, based on annual operation at historic 24-month average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.
Costs for increased PM collection efficiency are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

TABLE 2.5-8 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) LOS Unit 2

Alt. No.[1]	NO_X Control Technique	Levelized Total Annual Cost[2],[3] ($1,000)	Annual Emission Reduction[4] (Tons/yr)	Incremental Levelized Total Annual Cost[3],[5] ($1,000)	Incremental Annual Emission Reduction[4],[5] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[3],[6]
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	14,900	9,094	5,570	867	6,420
C	SNCR (using urea) w/ ASOFA	9,300	8,226	8,240	4,034	2,040
A	Advanced SOFA (ASOFA)	1,060	4,193	1,060	4,193	254
	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.
Costs for increased PM collection capacity are included in coal reburn option.

(3) – Annualized cost figures in 2005 dollars.

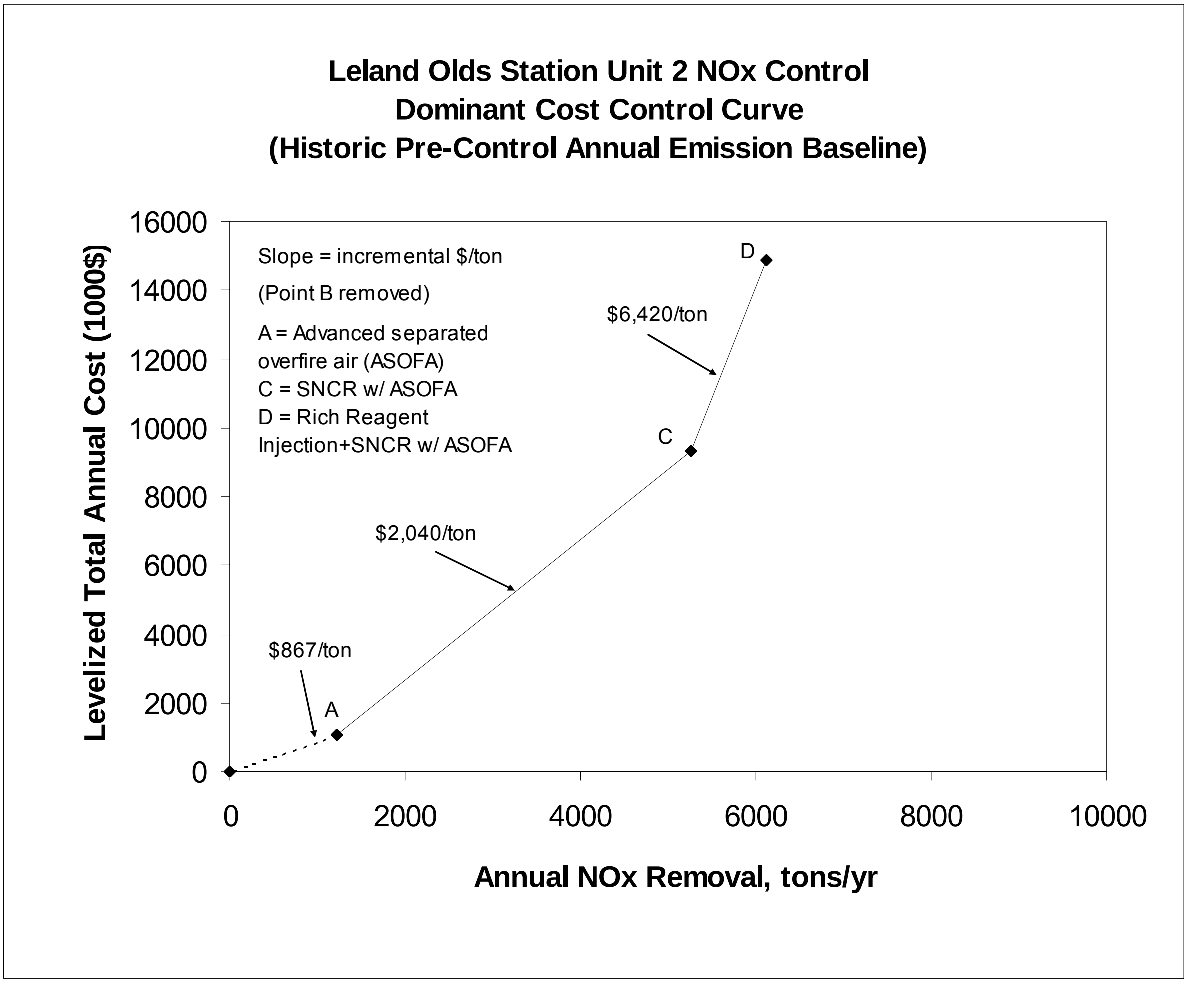
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 2.

(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

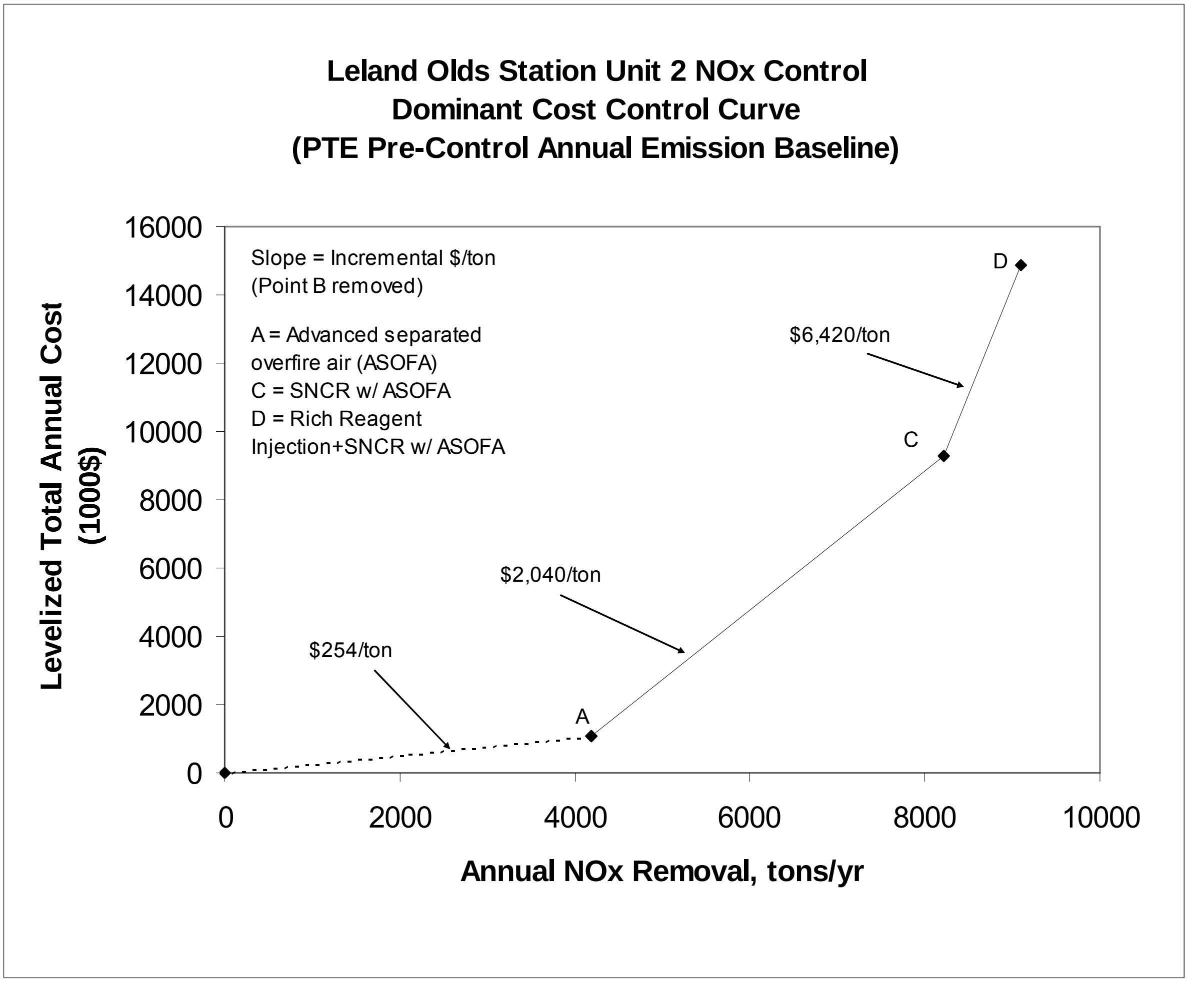
In the comparison displayed in Figure 2.5-3 and Figure 2.5-4, for the data shown in Table 2.5-7 and Table 2.5-8, the RRI+SNCR with Advanced SOFA NO_X control alternative (Point D) had a significantly higher incremental unit NO_X control cost (slope, $6,420/ton) compared against SNCR with ASOFA alternative (Point C) versus SNCR with ASOFA (Point C) compared against the ASOFA alternative (Point A) ($2,040/ton).

Figure 2.5-3 – NO_X Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-7.

Figure 2.5-4 – NO_X Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-8.

In the final BART Guidelines, the EPA neither proposes hard definitions for reasonable, or unreasonable Unit Control Costs nor for incremental cost effectiveness values. As can be seen from a review of Table 2.5-5, the average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the highest 24-hour historic baseline NO_X emission ranges from $867/ton to $2,430/ton. Table 2.5-6 shows average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the presumptive NO_X emission level ranges from $254/ton to $1,640/ton. The latter has lower costs per ton of NO_X emission removal due to the higher number of tons removed for the maximum emissions for pre-control baseline and additional controls under the future PTE case.

The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the Dominant Control Cost Curve) between successively more effective alternatives. The incremental cost analysis indicates that from a cost effectiveness viewpoint, the highest performing alternative is Rich Reagent Injection + SNCR with ASOFA (Point D). This control option is considered technically feasible for Leland Olds Station Unit 2 boiler, incurs a significant annual (levelized) incremental cost compared to the next highest feasible NO_X control technique, SNCR with ASOFA (Point C, slope from C to D =6,470 \$/ton) compared against the next lowest alternative, ASOFA (Point A, slope from A to C = 2,040 \$/ton).

The other elements of the fourth step of a BART analysis following cost of compliance are to evaluate the following impacts of feasible emission controls:

- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

For the purposes of this BART analysis, the remaining useful life of the source was assumed to exceed the 20-year project life utilized in the cost impact estimates. The other impacts for the LOS Unit 2 NO_X emissions control alternatives from the Dominant Control Cost Curve are discussed in Section 2.5.2 and Section 2.5.3. Visibility impairment impacts for these LOS Unit 2 NO_X emissions controls are summarized in Section 2.5.4.

2.5.2 ENERGY IMPACTS OF NO_X CONTROL ALTERNATIVES – LOS UNIT 2

Operation of the top NO_X control technologies considered feasible for potential application at the Leland Olds Station impose direct impacts on the consumption of energy required for the production of electrical power at the facility. The details of estimated energy usage and costs for the various LOS Unit 2 NO_X control alternatives are summarized in Appendix A.

Control alternatives for reduction of NO_X emissions were reviewed to determine if the use of the technique or technology will result in any significant or unusual energy penalties or benefits. There are several basic kinds of energy impacts for NO_X emissions controls:

- Potential increase or decrease in power plant energy consumption resulting from a change in thermal (heat) energy to net electrical output conversion efficiency of the unit, usually expressed as an hourly unit heat rate (Btu/kW-hr) or the inverse of pounds of pollutant per unit electrical power output (MW-hr). This may or may not change the net electrical output (MW) capacity of the EGU, depending on if there are physical or imposed limits on the total heat input to the boiler or electrical power output.

- Potential increase or decrease in net electrical output of the unit, resulting from changes in physical operational limitations imposed on the ability to sustain a fuel heat input rate (mmBtu/hr) which results in a potentially lower or higher unit net electrical output (MW) capacity. This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in auxiliary electrical power demand and usage (kW, kW-hrs). This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in reliability and availability to generate electrical power. This results in a change to the number of hours of annual operation, not necessarily a change in net electrical output (MW) capacity of the EGU.

2.5.2.1 ENERGY IMPACTS OF SOFA ALTERNATIVES

There should not be a major impact on energy consumption by the operation of the advanced variation of a separated overfire air system. ASOFA was the only NO_X control technology common to all four alternatives evaluated for LOS Unit 2. SOFA does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. Combustion air damper actuators' electrical power demand would be insignificant (+ 1 kW) change in net electrical power consumption from LOS Unit 2. For cyclone boilers, providing effective volumes and velocities of separated overfire air at the injection ports should not require higher forced draft fan power consumption resulting from higher fan discharge pressure. Higher lignite drying system vent ductwork pressure drop impacts of the advanced SOFA system on the forced draft fans' auxiliary electrical power consumption are expected to be negligible (less than 1% of the annual auxiliary power consumed by these fans) so that unit net electrical output (MW) capacity is essentially the same as the current nameplate rating.

Operation of a SOFA system may cause a small increase in levels of unburned carbon in the flyash emitted from the boiler compared with current operation. This represents a slight amount of lost potential electrical power generation from the incompletely burned fuel, so this inefficiency could have a small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kw-hr). This impact was not quantified, as the historical variation in coal heat content that influences plant unit heat rate may be more significant.

Boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures may be slightly elevated during air-staged cyclone operation with SOFA. This impact on the boiler's operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr) was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

SOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, once the amount of secondary combustion air that can be withdrawn from the cyclones is established for consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for LOS Unit 2. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion from sulfur compounds in the furnace gases being created above the cyclones and below the SOFA injection ports. Due to the relatively moderate amounts of sulfur content in the lignite, modest amount of air-staging of the existing cyclones during SOFA operation, and the potential use of recirculated flue gas along the lower furnace walls, the expected change in corrosion rate of the boiler tubes should be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube failures and changeouts is difficult to estimate, and has not been quantified.

2.5.2.2 ENERGY IMPACTS OF SNCR ALTERNATIVES

For SNCR-related NO_X control alternatives (with or without Rich Reagent Injection), the injection of a diluted urea solution requires some additional auxiliary power for heating and pumping the liquid, and using compressed air for atomization and cooling the reagent injection nozzles/lances, on the order of 150 to 400 kW. The injection of water (used for urea dilution) into the boiler flue gas also has a small negative impact on the plant heat rate (higher Btu/kw-hr), which is approximately equal to the heat released from the reaction of the reagent with NO_X or oxygen. The impact of additional flue gas created by operation of an SNCR-related system on induced draft fan power consumption should be insignificant.

Table 2.5-9 summarizes the gross demand and usage from auxiliary electrical power estimated for the NO_X control alternatives evaluated for LOS Unit 2.

TABLE 2.5-9 – Expected Auxiliary Electrical Power Impacts for NO_X Controls – LOS Unit 2

		NO_X Control Equipment Estimated Annual Average Auxiliary Electrical Power Demand and Usage		
Alt. No.(1)	**NO_X Control Technique**	**Aux. Power Demand (2) (kW)**	**Generation Reduction from Aux. Power Demand(2),(3) (kW-hrs/yr)**	**Generation Reduction from Reduced Unit Availability(4) (kW-hrs/yr)**
D	RRI + SNCR (using urea) w/ ASOFA	284	2,455,500	38,500,000
C	SNCR (using urea) w/ ASOFA	155	1,340,800	38,500,000
A	Advanced Separated Overfire Air (ASOFA)	1	8,760	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – The NO_X control equipment gross auxiliary electrical power demand is estimated.
(3) – The annual change in NO_X equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.
(4) – The estimated total hours per year of unit unavailability multiplied by average gross generation multiplied by annual running plant capacity factor for the particular control alternative. For this analysis, SOFA was not expected to reduce annual hours of possible operation.

2.5.3 NON-AIR QUALITY AND OTHER ENVIRONMENTAL IMPACTS OF NO_X CONTROL ALTERNATIVES – LOS UNIT 2

Nitrogen oxides react with oxygen in the atmosphere to produce elemental nitrogen and ozone (O_3). This is one of the common causes of visible pollution in the atmosphere referred to as “smog”. Operation of the various NO_X control technologies considered for potential application at the Leland Olds Station impose direct and indirect impacts on the environment. The most pronounced environmental impact expected from operation of any of the NO_X control options considered is the reduction of ozone and improvement in atmospheric visibility (i.e. reduced visibility impairment) downwind of the facility. This is discussed in detail in the Visibility Impacts section for LOS Unit 2.

2.5.3.1 ENVIRONMENTAL IMPACTS OF SOFA

The amount of unburned carbon in the flyash produced by the boiler, collected for disposal or potentially emitted to the atmosphere, may increase by small increments due to operation of LOS Unit 2 using separated overfire air for NO_X emissions control. The potential changes in the annual amounts of flyash emissions and disposal rates are expected to be inconsequential, and have not been quantified.

The operation of an advanced form of separated overfire air system is expected to slightly increase carbon monoxide concentrations in the stack flue gas. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

There were no other adverse or significant changes in non-air quality environmental impacts identified for LOS Unit 2 as a result of using separated overfire air for NO_X emissions control.

2.5.3.2 ENVIRONMENTAL IMPACTS OF SNCR ALTERNATIVES

The operation of a conventional SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs). The chemical form of the reagent will affect the amount of carbon dioxide emitted, since urea contains CO which is readily converted to CO_2 in the boiler-furnace and convection sections by combining with available free oxygen. One mole of carbon dioxide (CO_2) will be created and emitted for every mole of urea injected for reaction with NO_X. This is a relatively small increase in the total amount of CO_2 produced as part of the combustion of carbon-based fossil fuel in the form of lignite. As CO_2 is not currently a regulated pollutant, this increase has not been calculated.

Operation of an SNCR-related system will normally create a small amount of unreacted urea or ammonia to be emitted. The amount of ammonia slip produced by SNCR, with or without RRI, depends on the amount of reagent utilization and location of the injection points. Rich Reagent Injection operation typically does not produce any significant amount of ammonia slip, as the remainder of the reagent not reacted with NO_X is usually oxidized prior to leaving the boiler. Higher

SNCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 10 ppmvd, especially since the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates.

Some of the unreacted ammonia from SNCR operation will be collected with the flyash in the electrostatic precipitator. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be emitted from the stack as an aerosol or condensable particulate. This has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition. Although the predicted amount of such potential impact from ammonia slip emissions has not been determined, it is expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO_X emission reductions from the use of SNCR-related alternatives.

Storage of urea or ammonia reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Regulation of storage and containment of such reagents as hazardous substances will be under the requirements of various federal Acts, which are not part of this BART impact analysis.

Visibility impairment improvement impacts are discussed in the next section.

2.5.4 VISIBLITY IMPAIRMENT IMPACTS OF LELAND OLDS STATION NO_X CONTROLS – UNIT 2

The fifth step in a BART analysis is to conduct a visibility improvement determination for the source. For this BART analysis, there were two baseline NO_X emission rates assumed for LOS Unit 2 – one for the historic pre-control NO_X emission rate listed in the NDDH BART protocol[3], and one applying the Potential-To-Emit (PTE) pre-control annual NO_X emission rate associated with the future PTE case. The historic pre-control emission baseline was the 24-hour average NO_X emission rate from the highest emitting day of the years 2000-2002 (meteorological period modeled per the NDDH protocol[3]). The historic (protocol) NO_X baseline condition emission rate was modeled simultaneously with the highest 24-hour average SO_2 emission rate, and the highest 24-hour average PM emission rate of the 2000-2002 time period. The historic (protocol) baseline hourly NO_X emission rate used for modeling visibility impacts due to LOS Unit 2 under the conditions stated above was 3,959 lb/hr.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from historic (protocol) pre-control baseline and post-control average hourly emission rates representing the visibility impairment impact reduction for LOS Unit 2. Three post-control CALPUFF model runs for LOS Unit 2 were conducted with the same presumptive BART SO_2 emission baseline rate of 95%, constant PM emissions, and various levels of NO_X control assuming the same boiler design rating for heat input (5,130 mmBtu/hr). For the three post-control alternatives representing LOS Unit 2 PTE annual emissions associated with the future PTE case, the model used average unit NO_X emission rates of 0.48, 0.304, and 0.265 lb/mmBtu (corresponding to the design parameter in Table 1.2-1 and control rates in Table 1.4-1) multiplied by the boiler heat input rating of 5,130 mmBtu/hr to yield average hourly NO_X emission rates 2,462, 1,560, and 1,360 lb/hr. The boiler heat input basis for LOS Unit 2's historic highest 24-hour pre-control NO_X emission baseline, in keeping with the NDDH BART visibility impairment impact modeling protocol, is different than assumed for the PTE annual post-control conditions of the NO_X control alternatives evaluated for visibility impairment impacts.

The results of the visibility impairment modeling at the historic pre-control (protocol) baseline NO_X emission rate for LOS Unit 2 showed that all four of the designated Class 1 areas exceeded 0.5 deciView for highest predicted visibility impairment impact (90th percentile, averaged for 2000-2002). Lostwood National Wildlife Refuge (LNWR) showed the biggest predicted visibility impairment impact, which averaged 0.98 dV for the three years modeled (2000-2002). Average predicted visibility impairment impacts decreased significantly with presumptive BART SO_2 emission rate combined with constant PM emissions and various post-control ASOFA-enhanced NO_X emission rates for LOS Unit 2. This is shown in Table 2.5-10.

TABLE 2.5-10 – Average Visibility Impairment Impacts from Emission Controls – LOS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts(1) (deciView)			
	Historic Pre-Control Baseline	PTE Emissions, ASOFA(2)	PTE Emissions, SNCR w/ ASOFA(2)	PTE Emissions, RRI+SNCR w/ ASOFA(2)
TRNP-South Unit	0.807	0.221	0.158	0.143
TRNP-North Unit	0.756	0.180	0.139	0.129
TRNP-Elkhorn Ranch	0.535	0.120	0.093	0.087
Lostwood NWR	0.979	0.285	0.206	0.191

(1) - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection.

Analysis of the reduction in visibility impairment impact included a comparison of the emission controls' effectiveness of reducing predicted visibility impairment impacts for the conditions of the future PTE case operation of LOS Unit 2 versus the historic pre-control (protocol) baseline that was modeled. LNWR again showed the highest average predicted visibility impairment impact reduction resulting from LOS Unit 2 emissions controls during PTE (future PTE case) heat inputs versus historic pre-control baseline emissions. These comparisons are shown in Table 2.5-11.

TABLE 2.5-11 –Average Visibility Impairment Impact Reductions From Emission Controls – LOS Unit 2 (vs Historic Maximum 24-Hour Average Hourly Emission Baseline)

Federal Class 1 Area	Visibility Impairment Reductions(1) (deciView)		
	PTE Emissions, ASOFA(2)	PTE Emissions, SNCR w/ ASOFA(2)	PTE Emissions, RRI+SNCR w/ ASOFA(2)
TRNP-South Unit	0.586	0.649	0.664
TRNP-North Unit	0.577	0.617	0.628
TRNP-Elkhorn Ranch	0.415	0.441	0.447
Lostwood NWR	0.694	0.773	0.788

(1) - Difference of average 90th percentile predicted post-control visibility impairment impact versus historic pre-control (protocol) baseline visibility impairment impact. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection.

The comparison in Table 2.5-12 shows the reduction of average visibility impairment impact from LOS Unit 2 NO_X emissions expected to result from ASOFA combined with SNCR with and without RRI relative to the average visibility impairment impact from post-control ASOFA NO_X emission rates applied to LOS Unit 2.

TABLE 2.5-12 – Incremental Average Visibility Impairment Reductions from NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission Visibility Impairment Impact)

Federal Class 1 Area	Incremental Visibility Impairment Impact Reductions, from NO_X Emission Controls(1)	
	PTE Emissions, SNCR w/ ASOFA (dV)	PTE Emissions, RRI+SNCR w/ ASOFA (dV)
TRNP-South Unit	0.063	0.078
TRNP-North Unit	0.040	0.051
TRNP-Elkhorn Ranch	0.027	0.033
Lostwood NWR	0.079	0.094

(1) - Incremental average 90th percentile predicted post-control visibility impairment impact, compared to ASOFA for NO_X control with 95% SO_2 emissions control and existing ESP for PM emissions control at PTE heat input rate (future PTE case). A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

This analysis included a determination of the cost-effectiveness of reducing predicted visibility impairment impact for a particular NO_X emission rate associated with the control alternatives evaluated on LOS Unit 2. The basis of comparison was the average predicted visibility impairment impact and estimated levelized total annual cost (LTAC) for the advanced form of separated overfire air (ASOFA) alone under the future PTE case conditions. The estimated additional annualized costs of installing and operating each NO_X control alternative with PTE heat input (future PTE case) relative to the LTAC from post-control ASOFA NO_X emission rates applied to LOS Unit 2 are shown in Table 2.5-13.

TABLE 2.5-13 – LTAC for NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission LTAC)

Incremental LTAC Change for NO_X Emission Reduction(1)	
PTE Emissions, SNCR w/ ASOFA ($/yr)	**PTE Emissions, RRI+SNCR w/ ASOFA ($/yr)**
8,250,000	13,820,000

1 - Incremental Levelized Total Annual Cost for NO_X control alternatives compared to ASOFA for PTE heat input rate (future PTE case). All cost figures in 2005 dollars. See Table 2.5-8 for details.

The comparison in Table 2.5-14 shows that the additional annualized costs of installing and operating each NO_X control alternative with PTE heat input (future PTE case) divided by the additional average predicted visibility impairment impact reduction relative to the post-control ASOFA NO_X emission rates and LTAC applied to LOS Unit 2 would result in hundreds of millions of dollars per deciview of control cost visibility impairment impact effectiveness.

TABLE 2.5-14 – Cost Effectiveness for Incremental Average Visibility Impairment Reductions from NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission LTAC and Visibility Impacts)

	Incremental Visibility Impairment Reduction Unit Cost, from NO_X Emission Controls(1)	
Federal Class 1 Area	**PTE Emissions, SNCR w/ ASOFA ($/deciView-yr)**	**PTE Emissions, RRI+SNCR w/ ASOFA ($/deciView-yr)**
TRNP-South Unit	131,700,000	177,900,000
TRNP-North Unit	204,600,000	271,000,000
TRNP-Elkhorn Ranch	309,000,000	423,000,000
Lostwood NWR	104,900,000	147,500,000

(1) - Incremental Levelized Total Annual Cost divided by incremental average 90th percentile predicted post-control visibility impairment impact, compared to ASOFA for NO_X control with 95% SO_2 emissions control and existing ESP for PM emissions control at PTE heat input rate (future PTE case). All cost figures in 2005 dollars.

The number of days predicted to have visibility impairment due to LOS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the historic pre-control (protocol) NO_X, SO_2, and PM emission rates described previously in this Section. The results were summarized and presented in Table 3.4-15. Similarly, the same information for the post-control SO_2 and PM alternatives with presumptive BART NO_X PTE emission rates was summarized and is shown in Table 3.5-16. The differences in average visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between post-control SO_2 and PM alternatives with SNCR with ASOFA-controlled and RRI+ SNCR with ASOFA-controlled NO_X emission rates versus ASOFA-controlled NO_X emission rates are summarized and shown in Table 2.5-15.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 area. The highest number of days in which the predicted visibility impairment impact above background exceeded 0.5 deciViews was for the pre-control (protocol) emission case in year 2002 for TRNP's South Unit. A series of bar charts showing the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the pre-control model results is included in Section 3.5. The pair of post-control SO_2 and PM alternatives combined with SNCR with ASOFA or RRI+SNCR with ASOFA for NO_X control were only slightly lower for the predicted visibility impairment impacts and number of days predicted to have visibility impairment impacts greater than 0.50 and 1.00 deciViews compared to the same pair of post-control SO_2 and PM conditions with ASOFA-controlled NO_X emission rates. A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the RRI+SNCR with ASOFA-controlled PTE emission rates and SNCR with ASOFA-controlled PTE emission rates compared to ASOFA NO_X PTE emission rates with post-control SO_2 and PM alternatives is included in Figures 2.5-5, 2.5-6, and 2.5-7.

2.5.5 SUMMARY OF IMPACTS OF LELAND OLDS STATION NO_X CONTROLS – UNIT 2

Table 2.5-16 summarizes the various quantifiable impacts discussed in Sections 2.5.1 through 2.5.4 for the NO_X control alternatives evaluated for LOS Unit 2.

Table 2.5-15 – Visibility Impairment Improvements – Post Control vs ASOFA NO_X Control with SO_2 and PM Controls LOS Unit 2

Class 1 Area	NO_X Control Technique w/ SO_2 Control Level(1)	Visibility Impairment Reduction(2) (ΔdV)	ΔDays(3) Exceeding 0.5 dV in 2000	ΔDays(3) Exceeding 0.5 dV in 2001	ΔDays(3) Exceeding 0.5 dV in 2002	ΔDays(3) Exceeding 1.0 dV in 2000	ΔDays(3) Exceeding 1.0 dV in 2001	ΔDays(3) Exceeding 1.0 dV in 2002	ΔConsecutive Days(3) Exceeding 0.5 dV 2000	ΔConsecutive Days(3) Exceeding 0.5 dV 2001	ΔConsecutive Days(3) Exceeding 0.5 dV 2002
TRNP South	RRI+SNCR w/ ASOFA	0.078	4	8	9	2	2	8	0	1	0
	SNCR w/ ASOFA	0.063	3	7	6	2	2	7	0	1	0
TRNP North	RRI+SNCR w/ ASOFA	0.051	6	8	4	2	2	8	0	0	0
	SNCR w/ ASOFA	0.040	4	6	4	2	2	6	0	0	0
TRNP Elkhorn	RRI+SNCR w/ ASOFA	0.033	2	3	3	0	1	2	0	1	0
	SNCR w/ ASOFA	0.027	2	2	3	0	1	2	0	1	0
Lostwood NWR	RRI+SNCR w/ ASOFA	0.094	12	10	6	5	7	2	0	0	1
	SNCR w/ ASOFA	0.079	9	6	6	5	5	2	0	0	1

(1) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - Difference in average predicted visibility impairment impacts (90th percentile) for 2000-2002 for alternatives' post-control NO_X emission levels versus ASOFA-controlled NO_X emission level with same PTE heat input SO_2 and PM post-control alternatives' emission rate (future PTE case).

(3) - Difference in number of days is 100th percentile level for predicted visibility impairment impacts provided in Appendix D1.

Figure 2.5-5 – Days of Visibility Impairment Reductions – 0.5 dV
NO_X Controls versus ASOFA with SO_2 and PM Controls
LOS Unit 2

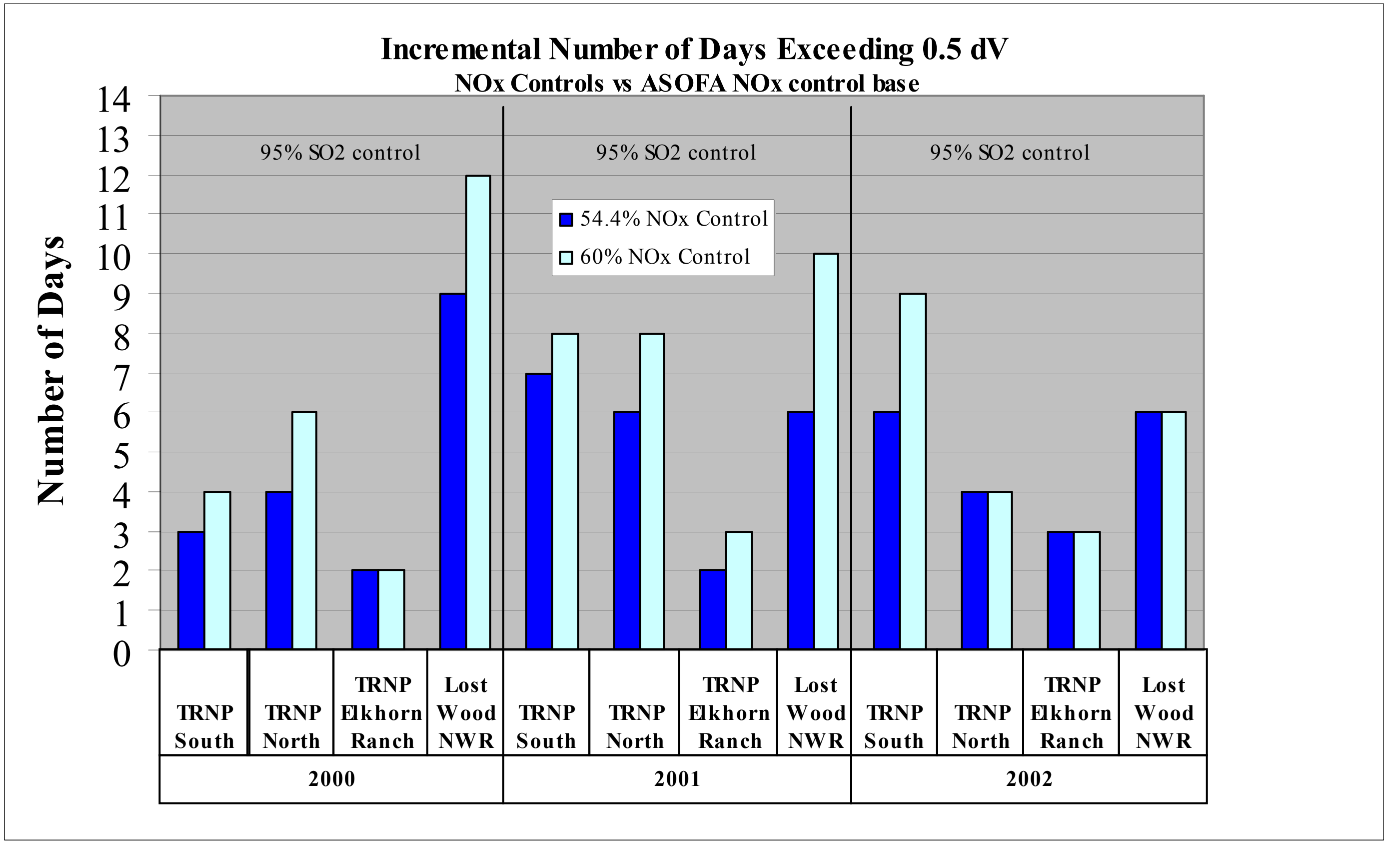


Figure 2.5-6 – Days of Visibility Impairment Reductions – 1.0 dV
NO_X Controls versus ASOFA with SO_2 and PM Controls
LOS Unit 2

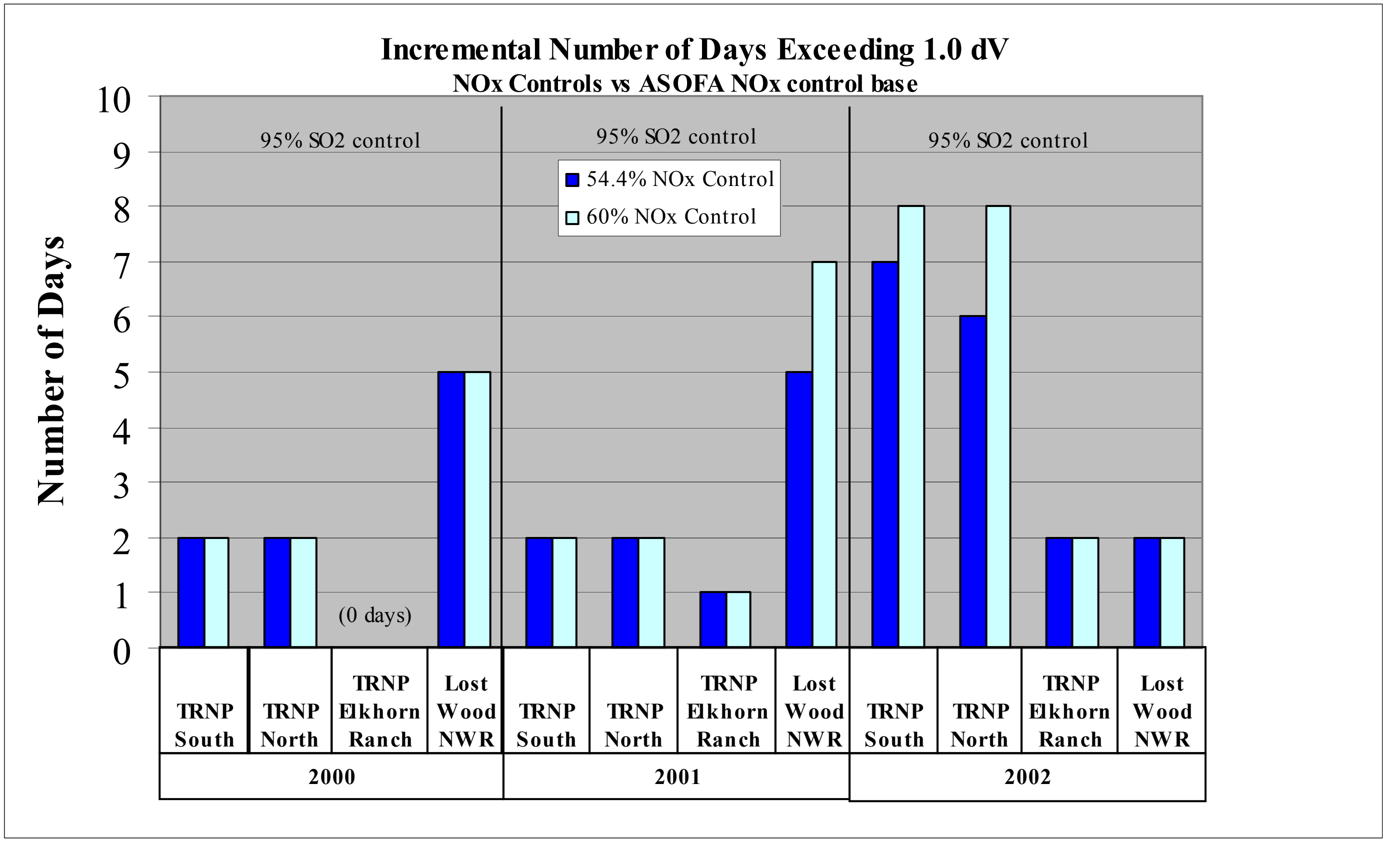


Figure 2.5-7 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV
NO_X Controls versus ASOFA with SO_2 and PM Controls
LOS Unit 2

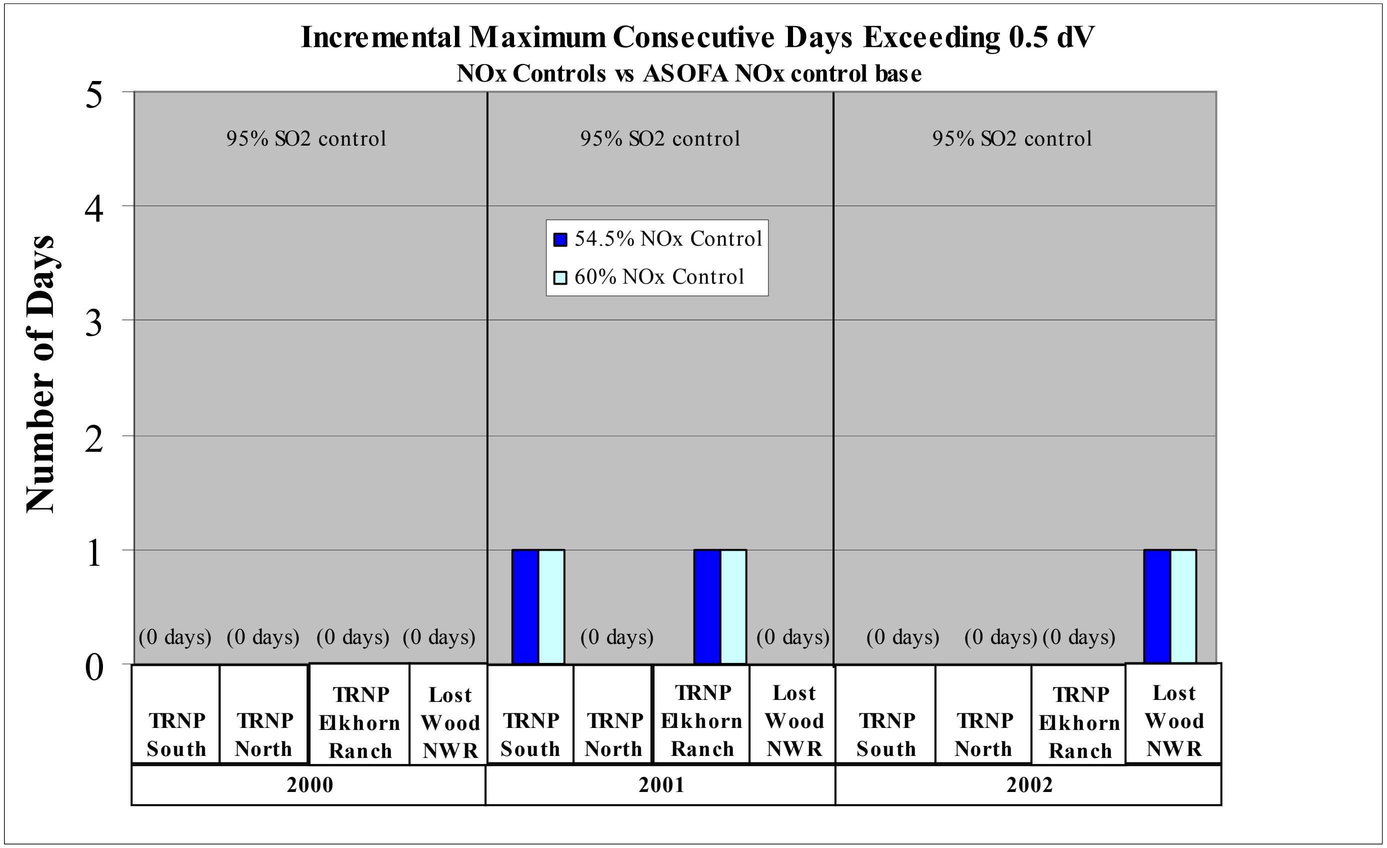


Table 2.5-16 – Impacts Summary for LOS Unit 2 NO_X Controls (vs Pre-Control PTE NO_X Emissions)

NO_X Control Technique w/ SO_2 Alternative	NO_X Control Efficiency (%)	Annual NO_X Emissions Reduction (tpy)	Levelized Total Annual Cost(1) ($)	Unit Control Cost ($/ton)	Visibility Impairment Impact Reduction		Incremental Visibility Impairment Reduction Unit Cost(1),(3) ($/dV-yr)	Energy Impact (kW)	Non Air Quality Impacts
					Class 1 Area	Incremental(2) ΔdV			
RRI+SNCR w/ ASOFA	60.3%	9,096	14,900,000	1,640	TRNP-S	0.078	177,900,000	284	Flyash unburned carbon increase
					TRNP-N	0.051	271,000,000		
					TRNP-Elk	0.033	423,000,000		
					LNWR	0.094	147,500,000		
SNCR w/ ASOFA	54.5%	8,235	9,320,000	1,130	TRNP-S	0.063	131,700,000	155	Flyash unburned carbon increase
					TRNP-N	0.040	204,600,000		
					TRNP-Elk	0.027	309,500,000		
					LNWR	0.079	104,900,000		
ASOFA	28%	4,193	1,060,000	254	TRNP-S	base	base	1	Flyash unburned carbon increase
					TRNP-N	base	base		
					TRNP-Elk	base	base		
					LNWR	base	base		

(1) - All cost figures in 2005 dollars.

(2) - Average predicted visibility impairment impact improvements (incremental, 90th percentile) from PTE post-control NO_X emission levels relative to ASOFA post-control NO_X emission levels; all cases have 95% control SO_2 emission level and same PM post-control level at 5,130 mmBtu/hr heat input and 8,760 hours per year operation for the future PTE case, for 2000-2002.

(3) - Incremental LTAC for RRI+SNCR w/ ASOFA = $13,820k/yr; SNCR w/ ASOFA = $8,250k/yr; vs ASOFA = $0k/yr (base), divided by incremental ΔdV. See Table 2.5-14 for details.

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3.0 SO_2 BART EVALUATION

The BART determination process has five predefined steps as described in Section 1. In this section, steps 1 through 5 of the BART determination for Leland Olds Station (LOS) are described for SO_2 and a presentation is made of the results. Potentially applicable SO_2 control technologies are first identified. A brief description of the processes and their capabilities are then reviewed for availability and feasibility. A detailed technical description of each control technology is provided in Appendix B1. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal SO_2 control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative, including taking a look at Balance Of Plant (BOP) requirements. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. In the final step of the analysis, feasible and available technologies are assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the impact analyses are tabulated and potential BART control options are listed.

3.1 IDENTIFICATION OF RETROFIT SO_2 CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit SO_2 control technologies. In order to identify the applicable SO_2 control technologies, several reference works were consulted, including "Controlling SO_2 Emissions: A Review of Technologies (EPA-600/R-00-093, October 2000) and the RACT/BACT/LAER Clearinghouse (RLBC). From these and other literature sources, a preliminary list of control technologies and their estimated capabilities was developed. Table 3.1-1 contains the results of this effort.

TABLE 3.1-1 – SO_2 Control Technologies Identified for BART Analysis

Control Technology	Approximate Control Efficiency
Fuel Switching	≤77%
Coal Cleaning	≤30%
Wet Flue Gas Desulfurization	95%
Spray Dryer Absorber (SDA)	90%
Circulating Dry Scrubber (CDS)	93%
Flash Dryer Absorber (FDA)	90%
Powerspan ECO™	98%

SO_2 emissions from the combustion of coal are due to the sulfur content of the coal participating in the combustion process. Sulfur is present in coal in both organic and inorganic forms. Upon combustion, these compounds disassociate and the sulfur component is oxidized to SO_2 and SO_3. For the purpose of BART determination, it is assumed that 100% of the sulfur content of the coal is oxidized and present in the flue gas stream as SO_2. Removal of SO_2 from flue gas can either be accomplished prior to combustion, or post combustion. Pre-combustion methods include coal washing and fuel switching. Post-combustion methods include wet Flue Gas Desulfurization (FGD) with limestone and three semi-dry FGD technologies using lime. Additionally, there are developing multi-pollutant technologies such as the PowerSpan Electro-Catalytic Oxidation (ECO™) system which targets SO_2, NO_X, and mercury. Following are descriptions and technical analyses of the identified technologies for application to LOS.

3.2 TECHNICAL DESCRIPTION AND FEASIBLITY ANALYSIS

The second step in the BART analysis procedure is a technical feasibility analysis of the options identified in Step 1. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology. A control technology is considered available, “if it has reached the stage of licensing and commercial availability.” (70 FR 39165) On the contrary, a control technology is not considered available, “if it is in the pilot scale testing stages of development.” (70 FR 39165) When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” (70 FR 39165) The technical and feasibility analysis is presented below for each identified option.

3.2.1 PRE-COMBUSTION FUEL TREATMENTS

3.2.1.1 FUEL SWITCHING

Fuel switching can be a viable method of fuel sulfur content reduction in certain situations. Often, fossil fuel fired EGUs are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. In the case of LOS, both boilers were designed and constructed specifically for firing North Dakota lignite, which is a low Btu content, high ash, high moisture, medium sulfur content fuel. For this analysis, fuel switching would consist of changing from North Dakota lignite to Powder River Basin (PRB) sub-bituminous coal. Technical characteristics associated with fuel switching are described in Appendix B1.

Basin Electric Power Cooperative conducted a short term test burn of PRB coal at LOS Unit 1 and 2 on February 5-12, 1997.[1] An analysis of this coal is provided in Table 1.2-2. Approximately 50,000 tons of PRB were burned during the test. Approximately one half of the test period was at high load conditions and the remainder at low load. Because the test period was short, the long term effects of a PRB coal conversion were not evaluated. However, several short term effects were observed including the following:

- Coal delivery problems related to delivery train length were observed and rail system modifications would be required for a complete conversion.
- Little risk of coal fires in the coal receiving and handling systems were encountered, or expected for long term conversion. However, additional coal fire suppression systems would likely be required for the coal bunkers as a safety precaution.
- Due to the greater heat content, a 20% reduction in fuel quantity (mass) was observed. Operating requirements, including fuel handling system power and maintenance were estimated to decrease 15% during the test period.
- Coal dust generation was observed to increase with PRB coal, which may necessitate additional dust control measures on coal handling equipment.
- Reduced ash quantities were observed during the tests, but not quantified. Minor adjustments to the ash handling systems were required to achieve satisfactory operation.
- Stack opacity conditions were stable, but were observed to deteriorate somewhat during the high load portion of the test, despite lower ash quantities. The cause of this was thought to be higher ash resistivity effects on electrostatic precipitator performance. Flue gas conditioning might be required for a full conversion to mitigate this effect.
- Air heater performance decreased, most likely due to reduced flue gas flow rates. While firing PRB total flue gas flow dropped approximately 15% on Unit 1. A similar reduction in flue gas flow was not observed on Unit 2.
- Induced Draft and Forced Draft fan power requirements decreased slightly during all parts of the test burn. Total air required for PRB coal was approximately 88% of that required for lignite under the same conditions. Specifically for Unit 1, current draw (amps) on the forced draft fan remained unchanged while the primary air and induced draft fan current demands decreased approximately 11%.
- On Unit 2, Gas Recirculation fan power requirements increased by approximately 4% during high load tests and almost 31% during low load testing.

- Boiler efficiency increased approximately 2.4%, primarily due to lower fuel moisture content in the as-received condition. As a result the Net Plant Heat Rate decreased by approximately 300 Btu/kW for Unit 1 and 350 Btu/kW for Unit 2.
- Station service requirements decreased approximately 2% with PRB coal. This was primarily attributed to lower combustion air requirements.
- Stable operating conditions, observed as similar main and reheat steam temperatures and attemperator flows, were observed at both high and low loads.
- Due to the test's brevity, it was not possible to observe changes in slag deposition locations or rates and possible effects on boiler operation.
- During an URGE (Uniform Rating of Generating Equipment) test for Unit 2, the unit became unstable and the test had to be discontinued. The URGE test is a test at maximum operating conditions.

Switching to a fuel such as PRB coal will achieve significant SO_2 emission reductions. The PRB coal listed in Table 1.2-2 is one of the lower sulfur coals available in the U.S. Switching to this coal would nominally achieve a 77% reduction in SO_2 emissions for the same heat input. However, additional SO_2 control measures, such as the post combustion controls listed in Table 3.1-1 might be required to achieve BART.

As shown during the short test in 1997, conversion of LOS to fire PRB coal is feasible, although several long term effects were not assessed during the test and some currently unidentified plant modifications may be required for a full conversion. Therefore, for the purpose of this BART analysis, fuel switching is considered a viable option for SO_2 control.

3.2.1.2 COAL CLEANING

The effectiveness of coal cleaning is strongly dependent upon the chemical form of sulfur in the coal. Traditional coal cleaning methods consist of crushing the coal and then separating and removing inorganic impurities including much of the inorganic sulfur and ash content using a gravimetric separation process. However, sometimes the majority of the sulfur is contained in the organic matrix of the coal and is difficult or impossible to remove using this process. While gravimetric processes can reduce the sulfur and ash content of a given coal, at the time of this report, no commercial scale, gravimetric coal cleaning systems are in operation that can significantly reduce the sulfur content of North Dakota lignite. Due to lack of commercial experience, traditional coal cleaning systems were determined not to be commercially available as a BART alternative and were not analyzed further.

Another form of coal cleaning that specifically targets low-rank coals, like lignite, uses a different process to reduce sulfur emissions. The K-Fuel™ process, developed by KFx, uses patented heating and pressurization methods to reduce the moisture content of the fuel and remove some of the pollutants. Although the process may remove some of the sulfur components in the coal, the main focus of the process is to remove moisture and increase the coal heating value. By increasing the coal heating value, less of the treated fuel will be required to achieve an equivalent boiler heat input. By burning less fuel there will be fewer emissions. KFx estimates that the K-Fuel™ coal cleaning process might effectively reduce the sulfur content of the lignite fuel by up to 30%. To simplify cost estimates associated with coal cleaning and due to the uncertainties associated with application of the K-Fuel™ process to North Dakota lignite, the analysis assumes that stated efficiencies translate directly to operations. In other words, a 30% reduction efficiency for sulfur content results in a 30% reduction in SO_2 and a 30% increase in heat content results in a 30% decrease in fuel usage. A test burn, which would be required to provide more specific data related to burning the K-Fuel™ product, was not available. Technical characteristics associated with the process can be found on the KFx website at kfx.com. Based on the estimated 30% control being significantly less efficient than the presumptive limits and the control efficiencies of the other control technologies, the K-Fuel™ process was identified as having insufficient SO_2 reduction for BART. Due to the lower removal efficiency, the K-Fuel™ process is not considered a reasonable BART alternative and is not analyzed further.

3.2.2 POST-COMBUSTION FLUE GAS DESULFURIZATION

Five different post-combustion processes for reducing SO_2 emissions were evaluated as BART alternatives in this analysis. These include two well established Flue Gas Desulfurization (FGD) processes (wet and semi-dry); two recent variations of the semi-dry technology, the Circulating Dry Scrubber (CDS) and the Flash Dryer Absorber™ (FDA) as well as the Power-Span Electro Catalytic Oxidation (ECO™) process.

Commercially-available wet and semi-dry FGD processes achieve SO_2 removal by absorption of the SO_2 into an aqueous slurry which contains a neutralizing agent, normally either lime or ground limestone. Chemical reaction(s) between the SO_2 and the neutralizing agent convert the SO_2 to a stable compound that can be readily sold or disposed of in a permitted facility.

One significant difference between the wet and semi-dry systems is the degree of saturation of the flue gas that is achieved in the process. The wet FGD process saturates the flue gas as a result of water evaporation from the slurry utilized to absorb and neutralize SO_2. Wet FGD process design must take into account both corrosion and scale formation in the wet parts of the system which can interfere with process operations. The flue gas saturation zone, where the hot dry flue gas first enters the absorber vessel and encounters the wet FGD slurry spray, is an area of constantly shifting chemistry. With the shifting back and forth between hot, dry conditions and cooler, wet conditions, this area experiences the most aggressive corrosion of any part of the scrubbing system. Consequently, exotic materials of construction are used in the wet FGD system to combat the corrosive environment.

The semi-dry FGD process utilizing a spray dryer absorber (SDA) utilizes an aqueous slurry as well, but the degree of flue gas saturation due to evaporation is controlled to a point well above the saturation temperature so that the semi-dry FGD byproducts are a dry free flowing solid leaving the absorber and corrosion problems are minimized. CDS' and FDAs operate similarly to the SDA, except that they utilize greater amounts of recycled flyash mixed with dry hydrated lime that is moistened by water and injected into the reactor. Here the moisture coats the surface of the recycled particles in a thin film and then the water evaporates, as opposed to evaporating an entire droplet of water containing lime slurry as in the SDA. The water content of the slurry droplet or liquid film evaporates and SO_2 is absorbed and neutralized simultaneously. All of the dry and semi-dry FGD technologies require a particulate matter control device downstream of the reactor. Therefore, these technologies are often referred to in this report with a /FF following the absorber designation. The reaction products of the semi-dry FGD processes, including the SDA, CDS and FDA, are mixed with flyash when captured, and thus not do not generally have an aftermarket value.

The most common chemical reagents used in FGD processes are quicklime (calcium oxide, CaO), hydrated lime (calcium hydroxide, $Ca(OH)_2$) and limestone (predominantly calcium carbonate, $CaCO_3$). As a general rule of thumb, wet FGD processes can be assumed to utilize limestone and semi-dry FGD, including SDA, CDS and FDA systems, use lime. There are wet FGD processes that utilize lime, but these are generally used in situations where limestone is not readily available and these incur greater operating costs as a result. Dry and semi-dry FGD systems exclusively utilize lime because of its greater reactivity under typical dry and semi-dry operating conditions.

The wet FGD process was exclusively used for FGD retrofits for compliance with Phase I of the Acid Rain Program. The semi-dry process is a common SO_2 control measure identified in the review of recent new coal-fired boiler BACT determinations from the EPA's RACT/BACT/LAER

Clearinghouse (RBLC). The FDA and CDS technologies are more recent developments in semi-dry FGD technology.

3.2.2.1 WET FLUE GAS DESULFURIZATION

Wet FGD technology utilizing lime or limestone as the reagent and employing forced oxidation to produce gypsum (calcium sulfate dihydrate, $CaSO_4 \cdot 2H_2O$) as the byproduct, is commonly applied to coal-fired boilers. Wet FGD utilizes either an open spray tower, or a spray tower with a perforated plate contactor to expose flue gas to the neutralizing slurry. Absorbed SO_2 is converted to calcium sulfite and then oxidized to calcium sulfate dihydrate (gypsum) which is filtered from the scrubber solution and either disposed of in a permitted disposal facility, or possibly sold for either wallboard or cement production. Historically wet FGD systems have operated with an SO_2 control efficiency anywhere from 70% to in excess of 95%. For the purposes of this study, wet FGD performance was evaluated at 95% SO_2 control as representative of presumptive BART requirements. Further technical characteristics associated with wet FGD are described in Appendix B.

Based on the ability of a wet FGD system to achieve 95% percent SO_2 removal efficiencies and commercial availability and applicability, wet FGD systems were found to be an acceptable BART alternative for SO_2 emission control.

3.2.2.2 SEMI-DRY FLUE GAS DESULFURIZATION

As an alternative to wet FGD technology, the control of SO_2 emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection.

There are several variations of the semi-dry process in use today. This section addresses the spray dryer FGD process. Two other variations, the Flash Dryer Absorber and Circulating Dry Scrubber are addressed in following sections. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. Technical characteristics associated with the SDA are described in Appendix B.

No variation of semi-dry FGD systems has clearly demonstrated the ability to achieve SO_2 removal levels similar to wet FGD systems in the U.S. Table B-1, in Appendix B, lists many of the recent lime spray dryer system installations in the U.S. The information in Table B-1 was obtained from the RACT/BACT/LAER Clearing House. Two units were recently permitted with SO_2 emission rates representing removal efficiencies of 94.5% and 95%. However, Burns & McDonnell recently completed a study of the emission reduction performance of existing, electric utility, semi-dry FGD systems.[3] Information utilized for the evaluation was derived from EIA coal quality data and EPA SO_2 stack emissions and heat input data. The evaluation determined that the highest SO_2 removal efficiency maintained on a continuous basis was just above 90%. No unit was able to maintain an efficiency of 95%. For the purpose of this BART determination, semi-dry FGD is considered a viable alternative, but the upper bound on SO_2 removal efficiency was set at 90% for application based on a review of the historic performance of this technology.

3.2.2.3 FLASH DRYER ABSORBER FLUE GAS DESULFURIZATION

The Flash Dryer Absorber (FDA) is a further development of the semi-dry FGD process. The approach is similar to the SDA in that the flue gas is only partially saturated during the process and thus corrosion problems are either reduced or eliminated. Like the SDA, the FDA mixes lime, water and recycled PM for enhanced surface area. Unlike the SDA, the FDA recycles a very high fraction of the captured PM and the flue gas flows vertically upward in the FDA. A second difference for the FDA is that it utilizes quicklime, instead of hydrated lime as a reagent. Additional technical characteristics associated with FDA are described in Appendix B.

The FDA is a relatively recent modification of the semi-dry FGD concept and as such, has not established a significant field record at this time. In their paper on FDA technology in 2002[4], Alstom cited a 280 MW plant in China with an 85% SO_2 removal efficiency. In its review of a recent Alstom proposal for a project involving an FDA downstream of a CFB boiler with limestone injection, Burns & McDonnell noted that the FDA mass balance included in the bid package indicated approximately 78% of the overall SO_2 removal occurred in the boiler. The FDA/FF combination on that project was guaranteed to achieve 75% SO_2 removal, but started with a significantly lower inlet SO_2 concentration that directly affects removal efficiency. Contrary to the lower emission rates presented in this section, the FDA has been shown to be similar in SO_2 removal performance to the SDA and thus was determined to be a feasible SO_2 control alternative for LOS.

3.2.2.4 CIRCULATING DRY SCRUBBER FLUE GAS DESULFURIZATION

In the circulating dry scrubbing process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle, and mixed with water, hydrated lime, recycled flyash and FGD reaction products. A CDS absorber vessel for either LOS unit would be a smaller diameter than the SDA discussed previously in this report. Particles that are entrained in the flue gas leaving the top of the reactor are collected in an ESP or fabric filter downstream of the CDS absorber. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization. CDS absorbers have been installed with both fabric filters and ESPs for particulate control. Additional technical characteristics associated with CDS are described in Appendix B.

For the purpose of this analysis, the CDS technology is evaluated with a maximum SO_2 removal efficiency of 93% with a reagent utilization ratio approximately 10% greater than that of a similar SDA. The CDS was considered a feasible SO_2 control technology for the purpose of this study.

3.2.2.5 POWERSPAN ELECTRO-CATALYTIC OXIDATION (ECO™) TECHNOLOGY

The Powerspan Electro-Catalytic Oxidation (ECO™) system is a multipollutant control technology designed to control emissions of NO_X, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO™ process has two main process vessels; a barrier discharge reactor and a multi-level wet scrubber. Additional technical characteristics associated with the ECO™ process are described in Appendix B.

Powerspan claims a routine SO_2 removal efficiency of 98% with inlet concentrations up to approximately 2,000 ppm and testing at a pilot plant has demonstrated performance, reliability and economics. However, no full size commercial scale ECO™ systems have been installed or are operating at the time of this report. The ECO system was determined not to be a feasible BART alternative because it is not commercially available.

3.2.3 RESULTS OF FEASIBILITY ANALYSIS

The evaluations of the identified BART alternatives following the feasibility analysis are summarized in Table 3.2-1.

TABLE 3.2-1 – BART SO_2 Control Feasibility Analysis Results

Control Technology	In service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable To Leland Olds Station
Fuel Switching	Yes	Yes	Yes	Yes
Coal Cleaning	No	Yes	Yes	No
Wet FGD	Yes	Yes	Yes	Yes
Lime Spray Dryer	Yes	Yes	Yes	Yes
Circulating Dry Scrubber	Yes	Yes	Yes	Yes
Flash Dryer Absorber	Yes	No	Yes	Yes
Powerspan ECO™	No	No	No	Yes

3.3 EVALUATE TECHNICALLY FEASIBILE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the BART analysis, the control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining BART alternatives following the feasibility analysis are summarized in Table 3.3-1. The alternatives are ranked in descending order according to their effectiveness in SO_2 control.

TABLE 3.3-1 – SO_2 Control Technologies Identified for BART Analysis

Control Technology	Control Efficiency
Wet Limestone Flue Gas Desulfurization	95%
Circulating Dry Scrubber (CDS)	93%
Spray Dryer Absorber (SDA)	90%
Flash Dryer Absorber (FDA)	90%
Fuel Switching	$\leq$77%

3.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS – UNIT 1

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis.

- The costs of compliance;

- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for LOS. In addition, as described in Section 1.1.6, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

3.4.1 COST ESTIMATES

Cost estimates for the wet and semi-dry (including SDA and fabric filter) SO_2 control technologies were completed utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the U.S. Environmental Protection Agency. The CUECost model is a spreadsheet-based computer model that was specifically developed to estimate the cost of air pollution control technologies for utility power plants within +/- 30 percent accuracy. The EPA released the version of the model used for this study in February 2000. The model is available for download from the U.S. EPA website at www.epa.gov/ttn/catc/products.

The user must specify the design parameters for the air pollution control technologies in CUECost. Unit costs for consumables, labor, and other variables can be modified by the user to fit the specific situation under evaluation. Because these models are in spreadsheet form, the calculation procedures and assumptions can be readily determined and adjusted by the experienced user as necessary to fit the unique requirements of the evaluation being conducted. The program itself is also somewhat user adjustable to compensate for local conditions. The CUECost default case is a generic facility located in Pennsylvania. Burns & McDonnell has adjusted the CUECost spreadsheets as described in the following sections to account for known facility and local conditions. In addition, Burns & McDonnell has added the Balance of Plant (BOP) costs not included in CUECost to the base estimate to provide a more complete cost estimate.

Operating information utilized as input into the model for the purpose of cost estimating is listed in Tables 1.2-1 and 1.2-2. Economic information utilized as input into the model is given in Table 1.2-3. Economic information was provided in 2004 by BEPC in 2004 dollars. The model was run with

2004 designated as the cost basis year because equipment cost estimating in the model is based on the Chemical Engineering Cost Index and the composite 2004 index is the latest version available. Following completion of the estimating on a 2004 cost basis year, all costs were escalated to a 2005 basis year utilizing the inflation rates designated in Table 1.2-3.

The default General Facilities factor in CUECost is 10% of the direct costs. Because LOS is located in North Dakota where weather protection requirements are much greater than the default state of Pennsylvania, the General Facilities factor was increased to 15% to account for this additional cost.

The electrical subcontract in the BOP cost estimates includes the electrical equipment, materials and labor for engineering, procurement and installation of all electrical distribution system components for each alternative as required. The electrical estimate is based on recent experience with the LOS plant and local costs developed during a recent electrical upgrade project at LOS.

The foundation subcontract cost estimate for each alternative includes 80-foot deep piles and the necessary design and installation provisions for the high water table at the LOS plant site. The number of piles and the amount of concrete and steel required were developed from previous experience completing foundation designs for similar sized air pollution control equipment. The additional foundation subcontract was required because the generic capital cost information provided by CUECost is based on typical spread footing type foundations and does not include these extra provisions required for installation at LOS.

Capital costs for the additional alternatives were estimated from various literature sources and Burns & McDonnell's in-house experience and resources. Information from such sources was adjusted for known local conditions and BOP costs were added separately.

The indirect costs are estimates of additional costs expected to be incurred during a complete project. Engineering costs are estimated as a percentage of total direct costs and are representative of the cost for architectural/engineering services such as system design, specification production, contract evaluations and negotiations, contract administration and construction field services. The contingency is also a percent of the total direct costs and accounts for miscellaneous scope items not covered by the direct cost estimate. Finally, the BEPC indirect costs are an estimation of BEPC internal costs that would be incurred for the implementation of each alternative.

3.4.1.1 WET FGD CAPITAL COST ESTIMATE

The capital cost estimate for the wet FGD system includes the SO_2 control system, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. The wet FGD system cost estimated by CUECost is broken down into the major subsystems of reagent preparation, SO_2 absorption tower, dewatering systems, flue gas handling systems (booster fans and ductwork) and support systems. BOP costs include a wet stack, make-up water treatment plant, electrical subcontract, foundations subcontract and repair/upgrade of the existing railroad tracks for limestone delivery. The results of the capital cost estimate are given in Table 3.4-1.

CUECost includes a cost estimate for a wet stack, but based upon Burns & McDonnell's recent experience with wet stack construction costs, this estimate was deleted from the CUECost results and a revised estimate by Burns & McDonnell was included in the BOP costs. The new stack estimate includes an alloy C-276 liner for the wet stack. The new wet stack was assumed to be 500' in height instead of the current 350' height of the existing LOS Unit 1 dry stack to prevent plume capture in building wakes.

The BOP costs include make-up water treatment equipment costs for pumps, piping, filters, and a clarifier. An estimated building cost for the makeup water treatment system is included in the Foundations Subcontract estimate.

Also included in the Foundations Subcontract cost estimate are roofed, two-walled enclosures for limestone and gypsum temporary storage to provide for weather protection.

An evaporation pond for disposal of periodic scrubber blowdown was included in the capital cost estimate.

Railroad delivery of limestone, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading approximately 1,500 feet of railroad track to provide for limestone delivery to the LOS Unit 1 limestone railcar unloading station. The estimate also includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

TABLE 3.4-1 – Capital Cost Estimate for LOS Unit 1 Wet FGD System

DIRECT COSTS	**Estimated Cost ($2005)**	**General Facilities Markup (15%)**	**Total Direct Cost**
Reagent Prep System	$14,050,000	$2,110,000	$16,160,000
SO_2 Absorption System	$21,110,000	$3,170,000	$24,280,000
Flue Gas Handling System	$7,710,000	$1,160,000	$8,860,000
ByProduct Handling System	$1,740,000	$260,000	$2,000,000
Support Equipment	$2,210,000	$330,000	$2,540,000
		FGD Total Direct Cost =	**$53,840,000**
BOP COSTS			
Wet Stack	$7,490,000	NA	$7,490,000
Water Treatment Equipment	$840,000	NA	$840,000
Evaporation Pond	$930,000	NA	$930,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Ductwork	$3,430,000	NA	$3,430,000
Foundations Subcontract	$1,890,000	NA	$1,890,000
Railroad Upgrade/Repair	$300,000	NA	$300,000
		BOP Total Direct Cost =	**$21,780,000**
		Total Direct Cost =	**$75,620,000**
INDIRECT COSTS			
		Contingency (20% of DC)	$15,120,000
		A/E Engineering and Construction Management (10% of DC)	$7,430,000
		Allowance For Funds During Construction (AFDC 6%)	$4,540,000
BEPC INDIRECTS			
		Project Development (1% of DC)	$760,000
	Spare Parts & Plant Equipment		
		Rolling Stock	$500,000
		Initial Inventory Spare Parts (1.5% of DC)	$1,130,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$380,000
		Construction All-Risk Insurance (1.5% of DC)	$1,130,000
		Contingency (15% of BEPC Indirects)	$470,000
		Indirect Cost Subtotal	$31,600,000
		Total Capital Cost	**$107,220,000**

The total estimated capital cost estimate for a complete, stand-alone wet FGD system utilizing limestone reagent and forced oxidation is $107,220,000, or $487/kW for Unit 1.

3.4.1.2 CIRCULATING DRY SCRUBBER CAPITAL COST ESTIMATE

The Circulating Dry Scrubber (CDS) FGD technology is a relatively recent innovation in the United States, but has been used previously in Europe. Cost information on the CDS system is not as widely available as the more common wet and semi-dry systems. Capital costs for the CDS system were based on CUECost estimates for the SDA semi-dry FGD system with modifications to reflect the design and operational differences. Several literature sources[5, 6] and Burns & McDonnell in-house information were utilized in making these modifications. The CDS cost estimate is presented in a line item format with individual items adjusted to reflect differences between the CDS and SDA. The capital cost estimate is presented in Table 3.4-2.

The CDS absorber vessel is similar to the SDA, but smaller in diameter to provide for a greater gas velocity to make fluidized bed operation possible. The cost of the CDS absorber vessel was estimated at 80% of the cost of the SDA absorber vessel.

Because the CDS recirculates a much greater fraction of the flyash and absorber reaction products (80-95% vs. 30%) than the SDA, the byproduct handling system cost for the SDA was increased by 100% for the CDS estimate to account for the greater system capacity requirements.

The estimated cost for ancillary support equipment was also based on the SDA estimate from CUECost. The CUECost estimate for these systems for the SDA was increased by 10% to reflect the additional reagent usage and higher recycle flow rate.

The CUECost estimate for SDA flue gas handling systems was increased by 15% to account for the additional booster fan capacity required to accommodate the greater pressure drop of the CDS. Ductwork costs were assumed not to change due to the CDS configuration versus the SDA.

TABLE 3.4-2 – Capital Cost Estimate for LOS Unit 1 CDS FGD System

DIRECT COSTS	**Estimated Cost ($2005)**	**General Facilities Markup (15%)**	**Total Direct Cost**
CDS System			
Reagent Prep System	$12,830,000	$1,920,000	$14,750,000
SO_2 Absorption System	$9,140,000	$1,370,000	$10,510,000
Flue Gas Handling System	$7,000,000	$1,050,000	$8,040,000
ByProduct Handling System	$3,620,000	$540,000	$4,160,000
Support Equipment	$2,940,000	$440,000	$3,380,000
		CDS Total Direct Cost =	**$40,840,000**
Fabric Filter			
Fabric Filter Housing	$8,840,000	$1,330,000	$10,160,000
Bags	$1,290,000	$190,000	$1,480,000
Ash Handling System	$6,620,000	$990,000	$7,610,000
Instruments & Controls	$300,000	$40,000	$340,000
		Fabric Filter Total Direct Cost =	**$19,590,000**
BOP Costs			
Water Treatment Facility	$700,000	NA	$700,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Ductwork	$3,430,000	NA	$3,430,000
Foundations Subcontract	$1,790,000	NA	$1,790,000
Railroad Upgrade/Repair	$300,000	NA	$300,000
		BOP Total Direct Cost =	**$13,120,000**
		Total Direct Cost =	**$73,560,000**

INDIRECT COSTS	
Contingency (20% of DC)	$14,710,000
A/E Engineering and Construction Management (10% of DC)	$7,660,000
Allowance For Funds During Construction (AFDC 6%)	$4,600,000
BEPC INDIRECTS	
Project Development (1% of DC)	$740,000
Spare Parts & Plant Equipment	
Rolling Stock	$500,000
Initial Inventory Spare Parts (1.5% of DC)	$1,100,000
Plant Furnishings (0.5% of DC)	$370,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$370,000
Construction All-Risk Insurance (1.5% of DC)	$1,100,000
Contingency (15% of BEPC Indirects)	$570,000
Indirect Cost Subtotal	$31,230,000
Total Capital Cost	**$104,790,000**

Because the CDS recirculates a much greater fraction of flyash and absorber reaction products than the SDA, the estimated cost for the ash handling system was increased 25% over the CUECost estimate for the SDA. In the same manner, the estimated ash handling system and instrumentation and control costs were increased to reflect additional capacity requirements.

A new stack was not included in the BOP capital cost estimate. It was assumed that the CDS facility would be located on the west side of the plant near Unit 1 and that the existing stack could be reused. Included in the Foundations Subcontract cost estimate is a silo for temporary storage of waste products prior to transport to the permitted waste disposal facility.

Railroad delivery of lime, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading approximately 1,500 feet of railroad track to provide for lime delivery to the LOS Unit 1 railcar unloading station. The estimate includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

The total estimated capital cost estimate for a complete, stand-alone CDS with Fabric Filter for SO_2 control for LOS Unit 1, utilizing hydrated lime as a reagent is $104,790,000, or $476/kW.

3.4.1.3 SEMI-DRY FGD CAPITAL COST ESTIMATE

Estimated direct costs for the semi-dry FGD system include the SDA, fabric filter, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a lime SDA/FF system supplier. The SDA/FF system costs estimated by CUECost are broken down into the major subsystems of reagent preparation, spray dryer absorber, waste handling systems, flue gas handling systems (booster fans and ductwork) and support systems. A fabric filter is included in the estimate for the capture of entrained absorption products. BOP costs include an electrical subcontract, foundations subcontract, water treatment equipment and repair/upgrade of the existing railroad tracks for lime delivery. The results of the capital cost estimate are given in Table 3.4-3.

A new stack was not included in the capital cost estimate. It was assumed for the purpose of the estimate that the existing stack would be reused as the flue gas is not near saturation.

Included in the Foundations Subcontract cost estimate is a silo for temporary waste product storage.

TABLE 3.4-3 – Capital Cost Estimate for LOS Unit 1 Semi-Dry FGD System

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
SDA System			
Reagent Prep System	$9,410,000	$1,410,000	$10,820,000
SO_2 Absorption System	$10,990,000	$1,650,000	$12,640,000
Flue Gas Handling System	$6,360,000	$950,000	$7,310,000
ByProduct Handling System	$1,770,000	$270,000	$2,040,000
Support Equipment	$2,670,000	$400,000	$3,070,000
	SDA Total Direct Cost =		**$35,880,000**
Fabric Filter			
Fabric Filter Housing	$8,840,000	$1,330,000	$10,160,000
Bags	$1,290,000	$190,000	$1,480,000
Ash Handling System	$3,560,000	$530,000	$4,100,000
Instruments & Controls	$300,000	$40,000	$340,000
	Fabric Filter Total Direct Cost =		**$16,080,000**
BOP Costs			
Water Treatment Equipment	$380,000	NA	$380,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Ductwork	$1,790,000	NA	$1,790,000
Foundations Subcontract	$3,430,000	NA	$3,430,000
Railroad Upgrade/Repair	$300,000	NA	$300,000
	BOP Total Direct Cost =		**$12,800,000**
	Total Direct Cost =		**$64,760,000**
INDIRECT COSTS			
Contingency (20% of DC)			$12,950,000
A/E Engineering and Construction Management (10% of DC)			$6,320,000
Allowance For Funds During Construction (AFDC 6%)			$3,790,000
BEPC INDIRECTS			
Project Development (1% of DC)			$650,000
Spare Parts & Plant Equipment			
Rolling Stock			$500,000
Initial Inventory Spare Parts (1.5% of DC)			$970,000
Construction Startup and Support			
O&M Staff Training (0.5% of DC)			$320,000
Construction All-Risk Insurance (1.5% of DC)			$970,000
Contingency (15% of BEPC Indirects)			$510,000
Indirect Cost Subtotal			$27,240,000
Total Capital Cost			**$92,000,000**

Railroad delivery of lime, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading approximately 1,500 feet of railroad track to provide for lime delivery to the LOS Unit 1 railcar unloading station.

The estimate includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

The total estimated capital cost estimate for a complete, stand-alone SDA/FF FGD system on LOS Unit 1, utilizing hydrated lime as a reagent is $92,000,000, or $418/kW.

3.4.1.4 FLASH DRYER ABSORBER CAPITAL COST ESTIMATE

The Flash Dryer Absorber (FDA) is a relatively recent development of the semi-dry FGD process. Because few FDA's have been placed in service at this time, cost breakdown information is difficult to find for them. The FDA cost estimate presented here is primarily based on in-house pricing information from Burns & McDonnell for an FDA/FF application to LOS Unit 1. The cost estimate includes the FDA reactor, the hydrator/mixer, the solids recycling system, and the Fabric Filter, with local waste solids handling systems. Additional cost information, for equipment and systems not included in the indicative pricing, were taken from the CUECost SDA cost estimate with individual line items adjusted to reflect modifications based on known differences in individual system capacities and capabilities. The results of the capital cost estimate for the FDA and Fabric Filter, along with BOP requirements, is provided in Table 3.4-4.

The estimated cost for the reagent preparation system for the FDA was taken as the CUECost estimate for a semi-dry system, including the estimated cost of a lime hydrator.

Estimated water treatment plant costs for the FDA system were decreased 45% from those of the wet FGD to reflect the lower makeup water requirements estimated for the FDA system.

The cost of the electrical subcontract for the FDA system was estimated to be equivalent to that of the semi-dry system due to the similarities in equipment requirements. Where system capacities changed significantly, such as ash handling systems, the number and capacity of electrical subsystems will undoubtedly change. However, sufficient information was not available to differentiate between the SDA and FDA electrical subsystem costs.

TABLE 3.4-4 – Capital Cost Estimate for LOS Unit 1 FDA with Fabric Filter

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
FDA System			
Reagent Prep System	$9,410,000	$1,410,000	$10,820,000
SO_2 Absorption System	$6,250,000	$310,000	$6,560,000
Flue Gas Handling System	$5,900,000	$890,000	$6,790,000
ByProduct Handling System	$1,470,000	$221,000	$1,691,000
Support Equipment	$2,400,000	$360,000	$2,760,000
		FDA Total Direct Cost =	**$28,620,000**
Fabric Filter			
Fabric Filter Housing	$10,630,000	$1,870,000	$12,500,000
Bags	$1,615,000	$285,000	$1,900,000
Instruments & Controls	$4,477,000	$790,000	$5,267,000
Ash Handling Systems	$2,270,000	$340,000	$2,610,000
		Fabric Filter Total Direct Cost =	**$22,300,000**
BOP Costs			
Water Treatment Plant	$570,000	NA	$570,000
Electrical Subcontract	$5,520,000	NA	$5,520,000
Ductwork	$3,430,000	NA	$3,430,000
Foundations Subcontract	$1,890,000	NA	$1,890,000
Railroad Upgrade/Repair	$300,000	NA	$300,000
		BOP Total Direct Cost =	**$11,140,000**
		Total Direct Cost =	**$62,060,000**
INDIRECT COSTS			
Contingency (20% of DC)			$12,520,000
A/E Engineering and Construction Management (10% of DC)			$5,620,000
Allowance For Funds During Construction (AFDC 6%)			$3,370,000
BEPC Indirects			
Project Development (1% of DC)			$630,000
Spare Parts & Plant Equipment			
Rolling Stock			$500,000
Initial Inventory Spare Parts (1.5% of DC)			$940,000
Construction Startup and Support			
O&M Staff Training (0.5% of DC)			$310,000
Construction All-Risk Insurance (1.5% of DC)			$940,000
Contingency (15% of BEPC Indirects)			$500,000
Indirect Cost Subtotal			$26,360,000
Total Capital Cost			**$88,980,000**

An estimate was not provided for a new stack for Unit 1. For the purposes of this study, it was assumed that the existing Unit 1 stack would be reused.

The estimated cost of the foundation subcontract (including pilings and weather enclosures) was left unchanged from that of the SDA primarily because it has been estimated that the reduced foundation requirements of the reactor are offset by the increased foundation requirements of the fabric filter. Similarly, for the basis of this estimate, it was assumed that any reduction in absorber enclosure requirements was offset by additional costs for enlargement of the fabric filter casing(s).

The estimated cost of the railroad upgrade/repair to allow for lime delivery was left unchanged from the SDA estimate because the slight change in reagent usage would not affect the cost of the modifications required to allow for rail delivery.

The total estimated capital cost for the installation of and FDA system on LOS Unit 1 is $88,980,000 or $404/kW.

3.4.1.5 FUEL SWITCHING CAPITAL COST ESTIMATE

The potential for switching to PRB fuel for LOS Unit 1 was investigated by BEPC and an internal report was generated in 1997[1]. This report examined the results of a test burn with a PRB coal similar to the current PRB coal used in the current blended fuel. From the 1997 report, a switch to 100% PRB usage in LOS Unit 1 would impact the operating and maintenance costs, but significant capital expenditures for modification of the coal handling system were not identified. The results of the cost estimate for the fuel switching alternative are given in Table 3.4-5. One significant problem that was identified was the unloading time of the coal delivery trains. Current rail car parking capacity is limited and with the current rail system configuration part of the coal train would have to be parked on the main line while unloading. The potential solutions to this particular problem are not analyzed in the report, though it is mentioned that it is possible the railroad operator can adjust to this condition. A cost estimate for potential rail line modifications was not included in this report because this question was not resolved during the short test period.

The cost of a flue gas conditioning system was included to maintain ESP performance for this alternative. The capital cost estimate for the flue gas conditioning system includes a dry sulfur unloading station, dry sulfur storage hopper, transfer conveyance from storage hopper to sulfur melter, sulfur metering pump skid with MCC and variable speed drives, SO_3 production skid and injection probes with metering ports.

TABLE 3.4-5 – Capital Cost Estimate for Fuel Switching with Flue Gas Conditioning

DIRECT COSTS		**Estimated Cost ($2005)**
Injection System		$969,000
Unloading Station		(Included Above)
Storage Hopper		(Included Above)
Transfer Conveyor		(Included Above)
Metering Pump Skid		(Included Above)
SO_3 Production Skid		(Included Above)
Injection Probes		(Included Above)
	Total Direct Cost =	**$969,000**
INDIRECT COSTS	Contingency (20% of DC)	$194,000
	A/E Engineering and Construction Management (10% of DC)	$97,000
	Allowance for Funds During Construction (AFDC 6%)	$58,000
BEPC INDIRECTS	Project Development (1% of DC)	$9,700
	Spare Parts & Plant Equipment	
	Initial Inventory Spare Parts (1.5% of DC)	$14,500
	Construction Startup and Support	
	O&M Staff Training (0.5% of DC)	$4,800
	Construction All-Risk Insurance (1.5% of DC)	$14,500
	Contingency (15% of BEPC Indirects)	$5,000
	Indirect Cost Subtotal	$398,000
	Total Capital Cost	**$1,367,000**

Additional capital investments may be required for a switch to PRB fuel, including construction of fuel barns and the installation of additional conveyors, but those costs were not identified as part of this study. The estimated total capital investment for fuel switching alternative for LOS Unit 1, including flue gas conditioning, is estimated to be $1,367,000 or $6.21/kW

3.4.1.6 WET FGD O&M COST ESTIMATE

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). These costs were developed as part of the CUECost model and include operating labor, administrative and support labor and maintenance. Table 3.4-6 summarizes the O&M cost estimates for the wet FGD system.

The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. The maintenance material and labor cost was estimated as approximately 3% of the wet FGD system direct capital cost in Table 3.4-1. Administrative and support labor cost was estimated as 12% of the maintenance material and labor cost plus 30 percent of the operating labor costs. Previous studies and guidelines for FGD O&M costs by EPRI and others are in line with these percentages.

TABLE 3.4-6 – O&M Cost Estimate for LOS Unit 1 Wet FGD System

Fixed Costs	
Operating Labor	$1,460,000
Admin and Support labor	$670,000
Maintenance Material and Labor	$1,950,000
Total Fixed O&M Costs =	$4,090,000
Variable Costs	
Limestone Reagent	$1,760,000
Byproduct Disposal	$630,000
Water	$270,000
Auxiliary Power	$1,600,000
Total Variable O&M Costs =	$4,260,000
Total Annual O&M Costs	**$8,350,000**
Net Annual O&M Cost ($/MWh)	**$4.81**

The operating labor cost is based on a total of 15 additional personnel, including two operators per shift (one in the control room and one on roving duty) with two truck drivers at 40 hours per week for hauling of FGD wastes and two laborers on day shift and one on roving assignment. In addition, four maintenance staff working one shift per day, five days per week are included in the maintenance cost estimate.

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on consumption rates modeled by the CUECost model and the unit cost information provided by BEPC and described in Table 1.2-3 Economic Design Criteria. A cost of $5.50 per ton for hauling the FGD wastes was included for waste disposal. No additional cost for landfilling at the permitted solid waste facility was included. The total estimated annual O&M cost for application of wet FGD to LOS Unit 1 is $8,350,000 or $4.81/kW.

3.4.1.7 CIRCULATING DRY SCRUBBER O&M COST ESTIMATE

Estimated O&M costs for the CDS/FF alternative were developed from the CUECost estimate of the O&M costs for the SDA/FF alternative. The operating labor was increased by 8% over that of the SDA as indicated in a recent study by Sargent & Lundy[5] comparing the two alternative technologies. Administration and Support and maintenance and material costs were similarly increased 8% based upon the same reference. The CDS reagent usage was also increased 17% (effective stoichiometric ratio of 2.1) above that for the SDA based upon the same findings. Waste disposal costs were increased 5% over those of the SDA, as estimated by CUECost, to reflect the increased reagent wastage. The power requirement for the CDS was increased 15% over that estimated by CUECost for the SDA based upon Sargent & Lundy's findings[5]. The estimated annual O&M costs for application of the CDS/FF alternative at LOS Unit 1 are given in Table 3.4-7.

TABLE 3.4-7 – O&M Cost Estimate for LOS Unit 1 CDS/FF System

Fixed Costs	
Operating Labor	$1,280,000
Admin and Support labor	$400,000
Maintenance Material and Labor	$1,460,000
Total Fixed O&M Costs =	$3,140,000
Variable Costs	
Lime Reagent	$4,470,000
Byproduct Disposal	$820,000
Water	$110,000
Auxiliary Power	$1,160,000
Total Variable O&M Costs =	$6,560,000
Total Annual O&M Costs	**$9,700,000**
Net Annual O&M Cost ($/MWh)	**$5.59**

3.4.1.8 SEMI-DRY FGD O&M COST ESTIMATE

The O&M cost estimate for the SDA/FF alternative was taken directly from CUECost. Lime usage was set at 1.80 lbmol of lime (CaO) per lbmol of SO_2 removed. A ratio of 5.5 lb of recycled solids per pound of lime added and a 35% solids slurry were also set as design conditions in CUECost. A total of 11" w.g. pressure drop across the combined SDA/FF system was also utilized as a design condition. The Fabric Filter was sized for a gas-to-cloth ratio of 3.5 ACFM/Ft^2. A three year bag life was assumed. The results of the SDA/FF O&M cost estimate are summarized in Table 3.4-8.

TABLE 3.4-8 – O&M Cost Estimate for LOS Unit 1 SDA/FF System

Fixed Costs	
Operating Labor	$1,150,000
Admin and Support labor	$360,000
Maintenance Material and Labor	$1,350,000
Total Fixed O&M Costs =	$2,860,000
Variable Costs	
Lime Reagent	$4,180,000
Byproduct Disposal	$780,000
Water	$110,000
Auxiliary Power	$1,010,000
Total Variable O&M Costs =	$6,080,000
Total Annual O&M Costs	**$8,940,000**
Net Annual O&M Cost ($/MWh)	**$5.15**

3.4.1.9 FLASH DRYER ABSORBER O&M COST ESTIMATE

The FDA/FF O&M costs were estimated from a combination of the CUECost estimate for the SDA/FF system and vendor supplied materials usage information for the FDA/FF. The operating labor, administration and support for the FDA/FF were taken directly from the SDA/FF estimate because the FDA/FF system operation is no more technically complex than the SDA/FF. Maintenance costs were estimated as 90% of the SDA/FF maintenance cost estimated by CUECost. Reagent usage and waste solids generation rates were estimated by a system vendor for the current fuel blend, increased for the additional sulfur content of the design fuel and the costs determined from the economic information in Table 1.2-3. Auxiliary power costs for the SDA/FF system were increased 10% for the FDA/FF usage. The results of the FDA/FF O&M cost estimate are given in Table 3.4-9.

TABLE 3.4-9 – O&M Cost Estimate for LOS Unit 1 FDA/FF System

Fixed Costs	
Operating Labor	$1,220,000
Admin and Support labor	$480,000
Maintenance Material and Labor	$1,000,000
Total Fixed O&M Costs =	$2,700,000
Variable Costs	
Lime Reagent	$5,070,000
Byproduct Disposal	$830,000
Water	$120,000
Auxiliary Power	$1,110,000
Total Variable O&M Costs =	$7,120,000
Total Annual O&M Costs	**$9,820,000**
Net Annual O&M Cost ($/MWh)	**$5.66**

3.4.1.10 FUEL SWITCHING O&M COST ESTIMATE

In the 1997 report[1] on the PRB test burn, BEPC reported several operational advantages to the use of PRB in LOS Unit 1. These included reduced station service (from 7.6 to 7.2%), reduced sulfur emissions and reduced ash quantities. The test report specifically mentions that although some features of PRB firing were documented, the test duration was extremely short and many potential long term impacts were neither investigated nor documented. Additional O&M cost might result from unknown impacts caused by a fuel switch. For the purpose of estimating impacts of a switch to 100% PRB fuel on the operating and maintenance costs of LOS Unit 1, the changes in fuel cost, station service costs and ash disposal were estimated based on the report contents and are summarized in Table 3.4-10.

The change in fuel cost calculated to result from a switch to 100% PRB was based upon the design heat input to LOS Unit 1, taking into account a 2.1% increase in boiler efficiency (at full generation). The station service benefit was calculated as the net decrease in station service based on operating costs given in Table 1.2-3. Because PRB has a significantly lower ash content, a credit for reduction in both bottom ash and flyash disposal costs is also included. The annual additional O&M cost of switching LOS Unit 1 to PRB is estimated to be $5,510,000 or $2.86/MWh.

TABLE 3.4-10 – O&M Cost Estimate for LOS Unit 1 Fuel Switching

Fuel Cost Change	$6,002,000
Reduced Station Service	-$292,900
Change in Ash Disposal Cost	-$355,100
Annual Flue Gas Conditioning Maintenance	$13,000
Flue Gas Conditioning Reagent	$143,000
Total Annual Change to O&M Cost	**$5,510,000**
Total Annual Change to O&M Cost ($/MWh)	**$2.86**

3.4.1.11 LEVELIZED TOTAL ANNUAL COST

The Levelized Total Annual Cost (LTAC) for all alternatives were calculated based on economic conditions given in Table 1.2-3 and a 20 year project life. The LTAC was calculated for each alternative utilizing the estimated costs in Tables 3.4-1 through 3.4-10 and the economic conditions described in Section 1 of this report. Estimated capital costs were split evenly over a two year construction period for all alternatives. A system startup date of December 17, 2013 was used based upon the projected timing of Regional Haze Rule implementation given by NDDH. O&M costs were included through the end of the calendar year 2034. No salvage value was assumed at the end of the service life for any of the alternatives. The LTAC for all BART alternatives remaining under consideration are presented in Table 3.4-11.

TABLE 3.4-11 – Levelized Total Annual Costs of Unit 1 BART SO_2 Control Alternatives(1)

BART Alternative	Control Efficiency	Annual Emission Reduction from Historical Case (tpy)(2)	Annual Emission Reduction from Future PTE Case (tpy)(3)	Installed Capital Cost ($2005)	Annual O&M Cost ($2005)	Levelized Total Annual Cost ($2005)(4)
Wet FGD	95%	17,019	37,453	$107,220,000	$8,350,000	$19,310,000
CDS/FF	93%	16,327	36,664	$104,790,000	$9,700,000	$20,720,000
SDA/FF	90%	15,289	35,482	$92,000,000	$8,940,000	$18,700,000
FDA/FF	90%	15,289	35,482	$88,980,000	$9,820,000	$19,480,000
Fuel Switching	77%	10,792	30,475	$1,367,000	$5,510,000	$6,690,000

(1) - All Costs in 2005 dollars.

(2) - Annual emission reduction is uncontrolled Historic case emissions minus controlled Future PTE case emissions.

(3) - Annual emission reduction is uncontrolled Future PTE case emissions minus controlled Future PTE case emissions.

(4) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

The annual tons of SO_2 reduction in this study are calculated for two cases. One case is the difference between the uncontrolled emissions from the Historical case (firing the baseline fuel at the historical heat input) and the controlled emissions for the Future PTE case at the nameplate heat input and a capacity factor of 1.0. The second case is the difference between the uncontrolled emissions and the controlled emissions for the Future PTE case.

Figure 3.4-1 is a plot of the Levelized Total Annual Cost for each technology alternative versus the annual removal in tons (Future PTE basis) for each BART alternative shown in Table 3.4-11. A similar graphic analysis is not presented for the Historic Case due to the similarity of the results. The purpose of Figure 3.4-1 is to identify the Dominant Controls Curve which is the rightmost boundary of the control cost envelope. The Dominant Controls Curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual removal tonnage for the various BART alternatives. Points distinctly above, or to the left of, this curve are inferior control alternatives on a cost effectiveness basis. Of the technically feasible BART alternatives considered for LOS Unit 1, data points for the CDS, the SDA and the FDA all lie distinctly above the least cost boundary of the control cost envelope. The reason for this

FIGURE 3.4-1 – LOS Unit 1 SO_2 Least Cost Envelope for Future PTE Case

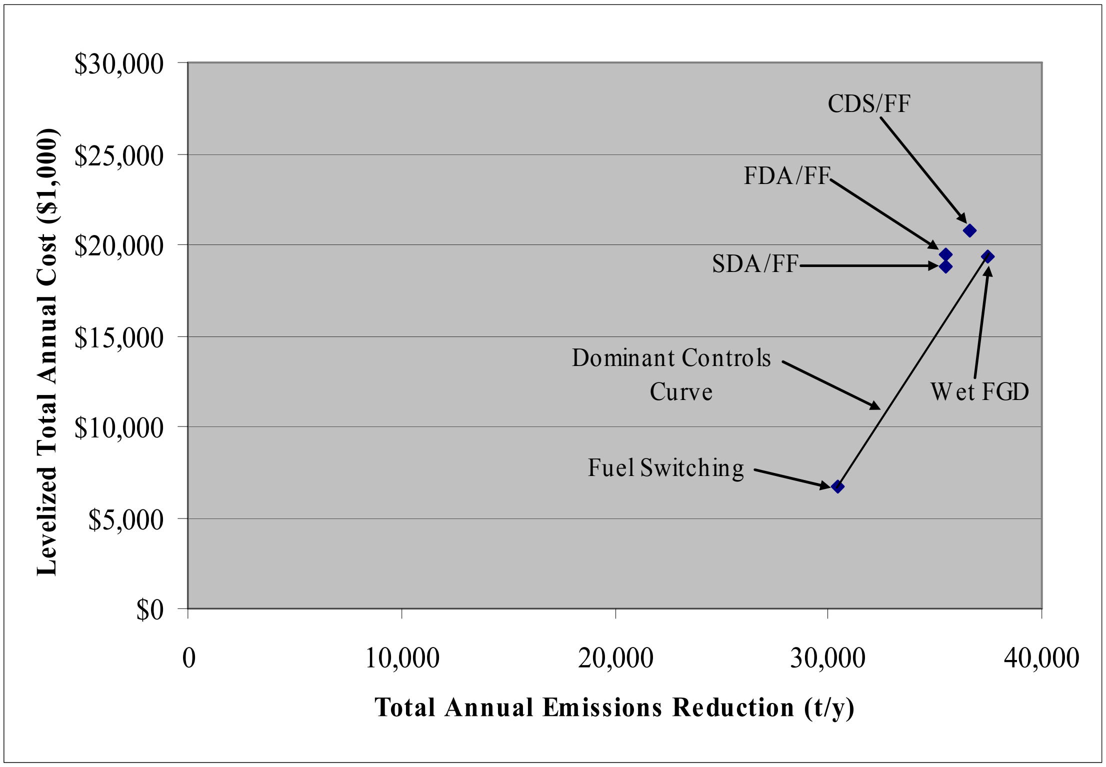


TABLE 3.4-12 – Unit Control Costs of Unit 1 BART SO_2 Control Alternatives

BART Alternative	Control Efficiency	Levelized Total Annual Cost ($2005)(1)	Annual Emission Reduction from Historical Case (tpy)	Historical Case Unit Control Cost ($/ton)	Annual Emission Reduction from Future PTE Case (tpy)	Future PTE Case Unit Control Cost ($/ton)
Wet FGD	95%	$19,310,000	17,019	$1,135	37,453	$516
CDS/FF	93%	$20,720,000	16,327	$1,269	36,664	$565
SDA/FF	90%	$18,700,000	15,289	$1,223	35,482	$527
FDA/FF	90%	$19,480,000	15,289	$1,274	35,482	$549
Fuel Switch	77%	$6,690,000	10,792	$620	30,475	$220

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

is clear from Table 3.4-12 where the unit control costs for the SO_2 control alternatives are listed. In a top down analysis each of the SO_2 control technologies represented by a data point above the Dominant Control Curve could be excluded from further analysis on a cost effectiveness basis. However, because the accuracy of the estimate (± 30%) is greater than the variance of the estimated LTACs (±11%) and the Unit Control Costs (± 12%) for all post combustion control alternatives, none of the alternatives were excluded from further analysis on a cost basis.

The next step in the cost effectiveness analysis for the remaining BART alternatives is to review the incremental cost effectiveness between a given alternative and those above and below it on the Dominant Controls Curve. Table 3.4-13 contains a repetition of the cost and control information from Table 3.4-11 and the incremental cost effectiveness for each dominant control alternative.

TABLE 3.4-13 – Incremental Cost Effectiveness of Unit 1 BART SO_2 Control Alternatives On the Dominant Controls Curve

BART Alternative	Levelized Total Annual Cost(1)	Annual Emission Reduction from Historic Case (tpy)	Incremental Cost Effectiveness for Historic Case ($/ton)	Annual Emission Reduction from Future PTE Case (tpy)	Incremental Cost Effectiveness for Future PTE Case ($/ton)
Wet FGD	$19,310,000	17,019	$2,267	37,453	$2,023
Fuel Switching	$6,690,000	10,792	NA	30,475	NA

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

In the BART Determination guidelines, EPA does not provide definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the dominant control cost curve) between successively less effective alternatives. The incremental cost effectiveness for wet FGD versus fuel switching in Table 3.4-13 is within the range of reasonable costs used in other regulatory analyses and thus does not indicate that wet FGD is prohibitively expensive relative to the fuel switching alternative.

The cost analysis portion of the BART determination for LOS Unit 1 has shown that none of the Unit Control Costs for the dominant alternatives are exceedingly expensive on a Unit Control Cost basis. However, three of the BART alternatives were established as being potentially inferior to alternatives forming the Dominant Controls Curve. None of these alternatives were excluded from further analysis due to the similarity of the estimated cost impacts compared to the estimate accuracy. From a top-down economic analysis viewpoint, wet FGD appears to be the most cost effective evaluated SO_2 control alternative for LOS Unit 1. However, because the capital costs of all of these technologies are subject to market conditions at the time of purchase, such as; alloy pricing, major equipment lead times (i.e., slurry pumps, booster fans, etc.) the relative closeness of the estimated capital costs is a good indicator that the cost ranking of these alternatives might even be reversed at the time of actual purchase.

At the conclusion of the cost impact analysis, the decision was made to delete the FDA/FF alternative from further consideration as it duplicated the control efficiency of the SDA/FF alternative, but at a higher price. This deletion is not anticipated to prejudice study results because of the relative closeness of the costs of the post combustion control alternatives. It is not intended to imply that the FDA/FF is excluded from consideration as an actual technology for BART compliance, only that this alternative is excluded from the remainder of this analysis as a duplicate alternative. When Basin Electric Power Cooperative initiates procurement of SO_2 control equipment, there is no reason to exclude the FDA/FF alternative from the bidding process. The purpose of the BART analysis is to identify the emission level that constitutes BART, not to restrict the source to a specific control technology.

3.4.2 ENERGY IMPACTS

The energy impacts of each alternative, in terms of both estimated kW of energy usage and the percent of total generation, are given in Table 3.4-14. The fuel switching option actually has a negative energy demand due to the decrease in plant services primarily resulting from the decrease in the Net Plant Heat Rate of approximately 300 Btu/kW.[1]

The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps, blowers, booster fans, ball mills for limestone grinding and vacuum pumps for byproduct slurry dewatering. The largest energy users for the semi-dry and dry alternatives are pumps, blowers, atomizers and booster fans. Building HVAC and interior and exterior lighting loads are also included, but the major energy consumption is due to the primary systems described above.

TABLE 3.4-14 – Energy Requirements of Unit 1 BART SO_2 Control Alternatives

BART Alternative	Energy Demand (kW)	Percent of Nominal Generation
Wet FGD	4,814	2.2%
CDS/FF	3,500	1.6%
SDA/FF	3,043	1.4%
Fuel Switching	-880	-0.4%

3.4.3 NON-AIR QUALITY ENVIRONMENTAL IMPACTS

Non-air quality environmental impacts of the installation and operation of the various BART alternatives include hazardous waste generation, solid and aqueous waste streams, and salable products that could result from the implementation of various BART alternatives. One general exception is the fuel switching alternative which would actually result in the reduction of ash quantities and might even produce salable flyash. The cost reduction for reduced ash disposal was included in the O&M cost estimate for fuel switching, but no credit was taken for potential future ash sales.

Captured mercury in the solid waste stream from any post combustion alternative would be present as a trace contaminant in the solid waste, not affecting disposal options as long as the waste passes the Toxic Characteristic Leaching Procedure (TCLP), which FGD system wastes have historically.

A wet FGD system for LOS Unit 1 is estimated to produce approximately 14.9 tons per hour of solid waste. The waste stream would be composed of gypsum solids and inerts at approximately 15% moisture. Over the course of a year, the total solid waste quantity is estimated to be approximately

130,500 tons of gypsum solids which would be landfilled in the current permitted solid waste disposal facility near the plant.

The annual quantity of aqueous waste that would be produced by a wet FGD system is difficult to quantify because the blowdown rate from a wet FGD system is primarily a function of the dissolved chloride levels in the absorber reaction tank. Most of the chloride reaching the scrubber is in the form of hydrochloric acid which is readily absorbed and neutralized. Hydrochloric acid removal rates in a typical wet FGD system typically exceed 95%. CUECost estimates 41 lb/hr of hydrochloric acid in the flue gas stream which is assumed to be completely removed by the absorber system. The waste solids stream leaving the wet FGD system contains approximately 15% water which would contain $CaCl_2$ which would not require blowdown for disposal. Assuming the chloride to be present in the blowdown stream as $CaCl_2$ and assuming an average chloride concentration of 9,000 parts per million, one can calculate approximately 41 pounds per hour of chloride would leave the plant in the entrained moisture in the solid waste. No blowdown specifically for chloride disposal would be required under these conditions. For the purpose of this analysis, it was assumed that an irregular blowdown stream would be required and would be sent to a dedicated evaporation pond on site for disposal.

During preparation for the visibility analysis a review of the cost impact analysis results was conducted and fuel switching (77%) was identified as a significantly inferior alternative compared to the post combustion SO_2 control alternatives (90-95%) and it was decided that fuel switching should be excluded from further consideration in the study. Further explanation is provided in the next section.

3.4.4 VISIBLITY IMPACTS

The final impact analysis conducted was to assess the visibility impairment impact reduction for each proposed BART alternative. Pre-control Historic emission rates and post-control emission rates for the Future PTE case were modeled for visibility impairment impacts. CALPUFF was used to model the long-range transport and interaction of SO_2, NO_X and PM to estimate the visibility impairment impact in deciViews (dV). The reduction in visibility impairment impact due to each control scenario was then calculated as the difference between the visibility impairment impact for each control scenario and the pre-control visibility impairment impact. Per the BART Guidelines and the modeling protocol provided by NDDH, the pre-control modeling case was the maximum 24 hour emission rate for each pollutant for the years 2000-2002, inclusive. The post-control emission rates for each pollutant were developed from the Future PTE case. These results were then compared to assess the relative visibility impairment reduction for each BART alternative.

The BART guidelines state that the comparison should be made at the 98th percentile level (70 FR 39170). However, NDDH directed that the comparison should be made at the 90th percentile to be consistent with the Western Regional Air Partnership (WRAP) protocol. Therefore, the visibility impairment impact reduction presented for each control scenario in this section is based on the 90th percentile value.

CALPUFF modeling was conducted separately for the application of each SO_2 control technology to the Future PTE case. The modeling results, expressed as the change in visibility impairment impact in deciViews (ΔdV), is the change in visibility impairment impact in the affected Class 1 area as a result of the emission reduction attributed to the implementation of each BART alternative on LOS Unit 1. The visibility impairment impact reduction (Δ dV) for each BART alternative is given in Table 3.4-15 for each affected Class 1 Area.

The visibility impairment impact reduction for each modeled BART alternative is given in column three of Table 3.4-15. This value is the average visibility impairment impact reduction over the three modeled years (2000-2002) for each affected Class 1 area. For all modeled conditions, the visibility impairment reduction for any BART alternative varied from approximately 0.2 to 0.5dV. The Lostwood National Wildlife Refuge (Lostwood NWR) shows the greatest average visibility impairment impact reduction, regardless of the BART alternative modeled, thus indicating that this area will gain the greatest benefit from SO_2 BART implementation of all the Class 1 Areas included in the modeling. The Teddy Roosevelt National Park, Elkhorn site (TRNP-Elkhorn) is shown to gain the least visibility impairment impact reduction, regardless of the BART alternative. A review of Table 3.4-15 finds the visibility impairment impacts for BART alternative vary by year and area. The observed variations between Class 1 Areas are primarily a result of different directions and distances from the plant as well as variability in the meteorological data for each area and each year.

In addition to the average ΔdV values, three other types of data are presented in Table 3.4-15, the number of days in each of the affected Class 1 Areas the visibility impairment impact, after implementation of a BART alternative, exceeded 0.5 dV, the number of days the impact exceeded 1.0

dV and the maximum number of consecutive days the impact exceeded 0.5 dV. The 0.5 dV value is the lowest visibility impairment impact that is considered discernible by the human eye and the EPA

TABLE 3.4-15 – Visibility Impairment Impacts - Unit 1

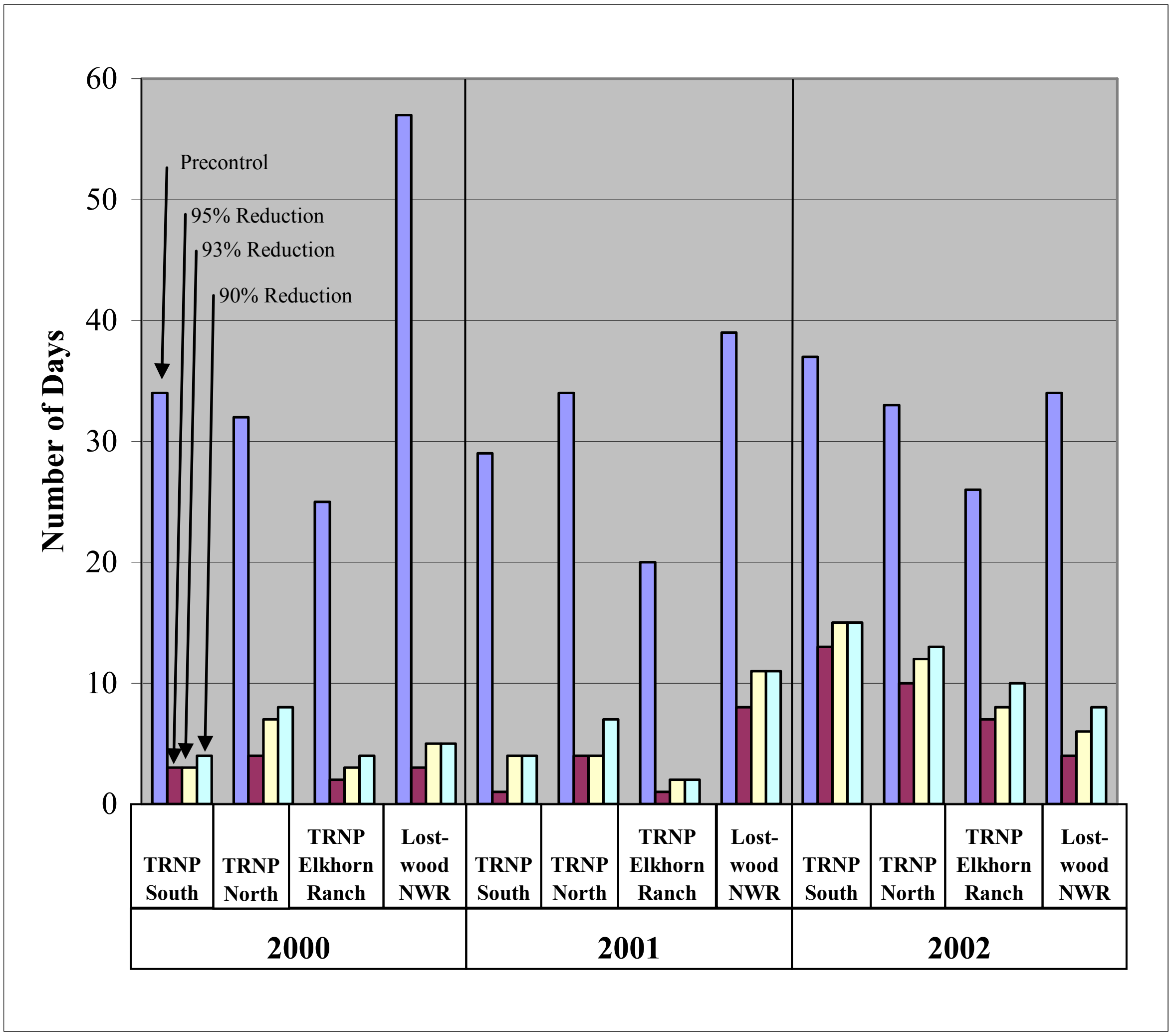
Class 1 Area	BART Alternative Control Efficiency(1)	Visibility Impairment Reduction (ΔdV)	Days Exceeding 0.5 dV in 2000	Days Exceeding 0.5 dV in 2001	Days Exceeding 0.5 dV in 2002	Days Exceeding 1.0 dV in 2000	Days Exceeding 1.0 dV in 2001	Days Exceeding 1.0 dV in 2002	Consecutive Days Exceeding 0.5 dV 2000	Consecutive Days Exceeding 0.5 dV 2001	Consecutive Days Exceeding 0.5 dV 2002
TRNP South	95%	0.337	3	1	13	0	0	3	1	1	2
	93%	0.335	3	4	15	2	0	3	1	2	2
	90%	0.316	4	4	15	2	0	3	1	2	2
TRNP North	95%	0.369	4	4	10	1	0	3	1	1	3
	93%	0.347	7	4	12	2	1	4	1	1	3
	90%	0.332	8	7	13	2	1	4	1	2	3
TRNP Elkhorn Ranch	95%	0.233	2	1	7	1	0	2	1	1	2
	93%	0.221	3	2	8	1	0	2	1	1	2
	90%	0.207	4	2	10	2	0	3	1	1	2
Lostwood NWR	95%	0.519	3	8	4	1	2	0	1	2	1
	93%	0.489	5	11	6	1	4	1	1	2	1
	90%	0.467	5	11	8	1	5	2	1	2	1

(1) - A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

set this threshold in the screening analysis, as the point above which a source is considered to be contributing to visibility impairment (70 FR 39120). The 1.0 dV threshold was established in the final rule as the threshold during the screening analysis at which a state should consider a source to be a cause of visibility impairment (70 FR 39120). The visibility impairment impact analysis consists of examining the magnitude of impact reduction for each alternative as well as the number of exceedances described above.

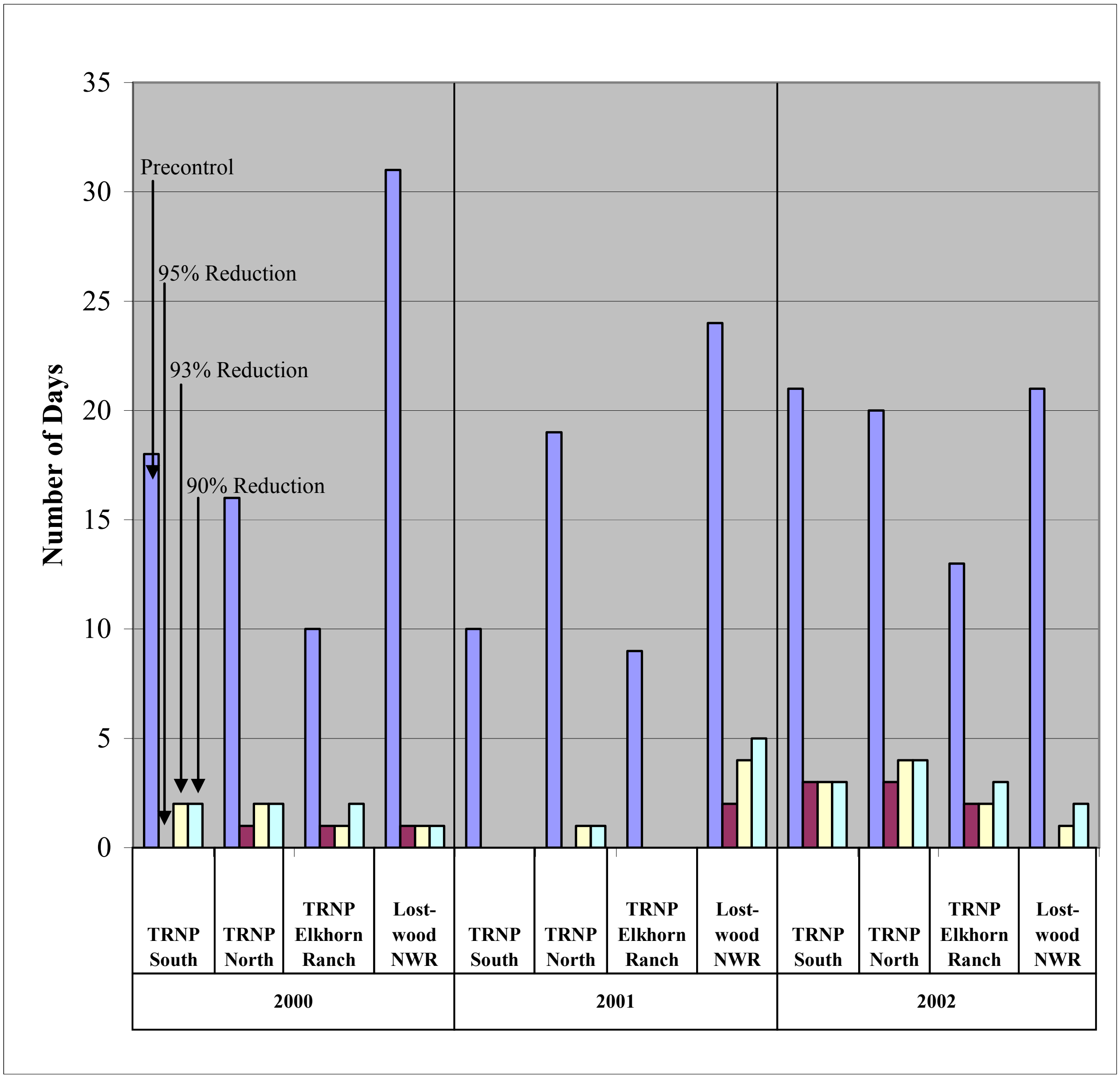
In the model year 2000, the worst impact in terms of days exceeding 0.5 dV occurs at TRNP-North, during 2001 at the Lostwood NWR and during 2002 at TRNP-South, regardless of the BART alternative under consideration. A graphic representation of these impacts is presented in Figure 3.4-2. A comparison of the number of exceedance days for the pre-control and post-control scenarios

FIGURE 3.4-2 – Number of Days Exceeding 0.5 dV for Pre- and Post-Control



shown in Figure 3.4-2 reinforces the earlier observation that the Lostwood NWR gains the most improvement in terms of visibility impairment reduction, regardless of the modeled BART alternative. A graphic representation of the number of days exceeding 1.0 dV is presented in Figure 3.4-3. During the years 2000 and 2002, the greatest number of days where visibility impairment impact

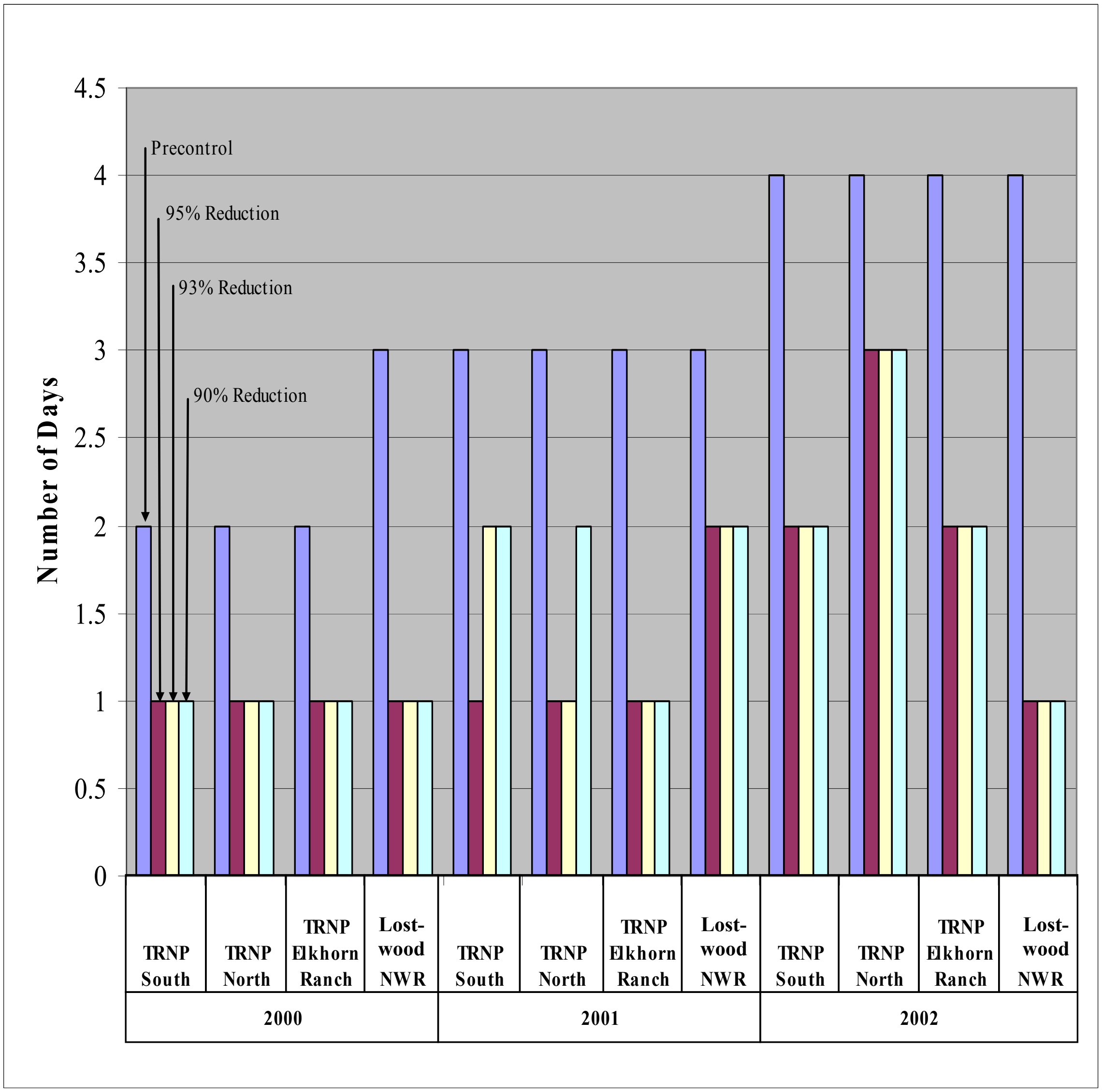
FIGURE 3.4-3 – Number of Days Exceeding 1.0 dV for Pre- and Post-Control



exceeds 1.0 dV, occurs in TRNP-North, but in the Lostwood NWR in 2001. In 2001 both TRNP South and TRNP Elkhorn Ranch have zero days of visibility impairment exceeding 1.0 dV according to the modeling results.

Figure 3.4-4 is a graphic presentation of the maximum number of consecutive days where the visibility impairment impact exceeds 0.5 dV for the modeled Class 1 Areas. Both pre-control and post-control conditions are presented for the three years 2000-2002, inclusive. In 2000, the number

FIGURE 3.4-4 – Maximum Consecutive Days Exceeding 0.5 dV for Pre- and Post Controls



of consecutive days exceeding 0.5 dV of impact is the same for all areas for both the uncontrolled and controlled scenarios. In 2001 TRNP-South and Lostwood NWR both experience the same number of consecutive days of visibility impairment greater than 0.5 dV for the 90% and 93% control cases, but at the 95% control level, the Lostwood NWR is predicted to experience two consecutive days versus one day for all other areas. In 2002 the TRNP-North area is predicted to experience three consecutive days of visibility impairment greater than 0.5 dV and in general, all modeled areas are predicted to experience more consecutive days of visibility impairment greater than 0.5 dV than in either of the two previous years.

The total number of days where the visibility impairment impact exceeded 0.5 dV over the entire modeling period (2000-2002) is greatest for TRNP-North. TRNP-South is predicted to have experienced the least number of days with a visibility impairment impact greater than 0.5 dV over the modeling period. Similarly, the total number of days where the impact exceeded 1.0 dV is greatest for TRNP-North over the modeled time period and least for the TRNP Elkhorn Ranch area. The maximum number of consecutive days with impacts greater than 0.5 dV also occurs in TRNP-North and the TRNP-Elkhorn Ranch and Lostwood NWR areas have the least number of consecutive days.

Compared to the baseline case the visibility impairment reduction predicted for each BART alternative by the visibility modeling, as shown in Figures 3.4-2 though 3.4-4, will result in a significant decrease in visibility impairment in all of the Class 1 areas. Even the least effective BART alternative under analysis will, under the worst modeled meteorological conditions, reduce the number of days with greater than 0.5dV of impact by over half. Days with visibility impairment greater than 1.0 dV will decrease by over 75% under those same worst case model meteorological conditions. Figure 3.4-4 clearly shows that averaged over all model years and Class 1 areas, the number of consecutive days with greater than 0.5 dV will be reduced by approximately half, regardless of the BART alternative under consideration.

The visibility impairment impact reduction results for each BART SO_2 removal alternative are summarized in Table 3.4-16. The second column contains the reduction in visibility impairment impact relative to the uncontrolled Future PTE case emissions. Column four shows the marginal visibility impairment impact improvement for the 93% and 95% SO_2 removal alternatives relative to a lowest removal efficiency condition of 90%. As can be seen in column four, the marginal visibility impairment impact reduction for any of the Class 1 areas is less than ten percent of the minimum change discernible by the human eye, as stated in the BART Guidelines (70 FR 39119, Footnote 28).

Therefore, it is reasonable to conclude from this table that in terms of discernible visibility impairment impact, there is no difference between any of the remaining SO_2 removal alternatives for LOS Unit 1.

TABLE 3.4-16 – Marginal Visibility Impairment Impact Reduction

BART Alternative	BART Alternative and Percent Reduction	Visibility Impairment Reduction (Δ dV)(1)	Marginal Visibility Impairment Reduction (Δ dV)(2)
TRNP-S	95%	0.337	0.021
	93%	0.335	0.019
	90%	0.316	Base
TRNP-N	95%	0.369	0.037
	93%	0.347	0.015
	90%	0.332	Base
TRNP-Elkhorn Ranch	95%	0.233	0.026
	93%	0.221	0.014
	90%	0.207	Base
Lostwood NWR	95%	0.519	0.052
	93%	0.489	0.022
	90%	0.467	Base

(1) - Average modeled visibility impairment impact over three model years. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - Marginal visibility impairment impact improvement relative to the base impact at 90% removal.

3.4.5 IMPACT SUMMARY

As stated in Section 3.4, this report has examined the listed impacts of each BART alternative as part of the BART determination process. Table 3.4-17 summarizes the various impacts discussed in Sections 3.4.1 through 3.4.4. The cost of compliance analysis examined the capital cost of the technology that is central to each feasible BART alternative and the Balance of Plant costs necessary to implement the alternative. In addition, the cost analysis examined the operating and maintenance costs associated with each alternative. These costs were then combined into the Levelized Total Annual Cost (LTAC) for a comparative assessment of the overall cost of each alternative. Finally, as part of the top down analysis, a Dominant Control Curve was plotted and the Unit Control Costs were determined for each alternative. As discussed in Section 3.4.4, the cost impact analysis was basically inconclusive as the difference between the minimum and maximum estimated LTAC was approximately one third of the estimate accuracy and thus no strong conclusion was indicated. The visibility impairment impact analysis examined the visibility impairment impact reduction attributable to each alternative and determined that the marginal change in visibility impairment impact between any two feasible BART alternatives was less than ten percent of the minimum change in visibility impairment discernible by the human eye. So, similar to the cost analysis, the visibility impairment impact analysis reached no definitive conclusion.

The energy impact was also evaluated for each alternative and some differentiation between alternatives was identified. The energy demand for the 90% SO_2 control alternative (SDA/FF) was approximately 60% of the energy demand for the most stringent SO_2 control alternative at 95% SO_2 control (WFGD). All three BART alternatives listed in Table 3.4-17 produce solid waste streams in similar quantities. The WFGD alternative is expected to also produce an intermittent liquid blowdown stream that would be disposed of in a permitted evaporation pond on site.

TABLE 3.4-17 – LOS Unit 1 Impacts Summary for SO_2 Control Alternatives

BART SO_2 Control Alternative	Annual Emissions Reduction (tpy)	Levelized Total Annual Cost(1)	Unit Control Cost ($/ton)	Visibility Impairment Impact Reduction		Energy Impact (kW)	Non Air Quality Impacts
				Area	ΔdV(2)		
95%	37,453	$19,310,000	$516	TRNP-S	0.337	4,800	Solid and Liquid Waste Streams
				TRNP-N	0.369		
				TRNP-Elk	0.233		
				LW-NWR	0.519		
93%	36,664	$20,720,000	$565	TRNP-S	0.335	3,500	Solid Wastes
				TRNP-N	0.347		
				TRNP-Elk	0.221		
				LW-NWR	0.489		
90%	35,482	$18,700,000	$527	TRNP-S	0.316	3,040	Solid Wastes
				TRNP-N	0.332		
				TRNP-Elk	0.207		
				LW-NWR	0.467		

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

(2) - Change in visibility impairment impact between uncontrolled Historical emissions and controlled Future PTE emissions.

3.5 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS – UNIT 2

Step four in the BART analysis procedure is the impact analysis. The BART determination guidelines (70 FR 39166) list four factors to be considered in the impact analysis. This BART Determination will consider the following four factors in the impact analysis:

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four factors considered in the impact analysis are discussed in the following sections. The factor for the remaining useful life of the source is incorporated as part of the cost of compliance. In addition, as described in Section 1.1.6, the visibility impairment impacts are to be evaluated as part of the analysis. Thus, visibility impairment is included as part of the impacts analysis.

3.5.1 COST ESTIMATES

The procedure used to obtain cost estimates for LOS Unit 2 SO_2 control technologies is the same general procedure described in Section 3.4.1 for LOS Unit 1. Any exceptions to this procedure are described in the following sections for each individual control alternative.

3.5.1.1 WET FGD CAPITAL COST ESTIMATE

The capital cost estimate for the wet FGD system includes the SO_2 control system, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. The wet FGD system cost estimated by CUECost is broken down into the major subsystems of reagent preparation, SO_2 absorption tower, dewatering systems, flue gas handling systems (booster fans and ductwork) and support systems. BOP costs include a wet stack, make-up water treatment plant, electrical subcontract, foundations subcontract and repair/upgrade of the existing railroad tracks for limestone delivery. The results of the capital cost estimate are given in Table 3.5-1.

CUECost includes a cost estimate for a wet stack, but based upon Burns & McDonnell's recent experience with wet stack construction costs, this estimate was deleted from the CUECost results and

TABLE 3.5-1 – Capital Cost Estimate for LOS Unit 2 Wet FGD System

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
Reagent Prep System	$15,300,000	$2,300,000	$17,600,000
SO_2 Absorption System	$32,180,000	$4,830,000	$37,010,000
Flue Gas Handling System	$12,170,000	$1,830,000	$14,000,000
ByProduct Handling System	$2,190,000	$330,000	$2,520,000
Support Equipment	$2,650,000	$400,000	$3,050,000
	FGD Total Direct Cost =		**$74,180,000**
BOP COSTS			
Wet Stack	$10,660,000	NA	$10,660,000
Water Treatment Equipment	$1,300,000	NA	$1,300,000
Evaporation Pond	$1,850,000	NA	$1,850,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Foundations Subcontract	$2,390,000	NA	$2,390,000
Relocate Pipe Rack	$390,000	NA	$390,000
Extend Ductwork	$5,720,000	NA	$5,720,000
Railroad Upgrade/Repair	$130,000	NA	$130,000
	BOP Total Direct Cost =		**$29,330,000**
	Total Direct Cost =		**$103,490,000**
INDIRECT COSTS			
Contingency (20% of DC)			$20,700,000
A/E Engineering and Construction Management (10% of DC)			$9,910,000
BEPC INDIRECTS			
Project Development (1% of DC)			$1,034,900
Spare Parts & Plant Equipment			
Rolling Stock			$1,000,000
Initial Inventory Spare Parts (1.5% of DC)			$1,550,000
Plant Furnishings (0.5% of DC)			$520,000
Construction Startup and Support			
O&M Staff Training (0.5% of DC)			$520,000
Construction All-Risk Insurance (1.5% of DC)			$1,550,000
Allowance For Funds During Construction (AFDC 6%)			$6,210,000
Contingency (15% of BEPC Indirects)			$690,000
Indirect Cost Subtotal			$44,120,000
Total Capital Cost			**$147,600,000**

a revised estimate by Burns & McDonnell was included in the BOP costs. The new stack estimate includes an alloy C-276 liner for the wet stack. The new wet stack was assumed to be 500' in height.

The BOP costs include make-up water treatment equipment costs for pumps, piping, filters, and a clarifier. An estimated building cost for the makeup water treatment system is included in the Foundations Subcontract estimate.

Also included in the Foundations Subcontract cost estimate are roofed, two-walled enclosures for limestone and gypsum temporary storage to provide for weather protection.

An evaporation pond for disposal of blowdown, for chloride control, was included in the capital cost estimate. Railroad delivery of limestone, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading of approximately 1,500 feet of railroad track to provide for limestone delivery to the LOS Unit 2 limestone railcar unloading station. The estimate also includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

The total estimated capital cost for a complete, stand-alone wet FGD system utilizing limestone reagent and forced oxidation is $147,600,000, or $335/kW for LOS Unit 2.

3.5.1.2 CIRCULATING DRY SCRUBBER CAPITAL COST ESTIMATE

The Circulating Dry Scrubber (CDS) FGD technology is a relatively recent innovation in the United States, but has been used previously in Europe. Cost information on the CDS system is not as widely available as the more common wet and semi-dry systems. Capital costs for the CDS system were based on CUECost estimates for the SDA semi-dry FGD system with modifications to reflect the design and operational differences. Several literature sources[5, 6] and Burns & McDonnell in-house information were utilized in making these modifications. The CDS cost estimate is presented in a line item format with individual items adjusted to reflect differences between the CDS and SDA. The capital cost estimate is presented in Table 3.5-2.

The CDS absorber vessel is similar to the SDA, but smaller in diameter to provide for a greater gas velocity to make fluidized bed operation possible. The cost of the CDS absorber vessel was estimated at 80% of the cost of the SDA absorber vessel.

TABLE 3.5-2 – Capital Cost Estimate for LOS Unit 2 CDS FGD System

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
CDS System			
Reagent Prep System	$16,210,000	$2,430,000	$18,640,000
SO_2 Absorption System	$16,990,000	$2,550,000	$19,540,000
Flue Gas Handling System	$11,340,000	$1,700,000	$13,050,000
ByProduct Handling System	$3,620,000	$540,000	$4,160,000
Support Equipment	$3,600,000	$540,000	$4,140,000
		CDS Total Direct Cost =	**$59,530,000**
Fabric Filter			
Fabric Filter Housing	$14,880,000	$2,230,000	$17,110,000
Bags	$2,690,000	$400,000	$3,090,000
Ash Handling System	$10,990,000	$1,650,000	$12,640,000
Instruments & Controls	$510,000	$80,000	$580,000
		Fabric Filter Total Direct Cost =	**$33,420,000**
BOP Costs			
Dry Stack	$8,530,000	NA	$8,530,000
Water Treatment Equipment	$1,220,000	NA	$1,220,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Foundations Subcontract	$2,050,000	NA	$2,050,000
Relocate Pipe Rack	$360,000	NA	$360,000
Extend Ductwork	$5,720,000	NA	$5,720,000
Railroad Upgrade/Repair	$130,000	NA	$130,000
		BOP Total Direct Cost =	**$24,900,000**
		Total Direct Cost =	**$117,850,000**
INDIRECT COSTS			
		Contingency (20% of DC)	$23,570,000
		A/E Engineering and Construction Management (10% of DC)	$11,080,000
BEPC INDIRECTS			
		Project Development (1% of DC)	$1,180,000
	Spare Parts & Plant Equipment		
		Rolling Stock	$1,000,000
		Initial Inventory Spare Parts (1.5% of DC)	$1,770,000
		Plant Furnishings (0.5% of DC)	$590,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$590,000
		Construction All-Risk Insurance (1.5% of DC)	$1,770,000
		Allowance For Funds During Construction (AFDC 6%)	$7,070,000
		Contingency (15% of BEPC Indirects)	$770,000
		Indirect Cost Subtotal	$50,090,000
		Total Capital Cost	**$167,900,000**

Because the CDS recirculates a much greater fraction of the flyash and absorber reaction products (80-95% vs. 30%) than the SDA, the byproduct handling system cost for the SDA was increased by 100% for the CDS estimate to account for the greater system capacity requirements.

The estimated cost for ancillary support equipment was also based on the SDA estimate from CUECost. The CUECost estimate for these systems for the SDA was increased by 10% to reflect the additional reagent usage and higher recycle flow rate.

The CUECost estimate for SDA flue gas handling systems was increased by 10% to account for the additional booster fan capacity required to accommodate the greater pressure drop of the CDS. Ductwork costs were assumed not to change due to the CDS configuration versus the SDA.

Because the CDS recirculates a much greater fraction of flyash and absorber reaction products than the SDA, the estimated cost for the ash handling system was increased 86% over the CUECost estimate for the SDA.

A new dry stack was included in the BOP capital cost estimate. It was assumed that the CDS facility would be in a new location and returning the ductwork to the existing stack would be cost prohibitive.

Included in the Foundations Subcontract cost estimate is a silo for temporary storage of waste products prior to transport to the permitted waste disposal facility.

Railroad delivery of lime, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading approximately 1,500 feet of railroad track to provide for lime delivery to the LOS Unit 2 railcar unloading station. The estimate includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

The total estimated capital cost estimate for a complete, stand-alone CDS with Fabric Filter for SO_2 control for LOS Unit 2, utilizing hydrated lime as a reagent is \$167,900,000, or \$382/kW.

3.5.1.3 SEMI-DRY FGD CAPITAL COST ESTIMATE

Estimated direct costs for the semi-dry FGD system include the SDA, fabric filter, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a lime SDA/FF system supplier and is presented in Table 3.5-3. The SDA/FF system costs estimated by CUECost are broken down into the major subsystems of reagent preparation, spray dryer absorber, waste handling systems, flue gas handling systems (booster fans and ductwork) and support systems. A fabric filter is included in the estimate for the capture of entrained absorption products. BOP costs include an electrical subcontract, foundations subcontract, water treatment equipment and repair/upgrade of the existing railroad tracks for lime delivery.

A new dry stack was included in the BOP capital cost estimate. It was assumed that the CDS facility would be in a new location and returning the ductwork to the existing stack would be cost prohibitive.

Included in the Foundations Subcontract cost estimate is a silo for temporary waste product storage.

Railroad delivery of lime, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading approximately 1,500 feet of railroad track to provide for lime delivery to the LOS Unit 2 railcar unloading station. The estimate includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

The total estimated capital cost estimate for a complete, stand-alone lime SDA FGD system with a fabric filter, utilizing lime as a reagent is $155,700,000, or $354/kW for LOS Unit 2.

TABLE 3.5-3 – Capital Cost Estimate for LOS Unit 2 Semi-Dry FGD System

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
Semi-Dry FGD System			
Reagent Prep System	$13,080,000	$1,960,000	$15,040,000
SO_2 Absorption System	$20,740,000	$3,110,000	$23,850,000
Flue Gas Handling System	$10,310,000	$1,550,000	$11,860,000
ByProduct Handling System	$1,770,000	$270,000	$2,040,000
Support Equipment	$3,270,000	$490,000	$3,760,000
		Semi Dry Total Direct Cost =	**$56,550,000**
Fabric Filter			
Fabric Filter Housing	$14,880,000	$2,230,000	$17,110,000
Bags	$2,690,000	$400,000	$3,090,000
Ash Handling System	$5,910,000	$890,000	$6,800,000
Instruments & Controls	$510,000	$80,000	$580,000
		Fabric Filter Total Direct Cost =	**$27,580,000**
BOP Costs			
Dry Stack	$8,530,000	NA	$8,530,000
Water Treatment Equipment	$1,010,000	NA	$1,010,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Foundations Subcontract	$2,390,000	NA	$2,390,000
Relocate Pipe Rack	$390,000	NA	$390,000
Extend Ductwork	$5,720,000	NA	$5,720,000
Railroad Upgrade/Repair	$130,000	NA	$130,000
		BOP Total Direct Cost =	**$25,050,000**
		Total Direct Cost =	**$109,190,000**
INDIRECT COSTS			
Contingency (20% of DC)			$21,840,000
A/E Engineering and Construction Management (10% of DC)			$10,660,000
BEPC INDIRECTS			
Project Development (1% of DC)			$1,090,000
Spare Parts & Plant Equipment			
Rolling Stock			$1,000,000
Initial Inventory Spare Parts (1.5% of DC)			$1,640,000
Plant Furnishings (0.5% of DC)			$550,000
Construction Startup and Support			
O&M Staff Training (0.5% of DC)			$550,000
Construction All-Risk Insurance (1.5% of DC)			$1,640,000
Allowance For Funds During Construction (AFDC 6%)			$6,550,000
Contingency (15% of BEPC Indirects)			$720,000
Indirect Cost Subtotal			$46,490,000
Total Capital Cost			**$155,700,000**

3.5.1.4 FLASH DRYER ABSORBER CAPITAL COST ESTIMATE

The Flash Dryer Absorber (FDA) is a relatively recent development of the semi-dry FGD process. The same methodology used for estimating the FDA capital costs for Unit 1 in Section 3.4.1.4 is used for Unit 2 with exceptions provided below. The results of the capital cost estimate for the FDA and Fabric Filter, along with BOP requirements, is provided in Table 3.5-4.

An estimate is provided for a new stack for Unit 2. For the purposes of this study, it was assumed that reusing the existing Unit 2 stack would be cost prohibitive.

The total estimated capital cost for the installation of and FDA/FF system on LOS Unit 2 is $147,000,000 or $334/kW.

TABLE 3.5-4 – Capital Cost Estimate for LOS Unit 2 FDA with Fabric Filter

DIRECT COSTS	**Estimated Cost ($2005)**	**General Facilities Markup (15%)**	**Total Direct Cost ($2005)**
FDA System			
Reagent Prep System	$13,970,000	$2,100,000	$16,070,000
SO_2 Absorption System	$11,980,000	$600,000	$12,580,000
Flue Gas Handling System	$9,910,000	$1,490,000	$11,400,000
ByProduct Handling System	$0	$0	$0
Support Equipment	$0	$0	$0
		FDA Total Direct Cost =	**$40,050,000**
Fabric Filter			
Fabric Filter Housing	$19,900,000	$2,980,000	$22,880,000
Bags	$2,896,000	$435,000	$3,330,000
Ash Handling System	$3,180,000	$480,000	$3,650,000
Instruments & Controls	$8,028,000	$1,204,000	$9,232,000
		Fabric Filter Total Direct Cost =	**$39,090,000**
BOP Costs			
Dry Stack	$8,530,000	NA	$8,530,000
Water Treatment Equipment	$840,000	NA	$840,000
Electrical Subcontract	$5,850,000	NA	$5,850,000
Foundations Subcontract	$2,170,000	NA	$2,170,000
Relocate Pipe Rack	$360,000	NA	$360,000
Extend Ductwork	$6,070,000	NA	$6,070,000
Railroad Upgrade/Repair	$130,000	NA	$130,000
		BOP Total Direct Cost =	**$23,950,000**
		Total Direct Cost =	**$103,090,000**
INDIRECT COSTS			
Contingency (20% of DC)			$20,620,000
A/E Engineering and Construction Management (10% of DC)			$9,170,000
BEPC INDIRECTS			
Project Development (1% of DC)			$1,030,000
Spare Parts & Plant Equipment			
Rolling Stock			$1,000,000
Initial Inventory Spare Parts (1.5% of DC)			$1,550,000
Plant Furnishings (0.5% of DC)			$520,000
Construction Startup and Support			
O&M Staff Training (0.5% of DC)			$520,000
Construction All-Risk Insurance (1.5% of DC)			$1,550,000
Allowance For Funds During Construction (AFDC 6%)			$6,190,000
Contingency (15% of BEPC Indirects)			$690,000
Indirect Cost Subtotal			$43,960,000
Total Capital Cost			**$147,000,000**

3.5.1.5 FUEL SWITCHING CAPITAL COST ESTIMATE

The potential for switching to PRB fuel for LOS Unit 2 was investigated by BEPC and an internal report was generated in 1997[1]. This report examined the test burn of a PRB coal similar to the current PRB coal used in the current blended fuel. From the 1997 report, a switch to 100% PRB usage at LOS Unit 2 would impact the operating and maintenance costs, but significant capital expenditures for modification of the coal handling system were not identified. The results of the cost estimate for the fuel switching alternative are given in Table 3.5-5. One significant problem that was identified was the unloading time of the coal delivery trains. Current rail car parking capacity is limited and with the current rail system configuration part of the coal train would have to be parked on the main line while unloading. The potential solutions to this particular problem are not analyzed in the report, though it is mentioned that it is possible the railroad operator can adjust to this condition. A cost estimate for potential rail line modifications was not included in this report because this question could not be resolved during the short test period.

The cost of a flue gas conditioning system was included to maintain ESP performance for this alternative. The capital cost estimate for the flue gas conditioning system includes the dry sulfur unloading station, dry sulfur storage hopper, transfer conveyance from storage hopper to sulfur melter, sulfur metering pump skid with MCC and variable speed drives, SO_3 production skid and injection probes with metering ports.

Additional capital investments may be required for a switch to PRB fuel, including construction of fuel barns and the installation of additional conveyors, but those costs were not identified as part of this study. The total capital investment for the fuel switching alternative, including flue gas conditioning, is estimated to be $1,247,000 or $2.83/kW for LOS Unit 2.

TABLE 3.5-5 – Capital Cost Estimate for Fuel Switching with Flue Gas Conditioning

Direct Costs	**Estimated Cost ($2005)**
Injection System	$884,000
Unloading Station	(Included Above)
Storage Hopper	(Included Above)
Transfer Conveyor	(Included Above)
Metering Pump Skid	(Included Above)
SO_3 Production Skid	(Included Above)
Injection Probes	(Included Above)
Total Direct Cost	**$835,000**
INDIRECT COSTS Contingency (20% of DC)	$177,000
A/E Engineering and Construction Management (10% of DC)	$88,000
Allowance for Funds During Construction (AFDC 6%)	$53,000
BEPC INDIRECTS Project Development (1% of DC)	$9,000
Spare Parts & Plant Equipment	
Initial Inventory Spare Parts (1.5% of DC)	$13,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$4,000
Construction All-Risk Insurance (1.5% of DC)	$13,000
Contingency (15% of BEPC Indirects)	$6,000
Indirect Cost Subtotal	$363,000
Total Capital Cost	**$1,247,000**

3.5.1.6 WET FGD O&M COST ESTIMATE

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). These costs were developed as part of the CUECost model and include operating labor, administrative and support labor and maintenance. Table 3.5-6 summarizes the O&M cost estimates for the wet FGD system.

The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. The maintenance material and labor cost was estimated as approximately 3% of the wet FGD system direct capital cost in Table 3.5-1. Administrative and support labor cost was estimated as 12% of the maintenance material and labor cost plus 30% of the operating labor costs. Previous studies and guidelines for FGD O&M costs by EPRI and others are in line with these percentages.

TABLE 3.5-6 – O&M Cost Estimate for LOS Unit 2 Wet FGD System

Fixed Costs	
Operating Labor	$2,330,000
Admin and Support labor	$1,020,000
Maintenance Material and Labor	$2,680,000
Total Fixed O&M Cost =	$6,030,000
Variable Costs	
Limestone Reagent	$3,340,000
Byproduct Disposal	$1,190,000
Water	$550,000
Auxiliary Power	$3,100,000
Total Variable O&M Cost =	$8,180,000
Total Annual O&M Cost =	**$14,210,000**
Net Annual O&M Cost ($/MWh)	**$4.34**

The operating labor cost is based on a total of 19 additional personnel, including two operators per shift (one in the control room and one on roving duty) with two truck drivers at 40 hours per week for hauling of FGD wastes and three laborers on day and second shifts and one on roving assignment. In addition, four maintenance staff working one shift per day, five days per week, plus two for weekend duty are included in the maintenance cost estimate.

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on consumption rates modeled by the CUECost model and the unit cost information provided by BEPC and described in Table 1.2-3 Economic Design Criteria. A cost of $5.50 per ton for hauling the FGD wastes was included for waste disposal. No additional cost for landfilling at the permitted solid waste facility was included. The LOS Unit 2 estimated annual O&M costs are $14,210,000 or $4.34/MWh.

3.5.1.7 CIRCULATING DRY SCRUBBER O&M COST ESTIMATE

Estimated O&M costs for the CDS/FF alternative were developed from the CUECost estimate of the O&M costs for the SDA/FF alternative. The operating labor was increased by 8% over that of the SDA as indicated in a recent study by Sargent & Lundy[5] comparing the two alternative technologies. The CDS reagent usage was also increased 7% above that for the SDA. Waste disposal costs were increased 5% over those of the SDA, as estimated by CUECost, to reflect the increased reagent wastage. The power requirement for the CDS was increased 18% over that estimated by CUECost for the SDA based upon Sargent & Lundy's findings[5]. The estimated annual O&M costs for application of the CDS/FF alternative at LOS Unit 2 are given in Table 3.5-7.

TABLE 3.5-7 – O&M Cost Estimate for LOS Unit 2 CDS/FF System

Fixed Costs	
Operating Labor	$1,860,000
Admin and Support labor	$740,000
Maintenance Material and Labor	$2,440,000
Total Fixed O&M Cost =	$5,040,000
Variable Costs	
Lime Reagent	$8,740,000
Byproduct Disposal	$1,460,000
Water	$230,000
Auxiliary Power	$2,430,000
Total Variable O&M Cost =	$12,870,000
Total Annual O&M Costs	**$17,910,000**
Net Annual O&M Cost ($/MWh)	**$5.16**

3.5.1.8 SEMI-DRY FGD O&M COST ESTIMATE

The O&M cost estimate for the SDA/FF alternative was taken directly from CUECost. Lime usage was set at 1.80 lbmol of lime (CaO) per lbmol of SO_2 removed. A ratio of 5.5 lb of recycled solids per pound of lime added and a 35% solids slurry were also set as design conditions in CUECost. A total of 11" w.g. pressure drop across the combined SDA/FF system was also utilized as a design condition. The Fabric Filter was sized for a gas-to-cloth ratio of 3.5 ACFM/Ft^2. A three year bag life was assumed. The results of the SDA/FF O&M cost estimate are summarized in Table 3.5-8.

TABLE 3.5-8 – O&M Cost Estimate for LOS Unit 2 SDA/FF System

Fixed Costs	
Operating Labor	$1,670,000
Admin and Support labor	$770,000
Maintenance Material and Labor	$2,260,000
Total Fixed O&M Cost =	$4,700,000
Variable Costs	
Lime Reagent	$8,170,000
Byproduct Disposal	$1,390,000
Water	$230,000
Auxiliary Power	$2,050,000
Total Variable O&M Cost =	$11,850,000
Total Annual O&M Costs	**$16,550,000**
Net Annual O&M Cost ($/MWh)	**$4.77**

3.5.1.9 FLASH DRYER ABSORBER O&M COST ESTIMATE

The FDA/FF O&M costs were estimated from a combination of the CUECost estimate for the SDA/FF system and vendor materials. The operating labor for the FDA/FF were taken directly from the SDA/FF estimate because the FDA/FF system operation is no more technically complex than the SDA/FF. Maintenance costs were estimated as 90% of the SDA/FF maintenance cost estimated by CUECost. Reagent usage and waste solids generation rates were taken from information supplied by Alstom for the current fuel blend, increased for the additional sulfur content of the design fuel and the costs determined from the economic information in Table 1.2-3. Auxiliary power costs for the SDA/FF system were increased 10% for the FDA/FF usage. The results of the FDA/FF O&M cost estimate are given in Table 3.5-9.

TABLE 3.5-9 – O&M Cost Estimate for LOS Unit 2 FDA/FF System

Fixed Costs	
Operating Labor	$1,670,000
Admin and Support labor	$710,000
Maintenance Material and Labor	$2,090,000
Total Fixed O&M Cost =	$4,470,000
Variable Costs	
Lime Reagent	$8,450,000
Byproduct Disposal	$1,540,000
Water	$180,000
Auxiliary Power	$2,160,000
Total Variable O&M Cost =	$12,320,000
Total Annual O&M Costs	**$16,800,000**
Net Annual O&M Cost ($/MWh)	**$4.84**

3.5.1.10 FUEL SWITCHING O&M COST ESTIMATE

In the 1997 report[1] on the PRB test burn, BEPC reported several operational advantages to the use of PRB in LOS Unit 2. These included reduced station service (from 7.6 to 7.2%), reduced sulfur emissions and reduced ash quantities. The test report specifically mentions that although some features of PRB firing were documented, the test duration was extremely short and many potential long term impacts were neither investigated nor documented. Additional O&M cost might result from unknown impacts caused by a fuel switch. For the purpose of estimating impacts of a switch to 100% PRB fuel on the operating and maintenance costs of LOS Unit 2, the changes in fuel cost, station service costs and ash disposal were estimated based on the report contents and are summarized in Table 3.5-10.

The change in fuel cost calculated to result from a switch to 100% PRB was based upon the design heat input to LOS Unit 2, taking into account a 2.1% increase in boiler efficiency (at full generation). The station service benefit was calculated as the net decrease in station service based on operating costs given in Table 1.2-3. Because PRB has a significantly lower ash content, a credit for reduction in both bottom ash and flyash disposal costs is also included. The annual additional O&M cost of switching LOS Unit 2 to PRB is estimated to be $11,213,000 or $2.91/MWh.

TABLE 3.5-10 – O&M Cost Estimate for LOS Unit 2 Fuel Switching

Fuel Cost Change Reduced Station Service Change in Ash Disposal Cost	$11,743,000 -$292,900 -$449,100
Flue Gas Conditioning Reagent	$200,000
Flue Gas Conditioning Equipment Maintenance	$12,000
Total Annual Change to O&M Cost	**$11,213,000**
Total Annual Change to O&M Cost ($/MWh)	**$2.91**

3.5.1.11 LEVELIZED TOTAL ANNUAL COST

The Levelized Total Annual Cost (LTAC) for all alternatives were calculated based on economic conditions given in Table 1.2-3 and a 20 year project life. The LTAC was calculated for each alternative utilizing the estimated costs in Tables 3.5-1 through 3.5-10 and the economic conditions described in Section 1 of this report. Estimated capital costs were split evenly over a two year construction period for all alternatives. A system startup date of December 17, 2013 was used based upon the projected timing of Regional Haze Rule implementation given by NDDH. O&M costs were included through the end of the calendar year 2034. No salvage value was assumed at the end of the service life for any of the alternatives. The LTAC for each alternative are presented below in Table 3.5-11.

The annual tons of SO_2 reduction in this study are calculated for two cases. One case is the difference between the uncontrolled Historical emissions and the controlled emissions for the Future PTE case. The second case is the difference between uncontrolled emissions and controlled emissions for the Future PTE case.

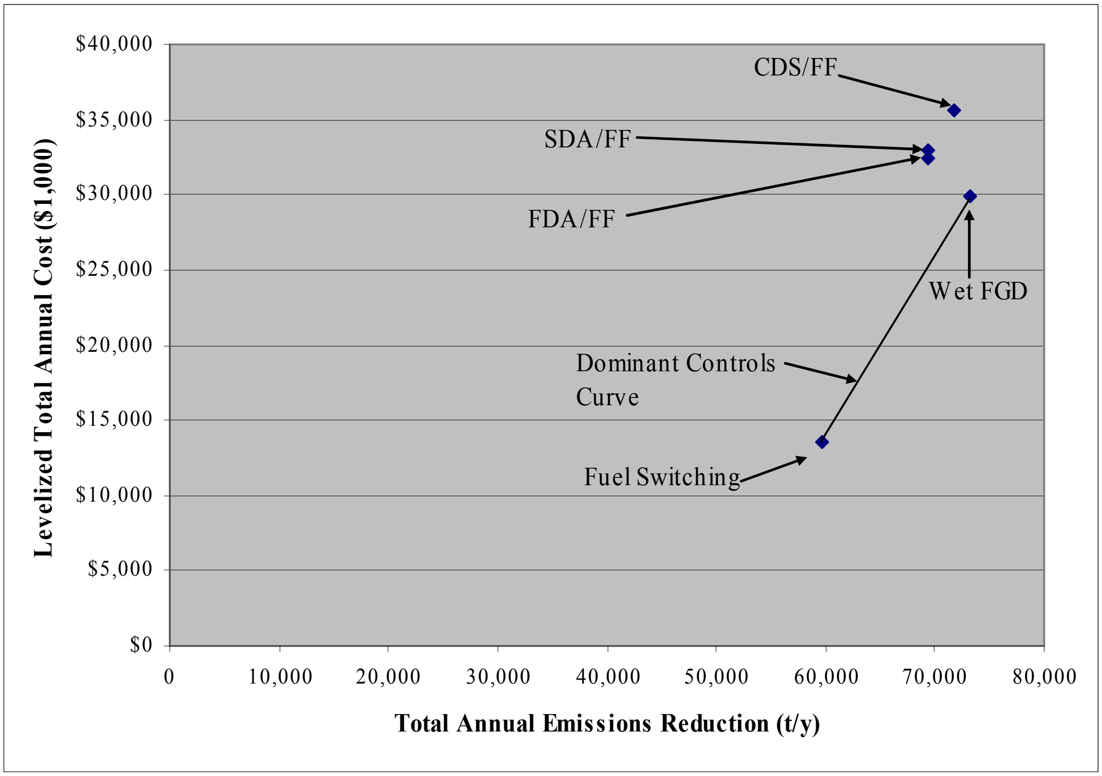
TABLE 3.5-11 – Levelized Total Annual Costs of Unit 2 BART SO_2 Control Alternatives(1)

BART Alternative	Control Efficiency	Annual Emission Reduction from Historical Case (tpy)(2)	Annual Emission Reduction from Future PTE Case (tpy)(3)	Installed Capital Cost ($2005)	Annual O&M Cost ($2005)	Levelized Total Annual Cost ($2005)(4)
Wet FGD	95%	35,568	73,272	$147,600,000	$14,210,000	$29,840,000
CDS/FF	93%	34,025	71,729	$167,900,000	$17,910,000	$35,580,000
SDA/FF	90%	31,711	69,415	$155,700,000	$16,550,000	$32,890,000
FDA/FF	90%	31,711	69,415	$147,000,000	$16,800,000	$32,430,000
Fuel Switch	77%	21,685	59,620	$1,247,000	$11,213,000	$13,490,000

(1) - All Costs in 2005 dollars.
(2) - Annual emission reduction is uncontrolled Historical emissions minus controlled Future PTE emissions.
(3) - Annual emission reduction is uncontrolled emissions minus controlled emissions for Future PTE case.
(4) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

Figure 3.5-1 is a plot of the Levelized Total Annual Cost versus the annual removal in tons (Future PTE case basis) for each BART alternative shown in Table 3.5-11. A similar graphic analysis was not presented for the Historic case due to the similarity to the Future PTE case analysis. The purpose

FIGURE 3.5-1 – LOS Unit 2 SO_2 Least Cost Envelope for Future PTE Case



of Figure 3.5-1 is to identify the Dominant Controls Curve which is the rightmost boundary of the control cost envelope. The Dominant Controls Curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual removal tonnage for the various BART alternatives. Points distinctly above or to the left of this curve are inferior control alternatives on a cost effectiveness basis. Of the technically feasible BART alternatives considered for LOS Unit 2, data points for the CDS, the SDA and the FDA all lie distinctly above the least cost boundary of the control cost envelope. The reason for this is clear from Table 3.5-12 where the unit control costs for all of the BART alternatives are listed. In a top down analysis each of the SO_2 control technologies represented by a data point above the Dominant Control Curve could be excluded from further analysis on a cost effectiveness basis.

TABLE 3.5-12 – Unit Control Costs of Unit 2 BART SO_2 Control Alternatives

BART Alternative	Control Efficiency	Levelized Total Annual Cost ($2005)[1]	Annual Emission Reduction from Historical Case (tpy)	Historical Case Unit Control Cost ($/ton)	Annual Emission Reduction from Future PTE Case (tpy)	Future PTE Case Unit Control Cost ($/ton)
Wet FGD	95%	$29,840,000	35,568	$839	73,272	$407
CDS/FF	93%	$35,580,000	34,025	$1,046	71,729	$496
SDA/FF	90%	$32,890,000	31,711	$1,037	69,415	$474
FDA/FF	90%	$32,430,000	31,711	$1,023	69,415	$467
Fuel Switch	77%	$13,490,000	21,685	$622	59,620	$226

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

The next step in the cost effectiveness analysis for the remaining BART alternatives is to review the incremental cost effectiveness between a given alternative and those above or below it on the Dominant Controls Curve. Table 3.5-13 contains a repetition of the cost and control information from Table 3.5-11 and the incremental cost effectiveness between each dominant control alternative.

TABLE 3.5-13 – Incremental Cost Effectiveness of Unit 2 BART SO_2 Control Alternatives

BART Alternative	Levelized Total Annual Cost ($2005)(1)	Annual Emission Reduction from Historical Case (tpy)	Incremental Cost Effectiveness for Baseline Case ($/t)	Annual Emission Reduction from Future PTE Case (tpy)	Incremental Cost Effectiveness for Future PTE Case ($/t)
Wet FGD	$29,840,000	35,568	$1,380	73,272	$1,406
Fuel Switching	$13,490,000	21,685	NA	59,620	NA

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

In the BART Determination guidelines, EPA does not provide definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the Dominant Control Cost curve) between successively less effective alternatives. The incremental cost effectiveness for wet FGD versus fuel switching in Table 3.5-13 is within the range of reasonable costs used in other regulatory analyses and thus does not indicate that wet FGD is prohibitively expensive.

The cost analysis portion of the BART determination for LOS Unit 2 has shown that none of the Unit Control Costs for the dominant alternatives are exceedingly expensive on a Unit Control Cost basis. However, three of the BART alternatives were established as being inferior based upon the Dominant Controls Curve. Unlike the Unit 1 SO_2 BART analysis, the range of the estimated LTACs (± 20%) for Unit 2 post combustion controls approaches much closer to the estimate accuracy (± 30%). Similarly, the range for the post combustion control alternative Unit Control Costs (± 25%) is much closer to the estimate accuracy. For this reason, the Unit 2 cost impact analysis results were interpreted to indicate that further analysis for the recommended SO_2 BART for LOS Unit 2 should be limited to alternatives on the Dominant Control Curve.

Considering the results of the cost impact analysis for LOS Unit 2, fuel switching (77%) was identified as a significantly inferior alternative to presumptive BART. Further, the remaining alternative, wet FGD, achieving 95% SO_2 emission reduction equals presumptive BART and was the recommended alternative at the end of the cost impact analysis. Therefore, Basin Electric Power Cooperative decided that fuel switching should be excluded from further consideration in the study.

This decision leaves wet FGD as the sole SO_2 control alternative for LOS Unit 2 and meets the recommended presumptive BART for units of its size.

3.5.2 ENERGY IMPACTS

The energy impacts of wet FGD, both in terms of estimated kW of energy usage and the percent of total generation, are given in Table 3.5-14. The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps, blowers, booster fans, ball mills for limestone grinding and vacuum pumps for byproduct slurry dewatering. Building HVAC and interior and exterior lighting loads are also included, but the major energy consumption is due to the primary systems described above.

TABLE 3.5-14 – Energy Requirements of Unit 2 BART SO_2 Control Alternatives

BART Alternative	Energy Demand (kW)	Percent of Nominal Generation
Wet FGD	9,315	2.1%

3.5.3 NON-AIR QUALITY ENVIRONMENTAL IMPACTS

Non-air quality environmental impacts of the installation and operation of the various BART alternatives include hazardous waste generation, solid and aqueous waste streams, and salable products that could result from the implementation of various BART alternatives.

The captured mercury in the solid waste stream from a wet FGD system is a trace contaminant in the solid waste, not affecting disposal options as long as the waste passes the Toxic Characteristic Leaching Procedure (TCLP), which most FGD system wastes do. Therefore, this potential non-air quality environmental impact was not considered to warrant attention during this analysis.

The wet FGD system for LOS Unit 2 is estimated to produce approximately 28.3 tons per hour of solid wastes. The waste stream would be composed of gypsum solids and inerts at approximately 10% - 15% moisture. Over the course of a year, the total solid waste quantity is estimated to be approximately 248,000 tons of gypsum solids which would be landfilled in the current permitted solid waste disposal facility near the plant.

The annual quantity of aqueous waste that would be produced by the wet FGD system is difficult to quantify because the blowdown rate from a wet FGD system is primarily a function of the dissolved chloride levels in the absorber and recycle tank. Most of the chloride reaching the scrubber is in the form of hydrochloric acid which is readily absorbed and neutralized. Hydrochloric acid removal rates in a typical wet FGD system typically exceed 95%. CUECost estimates 80 lb/hr of hydrochloric acid in the flue gas stream which is assumed to be completely removed by the absorber system. The waste solids stream leaving the wet FGD system contains approximately 15% water which would contain $CaCl_2$ which would not require blowdown for disposal. Assuming the chloride to be present in the blowdown stream as $CaCl_2$ and assuming an average chloride concentration of 9,500 parts per million, one can calculate approximately 80 pounds an hour of chloride would leave the plant in the gypsum wastes. No blowdown specifically for chloride disposal would be required. For the purpose of this analysis, it was assumed that an irregular blowdown stream would be sent to a dedicated evaporation pond on site for disposal.

3.5.4 VISIBILITY IMPACTS

The final impact analysis conducted was to assess the visibility impairment impact reduction for the presumptive BART control level. Visibility impairment impacts due to pre-control historical emissions and post-control (future PTE) emission levels were modeled. CALPUFF was used to model long-range transport of SO_2, NO_X and PM to estimate the visibility impairment impact in deciViews (dV). The reduction in visibility impairment impact due to presumptive SO_2 BART (95% control) was then calculated as the difference between the visibility impairment impact for wet FGD and the pre-control visibility impairment impact.

The BART guidelines state that the comparison should be made at the 98th percentile level (70 FR 39170). However, NDDH directed that the comparison should be made at the 90th percentile. Therefore, the visibility impairment impact reduction presented for each control scenario in this section is based on the 90th percentile value.

CALPUFF modeling was conducted for the application of presumptive BART. The modeling results, expressed as the change in visibility impairment impact, in deciViews (ΔdV) is the change in visibility impairment impact in the affected Class 1 area as a result of the implementation of wet FGD on LOS Unit 2. The visibility improvement for the modeled case is given in Table 3.5-15 for each Class 1 Area. In addition to the average ΔdV values, three other types of data are presented in this table, the number of days exceeding 0.5 dV, the number of days exceeding 1.0 dV and the maximum number of consecutive days exceeding 0.5 dV after implementation of presumptive BART. The 0.5 dV value is the lowest visibility impairment impact that is considered discernible by the human eye and the EPA set this threshold as the point where a given source is considered a "contributing source" (70 FR 39120). The 1.0 dV threshold was established in the final rule as the threshold at which a state should consider a source to be a cause of visibility impairment (70 FR 39120). Therefore, the number of occurrences of each of these impacts is part of the visibility impairment impact analysis. The final criteria, the maximum number of consecutive days in which the visibility impairment impact exceeds 0.5 dV is also tabulated as this is a further measure of the extent of visibility impairment attributable to a given source.

The visibility impairment impact reduction attributable to the application of presumptive BART is given in column 2 of Table 3.5-15. This value is the 90th percentile visibility impairment impact reduction over each modeled year (2000-2002) for each affected Class 1 area. Column 3 of the table lists the three year average impact for each Class 1 Area. The Lostwood National Wildlife Refuge (Lostwood NWR) shows the greatest average visibility impairment impact reduction, thus indicating that this area will gain the greatest benefit from BART implementation of all the Class 1 Areas included in the modeling. The Teddy Roosevelt National Park, Elkhorn site (TRNP-Elkhorn) is shown to gain the least visibility impairment impact reduction from presumptive BART implementation.

A review of Table 3.5-15 finds that the visibility impairment impacts for presumptive BART vary with area and year of modeled results. The greatest number of days exceeding 0.5 dV in column 4 of Table 3.5-15 is shown graphically in Figure 3.5-2 for clarity. Both precontrol and postcontrol modeling results are presented to demonstrate the impact reduction achieved by presumptive BART implementation. The worst impact in terms of days exceeding 0.5 dV after BART implementation

TABLE 3.5-15 – Visibility Impairment Impacts – Unit 2

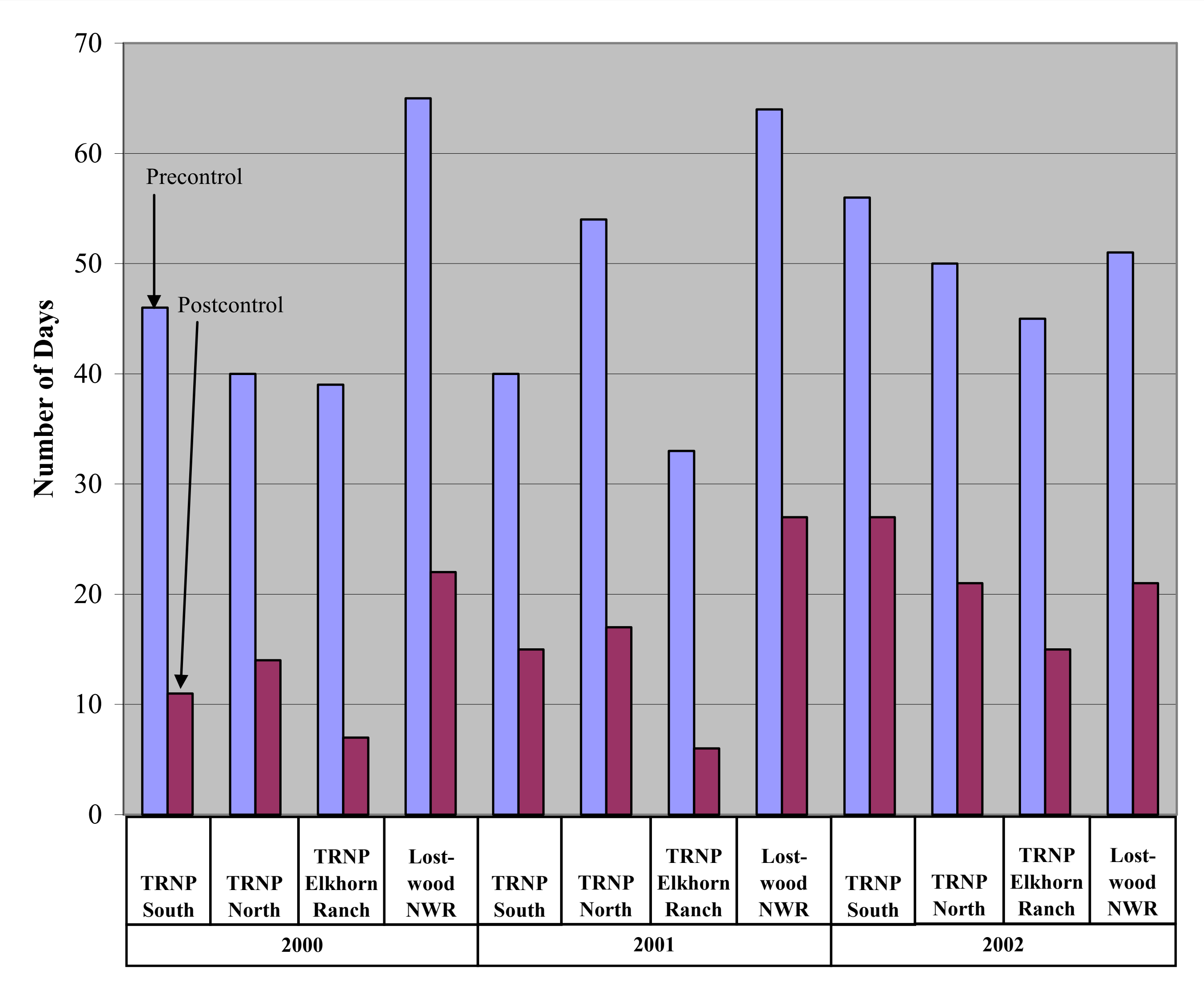
Year And Class 1 Area	Visibility Impairment Reduction (ΔdV)$^{(1),(2)}$	Three Year Average Visibility Impairment Reduction (Δ dV)	Days$^{(2)}$ Exceeding 0.5 dV	Days$^{(2)}$ Exceeding 1.0 dV	Consecutive Days$^{(2)}$ Exceeding 0.5 dV
2000					
TRNP South	0.496	0.586	11	4	2
TRNP North	0.535	0.578	14	6	1
TRNP Elkhorn	0.411	0.415	7	2	1
Lostwood NWR	0.802	0.694	22	6	2
2001					
TRNP South	0.438	0.586	15	2	2
TRNP North	0.646	0.578	17	5	2
TRNP Elkhorn	0.358	0.415	6	1	2
Lostwood NWR	0.693	0.694	27	12	3
2002					
TRNP South	0.825	0.586	27	15	3
TRNP North	0.549	0.578	21	14	3
TRNP Elkhorn	0.475	0.415	15	8	2
Lostwood NWR	0.587	0.694	21	5	3

(1) - 90th percentile visibility impairment impact reduction. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - All values in this table are for combination case of WFGD for SO_2 control and Advanced SOFA for NO_X control.

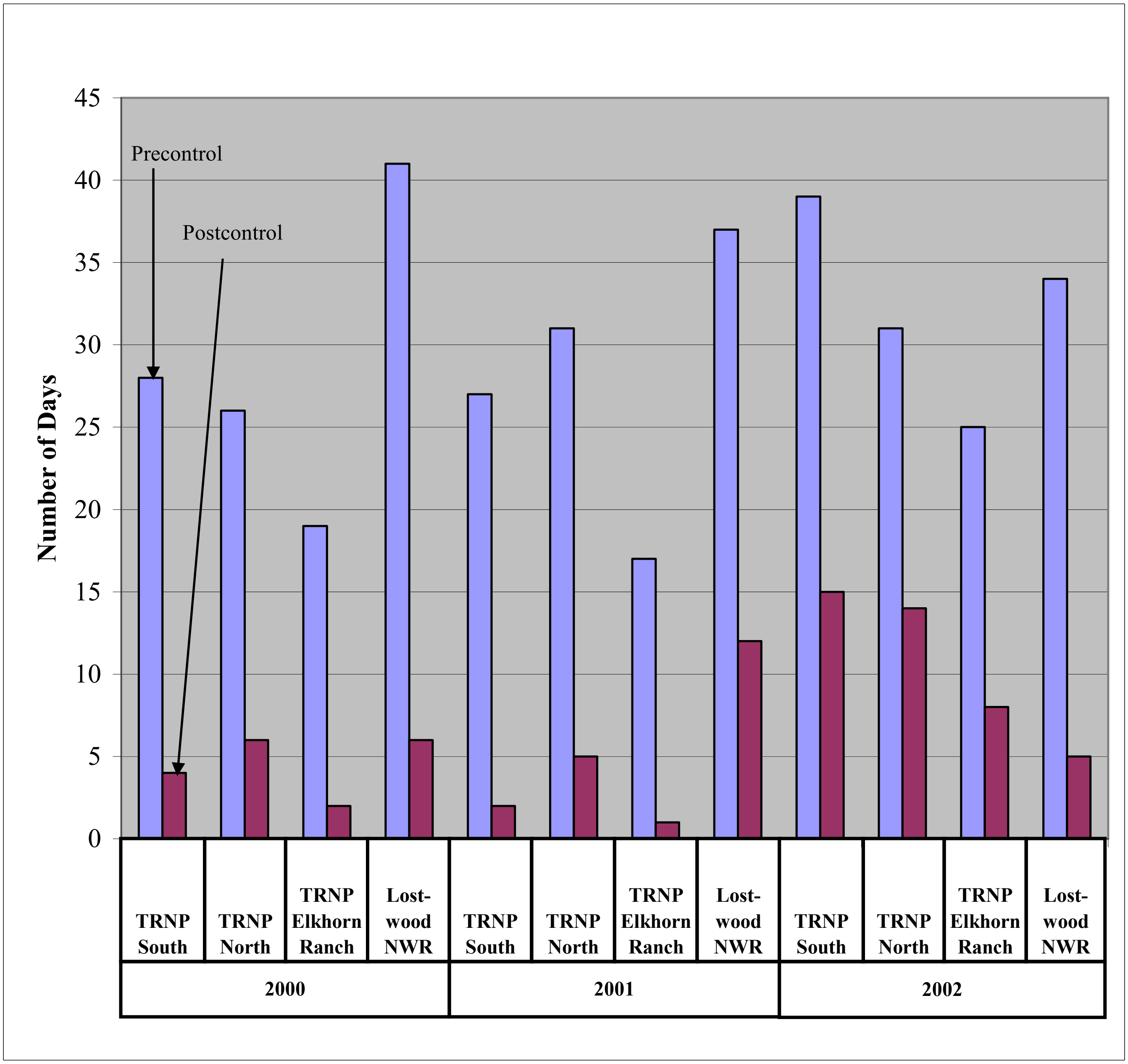
occurs at Lostwood NWR for model years 2000 and 2001. However, in 2002, the greatest number occurs at TRNP South. The TRNP Elkhorn Ranch site consistently exhibits the least number of days exceeding 0.5 dV after BART implementation.

FIGURE 3.5-2 – Number of Days Exceeding 0.5 dV for Pre- and Post-Control



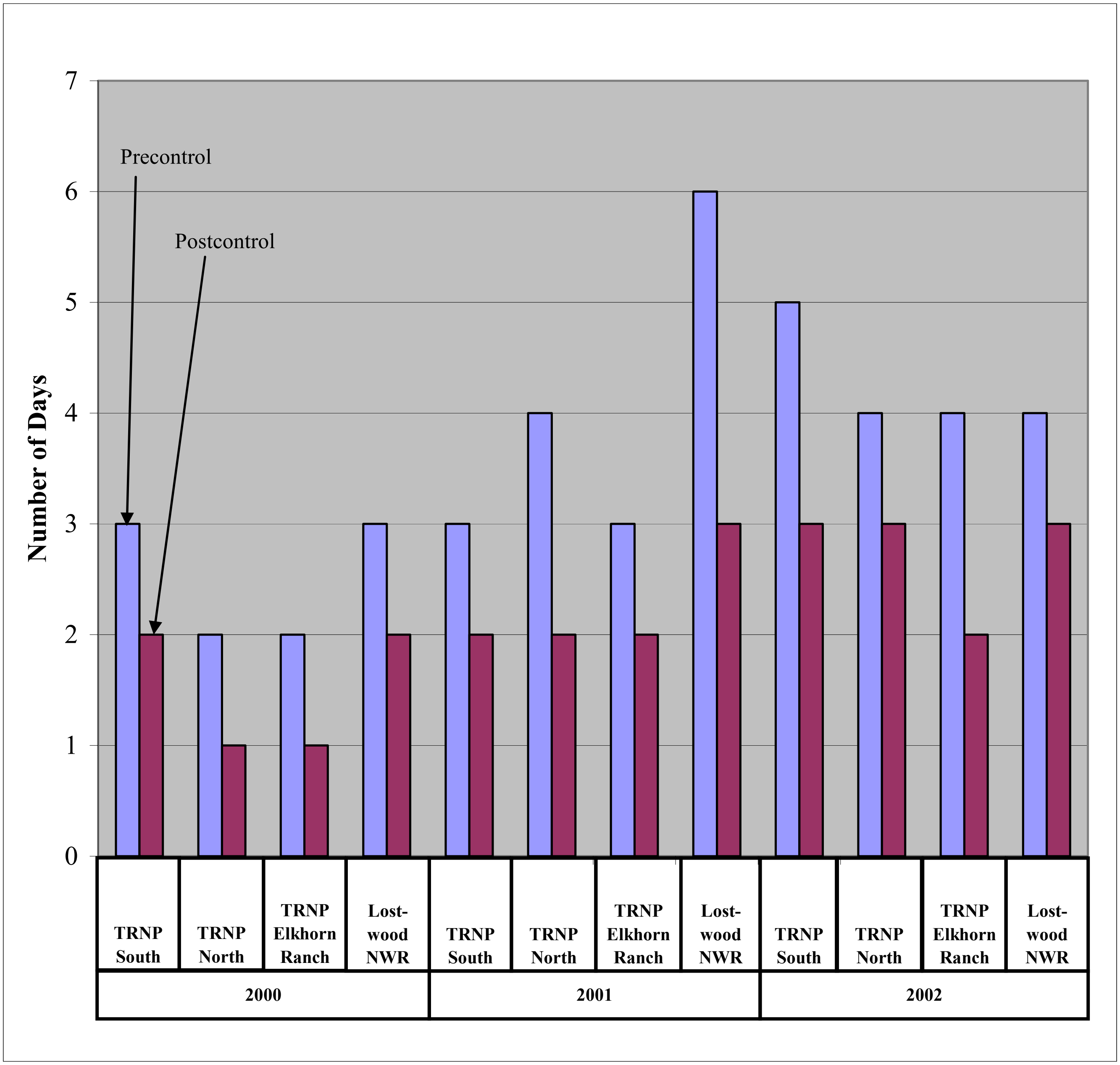
The number of days in a year where the modeled visibility impairment impact exceeded 1.0 dV are listed in column five of Table 3.5-15 and shown graphically in Figure 3.5-3. Both pre-control and post-control modeling results are presented to demonstrate the impact reduction achieved by presumptive BART implementation. The greatest number of days with at least 1.0 dV of impact occurs in both TRNP-North and Lostwood NWR in 2000, in Lostwood NWR in 2001 and TRNP-South in 2002. The least number of days with at least 1.0 dV of impact occurs in TRNP Elkhorn Ranch in 2000 and 2001 and in Lostwood NWR in 2002. This trend is similar to the one observed for the number of post BART implementation days with an impact exceeding 0.5 dV.

FIGURE 3.5-3 – Number of Days Exceeding 1.0 dV for Pre- and Post-Control



The greatest number of consecutive days exceeding 0.5 dV of impact is listed in column six of Table 3.5-15 and shown graphically in Figure 3.5-4. Both precontrol and postcontrol modeling results are presented to demonstrate the impact reduction achieved by presumptive BART implementation. The model year 2000 results are the same for TRNP-North and TRNP Elkhorn Ranch with only one day

FIGURE 3.5-4 – Maximum Consecutive Days Exceeding 0.5 dV for Pre- and Post-Control



occurrences. TRNP-South and Lostwood NWR tie for the highest number of consecutive days at two per year in 2000. The greatest number of consecutive days in 2001 occurs in Lostwood NWR at three days and two days per year for all TRNP sites. In 2002 the model predicts that TRNP-South, TRNP-North and Lostwood NWR would all experience the three consecutive days while the TRNP Elkhorn Ranch site would have only experienced two consecutive days that same year.

The total number of days where the visibility impairment impact exceeded 0.5 dV over the entire modeling period (2000-2002) is greatest for Lostwood NWR. Similarly, the total number of days where the impact exceeded 1.0 dV is greatest for TRNP-North over the model period and the maximum number of consecutive days with impacts greater than 0.5 dV is slightly greater for Lostwood NWR overall. The model results predict that the TRNP Elkhorn Ranch site would have experienced the least overall post BART implementation visibility impacts on all modeled sites.

A review of Table 3.5-15 and Figures 3.5-2 through 3.5-4 clearly demonstrates a significant visibility impairment reduction due to the implementation of presumptive BART (95% SO_2 control), regardless of model year and Class 1 area.

3.5.5 IMPACT SUMMARY

Section 3.5 of this report has analyzed the impacts of BART alternatives for LOS Unit 2. Table 3.5-16 summarizes the results of this analysis. At the conclusion of the cost impact analysis, it was determined that only two of the BART alternatives, wet FGD and fuel switching, were cost effective. The other three alternatives, CDS/FF, SDA/FF and FDA/FF were excluded from further analysis on a cost impact basis. Neither the Unit Control Costs for wet FGD and fuel switching, nor the marginal Unit Control Cost for wet FGD relative to fuel switching were unreasonable. Thus, it was determined that fuel switching at 77% control was clearly inferior to wet FGD as a BART alternative and fuel switching was also excluded from further analysis at the end of the cost analysis. Visibility impact analysis results were presented for the wet FGD alternative in Section 3.5.4. The impact analysis results for wet FGD are summarized in Table 3.5-16.

TABLE 3.5-16 – LOS Unit 2 Impacts Summary for SO_2 Control Alternatives

BART Alternative and Control Efficiency (%)	Annual Emissions Reduction (tpy)	Levelized Total Annual Control Cost ($2005)(1)	Unit Control Cost ($/tons)	Visibility Impairment Impact Reduction		Visibility Impairment Reduction Unit Cost ($/dV)	Energy Impact (kW)	Non Air Quality Impacts
				Class 1 Area	ΔdV(2)			
WFGD 95	73,272	$29,840,000	$407	TRNP-S	0.586	$50,920,000	9,315	Solid and Liquid Wastes
				TRNP-N	0.577	$51,720,000		
				TRNP-Elkhorn	0.415	$71,900,000		
				Lostwood NWR	0.694	$43,000,000		

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

(2) - Average three year change in visibility impairment impact between uncontrolled and controlled emissions for the Future PTE case with both WFGD and ASOFA.

SO_2 SECTION REFERENCES:

1. "Powder River Basin Coal Test at Leland Olds Station, Units 1 And 2"; Basin Electric Power Cooperative Internal Report; February, 1997.

2. http://www.state.nd.us/ndic/lrc-infopage.htm

3. "SO_2 Removal Efficiency Achieved in Practice by U.S. Electric Utility Semi-Dry FGD Systems"; Electric Utility Environmental Conference (EUEC); Weilert, C. and Randall, D.; Tucson, AZ; January 2006.

4. "Alstom Power's Flash Dryer Absorber For Flue Gas Desulfurization", Ahman, Barranger and Marin, Proceedings of IJPGC '02, June 24-26, 2002.

5. "Economics of Lime and Limestone for Control of Sulfur Dioxide"; DePriest, William & Gaikwas, Rajendra P. ; National Lime Association (www.lime.org/NLADryFGD.pdf); September, 2002.

6. "Use of a Circulating Fluid Bed for Flue Gas Desulfurization"' Toher, John, G. Lurgi-Lentjes N. America.

7. "K-Fuel™ Commercialization"; http://kfx.com.

8. "How much does K-Fuel™ cost"; http://kfx.com.

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4.0 PARTICULATE MATTER BART EVALUATION

The primary source of particulate matter (PM) associated with a coal-fired boiler is the ash from combustion of the coal. There is also unburned carbon present in the flue gas, which is the result of incomplete combustion that adds to the PM emissions. In this section, steps 1 through 5 of the BART determination for Leland Olds Station (LOS) Units 1 and 2 are described for PM. All PM control technologies are first identified. A technical description of the processes and their capabilities are then reviewed to determine availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal PM control capability. The impacts analysis then reviews the estimated cost, energy, and non-air quality impacts for each technology. The impact of the remaining useful life of the source was reviewed as part of the cost analysis. In the final step of the analysis, the remaining technologies were assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the complete analyses are tabulated and possible BART control options are listed.

The quantity of uncontrolled PM emissions is a strong function of the type of boiler utilized. Different boiler types generate different splits between bottom ash, which is collected in the bottom of the boiler, and fly ash, which is entrained in the flue gas and becomes boiler particulate matter emissions. Unit 1 is a wall-fired, dry-bottom, pulverized coal boiler with a bottom ash/fly ash split of 30/70 respectively. Unit 2 is a cyclone-fired unit burning crushed coal, with a bottom ash/fly ash split of 70/30 respectively. The design parameters, including coal analysis, unit type, unit size, etc., used in this analysis are displayed in Tables 1.2-1 and 1.2-2.

The BART guidelines published in the Federal Register on July 6, 2005 (70 FR 39104) do not specify presumptive BART levels for particulate matter (PM) emissions. The guidelines suggest the use of PM_{10} as the indicator for all $PM_{2.5}$, because $PM_{2.5}$ emissions are encompassed within the PM_{10} emissions fraction. (70 FR 39160) For modeling purposes, both the BART guidelines and the NDDH protocol specify that a distinction between coarse (PM_{10} minus $PM_{2.5}$) or fine ($PM_{2.5}$) PM be used to determine visibility impacts. The distinction between course and fine particulate was made during CALPUFF visibility modeling.

The BART guidelines indicate that one of the evaluated emission limits must be at least as stringent as the New Source Performance Standard (NSPS) requirement for the source (70 FR 39164). The PM emission limit under NSPS that most closely relates to LOS is 0.1 lb/mmBtu. Therefore, for the purpose of this report, at least one of the evaluated control technologies achieves a PM emission level of 0.1 lb/mmBtu.

4.0.1 FILTERABLE AND CONDENSABLE PARTICULATE MATTER

Particulate matter emissions are composed of filterable and condensable particles. The filterable particles are characterized using EPA standard reference methods (i.e., Method 5, 17, 201, or 201A) and are commonly referred to as the front-half of the particulate sample train. The reference method used for characterization is dependent upon the size of the particle, the temperature of the flue gas, and is usually specified in the applicable permit. Solid particles are captured using a heated filter while the majority of condensable particles are not collected as they are in the gaseous form until after the flue gas has passed through the filter.

As flue gas moves through the different processes associated with each unit, condensable particulate matter (condensable PM) may react with atmospheric or flue gas constituents and then either condense into a droplet, coalesce into a solid particle, or form a solid particle as more volatile components evaporate. Condensable PM is characterized using EPA standard reference Method 202 which is commonly referred to as the back-half of the particulate sampling train. Using Method 202, the flue gas passes through a heated filter to remove filterable PM and condensable flue gas constituents are condensed by bubbling them through water at 20^{o}C. The water is evaporated and the remaining residue is weighed to determine condensable PM emissions. However, Method 202 has an inherent flaw because the means by which condensable particulate is collected differs from how particulate condenses in the stack. Method 202 can provide inaccurate measurements due to the creation of PM artifacts in the sampling water that would not normally condense in the stack plume (e.g., SO_2 and NH_3 compounds). For a fixed operating condition, Method 202 can provide inconsistent emission rate measurements and can result in high emission rates. Thus, there is considerable uncertainty surrounding emissions measured with Method 202 for the purpose of compliance demonstration.

Condensable PM may include both organic and inorganic constituents. Organic constituents in the flue gas can exist as a vapor at stack temperatures and a liquid or solid at ambient temperatures. Control technologies designed to minimize the formation of condensable organic emissions are the same technologies that are used to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions. A review of the RBLC database shows that good combustion practices are universally used to control CO/VOC emissions for similar units. Both LOS units already practice good combustion practices while maintaining combustion efficiency in the boiler and controlling NO_X emissions. Because good combustion practices are already in use at both units, the organic portion of condensable PM is not addressed further in this report.

Sulfuric acid (H_2SO_4) mist is the most widely recognized form of inorganic condensable PM emitted by combustion sources. Other inorganic condensable PM constituents may include to a lesser extent other acid gases, ammonium sulfate ($(NH_4)_2SO_4$), and unidentified inorganic species. Control technologies designed to reduce sulfuric acid mist will also reduce the other inorganic constituents. H_2SO_4 is typically generated in the flue gas when sulfur trioxide (SO_3) reacts with water. SO_3 is a by-product created during the combustion of fuels containing sulfur and is formed when sulfur dioxide (SO_2) in the flue gas is oxidized. Limited data is available on the quantity of SO_2 that will be converted to SO_3 in a lignite fired unit. Estimates of the conversion range from 0.2 to 1.0 percent.

Combustion controls commonly used to control NO_X (e.g., staged combustion and separated overfire air) provide a co-benefit of sulfuric acid mist control by limiting the oxygen available in the boiler and reducing formation of SO_3 in the boiler. The H_2SO_4 vapor will adsorb on the fly ash as the flue gas cools under appropriate temperature and moisture conditions. Consequently, when those conditions exist, H_2SO_4 mist is removed from the gas stream by particulate control equipment. Control technologies designed to remove SO_2 will also achieve SO_3 removal and reduce emissions of H_2SO_4. Typical SO_3 removal associated a wet FGD process is 40 to 60 percent and higher for semi-dry FGD processes. The Southern Company estimates a 50% reduction in H_2SO_4 emissions for use of wet FGD.[1] Thus, control technologies used to control NO_X through combustion controls, SO_2 through a FGD process and filterable PM through a device to be analyzed in this section of the report are also able to provide H_2SO_4 control.

Under Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA), industrial facilities such as LOS must submit information to the State about the annual release of certain chemicals. Three of the main constituents of inorganic condensable PM are included in the chemicals that must be reported. Sulfuric acid mist, hydrogen chloride and hydrogen fluoride are the reported constituents that make up the majority of inorganic condensable PM emissions. During the period from 2000 to 2004 under EPCRA, utilizing the Southern Company estimating procedures, LOS reported a maximum annual condensable particulate release of 0.0029 lb/mmBtu and 0.0025 lb/mmBtu for Unit 1 and Unit 2 respectively. For the same time period LOS reported in their Annual

Emission Inventory report, the average front half particulate emission of 0.027 and 0.032 lb/mmBtu for Unit 1 and Unit 2 respectively. Therefore the total PM Emissions including PM_{10}, $PM_{2.5}$, HCL, HF and H_2SO_4 were approximately 0.030 and 0.034 lb/mmBtu respectively.

Based upon a review of the RACT/BACT/LAER database, the emission limit associated with the current Best Available Control Technology (BACT) for PM from new EGUs, including condensable PM, is approximately 0.03 lb/mmBtu. Because condensable PM is controlled through technologies that will be in place for NO_X, SO_2 and PM, the actual release of the main constituents of inorganic condensable PM are expected to be reduced by a minimum of 50% from the installation of SO_2 controls on each unit.

Recommended BART for condensable PM is the co-benefit of NO_X control through combustion controls, SO_2 control through a FGD process and filterable PM control through a device to be analyzed in this section of the report and is not addressed further. Therefore this BART analysis investigates control methods to reduce filterable PM emissions only.

4.1 IDENTIFICATION OF AVAILABLE RETROFIT PM CONTROL TECHNOLOGIES

The initial step of the BART determination is the identification of available retrofit PM control technologies. In order to produce a list of control technologies and their estimated capabilities, sources such as the RACT/BACT/LAER Clearinghouse (RBLC) were used. The results of the investigation determined that the removal of PM from flue gas is accomplished using post combustion technology. The two most common post combustion technologies used to control PM emissions include fabric filters (FF) and electrostatic precipitators (ESPs). The existing LOS configurations contain ESPs with each control technology rated at 99.1% control. Table 4.1-1 contains the results of the available PM control technologies.

TABLE 4.1-1 – PM Control Technologies Identified for BART Analysis

Control Technology	Approximate Control Efficiency
Fuel Switching with Flue Gas Conditioning w/ ESP	99.1%
Fabric Filter or Baghouse	99.7%
COHPAC Baghouse	99.7%
New Electrostatic Precipitator	99.7%
Existing Unit 1 Electrostatic Precipitator	99.5%
Existing Unit 2 Electrostatic Precipitators	99.1%

4.2 TECHNICAL DESCRIPTION AND FEASIBLITY ANALYSIS

The second step in the BART analysis procedure is a technical feasibility analysis of the options identified in Step 1. This analysis is presented below for each identified option.

4.2.1 FUEL SWITCHING WITH FLUE GAS CONDITIONING

Fuel switching along with flue gas conditioning is a viable method of reducing particulate matter emissions in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. In the case of LOS, the boilers were designed and constructed specifically for firing North Dakota lignite, which is a low Btu content, high ash, high moisture, and medium sulfur content fuel. For this analysis, fuel switching would consist of changing from North Dakota lignite to Powder River Basin (PRB) coal. Technical characteristics associated with fuel switching are described in Appendix C1.

Fly ash conditioning methods installed upstream of an ESP usually involve the injection of a chemical into the flue gas stream to reduce the electrical resistivity of the fly ash. The PRB coal being evaluated with this option contains low concentrations of sulfur (0.43%) while the ash has a relatively high concentration of calcium oxide (24.6%). The low sulfur content and the high alkaline ash both contribute to high resistivity. The low sulfur content limits the amount of sulfur trioxide that is formed while the calcium oxide will preferentially react with the acid and form a non-conducting ash. Therefore, this analysis assumed that flue gas conditioning would be required as part of any fuel switching option.

The most common types of flue gas conditioning systems for this application include humidification of the flue gas, sulfur trioxide injection, ammonia injection, or a combination of these conditioning methods. Because most, if not all, of the humidification process used for flue gas conditioning on

PRB coal have been replaced with another type of conditioning system, humidification was not evaluated in this analysis. Considering the size of the ESPs installed on both LOS units, it was assumed that sulfur trioxide injection alone could effectively reduce the resistivity of the ash and ammonia injection was not evaluated in this analysis.

Switching to a fuel such as PRB and adding a flue gas conditioning system to achieve lower PM emission rates would achieve approximately 50% reduction in PM emissions prior to particulate controls. Assuming that the control efficiency of the existing ESPs when firing PRB coal can be restored by adding a flue gas conditioning system, fuel switching was considered a viable option for PM control.

4.2.2 FABRIC FILTER (FF)

A fabric filter or baghouse removes particulate by passing flue gas through filter bags. A pulse-jet fabric filter (PJFF), a common type of fabric filter, consists of isolatable compartments and a tube sheet which separates the particulate laden flue gas from the clean flue gas. The flue gas passes through the PJFF by flowing from the outside of the bag to the inside up the center of the bag through the hole in the tube sheet and out the PJFF. Fly ash particles are collected on the outside of the bags and the cleaned gas stream passes through the bag to the outlet of the fabric filter. Each filter bag alternates between relatively long periods of filtering and short periods of cleaning. During the cleaning period, fly ash that has accumulated on the bags is removed by pulses of air and falls into a hopper for disposal. Additional technical characteristics associated with fabric filters are described in Appendix C1.

Fabric filters have been proven to control PM with removal efficiency in excess of 99%. It is anticipated that the use of fabric filters on LOS could achieve a filterable PM emission rate of approximately 0.015 lb/mmBtu. Therefore, the use of a fabric filter is a technically feasible option.

4.2.3 COHPAC

A COmpact Hybrid PArticulate Collector (COHPAC) is a high air-to-cloth ratio pulse jet fabric filter located downstream of an existing ESP. The COHPAC acts as a polishing device for control of particulate emissions. The difference between a COHPAC and the fabric filter described above is that a COHPAC is installed after an ESP. The ESP prior to the COHPAC will remove the majority of the fly ash. This allows the COHPAC to have a higher air-to-cloth ratio than a typical fabric filter. The air-to-cloth ratio for a COHPAC unit is typically greater than or equal to 6 ACFM/ft^2 while the air-to-cloth ratio for a typical pulse jet fabric filter is approximately 3.5 to 4.0 ACFM/ft^2.

The advantages and disadvantages of a COHPAC are similar to those mentioned for a fabric filter above; however, there are a few differences worth mentioning. Because the COHPAC has a higher air-to-cloth ratio, it is smaller and less costly than a conventional PJFF. However, the operation of the COHPAC is dependent upon continued operation and maintenance of the ESP.

COHPAC units have been proven to control PM removal efficiencies in excess of 99%. It is anticipated that for LOS Unit 1 or Unit 2, an installed COHPAC could achieve a filterable PM emission rate of 0.015 lb/mmBtu. Therefore, the use of a COHPAC is a technically feasible option.

4.2.4 ELECTROSTATIC PRECIPITATOR (ESP)

ESPs are commonly used as the primary filterable PM control device on coal fired units. The ESP discharge electrodes generate a high voltage electrical field that gives the particulate matter an electric charge (positive or negative). The charged particles will then be collected on a collection plate. Technical characteristics associated with ESPs are described in Appendix C1.

ESPs have proven to control PM in excess of 99%. It is anticipated that a new ESP installed for either unit at LOS could achieve a PM emission rate of approximately 0.015 lb/mmBtu. Therefore, the use of a new electrostatic precipitator is a technically feasible option.

Unit 1 at LOS has an existing ESP that is an older design which achieves lower removal efficiency than a new ESP. The existing ESPs can achieve a filterable PM emission rate of 0.1 lb/mmBtu. Therefore, the existing ESP is a technically feasible option.

Unit 2 at LOS has two parallel existing ESPs that are of an older design which achieves slightly lower removal efficiency than a new ESP. The existing ESPs can achieve a combined filterable PM emission rate of 0.1 lb/mmBtu. Therefore, the existing ESPs are a technically feasible option.

The results of the feasibility analysis for the available BART alternatives following the feasibility analysis are summarized in Table 4.2-1. Every alternative was identified as commercially available, in service on the same or similar services and technically applicable to LOS Units 1 & 2 in a retrofit situation.

TABLE 4.2-1 – BART PM Control Feasibility Analysis Results

Control Technology	In Service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable to Leland Olds Station
Fabric Filter	Yes	Yes	Yes	Yes
COHPAC	Yes	Yes	Yes	Yes
Fuel Switching with Flue Gas Conditioning	Yes	Yes	Yes	Yes
New ESP	Yes	Yes	Yes	Yes
Existing ESPs	Yes	NA	NA	Yes

4.3 RANK OF TECHNICALLY FEASIBLE PM CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis procedure is to rank the technically feasible alternatives. The BART alternatives remaining in consideration following the feasibility analysis are listed in Table 4.3-1, ranked according to their effectiveness in PM control.

TABLE 4.3-1 – PM Control Technologies Identified for BART Analysis

Control Technology	PM Emission Capability (lb/mmBtu)
COHPAC	0.015
Fabric Filter	0.015
New ESP	0.015
Fuel Switching with Flue Gas Conditioning	0.054
Existing Unit 1 ESP	0.10
Existing Unit 2 ESP	0.10

4.4 EVALUATION OF IMPACTS FOR FEASIBLE PM CONTROLS – UNIT 1

Step four in the BART analysis procedure is the impact analysis. The BART determination guidelines (70 FR 39166) list four factors to be considered in the impact analysis. This BART Determination will consider the following four factors in the impact analysis:

- The costs of compliance;
- Energy impacts;

- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four factors considered in the impact analysis are discussed in the following sections. The factor for the remaining useful life of the source is incorporated as part of the cost of compliance. In addition, as described in Section 1.1.6, the visibility impairment impacts are to be evaluated as part of the analysis. Thus, visibility impairment is included as part of the impacts analysis.

4.4.1 COST OF COMPLIANCE

Cost estimates for all of the Unit 1 particulate control technologies except fuel switching with flue gas conditioning were conducted utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the U.S. Environmental Protection Agency. A description of the CUECost model is in Section 3.4.1 of this report. Operating information utilized as input into the model for the purpose of estimating the cost of the particulate control technologies is listed in Table 1.2-1 and 1.2-2. Economic information utilized as input into the model is given in Table 1.2-3. Economic information was provided in 2004 by BEPC in 2004 dollars. The model was run with 2004 designated as the cost basis year because equipment cost estimating in the model is based on the Chemical Engineering Cost Index and the composite 2004 index is the latest version available. Following completion of the estimating with a 2004 cost basis year, all costs were escalated to a 2005 basis year utilizing the inflation rates designated in Table 1.2-3. Burns & McDonnell added estimated Balance of Plant (BOP) costs not included in the CUECost output to the base estimate to provide a more complete cost estimate.

The cost estimate for fuel switching with flue gas conditioning was obtained from vendor quotes. The estimate in this report only includes capital costs for the flue gas conditioning system and does not include any capital costs for fuel switching. As mentioned in Section 3.4.1 of this report, potential rail line modifications may be required to fully implement the fuel switching alternative, but no capital expenditures were included in the report for these modifications. Therefore, all of the costs associated with fuel switching were assumed to be operating and maintenance costs, which are discussed in the Operating and Maintenance Costs section.

4.4.1.1 CAPITAL COSTS

The capital cost estimate is comprised of direct costs and indirect costs. The direct costs for each technology except the flue gas conditioning system include the particulate control system, ash handling system, booster fan, instrument and controls, and balance of plant costs. The particulate control system cost is representative of a typical furnish and erect contract cost by a fabric filter or ESP system supplier. The particulate control system cost estimated by CUECost is broken down into the major subsystems consisting of fabric filter or ESP, ash handling system, booster fan, and instrumentation and controls. It should be noted that a booster fan would not be required for a new ESP as the existing ID fan is sufficient. BOP costs include the electrical subcontract.

The electrical subcontract estimate includes the electrical equipment, materials and labor for engineering, procurement and installation of all electrical distribution system components. The electrical estimate is based on recent experience with the LOS plant and local costs developed during a recent electrical upgrade project at LOS.

The capital cost estimate for the flue gas conditioning system includes the dry sulfur unloading station, dry sulfur storage hopper, transfer conveyance from storage hopper to sulfur melter, sulfur metering pump skid with MCC & variable speed drives, SO_3 production skid, and injection probes with metering ports. The existing ESP would be utilized with this option.

The indirect costs are estimates of additional costs expected to be incurred during fabrication, construction, startup and commissioning. Engineering costs are estimated as a percentage of total direct costs and are representative of the cost for architectural/engineering services such as system design, specification production, contract evaluations and negotiations, contract administration and construction field services. The contingency is estimated as a percent of the total direct costs and accounts for miscellaneous scope items not covered by the direct cost estimate. Finally, the BEPC indirect costs are an estimation of the internal costs that would be incurred by BEPC for a project. The results of the capital cost estimate are given in Table 4.4-1, Table 4.4-2, Table 4.4-3, and Table 4.4-4. The option to utilize the existing ESP does not require any capital expenditure so it is not shown.

TABLE 4.4-1 – Capital Cost Estimate for LOS Unit 1 Fabric Filter

Direct Costs	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
Fabric Filter	$10,810,000	$1,620,000	$12,440,000
Bags	$1,640,000	$250,000	$1,880,000
Ash Handling System	$1,200,000	$180,000	$1,380,000
Booster Fan	$1,390,000	$210,000	$1,600,000
Instruments & Controls	$290,000	$40,000	$330,000
BOP Subcontract	$690,000	NA	$690,000
		Total Direct Cost =	**$18,320,000**
INDIRECT COSTS		Contingency (20% of DC)	$3,660,000
		A/E Engineering and Construction Management (10% of DC)	$1,830,000
BEPC INDIRECTS		Project Development (1% of DC)	$180,000
	Spare Parts & Plant Equipment		
		Initial Inventory Spare Parts (1.5% of DC)	$270,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$90,000
		Construction All-Risk Insurance (1.5% of DC)	$270,000
		Allowance For Funds During Construction (AFDC 6%)	$1,100,000
		Contingency (15% of BEPC Indirects)	$120,000
		Indirect Cost Subtotal	$7,520,000
		Total Capital Cost	**$25,840,000**

TABLE 4.4-2 – Capital Cost Estimate for LOS Unit 1 New ESP

Direct Costs	Estimated Cost ($2003)	General Facilities Markup (15%)	Total Direct Cost
ESP	$11,680,000	$1,750,000	$13,430,000
Foundations	(resuse existing)		
Ash Handling System	$4,310,000	$650,000	$4,960,000
Instruments & Controls	$330,000	$50,000	$380,000
BOP Subcontract	$690,000	NA	$690,000
		Total Direct Cost =	$19,460,000
INDIRECT COSTS		Contingency (20% of DC)	$3,890,000
		A/E Engineering and Construction Management (10% of DC)	$1,950,000
BEPC INDIRECTS		Project Development (1% of DC)	$190,000
	Spare Parts & Plant Equipment		
		Initial Inventory Spare Parts (1.5% of DC)	$290,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$100,000
		Construction All-Risk Insurance (1.5% of DC)	$290,000
		Allowance For Funds During Construction (AFDC 6%)	$1,170,000
		Contingency (15% of BEPC Indirects)	$130,000
		Indirect Cost Subtotal	$8,010,000
		Total Capital Cost	**$27,470,000**

TABLE 4.4-3 – Capital Cost Estimate for LOS Unit 1 COHPAC

Direct Costs	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
COHPAC	$5,710,000	$860,000	$6,570,000
Foundations	(Included above)	(Included above)	
Bags	$860,000	$130,000	$990,000
Ash Handling System	$1,090,000	$160,000	$1,250,000
Booster Fan	$1,260,000	$190,000	$1,440,000
Instruments & Controls	$170,000	$30,000	$200,000
BOP Subcontract	$690,000	NA	
		Direct Cost Total	**$11,140,000**
INDIRECT COSTS		Contingency (20% of DC)	$2,230,000
		A/E Engineering and Construction Management (10% of DC)	$1,110,000
BEPC INDIRECTS		Project Development (1% of DC)	$110,000
		Spare Parts & Plant Equipment	
		Initial Inventory Spare Parts (1.5% of DC)	$170,000
		Construction Startup and Support	
		O&M Staff Training (0.5% of DC)	$60,000
		Construction All-Risk Insurance (1.5% of DC)	$170,000
		Allowance For Funds During Construction (AFDC 6%)	$670,000
		Contingency (15% of BEPC Indirects)	$80,000
		Indirect Cost Subtotal	$4,600,000
		Total Capital Cost	**$15,740,000**

TABLE 4.4-4 – Capital Cost Estimate for LOS Unit 1 Fuel Switching with Flue Gas Conditioning

Direct Costs	Estimated Cost ($2005)
Injection System	$969,000
Unloading Station	(Included Above)
Storage Hopper	(Included Above)
Transfer Conveyor	(Included Above)
Metering Pump Skid	(Included Above)
SO_3 Production Skid	(Included Above)
Injection Probes	(Included Above)
Total Direct Cost	**$969,000**
INDIRECT COSTS Contingency (20% of DC)	$194,000
A/E Engineering and Construction Management (10% of DC)	$97,000
BEPC INDIRECTS Project Development (1% of DC)	$10,000
Spare Parts & Plant Equipment	
Initial Inventory Spare Parts (1.5% of DC)	$15,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$5,000
Construction All-Risk Insurance (1.5% of DC)	$15,000
Allowance for Funds During Construction (AFDC, 6%)	$58,000
Contingency (15% of BEPC Indirects)	$7,000
Indirect Cost Subtotal	$401,000
Total Capital Cost	**$1,370,000**

4.4.1.2 OPERATING AND MAINTENANCE COSTS

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). These costs except for fuel switching with flue gas conditioning were developed as part of the CUECost model and include operating labor, administrative and support labor and maintenance.

The fixed costs include maintenance costs. The maintenance cost was estimated as approximately 1.35% of the sum of the total direct cost.

The annual variable cost for the fabric filter and COHPAC is the auxiliary power costs plus the cost of 1/3 of a total bag replacement. The 1/3 is derived from the estimated three year bag filter life. The variable costs for the existing ESP consist solely of the auxiliary power cost.

The annual variable cost for the fuel switching with flue gas conditioning consists of the fuel cost change, reduced station service, change in ash disposal cost and reagent cost for the flue gas conditioning system. Section 3.4.1.11 of this report contains a description of the variable annual O&M costs associated with fuel switching.

The fixed and variable costs of the existing ESP were also included in the evaluation. The existing ESP would no longer function if a fabric filter or new ESP were installed. Therefore, the O&M costs associated with the existing ESP are shown as negative costs for those alternatives that would result in the replacement of the ESP. However, if a COHPAC unit or fuel switching with flue gas conditioning were utilized, the O&M costs of the existing ESP would not constitute a new cost and thus would not appear in those cost estimates.

The annual O&M cost estimate for each of the particulate control alternatives is summarized in Table 4.4-5.

TABLE 4.4-5 – Annual O&M Cost Estimates for Unit 1 PM Control Alternatives

	FF	NEW ESP	COHPAC	Fuel Switching with Flue Gas Conditioning
Fixed Costs				
Maintenance Costs	$262,000	$279,000	$160,000	$13,000
Existing ESP Maintenance Costs	($91,000)	($91,000)	$0	$0
Total Fixed O&M Costs	**$171,000**	**$188,000**	**$160,000**	**$13,000**
Variable Costs				
Bag Replacement	$279,000	NA	$147,000	NA
Auxiliary Power	$565,000	$180,000	$520,000	(included below)
Auxiliary Power (Existing ESP)	($179,000)	($179,000)	$179,000	$0
Auxiliary Power & Reagent				$109,000
Fuel Cost Change				$4,796,000
Reduced Station Service				($292,900)
Change in Ash Disposal Cost				($369,100)
Total Variable O&M Costs	**$665,000**	**$1,000**	**$846,000**	**$4,243,000**
Total Annual O&M Costs	**$836,000**	**$189,000**	**$1,006,000**	**$4,256,000**
Net Annual O&M Costs ($/MWh)	**$0.43**	**$0.098**	**$0.52**	**$2.20**

4.4.1.3 LEVELIZED TOTAL ANNUAL COST RESULTS

In order to effectively compare the cost of installing, operating and maintaining each of the particulate control systems capital and O&M costs need to be evaluated on a levelized basis. The levelized costs and associated PM emissions are shown in Table 4.4-6.

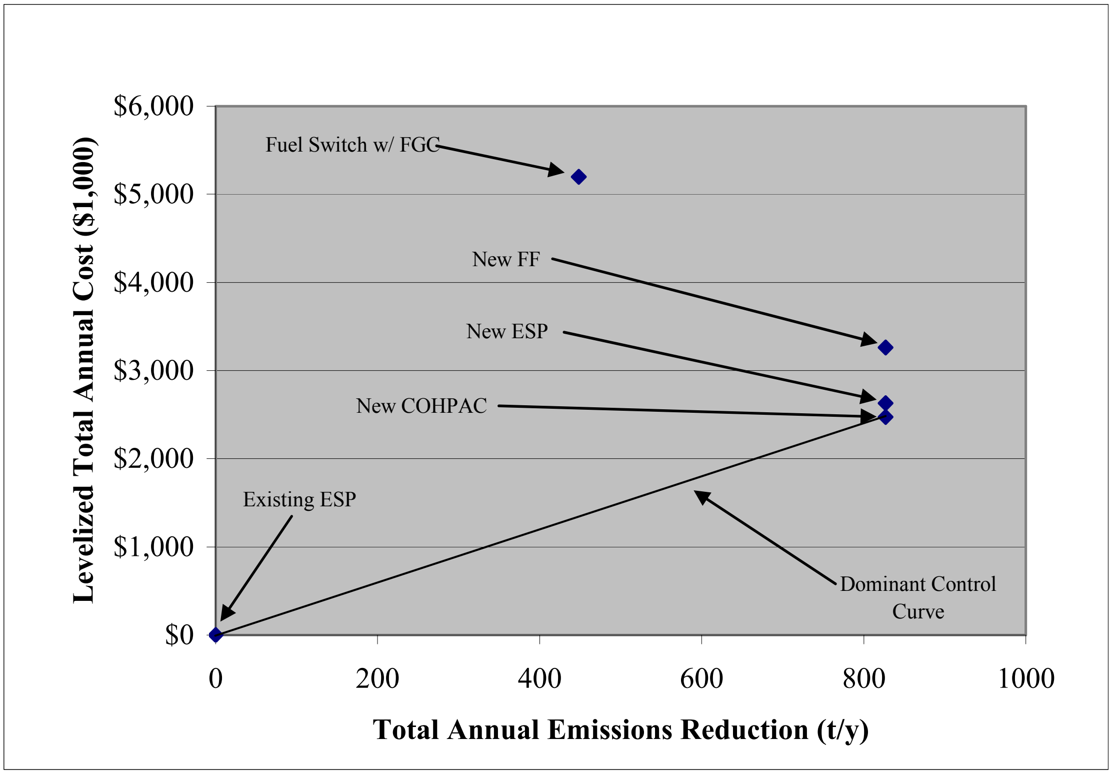
TABLE 4.4-6 – Levelized Total Annual Costs of Unit 1 BART PM Control Alternatives

	Emissions		Economic Impacts			
PM Control Alternative	**Emission Rate (lb/mmBtu)**	**Emission Reduction[1] (tons/yr)**	**Installed Capital Cost ($2005)**	**Annual O & M Cost ($2005)**	**Levelized Total Annual Cost ($2005/yr)**	**Unit Control Cost ($/ton)**
FF	0.015	827	$25,840,000	$836,000	$3,260,000	$3,940
New ESP	0.015	827	$27,470,000	$189,000	$2,630,000	$3,180
COHPAC	0.015	827	$15,740,000	$1,006,000	$2,473,000	$2,990
Fuel Switch with Flue Gas Conditioning	0.054	448	$1,370,000	$4,256,000	$5,197,000	$11,600
Existing ESP	0.100	Baseline	Baseline	Baseline	Baseline	Baseline
[1] Annual emissions are based on Future PTE case.						
					Life, years	20
					Cost of Money, %	6%
					Capital Recovery Factor	0.08718
					Conversion Tax (FF), $	7,947
					Conversion Tax (New ESP), $	7,949
					Conversion Tax (COHPAC), $	7,516
					O &M Levelization Factor	1.19314

Figure 4.4-1 is a plot of the Levelized Total Annual Cost (LTAC) for each alternative versus the annual removal in tons. The purpose of Figure 4.4-1 is to identify the Dominant Controls Curve, which is the rightmost boundary of the control cost envelope. The Dominant Controls Curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual removal tonnage for the various BART alternatives. Points distinctly to the left of this curve are inferior control alternatives on a cost effectiveness basis. The existing ESP was chosen as the baseline for both LTAC and annual emissions. Therefore, the existing ESP is shown graphically as not having any emission reduction benefits or any added cost.

Of the technically feasible BART alternatives considered for LOS Unit 1 the data point for the fuel switching with flue gas conditioning lies distinctly above the least cost boundary of the control cost envelope. This chart also clearly shows that the new FF and new ESP alternatives are inferior to a COHPAC as all three of these options can achieve the same emissions reduction, but the FF and ESP both have greater LTAC. The reason for this is clear from Table 4.4-6 where the unit control costs for all of the BART alternatives are listed. Considering the small cost difference between new ESP and COHPAC and the accuracy of the cost estimates, both technologies should be considered equivalent. In a BART analysis each of the PM control technologies represented by a data point above the Dominant Control Curve could be excluded from further analysis on a cost efficiency basis. Therefore, the fuel switching with flue gas conditioning, FF and new ESP options are not considered cost effective PM control alternatives for LOS Unit 1 and could be excluded from further analysis.

FIGURE 4.4-1 – LOS Unit 1 Least Cost Envelope for PM Control Alternatives



The next step in the cost effectiveness analysis for the remaining BART alternatives is to review the incremental cost effectiveness between a given alternative and those above and below it on the Dominant Control Curve shown in Figure 4.4-1. The incremental cost effectiveness is the slope of a line between any two adjacent points on the Dominant Controls Curve as shown in Figure 4.4-1. Table 4.4-7 contains a repetition of the cost and control information from Table 4.4-6 and the incremental cost effectiveness between the successive set of alternatives.

TABLE 4.4-7 – Incremental Cost Effectiveness of Unit 1 BART PM Control Alternatives

Alternative	Levelized Total Annual Cost ($2005)(1)	Annual Reduction (tpy)	Incremental Cost Effectiveness ($/t)
COHPAC	$2,473,000	827	$2,990
Existing ESP	$0	0	ND(2)

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Not Defined - baseline condition.

In the BART Determination guidelines, EPA neither proposes hard definitions for reasonable, or unreasonable, Unit Control Costs nor for incremental cost effectiveness values. The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the dominant control cost curve) between successive, dominant alternatives. While these findings do not eliminate any alternative, because there are no Unit Control Cost or incremental control cost criteria during a BART analysis, the findings do clearly define the more cost effective alternatives.

4.4.2 ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS

The energy requirement for an ESP is due to the pressure drop across the ESP, expressed as fan power, and the power required to operate the T/R sets and rappers. The power consumption of an ESP system is estimated to be approximately 590 kW. However, since there is an existing ESP installed on LOS Unit 1, it was assumed there would not be an additional energy impact with the installation of a new ESP as a similar level of power is currently being consumed by the existing ESP.

There are not any significant non-air quality environmental impacts associated with the existing ESP or a new ESP. One difference between the two options is that the new ESP will have a greater control efficiency and collect 827 more tons per year of fly ash that would be sent to the permitted disposal facility.

4.4.3 VISIBLITY IMPACTS

Visibility impacts for Historical pre-control and Future PTE post-control emission levels were modeled using CALPUFF. CALPUFF is used to model long-range transport of PM to determine the visibility impacts measured in deciViews (dV). Unlike emissions from NO_X and SO_2, PM emissions for LOS do not significantly contribute to visibility impacts in nearby Class 1 areas. As part of the CALPUFF output, every visibility impact is broken down into a percent contribution by each pollutant. This percentage was used to calculate the PM contribution to the modeled impact for each Class 1 area and then averaged over the three model years. When pre-control PM contributions were determined for the 90th percentile, the highest PM impact was 0.0097 dV for Unit 1 and occurred in Lostwood NWR.

Because this is the highest visibility impact attributed to PM emissions from Unit 1, any reduction in impact caused by the use of more effective controls would be only a percentage of this impact. To be conservative, this report analyzed a 100% reduction in visibility impairment impact for the visibility improvement comparison. In other words, although other control technologies would provide various levels of emission reduction and visibility impairment impact reduction, a reduction of 0.0097 dV was used as the best achievable impact reduction for the visibility comparison and assigned to each alternative. The assigned visibility improvement and estimated LTAC for each alternative are given in Table 4.4-8. The LTAC for each control technology was divided by the visibility impairment impact reduction in dV's to obtain a cost per dV of improvement relative to the existing ESP. These values are also tabulated in Table 4.4-8.

The highest modeled impact of 0.0097 dV is approximately 1.9 percent of the 0.5 dV impact that the BART guidelines define as contributing to visibility impairment. Achieving this slightly greater visibility improvement requires a significantly higher cost per dV when compared with other pollutants addressed in this study. Based upon these two factors, this analysis recommends that the existing ESP be maintained as the technology used for controlling particulate matter.

TABLE 4.4-8 – Visibility Improvement and Associated Costs

BART Alternative	Levelized Total Annual Cost ($2005)(1)	Visibility Impairment Impact Reduction (dV)	Cost per dV of Improvement ($/dV)
Fuel Switch w/ FGC	$5,197,000	0.0097	$535,800,000
New FF	$3,260,000	0.0097	$336,100,000
New ESP	$2,630,000	0.0097	$271,100,000
COHPAC	$2,473,000	0.0097	$254,900,000
Existing ESP	$0	0	ND(2)

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Not Defined - baseline condition.

Although condensable PM was removed from the BART analysis in Section 4.0.1, one additional aspect should be mentioned with regard to the effect of condensable PM on visibility in the nearest

Class 1 area. As discussed above, the modeled visibility impact for the filterable portion of PM was 0.0097 dV when modeled at the Permit Emission limit of 0.1 lb/MMBtu. Compared to a BART guideline that defines a contributing impact as more than 0.5 dV of visibility impairment impact, the filterable PM emission impact is insignificant. Current estimated emissions of condensable PM are approximately 11 percent of the amount of filterable PM emissions. Because condensable PM emission rates are significantly less than filterable PM emissions and the modeled visibility impairment impact attributable to filterable PM is insignificant even at the permit conditions, it is reasonable to assume that the visibility impairment impact attributable to condensable PM would also be insignificant. Thus, the elimination of condensable PM from this analysis is supported by the insignificant visibility impairment impact of filterable PM as determined by the visibility modeling included in this report.

4.4.4 IMPACT SUMMARY

The results of the impact analysis for PM control on LOS Unit 1 are presented below in Table 4.4-9. The cost of compliance analysis examined the capital cost of each alternative and any Balance of Plant costs necessary to implement the alternative. In addition, the cost analysis examined the operating and maintenance cost for each alternative. These costs were then combined into the Levelized Total Annual Cost for a comparative assessment of the total implementation cost of each alternative. As part of the top down analysis, a Dominant Control Curve was plotted and the Unit Control Cost for each alternative was evaluated. Two alternatives, the existing ESP and a COHPAC downstream of the existing ESP, were on the Dominant Controls Curve and identified as the more cost effective alternatives. Three of the alternatives, a new Fabric Filter, a new ESP and the COHPAC were evaluated at the same control level and the COHPAC, the more cost effective of the three, fell on the Dominant Control Curve. The estimated LTAC for these three alternatives varied by approximately 30% and thus the COHPAC was determined to be significantly more cost effective.

TABLE 4.4-9 – LOS Unit 1 Impacts Summary for PM Control Alternatives

PM Control Alternative	Emission Reduction (tpy)	Levelized Total Annual Cost ($2005)[1]	Unit Control Cost ($/t)	Maximum Visibility Impairment Impact Reduction (dV)	Unit Cost Effectiveness ($/dV)
Fabric Filter	827	$3,260,000	$3,942	0.0097	$443,900,000
New ESP	827	$2,630,000	$3,180	0.0097	$336,100,000
COHPAC	827	$2,473,000	$2,990	0.0097	$271,100,000
Fuel Switch w/ FGC	448	$5,197,000	11,600	0.0097	$254,900,000
Existing ESP	Baseline	$0	$0	0	ND[2]

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Not Defined - baseline condition.

The visibility impairment impact analysis evaluated the modeled impact of PM emission and determined that even if 100% of the visibility impairment impact attributed to PM emissions were eliminated, the change in visibility impairment would be significantly less than detectable by the human eye. As can be determined from the information summarized in Table 4.4-9, the cost of any PM_{10} BART alternative would be prohibitively high on both a unit cost and visibility impairment basis.

4.5 EVALUATION OF IMPACTS FOR FEASIBLE PM CONTROLS – UNIT 2

Step four in the BART analysis procedure is the impact analysis. The BART determination guidelines (70 FR 39166) list four factors to be considered in the impact analysis. This BART Determination will consider the following four factors in the impact analysis:

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four factors considered in the impact analysis are discussed in the following sections. The factor for the remaining useful life of the source is incorporated as part of the cost of compliance. In addition, as described in Section 1.1.6, the visibility impairment impacts are to be evaluated as part of the analysis. Thus, visibility impairment is included as part of the impacts analysis.

4.5.1 COST OF COMPLIANCE

Cost estimates for all of the Unit 2 particulate control technologies use the same general estimation procedure that was described for Unit 1 in Section 4.4.1. Any exceptions to this procedure are described in the following sections for each individual control alternative.

4.5.1.1 CAPITAL COSTS

The capital cost estimate is comprised of direct costs and indirect costs. The methodology used to estimate Unit 2 direct and indirect costs is the same as was described for Unit 1 in Section 4.4.1.1. The results of the capital cost estimate are given in Table 4.5-1, Table 4.5-2, Table 4.5-3, and Table 4.5-4. The option to utilize the existing ESP does not have any capital costs so it is not shown.

TABLE 4.5-1 – Capital Cost Estimate for LOS Unit 2 Fabric Filter

Direct Costs	**Estimated Cost ($2005)**	**General Facilities Markup (15%)**	**Total Direct Cost**
Fabric Filter	$18,520,000	$2,780,000	$21,300,000
Bags	$3,500,000	$520,000	$4,020,000
Ash Handling System	$1,090,000	$160,000	$1,250,000
Booster Fan	$2,220,000	$330,000	$2,550,000
Instruments & Controls	$480,000	$70,000	$550,000
BOP Subcontract	$680,000	NA	$680,000
		Total Direct Cost =	**$30,350,000**
INDIRECT COSTS		Contingency (20% of DC)	$6,070,000
		A/E Engineering and Construction Management (10% of DC)	$3,040,000
BEPC INDIRECTS		Project Development (1% of DC)	$300,000
	Spare Parts & Plant Equipment		
		Initial Inventory Spare Parts (1.5% of DC)	$460,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$150,000
		Construction All-Risk Insurance (1.5% of DC)	$460,000
		Allowance For Funds During Construction (AFDC 6%)	$1,820,000
		Contingency (15% of BEPC Indirects)	$480,000
		Indirect Cost Subtotal	$12,780,000
		Total Capital Cost	**$43,130,000**

TABLE 4.5-2 – Capital Cost Estimate for LOS Unit 2 New ESP

Direct Costs	**Estimated Cost ($2005)**	**General Facilities Markup (15%)**	**Total Direct Cost**
ESP	$22,580,000	$3,390,000	$25,970,000
Foundations	(Included Above)	NA	(Included Above)
Ash Handling System	$7,150,000	$1,070,000	$8,230,000
Instruments & Controls	$610,000	$90,000	$700,000
BOP Subcontract	$680,000	NA	$680,000
		Total Direct Cost =	**$35,580,000**
INDIRECT COSTS		Contingency (20% of DC)	$7,120,000
		A/E Engineering and Construction Management (10% of DC)	$3,560,000
BEPC INDIRECTS		Project Development (1% of DC)	$360,000
	Spare Parts & Plant Equipment		
		Initial Inventory Spare Parts (1.5% of DC)	$530,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$180,000
		Construction All-Risk Insurance (1.5% of DC)	$530,000
		Allowance For Funds During Construction (AFDC 6%)	$2,130,000
		Contingency (15% of BEPC Indirects)	$560,000
		Indirect Cost Subtotal	$14,970,000
		Total Capital Cost	**$50,550,000**

TABLE 4.5-3 – Capital Cost Estimate for LOS Unit 2 COHPAC

Direct Costs	**Estimated Cost ($2005)**	**General Facilities Markup (15%)**	**Total Direct Cost**
COHPAC	$9,780,000	$1,470,000	$11,250,000
Bags	$1,850,000	$280,000	$2,120,000
Ash Handling System	$990,000	$150,000	$1,130,000
Booster Fan	$2,010,000	$300,000	$2,310,000
Instruments & Controls	$280,000	$40,000	$320,000
BOP Subcontract	$680,000	NA	$680,000
		Total Direct Cost =	**$17,810,000**
INDIRECT COSTS		Contingency (20% of DC)	$3,560,000
		A/E Engineering and Construction Management (10% of DC)	$1,780,000
BEPC INDIRECTS		Project Development (1% of DC)	$180,000
	Spare Parts & Plant Equipment		
		Initial Inventory Spare Parts (1.5% of DC)	$270,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$90,000
		Construction All-Risk Insurance (1.5% of DC)	$270,000
		Allowance For Funds During Construction (AFDC 6%)	$1,070,000
		Contingency (15% of BEPC Indirects)	$280,000
		Indirect Cost Subtotal	$7,500,000
		Total Capital Cost	**$25,310,000**

TABLE 4.5-4 – Capital Cost Estimate for LOS Unit 2 Fuel Switching with Flue Gas Conditioning

Direct Costs	Estimated Cost ($2005)
Injection System	$884,000
Unloading Station	(Included Above)
Storage Hopper	(Included Above)
Transfer Conveyor	(Included Above)
Metering Pump Skid	(Included Above)
SO_3 Production Skid	(Included Above)
Injection Probes	(Included Above)
Total Direct Cost	**$884,000**
INDIRECT COSTS Contingency (20% of DC)	$177,000
A/E Engineering and Construction Management (10% of DC)	$88,000
BEPC INDIRECTS Project Development (1% of DC)	$9,000
Spare Parts & Plant Equipment	
Initial Inventory Spare Parts (1.5% of DC)	$13,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$4,000
Construction All-Risk Insurance (1.5% of DC)	$13,000
Allowance for Funds During Construction (AFDC 6%)	$53,000
Contingency (15% of BEPC Indirects)	$6,000
Indirect Cost Subtotal	$363,000
Total Capital Cost	**$1,247,000**

4.5.1.2 OPERATING AND MAINTENANCE COSTS

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). These costs except for fuel switching with flue gas conditioning were developed as part of the CUECost model and include operating labor, administrative and support labor and maintenance.

The fixed costs include maintenance costs. The maintenance cost was estimated as approximately 1.35% of the sum of the total direct cost.

The annual variable cost for the fabric filter and COHPAC is the auxiliary power costs plus the cost of 1/3 of the total bags. The 1/3 is determined by the bag life. It was assumed that the bag life for both of these systems is 3 years. The variable costs for the ESP consist solely of the auxiliary power costs.

The annual variable cost for the fuel switching with flue gas conditioning consist of the fuel cost change, reduced station service, and change in ash disposal cost. Section 3.4.1.11 of this report contains a description of the costs associated with fuel switching.

TABLE 4.5-5 – Annual O&M Cost Estimate for Unit 2 PM Control Alternatives

	NewFF	New ESP	New COHPAC	Fuel Switching with Flue Gas Conditioning
Fixed Costs				
Maintenance Costs	$435,000	$510,000	$255,000	$12,000
Existing ESP Maintenacne Costs	($91,000)	($91,000)	$0	$0
Total Fixed O&M Costs	**$344,000**	**$419,000**	**$255,000**	**$12,000**
Variable Costs				
Bag Replacement	$596,000	NA	$315,000	NA
Auxiliary Power	$1,197,000	$384,000	$1,101,000	(included below)
Auxiliary Power (Existing ESP)	($358,000)	($358,000)	$0	$0
Auxiliary Power & Reagent				$200,000
Fuel Cost Change				$9,383,000
Reduced Station Service				($292,000)
Change in Ash Disposal Cost				($467,200)
Total Variable O&M Costs	**$1,435,000**	**$26,000**	**$1,416,000**	**$8,835,000**
Total Annual O&M Costs	**$1,779,000**	**$445,000**	**$1,671,000**	**$8,835,000**
Net Annual O&M Cost ($/MWh)	**$0.54**	**$0.14**	**$0.51**	**$2.63**

The fixed and variable costs of the existing ESP were also included in the evaluation. The existing ESP would be abandoned if a fabric filter or a new ESP were installed; therefore, the O&M costs associated with the existing ESP are shown as negative costs. However, if a COHPAC unit or fuel switching with flue gas conditioning were utilized, the O&M costs of the existing ESP would remain.

The annual O&M cost estimate for each of the particulate control systems is summarized in Table 4.5-5.

4.5.1.3 LEVELIZED TOTAL ANNUAL COST RESULTS

In order to effectively compare the cost of installing, operating and maintaining each of the particulate control systems capital and O&M costs need to be evaluated on a levelized basis. The levelized costs and associated PM emissions are shown in Table 4.5-6.

TABLE 4.5-6 – Levelized Total Annual Costs of Unit 2 BART PM Control Alternatives

	Emissions		Economic Impacts			
PM Control Alternative	**Emission Rate (lb/mmBtu)**	**Emission Reduction[1] (tons/yr)**	**Installed Capital Cost ($2005)**	**Annual O & M Cost ($2005)**	**Levelized Total Annual Cost ($2005/yr)**	**Unit Control Cost ($/ton)**
FF	0.015	1,534	$43,130,000	$1,779,000	$5,892,000	$3,841
New ESP	0.015	1,534	$50,550,000	$445,000	$4,948,000	$3,226
COHPAC	0.015	1,534	$25,310,000	$1,671,000	$4,210,000	$2,744
Fuel Switch with Flue Gas Conditioning	0.054	830	$1,247,000	$8,835,000	$10,650,000	$12,830
Existing ESP	0.100	Baseline	Baseline	Baseline	Baseline	Baseline

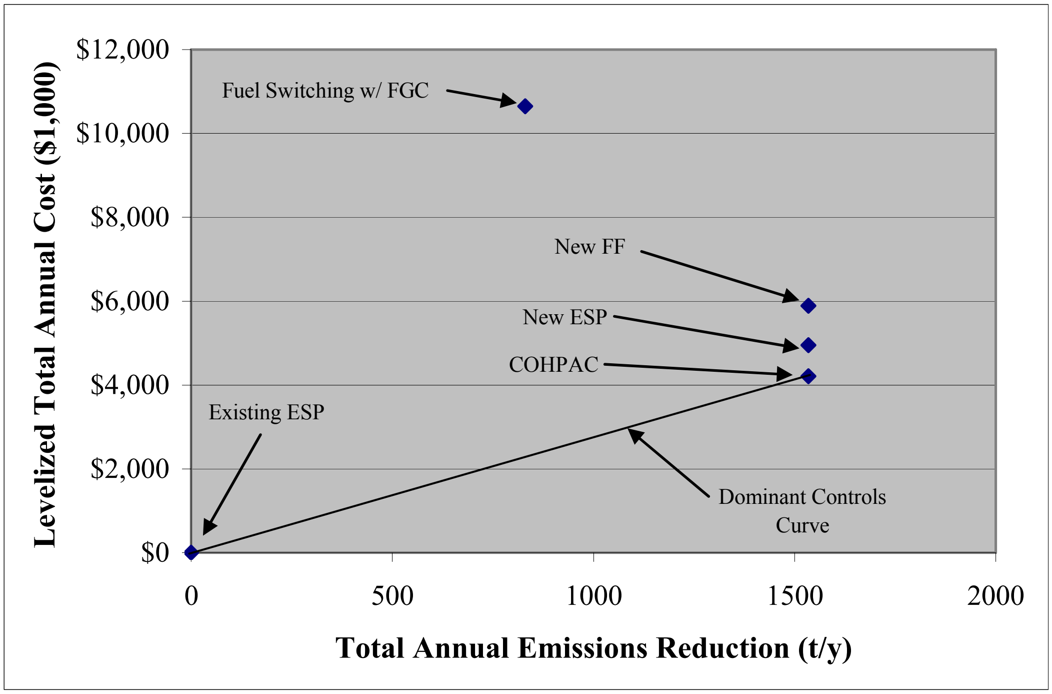
[1] Annual emissions are based on Future PTE Case.

Life, years	20
Cost of Money, %	6%
Capital Recovery Factor	0.08718
Conversion Tax (FF), $	15,845
Conversion Tax (New ESP), $	15,849
Conversion Tax (COHPAC), $	15,032
O &M Levelization Factor	1.19314

Figure 4.5-1 is a plot of the Levelized Total Annual Cost (LTAC) for each alternative versus the annual removal in tons. The purpose of Figure 4.5-1 is to identify the Dominant Controls Curve, which is the rightmost boundary of the control cost envelope. The Dominant Controls Curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual removal tonnage for the various BART alternatives. Points distinctly above and to the left of this curve are inferior control alternatives on a cost effectiveness basis. The existing ESP was chosen as the baseline for levelized cost and annual emissions. Therefore, the existing ESP is shown graphically as not having any emission reduction benefits or any added cost.

Of the technically feasible BART alternatives considered for LOS Unit 2 the data point for the fuel switching with flue gas conditioning lies distinctly above the least cost boundary of the control cost envelope. This chart also displays that a new FF and/or a new ESP are inferior to a COHPAC as all three of these options can achieve the same emissions reduction; however, the FF and the new ESP have a greater LTAC. The reason for this is clear from Table 4.5-6 where the unit control costs for all of the BART alternatives are listed. In a BART analysis each of the PM control technologies represented by a data point above the Dominant Control Curve can be excluded from further analysis on a cost efficiency basis. Therefore, the fuel switching with flue gas conditioning, the new FF and new ESP options are shown not to be cost effective PM control alternatives for LOS Unit 2 and could be excluded from further analysis.

FIGURE 4.5-1 – LOS Unit 2 Least Cost Envelope for PM Control Alternatives



The next step in the cost effectiveness analysis for the remaining BART alternatives is to review the incremental cost effectiveness between a given alternative and those above and below it in the ranking shown in Table 4.5-7. The incremental cost effectiveness is the slope of a line between any two adjacent points shown in Figure 4.5-1. Table 4.5-7 contains a repetition of the cost and control information from Table 4.5-6 and the incremental cost effectiveness between each successive set of alternatives.

TABLE 4.5-7 – Incremental Cost Effectiveness of Unit 2 BART PM Control Alternatives

Alternative	Levelized Total Annual Cost ($2005)⁽¹⁾	Annual Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
COHPAC	$4,210,000	1,534	$2,744
Existing ESP	$0	0	ND⁽²⁾

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

(2) - Not Defined - baseline condition.

In the BART Determination guidelines, EPA neither proposes hard definitions for reasonable, or unreasonable, Unit Control Costs nor for incremental cost effectiveness values. The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the dominant control cost curve) between successively less effective alternatives. The alternatives involving the installation of new PM control equipment were all evaluated at the same particulate matter control efficiency and thus the incremental analysis does not provide any useful information for comparing these alternatives. However, based on the cost estimates for each, the COHPAC is more cost effective than a new FF or ESP and thus only the COHPAC alternative needs to be carried forward from this analysis as representative of a general BART alternative for control of emissions to the 0.015 lb/mmBtu level.

4.5.2 ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS

The energy requirement for an ESP is due to the pressure drop across the ESP, expressed as fan power, and the power required to operate the T/R sets and rappers. The power consumption of the existing ESPs is estimated to be approximately 1,180 kW. Because two existing ESPs are installed on LOS Unit 2, it was assumed there would not be an additional energy impact with the installation of a new ESP.

There are no significant non air quality environmental impacts associated with the existing ESP versus a new ESP. One difference between the two options is that the new ESP will have a greater control efficiency. Therefore, a new ESP will collect 73 more tons per year of fly ash that would be sent to the landfill.

4.5.3 VISIBLITY IMPACTS

Visibility impacts for Historical pre-control and Future PTE post-control emission levels were estimated using CALPUFF. CALPUFF is used to model long-range transport of PM to determine the visibility impacts measured in deciViews (dV). Unlike emissions from NO_X and SO_2, PM emissions for LOS never significantly contribute to visibility impacts. As part of the CALPUFF results, each modeled impact includes a percent contribution for each pollutant. That percentage is used to calculate the PM contribution to the modeled impact for each Class 1 area and then is averaged for the 3 modeled years. When pre-control PM contributions are calculated for the 90th percentile, the highest impact is 0.015 dV for Unit 2 and occurs in Lostwood NWR.

The 0.015 dV visibility impact contribution was estimated by modeling the pre-control ESP emission rate. Since this is the highest impact attributed to PM emissions from Unit 2, any reduction in impact caused by the use of more effective controls would be only a percentage of this impact. To be conservative, this report uses a 100% reduction in visibility impairment reduction for the visibility impairment impact reduction evaluation. Although three control alternatives provide the same PM emission reduction, which would be an 85% reduction of PM emissions compared to the existing ESP, the potential visibility impairment reduction is very low and thus an improvement of 0.015 dV was the maximum possible visibility impairment impact reduction. The LTAC, maximum visibility impairment impact reduction and resultant cost per dV of improvement are given in Table 4.5-8. The LTAC for each control technology was divided by the visibility improvement to obtain a cost per dV of visibility impairment reduction for each alternative.

LOS Unit 2 has a particulate control device in operation that satisfactorily meets the permit limitation for PM emissions of 0.1 lb/mmBtu. Therefore, any PM control alternative was expected to be inordinately expensive on a Unit Control Cost basis as was shown in Section 4.5.1.3. The maximum potential visibility impairment reduction of 0.015 dV is approximately three percent of the 0.5 dV impact that the BART guidelines define as contributing to visibility impairment. Achieving this slightly greater visibility improvement requires a significantly higher cost per dV when compared with other pollutants addressed in this study. Therefore, the maximum achievable visibility impairment impact reduction would be extremely expensive on a unit cost basis and would not result in any discernible change in visibility in the affected Class 1 areas.

TABLE 4.5-8 – Visibility Improvement and Associated Costs

Alternative	Levelized Total Annual Cost ($2005)(1)	Maximum Visibility Impairment Impact Reduction (dV)	Unit Cost Effectiveness ($/dV)
Fuel Switch w/ FGC	$10,650,000	0.015	$710,000,000
New FF	$5,892,000	0.015	$392,800,000
New ESP	$4,948,000	0.015	$329,900,000
COHPAC	$4,210,000	0.015	$280,700,000
Existing ESP	$0	0	ND(2)

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Not Defined - baseline condition.

Although condensable PM was removed from the BART analysis in Section 4.0.1, one additional aspect should be mentioned with regard to the effect of condensable PM on visibility in the nearest Class 1 area. As discussed above, the modeled visibility impact for the filterable portion of PM was 0.015 dV when modeled at the Permit Emission limit of 0.1 lb/MMBtu. Compared to a BART guideline that defines a contributing impact as more than 0.5 dV of visibility impairment impact, the filterable PM emission impact is insignificant. Current estimated emissions of condensable PM are approximately 8 percent of the amount of filterable PM emissions. Because condensable PM emission rates are significantly less than filterable PM emissions and the modeled visibility impairment impact attributable to filterable PM is insignificant even at the permit conditions, it is reasonable to assume that the visibility impairment impact attributable to condensable PM would also be insignificant. Thus, the elimination of condensable PM from this analysis is supported by the insignificant visibility impairment impact of filterable PM as determined by the visibility modeling included in this report.

4.5.4 IMPACT SUMMARY

As stated at the beginning of this report, the cost, energy, non-environmental and visibility impacts of each PM_{10} BART alternative were evaluated in this Section. Table 4.5-9 summarized the various impacts discussed in Sections 4.5-1 through 4.5-3. The cost of compliance analysis examined the capital cost of each alternative and any Balance of Plant cost necessary to implement the alternative. In addition, the cost analysis examined the operating and maintenance cost associated with each alternative. These costs were then combined into the Levelized Total Annual Cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top down analysis, a Dominant Control Curve was plotted and the Unit Control Cost for each alternative was evaluated. Two alternatives, the existing ESP and installation of a new COHPAC following the existing ESP, were on the Dominant Controls Curve and thus were identified as the more cost effective alternatives. Three of the BART alternatives, a new Fabric Filter, a new ESP and a new COHPAC following the existing ESP, were evaluated at the same PM control level and only the least expensive of these, the COHPAC alternative, fell on the Dominant Controls Curve. The range of the cost estimates for these three alternatives was approximately 40% and thus the COHPAC was perceived to be significantly more cost effective than the other two alternatives.

The visibility impairment impact analysis evaluated the modeled impact of PM emissions and determined that even if 100% of the visibility impairment attributed to PM emissions were eliminated, the change in visibility impairment would be significantly less than detectable by the human eye. As can be determined from the information summarized in Table 4.5-9, the cost of any PM BART alternative would be prohibitively high on both a unit cost and visibility impairment basis.

TABLE 4.5-9 – LOS Unit 2 Impacts Summary for PM Control Alternatives

PM Control Alternative	Emission Reduction (tons/yr)	Levelized Total Annual Cost ($2005)(1)	Unit Control Cost ($/ton)	Maximum Visibility Impairment Impact Reduction (dV)	Unit Cost Effectiveness ($/dV)
New FF	1,534	$5,892,000	$3,841	0.015	$710,000,000
New ESP	1,534	$4,948,000	$3,226	0.015	$392,800,000
COHPAC	1,534	$4,210,000	$2,744	0.015	$329,900,000
Fuel Switch w/ FGC	830	$10,650,000	$12,830	0.015	$280,700,000
Existing ESP	Baseline	$0	Baseline	0	Baseline

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

PM SECTION REFERENCES:

1. "An Updated Method for Estimating Total Sulfuric Acid Emissions from Stationary Power Plants"; Monroe, Larry S. & Harrison, Keith E.; Southern Company Generation and Energy Marketing; Revised March, 2003.

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5.0 BART RECOMMENDATIONS

This report presents the analysis of control technologies for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Basin Electric Power Cooperative's (BEPC's) Leland Olds Station (LOS) Units 1 and 2. The final result of this analysis is a recommendation of the Best Achievable Retrofit Technology (BART) for each unit based upon "the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). The presented emission rates in this section are the BART recommendation. However, because the accuracy of the cost estimate is ± 30% and in some cases is greater than the variance of the estimated costs between control alternatives, the technology used to meet the BART recommendation may change. This section summarizes the analysis performed for each unit and its associated pollutants.

5.0 UNIT 1 BART RECOMMENDATIONS

In previous sections of the report, the 5 steps of the technology evaluation provided in the BART Determination Guidelines were completed for Unit 1 and the results for each pollutant were summarized. Each pollutant required a different approach in order to determine BART. This section provides a brief description of the approach used for each pollutant and summarizes the results for Unit 1.

5.0.1 UNIT 1 NO_X BART

In the BART Guidelines, the EPA lists the presumptive NO_X emission limits for BART-eligible coal-fired units, distinguished by unit type, and coal type. The analysis performed by the EPA for establishing the presumptive limits for NO_X emissions from pulverized coal-fired EGUs assumed only the application of low-NOx burners and overfire air combustion controls. For dry-bottom, wall-fired electric generating units (EGUs) burning lignite coal, the NO_X presumptive limit is 0.29 lb/mmBtu. These presumptions apply to EGUs greater than 200 MW at power plants with the generating capacity greater than 750 MW and are based on control strategies that the EPA determined are generally cost-effective for all such units.

Unit 1 at Leland Olds Station is a dry-bottom, wall-fired unit greater than 200 MW output located at a power plant less than 750 MW total output capacity. The actual highest 24-month rolling NO_X summation total from 2000-2004 divided by the actual 24-month rolling summation unit heat input for the same time period for Unit 1 at LOS meets the presumptive BART NO_X emission limits stated above. The requirements of performing a NO_X BART analysis, on a BART-eligible coal-fired unit with a nameplate capacity greater than 200 MW at a powerplant less than 750 MW that has a historic 24-month average unit NO_X emission rate that meets the EPA's presumptive BART NO_X emission limit for larger power plants, are not apparent in the BART Guidelines. However, this BART analysis performed a NO_X control technology feasibility evaluation, with impact analysis for a separated overfire air (SOFA) alternative. This included the four prescribed impact criteria plus the impact assessment for visibility impairment improvement following the general procedures of the BART Guideline.

The impacts analysis for separated overfire air at LOS Unit 1 found only insignificant negative energy and non-air environmental impacts; remaining useful life of the source was assumed to exceed the 20-year project life utilized in the cost impact estimate.

Average predicted visibility impairment impacts decreased significantly for the presumptive BART NO_X emission rate and high levels of SO_2 control, and slightly more with post-control SOFA-enhanced NO_X emission rates compared to the average predicted visibility impairment impacts at the pre-control (NDDH protocol) baseline emission rates for NO_X, SO_2, and PM. An analysis of the incremental cost-effectiveness of reducing predicted visibility impairment impact for the SOFA alternative was performed for LOS Unit 1. The comparison showed that the ratio of the estimated additional annualized costs of installing and operating SOFA to the average predicted visibility impairment improvement relative to the presumptive BART NO_X baseline emission rate for the future Potential-To-Emit boiler heat input (future coal case) scenario applied to LOS Unit 1 would result in millions of dollars per deciView-year of visibility impairment improvement. The range for this incremental visibility impairment impact reduction was \$7.8M to \$25.4M per deciView-yr, depending on the Class 1 area and SO_2 control associated with the SOFA NO_X control alternative.

The actual highest 24-month rolling average NO_X unit emission rate meets the EPA's presumptive BART NO_X emission limit of 0.29 pounds per million Btu of fuel heat input for BART-eligible coal-fired EGU's greater than 200 MW nameplate capacity at power plants with the generating capacity greater than 750 MW. Use of existing low-NO_X burners and close-coupled overfire air translates into a BART emission rate of 0.29 pounds per million Btu of fuel heat input for the future PTE coal case scenario applied to LOS Unit 1. Thus, this evaluation recommends the presumptive limit of 0.29 lb/MMBtu as BART.

5.0.2 UNIT 1 SO_2 BART

In step 1 of the technology evaluation, 7 control processes were identified for SO_2 control. The identified processes included Fuel Switching, Coal Cleaning, Wet Limestone Flue Gas Desulfurization (FGD), Spray Dryer Absorber (SDA), Circulating Dry Scrubber (CDS), Flash Dryer Absorber (FDA), and the Powerspan ECO™ process. While evaluating the availability and applicability of each process in step 2, the Coal Cleaning and the Powerspan ECO™ processes were eliminated. In step 3 the remaining 5 processes were ranked by effectiveness. After ranking the processes, the impacts analysis including visibility was conducted in steps 4 and 5. The main result of the impacts analysis was quantifying the cost effectiveness of each process. The SDA, CDS and FDA were quantified as being inferior on a cost effectiveness basis.

After conducting all steps of the evaluation for SO_2, 90% removal remains as the best possible control alternative. Based upon the cost analysis, none of the feasible BART alternatives were exceedingly expensive. Due to the relative closeness of the cost estimates and fluctuation in market conditions, all of the alternatives had similar cost impacts. The visibility impairment impact analysis examined the visibility impairment impact reduction attributable to each alternative and determined that the marginal change in visibility impairment impact between any two feasible BART alternatives was less than ten percent of the minimum change in visibility impairment discernible by the human eye. So, similar to the cost analysis, the visibility impairment impact analysis reached the conclusion that there is no definitive difference between alternatives. Since 90% control is cost effective and provides indiscernible visibility impact compared to other alternatives, it is recommended as BART. Application of 90% control for LOS Unit 1 translates into an emission rate of 0.34 pounds per million Btu.

5.0.3 UNIT 1 PM BART

Five control technologies were identified for step 1 of the PM control evaluation. The identified technologies included Fuel Switching with Flue Gas Conditioning, a Fabric Filter, a COHPAC Baghouse, a New Electrostatic Precipitator (ESP), and the Existing ESP. In step 2, all five of the control technologies were determined as feasible alternatives based upon availability and applicability. In step 3, the 5 processes were ranked by effectiveness. While evaluating the impacts of each technology during steps 4 and 5, visibility impairment became the principle factor for determining BART. PM emissions, unlike other pollutant emissions, use existing controls and do not significantly contribute to visibility impairment. In addition, using a new control technology to achieve a slightly greater visibility improvement requires a significantly higher cost per deciView when compared with other pollutants. Based upon these two factors, this analysis recommends that the existing ESP be maintained as the technology used for controlling particulate matter. The evaluated emission rate for the existing ESP was 0.10 pounds per million Btu.

5.1 UNIT 2 BART RECOMMENDATIONS

Unit 2 uses the same 5 steps of the technology evaluation provided in the BART Determination Guidelines. Previous sections provide the evaluation results for each pollutant and describe the different approaches used to determine BART. This section provides a brief description of the approach used for each pollutant and summarizes the results for Unit 2.

5.1.1 UNIT 2 NO_X BART

In step 1 of the technology evaluation, three basic categories of NO_X control for EGUs were-identified: pre-combustion, combustion, and post-combustion. Eleven basic types of NO_X control processes were derived from these three categories. Twenty two variations of these eleven processes were reviewed for NO_X controls potentially available and applicable to cyclone-fired EGUs burning North Dakota lignite. While evaluating the availability and applicability of each process for LOS Unit 2's NO_X control in step 2 of the BART analysis process, low NO_X burners, Selective Catalytic Reduction (SCR), and the Powerspan ECO™ process were eliminated. Controls such as oxygen-enhanced combustion, water/steam injection, hydrocarbon-enhanced SNCR, and fuel reburn with SNCR all lack appropriate demonstration or permanent installation experience in full-scale, full-time applications for NO_X emissions reduction on cyclone-fired boilers. Of the pre-combustion and combustion-related NO_X control processes, fuel switching, basic combustion control improvements, basic separated overfire air, flue gas recirculation, fuel lean gas reburn, and conventional gas reburn were considered technically feasible but have zero or low control effectiveness, or are economically unattractive due to the high capital costs and on-going natural gas consumption costs for implementation and operation.

An “advanced” form of separated overfire air, alone and in combination with coal reburn, and Selective Non-Catalytic Reduction (SNCR) with and without Rich Reagent Injection, were evaluated for cost-effectiveness. Of these four alternatives, coal reburn with ASOFA was determined to be an inferior control from a cost-effectiveness standpoint, and thus eliminated from further impacts analysis for LOS Unit 2. For Rich Reagent Injection + SNCR with ASOFA, the small incremental reduction in annual NO_X emissions (approximately 10 percent) for a 60 percent increase in levelized total annual cost yields a 220 percent increase in incremental dollars per ton control cost versus the SNCR with ASOFA alternative. The control cost-effectiveness analysis favored the SNCR with ASOFA alternative for LOS Unit 2 NO_X control.

The impacts analysis for remaining NO_X control alternatives at LOS Unit 2 found only insignificant negative energy and non-air environmental impacts; remaining useful life of the source was assumed to exceed the 20-year project life utilized in the cost impact estimate.

Average predicted visibility impairment impacts decreased significantly for the post-control ASOFA-enhanced NO_X emission rate, and slightly more with a SNCR-enhanced NO_X emission rate, and a very small incremental amount for the RRI + SNCR-enhanced NO_X emission rate when modeled with the single sulfur emission control rate for LOS Unit 2. These impacts were compared to the average predicted visibility impairment impacts at the pre-control (NDDH protocol) baseline emission rates for NO_X, SO_2 , and PM. An analysis of the incremental cost-effectiveness of SNCR and RRI + SNCR controls in reducing predicted visibility impairment impact beyond the ASOFA alternative was performed for LOS Unit 2. Installing and operating SNCR applied to LOS Unit 2 relative to the ASOFA NO_X emission rate for the future Potential-To-Emit boiler heat input (future coal case) scenario would result in hundreds of millions of dollars per deciView-year of control cost effectiveness visibility impairment improvement. The range for this incremental visibility impairment impact reduction was \$105M to \$310M per deciView-yr for SNCR -based control added to the ASOFA NO_X control alternative, depending on the Class 1 area. Adding RRI to the SNCR with ASOFA NO_X control alternative would reduce average predicted visibility impairment impact by 0 to 12.5 percent on a deciView basis while increasing control cost of the incremental visibility impairment improvement by 25 to 40 percent on a M\$ per deciView-year basis, depending on the Class 1 area. The range for this incremental visibility impairment impact reduction was \$148M to \$423M per deciView-yr for adding RRI + SNCR to the ASOFA NO_X control alternative, depending on the Class 1 area.

After conducting all steps of the evaluation for NO_X emissions control, Rich Reagent Injection + SNCR with ASOFA and SNCR with ASOFA alternatives remain as the highest and next highest-performing feasible control technologies for LOS Unit 2. An incremental analysis for control costs and visibility impairment impacts shows that the SNCR with ASOFA alternative was significantly more cost-effective. SNCR with ASOFA is recommended as BART for LOS Unit 2. Application of SNCR with ASOFA for 54.5 percent NO_X control translates into a BART emission rate of 0.304 pounds per million Btu of fuel heat input for the future PTE coal case scenario applied to LOS Unit 2.

5.1.2 UNIT 2 SO_2 BART

Steps 1 through 3 of the technology evaluation for Unit 2 ended with the same results from Unit 1. The 5 remaining processes, ranked in order by efficiency, are Wet Limestone Flue Gas Desulfurization (FGD), Circulating Dry Scrubber (CDS), Spray Dryer Absorber (SDA), Flash Dryer Absorber (FDA), and Fuel Switching. After ranking the processes, the impacts analysis including visibility was conducted in steps 4 and 5. The main result of the impacts analysis was quantifying the cost effectiveness of each process. The SDA, CDS and FDA were quantified as being inferior on a cost effectiveness basis. After conducting all steps of the evaluation for SO_2, Fuel Switching and Wet Limestone FGD remain as the best possible control technologies. Of the two BART alternatives remaining under consideration, wet FGD, achieving 95% SO_2 reduction, consistently achieves the greatest visibility impact reduction and meets presumptive BART limits. Because 95% SO_2 reduction is cost effective and meets presumptive BART limits, it is recommended as BART. Application of ninety-five percent control for LOS Unit 2 translates into an emission rate of 0.17 pounds per million Btu.

5.1.3 UNIT 2 PM BART

The approach used to recommend BART for Unit 2 was exactly the same as was used for Unit 1. The only difference was the higher costs associated with using a new control technology for Unit 2. The increased size of Unit 2 requires new controls to be larger and results in higher costs. Using a new control technology to achieve a slightly greater visibility improvement requires a significantly higher cost per deciView when compared with other pollutants and compared to Unit 1. However, using existing PM controls, emissions from Unit 2 still never significantly contribute to visibility impairment. Based upon these two factors, this analysis recommends that the existing ESPs be maintained as the technology used for controlling particulate matter. The evaluated emission rate for the existing ESP was 0.10 pounds per million Btu.

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6.0 PERMIT LIMIT RECOMMENDATIONS

To complete the determination process, the BART guidelines state that an enforceable emission condition must be established for each subject emission unit and for each pollutant subject to review. (70 FR 39172) The guidelines suggest that emission limits be developed on a 30-day rolling average for Electric Generating Units (EGUs). Unfortunately, the guidelines do not provide a methodology to calculate the limit for permitting purposes and only state that an enforceable limit that reflects BART requirements must be established.

The BART Determination was conducted based upon historical operating conditions for LOS. However, because the fuel characteristics of the North Dakota lignite fired at LOS will be changing in the future, a Future PTE case was developed for the recommended BART determination. Two additional factors, boiler Heat Input and short term variations in fuel composition were reviewed prior to recommending enforceable permit conditions for BART.

In general, when the Boiler Heat Input increases, emission rates of fuel borne pollutants increase. Although the design Heat Input is specified by the boiler manufacturer, factors such as fuel characteristics and operating procedures can affect the maximum Heat Input of a boiler that is actually experienced in practice. Historical Heat Input values from 2000-2004, for both LOS Unit 1 and Unit 2, were reviewed to determine the amount of time in which the Nameplate Heat Input Rating used as the basis for the predicted future emissions in this report was exceeded. The review showed that the design boiler Heat Input was exceeded 10.6% and 7.6% of the operating time for Units 1 and 2 respectively. Because a 30-day averaging period should mitigate some of the effect of higher Heat Input on emissions somewhat, a five percent increase in heat input was used for calculating the recommended emission limits for each pollutant. With this approach, Basin Electric Power Cooperative (BEPC) is provided a bit of a cushion between operating conditions and permit limits such that minor short term variations in operating conditions would not result in an apparent permit violation where BEPC had not, in fact, materially changed any of their normal daily operating conditions.

Variability in coal composition was the second factor that was taken into account because the emission rate of SO_2 and PM are directly related to the sulfur and ash content of the fuel. Sulfur content of the fuel is the primary constituent of concern because SO_2 emissions are directly related to the amount of sulfur in the coal and cannot be improved with combustion improvements as NO_X and

PM. When BART compliance is required for LOS, they will still be burning coal from the Freedom Mine in Beulah, ND. A forty year mining plan, provided by the mining company and containing projected coal quality data, was analyzed to determine the future annual average sulfur content of the coal (Appendix B2). The results indicated that the future coal will have a higher maximum annual average sulfur content of approximately 1.13%. A further analysis of the short term variability of fuel sulfur content and Higher Heating Value (HHV) was conducted by the mining company at the train load level, for LOS fuel deliveries over the 2000-2004 period. The detailed analysis identified one standard deviation in sulfur content as being equal to ± 0.12% change in fuel sulfur content and one standard deviation in the heat content as ± 158 Btu/lb. Assuming a normal distribution of both the fuel sulfur and heat content, the annual average, plus or minus one standard deviation, would represent approximately 68.27% of the possible range of sulfur and heat content LOS is expected to experience. This range was taken to be representative of the range of sulfur and heat content that LOS would experience over a given year on a 30 day rolling average. For determining a 30 day rolling average for the purpose of calculating SO_2 emissions, the average annual sulfur content of 1.13% plus one standard deviation of 0.12%, plus an average annual fuel heat content of 6,520 Btu/lb was utilized. Therefore, the basis for the recommended permit conditions for recommended BART for each unit was 105% of the nameplate Heat Input, while firing 1.25% sulfur fuel with a heat content of approximately 6,520 Btu/lb. In this manner, an owner's margin of one standard deviation on fuel and heat content would be preserved. This margin is important to protect the owner from variations in fuel properties over shorter operating periods than the annual average taken as the basis for the remainder of this analysis.

For NO_X emissions, the five percent higher Boiler Heat Input was the only variation from the BART Determination basis that was used to develop the proposed permit conditions. The Boiler Heat Input is the single most important variable affecting the NO_X emissions rate. Fuel nitrogen content may vary slightly but, because it is a minor contributor to overall NO_X emissions rates, potential variations were not taken into account while developing the recommended permit conditions. After performing emissions calculations for Unit 1 using the higher Heat Input and applying recommended BART, the resulting recommended NO_X permit limit is 0.29 lb/mmBtu.

For Unit 2, it is generally seen that when the Boiler Heat Input increases, the NO_X emission rate increases. Applying recommended BART to LOS Unit 2's boiler operating at a higher heat input rate with a higher pre-control baseline 30-day rolling average emission rate, the recommended NO_X

permit limit is 0.35 lb NO_X/mmBtu. These recommendations are summarized in Tables 6.0-1 and 6.0-2 below.

The recommended NO_X permit conditions are based upon performance estimates considering recognized operational factors and equipment designs that are different from emission reduction experience achieved by other coal-fired cyclone boilers. The combustion characteristics of the future lignite supply are expected to include a decrease in higher heating value (Btu/lb) and an increase in ash content. Operation of Unit 2 with air-staged cyclones with the advanced form of separated overfire air system and with low Btu/high ash lignite can cause conditions to occur that exceed the ability to adjust operational practices sufficiently to maintain low NO_X emissions. A provisional operating period of one year of operational experience is recommended in conjunction with the recommended BART 30-day rolling average NO_X emission rate limit. This provisional period will allow BEPC to demonstrate the actual control system capabilities of an SNCR system in addition to the ASOFA system specifically designed for lignite firing in Unit 2's boiler. At the end of that period, it is recommended that the BART NO_X emission limit be reviewed considering the demonstrated operating history.

To account for predicted variations in future fuel sulfur and heat content, a representative SO_2 emission rate was calculated based upon a five percent higher heat input, the maximum sulfur content plus 1 standard deviation and the future annual average fuel HHV minus one standard deviation). After performing emissions calculations for Unit 1 using the basis described above and applying the recommended BART SO_2 reduction level of 90%, the resulting recommended 30 day rolling average SO_2 permit limit for LOS Unit 1 is 0.39 lb SO_2/mmBtu. Similar calculations for Unit 2, applying recommended BART of 95% SO_2 control, yield a recommended SO_2 permit limit of 0.19 lb SO_2/mmBtu. These recommendations are summarized in Tables 6.0-1 and 6.0-2 below.

Emission rates for particulate matter are based upon the design of the existing electrostatic precipitator and the boiler heat input. To maintain the same methodology that was used for both NO_X and SO_2, the heat input used to calculate the emissions in pounds per hour was increased by five percent. Note that the emission rate in pounds per million Btu did not change. Along with recommended emission limits for NO_X and SO_2, PM emission limits for each unit are tabulated below.

Table 6.0-1 – Recommended 30-Day Rolling Average BART Emission Limits LOS Unit 1

Pollutant	Emission Rate lb/million Btu
SO_2	0.39
NO_X	0.29
PM	0.10

Table 6.0-2 – Recommended 30-Day Rolling Average BART Emission Limits LOS Unit 2

Pollutant	Emission Rate lb/million Btu
SO_2	0.19
NO_X	0.35
PM	0.10

Although the emission limits presented above for each unit are recommended for permitting purposes, this analysis also recommends discussing an alternative compliance method as suggested in the BART Guidelines. The guidelines provide that states, "should consider allowing sources to ''average'' emissions across any set of BART-eligible emission units within a fence line, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible units that constitute a BART-eligible source." (70 FR 39172) During the process of developing enforceable permit conditions, the opportunity to apply a plant-wide limit using an "averaging" or "bubbling" strategy should be considered.

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APPENDIX A

Technical Feasibility Assessment Details for NO_X Controls (A1)

Cost Estimate Details for NO_X Controls (A2)

U.S. Coal Cyclone NO_X Reduction Projects Summary (A3)

Retrofit NO_X Control Projects' Technical Literature Summary (A4)

EERC Report – Ash Impacts on SCR Catalyst Performance (A5)

A1 Technical Feasibility Assessment of NO_X Control Alternatives

A1.1 Pre-Combustion Controls – Fuel Switching/Blending

Fuel switching can be a viable method of NO_X emission reduction in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. In the case of Leland Olds Station, the Unit 1 and Unit 2 boilers were designed and constructed specifically for firing North Dakota lignite, which has a low fuel higher heating value (Btu/lb), medium to high ash, and high moisture content. Based on available emission data for LOS, switching fuel from a lignite/PRB coal blend to 100% PRB coal is expected to yield little or no significant additional NO_X reduction. Ottertail Power Company's Big Stone Unit 1's boiler, located in South Dakota, was originally designed to burn northern Midwest lignite, and has cyclone furnaces and the same physical size and arrangement as LOS Unit 2's boiler. Big Stone Unit 1's boiler was converted from firing lignite to PRB coal in 1997. Based on available EPA Acid Rain Program's Clean Air Market Division (CAMD) emission data for Big Stone Unit 1, switching fuel from a lignite coal to PRB coal is the expected to yield no significant additional NO_X emissions reduction relative to current baseline levels for Unit 2 at Leland Olds Station.

Conversion of Leland Olds Station Unit 1 and Unit 2 to fire lignite/western subbituminous coal blends up to 100% PRB coal is technically possible. It is expected that various off-site, plant site, and powerplant modifications will be required. This has not been closely examined for all aspects of design, construction, operation and maintenance. A relatively modest quantity of PRB coal is currently burned annually at this plant. Rail service is presently installed at this site, so the additional operational and capital costs to bring in large quantities of PRB coal are expected to be of modest significance. This is described in more detail in the main report, Section 2.4.1.5 for LOS Unit 1 and Section 2.5.1.5 for LOS Unit 2. PRB coal cost (delivered) will be approximately 60% more per ton or 29% more per mmBtu delivered than North Dakota lignite from Basin Electric's existing source. However, with such a negligible amount of NO_X emissions reduction expected from application of fuel switching, this alternative will not be economically competitive with other technologies that offer similar or better results expected for a much lower combination of capital and operational costs. This alternative was not included in the NO_X control cost-effectiveness analysis.

A1.2 Combustion Controls

Nitrogen oxides (NO_X) are produced when nitrogen in the fuel and combustion air are exposed to high temperatures. Nitrogen oxide (NO) is the most predominant form of NO_X emissions, along with nitrogen dioxide (NO_2). The formation of these compounds in utility powerplant boilers is sensitive to the method of firing and combustion controls utilized. The techniques employed for mixing the combustion air and fuel, which creates flames and high temperature combustion products, results from the rapid oxidization of carbon, hydrogen, and other exothermic reactions. Cyclone-fired boilers, by design, create intense heat release rates to melt and fluidize the coal ash introduced into the barrel-shaped furnaces. This produces very high uncontrolled NO_X emissions.

Combustion controls employ methods that reduce the amount of NO_X emissions created in the combustion zone of the boiler prior to exhausting the flue gases from the furnace (upstream of the convective heat transfer zones). This results in fewer emissions that may require subsequent reduction from applicable post-combustion techniques.

A1.2.1 Basic Combustion Improvements

Combustion improvements are commonly-applied, combustion-related NO_X emission reduction techniques. In their most basic form, these typically provide improvements to combustion air flow distribution, measurement, and pressure, together with fuel flow measurement and metering, to promote consistent combustion performance by burning fuel with more accuracy in maintaining a desired fuel/air ratio[1].

These improvements may allow, or be combined with, a technique called “low excess air” (LEA) operation of the pulverized lignite burners or cyclones, where a slight decrease in the total amount of combustion air is supplied to the burners, thus reducing the amount of thermal NO_X emissions produced during combustion. Other operational techniques to reduce NO_X emissions may utilize burners out-of-service (BOOS) and biased firing (BF). With BOOS, selected burners are removed from service by stopping fuel flow but maintaining airflow, so as to force the remaining active (i.e. firing) burners or cyclones to operate fuel-rich, thus promoting lower NO_X emissions. In biased firing, often the lower burners or cyclones are operated with more fuel than the upper levels, which also produces low excess air or “fuel-rich” combustion conditions in the lower burners. These basic techniques are often applied prior to, or along with, other combustion techniques and technologies associated with NO_X emission control. The amount of potential NO_X emission reduction is highly-dependent on the specific type of firing, fuel, and conditions which apply to the boiler(s) being reviewed. Typically, the operation of burners in an air-starved, fuel-rich mode is similar to that included as part of separated overfire air system implementation.

Significant additional long-term NO_X emissions reduction at LOS from these improvements is not expected. Improvements to the operation of the combustion equipment in a manner that allows modest amounts of burner/cyclone air staging, along with reducing combustion air inputs have already decreased pre-control baseline annual average NO_X emissions. This will subsequently affect (limit) the amount of further NO_X reduction possible from these basic combustion improvements. The benefits from this alternative were assumed to be included in the alternatives involving separated overfire air. This alternative was eliminated from consideration as a separate stand-alone option for additional NO_X reduction at LOS Station.

A1.2.2 Low-NOx Burners (LNB)

Low NO_X burners (LNBs) of various designs have been commonly applied to pulverized coal-fired utility and industrial boilers for more than ten years. These are often, but not always, installed with some form of overfire air to allow for air-staged or "starved air" combustion to lower NO_X emissions. LOS Unit 1 already has low NOx burners suitable for good combustion performance and low NO_X emissions with pulverized lignite fuel. Installed low-NO_X burners at Leland Olds Station Unit 1 with close-coupled overfire air have already decreased pre-control baseline annual average NO_X emissions to approximately 0.29 lb/mmBtu. Installing the latest multi-zone LNBs would not be expected to significantly lower NO_X emissions without potentially introducing adverse operational consequences, such as unstable pulverized fuel ignition and high unburned carbon content in the boiler's particulate emissions.

LNBs are not applicable to cyclone-fired boilers[1]. This is due to the physical constraints imposed by the cyclone furnaces' (barrels) length and diameter, and the incompatibility with the amount of heat released and flame dispersion patterns, and insufficient amount of fine coal particles required to sustain stable combustion associated with air-staged firing of coal using low-NO_X burners with pulverized fuel. This alternative was eliminated from consideration for potential additional NO_X emissions reductions from LOS boilers.

A1.2.3 Separated Overfire Air (SOFA)

Separated overfire air (SOFA) is a commonly-applied, combustion-related NO_X emission reduction technology. Separated Overfire Air (SOFA) is an air-staging NO_X reduction technique that is usually based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the firing zone. LOS Unit 1 operates with close-coupled overfire air (CCOFA), which has ports that are closer in vertical distance above the top row burners than optimized separated overfire air ports. It is believed that LOS Unit 1's boiler would be a suitable candidate for the installation of SOFA and removal of CCOFA ports for additional NO_X control, if this is necessary. This technology is feasible for LOS Unit 1's boiler if NO_X control beyond the presumptive BART level of 0.29 lb/mmBtu is required.

For typical cyclone coal-fired boilers, the operation of SOFA involves diverting approximately 20 percent of the secondary combustion air from the burner barrels, forcing the cyclones to operate fuel-rich. The diverted combustion air is then injected in the upper furnace, where combustion is completed.

SOFA can achieve significant NO_X reduction, typically 50 to 70 percent on typical cyclone coal-fired boilers with this typical amount of air staging. A summary of several of the first OFA retrofits to cyclone-fired boilers is described in published technical papers[1,2]. At least thirty nine existing cyclone-fired boilers, firing eastern bituminous, midwestern bituminous, and western subbituminous ("Powder River Basin") coals in units ranging in size from 50 to 1150 MW, have been retrofitted with commercial SOFA since 1998[3]. Additional cyclone-fired boilers have installed separated overfire air systems in conjunction with commercial fuel reburn retrofit projects[4]. Other NO_X emission reduction demonstration projects, primarily sponsored by U.S. Department of Energy National Energy Technology Laboratory's Clean Coal Technology Program[5], and other fuel reburn retrofit projects[6] have also installed separated overfire air on cyclone boilers. These cyclone boiler retrofit SOFA installations are listed in the U.S. NO_X Reduction Projects Summary in Appendix A.3.

A cyclone-fired boiler at Ameren Electric's Sioux plant (Unit 1) reduced NO_X emissions from 1.2 lb/mmBtu to as low as 0.38 lb/mmBtu in 2002 when operating with air-staged cyclones and separated overfire air, dropping NO_X as much as 68% at full load (480 MW) firing a blend of 85% western subbituminous (PRB) fuel and 15% Illinois bituminous coals[7]. This 500 MW unit, typically firing a blend of PRB and Illinois coals, is close in unit output to LOS Unit 2. Further operation at greater amounts of overfire air and deeper cyclone air-staging in 2004 demonstrated NO_X emissions down to 0.30 lb/mmBtu, a 75% reduction[8]. Additional testing in May-June 2005 achieved NO_X emissions as low as 0.20

lb/mmBtu by "deep air-staging" the cyclones using high amounts of overfire air when firing an 80:20 PRB/Illinois coal blend at 480 MWg, an 83% reduction[9].

A basic form of separated overfire air (SOFA) can be applied and installed on LOS Unit 1 and Unit 2 boilers. There are potential impacts and limitations unique to cyclone boilers firing North Dakota lignite that should be recognized as part of this emission reduction technology application.

A key aspect of successfully applying and operating separated overfire air on a cyclone-fired boiler is the ability to maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps. As secondary combustion air is diverted, less heat is released during air-staged combustion from the intentional formation of carbon monoxide, and temperatures within the cyclones decreases. The degree to which the cyclones can be operated with less than theoretical (stoichiometric) combustion air directly contributes to less NO_X formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. Due to the variability of the combustible and ash components of North Dakota lignite, and the complex behavior of lignite ash when exposed to high temperatures, the ability to achieve NO_X control similar to percentages demonstrated while firing bituminous or subbituminous coals with significant amounts of air-staged cyclone combustion is uncertain. Basin Electric has operated Leland Olds Station (LOS) Unit 2 with low excess air and a cyclone barrel air/fuel ratio estimated to be approximately 95% of the theoretical amount required for complete combustion, yielding a highest 24-month period average NOx emission rate during the 2000-2004 output around 0.67 lb/mmBtu while firing a high lignite/Powder River Basin (PRB) coal blend. The lignite drying systems' vents add moisture and oxygen, raising furnace excess oxygen to appropriate levels. Using a basic SOFA system, assuming a sustainable level of NO_X emissions control with the operation of modestly air-staged cyclone furnaces with suitable combustion controls, is considered feasible for LOS Unit 2.

In order to potentially achieve lower NO_X emission rates with air-staged combustion for LOS Unit 2's boiler, additional combustion improvements can be installed. One potential improvement is to implement a unique form of SOFA for North Dakota-lignite–fired cyclone boilers. "Advanced" SOFA for lignite-fired cyclone boilers offers the highest performing version of this technology, and includes relocated lignite drying system vent ports, and relocated flue gas recirculation ports.

The basic version of separated OFA for LOS Unit 2 is expected to be technically feasible to design, furnish, install, and operate. There are several challenges anticipated for implementing advanced SOFA, primarily involving the ability to route large SOFA ductwork for diverting secondary air from the windboxes and extend the existing vent piping to new lignite drying systems' vent ports relocated from the lower to the upper furnace walls. These are believed to be solvable.

For LOS Unit 1's wall-fired boiler, basic SOFA is expected to have a modest NO_X reduction of approximately 20% below the 2000-2004 pre-control highest 24-month average baseline level, down to 0.23 lb/mmBtu. For LOS Unit 2's cyclone boiler, ASOFA alone is expected to have a modest NO_X reduction of approximately 28% below the 2000-2004 pre-control highest 24-month average baseline level, down to 0.48 lb/mmBtu. This estimate is based on the premise that cyclone air/fuel stoichiometric ratios will be restricted (limited to around 0.95) because of concerns for possible slag freezing, and that air-staged NOx control effectiveness will be diminished compared to demonstrated SOFA performance at other cyclone boilers.

Forms of separated overfire air described above are considered feasible as a combustion-related NO_X control technique for application to LOS Station Unit 1 and Unit 2 boilers.

Another form of separated overfire air being marketed commercially is "Rotating Opposed Fired Air" (ROFA). For utility applications in the United States, this has only been applied to pulverized coal-fired boilers, primarily small to medium-sized tangentially-fired units. It is different than basic SOFA in that it includes a hot air booster fan, and injects the overfire air in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. The vendor (Mobotec USA) claims ROFA maximizes air-staged in-furnace combustion NOx reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon. More than three tangentially-fired utility boilers burning eastern bituminous coal or Illinois bituminous coal have been retrofitted with ROFA, each achieving a NO_X reduction of approximately 53-62% from pre-installation baselines of 0.54 to 0.60 lb/mmBtu without low-NO_X burners[10,11,12]. Even though boosted SOFA (ROFA) is not expected to produce a significant NO_X control reduction advantage compared with conventional SOFA to compensate for the higher costs of supplying, installing, and operating the hot air booster fan for LOS Unit 1, it was considered technically feasible for additional NO_X reduction on Unit 1 at LOS Station. For LOS Unit 1's wall-fired boiler, boosted SOFA (ROFA) is expected to reduce NO_X emissions approximately 24.3% below the 2000-2004 pre-control highest 24-month average baseline level, down to 0.216 lb/mmBtu.

While this variation of separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Since cyclone boilers do not require the addition of hot air booster fans for SOFA, this technique is not distinct enough from basic SOFA from functional and air-staged cyclone NO_X reduction performance standpoints to warrant individual consideration. This alternative was eliminated from consideration for additional NO_X reduction on Unit 2 at LOS Station.

A.1.2.4 Oxygen-Enhanced Combustion (OEC)

A supplier of liquid oxygen (Praxair) has developed a method of replacing some of the combustion air supplied to the burners with pure oxygen. Combustion air, which is normally input through the secondary air system ductwork downstream of the forced draft (FD) fan and air heater, is supplemented with pure oxygen directly injected into the burners. Oxygen-enhanced combustion (OEC) can reduce boiler NO_X emissions resulting from " thermal NO_X", a reaction of the nitrogen in the combustion air admitted to the burners with the available oxygen component of the air in the flame or peak temperature regions of the fuel combustion process. The use of pure oxygen instead of air reduces the availability of nitrogen from the air to be oxidized in the high temperature regions, thus reducing formation of thermal NO_X. This technique has only been demonstrated in a boiler with pulverized fuel burners firing bituminous coal[13,14]. OEC was considered technically infeasible for additional NO_X reduction on Unit 1 at LOS Station.

The lack of adequate experience on any cyclone-fired coal burning boiler, on a temporary demonstration or permanent full-scale basis, for a coal-fired facility of this size precludes consideration of oxygen-enhanced combustion at Leland Olds Station for the Unit 2 boiler. This is deemed to be infeasible technology at LOS for Unit 2 at the present time.

A1.2.5 Flue Gas Recirculation

Flue gas recirculation has been commonly applied to coal-fired boilers, primarily to inject flue gas into the lower furnace, just above the burners, supplied from the boiler's economizer flue gas outlet via a hot gas booster fan. This modifies the amount and temperature of hot furnace gas either in the lower-middle or upper furnace and convection heat transfer zones. Flue gas recirculation for NO_X control is most commonly applied with gaseous or liquid fossil fuels to reduce the high temperatures which convert nitrogen in the combustion air to nitrogen oxides.

No examples of using or installing FGR on wall-fired or cyclone-fired coal-burning boilers strictly for NO_X emissions control were found in available technical literature. Although FGR could be installed on LOS Unit 1's boiler, it has not been necessary for steam temperature or furnace exit gas temperature control purposes, and is not expected to reduce NOx emissions. This technology is considered technically infeasible as a stand-alone, effective NO_X emissions control option for LOS Unit 1's boiler.

This technique is already practiced at Leland Olds Station in the Unit 2 boiler, primarily for operational reasons. As this flue gas typically has an oxygen content around 2-5%, it limits the availability of oxygen in a high temperature, possibly fuel-rich lower furnace zone. For LOS Unit 2's boiler, FGR could aid in potentially providing some additional NO_X emissions control if it were modified from its current configuration, as part of an advanced form of separated overfire air.

Although FGR is technically feasible for LOS Unit 2 in conjunction with other combustion improvements as part of the advanced form of SOFA, it has not been considered further as a stand-alone, effective NO_X emissions control option for LOS Unit 2's boiler.

A1.2.6 Water/Steam Injection (Combustion Tempering)

When applied to older gas-fired and oil-fired utility and industrial boilers, water and/or steam injection adds moisture into the lower furnace, concurrent with or near (to the side or slightly above) the burners, supplied from the boiler's treated feedwater or auxiliary steam systems via a metering pump or valve. Water/steam injection has been applied and practiced on natural gas-fired utility boilers for NO_X emissions control, but is believed to be relatively uncommon for continuous use on large pulverized coal utility boilers. There has been some limited testing and practice of water injection for NO_X emissions control on coal-fired and natural gas-fired cyclone boilers, respectively, demonstrating up to 30% reduction at full load[1,15]. This technique is most effective on gas-fired or bituminous coal-fired boilers. However, no examples of using or installing water injection and continuously operating such applications strictly for NO_X emissions control on wall-fired or cyclone-fired boilers burning subbituminous coal were found in available technical literature. Successful long-term operation of water injection would be difficult for lignite-fired boilers, due to the high moisture levels in the coal and the need to readily ignite and sustain stable combustion (and molten slag formation in the cyclone furnaces). For these reasons, water/steam injection is considered technically infeasible for NO_X control application at Leland Olds Station.

A.1.2.7 Fuel Reburn

Another combustion technology that may be applicable to control NO_X emissions from the Leland Olds Station units is fuel reburn. In a similar manner that overfire air diverts a portion of the combustion air input to the main firing zone, the reburning process involves supplying a portion of the fuel heat input to the boiler at a higher elevation in the furnace. In consideration of applying fuel reburn to LOS boilers, the existing burners/cyclones will be supplied with the majority of the fuel in the form of pulverized coal/crushed coal, respectively, and the balance of fuel is supplied to feed the reburn injection ports, such that the total heat input to each boiler is essentially the same as without fuel reburn. This creates an upper furnace atmosphere where the reburn fuel's combustion products causes some of the NO_X formed in the main burner combustion zone and reburn zone to be converted into molecular nitrogen. Depending on the amount of reburn fuel added and the amount of oxygen available in the furnace gases to combine with the reburn fuel introduced, additional combustion air may be supplied as supplemental or overfire air. Downstream of the air injection elevation, the intention is to complete the reaction of any remaining carbon monoxide (CO) to carbon dioxide (CO_2), plus reduce the amount of combustible matter remaining in the entrained flyash.

The most common forms of reburn technology applied to utility powerplant boilers are:

- Pulverized or micronized coal reburn (PCR or MiCR); and
- Gas reburn (GR).

Pulverized coal reburning and micronized coal reburning have been applied to pulverized coal and cyclone-fired boilers. NO_X reduction efficiencies of 50 to 60 percent have been demonstrated on eastern bituminous coal and midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone[5].

For utility powerplant boiler applications, natural gas has been utilized as reburn fuel most often, demonstrated in two basic approaches:

- Conventional gas reburn (CGR); and
- Fuel-lean gas reburn (FLGR™).

Either natural gas or pulverized coal (lignite) can be used as the reburn fuel. A sufficient quantity of natural gas is not currently available at the Leland Olds Station plant site. Supplying enough natural gas to provide 6 to 30% of the total heat input to either or both boilers at LOS is expected to be technically feasible, although transport pipeline installation capital costs, and current and predicted future unit natural gas costs and operating economics, are expected to be unfavorable.

Various forms of fuel reburning have been demonstrated and operated routinely on pulverized coal and cyclone boilers for NO_X emission controls[1,2,4,5,6,,16,17,18,19]. This technique has been applied to units firing eastern bituminous coal, and western subbituminous or PRB/bituminous coal blends, using pulverized or micronized coal or natural gas as the most common reburn fuel. Reburning for NO_X emissions reduction has never been demonstrated on a full-scale utility boiler firing high moisture, low heat content North Dakota lignite. Pulverized and micronized coal, along with conventional and fuel lean gas reburn technologies, are discussed below.

A.1.2.7.1 Coal Reburn

Conventional pulverized or micronized coal reburn (PCR or mCR) have been installed and demonstrated as effective for NO_X control on pulverized coal and cyclone boilers[5,6,16,17,18,19]. PCR/mCR replaces around 15-30% of total boiler fuel heat input with reburn fuel injected downstream of burners and upstream of SOFA, with or without air-staging the burners/cyclones. PCR/mCR will likely involve operation with fewer active pulverized coal main burners/cyclones. As a NO_X control technology, PCR/mCR is considered technically feasible for application on Leland Olds Station Unit 1 boiler. Examples of PCR/mCR applied to several pulverized coal-fired boilers are included in Appendix A3. Potential application of this alternative as a NO_X control option for LOS Unit 1's pulverized coal-fired boiler has similar combustion-related fuel- and air-staging, fuel preparation, and particulate emission issues as coal reburn applied to LOS Unit 2's cyclone boiler.

Pulverized or micronized coal reburn with the basic and boosted forms of separated overfire air (ROFA) can be applied and installed on Leland Olds Station Unit 1 boiler. PCR/mCR with basic SOFA is expected to reduce NO_X emissions approximately 46.2% from 2000-2004 pre-control highest 24-month average baseline levels, down to 0.154 lb/mmBtu for the LOS Unit 1 boiler. PCR/mCR with boosted SOFA is expected to reduce NO_X emissions approximately 48.7% from 2000-2004 pre-control highest 24-month average baseline levels, down to 0.147 lb/mmBtu for the LOS Unit 1 boiler. These expected levels of NO_X reduction are considered to be a reasonable estimate, given the concerns expressed about the potential impacts of this technique. Using finely pulverized lignite for reburn fuel is considered technically feasible for NO_X emissions control under evaluation for application to the LOS Unit 1 boiler.

In the case of applying conventional coal reburn to cyclone boilers, the existing cyclones are supplied with the majority of the fuel, with either natural gas or pulverized coal (lignite) used as the reburn fuel such that the total heat input to the boiler is essentially the same as without fuel reburn. Separated OFA ports are located above the reburn fuel injection section of the furnace. These SOFA ports provide sufficient oxygen in a conventional fuel reburn installation to complete the combustion process that begins in the main combustion zone and is supplemented in the reburn and burnout zones. This is shown schematically for a pulverized coal reburn application on a cyclone-fired boiler with SOFA in Figure A.1-1.

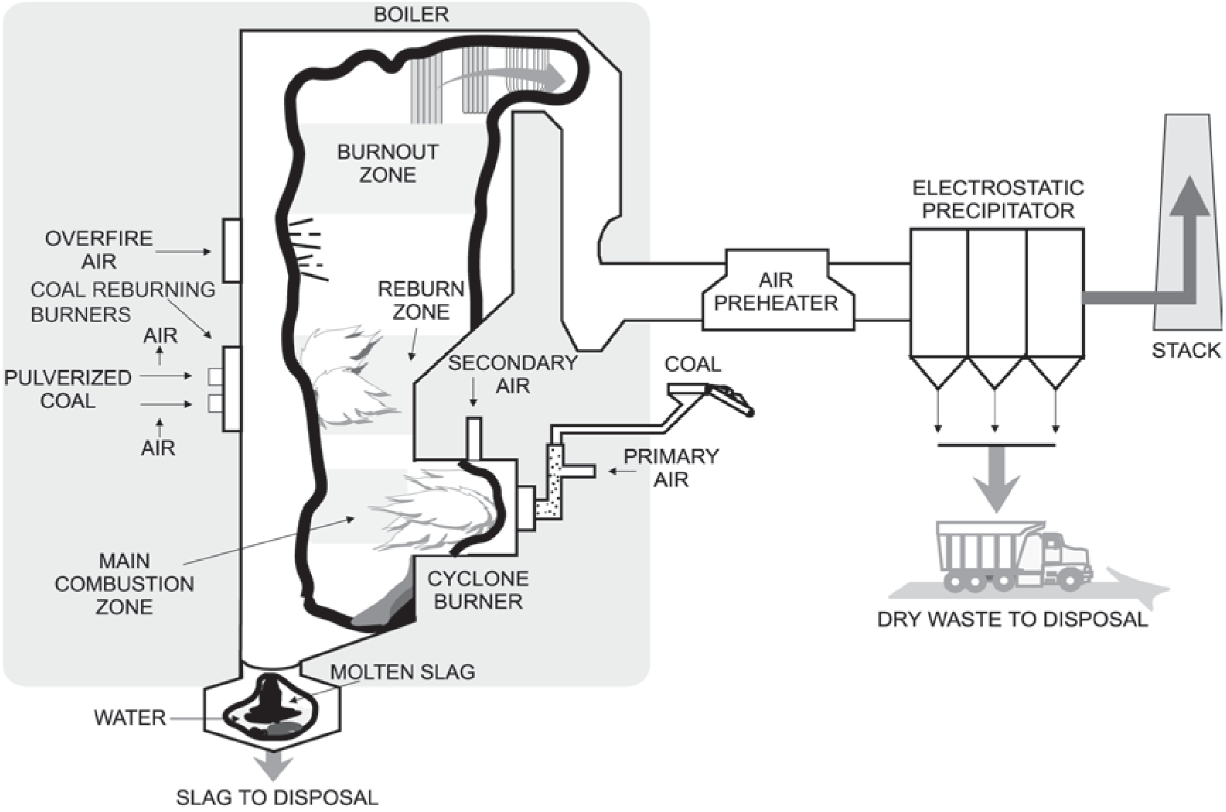


Figure A.1-1 Pulverized Coal Reburn Application on Cyclone Boiler With Overfire Air[19]

In the United States, pulverized coal reburning and micronized coal reburning techniques for utility powerplant NO_X emissions reduction have been applied on a very limited full-scale, full-time basis to cyclone-fired boilers in field demonstration tests and longer-term demonstration operation, respectively. There have been only two known pulverized or micronized coal reburn installations in the United States on cyclone boilers, one on a utility boiler in Wisconsin, and one on a small industrial-size cyclone boiler in New York state[5]. NO_X emissions reduction efficiencies of 57 percent have been demonstrated on cyclone boilers firing eastern bituminous coal, or midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone. With the exception of the U.S. Department of Energy's (DOE) Clean Coal Technology Program demonstration projects[7,21], no known commercially-available coal reburn systems have been installed and were/are routinely operated on cyclone boilers in the United States to date. The DOE-CCTP projects for coal reburn applied to cyclone boilers are described below.

Pulverized coal reburning for NO_X emissions reduction in a cyclone-fired boiler was demonstrated on the 110 MW Nelson Dewey Unit 2 for Wisconsin Power & Light in 1991-1992. Reburn fuel preparation and handling, reburn burners with flue gas recirculation, and a separated overfire air system were added. Coal reburn tests were conducted on this unit while firing bituminous and PRB coals. NO_X emission control efficiencies of 50 to 60 percent, with reductions from 0.75-0.83 lb/mmBtu baselines to around 0.38 lb/mmBtu, but as low as 0.29 to 0.32 lb/mmBtu, with PRB coal at full load with approximately 25-30% of the total fuel heat input from reburn fuel were demonstrated[5,17,18]. The reburn system is no longer operated on Nelson Dewey Unit 2.

Micronized coal reburning has been demonstrated in 1997-1998, and continues to operate year-round on a small industrial cyclone boiler (400,000 lb/hr steam output, 50 MW gross equivalent) for Eastman Kodak Company at their Kodak Park facility in Rochester, NY. This unit (Boiler #15) achieves a NO_X reduction efficiency of approximately 57 percent on eastern bituminous coal, involving limited cyclone air-staging (cyclones believed to be slightly above 0% excess air) and a modest amount of overfire air injection downstream of the micronized reburn fuel input nozzles. Approximately 17% of the boiler's total fuel heat input is typically supplied to the reburn zone. This coal reburn system continues to operate routinely at this facility. This installation is reported to use a Fuller MicroMill to produce micronized coal with 80% passing through a 325 mesh screen[5,16].

Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. As a reburn fuel, lignite is expected to behave appropriately upon introduction in the lower middle furnace to help reduce NO_X emissions. The concerns are that the diversion of a significant amount of heat input from the cyclone barrels to use as a source of reburn fuel in the form of pulverized or micronized lignite may reduce active cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Coal reburn can be applied with or without air-staging the cyclones, i.e. operate in normal-low excess air mode or substoichiometrically. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction as part of this reburn technique will further risk slag “freezing” in the barrels and lower furnace. Reducing the number of active cyclones to maintain fuel and heat input rates comparable to normal pre-control baseline (i.e. non coal reburn) operation can accommodate reduced total cyclone coal firing rates while operating a coal-fired boiler with reburn and separated overfire air is the typical approach to avoid slag tapping problems. However, if the fewer number of active cyclones are air-staged, this limits the amount of in-furnace NO_X reduction that may be achieved with this technique.

Significant additions to the fuel preparation equipment in the existing plant facilities will be required. The coal reburn system expected to be applied to each of the LOS boilers would use two new dedicated fine-grind pulverizers and dynamic classifiers for each boiler to achieve the level of coal particle size distribution required.

Higher unburned carbon levels in the flyash exhausted from the boiler may occur, especially when the reburn fuel is coal, and the main burners/cyclones are fired with less than theoretical amounts of combustion air commonly practiced with the use of overfire air.

Particulate emissions and flue gas opacity from the stack will increase during coal reburn operation with particulate matter (PM) removal performed by an electrostatic precipitator (ESP), due primarily to higher inlet particulate loadings and smaller particle sizes of the flyash. The estimated increase in LOS Unit 2’s ESP inlet PM during coal reburn will be approximately +50% of the baseline amounts. This magnitude of flyash increase is usually not significant enough to preclude the use of reburn fuel due to exceeding permitted opacity limits, unless the ESP is already marginal on flyash removal efficiency. However, assuming that LOS Unit 2’s ESP outlet PM emissions are not allowed to increase due to the coal reburn conditions as described above, then additional PM collection equipment to increase PM collection capacity, or boiler firing restrictions, will need to be implemented. This is very significant for LOS Unit 2. Since the LOS Unit 2 boiler is fired with crushed coal, and the cyclone boiler’s typical PM emission is approximately one third to one half of the boiler’s total ash input, the existing ESPs are designed for relatively modest inlet dust loadings. There is likely to be insufficient flyash collection efficiency if coal reburn were to be applied without additional PM collection equipment to increase PM collection capacity.

An issue that affects the feasibility of lignite reburning is the uptime required for the lignite reburn fuel pulverizing system, and impact of the reburn system on effectiveness in reducing NO_X emissions during load changes and lower loads. Typically, one new pulverizer is dedicated to prepare reburn fuel in existing pulverized fuel-fired boiler applications. Cyclones may be fired with less fuel or deactivated during current boiler operation in order to accommodate changes in fuel combustion characteristics, boiler load, and for scheduled or unscheduled individual crusher maintenance. Leland Olds Station Unit 2 has twelve crushers for cyclone coal grinding, each dedicated to one of the twelve cyclones. Diverting as much as 30% of the total heat input as reburn fuel could require two to four existing cyclones to be deactivated, and two new MPS-89 pulverizers to be dedicated to reburn fuel preparation. As each of these mills requires periodic maintenance, boiler emissions and/or load could be negatively impacted during individual reburn mill outage periods while the boiler remained in service. A high level of fineness of coal particles from the reburn mills is important to achieve and maintain in order to limit increases in flyash combustibles. A minimum of 60 percent passing through 200 mesh fineness is recommended by one of the reburn technology vendors (B&W) for pulverized lignite reburn. Micronized coal reburn requires even greater fineness: 70-80 percent passing through a 325 mesh screen.

Pulverized or micronized coal reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on Leland Olds Station Unit 2 boiler. These combined techniques are expected to reduce NO_X emissions approximately 52% from 2000-2004 pre-control highest 24-month average baseline levels, down to 0.32 lb/mmBtu for the LOS Unit 2 boiler. The expected level of NO_X reduction is considered to be a reasonable estimate, given the concerns expressed about the potential impacts of this technique. Using finely pulverized lignite for reburn fuel is considered technically feasible for NO_X emissions control under evaluation for application to the LOS Unit 2 boiler.

A1.2.7.2 Conventional Gas Reburn

Natural gas has been preferred as the reburn fuel of choice. Natural gas has been utilized for reburn fuel in two basic approaches: conventional gas reburn (CGR) and fuel-lean gas reburn. In the conventional approach, up to 30% of the boiler's total fuel heat input is supplied to the reburn zone, followed by a significant amount of overfire air for completion of combustion prior to flue gases exiting the boiler.

One example of CGR applied to a pulverized coal-fired boiler is included in Appendix A3. Potential application of this alternative as a NO_X control option for LOS Unit 1's pulverized coal-fired boiler has similar issues as gas reburn applied to LOS Unit 2's cyclone boiler.

A schematic graphic of conventional gas reburn on a pulverized coal-fired boiler is shown in Figure A.1-2.

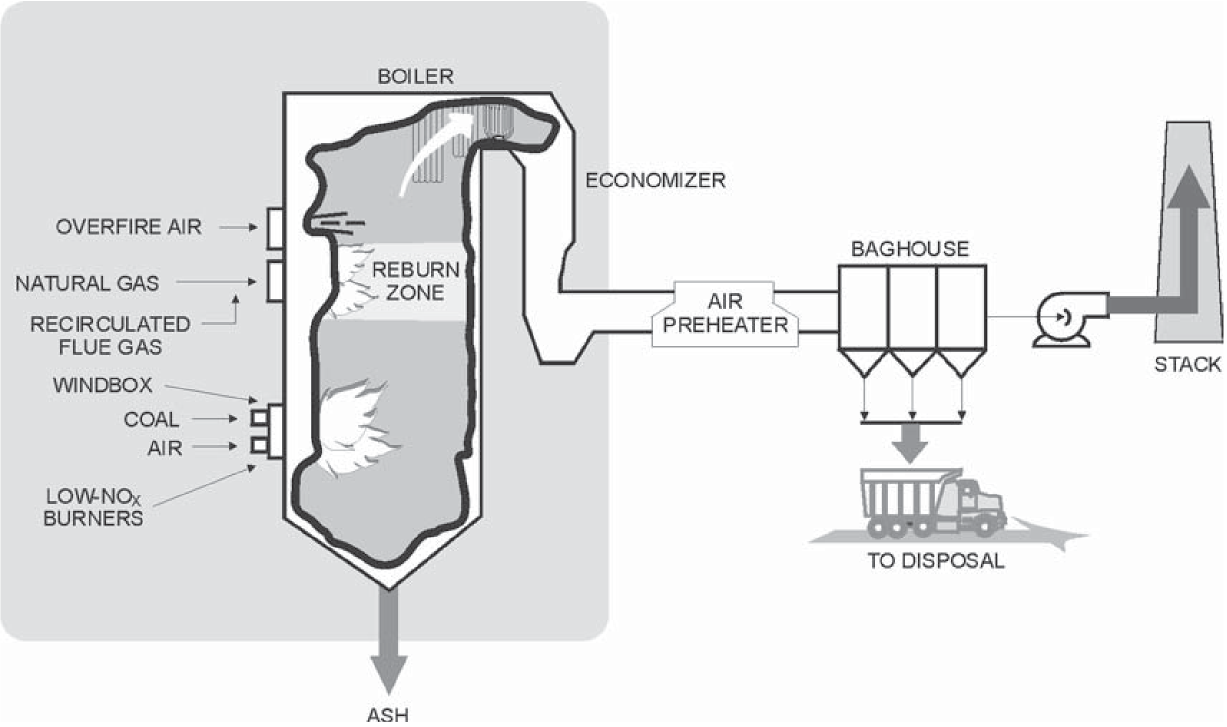


Figure A.1-2 Natural Gas Reburn Application on Wall-Fired Pulverized Coal Boiler with Overfire Air[19]

As a NO$_X$ control technology, conventional gas reburn is considered technically feasible for application on Leland Olds Station Unit 1's boiler. Natural gas unit costs are expected to be approximately nine times more expensive per million Btu than coal. Leland Olds Station does not have a supply of large quantities of high-pressure natural gas to consume for reburn fuel. Bringing a high-pressure gas pipeline approximately 26 miles to the plant site is considered technically feasible. An order of magnitude estimated cost of $1 Million per mile would be significant; the installed capital cost of such an asset, and the expected high unit gas prices are significant economic disadvantages, and make this alternative economically unfavorable compared to other NO$_X$ control options with similar expected performance. For these reasons, conventional gas reburn was not evaluated for consideration as an option for LOS Unit 1.

Conventional gas reburning in a cyclone-fired boiler has been available at Tennessee Valley Authority's Allen Station Boiler #1 (300 MW) since 1998. The reburn technology provider (vendor) claims NO_X emissions were reduced 67% from a full-load baseline of 1.29 (down to 0.42) lb/mmBtu when firing a blend of western bituminous and PRB coals[8]. Conventional gas reburn fuel input rates were not available from the technology vendor's literature. Another reference source of information stated NO_X emissions were reduced 65% from a full-load baseline of 0.86 (down to 0.30) lb/mmBtu with 7 percent of the total fuel heat input supplied as reburn fuel[5].

Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. As a reburn fuel, natural gas is expected to behave appropriately upon introduction in the lower middle furnace to help reduce NO_X emissions. The concerns are that the withholding of a significant amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones for use of separated overfire air to further complement combustion NO_X reduction as part of this reburn technique will further risk slag "freezing" in the barrels and lower furnace. Reducing the number of active cyclones which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with reburn and separated overfire air is the typical approach to avoid slag tapping problems.

Natural gas reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on Leland Olds Station Unit 2's boiler. There are no published CFD model studies showing potential results of applying conventional gas reburn techniques to a North Dakota lignite-fired cyclone boiler to predict the level of NO_X control that may be achievable. For lignite-fired cyclone boilers, conventional reburn fuel firing with a basic form of separated overfire air is expected to be much less effective in reducing NO_X emissions than previously demonstrated elsewhere. Using high-pressure natural gas for reburn fuel is considered technically feasible for NO_X emissions control applicable to Leland Olds Station'a Unit 2's boiler. However, due to the expected high installed capital cost of bringing a high-pressure gas pipeline to the plant site, and high unit gas prices make this alternative economically unfavorable compared to other NO_X control options with similar expected performance. CGR was not evaluated for consideration as an option for LOS Unit 2.

A1.2.7.3 Fuel Lean Gas Reburn

Another approach to gas reburning is “fuel-lean gas reburn” (FLGR™) technology, which injects limited amounts of natural gas above the burners (or cyclones) with or without significant air-staging of the burners (cyclones) or the addition of overfire air upstream of the fuel injection elevation.
More commonly, FLGR™ has been applied on medium to large pulverized coal wall-fired boilers burning eastern bituminous or western subbituminous coals. On Wisconsin Electric Power Company’s (WEPCO’s) Pleasant Prairie Unit 1, a 620 MWg Riley turbo-fired wet-bottom (slagging) pulverized coal boiler, FLGR™ alone was predicted to reduce NO_X emissions by 35-39 percent at a gas reburn rate of 7-8 percent but only achieved 20% from a baseline of 0.45 lb/mmBtu[21,23]. This is presumably without burner air-staging or SOFA. It has also been applied in combination with SNCR at this WEPCO site. Several other examples of FLGR™ applied to pulverized coal-fired boilers are included in Appendix A3.

As a NO_X control technology, FLGR™ is considered technically feasible for application of Leland Olds Station Unit 1 boiler. Potential application of this alternative as a NO_X control option for LOS Unit 1’s pulverized coal-fired boiler has similar issues as conventional gas reburn. Leland Olds Station does not have a supply of large quantities of high-pressure natural gas to consume for reburn fuel. Bringing a high-pressure gas pipeline to the plant site is considered technically feasible. However, the installed capital cost of such an asset, and the expected high unit gas prices are significant economic disadvantages, and make this alternative economically unfavorable compared to other NO_X control options with similar expected performance. For these reasons, fuel lean gas reburn was not evaluated for consideration as an option for LOS Unit 1.

FLGR’s first field-test on a cyclone-fired boiler was at Commonwealth Edison’s Joliet Unit 6 (327 MW), a 9-cyclone-furnace boiler[20]. NO_X emissions reduction with FLGR (without SOFA) was believed to be approximately 35-40% with 7% of the boiler’s total fuel heat input supplied in the reburn zone. This test yielded 0.59 lb/mmBtu NO_X emissions from a baseline of 0.98 lb/mmBtu[21]. One other cyclone boiler has been modeled using computational fluid dynamics (CFD) as part of a study looking at applying FLGR at Owensboro Municipal Utilities’ Elmer Smith Station Unit 1 (150 MW single-wall, eastern bituminous coal-fired boiler with three cyclones). This model predicted that NO_X emissions could be reduced by 25-30% over that achievable from overfire air and SNCR[22].

Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. As a reburn fuel, natural gas is expected to behave appropriately upon introduction in the upper furnace (above the SOFA elevation) to help reduce NO_X emissions. There are concerns that the withholding of a modest amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Limited additional potential NOx reduction is anticipated when FLGR™ is operated with lignite-fired cyclones, due to the potential need to remove one or more cyclones from active firing to maintain adequate heat input in the remaining active cyclones for keeping satisfactory slag formation and flow. This creates lower furnace conditions where oxygen (cooling air from the idle cyclones) is introduced in proximity to the reburn fuel, disrupting the desired in-furnace reduction process for nitrogen oxides.

In the case of FLGR™ applied to lignite-fired cyclone boilers, the amount of fuel injected above the existing lignite drying system vent ports is expected to be substantially more than previously demonstrated in order to compensate for the higher oxygen levels due to the introduction of moist air in the lower furnace above the cyclones without relocating the vent ports. The existing lignite drying systems' vent ports' locations and introduction of oxygen to the lower furnace below the presumed FLGR™ injection points (as part of the basic form of SOFA) will likely limit the NO_X emission reduction potential of the FLGR™ component.

Fuel lean gas reburn can be applied and installed on LOS Unit 2 boiler. There are no published CFD model studies showing potential results of applying fuel lean gas reburn techniques to a North Dakota lignite-fired cyclone boiler to predict the level of NO_X control that may be achievable. Although this technique is considered technically feasible for application to LOS Unit 2 boiler, the unit operating and capital costs to supply large quantities of gaseous fuel not currently available at this site are economic disadvantages compared to other NO_X control options with similar expected performance. It was not evaluated for consideration as an option for LOS Unit 2.

Other demonstrated forms of fuel lean gas reburning, such as FLGR™ with various forms of separated overfire air, and amine-enhanced fuel lean gas reburn (FLGR™ with SNCR), are discussed under the layered technologies section.

A1.2.7.4 Fuel Oil Reburn

Fuel oil has been substituted for natural gas in a conventional reburn application. This is much less common in the United States than using natural gas as a reburn fuel, due to the general lack of demand and difficulties in supplying the volume of fuel oil which would be required. It has been installed commercially on three 350 MW oil-fired boilers in New Brunswick (Canada) at the Coleson Cove plant[4,5,17]. NO_X emissions reduction with reburn and SOFA was 78% with 25% of the boiler's total fuel heat input supplied in the reburn zone. This yielded 0.22 lb/mmBtu NO_X emissions from a baseline of 1.0 lb/mmBtu[7]. One example of conventional fuel oil reburn applied to a very large (800 MW) pulverized coal-fired boiler is included in Appendix A3. No examples of conventional fuel oil reburn applied to a coal-fired cyclone boiler were found in available literature.

Fuel oil reburn could potentially be considered for application to LOS Unit 1 and Unit 2's boilers. Potential application of this alternative as a NO_X control option for LOS Unit 1's pulverized coal-fired boiler and Unit 2's cyclone-fired boiler has similar issues as conventional gas reburn. Investigation of the specific source, distance, and costs for supplying significantly increased quantities of fuel oil via transport trucks hauling tanker trailers or underground pipeline to LOS has not been performed. The expected high unit operating and capital costs to supply large quantities of high-volume liquid fossil fuel at this site are economic disadvantages. The concerns regarding potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application are similar to those expressed for conventional gas reburn. It is believed that potential NO_X control with oil reburn would be slightly less than comparable conventional gas reburn systems.

Although fuel oil reburn could potentially be considered for application to LOS Unit 1's and Unit 2's boilers, the lack of any distinct potential NO_X reduction advantages and demonstration on cyclone-fired boilers does not appear to support its consideration. This alternative was not included in the NO_X control cost-effectiveness analysis for Unit 1 and Unit 2 at Leland Olds Station.

A1.3 Post-Combustion Controls

Post-combustion controls deal with techniques that thermally or chemically-treat the flue gases to reduce NO_X emissions after they have exited the boiler's lower furnace. In the case of Leland Olds Station Units 1 and 2, this primarily involves forms of selective catalytic reduction (SCR) and selective non-catalytic reduction (SCR) technologies. Another emerging technology that has recently entered the commercial market is Powerspan's Electro Catalytic Oxidation®, which treats utility boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury. Another emerging technology that has recently entered the pilot-scale commercial demonstration phase of development in the utility air pollution control market is Powerspan's Electro Catalytic Oxidation®, which treats boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury.

A1.3.1 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR), and variations such as hydrocarbon-enhanced SNCR (sold under the trade name of NOxStar™), and Rich Reagent Injection (RRI), are all post-combustion types of boiler NO_X emission controls. While these technologies promote NO_X reduction with chemical reactions that are insensitive to the specific fuel types whose combustion products are being treated, the large majority of boiler applications to date have been on pulverized coal-fired units burning eastern bituminous fuels. SNCR has been used to reduce NO_X emissions on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used with fuel oil and natural gas-fired units. SNCR (and hydrocarbon-enhanced SNCR) technologies can each be applied to fossil fuel-fired boilers with or without the use of a SOFA system. The ability to apply SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without overfire air in full operation. Operation at these plants has demonstrated that SNCR can decrease NO_X emissions as much as 15-40% at full load, most typically between 25-35%[23,24,25].

In the conventional SNCR process, urea or ammonia is injected into the boiler in a region where the combustion gas temperature is in the 1700 to 2100 degrees F range. Under these temperature conditions, the urea reagent [$CO(NH_2)_2$] or ammonia [NH_3] reacts with the nitrogen oxides [NO_X], forming elemental nitrogen [N_2] and water, reducing NO_X emissions.

Several examples of SNCR applied to pulverized coal-fired boilers are included in Appendix A3. Long-term examples where SNCR has been used to reduce NO_X emissions on two cyclone-fired boilers are on a 138 MW unit and 160 MW unit burning eastern bituminous coal at Conectiv's B.L England Station (Units 1 and 2) since 1995 and 1996, respectively. Tests at this cyclone-fired boiler powerplant demonstrated that SNCR can decrease NO_X emissions as much as 30-36% at full load, from around 1.3-1.4 lb/mmBtu respectively to as low as 0.85 lb/mmBtu (without overfire air)[23,24,25]. These boilers, located near Atlantic City, New Jersey, continue to operate SNCR (with OFA) for NOx emissions control recently reported annual average emission rates around 0.55 and 0.45 lb/mmBtu, respectively.

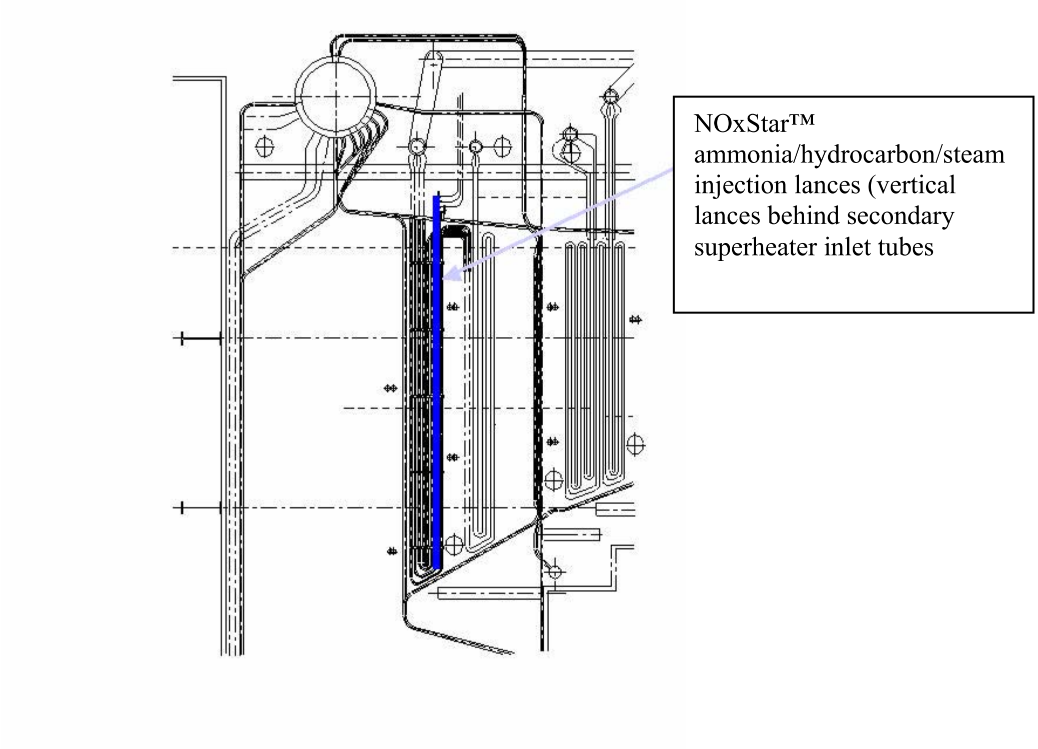
SNCR can be applied and installed on the Leland Olds Station boilers. However, with much higher installation and operation costs compared with SOFA, this alternative (without SOFA) was not evaluated for consideration as a stand-alone option for LOS Unit 1 or Unit 2.

SNCR can be installed in combination with existing close-coupled OFA, or basic or boosted forms of separated overfire air for Unit 1. The highest-performing feasible versions of conventional SNCR for LOS Unit 2 are combinations of SNCR with ASOFA with and without Rich Reagent Injection. The predicted NO_X emissions for these combinations are included in the "Layered NO_X Reduction Technologies" section of this report.

A1.3.1.1 Hydrocarbon-enhanced SNCR (NOxStar™)

Hydrocarbon-enhanced SNCR technology, commercially marketed as NO_XStar™, is offered by a single vendor (Mitsui Babcock) as a post-combustion type of enhanced SNCR technology. This involves an ammonia-based reagent that is continuously injected into the superheater/reheater pass of an operating boiler with small amounts of gaseous hydrocarbon (typically either natural gas or propane) and air or steam to provide lance cooling and aid reagent dispersion. The targeted combustion gas temperature range is between 1500°F and 2000°F. The amount of gaseous hydrocarbon introduced is small enough (0.1 to 0.2% of total fuel heat input) that this is not intended to act as a form of reburn or staged fuel combustion. An array of permanently-installed injection lances are located within the boiler convection pass, divided into numerous discrete zones across the full width and height of the duct. The hydrocarbon auto-ignites, forming hydroxyl (OH) radicals which react with the NO_X and ammonia to produce elemental nitrogen (N_2) and water vapor (H_2O).

An example of a hydrocarbon-enhanced SNCR installation on a wall-fired pulverized fuel boiler is shown as a sectional side elevation view of the upper furnace[29] in Figure A.1-3.



NOxStar™ ammonia/hydrocarbon/steam injection lances (vertical lances behind secondary superheater inlet tubes

Figure A.1-3 Hydrocarbon-enhanced SNCR Application on PC-fired Boiler[29]

NO_XStar™ was demonstrated at Tennessee Valley Authority's Kingston Power Station Unit 9 (tangentially-fired 200 MW twin-furnace boiler firing eastern bituminous coal) in 2002[26]. This technology was subsequently permanently-installed at TVA's Colbert Station Unit 4 in late 2003 on a 192 MW wall-fired boiler burning eastern bituminous coal[27]. NO_X reduction was stated as 68-80% for these applications, which included the impact of overfire air and air-staged combustion upstream of the ammonia and propane injection locations. The specific NOx reduction strictly attributable to the enhanced reagent injection without combustion effects was not disclosed.

The supplier (Mitsui Babcock) of hydrocarbon-enhanced SNCR technology claims there is little sensitivity to the type fuel (coal) or burners this technique can be potentially applied to in order to reduce NO_X emissions. Non-retractable ammonia injection lances arranged in a parallel-series manner are permanently mounted inside the upper furnace zone, attached to convective tube elements. Different sections of the injection "grid" can be turned off or on, depending on load and firing conditions and amount of NO_X reduction required. Injection nozzles are continuously purged and cooled by extracted superheated steam from the boiler's main steam outlet, whether ammonia reagent is being introduced into the flue gas stream or not. Ammonia slip can be minimized by injecting less reagent, although NO_X control performance will be reduced.

There are a number of issues related to firing North Dakota lignite that make the applicability of hydrocarbon-enhanced SNCR more difficult than in other coal-fired powerplants. These issues include:

- The chemical reagent injection for hydrocarbon-enhanced SNCR (NO_XStar™) NO_X control technology must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) model simulations are needed to determine the optimum injection points and spray patterns. Boiler operating conditions change with unit load and varying fuel characteristics. The NO_XStar™ process control system must be able to adjust for these changing conditions in order to be effective throughout the intended load range and firing conditions encountered.
- The physical arrangement of the NO_XStar™ reagent injection lances expected to be required in LOS boilers' upper furnaces will be difficult to install. Limited convection heat transfer surface is installed, resulting in high flue gas temperatures entering the air preheater so it can produce very hot combustion air for effective coal pre-drying and cyclone lignite firing. The reheater pendants or area between the reheater and primary superheater tubes are in the gas path where the temperature window is believed to be suitable for effective NO_X control. The convection heat transfer surfaces in this zone are either tightly spaced or non-existent. Since the NO_XStar™ reagent injection lances are permanently installed within the flue gas path, and attached to the convection heat transfer surfaces, this situation is not conducive to this type of reagent injection lance installation.
- Hydrocarbon-enhanced SNCR (NO_XStar™) technology has been only applied on pulverized coal-fired boilers burning eastern bituminous fuels to date. It has not been applied to cyclone boilers, especially on units firing high-slagging coals such as western subbituminous (PRB) and lignite. The heat transfer surfaces in the convective heat transfer zone of the LOS boilers where the reagent mixture would be injected are prone to severe fouling from flyash constituents common in North Dakota lignite coals. Flyash deposit accumulation on the outside of the NO_XStar™ lances in LOS boilers' upper furnaces is expected to be significant, potentially occurring within a matter of a few weeks from startup and nearly impossible to prevent or remove effectively during boiler operation. Such buildup is expected to cause significant maldistribution of the NO_X

> reduction chemical reagent from the injection nozzles. Effective on-line removal of these deposits from the injection nozzles is anticipated to be insufficient to maintain effective injection distribution and volume control. It is anticipated that this would significantly reduce the NO_X emission reduction performance consistently achieved on a sustainable basis.

This technology is considered to be technically infeasible for application on North Dakota lignite-fired boilers. The expected difficulties for installation and susceptibility of the embedded reagent injection nozzles to rapid, severe fouling will prevent consistent performance. The specific conditions of reagent lance placement and lack of experience with this type of boiler and this high-slagging coal makes the application of hydrocarbon-enhanced SNCR technically infeasible for NO_X reduction over the long term on North Dakota lignite-burning wall-fired and cyclone boilers.

A1.3.1.2 Rich Reagent Injection (RRI)

Rich Reagent Injection (RRI) is a NO_X control technology that has been developed and demonstrated specifically for use on cyclone boilers. RRI is not applicable to pulverized coal-fired boilers, and therefore is technically infeasible for LOS Unit 1. Rich Reagent Injection is an SNCR process that involves the injection of urea into the lower furnace between the cyclones and the SOFA ports. RRI targets a high temperature, fuel-rich zone within the boiler-furnace environment immediately adjacent to the cyclone burners, and requires temperatures in the range of 2400 to 3100 degrees F. The combustion gases must be essentially devoid of free oxygen, in order to avoid oxidizing the nitrogen contained in the injected reagent, which would create NO_X emissions instead of reducing them.

The RRI process for NO_X reduction must be used in conjunction with air-starved (substoichiometric staged-air) cyclone combustion resulting from the installation and operation of an OFA system, with or without SNCR. The cyclones' air/fuel stoichiometry must be carefully controlled to maintain fuel-rich conditions for the RRI process to be effective. The existing lignite drying system's vent ports are immediately above the top rows of cyclones. This introduces oxygen in the same vicinity as the reagent injection ports, and will disrupt the beneficial action of the fuel-rich zone and amine reagent to significantly reduce NO_X emissions. Without the "advanced" version of SOFA, RRI will not contribute positively to NO_X emissions control on Leland Olds Station Unit 2 boiler. This places a large emphasis on the expected performance of ASOFA in order for RRI to be successful in producing significant additional NOx emissions reduction on lignite-fired cyclone boilers.

The three zones of a Rich Reagent Injection SNCR application on a boiler with separated overfire air are shown as a sectional side elevation view of the furnace[29] in Figure A.1-4.

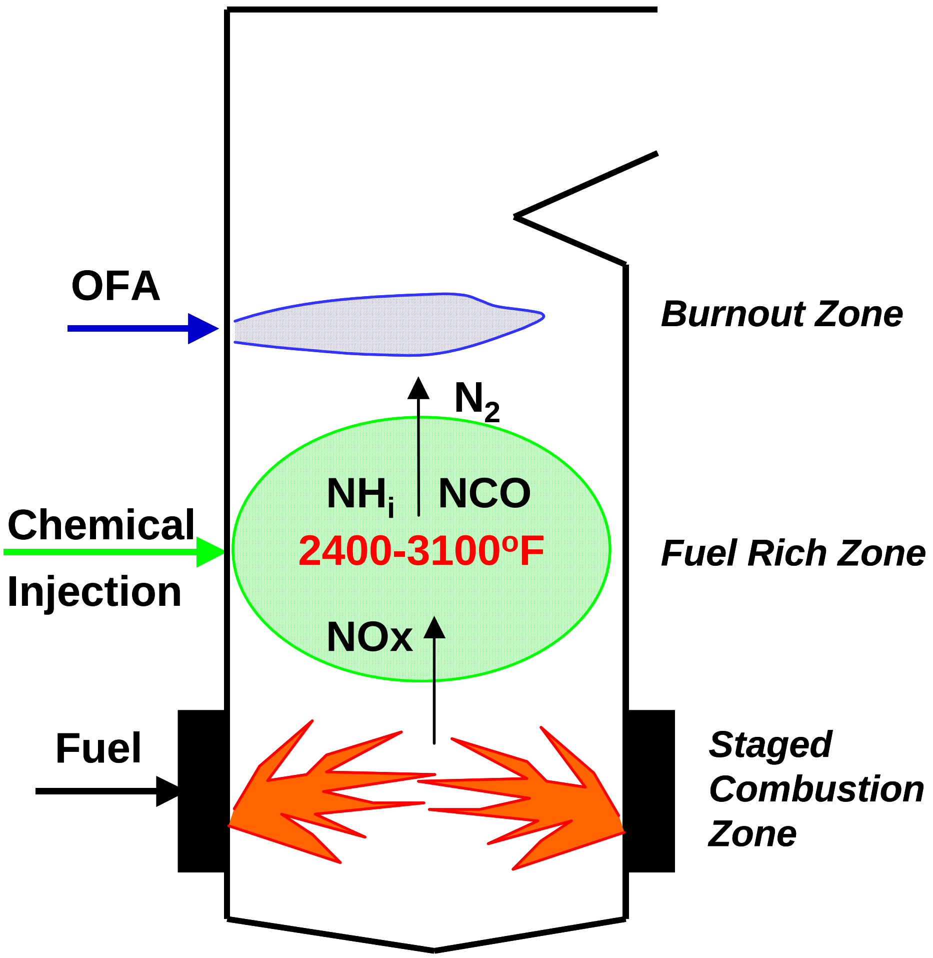


Figure A.1-4 Rich Reagent Injection Application on Boiler With Overfire Air[29]

The Rich Reagent Injection (RRI) process has been successfully demonstrated on at least two cyclone-fired boilers, with the most recent installation at Ameren's Sioux Unit 1, a 500 MW boiler firing a blend of PRB and midwestern bituminous coals. Short-term testing of the RRI process has been performed alone and in combination with SNCR on B.L. England Unit 1 in 1999[25,28,29], and more recently at Ameren's Sioux Unit 1 in 2002[7,8,29], and in the first half of 2005[9] (RRI + OFA with and without SNCR).

The NO_X emission reduction reagent injection for RRI processes must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) simulations are needed to determine the optimum injection points. Boiler operating conditions will change with unit load and varying fuel characteristics. The RRI process control systems must be able to adjust for these changing conditions.

RRI has the potential to provide a moderate degree of NO_X reduction on coal-fired cyclone boilers. Short-term parametric demonstration test data from B.L. England and Sioux show this technology can reduce NO_X emissions between 10 and 36 percent[7,8,9,28,29]. So far, the RRI process is feasible to be used only in conjunction with air-starved (substoichiometric staged-air) cyclone combustion resulting from the installation and operation of an OFA system.

The RRI process has not been demonstrated on any unit that fires North Dakota lignite. As of May 2006, commercial installation of a permanent Rich Reagent Injection system has not been made on any cyclone-fired boiler. There is only one holder of a commercial license for modeling and conceptually designing RRI (Reaction Engineering International), with two vendors sub-licensed to design and sell RRI equipment (Fuel Tech and Combustion Components Associates). Since these license agreements are in place, and considering that successful demonstration testing has been performed at two boiler powerplants, this technology is considered to be commercially available for potential application on LOS Unit 2's lignite-fired cyclone boiler.

Rich Reagent Injection can potentially be applied and installed on LOS Unit 2's boiler, which must only be with an advanced form of separated overfire air (ASOFA), in combination with and without SNCR. The predicted NO_X emissions for these combinations are included in the "Layered NO_X Reduction Technologies" section of this report.

A1.3.2 Selective Catalytic Reduction (SCR)

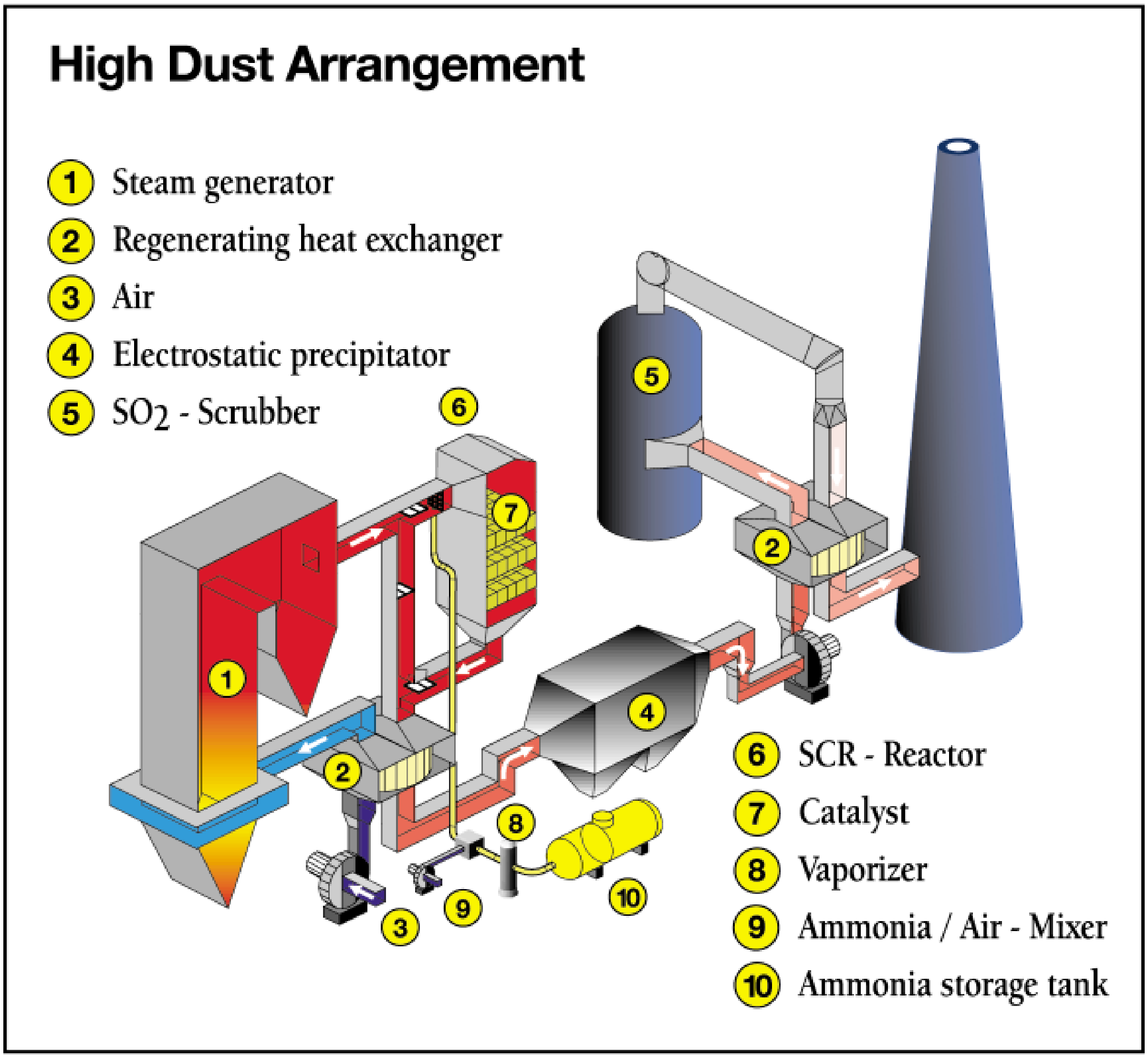
The lowest NOx emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NO_X to molecular nitrogen and water. The process is termed "selective" because the ammonia preferentially reacts with the NO_X rather than with the oxygen in the flue gas. A catalyst is used to enhance NO_X reduction and ammonia utilization at appropriate flue gas temperatures. SCR is usually applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO_X emission reduction effect. These are described below.

A1.3.2.1 High-Dust Selective Catalytic Reduction (HD-SCR)

For coal-fired boilers, a conventional SCR reactor utilizes readily-available catalyst materials and reagent in the form of ammonia. A conventional SCR reactor is commonly installed in a high-dust, hot-side arrangement, located between the economizer outlet and air heater inlet, where the flue gas temperature is within the desired operating range for the SCR catalyst.

A schematic graphic diagram for a conventional high-dust, hot-side SCR system on a boiler with a flue gas desulfurization system and stack gas reheat is provided in Figure A.1-5.

Figure A.1-5 Conventional High-Dust SCR Arrangement with FGD Scrubber Outlet Reheat



(figure copied from Wheelabrator Air Pollution Control literature)

The conventional SCR reactor arrangement is preferred for most coal-fired applications in utility boilers because it avoids the added expense of reheating the flue gas if placed after the air heaters which cool the flue gas, and downstream of any flue gas treatment to remove acid gases. Conventional SCR technology uses an ammonia injection grid (AIG), which consists of multiple nozzles, for distributing the reagent into the flue gas at the boiler's economizer flue gas outlet.

Conventional high-dust, hot-side SCR technology has been installed on several pulverized coal and cyclone boilers firing bituminous and subbituminous coal in the United States. There are also a limited number of European SCR installations on steam electric generating units (SEGUs) firing lower grade (brown) coal. There are, however, no existing full-scale SCR installations on units that fire North Dakota lignite. The feasibility of this alternative was evaluated for consideration as an option for LOS Unit 1 following many of the same arguments as for cyclone-fired lignite-burning boilers, as discussed below.

There are 56 BART-eligible cyclone-fired units. Over half of these units are planning to install conventional high-dust, hot-side SCR systems in response to the EPA's NO_X SIP call. The installation of conventional high-dust, hot-side SCR systems has been completed on approximately 22 of these units. Appendix A3 lists several conventional high-dust hot-side U.S. SCR installations on pulverized coal and cyclone-fired utility boilers, along with measured NO_X emissions. Initial data from these units indicate that conventional high-dust, hot-side SCR systems operated on suitable cyclone-fired units may be able to reduce NO_X emissions to as low as 0.07 lbs/mmBtu. Several SCR installations have been retrofit on existing cyclone-fire boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). For cyclone coal-fired utility boilers retrofitted with SCR technology, all were originally designed to burn bituminous coal.

Two byproducts from the high-dust, hot-side SCR process are ammonia slip and SO_3:

- Ammonia Slip: Slip is ammonia that is unreacted in the NO_x emission reduction process. Maximum ammonia slip for a gas fired unit is usually 10 ppmvd whereas, on a coal fired unit, ammonia slip below 2 ppm is desired. For certain applications, this concentration can be problematic, therefore requiring more catalyst to reduce slip. Most new SCR applications have ammonia slip guaranteed at a 2 ppmvd maximum for an initial operating period, and are expected to continue to operate at these low ammonia slips levels beyond the end of the initial period.
- SO_3: Due to the composition of typical SCR catalysts, a small percentage of inherent SO_2 will be oxidized to SO_3. This oxidation can be controlled by catalyst selection and can be less than 1 percent. SO_2 to SO_3 oxidation must be carefully controlled to avoid creating SO_3 levels sufficiently high to raise the possibility of air heater fouling. A unit firing high-sulfur coal with SCR technology is especially vulnerable to SO_2 oxidation and ammonia slip-related fouling problems. The deposition and fouling is due to formation of solid ammonium sulfate ($(NH_4)_2SO_4$) and liquid ammonium bisulfate (NH_4HSO_4). The most important design variable is optimizing the catalyst selection and amount of catalyst that will reduce NO_X emissions, control ammonia slip, and minimize SO_2 oxidation.

Recent technology has allowed catalyst suppliers to make more rigorous and lengthy guarantees. A reasonable initial operating period for conventional catalysts in high-dust reactor arrangements on boilers firing eastern or midwestern bituminous coal is around 24,000 active operating hours (i.e. when the catalyst is exposed to flue gas). Limited annual operation (i.e. ozone season only) is a significant factor with respect to SCR equipment reliability, maintenance, operational costs, and catalyst life. The demands on the SCR system are much more severe if the equipment is required to operate on a full-time, annual basis. Factors that need to be taken into account in design of a high-dust, hot-side SCR application that affect the need for catalyst replacement are:

- Pressure drop: The amount of restriction to flue gas flow through the SCR inlet, ammonia injection grid, SCR reactor, and downstream ductwork directly increases induced draft fan horsepower required to maintain adequate boiler draft. This is an important parameter to consider and minimize during the design stage. Pressure drop is a function of the average and maximum SCR reactor duct velocities, the amount of restriction caused by flow distribution correction devices (baffles or vanes), and the number and geometrical aspects of the catalyst layers. Many retrofit SCR installations require a booster fan or upgraded induced draft fan to overcome the added flow resistance. This increase in auxiliary power consumption increases operating cost and loss of saleable electric power. The type and pitch of the catalyst are factors most influential in determining the amount of pressure drop.
    - Catalyst type: The most common types or forms of catalyst material are honeycomb or plate. The former offers more surface area per volume, but can be more restrictive and prone to pluggage from ash deposits. The latter is usually less restrictive but requires more catalyst per layer or more layers to achieve the active surface needed to achieve the intended NO_X emission reduction.
    - Catalyst pitch: The pitch of the catalyst, a term used to describe the size of the gas path openings through the catalyst, varies depending on the manufacturer and design dust loading. Pitch is generally on the order of 6 to 7 millimeters for plate-type catalyst, and 7 to 8 mm for honeycomb-type. Potential pluggage of flow channels within the catalysts layers is therefore an issue that must be dealt with during design.
- Catalyst performance: The amount of NO_X emission reduction expected is a function of the specific activity level of the catalyst material and the amount of catalyst installed, over a given period of time. Catalyst formulation selection and features of construction have a significant impact on long-term NO_X emission reduction and subsequent costs for reagent and catalyst replacement.

- Catalyst replacement: The frequency of catalyst replacement is influenced strongly by:
    - Catalyst erosion: Erosion of the catalyst material in coal fired units from entrained flyash or sootblowing action reduces the amount of active surface available for reacting with the reagent and flue gas, and can cause distortions in gas distribution ("channeling") through the SCR reactor. Catalyst material is fragile and can be easily damaged. Some catalyst is provided with erosion-resistant top edges to mitigate this tendency.
    - Moisture absorption: Many types of catalyst are damaged by absorption of moisture. The reactor must be kept above ambient dewpoint temperatures or protected from freezing during outages in order to protect the catalyst from moisture damage. Spare catalyst must be carefully packaged to keep it dry and must be handled delicately to prevent damage.
    - Thermal degradation: The specific active elements of the catalyst surface, or the matrix structure itself upon which the catalyst material is applied, can degrade when exposed to flue gas temperatures greater than the intended design of the formulation. High flue gas temperatures within the reactor causes sintering, leading to a permanent loss of catalyst activity due to a change in the pore structure of the catalyst.
    - Catalyst poisoning: The loss of performance or activity of the catalyst over time can be due to chemical damage or poisoning. Two elements especially detrimental to the life of common titanium-supported vanadium pentoxide SCR catalyst are arsenic and zinc. Vanadia/tungsten-based catalysts are particularly susceptible to rapid deactivation due to gaseous arsenic poisoning. In some German SCR installations, a 50% loss of activity has been reported within 10,000-15,000 operating hours. Addition of molybdenum to a plate-type vanadia-titanium SCR catalyst on similar applications shows relative activity reductions of 20-25%. Progressive loss of SCR NO_X reduction performance from catalyst deactivation due to poisoning is not possible to restore without effective cleaning to remove the deposits, or eventual replacement.
    - Catalyst fouling: The surface area potentially exposed to the reagent (ammonia) and nitrogen oxides in the flue gas can become fouled with flyash or sulfur-related compounds. The presence of excess sodium or calcium oxide in the presence of sulfur in the flue gas can form a sodium sulfate or calcium sulfate surface coating that can be extremely dense, masking the pores of the catalyst. Progressive loss of SCR NO_X reduction performance from catalyst deactivation due to fouling is difficult to restore without effective cleaning to remove the deposits, or eventual replacement.

SCR technology has been installed on numerous coal-fired utility boiler facilities around the world and there are a large number of manufacturers that market the catalyst. The effectiveness of the SCR process is highly dependent upon the ability of the nitrogen oxides in the flue gas being able to contact the active sites within microscopic pores of the catalyst in the presence of ammonia reagent with minimal interference from contaminants. The question is whether SCR is a feasible technology for a unit firing North Dakota lignite. There are serious concerns whether installation of SCR technology on a North Dakota lignite-fired unit can be successful, especially in a conventional "hot-side, high-dust" configuration.

A recent article "Ash and Mercury Behavior in SCR Catalysts When Firing Subbituminous and Lignite Coals" by the Energy & Environmental Research Center (EERC) of the University of North Dakota was published in the February 2005 issue of Fuel Processing Technology magazine[30]. This paper summarized the results of SCR catalyst slipstream testing at two PRB-fired plants and one North Dakota lignite-fired powerplant. The evaluation included determination of impacts of ash on SCR catalyst plugging and blinding. Flue gas was isokinetically extracted from the convective pass of the boiler upstream of the air heater. Pressure drop across the catalyst was measured during the initial 2-month test period, and the two consecutive 2-month test periods following the initial trial, while holding flue gas flow and temperatures constant. Ammonia was injected downstream of a screen, upstream of a flow straightener and air pulse section. Compressed air was injected ahead of the reactor, and was periodically pulsed to simulate sootblowing to minimize ash deposit accumulation.

This slipstream SCR testing examined the significance of ash accumulations on SCR catalyst on both the macroscopic and microscopic levels. Very small flyash particles were found bonded together by a matrix of sodium-, calcium-, and sulfur-rich materials, likely in the form of calcium sulfate. North Dakota lignite coal contains many alkali and alkaline-earth elements, and sulfur. The firing of lignite coal which produces fine (less than 5-µm diameter) flyash particles that enter the pores of the catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into the matrix.

As posted on Electric Power Research Institute Inc.'s (EPRI's) website regarding the impact of coal type on SCR catalyst life and performance, a recent EPRI study[31] produced field data analyzed from an "In-Situ Mini SCR Reactor" system installed in a typical "high-dust" location at seven different test sites, including four firing PRB coal, one firing Texas lignite, one firing high-sulfur eastern bituminous coal, and one firing a PRB/eastern bituminous coal blend. The PRB/bituminous coal blend test was performed at AmerenUE's Sioux Station, on one of the two 500 MW cyclone-fired boilers. This study found that the cyclone unit firing the PRB/bituminous coal blend exhibited the fastest rate of catalyst activity degradation. Also, the higher deactivation rates seen at this site were due to economizer exit flue gas temperatures being significantly higher than at the other sites. A comparison of the Texas lignite and one of the PRB-fired sites of two different catalysts' deactivation was more a function of trace elements in the flue gas and flyash than the specific catalyst type or formulation.

North Dakota lignite produces an ash that is very sticky and creates severe ash deposition problems. There have been no installations of SCR systems (full-scale) on units that fire North Dakota lignite. A technical assessment was conducted for the installation of SCR technology on North Dakota lignite-fired cyclone boilers. In order to further evaluate the feasibility of installing a conventional SCR system on North Dakota lignite-fired cyclone boilers, the Energy & Environmental Research Center (EERC) at the University of North Dakota was consulted. EERC has extensive experience investigating the deposition characteristics of North Dakota lignite ash. A technical paper[32] was produced, from which the following technical feasibility analysis was developed. A copy of EERC's paper is included in Appendix A5. Although the source of North Dakota lignite supplied to the cyclone-fired boilers of interest in the technical paper is different than the mine supplying lignite to Leland Olds Station, it is considered similar in characteristics and suitable for comparison purposes in this feasibility analysis.

Technical difficulties and anticipated operating problems that are unresolved with respect to installing conventional SCR technology at Leland Olds Station include the impacts of severe ash deposition, "popcorn ash", high temperatures, and erosion on the catalyst. For these reasons, application of available conventional high-dust SCR technology is considered technically infeasible for Leland Olds Station, especially on Unit 2's boiler. These concerns can be divided into four categories. Each category is addressed below. An explanation of the factors that make conventional SCR technology infeasible for these boilers follows:

1. Ash Deposition: North Dakota lignite contains a variable and complex variety of inorganic compounds that contribute to ash deposition. This fuel produces ash with severe deposition characteristics that are not typical with other coals. When exposed to the heat of the combustion process inside the cyclone burners, the majority of the fuel ash becomes molten and flows into the bottom of the furnace. A significant portion of the fuel ash is entrained into the flue gas exiting the cyclone barrels at high velocity, where it comes into contact with the lower furnace

waterwalls. The portion that is carried with the rising flue gas cools and some is deposited on heat transfer surfaces in the upper furnace and boiler convection pass. Ash deposition on heat transfer surfaces is a substantial problem for units that fire North Dakota lignite. The problem is serious enough at Leland Olds that the Unit 2 boiler must be shut down to allow for cleaning of ash deposits from the boiler heat transfer surfaces in order to restore reasonable furnace exit gas velocities and temperatures.

Sodium is a significant contributor to the "stickiness" of the ash produced from firing North Dakota lignite. Sodium content of the LOS lignite ash averages approximately 7.6%, and can be above 9% for some of the lignite produced from the Center mine, for which the following numbers were calculated. PRB coal typically averages around 1.5% sodium content. Boilers firing North Dakota lignite typically have a 2.5% higher heat rate (million Btu per kilowatt of electric generation) than a typical boiler firing PRB coal, thus requiring more heat input and firing more fuel per megawatt of electric output. A cyclone boiler firing North Dakota lignite also converts as much as 50% of the fuel ash to flyash, compared with a 35% conversion rate for PRB coal-fired cyclone boilers. Overall, this results in an amount of sodium emitted from a cyclone boiler firing North Dakota lignite of approximately 7.3 lbs/MW-hr compared with 0.9 lbs/MW-hr for a PRB-fired cyclone boiler.

The catalysts in coal-fired boiler SCR reactors are exposed to flue gas with entrained particulate matter. In a typical conventional high-dust SCR reactor, the flue gas typically passes through two to four layers of catalyst modules. The catalyst modules have numerous narrow passages to provide intimate contact between the flue gas, ammonia and catalyst. The clearance (pitch) in these passages is typically 6-10 millimeters. A typical catalyst layer is approximately 1 to 1.5 meters deep. The catalysts in coal-fired boiler SCR reactors must be cleaned frequently using soot blowers and/or sonic horns. This is true even on units firing fuels that do not produce a sticky ash that contributes to ash deposition.

Sulfur in the coal is oxidized during excess air combustion to form sulfur dioxide (SO_2), and a small amount of sulfur trioxide (SO_3). Some of the ammonia-based reagent injected upstream of the SCR reactor will combine with SO_3 to form ammonium bisulfate. The catalyst in the SCR reactor will also oxidize a portion of the SO_2 to SO_3. Excess unreacted ammonia reagent carryover ("ammonia slip") from the SCR reactor will also react with these sulfuric acid compounds in a similar fashion. The dominance of sodium and calcium compounds present in North Dakota lignite ash emitted from the LOS cyclone boiler will also combine with sulfur to form blinding deposits within the catalyst. The ash deposition characteristics for a cyclone-fired unit burning North Dakota lignite will create difficult-to-remove ash deposits and pluggage of a conventional high-dust catalyst, and increase the probability that the air preheater downstream and flue gas ductwork will be prone to accumulations which could be severe. It is anticipated that high-dust SCR performance and catalyst life for a cyclone-fired unit burning North Dakota lignite will be severely impacted. Such a high-dust SCR's catalyst life may be shortened from 3-6 years (typical) to as little as 2-12 months, requiring extended, frequent outages for replacement.

Hot-side air preheaters are susceptible to gas-side fouling. Tubular air pre heaters typically supplied with cyclone boilers tolerate moderate dust loadings and gas-side fouling, since their height and size make them difficult to maintain gas-side cleanliness. Leak tightness of the air preheater is important on cyclone-fired boilers with relatively high forced draft fan discharge (combustion air supply) pressures. It is expected that a high-dust SCR installation on a cyclone-fired unit burning North Dakota lignite will be prone to air preheater tube fouling and pluggage, requiring extended, frequent outages for cleaning.

2. "Popcorn Ash": A second consideration in the application of conventional high-dust SCR technology on a lignite-fired unit is the potential of the SCR reactor catalyst pluggage resulting from carry over of "popcorn ash" from the boiler. Boilers firing North Dakota lignite have severe problems with ash deposition on boiler furnace and convection pass fireside surfaces. For lignite-fired units, the boiler's heat transfer surfaces must be cleaned by sootblowing and other methods (e.g. water lances) frequently to maintain satisfactory boiler operation. Some of the removed deposits released by the cleaning action within the boiler and convection passes form "popcorn ash", which will be entrained in the flue gas. There is concern that carry over of boiler ash deposits will contribute to pluggage of the "popcorn ash" screen ahead of the top layer of SCR reactor catalyst in a high-dust, hot-side installation on a cyclone-fired unit burning North Dakota lignite. This can cause distortions in gas distribution ("channeling") through the SCR reactor, which can concentrate the amount of NO_X passing through unrestricted areas with insufficient reagent, thus producing ineffective performance of the catalyst.

3. Temperature: A third issue that impacts the feasibility of installing high-dust SCR technology on the North Dakota lignite-fired units is gas temperature. The performance of any SCR catalyst is highly dependent on the flue gas temperature. Typically, a temperature of 600 – 750 degrees F is required to obtain satisfactory operation of an SCR reactor. Operation of commonly-supplied catalyst suitable for a high-dust SCR reactor at temperatures above 800°F results in severe and rapid deterioration of the catalyst and SCR reactor's NO_X emission reduction performance. For bituminous and sub-bituminous coal-fired units, boiler flue gas passing between the economizer outlet and air heater inlet is generally within a temperature range acceptable for conventional SCR catalysts without additional heating or cooling of the flow stream.

   North Dakota lignite-fired cyclone boilers, including those at Leland Olds Station, have limited gas-path economizer surface and high temperatures at the economizer's flue gas outlet by design. The highest gas temperatures downstream of the convection pass economizer sections and upstream of the air heater inlet in Leland Olds Unit 2 can be significantly higher than 750°F.

   High gas temperatures at the air heater inlet of North Dakota lignite-fired cyclone boilers are required to produce the high air temperatures (700°F) needed for the pre-combustion lignite drying system, along with primary and secondary combustion air supplied to the cyclones. Such air preheater arrangements and capabilities have been taken into account in the design of the North Dakota lignite-fired cyclone boilers. Reducing this high gas temperature to accommodate conventional catalysts for a conventional high-dust SCR reactor would result in pre-combustion air temperatures that are too low to provide satisfactory drying and rapid ignition of the high-moisture fuel. This will seriously impact reliable combustion, slag formation and tapping in the cyclone burners. Consequently, it is not feasible to modify the Leland Olds unit to operate with the lower economizer outlet flue gas temperatures.

   Catalysts for a conventional high-dust, hot-side SCR system have not been installed nor successfully demonstrated in a full-scale installation of an operating solid fuel-fired unit that are designed to continuously operate at the high temperatures (above 800°F) that exist between the convection pass economizer and air heater on the Leland Olds Station Unit 2's boiler.

4. Erosion: A final consideration on whether hot-side, high-dust SCR technology can be successful on a North Dakota lignite-fired unit is the potential for erosion of the SCR catalyst. North Dakota

> lignite has a modest to high ash content. Lignite supplied from the Center mine, for which the following numbers were calculated, has an average annual fuel ash content of 10.5%, and can have an ash content up to 25.5 percent. PRB coal fuel ash content typically averages approximately 5 percent. As previously stated, a cyclone boiler firing North Dakota lignite converts a significantly greater amount of flyash than a PRB-fired cyclone boiler. Overall, this results in a flyash output rate from a cyclone boiler firing North Dakota lignite of approximately 83 lbs/MW-hr compared with 21 lbs/MW-hr for a PRB-fired cyclone boiler. High ash contents in the flue gas stream can result in physical erosion of the catalyst. Severe ash depositions can cause distortions in gas distribution ("channeling") through the SCR reactor, which will aggravate erosion in the high velocity areas and create conditions leading to ineffective performance of the catalyst. In addition, effective on-line cleaning of the high-dust catalyst will likely require steam or compressed air sootblowing. Cleaning cycles of the catalyst in a high-dust SCR installation for a cyclone boiler firing North Dakota lignite may need to be more frequent than a typical conventional SCR installation due to the ash deposition characteristics of the North Dakota lignite. Frequent sootblowing of the catalyst to remove fouling deposits and ash accumulations will contribute to erosion and decreased catalyst life. There is some European experience with high ash brown coals that catalyst manufacturers will be able to draw upon. This experience, however, will not be directly applicable to these United States units because of the severe deposition characteristics of the North Dakota lignite ash compared to brown coal.

The EPA's BART Guideline states that for a technology to be feasible it must be "available and applicable". SCR technology is an available technology which has been installed on numerous powerplant facilities around the world and there are a large number of manufacturers that market the technology. The question is whether SCR technology is "applicable" for a cyclone-fired unit burning North Dakota lignite.

In accordance with EPA's BART Guideline, a "commercially available control option will be presumed applicable if it has been used on the same or similar source type" [70 CFR 39165]. Hot-side, high-dust SCR technology has been retrofitted on existing coal-fired units featuring cyclone boilers. However, there are no SCR installations in operation or planned on units that include cyclone burners firing North Dakota lignite with severe slagging and fouling tendencies combined with such high boiler economizer outlet gas temperatures (over 750°F) required for high-moisture fuel pre-drying systems and tubular air preheaters.

The EPA's BART Guideline also states a technology identified as technically infeasible, "[the States] should demonstrate that the option is either commercially unavailable, or that specific circumstances preclude its application to a particular emission unit" [70 CFR 39165]. Such a demonstration of technical infeasibility "involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g. size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility)"[70 CFR 39165]. In this SCR technology application, it appears that a cyclone-fired utility powerplant firing North Dakota lignite would experience extended time delays or be required to devote significant internal resources and engage outside research, followed by extended field trials to learn how to apply a conventional high-dust, hot-side SCR technology on such a fuel source. The risk of failure and uncertainty of successfully applying high-dust, hot-side SCR technology to a cyclone-fired utility powerplant firing North Dakota lignite appears substantial.

Based upon this technical assessment that looked at the various design and operational issues associated with the installation of hot-side, high-dust SCR technology on a North Dakota lignite-fired steam-electric generating unit, this control option is considered technically infeasible for the pulverized coal-fired Unit 1 boiler and the cyclone-fired boiler on Unit 2 at Leland Olds Station.

A1.3.2.2 Low-Dust Selective Catalytic Reduction (LD-SCR)

Low-dust SCR (LD SCR) technology could potentially be applicable to North Dakota lignite-fired boilers for NO_X emission control. Low-dust SCR refers to the location of the SCR system downstream of a particulate collection system, such as an electrostatic precipitator or a fabric filter. If the low-dust SCR is downstream of a hot-side electrostatic precipitator and prior to the air preheater, flue gas reheating is unnecessary. This has been the prevalent form of alternative retrofit SCRs in the United States for coal-fired utility boilers. There are ten known hot-side low-dust SCR installations (without flue gas reheat) operating in the United States as of July 2005. These are listed in the U.S. NO_X Control Project Summary listing in Appendix A. If applied to LOS Unit 1's pulverized coal-fired boiler and Unit 2's cyclone-fired boiler, the low-dust SCR equipment would be downstream of a cold-side electrostatic precipitator; flue gas reheat prior to the LD SCR reactor inlet would be required for proper NO_X emission reduction performance.

For a cold-side LD SCR, the ESP outlet flue gas passes through a low-dust gas-to-gas heat exchanger (LD GTG-HE), prior to passing to the low-dust SCR reactor. After the LD GTG-HE, the flue gas will travel through new ductwork leading to a supplemental heat addition section ahead of an ammonia injection grid, turning vanes and then into the LD SCR reactor. The flue gas entering the inlet to the LD GTG HE is expected to be near the air heater outlet temperature (330-340°F) in a cold-side LD SCR application. The supplemental heat added upstream of the LD-SCR reactor can be supplied from high pressure/temperature steam coils (indirect heat exchange) or directly from fossil fuel (natural gas, fuel oil, or propane)-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the LD SCR NO_X– ammonia reaction to be effective. The LD gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the FGD system (if applicable) and stack. The use of rotary regenerative-type heat exchangers has been applied in European LD SCRs. With this design, there will be a small amount of leakage between the untreated and treated gas streams such that the exit flue gas has higher NO_X concentrations than the LD SCR outlet gas. The direct-fired flue gas reheat duct burners will also create NO_X emissions, which will add to the amount from the boiler input into the LD SCR reactor. The GTG-HE outlet flue gas temperature on the downstream side of the LD SCR has to be higher than the inlet gas temperature.

The LD SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This normally requires an induced draft fan upgrade or a booster fan addition.

The factors that make low-dust SCR technology infeasible for Leland Olds Station’s pulverized coal-fired Unit 1 boiler and Unit 2’s cyclone-fired boiler with existing particulate collection via electrostatic precipitators are as follows:

- Catalyst Fouling and Deactivation: An existing electrostatic precipitator upstream of a low dust SCR reactor will still expose the catalyst to the acid gas content and fine particulate containing high alkali mineral content of the entrained lignite flyash not removed by the ESP upstream. Although the total amount of flyash carryover into the LD-SCR reactor is greatly reduced compared with a high-dust design, there is concern that the low-dust SCR catalyst life will still be unacceptably short. The small particle flyash passing into the reactor could cause pluggage of the catalyst pores, resulting in deactivation of the catalyst. The firing of lignite coal produces fine (less than 5-µm diameter) flyash particles, which are also least likely to be removed by the existing particulate collection equipment (e.g. ESP) upstream of a low-dust or low-dust/tail-gas SCR. This creates conditions that allow these small flyash particles to enter the pores of the catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into a matrix of sodium-, calcium-, and sulfur-rich materials (likely in a form of sodium or calcium sulfate). Once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. One catalyst vendor has stated it is their "experience that low-dust catalyst is more difficult to clean than that from high-dust"[33]. Ash deposition characteristics for a cyclone-fired unit burning North Dakota lignite will create difficult-to-remove ash deposits and blinding of conventional catalyst. Low-dust SCR performance and catalyst life could be severely negatively impacted. Shortened lifespans of the LD SCR catalyst will require premature, extended, frequent outages for replacement.

Deposits on the gas-to-gas heat exchanger ahead of the low-dust SCR reactor will decrease heat transfer between the incoming (warm) flue gas and the outgoing (warmer) flue gas and be increasingly difficult to successfully remove over time. Low flue gas temperatures are inadequate to promote the effective activity of the catalyst in reducing NO_X emissions. Thus, increased consumption of supplemental heat, preferably in the form of propane or natural gas, will be required to raise the temperature of the flue gas ahead of the LD-SCR reactor. Sootblowers could be used to remove the accumulated deposits from the GTG HE, but the SCR reactor could still suffer catalyst fouling from the deposits dislodged from the rotary regenerative-type GTG HE cleaning cycle becoming reentrained in the reheated flue gas. This can lead to further accumulation of deposits at the inlet and within the catalysts layers of the TG-SCR reactor, creating a vicious cycle of diminishing performance.

The challenges for installation of new ductwork, SCR reactors, and flue gas reheating equipment are numerous. The lack of pertinent experience with all aspects of design, construction, operation, and maintenance of low-dust SCRs on such high-fouling coals as North Dakota lignite are significant. The flue gas conditions that the LD-SCR catalyst will be exposed to will create unresolvable fouling and blinding that makes successful application of this technology difficult, expensive, and uncertain.

The risk of failure and uncertainty of successfully applying low-dust, cold-side SCR technology to a cyclone-fired utility powerplant firing North Dakota lignite appear substantial.

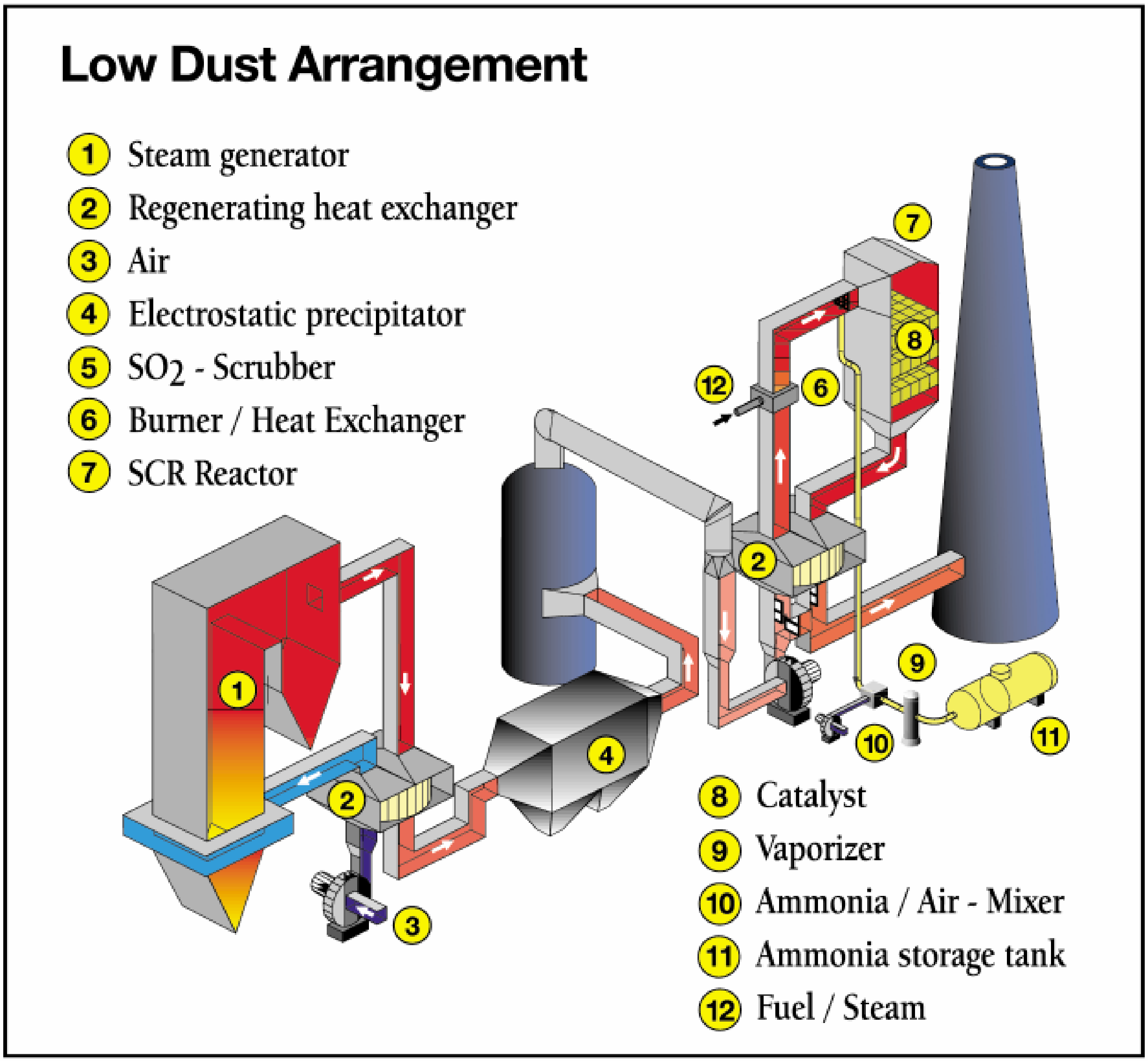
Based upon a technical assessment that looked at the various design and operational issues associated with the installation of low-dust SCR technology on a North Dakota lignite-fired steam-electric generating unit with a cyclone-fired boiler, this control option is considered technically infeasible for Leland Olds Station's pulverized coal-fired Unit 1 boiler and the cyclone-fired boiler of Unit 2.

A1.3.2.3 Tail-Gas Selective Catalytic Reduction (LD-SCR)

A tail-gas (TG) SCR is a low-dust SCR system where the SCR reactor is installed on the cold side of the air preheater downstream of a FGD scrubber. The FGD outlet flue gas passes through a low-dust gas-to-gas heat exchanger (GTG-HE), prior to passing to the tail-gas SCR reactor. After the LD GTG-HE, the flue gas will travel through new ductwork leading to a supplemental heat addition section ahead of an ammonia injection grid, turning vanes and then into the TG SCR reactor. The TG SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This retrofit normally requires an induced draft fan upgrade or a booster fan addition.

A schematic graphic diagram for a low dust arrangement is shown in Figure A.1-6.

Figure A.1-6 Tail-Gas SCR Arrangement



(figure copied from Wheelabrator Air Pollution Control literature)

The flue gas from a wet FGD scrubber outlet entering the inlet to the gas-to-gas heat exchanger is expected to be near the saturation temperature (140°F) in a TG SCR application. The supplemental heat added downstream of the TG GTG-HE can be supplied from high temperature steam coils (indirect heat exchange) or directly from fossil fuel-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the NO_X – ammonia reaction in the presence of the TG SCR catalyst to be effective. The gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the stack. With a rotary regenerative-type gas-to-gas heat exchanger, there will be a small amount of leakage between the untreated and treated gas streams. With a positive flue gas pressure FGD system upstream, the leakage will be such that the GTG-HE outlet exit (stack inlet) flue gas has a higher NO_X concentration than the TG SCR reactor outlet gas. The direct-fired flue gas reheat duct burners will also create NO_X emissions, which will add to the amount from the boiler input into the TG SCR reactor. The GTG-HE outlet flue gas temperature on the downstream side of the TG SCR going to the stack will be significantly lower than would occur in a conventional high-dust, hot-side SCR or low-dust, cold-side SCR application.

There is no experience with low-dust/tail-gas SCR technology on eastern bituminous, western subbituminous coal or lignite-fired SEGUs requiring full flue gas reheat prior to the reactor inlet in the United States. As of 1997, there was one low-dust/tail-gas SCR on a 220 MWe German cyclone-fired boiler with a 1988 retrofit installation. This boiler was reported to be operating without combustion controls or FGD, burning low sulfur, low ash, moderate moisture bituminous coal with an average pre-SCR NO_X emission rate of approximately 1.07 lb/mmBtu, and was meeting a 30-day rolling average emission limit of approximately 0.16 lb/mmBtu (85% reduction)[34].

Leland Olds Station Unit 1 and Unit 2 boilers do not currently incorporate any flue gas desulfurization equipment, which without such FGD would place the reactor catalyst in a low-dust SCR configuration, which is considered infeasible when burning North Dakota lignite. Both Unit 1's boiler and Unit 2's boiler will have new FGD systems to implement future BART sulfur control requirements associated with the North Dakota State Implementation Plan (SIP).

The factors that make tail-gas SCR technology infeasible for the pulverized coal-fired Unit 1 boiler and the cyclone-fired Leland Olds Station Unit 2 boiler with existing particulate collection via electrostatic precipitators are as follows:

- The TG SCR reactor downstream of a FGD scrubber will still be exposed to flue gas with entrained fine particulate matter, including some involving sodium and sulfur-containing compounds passing through and carried-over from a wet FGD scrubber. The treated gas stream will carry sodium sulfate solids, formed by homogenous condensation after exiting the boiler and not removed by the FGD system, into the catalyst layers of the TG-SCR reactor. There is serious concern that these fine particles will accumulate within the catalyst, and be resistant to removal by conventional sootblowers and other cleaning technologies. Catalyst that is exposed to such conditions will be ineffective at maintaining adequate activity upon which the performance of the TG-SCR's NO_X removal is based.

- Deposits on the gas-to-gas heat exchanger ahead of the tail gas SCR reactor will decrease heat transfer between the incoming (cool) flue gas and the outgoing (warm) flue gas and be increasingly difficult to successfully remove over time. Low flue gas temperatures are inadequate to promote the effective activity of the catalyst in reducing NO_X emissions. Thus, increased consumption of supplemental heat, preferably in the form of propane or natural gas, will be required to raise the temperature of the flue gas ahead of the TG-SCR reactor. Sootblowers could be used to remove the accumulated deposits from the GTG HE, but the TG SCR reactor could still suffer catalyst fouling from the deposits dislodged from the rotary regenerative-type GTG HE cleaning cycle becoming reentrained in the reheated flue gas. This can lead to further accumulation of deposits at the inlet and within the catalysts layers of the TG-SCR reactor, creating a vicious cycle of diminishing performance.

The challenges for installation of new ductwork, SCR reactors, and flue gas reheating equipment and the lack of pertinent experience with all aspects of design, construction, operation and maintenance of tail-gas SCRs on such high-fouling coals as North Dakota lignite are significant. The flue gas conditions that the TG-SCR catalyst will be exposed to will create unresolvable fouling and blinding that makes successful application of this technology difficult, expensive, and uncertain.

The risk of failure and uncertainty of successfully applying low-dust, tail-gas SCR technology to a pulverized coal-fired boiler and the cyclone-fired utility powerplant firing North Dakota lignite appear substantial.

Based upon a technical assessment that looked at the various design and operational issues associated with the installation of tail-gas SCR technology on a North Dakota lignite-fired steam-electric generating unit including a cyclone boiler, this control option is considered technically infeasible for the Leland Olds Station pulverized coal-fired Unit 1 boiler and the cyclone-fired Unit 2 boiler.

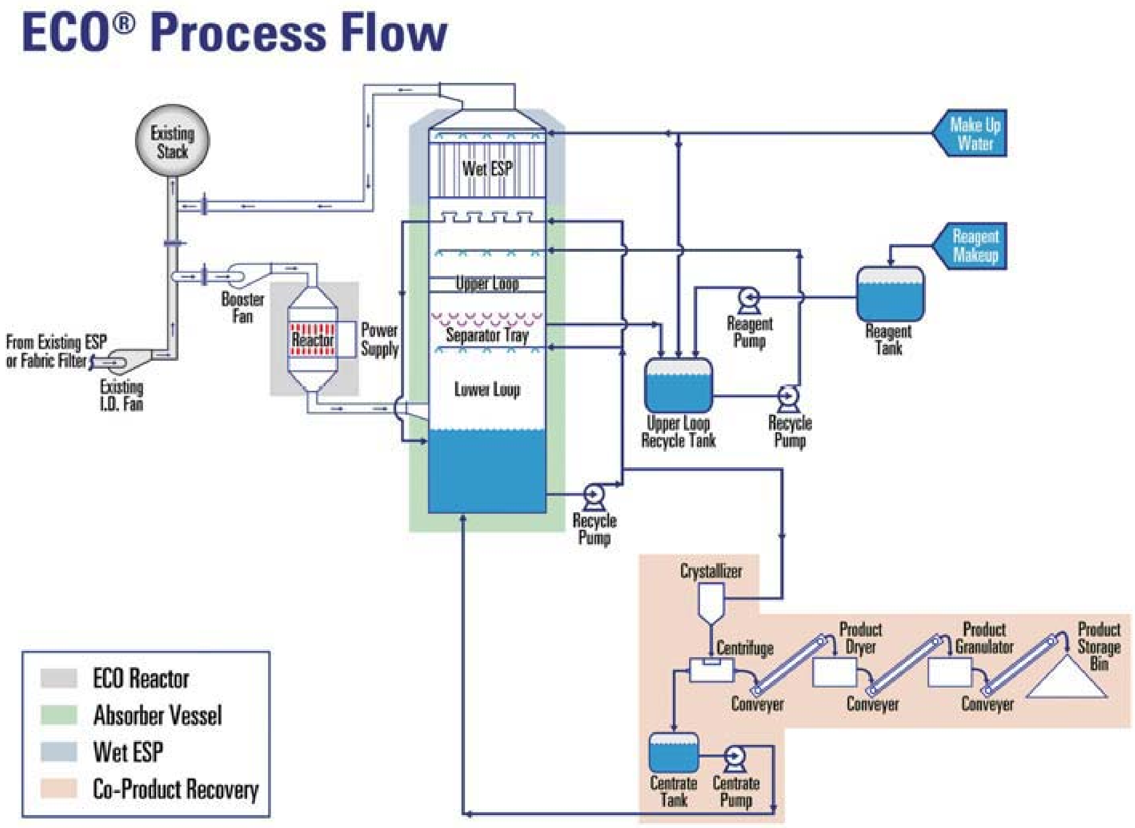
A1.3.3 Electro-Catalytic Oxidation (ECO®)

Powerspan's Electro-Catalytic Oxidation (ECO®) system is a multi-pollutant technology designed to control emissions of NO_X, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO® process has two main process vessels, a barrier discharge reactor, and a multi-level wet scrubber. The barrier discharge reactor utilizes an electrical discharge to create oxygen and hydroxide radicals which then react with NO_X, and other constituents in the flue gas stream. The flue gas stream then enters the bottom of the ECO® scrubber where the lower loop cools the flue gas and removes a portion of the acid gasses [sulfur trioxide (SO_3), sulfuric acid (H_2SO_4), nitric acid (HNO_3)] produced in the barrier reactor and oxidized metals such as mercury, with a low pH aqueous ammonia reagent. A second scrubbing loop is then entered where additional SO_2, NO_2, acid gases and oxidized metals are removed with an aqueous ammonia reagent, though at a higher pH. Above the second scrubber loop is an absorber section for absorbing fugitive ammonia from the first and second scrubbing loops. The final step in the ECO® process is a wet electrostatic precipitator (WESP) which collects fine particulate matter, aerosols generated in the scrubber and additional mercury.

An updated schematic process flow diagram for the basic ECO® process is shown in Figure A.1-7.

Figure A.1-7 – Electro-Catalytic Oxidation (ECO®) Process Flow Diagram

(copied from http://www.epa.gov/appcdwww/aptb/EPA600R03110.pdf)



Powerspan has been involved in an extended ECO® process demonstration using a 28 MW equivalent “slipstream” Commercial Demonstration Unit (CDU) at R.E. Burger Station Units 4&5. The ECO® CDU project treated a slipstream and demonstrated performance, reliability and economics for approximately one year. The demonstration program started in January, 2004. NO_X removal is stated to be up to 90% with a claimed 0.05 lb NO_X/mmBtu outlet condition achievable for the front-end of the ECO® process. Further sustained operational tests of the ECO® CDU were performed during the second and third quarters of 2005.

As this is a post-combustion multi-pollutant control technology, it is claimed that there is little sensitivity to the type boiler or burners that Powerspan's Electro-Catalytic Oxidation (ECO®) process can be potentially applied to in order to reduce NO_X emissions. The effectiveness of this ECO® process for NO_X control has been demonstrated on a slip-stream commercial demonstration unit (CDU) associated with pulverized fuel boilers firing midwestern or eastern bituminous coal.

Powerspan's published data from the commercial demonstration unit's performance of up to 90% when treating flue gas with an inlet NO_X concentration around 0.5 lb/mmBtu. This would result in a stack NO_X emission around 0.05 lb/mmBtu.

As of May, 2006, the ECO® process has not been demonstrated in a full-scale (or less-than full-scale) configuration on any boiler that fires western subbituminous coals or North Dakota lignite. It has also not been applied to emissions from any coal-fired cyclone boiler. According the EPA's BART Guideline, "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available: an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice" [70 CFR 39164].

There are a number of issues with firing North Dakota lignite that make the applicability of the ECO® process technically infeasible for Unit 1's pulverized coal-fired boiler and the LOS Unit 2 cyclone boiler. These issues include:

- Deposits and Pluggage: The flyash deposition characteristics of the North Dakota lignite are extremely severe. Anything that contributes to flyash deposition and pluggage within the barrier reactor is expected to have a detrimental impact on the multi-pollutant control performance of the ECO® process, and thus could have a serious impact on Leland Olds Station operations. The lack of demonstrated operation on treating the emissions from a boiler firing coal with a high slagging index precludes the use of the ECO® process as technically feasible for BART as applied to a boiler firing North Dakota lignite.

- Reliability and Availability: Leland Olds Station's major planned outages for each unit are scheduled to occur once every three years. Any NO_X control technology selected as BART will need to operate year-round, year in and year out, on a routine basis, while performing at high levels of pollutant reduction. The Powerspan ECO® system is a new technology and is not as highly developed as other more common NO_X and SO_2 control technologies such as SCR or SNCR plus wet or semi-dry flue gas desulfurization (FGD). It is expected to require a full-time, full-scale application with sustained continuous operation to confirm levels of currently demonstrated reliability and availability from the ECO® CDU are acceptable to meet the expectation of infrequent major outages over long time periods while maintaining high levels of control.

There are additional factors that make the application of the ECO® process potentially more difficult than other established emission control technologies available for coal-fired powerplants:

- There is a lack of experience with the ECO® downstream ammonia scrubber's coproduct crystallization and granulization equipment design, operation, and maintenance, which was not included with the initial commercial demonstration unit. The coproduct stream that would normally feed into the crystallization and granulation processes was collected and transported offsite for this process step during CDU operation. Because crystallization and granulation of ammonium sulfate from an ammonia scrubber solution is not a new technological process, this was not considered a technical feasibility deficiency. For instance, the Dakota Gasification Company (DGC) in Beulah, ND currently operates an SO_2 scrubber utilizing ammonia as a reagent. Following the generation of ammonium sulfate, DGC crystallizes and granulates a fertilizer product on site. However, at LOS, considerable costs would be incurred for interim storage and shipment of the ECO® process scrubber's liquid bleedstream until sufficient experience has identified and eliminated potential failures and repairs for the crystallization and granulation equipment should it prove to be unreliable.
- Size of the barrier reactor: Powerspan recently indicated that they would scale the barrier reactor for optimum cost and space arrangement based upon lessons learned from the CDU plant operation. The number of individual passages within a barrier reactor sized for LOS Unit 1's pulverized coal-fired boiler and Unit 2 cyclone boiler's maximum flue gas flow and gas stream

constituents is expected to require a cross-sectional area comparable to half of a large electrostatic precipitator. Although this has not been closely examined for all aspects of design, construction, operation and maintenance, the amount of physical space required to hold the barrier reactor and inlet and outlet ductwork could be limited for potential retrofit to LOS Unit 1's pulverized coal-fired boiler and Unit 2's cyclone boiler. Site space constraints are considered to be a detriment to technical feasibility for potential application of the ECO® process at Leland Olds Station for Unit 1 and Unit 2's boilers.

- Additional station auxiliary power consumption: The barrier reactor, plus the ammonia scrubber and wet electrostatic precipitator additions by an ECO™ system, require an increase in station auxiliary power consumption. For NO_X control, this includes more horsepower required by the booster fan needed to compensate for the flue gas pressure drop created across the barrier reactor. It also includes the power consumed by the electrodes of the barrier reactor itself.

Because of the lack of full-time, full-scale experience, especially on such high fouling coals as North Dakota lignite, and other operational issues, the ECO® system was considered technically infeasible as a BART alternative for Leland Olds Station for Unit 1's pulverized coal-fired boiler and Unit 2's cyclone-fired boiler.

A1.4 "Layered" NOx Reduction Technologies

Many of the NO_X emission reduction technologies which involve furnace or convection pass areas for their introduction into the flue gas stream have been, or can potentially be, applied in combinations so as to result in an overall higher level of removal. Separated overfire air, various types of fuel reburn, and various forms of SNCR could potentially be combined in series to reduce NO_X emissions prior to a boiler's flue gas exit. However, all the possible NO_X control technology combinations have not been installed on coal-fired powerplants, so actual feasibility of some combinations have not been demonstrated as viable, particularly in consideration of the special challenges posed by firing lignite coal.

A1.4.1 SOFA Combined With Other NO_X Reduction Technologies

Separated Overfire Air (SOFA) can be favorably combined with every other method in order to reduce the amount of reagent or reburn fuel required to achieve the resulting level of NO_X emission reduction. Some control technologies, especially conventional fuel reburn systems, require overfire air to complete the combustion of the staged fuel admitted to the upper furnace.

A1.4.1.1 SOFA with SNCR

Selective non catalytic reduction technologies are post-combustion, in-furnace NO_X control alternatives that have been installed in numerous boilers of various designs, fuel types, with and without overfire air. It is usually advantageous to apply overfire air so that the mass rate of NO_X will be lower, thus allowing the amount of chemical reagent consumption to be minimized in order to achieve the targeted NO_X emission rate from the boiler outlet.

Several examples of SNCR technology applied to pulverized coal-fired boilers are included in Appendix A3. As a NO_X control technology, SNCR with close-coupled OFA, or basic or boosted SOFA is considered technically feasible for application on Leland Olds Station Unit 1's boiler. SNCR with close-coupled OFA is expected to reduce NO_X emissions approximately 24.5% below 2000-2004 pre-control highest 24-month average NO_X baseline levels for the LOS Unit 1 boiler with ammonia slip limited to approximately 5 ppmvd. SNCR with basic separated OFA is expected to reduce NO_X emissions approximately 42% below 2000-2004 pre-control highest 24-month average NO_X baseline levels. The highest performing basic SNCR system combined with the boosted form of SOFA (ROFA) on LOS Unit 1's boiler is potentially able to achieve NO_X emission rates of 0.157 lb/mmBtu, an overall reduction of 45.1% below 2000-2004 pre-control highest 24-month average NO_X baseline levels during operation at full load.

Tests on the cyclone boilers at Conectiv's B.L England Station (Units 1 and 2) demonstrated that SNCR can decrease NO_X emissions as much as 31% at full load, from 0.55 to 0.38 lb/mmBtu, over and above the reduction possible from overfire air alone (approximately 60% drop, from 1.3 to 1.4 down to 0.55) in full operation. This is an overall NO_X emission reduction of 72% from pre-retrofit baseline[23,24].

SNCR with either the basic or the advanced forms of separated overfire air (ASOFA) can be applied and installed on LOS Unit 2's boiler. Air-staging the Unit 2 cyclones with the use of separated overfire air to further complement combustion NO_X reduction is an optional part of this technique. However, this will risk slag "freezing" in the barrels and lower furnace. Estimated NO_X emission rates for using SNCR techniques with North Dakota lignite considered published levels achieved by cyclone-fired units firing western subbituminous coal, and vendor predictions. SNCR with ASOFA is expected to reduce NO_X emissions approximately 38% below NO_X levels predicted for ASOFA operation, and potentially 54.5% overall from 2000-2004 pre-control highest 24-month average baseline levels for the LOS Unit 2 boiler with ammonia slip limited to approximately 5 ppmvd. This highest performing basic SNCR system is potentially able to achieve NO_X emission rates of 0.304 lb/mmBtu, respectively, when combined with the advanced form of SOFA on LOS Unit 2 boiler during operation at the pre-controlled baseline load. This expected level of sustained NO_X reduction is considered to be a reasonable estimate, given the concerns expressed about the potential limits of separated overfire air techniques to achieve typical NO_X reduction percentages when applied to lignite-fired cyclone boilers.

Another form of SNCR is combined with separated overfire air. This is currently being marketed commercially as “Rotating Mixing” (Rotamix). In the United States’ utilities industry, this has only been applied to pulverized coal-fired boilers. It is different than basic SNCR in that it includes a hot air booster fan and a small ambient air fan, and injects the ammonia (or urea) reagent into the high-pressure overfire air. This mixture is imparted into the boiler in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. This vendor (Mobotec USA) claims that Rotamix (rotating opposed fire air or ROFA + SNCR) helps to distribute the reagent across the furnace cross section, which maximizes in-furnace NOx reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon. Three tangentially-fired utility boilers burning eastern bituminous coal or Illinois bituminous coal were retrofitted with Rotamix, each achieving a NO_X reduction of approximately 0-55% beyond the levels produced by ROFA alone, from pre-SNCR baselines of 0.22 to 0.28 lb/mmBtu down to 0.10 to 0.23 lb/mmBtu without low-NO_X burners[10,11,12].

While this variation of SNCR combined with separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Because cyclone boilers do not require the addition of hot air booster fans for SOFA, and optimum injection locations for both SOFA and SNCR reagent may not coincide, Rotamix may not perform as well as, or significantly better than, a well-designed combination of conventional SOFA and SNCR. This technique is not distinct enough from basic SNCR from functional and air-staged cyclone NO_X reduction performance standpoints to warrant individual consideration for Leland Olds Station boilers. It was not evaluated for consideration as an option for LOS Unit 1 or Unit 2 boilers.

A1.4.1.2 SOFA with RRI

As previously stated, Rich Reagent Injection is not applicable to pulverized coal-fired boilers, and therefore is technically infeasible for LOS Unit 1. RRI must be combined with an advanced form of separated overfire air, and can be installed and operated with and without SNCR, for coal-fired cyclone boilers. RRI must be used in an oxygen-deprived atmosphere in order to effectively reduce nitrogen oxide emissions. This requires air-staged cyclones and separated overfire air operation. For lignite-fired cyclone boilers, the basic form of separated overfire air is incompatible with RRI, and is expected to be much less effective in reducing NO_X emissions than previously demonstrated elsewhere. This is related to the likelihood that the injection of reagent will be near the elevation of the existing lignite drying system vent ports, and that the oxygen introduced with the lignite drying system's vented moisture-laden airstream will disrupt the desired in-furnace nitrogen oxides reduction process.

Demonstration of RRI at Ameren's Sioux Unit 1 boiler, a 500 MW unit firing a blend of PRB and midwestern bituminous coals (without SNCR), with SOFA in August 2001 at a lower furnace SR approximately 1.0, NOx emissions were reduced approximately 55% to 0.55 lb/mmBtu w/ SOFA only, and an additional 15% NOx reduction from RRI (down to 0.47 lb/mmBtu) with zero ammonia slip[7]. Testing RRI with SOFA in 2002 at an average cyclone air-to-fuel stoichiometric ratio (S.R.) of 0.95 resulted in NO_X reductions as much as 29% for RRI (down to 0.27 lb/mmBtu) beyond those achieved with a modest amount of cyclone air-staging with SOFA (68% drop down to 0.38 lb/mmBtu from SOFA alone), for an 80% overall decrease from uncontrolled baseline[7]. Tested NO_X emissions with RRI+SOFA in 2002 were with a reagent normalized stoichiometric ratio (NSR) of 3 (lbs/ NH_3 per lb NO_X)[7]. In 2004, further operation of the SOFA system at lower cyclone stoichiometric ratios (S.R. of 0.90) resulted in reducing NO_X emissions down to 0.3 lb/mmBtu with approximately 26% overfire air flow without RRI[8]. Parametric testing in May 2005 reduced NO_X emissions between 15-38% with RRI+SOFA, down to 0.15 to 0.20 lb/mmBtu with reagent NSR between 1.0 and 4.0 and low ammonia slip levels less than 2 ppm from an established baseline condition of 0.20 to 0.285 lb/mmBtu level achieved with deep cyclone air-staging and SOFA operation firing an 80:20 PRB/Illinois coal blend at 480 MWg unit output[9].

It should be recognized that these demonstration tests of RRI were very limited in duration, with a particular combination of active cyclones, boiler output, active injector patterns, reagent concentration and mass flow rate, injection velocity, dispersion angle, and droplet size being established for a few hours over the course of a few days or weeks. Thus, the stated results do not reflect long-term NO_X control performance, reagent usage, or ammonia slip levels.

For LOS's Unit 2 lignite-fired cyclone boiler, RRI with ASOFA is potemtially able to be installed and operate. This option is assumed to provide a modest NO_X reduction of approximately 43% below the 2000-2004 pre-control highest 24-month average baseline level, down to 0.38 lb/mmBtu, for Unit 2's boiler, with less than 1 ppm ammonia slip. This is approximately 22% lower than the level produced by

ASOFA alone. This estimate is based on the premise that cyclone air/fuel stoichiometric ratios will be restricted (limited to around 0.95) because of concerns about possible slag freezing, and that reagent effectiveness will be diminished compared to demonstrated performance at B.L England Station Unit 1 and Sioux Unit 1 boilers. This option was not included in the cost-effectiveness analysis due to estimated lower NOx reduction and higher reagent consumption versus SNCR with ASOFA.

A1.4.1.3 SOFA with RRI and SNCR

When RRI is combined with separated overfire air and SNCR, it has demonstrated very high NO_X emissions reduction at Conectiv's B.L. England Unit 1 boiler firing eastern bituminous coal, on the order of 80% from an uncontrolled baseline around 1.2 lb/mmBtu[30]. In May 2005, testing RRI+SNCR+SOFA at Ameren's Sioux Unit 1 boiler firing a high PRB-blend coal Sioux Unit 1 reportedly demonstrated NO_X emissions as low as 0.12 lb/mmBtu. This was from an established baseline condition of 0.20 lb/mmBtu level achieved with deep cyclone air-staging and SOFA operation firing an 80:20 PRB/Illinois coal blend at 480 MWg unit output with a reagent NSR of 4 and ammonia slip limited to less than 5 ppmvd, for an overall 90% reduction with no apparent adverse short-term impacts of deeper air-staged combustion together with overfire air, RRI and SNCR applications. A technical paper by REI was presented at a late 2005 conference documenting these findings[11].

As with RRI with ASOFA, demonstration tests of RRI and SNCR with ASOFA were very limited in duration. Thus, the stated results do not reflect long-term sustained NO_X control performance, reagent usage, or ammonia slip levels.

For LOS's Unit 2 lignite-fired cyclone boiler, RRI and SNCR with ASOFA is potemtially able to be installed and operate. This combination was assumed to be capable of achieving an overall NO_X reduction of approximately 60% below a baseline level, down to 0.265 lb/mmBtu, for Unit 2's boiler, with ammonia slip limited to 5 ppmvd. This is a reduction approximately 46% beyond the level produced by ASOFA alone, with the SNCR contribution approximately 30% below RRI+ASOFA. As previously discussed, this level of NO_X emissions reduction is considered to be a reasonable estimate, given the concerns expressed about the ability of RRI to be effective due to potential limits of separated overfire air techniques when applied to lignite-fired cyclone boilers.

A1.4.1.4 SOFA with Reburn

Most, if not all, of the recent conventional fuel reburn installations include separated OFA. Coal reburn and conventional gas reburn (CGR) are combined with SOFA. Several of these examples were already described[4,5,6,7,8, 18,19,20,21].

For the most effective NO_X reduction performance by applying the various available forms of fuel reburn, the injection of gaseous fuel is usually performed using recirculated flue gas as a diluent and carrier media to aid dispersion and avoid completely oxidizing the carbon and nitrogen components in the fuel and furnace gases generated from staged burners below the fuel reburn injection location. Improved gas reburn designs have reduced or eliminated FGR with higher gas injection pressures.

For lignite-fired cyclone boilers, conventional reburn fuel firing with a basic form of separated overfire air is expected to be much less effective in reducing NO_X emissions than previously demonstrated elsewhere. This is related to the likelihood that the injection of reburn fuel will be near the elevation of the existing lignite drying system vent ports, and that the oxygen introduced with the lignite drying system's vented moisture will oxidize the reburn fuel and significantly disrupt the desired in-furnace reduction process for nitrogen oxides.

It should be recognized that application of air-staged cyclones with basic or advanced forms of SOFA in combination with reburn techniques will require the overfire air injection ports to be located at a somewhat lower elevation of the furnace compared to SOFA with air-staged cyclones without reburning. This is significant, especially for alternatives with coal reburn to allow the solid fuel introduced below the SOFA ports to burn completely prior to the furnace exit plane. This means that less air-staging of the cyclones may be practiced, or that less residence time will be available for the in-furnace NO_X reduction process to occur.

Fuel-lean gas reburn (FLGR™) can be applied with or without SOFA, as this limited amount of staged fuel is introduced into an oxygen-rich atmosphere downstream of the burners and any OFA injection points. More commonly, FLGR™ has been installed with SNCR for NO_X emission reduction[22,23,24,25]. A potential advantage of FLGR™ over conventional gas reburn is that the former involves less reburn fuel consumption. As discussed below, FLGR™ alone or in combination with basic SOFA (without ASOFA) is expected to be ineffective on lignite-fired cyclone boilers.

As a NO_X control technology, FLGR™ with SOFA is considered technically feasible for application on Leland Olds Station Unit 1 boiler. However, because of the lack of apparent NO_X control performance advantage over other similar or better performing control alternatives, high operating cost and significant capital costs for supplying natural gas, this alternative was not evaluated for consideration as an option for LOS Unit 1. More commonly, FLGR™ has been installed with SNCR for NO_X emission reduction[22,23,24,25]. This is discussed in a subsequent section involving amine-enhanced FLGR™.

In the case of FLGR™ applied to lignite-fired cyclone boilers, air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction is an optional part of this reburn technique which will further risk slag "freezing" in the barrels and lower furnace. The amount of fuel injected above the existing lignite drying system vent ports (which will not be relocated as part of the basic form of SOFA) is expected to be substantially more than previously demonstrated in order to compensate for the higher oxygen levels due to the introduction of moist air in the lower furnace above the cyclones without relocating the vent ports. The existing lignite drying systems' vent ports' locations and introduction of oxygen to the lower furnace below the presumed FLGR™ injection points will likely limit the NO_X emission reduction potential of the FLGR™ component. Limited additional potential NOx reduction is anticipated when FLGR™ is operated with lignite-fired cyclones, due to the potential need to remove one or more cyclones from active firing to maintain adequate heat input in the remaining active cyclones for keeping satisfactory slag formation and flow. Reducing the number of active cyclones, which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with reburn and separated overfire air, is the typical approach to avoid slag tapping problems. This creates lower furnace conditions where oxygen (cooling air from the idle cyclones) is introduced in proximity to the reburn fuel, disrupting the desired in-furnace reduction process for nitrogen oxides.

FLGR™ technology with basic and advanced forms of SOFA was not included in the cost-effectiveness analysis for LOS Unit 2, because of the lack of apparent NO_X control performance advantage over other similar or better performing control alternatives, high operating cost and significant capital costs for supplying natural gas.

A1.4.2 SNCR and Reburn

Various forms of SNCR could potentially be installed downstream of separated overfire air and various types of fuel reburn, to reduce NO_X emissions prior to the boiler's flue gas exit. Conventional gas (CGR) or coal reburn systems, by and large, have not been combined with forms of SNCR, although at least one vendor (GE Energy) has promoted a combination of conventional gas reburn with SNCR and overfire air systems[18] as “advanced” gas reburn. Only one example of permanent installation of SNCR with conventional gas reburn (and overfire air) on a tangentially-fired boiler was found in available technical literature or vendor experience lists. The vendor (GE Energy) that provided the advanced gas reburn system at 120 MW NRG Somerset Station claimed NO_X emissions were reduced by 44% from a baseline of 0.45 down to 0.25 lb/mmBtu with overfire air alone; an additional reduction of 20% resulting from conventional gas reburn with overfire air, down to 0.20 lb/mmBtu; and further decrease of 45% down to 0.11 lb/mmBtu using gas reburn with SNCR with an unstated amount of ammonia slip, for an overall reduction of 75% from pre-control baseline[6,35].

As a combination of NO_X control technologies, conventional gas reburn with SNCR and SOFA may be capable of being installed on the Leland Olds Station Unit 1 boiler. However, because of the lack of any permanent commercial gas reburn experience applying this combination of technologies to wall-fired coal-burning boilers, and apparent negative economic advantage due to high operating cost and significant capital costs for supplying natural gas versus the expected slight potential gain in NO_X control performance, CGR with ASOFA and SNCR alternative was not evaluated for consideration as an option for LOS Unit 1.

No example of actual demonstration or permanent installation of SNCR with conventional gas or coal reburn (and overfire air) on cyclone-fired boilers was found in available technical literature. As previously expressed with layered technologies involving conventional reburn, an “advanced” form of SOFA is desired for lignite-fired cyclone boilers. The lack of experience with this combination on a cyclone-fired boiler, especially for lignite-firing, makes the prediction of success and the level of NO_X emission reduction potential uncertain. CGR with ASOFA and SNCR was considered technically infeasible as an option for LOS Unit 2.

Rich Reagent Injection has not been demonstrated of being capable of combining with fuel reburn, especially conventional fuel reburn alternatives with high amounts of reburn fuel injection. No example of actual demonstration or permanent installation of RRI with reburn (and overfire air) on cyclone-fired boilers was found in available technical literature or vendor experience lists. This combination of technologies is considered technically infeasible as an option for LOS Unit 2.

Because of the lack of any permanent commercial coal reburn experience applying this combination of technologies to pulverized coal-fired or cyclone-fired boilers, apparent negative economic advantage due to high operating cost and significant capital costs for preparing the reburn fuel versus the expected slight potential gain in NO_X control performance, PCR/mCR with ASOFA and SNCR alternative was not evaluated for consideration as an option for LOS Unit 1's and Unt 2's boilers. This combination of technologies is considered technically infeasible as an option for LOS Unit 1's and Unt 2's boilers.

A1.4.2.1 Amine-Enhanced FLGR™ (AEFLGR™) or FLGR™ + SNCR

Fuel-lean gas reburn has been combined with SNCR on at least five pulverized coal-fired utility powerplants retrofit installations within the United States[23]. This combination of technologies allows the boiler to be operated with FLGR™ alone, FLGR™ and SNCR, or SNCR only (without SOFA) for the specific level of control desired or required. The vendor (Fuel Tech) that provided the AEFLGR™ system at Mercer Station claimed NO_X emissions were reduced by 60% (from a baseline of 1.4 down to 0.56 lb/mmBtu) with 5 ppm ammonia slip without overfire air. A technical paper provides more details[36].

As a combination of NO_X control technologies, FLGR™ with SNCR (with or without SOFA) is considered technically feasible for application of Leland Olds Station Unit 1 boiler. However, with disadvantages of high operating cost and significant capital costs for supplying natural gas compared to other similar or better performing control alternatives, this alternative was not evaluated for consideration as an option for LOS Unit 1.

No example of actual demonstration or permanent installation of FLGR™ + SNCR (with or without overfire air) applied to a cyclone-fired boiler was found in available technical literature or vendor experience lists. It may be possible to be applied on a cyclone-fired boiler burning lignite, but the amount of NO_X control performance contribution from the FLGR™ system is expected to be limited.

Because a FLGR™ + SNCR (AEFLGR™) system (without basic or advanced versions of SOFA) lacks demonstrated and commercial experience in this application, particularly on a cyclone-fired boiler burning lignite, this combination is considered infeasible as an option for LOS Unit 2.

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A2 Cost of Compliance for NO_X Controls - Estimate Details

An evaluation was performed to determine the compliance costs of installing various feasible NO_X control alternatives on Leland Olds Station boilers. This evaluation includes estimated:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, procure, construct, install, startup, test, and place into sustained annual commercial operation the particular control technology. The results of this evaluation are summarized in the main report, Tables 2.4-1 through 2.4-7 for LOS Unit 1, and Tables 2.5- through 2.5-9 for LOS Unit 2.

A2.1 Capital Cost Estimates for NO_X Controls

The capital costs to implement the various NO_X control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. In the cases with SNCR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. The capital costs for combinations of NOx reduction technologies evaluated were typically estimated based upon simple arithmetic addition of the individual unit output capital cost factors for these technologies, multiplied by the nameplate capacity ratings of the steam-electric generating units at Leland Olds Station. These cost estimates were adjusted for inflation where appropriate (to 2005$), and are considered to be study grade, which is + or – 30% accuracy, or better.

The limitations of these capital cost estimates developed from unit capital cost factors multiplied by unit output are subject to:

- Scope basis uncertainty – inability to precisely determine what scope of supply, including such things as balance-of-plant (BOP) systems and equipment improvements were required, assumed, or accounted for when developing the unit cost factors. Some alternatives may have higher indirect or BOP capital costs than others. Similarly, the inclusion of general facilities, preproduction and inventory costs, and other indirect costs is not known. It is likely that the utility owner's final total expenditure for the implementation of the alternatives, especially options that are most capital cost-intensive, will be greater than the calculated cost estimates.
- Location-specific influences – most NO_X control techniques have been applied primarily to eastern bituminous coal-fired plants located near large metropolitan areas, not in largely rural,

upper midwestern United States locales. The amount of space available is dependent on the existing powerplant equipment and building layout and property plot area, versus what is expected to be required for implementing various control technologies. Transportation and local/regional labor costs are also variables.

- Size influences – some technologies' capital costs are more sensitive to "economies of scale" than others.
- Capacity margins – some technologies' may require higher capacity margins to allow sustained operation at high throughput rates over extended periods of time.
- Reliability concerns – some technologies' have been refined to a higher degree, and others may require more component redundancy than others in order to avoid performance reductions and potential outages for failures and repairs or replacements.
- Inflationary influences – the significant increases in 2004-2005 for raw material costs, especially steel and alloys for fabrication of structural and mechanical components, has occurred after many of these technologies were installed in projects upon which the referenced unit capital cost factors were based.
- Market conditions – as demand increases for emission controls, some alternatives become more cost-competitive, while others do not. This can be influenced by the relative supply and demand for the technology and number of suppliers who can furnish it. The demand for some alternatives can also be strongly influenced by the stringency of the local, state, and national regulatory requirements. Schedule demands for implementation and availability of local/regional labor for installation contractors are also market-driven factors.

The estimated installed capital cost for each alternative evaluated was multiplied by the capital levelization factor (0.08718) to yield levelized total annualized capital cost.

A2.1.1 Combustion Controls' Capital Cost Estimates

A2.1.1.1 Separated Overfire Air Capital Cost Estimates

Installation of separated overfire air systems typically includes windbox and/or secondary combustion air supply duct modifications, boiler waterwall tube openings, airflow distribution devices (dampers/registers), airflow controls and measurement instrumentation, and related structural and electrical tie-ins to the existing plant facilities. A basic separated overfire air retrofit system installed on LOS wall-fired and cyclone boilers includes ports across the front and rear walls of the upper furnace.

The unit capital cost factor is expected to be at the low end of the typical range[37] for LOS Unit 1: $6.3/kW or $1.4M; and near the high end of the same range for LOS Unit 2: $12.5/kW or $5.5M.

A basic form of SOFA for potential retrofit on LOS Unit 1's boiler will include providing new (or relocating the existing close-coupled) overfire air ports and waterwall tube openings adjacent and above the top row burners in the middle furnace to a slightly higher elevation across the front and rear walls. This requires extension of the existing CCOFA windbox or creation of a new SOFA windbox to supply the new ports. This retrofit will also close-off the existing CCOFA ports.

A boosted form of SOFA (ROFA) for potential retrofit on LOS Unit 1's boiler will include additional secondary air ductwork to and from a new hot air booster fan. This is expected to cost in the area of +$14.4/kW or approximately $3.1M for Unit 1's additional capital cost over and above the basic SOFA system. Overall, the boosted version of SOFA is estimated to have an installed capital cost of approximately $20.7/kW or $4.5M for LOS Unit 1. The installed capital cost estimate for LOS Unit 1's boosted SOFA (ROFA) alternative used in this cost effectiveness analysis was estimated based upon applying a 3.5% assumed inflation cost adjustment to the unit capital cost factor for ROFA of $20/kW (x 1.035 = $20.7/kW) included in a WRAP (Western Regional Air Partnership) draft report[38] published on their website, dated April 26, 2005. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BART analysis.

For LOS Unit 2, an advanced form of SOFA unique to North Dakota lignite-fired cyclone boilers will include relocation of the existing lignite drying system vent port openings from the lower primary furnace to the upper furnace, to be placed at the same elevation as the new SOFA ports. This requires extension of the lignite drying systems' vent piping to supply the new ports. This is expected to cost in the area of +$5/kW or approximately $2.1M for Unit 2's additional capital cost over and above the basic SOFA system. This retrofit will also close-off the existing FGR ports, currently coinciding with the existing pre-dry vent ports on Unit 2. These FGR ports may be relocated to the lower portion of the upper (secondary) furnace, across the front and rear walls. This is expected to cost in the area of +$5.6/kW or +$2.5M for Unit 2's additional capital cost over and above the basic SOFA system. Overall, the advanced version of SOFA is estimated to have an installed capital cost of approximately $23/kW or $10.1M for LOS Unit 2. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BART analysis.

Reduced-diameter replacement cyclone reentrant throats (boiler waterwall tubes) are hardware modifications which can be specifically designed to complement the air-staged combustion/SOFA approach and may improve the ability to increase the retention of fine coal particles during staged combustion on the Unit 2 boiler at LOS. This is estimated to cost in the area of $18.2/kW or approximately $8M for Unit 2. However, these capital costs were not included in the figures used in the determination of the NO_X control technology cost-effectiveness for any alternatives.

A2.1.1.2 Coal Reburn Capital Cost Estimates

There are several alternatives that include a new fuel reburn system. Capital cost estimates for coal reburn systems are highly dependent on the requirements for reburn fuel preparation and feeding to the boiler. For the purposes of this analysis, the application of a pulverized coal reburn system assumed the need to make extensive additions to the existing fuel preparation equipment in the existing plant facilities and feeding to new furnace injectors. At least two new fine-grind pulverizers, or MPS-89 standard pulverizers followed by dynamic classifiers are expected to supply the amount of finely ground reburn coal for this method. Addition of new electrical loads for the pulverized coal preparation equipment to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power will be available for powering the new pulverizers/micro-mills and related new coal reburn equipment, but this has not been confirmed.

The existing LOS Unit 1 boiler's pulverizer bays do not have floor space available to allow the new milling equipment for reburn fuel preparation to be located adjacent to the existing coal pulverizers. This will require a separate building or addition to the existing powerhouse to be built to provide sufficient space to enclose the new milling and coal silo/handling equipment. Separate modified pulverized coal-style burners or coal injectors will be installed through new openings in the upper furnace front and rear waterwalls at or above the elevation of the existing cose-coupled overfire air system ports, along with new separated overfire air ports located at a higher elevation, above the reburn fuel injectors. This would have the capacity to supply approximately up to thirty percent of the total full load fuel heat input to the boiler through the coal reburn injectors. The coal reburn system design was not expected to change the existing main burner silo/feeder arrangement, such that all main burners would remain operational. Both basic and boosted forms of SOFA for pulverized coal reburn were included. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BART analysis.

The installed capital cost of pulverized coal reburn for LOS Unit 1 used in this cost effectiveness analysis was estimated based upon a Clean Air Markets Division [CAMD] of the US EPA dollar per kilowatt unit capital cost factor for cyclone boilers, because of the need to make extension additions to the existing feul prepearation system equipment/facilities. The installed capital cost estimate of $19.8M for LOS Unit 1's pulverized coal reburn alternative with basic SOFA used in this cost effectiveness analysis was estimated based upon applying a 3.5% assumed inflation cost adjustment to the CAMD unit capital cost factor for cyclones of $82.33/kW (x 1.035 = $85.2/kW) included in a WRAP (Western Regional Air Partnership) draft report[38] published on their website, dated April 26, 2005. Including the estimated additional capital costs for retrofitting basic SOFA in place of CCOFA previously described in the separated overfire air capital cost estimate section raised the installed unit capital cost factor to $91.5/kW.

Including the estimated additional capital costs for boosted SOFA previously described in the separated overfire air capital cost estimate section raised the installed unit capital cost factor to $105.9/kW, bringing the estimated subtotal of LOS Unit 1's coal reburn system with boosted SOFA to $22.9M.

As discussed in the coal reburn feasibility review, additional particulate matter collection equipment to increase PM collection capacity of LOS Unit 1 will be needed for this alternative. This was assumed to include a hybrid particulate matter collection system associated with the existing electrostatic precipitator referred to as COHPAC. A description of this technology is provided in the main report under the PM control section. The COHPAC addition due to coal reburn was estimated based on flue gas flow at the boiler design rating (2,622 mmBtu/hr) heat input rate. Installed capital cost for this COHPAC addition was $15.7M ($72.9/kW). This is generally described in more detail in the capital cost estimate portion of the main report for particulate matter controls, Section 4.5.1.1 for LOS Unit 2.

Addition of new electrical loads for the LOS Unit 1 boiler's pulverized/micronized coal preparation equipment, and associated with adding COHPAC to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power capacity will be available for powering the new pulverizers/micro-mills, COHPAC, and auxiliary equipment related to the new coal reburn facility. Any capital costs for providing the additional auxiliary electrical power distribution capacity not included in the assumed project scope has not been estimated or included.

Adding the \$15.7M for the COHPAC PM collection capacity increase to the coal reburn system with basic SOFA subtotal of \$19.8M yields a total estimated installed capital cost of \$35.5M (\$164.4/kW) for this coal reburn alternative. Adding the \$15.7M for the COHPAC PM collection capacity increase to the coal reburn system with boosted SOFA subtotal of \$22.9M yields a total estimated installed capital cost of \$38.6M (\$178.8/kW) for this coal reburn alternative. This was deemed sufficient to use in the cost-effectiveness analysis for applying coal reburn to Leland Olds Station Unit 1's boiler.

The existing LOS Unit 2 boiler's crusher bays do not have floor space available to allow the new milling equipment for reburn fuel preparation to be located adjacent to the existing coal crushers. This will require a separate building or addition to the existing powerhouse to be built to provide sufficient space to enclose the new milling and coal silo/handling equipment. Separate modified pulverized coal-style burners or coal injectors will be installed through new openings in the upper furnace front and rear waterwalls at or above the elevation of the existing lignite drying system vent ports, along with new overfire air ports located at a higher elevation, above the reburn fuel injectors. This would have the capacity to supply approximately up to thirty percent of the total full load fuel heat input to the boiler through the coal reburn injectors. The coal reburn system design was not expected to change the existing cyclone silo/feeder arrangement, such that all cyclones would remain operational. To achieve maximum NO_X emission control, only the advanced form of SOFA for pulverized coal reburn was included. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BART analysis.

The installed capital cost of pulverized coal reburn for LOS Unit 2 used in this cost effectiveness analysis was estimated based upon a Clean Air Markets Division [CAMD] of the US EPA dollar per kilowatt unit capital cost factor for cyclones. The installed capital cost estimate of \$37.5M for LOS Unit 2's pulverized coal reburn alternative used in this cost effectiveness analysis was estimated based upon applying a 3.5% assumed inflation cost adjustment to the CAMD unit capital cost factor for cyclones of \$82.33/kW (x 1.035 = \$85.2/kW) included in a WRAP (Western Regional Air Partnership) draft report[38] published on their website, dated April 26, 2005. Including the estimated additional capital costs for relocating special lignite drying system vent ports and flue gas recirculation ports previously described in the separated overfire air capital cost estimate section raised the installed capital cost estimate subtotal of LOS Unit 2's coal reburn system to \$42.1M.

As discussed in the coal reburn feasibility review, additional PM collection equipment to increase PM collection capacity of LOS Unit 2 will be needed for this alternative. This was assumed to include a hybrid particulate matter collection system associated with the existing electrostatic precipitator referred to as COHPAC. A description of this technology is provided in the main report under the PM control section. The COHPAC addition due to coal reburn was estimated based on flue gas flow at the boiler design rating (5,130 mmBtu/hr) heat input rate. Installed capital cost for this COHPAC addition was $25.3M ($57.5/kW). This is described in more detail in the capital cost estimate portion of the main report for particulate matter controls, Section 4.5.1.1 for LOS Unit 2.

Addition of new electrical loads for the pulverized/micronized coal preparation equipment, and associated with adding COHPAC to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power capacity will be available for powering the new pulverizers/micro-mills, COHPAC, and auxiliary equipment related to the new coal reburn facility. Any capital costs for providing the additional auxiliary electrical power distribution capacity not included in the assumed project scope has not been estimated or included.

Adding the $25.3M for the COHPAC PM collection capacity increase to the coal reburn system with ASOFA subtotal of $42.1M yields a total estimated installed capital cost of $67.425M ($153.2/kW) for this alternative. This was deemed sufficient to use in the cost-effectiveness analysis for applying coal reburn to Leland Olds Station Unit 2’s boiler.

A2.1.2 Capital Cost Estimates for Post Combustion Controls

A2.1.2.1 SNCR Capital Cost Estimate

The alternatives for LOS Unit 1 that include selective non-catalytic reduction systems assume the use of urea unless noted otherwise. The SNCR systems’ preliminary design and estimated capital costs were based upon a 2004 budgetary proposal[39] for a nominal 240 MW unit by a vendor (Fuel Tech) with experience in supplying urea-based SNCR equipment. Circulation, metering, dilution, control, in-line and storage tank heating, water dilution, and reagent metering equipment. Estimated capital costs of $3.9M ($18.06/kW) include budgetary numbers for equipment installation, including installation management, material and labor assumed for a SNCR system applied to LOS Unit 1’s 216 MW boiler. Costs for work outside the vendor’s scope, such as outdoor reagent storage tank and building enclosure/equipment foundations and containment, and balance-of-plant additions plus other indirect costs were estimated to add approximately \$1.0M (25% plus 10% contingency) to the vendor's estimated installed cost for their scope of supply. These adjustments result in a total installed capital cost for SNCR (without SOFA) estimated to be approximately \$3.9M plus \$1.0M = \$4.9M for 216 MW LOS Unit 1.

Adding the basicSOFA capital cost of \$1.4M yields a total estimated installed capital cost of \$6.2M (\$28.9/kW) for the SNCR with basic SOFA alternative for LOS Unit 1.

Including the estimated additional capital costs for boosted SOFA previously described in the separated overfire air capital cost estimate section raised the installed unit capital cost factor to \$43.3/kW, bringing the estimated subtotal of LOS Unit 1's SNCR system with boosted SOFA (Rotamix) to \$9.3M.

The alternatives for LOS Unit 2 that include selective non-catalytic reduction systems assume the use of urea unless noted otherwise. The SNCR systems' preliminary design and estimated capital costs were based upon a late 2004 budgetary proposal[39] for a nominal 450 MW unit by a vendor (Fuel Tech) with experience in supplying urea-based SNCR equipment. Circulation, metering, dilution, control, in-line and storage tank heating, water dilution, and reagent metering equipment. The conceptual SNCR project estimates a 180,000 gallon field-erected stainless steel storage tank will hold the 50% urea solution (as delivered by truck or rail). Individual and multiple nozzle lances with multiple levels of urea reagent injection will be designed and located to optimize distribution and accommodate various boiler load conditions. Capacity of the SNCR system is expected to be sufficient to be operated alone or in conjunction with other NO_X reduction technologies, such as advanced SOFA and Rich Reagent Injection. Estimated capital costs of \$4.9M include budgetary numbers for equipment installation, including installation management, material and labor assumed for a SNCR system applied to a 450 MW boiler. Costs for work outside the vendor's scope, such as outdoor reagent storage tank and building enclosure/equipment foundations and containment, and balance-of-plant additions plus other indirect costs were estimated to add approximately \$1.9M (25% plus 10% contingency) to the vendor's estimated installed cost for their scope of supply. These adjustments result in a total installed capital cost for SNCR (without advanced SOFA or RRI) estimated to be approximately \$6.7M for 440 MW LOS Unit 2. Adding the advanced SOFA capital cost of \$10.1M yields a total estimated installed capital cost of \$16.8M (\$38.3/kW) for the SNCR with ASOFA alternative for LOS Unit 2.

Addition of new electrical loads for the SNCR reagent storage, pumping, dilution, metering, and related compressed air control equipment for reagent injector cooling, will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power capacity will be available for powering the new SNCR system and associated auxiliary equipment. Any capital costs for providing the additional auxiliary electrical power distribution capacity has not been estimated or included.

A2.1.2.2 Rich Reagent Injection Capital Cost Estimate

The alternative for LOS Unit 2 that includes Rich Reagent Injection (RRI) form of selective non-catalytic reduction systems assumes the use of urea as the effective NO_X control reagent. The RRI systems' preliminary design and estimated capital costs were derived from information by the vendor licensed for this technology (Reaction Engineering International). If RRI were to be supplied without SNCR, total capital cost is assumed to be the same as SNCR with ASOFA, or $16.8M for LOS Unit 2.

Expansion of the base SNCR alternative's reagent circulation, metering, dilution, control, in-line and storage tank heating, storage and injection equipment is assumed to be included when RRI is added to this other alternative. Individual RRI lances with multiple levels of urea reagent injection in the lower furnace will be designed and located to optimize distribution and accommodate various boiler load conditions. Capacity of the RRI system is expected to be sufficient to be operated in conjunction with other NO_X reduction technologies, such as ASOFA with or without SNCR. Estimated capital costs for RRI in combination with SNCR assumed the addition was 50% of SNCR's capital costs. These adjustments result in an incremental installed capital cost for RRI estimated to be $3.4M for LOS Unit 2 (without ASOFA or SNCR costs included in the assumed RRI+SNCR w/ ASOFA "layered" alternative). Adding the SNCR with advanced SOFA estimated capital cost of $16.8M yields a total estimated installed capital cost of $20.2M ($46/kW) for this RRI+SNCR with ASOFA alternative.

Addition of new electrical loads for the RRI portion of the SNCR reagent storage, pumping, dilution, metering, and related cooling water and compressed air control equipment for reagent injector cooling and dispersion, will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power capacity will be available for powering the RRI portion of the new SNCR system and associated auxiliary equipment. Any capital costs for providing the additional auxiliary electrical power distribution capacity has not been estimated or included.

A2.2 Operating and Maintenance Cost Estimates for Leland Olds Station NO_X Controls

An evaluation was performed to determine the estimated operating, maintenance, and capital cost impacts of installing various feasible NO_X control technologies on Leland Olds Station Units 1 and 2. These were estimated to be in addition to existing O&M costs to operate and maintain the LOS equipment.

The expected loss of electrical power sales from the operation of the specific NO_X control alternative was included as an annualized cost, assuming $38 per megawatt-hour. This was determined to include estimates for:

- Reduction in annual unit output due to an expected negative reliability (i.e. uptime availability) impact for each alternative. This “lost generation” was calculated by multiplying the estimated additional numbers of outage hours per year by the average running plant capacity factor for that specific alternative.
- Net additional auxiliary electric power demand for the added control equipment for each specific alternative based on assumptions for gross horsepower and loading factor, plus additional power demand for induced draft fans caused by flue gas pressure drop, pulverizers and feeders for coal reburn, and compressed air or service water consumed for injection media and lance cooling, respectively, for SNCR and RRI alternatives.
- The average running plant capacity factor for each alternative, which may also include an expected negative impact on the unit capacity from operation of the technology. Examples are lower boiler thermal efficiency (higher unit heat rate) when firing natural gas (due to higher moisture content of the flue gas).

For alternatives that involve a chemical reagent injected for NOx control, such as urea (or ammonia converted from urea), the annual reagent consumption based on an assumed actual stoichiometric ratio (ASR) of moles of equivalent NH_3 injected per mole of uncontrolled NO_X emission estimated at the point of injection, converted to a mass rate (lbs/hr) by multiplying by the estimated annual number of hours of operation and the estimated NOx reduction fraction, and then multiplied by unit reagent cost. For SNCR-related alternatives, a December 2004 vendor proposal and subsequent followup in September 2005 is the primary basis for the reagent consumption estimates (for a specific NO_X emission reduction and ammonia slip level).

General annual maintenance costs were assumed to be 1.5 percent of the estimated installed capital cost for each alternative, except for the pulverizer portions of the coal reburn alternatives, which were assumed to be 3 percent.

Additional operating labor costs directly attributable to each alternative were assumed to be zero for all alternatives.

Other operating costs include:

- Reagent dilution water for those alternatives that involve a chemical reagent injected for NOx control, typically four times the amount of urea consumption (assumes urea is a 50% solution as delivered and is injected as a 10% solution); this follows EPA OAQPS convention.
- Heat required for reagent storage; for those alternatives that involve a chemical reagent injected for NOx control; the source of heat is assumed to be auxiliary electrical power, but could be auxiliary steam (depending on heat source availability and plant preference). All SNCR-related alternatives assume the direct use of diluted urea solution.
- Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water; this follows EPA OAQPS convention, but is not accepted practice by an experienced SNCR vendor (Fuel Tech) who claims that the heat produced from the exothermic reaction of urea and NO_X is approximately equal to the heat required to evaporate the dilution water. For the purposes of this study, this additional coal consumption has not been included in the annual O&M costs.

The sum of the estimated annual O&M costs was multiplied by the O&M levelization factor (1.19314) for each alternative to yield levelized total annual O&M costs.

A2.2.1 Combustion Controls' O&M Cost Estimates

A2.2.1.1 Separated Overfire Air O&M Cost Estimates

Operation of the basic form of SOFA on LOS Unit 1's boiler is expected to add a small amount of O&M cost, primarily electricity consumed by the conventional SOFA damper electric drive actuator and overfire airflow measuring system transmitter supplying each SOFA windbox on the front and rear walls. A substantial mount of additional electricity will be consumed by the hot air booster fan for operation of the boosted form of SOFA on LOS Unit 1's boiler. Using the existing forced draft, induced draft, and primary air fans is not expected to change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. Boiler furnace waterwall tube maintenance may increase slightly as a result of more fireside corrosion due to substoichiometric burner operation with SOFA. Maintenance of the new windbox-style overfire air ports is expected to be similar to the expenses associated with the existing CCOFA ports of Unit 1. Maintenance costs for alternatives that include SOFA are assumed to be 1.5 percent of the installed capital cost.

Operation of the advanced form of SOFA on LOS Unit 2's boiler is expected to add a small amount of O&M cost, primarily electricity consumed by the conventional SOFA damper electric drive actuator and overfire airflow measuring system transmitter on each port. Using the existing forced draft, induced draft, and flue gas recirculation fans is not expected to change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. Boiler furnace waterwall tube maintenance may increase slightly as a result of more fireside corrosion due to substoichiometric cyclone operation with SOFA. Maintenance of the new open-style overfire air ports is expected to be similar to the expenses associated with the existing flue gas recirculation ports of Unit 2. Maintenance costs for alternatives that include ASOFA are assumed to be 1.5 percent of the installed capital cost.

A2.2.1.2 Coal Reburn O&M Cost Estimates

The alternatives that include a new coal reburn system assume the use of new equipment for preparing the reburn fuel to replace 25% of each LOS boiler's total fuel heat input. Two additional lignite silos, with coal feeders and fine-grind pulverizers followed by dynamic classifier(s), or possibly four micromills, are assumed to be located in a new separate building or powerhouse enclosure for each LOS boiler. A booster fan (exhauster) is assumed to be required to overcome the pressure drop across the fine-grind pulverizers or micromills and dynamic classifiers for supplementing the existing primary air system for the additional reburn fuel milling. Using the existing forced draft, induced draft, primary air (LOS Unit 1) and flue gas recirculation (LOS Unit 2) fans is not expected to significantly change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. The expected loss of electrical power sales from the additional auxiliary electric power demand for the reburn milling equipment from an estimated 0.4% (940 kW for LOS Unit 1's) and 2.5 MW for LOS Unit 2's reduction in net output was included as a cost of $0.3M/yr and $0.8M/yr, assuming $38 per megawatt-hour for LOS Unit 1 and Unit 2, respectively. The twenty existing mills on Unit 1 and twelve existing coal crushers and feeders on Unit 2 used for preparing the main (burner and cyclone) fuel fraction will have approximately 25% lower electrical demand, which was \$100,000/yr and \$150,000/yr subtracted from the additional reburn auxiliary power costs for LOS Unit 1 and Unit 2, respectively.

Maintenance of the separate reburn coal injectors is expected to be similar to the expenses associated with typical pulverized coal burners. The estimated additional annual maintenance costs for a new micronized coal reburn system was assumed to be 3.0 percent of the installed capital cost, or roughly \$0.6M per year for LOS Unit 1 and \$1.26M per year, for LOS Unit 2.

Operation and maintenance costs of the basic and boosted forms of SOFA on LOS Unit 1's boiler, and the advanced version of SOFA on LOS Unit 2, are assumed to be included for coal reburn alternatives.

Increase in auxiliary electrical power for the COHPAC addition associated with the coal reburn alternatives for NO_X control was estimated to be approximately \$0.5M/yr and \$0.8M/yr for LOS Unit 1 and LOS Unit 2 respectively. This is mostly the result of higher induced draft fan horsepower demand to overcome the resistance (pressure drop) of the filter media to the flue gas flow. Additional auxiliary electrical power must be supplied to those fans' electric motors. Maintenance of the COHPAC addition to LOS Unit 1 and LOS Unit 2 includes replacement of the filter bags, and general maintenance expenses. This was assumed to be approximately \$0.4M/yr and \$0.8M/yr for LOS Unit 1 and LOS Unit 2 respectively. Section 4.5.1.2 of the main report for LOS Unit 2 describes the O&M cost estimate portion for particulate matter controls in more detail.

A2.2.2 Post-Combustion NO_X Controls' O&M Cost Estimates

A2.2.2.1 SNCR O&M Cost Estimates

The alternatives that include selective non-catalytic reduction systems will involve higher operating costs compared with the existing operation of LOS Unit 1 and Unit 2. Urea supply is believed to be available regionally, with an estimated unit cost assumed to average \$379/ton delivered as a 50% concentration aqueous solution (2006\$). This unit price is volatile, and changes primarily on the basis of the unit cost of natural gas. Consumption of aqueous urea reagent was derived from preliminary numbers included in a late 2004 budgetary proposal by a vendor of urea-based SNCR equipment (Fuel Tech), allowing for a boiler flue gas exit ammonia slip of 5 ppmvd. This estimated urea consumption rate is significantly higher than that predicted by equations published in the EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Oxidation[40].

New electrical loads are required for high flow urea circulation, water dilution, in-line and storage tank heating, and reagent metering equipment. These auxiliary electrical demands and reagent dilution water usage were calculated based upon equations published in the EPA OAQPS SNCR Cost Manual[40]. Compressed air for reagent atomization and lance purging and cooling, as well as multiple nozzle lance water cooling are additional demands on the existing plant facilities. These powerhouse building service supplies were assumed to be available. The new urea reagent injection nozzle lances, reagent pumps, dilution water pumps, and distribution piping/valve trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost.

The O&M costs associated with an SNCR system for LOS Unit 1 and Unit 2 assumes that no additional operating labor is required, as suggested in the EPA OAQPS SNCR Cost Manual[40].

Operation and maintenance costs of the basic and boosted forms of SOFA on LOS Unit 1's boiler, and the advanced version of SOFA on LOS Unit 2, are assumed to be included for SNCR alternatives that include SOFA technology.

A2.2.2.2 RRI O&M Cost Estimates

Operating and maintenance costs for Rich Reagent Injection assumes this technology was combined with the advanced form of SOFA and SNCR for LOS Unit 2. Consumption of the 50% concentration aqueous urea reagent for RRI system operation without including the reagent consumed by the SNCR system was based upon a reagent consumption rate of two times the comparable SNCR urea usage rate for the same uncontrolled NO_X emission conditions and percent NO_X reduction. The estimated aqueous urea consumption for the combined RRI+SNCR systems was determined by simple addition of the usage of the individual technologies, based on their estimated individual performance contributions.

Additions to the new electrical loads assumed for SNCR are required for increased capacity high flow urea circulation, water dilution, in-line and storage tank heating, and reagent metering equipment. These auxiliary electrical demands and reagent dilution water usage were calculated based upon equations published in the EPA OAQPS SNCR Cost Manual[40]. Compressed air for reagent atomization and lance purging and cooling, as well as multiple nozzle lance water cooling are additional demands on the existing plant facilities. These powerhouse building service supplies were assumed to be available. The additional new urea reagent injection nozzle lances, reagent pumps, dilution water pumps, and distribution piping/valve trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost for this alternative.

Similar to SNCR, the O&M costs associated with an RRI+SNCR system for LOS Unit 2 assumes that no additional operating labor is required, as suggested in the EPA OAQPS SNCR Cost Manual[40].

A2.2.4 Summary of O&M Cost Estimates for LOS NO_X Controls

The results of this evaluation for expected operating and maintenance costs for the individual NOx control alternatives are summarized in the main report (Sections 2.4 and 2.5). The expected O&M costs are dependent upon the assumptions involving reductions in unit availability (uptime) and capacity included in Tables A.2-1 through A.2-4. The O&M costs associated with electrical power demands and usage are shown in Tables A.2-5 and A.2-6. The O&M costs for expected NO_X reagent usage are shown in Tables A.2-7 and A.2-8.

TABLE A.2-1 – Expected Availability Reductions for LOS Unit 1 NO_X Controls

Alt. #[1]	NOx Control Technique	Estimated Annual Average Availability[2]	Estimated Annual Average Operating Time, hrs/yr[3]	Estimated Annual Average Outage Time, hrs/yr[4]	Estimated Annual Average Lost Operating Time, hrs/yr[5]
G	Coal Reburn w/ boosted SOFA	0.990	8,672	88	88
F	Coal Reburn w/ basic SOFA	0.990	8,672	88	88
E	SNCR with boosted SOFA	0.990	8,672	88	88
D	SNCR with basic SOFA	0.990	8,672	88	88
C	SNCR with Close-Coupled SOFA	0.990	8,672	88	88
B	Boosted SOFA	1.000	8,760		
A	Separated OFA (basic)	1.000	8,760	0	0

[1] – Alternative number has been previously assigned from least removal to highest removal percentage.

[2] – Baseline availability is assumed at 100.0 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.

[3] – Annual operating time is annual availability multiplied by 8760 hrs/yr of possible uptime.

[4] – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.

[5] – Annual lost operating time resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.

TABLE A.2-2 – Expected Availability Reductions for LOS Unit 2 NO_X Controls

Alt. #[1]	NOx Control Technique	Estimated Annual Average Availability[2]	Estimated Annual Average Operating Time, hrs/yr[3]	Estimated Annual Average Outage Time, hrs/yr[4]	Estimated Annual Average Lost Operating Time, hrs/yr[5]
D	RRI+SNCR w/ ASOFA	0.990	8,672	88	88
C	SNCR w/ ASOFA	0.990	8,672	88	88
B	Coal Reburn w/ ASOFA	0.985	8,629	131	131
A	Advanced SOFA (ASOFA)	1.000	8,760	0	0

[1] – Alternative number has been previously assigned from least removal to highest removal percentage.
[2] – Baseline availability is assumed at 100.0 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
[3] – Annual operating time is annual availability multiplied by 8760 hrs/yr of possible uptime.
[4] – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.
[5] – Annual lost operating time resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.

TABLE A.2-3 – Expected Capacity Reductions for LOS Unit 1 NO_X Controls

Alt. #[1]	NOx Control Technique	Estimated Annual Average Running Plant Capacity Factor[2]	Estimated Annual Average Electricity Generation Reduction MW-hrs/yr[3]	Estimated Annual Average Generation Reduction Cost, K$/yr[4]
G	Coal Reburn w/ boosted SOFA	0.995	18,827	715
F	Coal Reburn w/ basic SOFA	0.995	18,827	715
E	SNCR with boosted SOFA	0.999	18,893	718
D	SNCR with basic SOFA	0.999	18,893	718
C	SNCR with Close-Coupled SOFA	0.999	18,893	718
B	Boosted SOFA	1.000	0	0
A	Separated OFA (basic)	1.000	0	0

[1] – Alternative number has been previously assigned from least removal to highest removal percentage.
[2] – Baseline running plant capacity factor is assumed at 100.0 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
[3] – Annual electricity generation lost is annual lost operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the unit nameplate gross output capacity rating: 216 MW for LOS Unit 1.
[4] – Annual electricity generation lost cost is the annual electricity generation lost (MW-hrs/yr) resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $38.00/MW-hr. All cost figures in 2005 dollars.

TABLE A.2-4 – Expected Capacity Reductions for LOS Unit 2 NO_X Controls

Alt. #[1]	NOx Control Technique	Estimated Annual Average Running Plant Capacity Factor[2]	Estimated Annual Average Electricity Generation Reduction MW-hrs/yr[3]	Estimated Annual Average Generation Reduction Cost, K$/yr[4]
D	RRI+SNCR w/ ASOFA	0.999	38,486	1,462
C	SNCR w/ ASOFA	0.999	38,486	1,462
B	Coal Reburn w/ ASOFA	0.995	57,527	2,186
A	Advanced SOFA (ASOFA)	1.000	0	0

[1] – Alternative number has been previously assigned from least removal to highest removal percentage.

[2] – Baseline running plant capacity factor is assumed at 100.0 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.

[3] – Annual electricity generation lost is annual lost operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the unit nameplate gross output capacity rating: 440 MW for LOS Unit 2.

[4] – Annual electricity generation lost cost is the annual electricity generation lost (MW-hrs/yr) resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $38.00/MW-hr. All cost figures in 2005 dollars.

TABLE A.2-5 – Expected Auxiliary Electrical Power Demand and Usage for LOS Unit 1 NO_X Controls

Alt. #[1]	NOx Control Technique	Estimated Annual Average NOx Equipment Auxiliary Electrical Demand & Usage		
		Total Net Demand[2] kW	Net Generation Reduction kW-hrs/yr[3]	Annual Cost, K$/yr[4]
G	Coal Reburn w/ boosted SOFA	3,900	33,864,255	1,287
F	Coal Reburn w/ basic SOFA	2,220	19,160,595	728
E	SNCR with boosted SOFA	1,713	15,002,180	570
D	SNCR with basic SOFA	37	318,749	12
C	SNCR with Close-Coupled SOFA	49	423,483	16
B	Boosted SOFA	1,680	14,712,420	559
A	Separated OFA (basic)	1	8,760	0.3

[1] – Alternative number has been previously assigned from least removal to highest removal percentage.

[2] – The estimated NOx equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects.

[3] – The estimated annual NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.

[4] – The estimated annual NOx equipment auxiliary electrical power demand electricity cost is the estimated annual kW-hrs/yr for these alternatives resulting from the implementation of the individual NOx control technique multiplied by the incremental value of auxiliary electricity generation, assumed to be $38.00/MW-hr. All cost figures in 2005 dollars.

TABLE A.2-6 – Expected Auxiliary Electrical Power Demand and Usage for LOS Unit 2 NO_X Controls

		Estimated Annual Average NOx Equipment Auxiliary Electrical Demand & Usage		
Alt. #[1]	**NOx Control Technique**	**Total Net Demand[2] kW**	**Net Generation Reduction kW-hrs/yr[3]**	**Annual Cost, K$/yr[4]**
D	RRI+SNCR w/ ASOFA	285	2,464,270	94
C	SNCR w/ ASOFA	156	1,349,578	51
B	Coal Reburn w/ ASOFA	5,395	46,313,786	1,760
A	Advanced SOFA (ASOFA)	1	8,760	0.3

[1] – Alternative number has been previously assigned from least removal to highest removal percentage.

[2] – The estimated NOx equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects.

[3] – The estimated annual NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.

[4] – The estimated annual NOx equipment auxiliary electrical power demand electricity cost is the estimated annual kW-hrs/yr for these alternatives resulting from the implementation of the individual NOx control technique multiplied by the incremental value of auxiliary electricity generation, assumed to be $38.00/MW-hr. All cost figures in 2005 dollars.

TABLE A.2-7 – Expected NOx Reagent Usage and Cost Estimates for LOS Unit 1 NO_X Controls

Alt. #[1]	NOx Control Technique	NOx Reduction Reagent Urea Usage (undiluted, as delivered)			NOx Reduction Reagent Dilution Water Usage[3]	
		lbs/hr	tons/yr	$1000/yr	1000 gal/yr	$1000/yr
E	SNCR with boosted SOFA	637	2,764	1,050	2,645	1.1
D	SNCR with basic SOFA	765	3,345	1,270	3,175	1.3
C	SNCR with Close-Coupled SOFA	960	4,199	1,590	3,985	1.6

[1] – Alternative number has been previously assigned from least removal to highest removal percentage.

[2] – Reagent consumption derived from vendor (Fuel Tech) December 2004 proposal for SNCR. Reagent usage for RRI is twice the amount of urea usage for comparable SNCR conditions and percent reduction. All cost figures in 2006 dollars.

[3] – Reagent dilution water usage assumes filtered steam turbine condenser recirculated cooling water is added to create a 10% urea concentration (4 parts water to 1 part aqueous urea at 50% concentration as delivered) prior to injection. Dilution water unit cost assumed to be $0.40 per thousand gallons.

TABLE A.2-8 – Expected NOx Reagent Usage and Cost Estimates for LOS Unit 2 NO_X Controls

Alt. #[1]	NOx Control Technique	NOx Reduction Reagent Urea Usage (undiluted, as delivered)			NOx Reduction Reagent Dilution Water Usage[3]	
		lbs/hr	tons/yr	$1000/yr	1000 gal/yr	$1000/yr
D	RRI+SNCR w/ ASOFA	5,550	24,000	9,100	23,100	9
C	SNCR w/ ASOFA	2,920	12,600	4,800	12,100	5

[1] – Alternative number has been previously assigned from least removal to highest removal percentage.

[2] – Reagent consumption derived from vendor (Fuel Tech) December 2004 proposal for SNCR. Reagent usage for RRI is twice the amount of urea usage for comparable SNCR conditions and percent reduction. All cost figures in 2006 dollars.

[3] – Reagent dilution water usage assumes filtered steam turbine condenser recirculated cooling water is added to create a 10% urea concentration (4 parts water to 1 part aqueous urea at 50% concentration as delivered) prior to injection. Dilution water unit cost assumed to be $0.40 per thousand gallons.

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38. “Analysis of Combustion Controls for Reducing NO_X Emissions From Coal-fired EGU’s in the WRAP Region” WRAP Draft Report EGR Contract Number 30204-101, prepared by Eastern Research Group, Inc., dated April 26, 2005, posted at their website: http://www.wrapair.org/forums/ssjf/documents/eictts/NOxEGU/050426Coal-fired%20EGUs_in_WRAP_Region-draft.pdf.

39. Budgetary Proposal, Fuel Tech, Inc. NOxOUT® SNCR and SNCR/FLGR® Systems, for one 450 MW cyclone-fired unit, dated December 9, 2004.

40. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2ch1.pdf

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Appendix A.3 - U.S. Cyclone NOx Reduction Projects Summary

SEPARATED OVERFIRE AIR

Cyclone-Fired Boilers

Alliant Energy (formerly Wisconsin Power & Light)
Edgewater Unit 4 Crushed Coal, single-wall cyclone-fired 1969 vintage
330 MW B&W boiler PRB/Illinois Coal blend
Boiler has 7 cyclone burners, arranged "3 over 4" style, on front wall, and fired a blend of 80% western subbituminous (PRB) coal, with 20% Illinois bituminous coal sometimes amended with 3% tire-derived fuel. After cyclone barrel reentrant throat and damper modifications allow firing up 100% PRB coal.
A SOFA system began operation in mid-2001(1), which initially reduced NOx emissions approx. 40-50% reduction from 1.08-1.15 (assume average of 1.10) down to 0.3 to 0.5 lb/mmBtu (assume average of 0.39) with typical cyclone air-staging (cyclone SR not stated but believed to be around 0.90) (2). Subsequent testing and optimized full load SOFA operation at deeper cyclone air-staging (SRs believed to be ≤ 0.90) dropped NO_X to average of 0.27 lb/mmBtu in 2003(2).
Source: (1)EPA Acid Rain Program CAMD June 15, 2005 Technical Support Document.
(2)Alliant/RMT 2003 Technical Paper. Also listed in (3)B&W Sept. 2002 OFA port experience list.

Ameren UE (formerly Union Electric Co.)
Sioux Unit 1 Crushed Coal, opposed-wall cyclone-fired 1969 vintage
500 MW B&W boiler PRB/Illinois Coal blend
Boiler has 10 cyclone burners, arranged "2 over 3" style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel. A ten-port OFA system (five ports on each front and rear wall) began operation in mid-2001, which reduced NOx emissions approx. 53% reduction from 1.1-1.3 (assume average of 1.19) down to 0.55 lb/mmBtu with moderate cyclone air-staging (cyclone SR from 1.19 to 1.0) (4). Subsequent testing and full load operation at deeper cyclone air-staging has dropped NO_X with SOFA alone to 0.38 lb/mmBtu in 2002, around 0.3 lb/mmBtu in 2004(4), and as low as 0.20 lb/mmBtu in 2005 (SRs ≤ 0.90)(7).
Source: REI 2002(4), 2003(5), 2004(6), 2005(7) Technical Papers.

Ameren UE (formerly owned by Central Illinois Public Service)
Coffeen Unit 1 Crushed Coal, opposed-wall cyclone-fired 1965 vintage
600 MW B&W boiler Illinois Coal (midwestern bituminous)
Unit 2 boiler has 14 cyclone burners, arranged "3 over 4" style, on front and rear walls.
SOFA system began operation in early-2000; average annual NOx emissions approx. 1.03 lb/mmBtu down 27% to 0.75 lb/mmBtu average(1).
Source: EPA Acid Rain Program CAMD June 15, 2005 Technical Support Document(1). Also listed in B&W Sept. 2002 OFA port experience list(3).

Dominion Resources (formerly owned by Commonwealth Edison)
Kincaid Units 1 and 2 Crushed Coal, opposed-wall cyclone-fired 1967, 1968 vintage
660 MW B&W boilers PRB Coal
Boilers have 14 cyclone burners, arranged "3 over 4" style, on front and rear walls.
SOFA systems with 11 ports each began operation in mid-2000; avg. 1999 annual NOx emissions approx. 0.91 and 0.94 lb/mmBtu, decreasing 27% in 2001 to 0.66 and 0.69 lb/mmBtu avg (respectively)(1).
Source: EPA Acid Rain Program CAMD June 15, 2005 Technical Support Document(1). Also listed in B&W Sept. 2002 OFA port experience list(3).

Tennessee Valley Authority (TVA) Crushed Coal, cyclone-fired, 1959 vintage
Allen Station Units 2 & 3 (TN) (seven cyclones)
300 MW B&W boilers PRB & western bituminous coal blend
GE-EER Overfire air (duplicate of Allen 1), 1999 startup
GE-EER claimed to lower NOx with OFA alone up to 29% from baseline 1.20 lb/mmBtu to 0.85 lb/mmBtu on Units #2 and 3 at full load(8).
Source: GE-EER Sept. 2005 experience list(8).

TABLE A.3-1 – Cyclone-Fired Boiler Overfire Air Retrofit Installations(1)

Facility Name	Installation Date	Comments
Allen Station Unit 2	Installed 1999*	Similar to Unit 1, w/o CGR) have SCR
Allen Station Unit 3	Installed 1999*	Similar to Unit 1, w/o CGR) have SCR
Asbury Unit 1	Installed 5/10/1999	Empire District, BART-eligible
Bailly Unit 7	Installed 2003(9)	SCR to be installed in 2006-7
Bailly Unit 8	Installed 5/31/2000	SCR retrofit 5/11/2004
Baldwin Unit 1	Installed 12/31/1999	SCR retrofit 4/28/2003
Baldwin Unit 2	Installed 5/8/2000	SCR retrofit 4/12/2002
Big Stone Unit 1	Installed 10/22/1997	part of conversion to PRB
BL England Unit 2	Installed 1998*	previous SNCR retrofit in 1996
Coffeen Unit 1	Installed 2/1/2001	SCR retrofit 4/21/2003
Coffeen Unit 2	Installed 2/9/2000	SCR retrofit 4/09/2002
Edgewater Unit 3	Installed 11/2001(9)	
Edgewater Unit 4	Installed 6/19/2001	
Joliet 9 Unit 6	Installed 2000(9)	
Kincaid Unit 1	Installed 4/28/2000	SCR retrofit 12/17/2002
Kincaid Unit 2	Installed 5/24/2000	SCR retrofit 6/07/2002
Allen S. King Unit 1	Installed 11/30/1999	
LaCygne Unit 1	Installed 2/28/2000	
Lake Road Unit 6	Installed 6/01/2002	
Michigan City Unit 12	Installed 4/1998(9)	SCR retrofit 5/01/2003
Nelson Dewey Unit 1	Installed 2002(9)	
Nelson Dewey Unit 2	Installed 2002(9)	
Paradise Unit 1	Installed 11/14/1998	SCR retrofit 5/01/2001
Paradise Unit 2	Installed 12/8/1999	SCR retrofit 5/01/2000
Paradise Unit 3	Installed 5/4/2000	SCR retrofit 3/10/2004
Powerton Unit 5-1	Installed 6/1/2003	
Powerton Unit 5-2	Installed 6/1/2003	
Powerton Unit 6-1	Installed 6/1/2002	
Powerton Unit 6-2	Installed 5/4/1999	
Schahfer Unit 14	Installed early 2000(9)	SCR retrofit 5/11/2004
Sibley Unit 2	Installed 5/24/2002	
Sibley Unit 3	Installed 5/4/1999	
Sioux Unit 1	Installed 4/30/2001	SNCR demo May 2005
Sioux Unit 2	Installed 4/30/1997	
State Line Unit 4	Installed 11/2001(9)	Similar to Joliet 9 Unit 6
Tanners Creek Unit 4	Installed 5/12/2002	
Thomas Hill Unit 1	Installed June 2004(9)	
Thomas Hill Unit 2	Installed November 2000(9)	

Note: This table does not include every installed U.S. coal-fired cyclone boiler OFA retrofit project.
Source: (1) US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005 (except as noted below)
* Vendor experience list (GE Energy for Allen Station Units 1-3; RJM for BL England Unit 2)
(9) Burns & McDonnell internal database.

TABLE A.3-2 – Cyclone-Fired Boiler Reburn Overfire Air Retrofit Installations(1)

Facility Name	Installation Date	Comments
Allen Station Unit 1	Installed 1998*	OFA w/ CGR retrofit; has SCR
CP Crane Unit 1*	Installed 1999	OFA w/ CGR retrofit
CP Crane Unit 2	Installed 2/1/1999	OFA w/ CGR retrofit
Lakeside Unit 7†	Installed 1992*	OFA w/ CGR retrofit; DOE-NETL
Kodak Park #15 Boiler†	Installed 1997*	OFA w/ micronized coal retrofit; DOE-NETL
Kodak Park #43 Boiler	Installed 1995	OFA w/ CGR retrofit
Kodak Park #41 Boiler	Installed 1998	OFA w/ CGR retrofit
Kodak Park #42 Boiler	Installed 1998	OFA w/ CGR retrofit
Nelson Dewey Unit 2†	Installed 1991	OFA w/ pulverized coal reburn; DOE-NETL

Note: This table does not include every installed U.S. coal-fired cyclone boiler OFA retrofit project for reburn.

Source: (1) US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005 (except as noted below)

* Vendor experience list (GE Energy for Allen Station Units 1-3; RJM for BL England Unit 2)

† U.S. Department of Energy National Energy Technology Laboratory Clean Coal Technology Demonstration Program project (not commercially available at time of implementation)(11)

REBURN – GAS, CONVENTIONAL

Cyclone-Fired Boilers

Constellation Energy (formerly Baltimore Gas & Electric)
C.P. Crane Station, Units 1 & 2 (MD) Crushed Coal, cyclone-fired, eastern bituminous coal
2 x 200 MW B&W boilers (four cyclones each) 1961, 1963 vintage
GE-EER Conventional Gas Reburn, 1999 startup
Added gas supply piping, metering, hangers, supports; reburn injectors and cooling air ductwork, OFA ductwork, injection nozzles and wall ports, field (assume eastern bituminous coal)
GE-EER claimed Gas Reburn with OFA lowered NOx between 60% and 65% from baselines of 1.50 lb/mmBtu to between 0.60 and 0.52 lb/mmBtu, at full load with reburn operation(8). No claims of percent reburn fuel or percent OFA included in GE-EER's experience list.
Another technical paper showed this installation of CGR operated with 25 percent reburn fuel(11).
Source: Sept. 2005 GE-EER experience list(8); DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).

City Water, Light & Power
Lakeside Unit 7 Crushed Coal, front-wall cyclone-fired, midwestern bituminous coal
300,000 lb/hr steam B&W boiler (approx. 33 MWe equivalent, two cyclones) 1961 vintage
Springfield, IL DOE Clean Coal demonstration project (included sorbent injection)
GE-EER conventional gas reburn w/ OFA 1992 startup (CGR not currently operating)
Vendor claimed to lower NOx by 66% from 0.95 lb/mmBtu baseline to 0.32 lb/mmBtu(8). A GE-EER 2004 technical paper showed 25% reburn fuel yielded minimum NOx emissions(11).
A DOE NETL technical paper showed this demonstration of CGR from 5/93-10/94 (assume with OFA) with 23 percent reburn fuel reduced NOx 60% from 0.97 to 0.39 lb/mmBtu (10).
Source: Sept. 2005 GE-EER experience list(8); GE-EER 2004 Technical paper(11); DOE-NETL 2004 Reburn Conference Technical paper(10).

Eastman Kodak Company
Kodak Park Boilers 41 & 42 Crushed Coal, front-wall cyclone-fired, 1964 & 1966 vintage
400,000 lb/hr steam B&W boilers (approx. 50 MWe equivalent, two 8-ft dia. cyclones)
Rochester, NY eastern bituminous coal
B&W conventional gas reburn w/ OFA December 1998, July 1998 startups (still operating)
Commercial installation of CGR, with (1) gas burner added to each sidewall + (2) large and (2) small OFA ports added to front wall above cyclones, utilizing higher reburn gas pressure (vs. Boiler #43) requires no flue gas recirculation; {Very small furnace w/ cyclone SR believed not <1.0}.
B&W claimed reburn with OFA lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu.
B&W graph shows 10-12% percent reburn fuel to achieve 0.6 lb/mmBtu and 23-24% reburn gas input to reach 0.33 lb/mmBtu NOx (73% reduction) (12).
Another technical paper showed NOx lowered by 52% from 1.25 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel(10).
Source: B&W Technical Paper(12); DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).

REBURN – GAS, CONVENTIONAL, continued

Cyclone-Fired Boilers

Eastman Kodak Company
Kodak Park Boiler 43 Crushed Coal, front-wall cyclone-fired 1968 vintage
600,000 lb/hr steam B&W boiler (approx. 60 MWe equivalent, two cyclones)
Rochester, NY eastern bituminous coal

B&W conventional gas reburn 1995 startup (still operating)

Commercial installation of CGR, with flue gas recirculation (FGR) for injection mass momentum w/ (1) FGR fan; (1) gas burner added to each sidewall + (2) OFA ports added front wall above cyclones. {Very small furnace/low residence time w/ cyclone SR believed not <1.0}

B&W claimed reburn with OFA & FGR lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. B&W graph shows 18% percent reburn fuel to achieve 0.6 lb/mmBtu and 29% reburn gas input to reach 0.36 lb/mmBtu NOx (70% reduction)(12).

Another technical paper showed NOx lowered by 56% from 1.35 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel(10).

Source: 2004 B&W Technical Paper(12); DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)(10).

Tennessee Valley Authority (TVA)
Allen Station Unit 1 (TN) Crushed Coal, cyclone-fired (seven cyclones) 1959 vintage
300 MW B&W boiler PRB &western bituminous coal blend fired
GE-EER Conventional Gas Reburn, 1998 startup

Commercial installation added gas supply piping, metering, hangers, supports; reburn injectors and cooling air piping, OFA ductwork, injection nozzles and wall ports, field I&C devices.

Reburn with OFA claimed to lower NOx 65% from baseline 1.20 lb/mmBtu to 0.42 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included. (TVA also installed duplicate OFA systems on Allen Units 2 & 3 boilers)(8).

Another technical paper showed NOx lowered by 65% from 0.86 lb/mmBtu baseline (to 0.30 lb/mmBtu) with 7 percent reburn fuel(11).

Source: Sept. 2005 GE-EER experience list(8); DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)(10).

REBURN – COAL, CONVENTIONAL

Cyclone-Fired Boilers

Alliant Energy (formerly Wisconsin Power & Light)
Nelson Dewey Station Unit 2 Crushed Coal, cyclone-fired, PRB coal 1962 vintage
110 MW B&W boiler 3-cyclones across front wall, 4 reburn burners +
4 OFA ports across rear wall, aligned vertically in columns.

US DOE Clean Coal Demonstration project of B&W's Conventional Coal Reburn, 1991 startup (since discontinued) added coal supply piping, reburn burners with flue gas recirculation, OFA ductwork + dual zone ports; coal feeder, pulverizer & PA fan, tested with PRB and bituminous coals. (western subbituminous coal)

B&W claimed reburn operation lowered NOx by 57% from baseline of 0.83 mmBtu to 0.38 lb/mmBtu at full load(13). Approx. 30% percent of total fuel input supplied as reburn fuel. Increased unit output by 10 MW, increased flyash unburned carbon by 4% (13-22% vs 9-18%), decreased furnace exit gas temperature (FEGT). OFA ports listed in B&W experience list(3).

B&W shows full load NOx w/o reburn was 0.75 lb/mmBtu, and 0.29-0.32 lb/mmBtu w/ PRB fuel during reburn operation (57% decrease). At 75% load, 0.64 vs 0.29-0.32 lb/mmBtu. At 55% load, 0.62 vs 0.29-0.31 lb/mmBtu without and with reburn activated(13).

Another technical paper showed NOx lowered by 52-55% from 0.82 lb/mmBtu baseline (to 0.39-0.34 lb/mmBtu) with 25-30 percent reburn fuel(11).

Source: 2004 B&W Technical Paper(12); DOE-NETL 2004 Reburn Conference Technical paper(11); B&W case history (from website, dated 1997)(13).

REBURN – COAL, MICRONIZED, CONVENTIONAL

Cyclone-Fired Boilers

Eastman Kodak Company
Kodak Park #15 Boiler Crushed Coal, front-wall cyclone-fired, 1956 vintage
400,000 lb/hr steam B&W boiler (approx. 50 MWe equivalent, two cyclones)
Rochester, NY eastern bituminous coal
GE-EER micronized coal reburn1996 initial startup (operating since 1997)

Demonstration project performed with Dept. of Energy's US Clean Coal Technology Program. Project added flue gas recirculation for injection mass momentum, FGR fan and two micronized coal pulverizers; (6) reburn coal injectors added to rear wall + (1) reburn coal injector on each of the sidewalls, with (4) OFA ports added across front wall above cyclones(15). GE-EER designed and fabricated the coal injectors and OFA ports. {Extremely small furnace and low residence time}.

GE-EER claimed reburn + OFA w/ FGR reduced NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. No claims of percent reburn fuel included(8).

Another technical paper showed this demonstration of micronized coal reburn from 4/97-10/98 lowered NOx by 57% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 17 percent reburn fuel(11).

Source: DOE Topical Report Number 14 (May 1999) (14); GE-EER experience list(8); DOE-NETL 2004 Reburn Conference Technical paper(10).

REBURN – FUEL LEAN GAS REBURN

Cyclone-Fired Boilers

Midwest Generation (formerly Commonwealth Edison)
Joliet Station 9, Unit 6 Crushed Coal, opposed-wall cyclone-fired (nine cyclones)
340 MW B&W boiler 1959 vintage, 1997 startup (FLGR has since been decommissioned)

Energy Systems Associates demonstrated 25-30% NOx reduction using 5-10% of total heat input as reburn natural gas injected (without OFA)(10).

Another technical paper showed this demonstration in collaboration with Gas Research Institute of FLGR lowered NOx by 28-43% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 7 percent reburn fuel(15).

Source: DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10);
NGB Technologies Technical Paper (15).

REBURN – FUEL LEAN GAS REBURN w/ SNCR

Cyclone-Fired Boilers

Owensboro Municipal Utilities (KY) Crushed Coal, front-wall cyclone-fired
Elmer Smith Unit 1 (three cyclones) 1965 vintage
150 MW B&W boiler

CFD model study only predicted NOx reductions from 1.59 to 0.39 lb/mmBtu with OFA only (75% reduction, 0.90 SR); 25-30% NOx reduction using 6% of total heat input as reburn natural gas injected above OFA; 40-45% NOx reduction from SNCR with <5 ppm ammonia slip(16).

Source: REI 2001Technical paper(16).

SELECTIVE NON-CATALYTIC REDUCTION/ RICH REAGENT INJECTION

Cyclone-Fired Boilers

Conectiv (formerly Atlantic Electric)
BL England Unit 1 Crushed Coal, single-wall cyclone-fired 1962 vintage
138 MW B&W boiler aqueous urea SNCR, 1995 startup eastern bituminous coal
Boiler has only 3 cyclone burners, arranged “1 over 2” style.

RJM implemented commercial Fuel Tech urea-based SNCR system installation in 1995 after short-term (3-month demonstration test) in 1993-1994. 31 % NOx reduction claimed, from 1.31 lb/mmBtu NOx baseline[1] for SNCR only; RJM claimed 35% reduction from 1.31 lb/mmBtu down to 0.85 lb/mmBtu (without overfire air) with urea-to-NOx NSR = 0.85 [17].

Added eight temporary RRI ports (three nozzles on each lower sidewall, and two nozzles on the upper rear wall, and performed one month demonstration parametric testing of overfire air only (without SNCR or RRI), at 120 MW nominal boiler load and cyclone S.R. = 0.90 in 1999. REI claimed 55% NOx reduction from a 1.2 lb/mmBtu uncontrolled NOx baseline to 0.55 lb/mmBtu with OFA only, with stack CO emissions below 50 ppm. For Rich Reagent Injection; REI claimed 25-30% NOx reduction for RRI down to 0.38 lb/mmBtu from controlled baseline w/ OFA alone of 0.55 lb/mmBtu NOx and a RRI urea-to-NOx NSR = 2; also showed RRI+SNCR w/ OFA reduced NOx 55% to 0.25 lb/mmBtu (34% beyond RRI w/ OFA), for an overall 79% NOx reduction with a SNCR urea-to-NOx NSR = 1. Measured less than 1 ppm ammonia slip during RRI testing, < 5 ppm slip for RRI + SNCR. No significant increase in CO emissions during RRI testing[18].
Source: RJM experience list[17]; 2001 REI Technical Paper[18];
(Also listed in ICAC SNCR 2000 White Paper[19]).

Conectiv (formerly Atlantic Electric)

BL England Unit 2	Crushed Coal, cyclone-fired, single-wall-fired	1964 vintage
160 MW B&W boiler	SNCR, 1996 startup eastern bituminous coal	

RJM implemented commercial Fuel Tech urea-based SNCR system in 1996, claimed 36% reduction from 1.36 lb/mmBtu down to 0.85 lb/mmBtu, urea-to-NOx NSR = 0.85 (without overfire air) [17].
An OFA system was added in 1998, resulting in NOx emissions of 0.33 lb/mmBtu, for an overall NOx reduction of 76%[17].
Source: RJM experience list[17]. (Also listed in ICAC SNCR 2000 White Paper[19]).

AmerenUE (formerly Union Electric Co.)

Sioux Unit 1	Crushed Coal, opposed-wall cyclone-fired	1969 vintage
500 MW B&W boiler	Rich Reagent Injection demonstration testing in 2001	

Boiler has 10 cyclone burners, arranged “2 over 3” style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel.

Installed twenty temporary RRI ports (six nozzles on each lower sidewall, and four nozzles on each front and rear wall), and performed one month demonstration parametric testing of overfire air only and initial testing with RRI in August 2001, followed by additional testing in March 2002, and the second quarter of 2004. Added 8 RRI ports (1 in each sidewall, 4 in each front and rear wall) and 14 SNCR ports (5 on upper front wall, 9 on upper rear wall) to the furnace in early 2005, followed by three weeks of parametric testing and 3 days of continuous testing of RRI with SNCR and deeper-staged OFA.
Tested in August 2001 at lower furnace SR approx.=1.0, 0.55 lb/mmBtu w/ OFA only, only 15% NOx reduction w/ RRI, zero ammonia slip[4].
Tested in March 2002 at lower furnace SR approx.=0.95, from 0.38 lb/mmBtu baseline w/ OFA only, achieved 29% NOx reduction w/ RRI down to 0.27 lb/mmBtu, NSR=3, zero ammonia slip[4].
(assume blend of PRB and Illinois bituminous coal w/ tire-derived fuel and petroleum coke)[4].
Operation in the second quarter 2004 showed actual stack NOx averaged around of 0.30 lb/mmBtu with OFA only and lower furnace at a cyclone SR around 0.88 burning a 85% PRB, 15% Illinois #6 bituminous coal blend, presumably at 440 MW. This is a 75% NOx reduction from a 1.19 lb/mmBtu pre-control baseline. REI using CFD modeling predicted NOx down to 0.18 lb/mmBtu with RRI+OFA, and below 0.15 with RRI+SNCR under similar deep cyclone air-staging (1.19 to 0.28 lb/mmBtu is 76% reduction, 0.18 vs 0.28 is an additional 36% reduction w/ RRI, and 0.14 vs 0.28 is a 50% reduction w/ RRI+SNCR, for an overall reduction of 88%)[5,6].

Tested in May 2005 at 480 MWg with lower furnace SR approx. = 0.85-0.88, 76-83% reduction from 1.2 lb/mmBtu baseline down to as low as 0.20 lb/mmBtu w/ SOFA only firing 80% PRB, 20% Illinois #6 bituminous coal blend; additional 15-39% NOx reduction w/ RRI, to as low as 0.15 lb/mmBtu from 0.20-0.28 lb/mmBtu baseline w/ SOFA only at urea NSR varied between 1 and 4, with one ppm ammonia slip; achieved additional NOx reduction w/ RRI +SNCR down to 0.12 lb/mmBtu, NSR=4, ammonia slip10 ppm or less. RRI+SNCR w/ SOFA NOx reduction percentage varied from 15% to 50% below SOFA-only levels, with NSRs between 1 and 4.5. SNCR alone had 13% (NSR=1) to 32% (NSR=1) NOx reduction with ammonia slip around 1-2 ppm (7).
Source: REI 2002(4) and 2003(5) Technical Papers; REI 2004(6) Technical paper; REI 2005(7) Technical paper.

Coal burning cyclone-fired utility boilers in the United States that have been retrofitted with SCR technology are listed in Table A.3-3. This list includes at least eight cyclone-fired boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). The highest emission reductions listed in Table A.3-3 for SCR systems are for clean reactor catalyst and ideal operating conditions.

TABLE A.3-3 – Cyclone-Fired Boiler High-Dust SCR Installations

Facility[1]	Unit Size[2],MW	Tested Control Efficiency[3]	Tested Outlet NO_X Emission Rate (lb/mmBtu)[3]	2003 Ozone Season Average NO_X Emission Rate[4] (lb/mmBtu)
Allen 1, 2, & 3[5,6]	330 ea.	91.1/NAD[7]/88.7	0.070/NAD[7]/0.088	0.088/0.077/0.086
Baldwin 1[5,6]	600[3]	82.9	0.072	0.238
Baldwin 2[5,6]	605[3]	83.5	0.067	0.286
Bailly 8[5,6]	422	NAD[7]	NAD[7]	0.84
Coffeen 1[5,6]	389	NAD[7]	NAD[7]	0.114
Coffeen 2[5,6]	617	NAD[7]	NAD[7]	0.120
Dallman 31 & 32	207	NAD[6]	NAD[6]	0.149/0.146
Kincaid 1 & 2[5,6]	660[3] ea.	89/89	0.079/0.079	0.181/1.198
Marion 4	173	94.3	0.067	0.252
Merrimack 1[5,8]	114	50.5[9]	0.148	0.158
Merrimack 2	346	51.3[9]	0.155	0.171
Michigan City 12[5,10]	540	84.2	0.109	0.418
New Madrid 1 & 2[8,10]	600 ea.	87.4/88.1	0.149/0.147	0.319/1.172
Paradise 1 & 2[5,6]	704 ea.	87.7/87.7	0.102/0.101	0.124/0.113
Paradise 3[5,6]	1150	89.1	0.088	0.658
Schahfer 14[5,10]	540	83.5	0.106	0.478

[1] – original design fuel for all listed cyclone boilers was bituminous coal

[2] – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.

[3] – Burns & McDonnell internal database.

[4] – as reported to US EPA, available from their website at http://cfpub.epa.gov/gdm/index.cfm

[5] – includes application of separated overfire air for combustion NO_X control

[6] – current fuel believed to be a blend of subbituminous and bituminous coals

[7] – NAD = no published data from SCR emission testing found on these units.

[8] – original air preheaters were tubular-type; changed to rotary-type during SCR retrofit

[9] – Design NO_X removal efficiency is higher, approx. 90%.

[10] – current fuel believed to be subbituminous coal

For Merrimack Unit 1's SCR, inlet (i.e. uncontrolled) NO_X was 1.34 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. The catalyst was designed for 88.9% NO_X removal efficiency and 5 ppm ammonia slip. SCR commercial service date July 20, 1999(20).
Source: Babcock Borsig Power 2000 technical paper on SCRs(20).

For Merrimack Unit 2's SCR, inlet (i.e. uncontrolled) NO_X was 2.66 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. Initial testing demonstrated 70% removal(21), which exceeded the 65% requirement to

achieve a 0.92 lb/mmBtu permit limit. The catalyst was designed for 85-95% NO_X removal efficiency and 5 ppm ammonia slip(22).
Source: NETL-DOE Clean Coal Technology 1997 technical paper on SCRs(21); 1997 ICAC White Paper on SCRs(22).

Northern Indiana Public Service Company (NIPSCO)
Bailly Unit 8 Crushed Coal, cyclone-fired, opposed-wall-fired 1968 vintage
360 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2004 startup
Boiler fires a blend of 85% western subbituminous (PRB) coal, with Illinois bituminous coal.
Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia vapor reagent ahead of high-dust SCR(23). An OFA system was retrofitted in 2000(9).
Source: Fuel Tech experience list dated 1/28/2005(23); Burns & McDonnell internal database(9).

Northern Indiana Public Service Company (NIPSCO)
Michigan City Unit 12 Crushed Coal, cyclone-fired, opposed-wall-fired 1974 vintage
520 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2003 startup
Boiler fires western subbituminous (PRB) coal.
Commercial Fuel Tech urea-based system installed in 2003 to convert urea to ammonia vapor reagent ahead of high-dust SCR(23). An OFA system was retrofitted in 1998(9).
Source: Fuel Tech experience list dated 1/28/2005(23); Burns & McDonnell internal database(9).

Northern Indiana Public Service Company (NIPSCO)
Schahfer Unit 14 Crushed Coal, cyclone-fired, opposed-wall-fired 1975 vintage
520 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2004 startup
Boiler fires western subbituminous (PRB) coal.
Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia vapor reagent ahead of high-dust SCR(23). An OFA system was retrofitted in 2000(9).
Source: Fuel Tech experience list dated 1/28/2005(23); Burns & McDonnell internal database(9).

Pulverized coal-fired utility boilers in the United States that have been retrofitted with low-dust SCR technology are listed in Table A.3-4.

TABLE A.3-4 – Low-Dust Pulverized Coal-Fired Boiler SCR Installations

Operator/Facility[1,2]	**SCR Startup Date[3]**	**Average NO_X Emission Rates[4] (lb/mmBtu)**	**Unit Size[5], MW**
AEP/Cardinal Unit 3[6]	5/01/03	0.74 / 0.34 / 0.135	650
Carolina P&L/Mayo Unit 1[7]		- / (0.36) / N/A	368 x 2
Carolina P&L/Roxboro Unit 4[7,8]	5/07/01	0.57 / 0.26 / 0.081	372 x 2
Cinergy/East Bend Unit 1	4/01/02	- / (0.28) / 0.067	648
Constellation/Brandon Shores Unit 1[8]	(2001)	0.47 /0.33 / 0.126	685
Constellation/Brandon Shores Unit 2[8]	(2000)	0.45 / 0.31 / 0.094	685
Dayton P&L/Killen Station Unit 2	11/01/03	- / (0.48) / 0.06[9]	666
Dynegy Midwest Gen/Havana Unit 6[10]	(2000)	0.46 /0.20 / 0.102[9]	488
PSEG Power LLC / Mercer Unit 1[11]	(2005)	- / (0.63) / N/A	320
PSEG Power LLC / Mercer Unit 2[11]	(2004)	- / (0.76) / N/A	320

[1] – Burns & McDonnell internal database.

[2] – Current fuel is eastern or midwestern bituminous coal, except Havana

[3] – US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, except where noted. Dates in () are believed to be accurate but have not been confirmed.

[4] – The three values are "Pre-control average", "2004 annual average", and "2003 ozone season average" NO_X emission rates, as reported to US EPA. Pre-control and year 2004 annual average data as shown in US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b. Values shown in parentheses are year 2003 annual average where 2004 data is not available. Year 2003 and 2003 ozone season data is available from the EPA's website at http://cfpub.epa.gov/gdm/index.cfm, includes application of separated overfire air for combustion NO_X control where applicable.

[5] – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.

[6] – This boiler has low-NOx burners for combustion controls.

[7] – Carolina Power & Light plants listed here have two boilers per unit, total nameplate for Mayo is 736 MW, Roxboro is 745 MW; emission numbers are the average of both boilers.

[8] – This boiler has low-NOx burners and overfire air for combustion controls.

[9] – This is preliminary data reported to the US EPA for 2004 ozone season average emission rate.

[10] – This boiler's current fuel is believed to be subbituminous coal.

[11] – Mercer boilers listed have low-dust SCR with flue gas reheat. Unit size is approximate, not nameplate.

N/A = complete 2004 ozone season data is not available, and 2003 ozone season data is not representative of the post-SCR installation emission rate.

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR

Pulverized coal-fired boilers

AEP Cardinal Unit 1 Pulverized Coal cell-burner, opposed wall-fired B&W boiler
600 MW (nominal) 1967 vintage; Low NO_x burners installed in October 1998
Produced 0.75 lb/mmBtu NOx post-LNB install baseline at full load.
LNBs reduced NO_X 57% from 1.20 down to 0.52(24), produce NO_X at approx. 0.57 lb/mmBtu at min. load w/o SNCR (range 0.51 to 0.65) and produce 0.75 lb/mmBtu NO_X at approx. 585 MW (top of load range tested, NO_X range 0.73 to 0.86 lb/mmBtu) (25).
(50) original B&W circular burners were recently replaced on Cardinal Units 2 & 3 by Buckeye Power with DB Riley (now Babcock Power) CCV type low NOx burners.
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list(24); 2000 Fuel Tech technical paper(25).
(Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 startup
Low NO_X burners were previously retrofitted in 1997 without separated overfire air(1). NOx reduction was 46% from pre-LNB installation baseline of 1.08 lb/mmBtu (1) down to 0.58 lb./mmBtu (26).
(Also see SNCR, and FLGR with SNCR installation summaries for pulverized coal boilers).
Source: 2005 US EPA Docket OAR-2002-0076-0446 Technical Support Document spreadsheet(1);
CP&L and Fuel Tech 2001 Technical paper(26).

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 5 1956 vintage; eastern bituminous coal
154 MW CE boiler ROFA startup in 2000
Mobotec USA's Rotating Opposed Fire Air (ROFA) is a high velocity boosted separated overfire air system claimed to lower NO_X without retrofitting low-NOx burners. This was the first U.S. installation of Mobotec USA's "Rotating Opposed Fire Air" (ROFA) on a utility boiler, which utilizes a booster fan.
CP&L technical paper claimed to lower NO_X 53% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.28 lb/mmBtu with ROFA alone following the installation of ROFA in 2000(27).
Source: CP&L 2002 Technical paper(27).
(Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 6 twin-furnace (eight corner), 1958 vintage; eastern bituminous coal
175 MW CE boiler ROFA startup in 2001
This unit's "ROFA" system was installed as part of a "Rotamix" SNCR + ROFA system.
CP&L technical paper shows ROFA alone reduced NOx 57% from full-load pre-ROFA baseline 0.54 lb/mmBtu to a NO_X emission rate of 0.23 lb/mmBtu. (27)
Source: CP&L 2002 Technical paper(27).
(Also see SNCR installation summaries for pulverized coal boilers).

Conectiv (formerly Delmarva Power & Light)
Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage
B&W, DB Riley boilers eastern bituminous coal
REI performed CFD modeling on both units for potential SNCR application.
Unit 3 has Riley Low NOx burners (16), (8) front wall and (8) rear wall OFA ports, (8) wall boundary air ports, (66) side wall OFA slots, claimed baseline NOx around 0.37 lb/mmBtu w/o SNCR (28).

Unit 4 has (24) front and rear wall down-fired burners, (28) front and rear wall SOFA ports, claimed NOx around 0.44 lb/mmBtu w/o SNCR (28) {furnace has "Mae West" belt}.
Riley provided 16 CCV low-NOx burners for Unit 3 in 1994, and claimed to reduce NOx emissions by 67% from pre-LNB baseline of 1.05 lb/mmBtu down to 0.34 lb/mmBtu(24).
Source: REI 1999 Technical Paper(28); Riley Power (Babcock Power Inc.) 8/16/04 experience list(24).
(Also see SNCR installation summaries for pulverized coal boilers).

LOW NO$_x$ BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued
Pulverized coal-fired boilers

Dayton Power & Light — Pulverized Coal, Tangentially-fired
Killen Station, Unit 2 — 1955 vintage
632 MW — CE boiler, bituminous Illinois coal
GE-EER provided low-NOx burners in 1999. Vendor claimed full load NO_X was reduced by 23% from a 0.57 lb/mmBtu baseline down to 0.44 lb/mmBtu(8).
Source: GE Energy (formerly GE-EER) experience list September 29, 2005(8).
(Also see low-dust SCR installation list for pulverized coal boilers)

Dynegy Midwest Generation (formerly Illinois Power) — Pulverized Coal, wall-fired
Havana Station, Unit 6 — 1978 vintage
460 MW — B&W boiler, bituminous Illinois coal
GE-EER provided modifications to the original B&W dual-register burners, and an OFA system in 2000. Vendor claimed full load NO_X was unchanged from 0.38 lb/mmBtu baseline(8).
Source: GE Energy (formerly GE-EER) experience list September 29, 2005(8). (Also see low-dust SCR installation list for pulverized coal boilers)

Dynegy Midwest Generation (formerly Illinois Power) — Pulverized Coal, Tangentially-fired
Vermillion Station, Unit 1 — 1955 vintage
82 MW — CE boiler, bituminous Illinois coal
This rotating opposed fire air (Mobotec USA ROFA) system was installed in July 2002, as part of a "Rotamix" SNCR + ROFA system, without low-NOx burners.
Mobotec 2004 technical paper claimed to lower full load NO_X by 62% from 0.58 lb/mmBtu baseline to 0.22 lb/mmBtu in July 2002 (without LNB or SNCR). (29)
Source: Mobotec 2004 technical paper(29).
(Also see SNCR installation summaries for pulverized coal boilers).

Georgia Power — Pulverized coal, opposed wall-fired,
Harlee Branch Unit 1 — 250 MW B&W boiler, 1965 vintage — 2003 startup
Harlee Branch Unit 2 — 359 MW Riley boiler, 1967 vintage — 1998 startup
B&W provided 24 DRB-4Z low NOx burners for Unit 1 B&W boiler, 24 DRB-XCL low NOx burners for Unit 2 Riley boiler(3) (believe southeast coast lignite is primary fuel).
Source: B&W's experience list(3). No NOx reduction claims.

Kansas City Power & Light — Pulverized coal, opposed wall-fired, 600 MW B&W boiler
Hawthorn Unit 5 — 30 burners, 2001 vintage, (Powder River Basin coal)
B&W provided 30 DRB-4Z low NOx burners and 11 OFA ports with the new boiler(3).
Source: B&W's experience list(3). No NOx reduction claims.

LOW NO$_x$ BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

New England Power Company (NEPCO)
Salem Harbor Station Pulverized Coal, front wall-fired,
Units 1, 2 & 3 1952, 1952, 1958 vintage (eastern bit. coal)
84 MWe x 2, & 156 MWe B&W boilers LNBs startup in 1995, 1995, and 1993
Riley claimed Unit 1 LNBs reduced NOx emissions by 57% from baseline of 1.10 lb/mmBtu down to 0.42 lb/mmBtu; Unit 2's LNBs achieved 42% NOx reduction from a baseline of 0.95 lb/mmBtu down to 0.55 lb/mmBtu; Unit 3's LNBs achieved 60% NOx reduction from a baseline of 1.05 lb/mmBtu down to 0.42 lb/mmBtu$^{(24)}$.
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list$^{(24)}$.
(Also see SNCR installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)
Shiller Station Pulverized Coal/#6 Fuel oil, front-wall-fired
Units 4, 5, & 6 1952, 1955, 1957 vintage
50 MWe x 3 Foster Wheeler boilers
RJM provided (6) Low NO$_x$ burner modifications per boiler in 1994, 1992, & 1994 respectively; LNBs reduced NOx 43% from 0.85 to 0.48, 50% from 1.0 to 0.50, and 51% from 0.82 to 0.40 lb/mmBtu$^{(17)}$.
Source: RJM experience list September 3, 2004$^{(17)}$

Potomac Electric Power (formerly West Pennsylvania Power)
Chalk Point Station Pulverized Coal opposed wall-fired
Units 1 & 2 1964, 1965 vintage eastern bituminous coal
360 MW (nominal) B&W boilers
DB Riley (now Babcock Power) CCV type low NOx burners retrofitted in 1993 and 1994, respectively. Vendor claimed to lower NOx up to 52% and 50% from 1.35 and 1.40 lb/mmBtu baselines (to 0.65 and 0.70 lb/mmBtu$^{(24)}$, assumed at full load).
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list$^{(24)}$.
(Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

Xcel Energy (formerly Public Service Company of Colorado)
Cherokee Unit 3 Pulverized coal, wall-fired, B&W boiler, 16 burners, 1962 vintage
175 MW October 1992 baseline testing started (western bituminous coal)
Installed (16) Foster Wheeler Controlled Flow/Split Flame low NO$_x$ replacement burners as part of a DOE Clean Coal Technology gas reburn demonstration performed with Gas Research Institute 1992-1995.
Uncontrolled NOx w/ original B&W flare-type burners was 0.73 lb/mmBtu. Replacement LNBs (assuming OFA included) reduced NO$_X$ 37% to 0.46 lb/mmBtu$^{(30)}$.
Source: DOE NETL 2001 Technical paper$^{(30)}$.

REBURN – GAS, CONVENTIONAL

Pulverized coal-fired boilers

Allegheny Power (formerly West Pennsylvania Power) Pulverized Coal, opposed wall-fired
Hatfield's Ferry Station cell-burner, 1969 & 1972 vintage
Units 2 & 3, 600 MW (nominal) each (B&W boilers) eastern bituminous coal
GE-EER Gas Reburn; 1999 startup (Unit 2) & 2003 (Unit 3)
GE-EER Low NOx burners, boosted OFA, gas reburn system.

GE-EER claimed to lower NOx up to 67% from baseline of 0.60 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation on Unit 2, 68% from 0.62 lb/mmBtu to 0.20 lb/mmBtu on Unit 3. No claims of percent reburn fuel included(8).
GE-EER technical paper shows approx. 35% NOx reduction at 600 MW load with LNB + OFA w/o reburn fuel, and an additional 50% reduction to 0.20 lb/mmBtu with reburn fuel(31).
B&W added 20 OFA ports in 1994 per B&W's experience list. No NOx reduction claims.(3)
Source: Sept. 2005 GE-EER experience list(8); GE-EER 2004 Technical paper(31). Unit 2 and Unit 3 listed in (10) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Conectiv (formerly Delmarva Power & Light)   Pulverized Coal, Tangentially-fired
Edgemoor Unit 4   1966 vintage, eastern bituminous coal
160 MW CE boiler   1999 startup
GE-EER Gas Reburn project added gas supply piping, metering, hangers, supports, reburn injectors and cooling air piping; OFA ductwork, injection nozzles and wall ports, field instrumentation. No FGR or OFA booster fans.
Vendor claimed to lower NOx up to 48% from baseline of 0.32 lb/mmBtu to 0.16 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included(8).
GE-EER technical paper shows approx. 32% NOx reduction for gas reburn with 4-mill operation at 160 MW load from 0.31 lb/mmBtu LNB + OFA baseline w/o reburn fuel (down to 0.21 lb/mmBtu), and 48% NOx reduction for gas reburn with 3-mill operation, to 0.16 lb/mmBtu (31).
Source: Sept. 2005 GE-EER experience list(8); GE-EER 2004 Technical paper(31). Listed in (10) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)

Dynegy (formerly Illinois Power)   Pulverized Coal, Tangentially-fired
Hennepin Unit 1   1966 vintage
71 MW CE boiler   eastern bituminous coal
GE-EER Gas Reburn, 1990 startup (not currently operating); GE-EER Orimulsion Reburn, 1997.
DOE Clean Coal demonstration project (included sorbent injection).
Vendor claimed gas reburn w/ OFA lowered NOx up to 67% from baseline of 0.75 lb/mmBtu to 0.25 lb/mmBtu) at full load; 65% reduction from baseline of 0.75 lb/mmBtu down to 0.26 lb/mmBtu with subsequent Orimulsion reburn operation(8).
GE-EER 2004 technical paper shows 18% gas reburn fuel yielded minimum NOx emissions(11).
Another technical paper showed this 80 MW US DOE Clean Coal demonstration project in January 1991-January 1993 lowered NOx by 67% from 0.75 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 18 percent reburn fuel(11).
Source: Sept. 2005 GE-EER experience list(8); GE-EER 2004 Technical paper(11); DOE-NETL 2004 Reburn Conference technical paper, and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).
(Also see Conventional Oil reburn installation summaries for pulverized coal boilers).

AES (formerly New York State Gas & Electric (NYSEG)
Greenidge #6 (NY)   Pulverized Coal, Tangentially-fired,   1953 vintage
100 MW CE boiler   GE-EER Conventional Gas Reburn, 1996 startup
Vendor claimed to lower NOx 55% from 0.63 lb/mmBtu baseline to 0.28 lb/mmBtu at full load with reburn operation burning eastern bituminous coal. Gas Research Institute predicted would achieve 76% (down to 0.15 lb/mmBtu) w/ advanced gas reburn(8).
GE-EER 2004 technical paper shows 23% reburn fuel yielded minimum NOx emissions around 0.23 lb/mmBtu(11).

EPA's "Scorecard on Reburning 6/1/2004" shows a 109 MW t-fired boiler (listed as Greenidge Unit 4) lowered NOx by 50% from 0.50 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 10 percent reburn fuel (no longer operating) (10).
Source: Sept. 2005 GE-EER experience list(8); GE-EER 2004 Technical paper(11); DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).

REBURN – GAS, CONVENTIONAL continued
Pulverized coal-fired boilers)

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station	Pulverized Coal	opposed wall-fired B&W boilers
Units 1 & 2	1964, 1965 vintage	eastern bituminous coal
360 MW (nominal)	GE-EER Gas Reburn, 2000 startup	

Vendor claimed to lower NOx up to 43% and 45% from 0.60 lb/mmBtu baseline to 0.34 and 0.33 lb/mmBtu) at full load with reburn operation, respectively. No claims of percent reburn fuel included(8).
Source: Sept. 2005 GE-EER experience list(8). Listed in DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3	Pulverized coal, wall-fired, 1962 vintage
175 MW B&W boiler	western bituminous coal
DOE Clean Coal demonstration project	November 1992-January 1995

Gas reburn demonstration performed with Dept. of Energy and Gas Research Institute 1992-1995. Existing boiler with 16 burners was retrofitted with low NO$_X$ burners and GE-EER gas reburn OFA, FGR, and reburn injectors. Added OFA booster fan, 800 hp flue gas recirculation fan for injection mass momentum, for increased gas injection mass momentum (which was subsequently removed). The CGR installation portion has since been decommissioned.
Vendor claimed to lower NOx up to 64% from baseline of 0.73 lb/mmBtu to 0.26 lb/mmBtu) at full load with reburn operation(8).
GE-EER 2004 technical paper shows 15-20% reburn fuel yielded minimum NOx emissions(11).
A 2004 DOE-NETL technical paper showed this project achieved 0.46 lb/mmBtu NO$_X$ emissions with low NO$_X$ burners alone (37% reduction), further reduced NO$_X$ by 44% with 12.5 percent reburn fuel(10).
A 2001 DOE-NETL technical paper claimed a NOx reduction of 65% at an average reburn gas heat input of 18% of total boiler fuel input, with and without FGR. Demonstrated 70% NOx reduction at higher reburn input rates. Referred to technology as GR-LNB. FGR was added for gas injection momentum but was subsequently removed to reduce fuel input. (30)
Source: Sept. 2005 GE-EER experience list(8); GE-EER 2004 Technical paper(11); DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10); DOE-NETL 2001 Technical paper(30); also in DOE 1999 Topical Report Number 14(14).

REBURN – OIL, CONVENTIONAL
Pulverized coal-fired boilers

Dynegy (formerly Illinois Power)	Pulverized Coal, Tangentially-fired	
Hennepin Unit 1	1966 vintage, eastern bituminous coal	
71 MW	CE boiler	1997 startup

GE-EER Orimulsion Reburn system w/ OFA, claimed orimulsion reburn lowered NOx up to 65% from baseline of 0.75 lb/mmBtu to 0.26 lb/mmBtu at full load with Orimulsion reburn operation (installed after gas reburn was demonstrated in early 1990's). No claims for percent reburn fuel included(8).
GE-EER 2004 technical paper shows 60% reduction with subsequent Orimulsion reburn (11).

Source: Sept. 2005 GE-EER experience list(8); GE-EER 2004 Technical paper(11). Orimulsion not mentioned in DOE-NETL 2004 Reburn Conference technical paper or DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).
(Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

New Brunswick Power
Coleson Cove, Bunker C/Orimulsion–fired, opposed-wall
St. John, New Brunswick, Canada
3x 350 MW B&W Boilers
Sixteen new low-NO_X oil/Orimulsion burners, eight reburn burners, nine SOFA ports, two combustion air booster fans, reburn and OFA wall penetration openings, OFA windboxes, ductwork, dampers, and accessories were added(12).
Another technical paper showed this reburn system lowered NOx by 78% from 1.0 lb/mmBtu baseline to 0.22 lb/mmBtu at 25 percent reburn fuel input(10).
Source: B&W 2004 Technical Paper(12); DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).

Georgia Power Pulverized Coal, Tangentially-fired
Scherer Unit 1 1982 vintage
887 MW CE boiler 2000 oil reburn startup
GE-EER Oil Reburn system, claimed to lower NOx from baseline of 0.36 lb/mmBtu.
GE-EER 2004 Technical paper shows reduction up to 48% (to 0.19 lb/mmBtu) at 800 MW load with oil reburn operation. No claims of percent reburn fuel included(11).
Source: Sept. 2005 GE-EER experience list shows this as a coal reburn project with eastern bituminous coal, reducing NO_X emissions 33% from 0.36 to 0.24 lb/mmBtu; GE-EER 2004 Technical paper(31).
Not listed in DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).

REBURN – COAL, MICRONIZED, CONVENTIONAL

Pulverized coal-fired boilers

AES (formerly New York State Electric and Gas Milliken Station Unit 1)
Cayuga tangentially-fired, pulverized coal, 1956 vintage
148 MWe, CE boiler eastern bituminous coal
GE-EER micronized coal reburn system 1996 startup (still operating)
US DOE Clean Coal demonstration project from March 1997-April 1999 lowered NOx with this reburn system by 29% from 0.35 lb/mmBtu baseline to 0.25 lb/mmBtu at 14 percent reburn fuel input(10).
Not listed in GE-EER's experience list nor in their 2004 technical paper.
Source: DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).

E. ON US Holdings (formerly Louisville Gas and Electric)
R.D. Green Station Units 1 & 2 (KY) wall-fired, pulverized coal, vintage unknown
293 MWe, 2 boilers eastern bituminous coal
GE-EER coal reburn system Startup dates: 2003 & 2002, respectively
Vendor claimed to lower NOx up to 57% from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation(8).
Reburn system listed on EPA's "Scorecard on Reburning 6/1/2004" shows NOx lowered by 44% from baseline of 0.45 lb/mmBtu down to 0.25 lb/mmBtu (with unknown reburn fuel input(10)).
Another technical paper showed baseline NOx with existing low-NOx burners was 0.45 lb/mmBtu, and reduced NOx emission 40% to 0.27 lb/mmBtu with OFA, and further reduced NOx emissions 22% down to 0.21 lb/mmBtu with the coal reburn system in operation[32].

Source: Sept. 2005 GE Energy (formerly GE-EER) experience list(8); DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10); March 2004 Modern Power Systems issue article (32).

REBURN – COAL, MICRONIZED, CONVENTIONAL continued

Pulverized coal-fired boilers

Cheng Loong (not in United States)
Unit #1, 250 MWe   wall-fired, bituminous pulverized coal, vintage & mfr unknown
GE-EER coal reburn system   2000 Startup (still operating)
Vendor claimed to lower NOx 44% from baseline 0.45 lb/mmBtu to 0.25 lb/mmBtu) at full load with OFA alone; further reduced NOx 28% to 0.18 lb/mmBtu, for 60% overall reduction. Recent (2004) data shows NOx down to 0.14 lb/mmBtu (69% overall) with up to 30 percent reburn fuel(8).
Source: Sept. 2005 GE Energy (formerly GE-EER) experience list(8); Listed in DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).

REBURN – GAS, CONVENTIONAL w SNCR

Pulverized coal-fired boilers)

NRG Somerset   Pulverized Coal, Tangentially-fired,   vintage unknown
Unit 6 Boiler 8 (NY)   GE-EER Conventional Gas Reburn,
120 MW CE boiler   Fuel Tech SNCR, 2003 startup
Reburn vendor claimed to lower NOx 55% from 0.45 lb/mmBtu baseline to 0.20 lb/mmBtu at full load with reburn operation burning Venezuelan coal. The SNCR system further reduced NOx emissions 45% down to 0.11 lb/mmBtu, for an overall reduction of 77%(32).
Source: Sept. 2005 GE Energy experience list(8); March 2004 Modern Power Systems issue(32).

REBURN – FUEL LEAN GAS REBURN (FLGR)

Pulverized coal-fired boilers

Duke Power Company   tangentially-fired, pulverized coal
Riverbend Unit 7   eastern bituminous coal   1954 vintage
140 MWe, CE boiler   1998 FLGR startup, gas reburn decommissioned since then
Previously installed ABB/CE's Low NOx Concentric Firing System (LNCFS-1) with Close-Coupled Overfire Air (CCOFA); (pre-mod NOx + combustion mods date not known).
Commercial FLGR installation claimed 34% NOx reduction from full-load baseline of 0.42 lb/mmBtu down to 0.29 lb/mmBtu w/ the combustion modifications and FLGR gas reburn fuel at 7% of total boiler heat input. CO emissions were above 1000 ppm corrected to 3% O_2.(33)
Vendor claimed to lower NOx 57% from 0.47 lb/mmBtu baseline to 0.20 lb/mmBtu) at full load with separated OFA alone; further reduced NOx 45% to 0.11 lb/mmBtu with low-NOx burners, OFA, gas reburn, and SNCR, for 77% overall reduction; no claims for amount of reburn fuel(32).
EPA's "Scorecard on Reburning 6/1/2004" showed this reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input(10).
Source: ESA, GRI, NGB 1998 Technical paper(33); GE Energy 2004 Technical paper(32); DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).

Wisconsin Electric Power Company (WEPCO)
Pleasant Prairie Unit 1   DB Riley, turbo-fired PC, Powder River Basin coal
620 MWg   1980 vintage   1999 startup
Fuel Tech listed FLGR installation and claimed 20% NOx reduction from baseline of 0.45 lb/mmBtu (to 0.36 lb/mmBtu). No claims of percent reburn fuel input included(23).

Source: Fuel Tech experience list dated 1/28/2005(23). Also listed in DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).
(Also see FLGR + SNCR installation summaries for pulverized coal boilers).

REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR)

Pulverized coal-fired boilers

Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 startup
Commercial urea-based Fuel Tech SNCR +FLGR installation claimed 50% NOx reduction from baseline(19) of 0.58 lb/mmBtu (426 ppm) down to 0.29 lb./mmBtu w/ 5 ppm ammonia slip(23). Low NO_X burners were previously retrofitted in 1997 without separated overfire air(26). This is 33 % lower than 0.44 lb/mmBtu baseline for SNCR alone. (Also see SNCR installation summaries for pulverized coal boilers). Urea-to-NOx NSR not stated.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating(10).
Another technical paper showed 52% NOx reduction down to 0.28 lb/mmBtu at all loads, from 99 MWg to 207 MWg (48% to 100% MCR) with an average NH_3 slip of 3 ppm. FLGR alone achieved 23% NOx reduction with 6% reburn fuel and < 400 ppm CO at full load. (26)
Source: Fuel Tech experience list 1/28/05(23); ICAC SNCR 2000 White Paper(19); DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10); CP&L and Fuel Tech 2001 Technical paper(26).
(Also see SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage
660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup
Commercial SNCR + FLGR urea-based Fuel Tech installation claimed 40% NOx reduction from baseline of 0.65 lb/mmBtu (down to 0.39 lb/mmBtu) w/ 10 ppm ammonia slip(19). This is 20 % lower than 0.49 lb/mmBtu baseline for SNCR alone. Urea-to-NOx NSR not stated.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating(10).
Source: Fuel Tech experience list 1/28/05(23), ICAC SNCR 2000 White Paper(19); DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).
(Also see SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Mercer Station (2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired
Unit 1 and Unit 2 front wall PC, wet-bottom (slagging ash) eastern bituminous coal
Furnace #11 & #12 1960 vintage May 1999 startup
Furnace #21 & 22 1961 vintage May 1999 startup
Commercial urea-based Fuel Tech SNCR + FLGR installation claimed 60% NOx reduction from baseline of 1.4 lb/mmBtu (down to 0.56 lb/mmBtu) w/ 5 ppm ammonia slip (19). This is 72 % lower than 2.0 lb/mmBtu baseline without control. Initial demonstration of AEFLGR coinjected amine-enhanced natural gas into Furnace 22 in 1998. Subsequently installed AEFLGR on both units to reduce NOx starting in May 1999 using (2) levels of AEFLGR retractable gas injectors and (2) levels of SNCR injectors(34). Urea-to-NOx NSR not stated, goal was NSR < 1.25.

{Note both units have since been retrofitted with low-dust tail-end SCRs in 2004; SNCR systems are still capable and operated as needed, mostly for flyash conditioning to aid ESP performance}
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 1999, but not currently operating(10).
Source: Fuel Tech experience list 1/28/05 (23), ICAC SNCR 2000 White Paper(19); PSE&G, FT and ESA 2000 Technical paper(34); DOE-NETL Scorecard on Reburning 6/1/2004 (2004 Reburn Conference). (10)

REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR) continued
Pulverized coal-fired boilers

Wisconsin Electric Power Company (WEPCO)
Pleasant Prairie Unit 1 DB Riley, turbo-fired PC, Powder River Basin coal
620 MWg 1980 vintage 1999 startup
Fuel Tech urea-based SNCR +FLGR demonstration installation claimed 56% NOx reduction from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu w/ 5 ppm ammonia slip(19). This is 44 % lower than 0.36 lb/mmBtu baseline for FLGR alone.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating(5).
Source: Fuel Tech experience list 1/28/05(23), ICAC SNCR 2000 White Paper(19) ;
DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference) (10).

SELECTIVE NON-CATALYTIC REDUCTION
Pulverized coal-fired boilers

American Electric Power (AEP) Pulverized Coal, cell-burner, opposed wall-fired B&W boiler
Cardinal Unit 1 1967 vintage; Low NO_x burners installed in October 1998
600 MW (nominal) Brilliant, Ohio
Fuel Tech urea-based SNCR installed in October 1998.
Fuel Tech, DOE, EPRI-member utilities SNCR demonstration project. Tested in March-April 1999, claimed 65% reduction with LNBs + SNCR w/ 5 ppm NH_3 slip, (from pre-LNB retrofit baseline of 1.20 lb/mmBtu(24)) down to 0.52 lb/mmBtu at 620 MW (100% MCR). SNCR reduced NO_X 31% below LNBs alone (0.75 lb/mmBtu baseline), at 620 MWg (100% MCR), 34% reduction at 75% MCR (450 MWg), and 42% reduction at minimum load (340 MWg, 55% MCR) ≤ 5% ammonia slip(25), burning eastern bituminous coal. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005(23); ICAC SNCR 2000 White Paper(19), 2000 Fuel Tech technical paper(25), Riley Power (Babcock Power Inc.) experience list 8/16/04(24).

Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 SNCR startup
Fuel Tech commercial SNCR installation claimed 25% NOx reduction from low-NO_X burner w/o OFA baseline of 0.58 lb/mmBtu (down to 0.44 lb/mmBtu on SNCR alone)(23). Urea-to-NOx NSR not stated. (Also see FLGR + SNCR installation summaries for pulverized coal boilers).
Source: Fuel Tech experience list dated 1/28/2005(23).

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 5 1956 vintage; eastern bituminous coal
154 MW CE boiler SNCR startup in 2002
Mobotec USA "Rotamix" ammonia-based SNCR system injects aqueous ammonia liquid into a high velocity boosted separated overfire air (ROFA) system at the boiler.
CP&L technical paper claimed to lower NO_X from 0.28 lb/mmBtu baseline by 43% to 0.16 lb/mmBtu in 2002 with 5 ppm NH_3 slip following the installation of ROFA in 2000.

Overall reduction 73% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.16 lb/mmBtu(27).
Mobotec claimed further NO_X reduction was possible by injecting urea in place of ammonia, achieving 0.13 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 54% decrease from 0.28 lb/mmBtu with ROFA alone, or 78% overall decrease(35). Ammonia-to-NOx NSR not stated.
Source: CP&L 2002 Technical paper(27); Mobotec 2003 technical paper(35).

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 6 twin-furnace (eight corner), 1958 vintage; eastern bituminous coal
175 MW CE boiler SNCR startup in 2001
Mobotec USA "Rotamix" ammonia-based SNCR system, injects aqueous ammonia liquid into a high velocity boosted separated overfire air ("ROFA") system at the boiler.
CP&L technical paper claimed to lower NO_X from 0.23 lb/mmBtu baseline by 22% to 0.18 lb/mmBtu with 5 ppm NH_3 slip following the installation of ROFA+SNCR in 2001(27). Presentation slide graph shows no reduction for Rotamix beyond ROFA alone at full load NO_X emission rate of 0.23 lb/mmBtu. Ammonia-to-NOx NSR not stated.
Overall reduction 67% from full-load pre-ROFA baseline 0.54 lb/mmBtu to 0.18 lb/mmBtu.
Mobotec claimed further NO_X reduction was possible by injecting urea in place of ammonia, achieving 0.10 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 56% decrease from 0.23 lb/mmBtu with ROFA alone, or 81% overall decrease(35). Urea-to-NOx NSR not stated.
Source: CP&L 2002 Technical paper(27); Mobotec 2003 technical paper(35).

Cinergy (formerly Cincinnati G&E) Pulverized Coal, Tangentially-fired,
Miami Fort Unit 6 (Ohio) 1960 vintage; startup prior to 2000
163 MW CE boiler
Fuel Tech urea-based SNCR system, claimed to lower NOx by 35% from 0.55 lb/mmBtu baseline(20).(assume eastern bituminous coal). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005(23), ICAC SNCR 2000 White Paper(19).

Conectiv (formerly Delmarva Power & Light)
Edgemoor Unit 3 Pulverized Coal, Tangentially-fired, 1954 vintage
84 MW CE boiler mid-March 1996 startup; (assume eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR system. HRC claimed 35% NOx reduction with less than 10 ppm ammonia slip. Urea-to-NOx NSR not stated.
Another source shows a 30% reduction from 0.54 lb/mmBtu baseline(20).
Source: Hamon experience list (not listed by Fuel Tech)(36); ICAC SNCR 2000 White Paper(19).

Conectiv (formerly Delmarva Power & Light) Pulverized Coal
Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage
B&W, DB Riley boilers Spring 2000 startup (eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR system (not listed by Fuel Tech) on both units. HRC claimed 35% NO_X reduction with less than 5 ppm ammonia slip(36). Urea-to-NOx NSR not stated.
An REI 1999 technical paper shows a pre-SNCR baseline of 0.37 and 0.44 lb/mmBtu, respectively(28).
Another source listed these units as having a pre-control NO_X baseline of 0.97 and 0.57 lb/mmBtu, and 2004 post-SNCR startup average of 0.32 and 0.33 lb/mmBtu, respectively(1).
Source: Hamon experience list (not listed by Fuel Tech)(36); REI 1999 technical paper(28);
US EPA Docket OAR-2002-0076-0446 Excel Spreadsheet 6/15/2005(1).

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Dominion Generation (Virginia E&P Co.)
Clover Station, Units 1 & 2 (VA)
2 x 465 MW
Urea-based SNCR (Fuel Tech system)

Pulverized Coal, Tangentially-fired
ABB/CE boilers, 1995, 1996 vintage
(eastern bituminous coal)
1995, 1996 startup (initial commercial)

Fuel Tech claimed NOx reduced by 25% from 0.32 lb/mmBtu baseline (to 0.24 lb/mmBtu)(23).
Source: Fuel Tech experience list dated 1/28/2005(23). Urea-to-NOx NSR not stated.

Dynegy Midwest Generation (formerly Illinois Power)
Vermillion Station, Unit 1
82 MW

Pulverized Coal, Tangentially-fired
1955 vintage
CE boiler, bituminous Illinois coal

Mobotec USA "Rotamix" urea-based SNCR system with rotating opposed fired air (ROFA).
Mobotec 2004 technical paper claimed to lower NO_X by 55% from 0.22 lb/mmBtu baseline to 0.10 lb/mmBtu in April 2004 with urea-based Rotamix SNCR and < 5 ppm CO. NH_3 slip not mentioned. Overall reduction 83% from full-load pre-ROFA baseline 0.58 lb/mmBtu to 0.10 lb/mmBtu (29). Urea-to-NOx NSR not stated.
Source: Mobotec 2004 technical paper(29).

Eastern Utilities Associates,
Montaup Electric Company
Somerset Unit 8 (Massachusetts)
112 MW CE boiler

Pulverized Coal, Tangentially-fired
1959 vintage
Summer 1995 startup
(eastern bituminous coal)

Hamon Research-Cottrell supplied a urea-based SNCR (Fuel Tech system), claimed to lower NOx below 0.38 lb/mmBtu (Mass. RACT)(36). Urea-to-NOx NSR not stated.
Another source listed 28-60% NOx reduction from a 0.49-0.89 lb/mmBtu baseline(19).
Source: Hamon experience list 4/26/04(36), Fuel Tech experience list dated 1/28/2005(23), ICAC SNCR 2000 White Paper(19).

First Energy
Eastlake Unit 3 (Ohio)
130 MW CE boiler (w/ division wall)
Urea-based SNCR (Fuel Tech system)

Pulverized Coal, Tangentially-fired,
1954 vintage
(eastern bituminous coal)
SNCR startup prior to 2000

Fuel Tech claimed to lower NOx from 20-32.5% from 0.34-0.40 lb/mmBtu baseline(23). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005(23); ICAC SNCR 2000 White Paper(19).

First Energy
Sammis Unit 2 (Ohio)
180 MW Foster Wheeler boiler
Urea-based SNCR (Fuel Tech system)

Pulverized Coal, wall-fired,
1960 vintage
SNCR startup Fall 1999
(eastern bituminous coal)

Fuel Tech claimed to lower NOx from 25-30% from 0.45 lb/mmBtu baseline (23). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005(23), ICAC SNCR 2000 White Paper(19).

First Energy
Sammis Units 6 & 7 (Ohio)
680 MW B&W Universal Pressure boilers
Urea-based SNCR (Fuel Tech system)

Pulverized Coal, wall-fired,
1969 & 1971 vintage
(eastern bituminous coal)
SNCR startup after 1999

Fuel Tech claimed to lower NOx from 25% from 0.38 lb/mmBtu baseline(23). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005(23).

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

New England Power Company (NEPCO)
Salem Harbor Station
Units 1, 2 & 3
84 MWe x 2, & 156 MWe B&W boilers
Urea-based SNCR (Fuel Tech system)
Pulverized Coal, front wall-fired,
1952, 1952, 1958 vintage (eastern bit. coal)
SNCR startup prior to 2000
Fuel Tech claimed 66% (50-75%) NOx reduction from baseline of 1.0 ± 0.1 (range 0.85-1.12) lb/mmBtu(23), (which would lower NOx to around 0.34±0.07 lb/mmBtu). Urea-to-NOx NSR not stated.
{These NOx reduction percentages may include impact of low-NOx burners}.
Source: Fuel Tech experience list dated 1/28/2005(23), ICAC SNCR 2000 White Paper(19).
(Also see LNB installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)
Schiller Units 4, 5, & 6
50 MWe x 3Foster Wheeler boilers
Urea-based SNCR (Fuel Tech system)
Pulverized Coal/#6 Fuel oil, front-wall-fired
1952, 1955, 1957 vintage
Colombian bituminous coal
August 1999 startup
RJM implemented Fuel Tech urea-based commercial SNCR installation on all three boilers.
RJM claimed 50% reduction from 0.50 lb/mmBtu pre-SNCR baseline to 0.25 lb/mmBtu for SNCR coal-firing operation; NO_X baseline 0.82 lb/mmBtu prior to RJM's LNB modifications installed in 1994, 1992, & 1994 (39% reduction)(17); Urea-to-NOx NSR not stated.
Fuel Tech claimed 30% NO_X reduction for SNCR from baseline of 153 ppm firing #6 fuel oil on Units 4 & 6 only(23).
Source: RJM experience list 9/3/04(17), Fuel Tech experience list dated 1/28/2005(23).

Owensboro Municipal Utilities (KY)
Elmer Smith Unit 2
300 MW CE boiler
Pulverized Coal, Tangentially-fired,
1974 vintage
eastern bituminous coal
Hamon Research-Cottrell supplied an ammonia-based SNCR system but stated no claims for NOx reduction(36); (this project is not listed in ICAC SNCR 2000 White Paper(19)). Ammonia-to-NOx NSR not stated.
Source: Hamon experience list 4/26/04(36).

PECO Energy (formerly Philadelphia Electric Company)
Cromby Unit 1
160 MWe B&W boiler 1954 vintage
Pulverized Coal, front wall-fired divided furnace
eastern bituminous coal
RJM installed Fuel Tech urea-based SNCR with low NO_X burner modifications & OFA in 1999, June 1999 startup.
RJM claimed 29% SNCR NO_X reduction from baseline of 0.35 lb/mmBtu, down to 0.25 lb/mmBtu with urea NSR = 0.8; RJM provided burner modifications of B&W XCL low-NOx burners installed in 1994 + OFA; this reduced NO_X from 0.50 to 0.35 lb/mmBtu (30% reduction) without SNCR(17). Urea-to-NOx NSR not stated.
Source: RJM experience list9/3/2004(17); ICAC SNCR 2000 White Paper(20).

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Exelon (formerly PECO Energy/ Pennsylvania Electric Company)
Eddystone Units 1 & 2 Pulverized Coal Tangentially-fired, 1954 vintage
318, 333 MW each CE boilers 1999 SNCR startup, eastern bituminous coal
Fuel Tech claimed 30% NOx reduction from baseline of 0.26 lb/mmBtu(23).
Source: Fuel Tech experience list dated 1/28/2005(23).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage
660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup
Fuel Tech urea-based commercial SNCR installation claimed 25% (initial) NOx reduction for SNCR alone from baseline of 0.65 lb/mmBtu (down to 0.49 lb/mmBtu)(23). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005(23), also listed in ICAC SNCR 2000 White Paper(19).
(Also see FLGR+SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Mercer Station (2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired
Unit 1 and Unit 2 front wall PC, wet-bottom (slagging ash) eastern bituminous coal
Furnace #11 & #12 1960 vintage April 1999 startup
Furnace #21 & 22 1961 vintage May 1999 startup
Fuel Tech urea-based commercial SNCR installation claimed 30-35% NOx reduction from baseline of 2.0 lb/mmBtu on SNCR alone, down to 1.4 lb/mmBtu(23). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005(23), also listed in ICAC SNCR 2000 White Paper(19).
(Also see FLGR+SNCR installation summaries for pulverized coal boilers).

Reliant Energy (formerly GPU Genco) Pulverized Coal
(formerly Sithe, formerly Penelec) Tangentially-fired
Seward # 15 (PA) mid-1990's SNCR startup
Units 4 & 5 eastern bituminous coal
62 & 156 MW CE boilers 1950 & 1957 vintage
Urea-based SNCR (Fuel Tech system), later installed an in-duct SCR to reduce NH_3 slip.
Fuel Tech claimed to lower NOx 35% for SNCR only (55% for combined SNCR/SCR from 0.78 lb/mmBtu baseline)(23). Boilers have since been demolished and replaced with CFBs. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005(23), ICAC SNCR 2000 White Paper(19).

Rochester Gas & Electric Pulverized Coal, Tangentially-fired
Russell Station, Units 1-4 (NY) 1948, 1950, 1953, 1957 vintage
1 x 50 MW, 2 x 65 MW, 1 x 85 MW CE boilers eastern bituminous coal
Urea-based SNCR (Fuel Tech system) SNCR startup prior to 2000
Vendor claimed to lower NOx by 15-27.5% from 0.28 – 0.42 lb/mmBtu baselines(23). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005(23).

HYDROCARBON-ENHANCED AMMONIA SNCR (NOxStar™)

Pulverized coal-fired boilers

Tennessee Valley Authority (TVA)	Pulverized Coal twin-furnace, tangentially-fired,
Kingston Power Station (TN)	1955 vintage eastern bituminous coal
Unit 9, 200 MWe CE boiler	NOxStar™ startup January 2002

Demonstration of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR installation.
Mitsui Babcock claimed 68% NOx reduction from baseline of 0.55 lb/mmBtu down to 0.17 lb/mmBtu with boosted OFA and NOxStar™ with < 5 ppm ammonia slip; NOxStar™ alone reduced NOx by 53%(37); boosted OFA only reduced NOx from 0.55 to 0.45 lb/mmBtu (18% reduction). Ammonia-to-NOx NSR not stated.
TVA's website reported that "an earlier version of NOxStar was installed at Kingston Fossil Plant Unit 9 in 2002 with mixed results. NOx reductions were achieved, but the boiler was damaged" (http://www.tva.gov/environment/repotrs/envreports/aer/2003/env_compliance.htm)
Source: Mitsui Babcock Technical paper, October 2003(37).

Tennessee Valley Authority (TVA)	Pulverized Coal, wall-fired
Colbert Station (AL)	1955 vintage
Unit 4, 192 MWe twin-furnace B&W boiler w/ FGR	eastern bituminous coal

First commercial installation of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR technology.
Mitsui Babcock showed 80% NOx reduction from baseline of 0.50 to 0.10 lb/mmBtu; using < 0.1% of total boiler heat input for propane input and 1% of total steam flow generated in the boiler for lance cooling(38); 2004 SNCR system startup. Ammonia-to-NOx NSR not stated.
Source: Mitsui Babcock 2004 Technical paper(38).

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Appendix A4 - Technical Literature References for U.S. Cyclone NOx Reduction Projects Summary:

(1)EPA Acid Rain Program Clean Air Markets Division, Technical Support Document – Methodology For Developing BART NO_x Presumptive Limits, June 15, 2005, OAR-2002-0076-0445, and EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: from EDOCKET at http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b

(2) RMT 2003 Technical Paper "NOx Control In Coal Fired Cyclone Boilers using SmartBurn^{SM} Combustion Technology" by Edmundo R. Vásquez, PhD, Alliant Energy Corporate Services, and Hani Gadalla, Keir McQuistan, Felicia Iman and Rodney E. Sears, RMT Inc. presented at 2003 MEGA Powerplant Air Pollution Control Symposium, Washington D.C., May 19-22, 2003.

(3) B&W experience list September 18, 2002.

(4) REI 2002 Technical Paper "Demonstration of Rich Reagent Injection for NOx Control in AmerenUE's Sioux Unit 1" by Marc A. Cremer and Bradley R. Adams, Reaction Engineering International, David E. Boll, AmerenUE, and David C. O'Connor, Electric Power Research Institute, presented at the US DOE Conference on SCR/SNCR for NOx Control, Pittsburgh, PA, May 15-16, 2002; and

(5) REI 2003 Technical Paper "Improved Rich Reagent Injection (RRI) Performance For NOx Control In Coal Fired Utility Boilers" by Marc A. Cremer and Huafeng D. Wang, Reaction Engineering International, David E. Boll, AmerenUE, Edmund Schindler, RJM Corporation, and Edmundo Vasquez, RMT, Inc., Alliant Energy Corp., presented at 2003 U.S. DOE Conference on SCR and SNCR for NOx Control, Pittsburgh, PA, October 29-30, 2003.

(6) REI 2004 Technical paper, "Evaluation of Cost Effective Non-SCR Options for NOx Control in PRB Fired Cyclone Boilers" by Marc A. Cremer and David H. Wang, and Bradley R. Adams, Reaction Engineering International, David E. Boll and Kenneth B. Stuckmeyer, AmerenUE, presented at the Western Fuels Symposium, 19th International Conference on Lignite, Brown, and Subbituminous Coals (formerly Low-Rank Fuels), October 12-14, 2004, Billings, MT.

(7) REI 2005 Technical paper "NOx Emissions Below 0.15 lb/Mbtu Achieved in a Cyclone-Fired Boiler Using In-Furnace Control", by M. Cremer, B. Adams, and A. Chiodo, Reaction Engineering International; C. Giesmann, K. Stuckmeyer, and J. Boyle, AmerenUE, presented at the Powergen International 2005 conference, December 6-8, 2005, Las Vegas, Nevada

(8) GE Energy (formerly GE-EER) experience list September 29, 2005.

(9) Burns & McDonnell internal database for OFA NOx reduction projects.

(10) DOE-NETL 2004Technical Paper "Reburning Projects in the Department of Energy's Clean Coal Technology Demonstration Program", by Al Mann and Tom Ruppel, Parsons Corporation, and Tom Sarkus, National Energy Technical Laboratory, presented at the 2004 DOE-NETL Conference on Reburning for NOx Control, Morgantown, WV, May 18, 2004. A reburn-related document (an updated version of a poster from the May 18 Conference) is titled "Scorecard on Reburning 6/1/2004" by Al Mann and Tom Ruppel, Parsons Corporation, available on-line at: http://www.netl.doe.gov/publications/proceedings/04/NOx/posters/Reburning%20Scorecard.pdf

(11) GE Energy 2004 Technical paper “Reburn Technology Application Guidelines”, by David Moyeda, GE Energy, presented at the 2004 DOE-NETL Conference on Reburning for NOx Control”, Morgantown, WV, May 18, 2004.

(12) B&W 2004 Technical Paper “B&W’s Reburning Experience”, by H. Farzan, G. Maringo, A. Yagiela, A. Kokkinos, Babcock & Wilcox, Co., presented at the 2004 DOE-NETL Conference on Reburning for NOx Control, Morgantown, WV, May 18, 2004. (This data is a duplicate of a more detailed technical paper published earlier, “B&W’s Advance on Cyclone NOx Control Via Fuel and Air Staging Technologies”, by H. Farzan, G. Maringo, D.W. Johnson, and D.W. Wong, Babcock & Wilcox, Co., C.T. Beard, Eastman Kodak Company, and S.E. Brewster, Tennessee Valley Authority, presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, Atlanta, GA, August 16-20, 1999).

(13) B&W case history “B&W Cyclone Reburn Leads to NO_X Reduction, Wisconsin Power & Light Co. Nelson Dewey Unit No. 2” (from website http://www.babcock.com/pgg/ps/casehistories.html, dated 1997).

(14) DOE Topical Report Number 14 “Reburning Technologies for the Control Of Nitrogen Oxides Emissions from Coal-Fired Boilers”, conducted under separate cooperative agreements between the U.S. Department of Energy, the Babcock & Wilcox Company, Energy and Environmental Research Corporation, and New York State Electric & Gas Corporation, May 1999.

(15) Technical Paper “Predictions of FLGR at Commonwealth Edison’s Joliet Unit 6” by NGB Technologies, posted on their website: http://www.ngbtech.com/subpages/proj/joliet_results.html

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APPENDIX A5 - EERC Report – Ash Impacts on SCR Catalyst Performance

ASH IMPACTS ON SCR CATALYST PERFORMANCE

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ASH IMPACTS ON SCR CATALYST PERFORMANCE

EXECUTIVE SUMMARY

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be plagued with problems. The Center lignite fired at the Milton R. Young (MRY) Power Station is highly variable in abundance of various types of ash/slag-forming components. Ash-forming components consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. The alkali and alkaline-earth elements combine with minerals during combustion, resulting in low-melting-point phases that cause a wide range of fireside deposition problems. In addition, the alkali and alkaline-earth elements also form very small particles that are carried into the backpasses of the combustion system and react with flue gas to form sulfates that can cause deposition, blinding, and plugging problems in selective catalytic reduction (SCR) systems. This report analyzes these problems, and concludes that SCR is not a feasible option to control NOx emissions at MRY Power Station because of the high sodium levels present in the coal.

Following is a list of the key problems that are associated with Center lignite which have not been overcome and, in our opinion, make the installation of SCR at the MRY plant technically infeasible for NO_x control.

- Blinding of Catalyst Pores by High Sodium Compounds

  X High levels of alkali and alkaline-earth elements present in the coal fired at the MRY plant produce small particles that react to form sulfates that blind the catalyst pores. The high levels of sodium in the coals combined with calcium will produce low-melting-point eutectic sulfate compounds that will form and melt inside the pores of the catalyst.
  - Alkali and alkaline earth sulfates are enhanced by cyclone fired system. The cyclone firing results in partitioning of the ash between bottom slag and the body of the boiler. The sulfate forming materials are more concentrated in the ash as a a result of cyclone firing.

  - Sulfate formation is enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.

  - The sulfate reactions are more severe at MRY because of the high temperature where an SCR would be installed. The higher temperature increases the rate of formation of sulfates and rate of pore plugging.

  - The testing conducted by the Germans found catalyst deactivation and blinding occurs when firing coals with lignite or brown coals that have ashes that are rich in alkali and alkaline-earth elements. .

- The findings by the Germans were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-rich sulfate formation that fill and plug the catalyst at both lignite- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or "popcorn ash," plugging the top of the SCR catalyst is a significant problem because of the extremely high deposition rates of the Center coal. When firing Center coal, deposits form on various parts of the boiler requiring continuous sootblowing. The sootblowing of upstream heat-exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, resulting in plugging. In addition, during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

- Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

➢ Cold Side SCR Installation

- High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces significant levels of homogeneously condensed sodium sulfate that pass through the ESP and wet scrubber.

- These small particles have been shown to pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials require sootblowing to remove the particulate and will result in increased opacity.

- Liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems are known to catalyze the formation of SO_3 from SO_2. The presence of SO_3 significantly enhances the formation of the pyrosulfates.

ASH IMPACTS ON SCR CATALYST PERFORMANCE

INTRODUCTION

Ash produced during combustion of coal in conventional power systems is a major problem that results in decreased efficiency, unscheduled outages, equipment failures, and increased cleaning. The many ways in which the detrimental effects of ash manifest themselves in a boiler system include fireside ash deposition on heat-transfer surfaces, corrosion and erosion of boiler parts, poor slag flow, and production of fine particulates that are difficult to collect. Decades of research have been conducted to develop a better understanding of the chemical and physical processes of ash formation and deposition in combustion systems. Overviews of ash-related issues and compilations of work by many investigators can be found by referring to the work of Mehta and Benson (1), Schobert (2), Baxter and DeSollar (3), Couch (4), Williamson and Wigley (5), Benson and others (6), Benson (7), Bryers and Vorres (8), Raask (9, 10), and Benson (11). This work has led to a detailed understanding of ash formation and behavior in combustion systems as well as the development of predictive methods (12, 13).

The chemical composition and physical characteristics of ash-forming or inorganic components (mineral and organically associated elements) of the fuel(s) fired have an influence on the following processes in the combustion systems:

- Firing conditions such as cyclone, pulverized coal, and low-NO_x burners
- Transformations of coal inorganic components to ash particulate and vapor-phase species
- Boiler design characteristics, including number of burners, radiant section area, tube bank spacing, access for cleaning, and number of sootblowers
- Ash transport to heat-transfer surfaces in utility boilers
- Erosion wear and sticking
- Ash deposit growth and impact on heat transfer
- Ash blinding and plugging of selective catalytic reduction (SCR) catalysts
- Ash deposit removability

The ash deposition in North Dakota lignite-fired power plants is a major problem that impacts all fireside surfaces of the power plant. The ash problems are due to the variable and complex nature of inorganic components associated with lignite coals (2). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. During the gas-cooling processes in the boiler, the gas-phase species condense and the liquid-phase materials solidify. The abundance of these gas-phase and liquid materials entrained in the bulk gas flow is highly dependent upon coal composition and system operating conditions. The inorganic materials are transported to heat-transfer and catalyst surfaces by diffusion, electrophoresis, thermophoresis,

and inertial impaction. The particle sticking and accumulation rates are dependent upon the quantity of ash and the abundance and viscosity of the liquid-phase components. In high-temperature regions of the boiler, high-temperature sodium–calcium–aluminosilicate liquid phases act as the sticky material, causing deposit initiation, growth, and development of deposit strength. As the temperature of the flue gases decreases, the condensation and reaction of flame-volatilized species play a more significant role in the formation of deposits from lignite coals. The formation of sodium and/or calcium magnesium sulfates dominates the deposit accumulation mechanisms at lower temperatures. The aluminosilicate phases are dominant above about 1800°F. Below about 1800°F, the sulfate phases become stable, with an optimum temperature of formation of about 1400°F, and can form at temperatures as low as 300°F.

The most significant problems that prohibit the successful operation of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates and phosphates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16).

INORGANIC COMPOSITION OF LOW-RANK COALS

Inorganic elements in coal occur as discrete minerals, organically associated cations, and cations dissolved in pore water. The fraction of inorganic components that are organically associated varies with coal rank. Lower-ranked subbituminous and lignitic coals have high levels of oxygen, which act as bonding sites for cations such as sodium, magnesium, calcium, potassium, strontium, and barium (other minor and trace elements may also be present in this form). In higher-ranked coals, bituminous and anthracite, inorganic components consist mainly of minerals. Mineral grains are usually the most abundant inorganic component in coal. The major mineral groups found in coals include silicates, aluminosilicates, carbonates, sulfides, sulfates, phosphates, and some oxides.

The behavior of ash produced during coal combustion is related to the abundance, size, and association of mineral grains in the coal. In addition, the association of the mineral grain with the coal matrix influences the temperature and gaseous environment the mineral is exposed to during combustion. A mineral associated with the organic part of a coal particle is said to be included. A mineral that is not associated with organic material is referred to as excluded. The behavior of the organically associated elements, those elements that are atomically dispersed in the coal matrix, must also be measured as to their abundance in the coal. The organically associated elements will react and interact with the other ash-forming constituents during combustion.

The Center lignite is highly variable in abundance of various types of ash/slag-forming constituents. Ash-forming components in the Center lignite are of two types. The first form may constitute up to 50% of the ash and is derived from inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix of the coal. The second type consists of mineral grains (sand, clay, limestone, and pyrite). The minerals are discrete particles of ash-forming species and the sources of silicon, aluminum, iron, titanium, and minor amounts of the calcium and potassium. The Center lignite fired at the Milton R. Young (MRY) plant has been examined extensively because of its problem with ash behavior. Analyses

of as-fired and drill core samples have been conducted. The mean and the range of selected components are shown in Figure 1. The results indicate that both the abundance of ash and the abundance of major oxides in the ash vary significantly. In addition, the abundance of alkali and alkaline-earth elements (Na and Ca) varied dramatically. Variations in Si were found to be the most significant. High levels of Ca and/or Na were found for lower-ash coals as compared to high levels of Al and Si associated with higher-ash coals (17, 18).

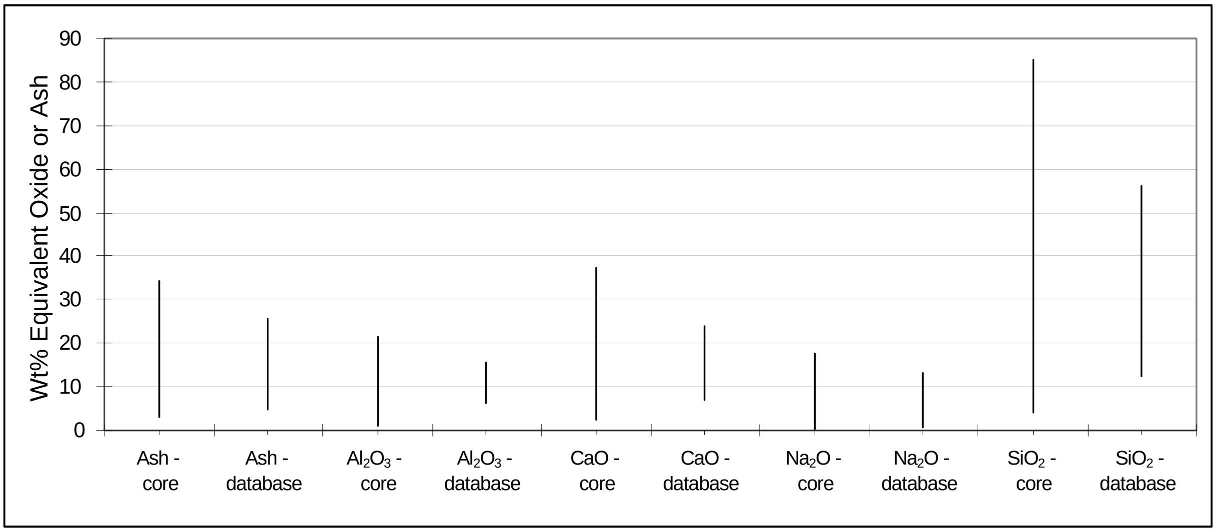


Figure 1. Variability of ash and selected constituents in core analysis database provided by BNI Coal, Ltd. and Minnkota as fired coal analysis database.

The variability of the ash-forming components has been examined for the approximately 5000 samples characterized to date. Wide variations in ash contents and the major ash-forming constituents are observed. During the mining processes, the inorganic components are mixed, and some of the extreme characteristics are diluted (17).

INORGANIC TRANSFORMATIONS AND ASH FORMATION

The inorganic coal components undergo complex chemical and physical transformations during combustion to produce intermediate ash species. The inorganic species consist of vapors, liquids, and solids. The partitioning of the inorganic components during combustion to form ash intermediates depends upon the association and chemical characteristics of the inorganic components, the physical characteristics of the coal particles, the physical characteristics of the coal minerals, and the combustion conditions.

The physical transformation of inorganic constituents depends on the inorganic composition of the coal and combustion conditions. The inorganic components can consist of organically associated cations, mineral grains that are included in coal particles, and excluded mineral grains. There is a wide range of combinations of mineral–mineral, mineral–coal,

mineral–cation–coal, and mineral–mineral–cation–coal associations in coal. These associations are unique to each coal sample.

The physical transformations involved in fly ash formation include 1) coalescence of individual mineral grains within a char particle, 2) shedding of the ash particles from the surface of the chars, 3) incomplete coalescence due to disintegration of the char, 4) convective transport of ash from the char surface during devolatilization, 5) fragmentation of the inorganic mineral particles, 6) formation of cenospheres, and 7) vaporization and subsequent condensation of the inorganic components upon gas cooling. As a result of these interactions, the ash has a bimodal size distribution. The submicron component is largely a result of the condensation of flame-volatilized inorganic components. The mass mean diameter of the larger particles is approximately 12 to 15 μm, depending upon the coal and combustion conditions. The larger-size particles have been called the residual ash by some investigators (19) because these ash particles resemble, to a limited degree, the original minerals in the coal. Processes such as ash mineral coalescence, partial coalescence, ash shedding, and char fragmentation during char combustion and mineral fragmentation, all play an important role in the size and composition of the final fly ash. Loehden and others (20) and Zygarlicke and others (21) indicate that three potential modes for fly ash generation can be used to describe fly ash particle-size and composition evolution. The first, “fine limit,” assumes that each mineral grain forms a fly ash particle and that the organically associated elements form fly ash particles of less than 2 μm. The second, “total coalescence,” assumes one fly ash particle forms per coal particle. The third, “partial coalescence,” suggests that the fly ash composition and particle size evolve because of partial coalescence.

The transformations of excluded minerals are dependent upon the physical characteristics of the mineral. Excluded minerals such as quartz (SiO_2) can be carried through the combustion system with its angular structure still intact. Excluded clay minerals can fragment during dehydration, melt, and form cenospheres. The behavior of excluded pyrite depends upon its morphology. Some of the pyrite may be present as framboids. Framboidal pyrite may fragment more easily than massive pyrite particles. In addition, the decomposition of pyrite is very exothermic, and it transforms to pyrrhotite and oxidizes to FeO, Fe_3O_4, and Fe_2O_3 during combustion.

ASH DEPOSITION ON HEAT-TRANSFER AND OTHER SURFACES EXPOSED TO ASH AND FLUE GAS

The characteristics of a deposit depend upon the chemical and physical characteristics of the intermediate ash species, geometry of the system (gas flow patterns), gas temperature, gas composition, and gas velocity. Figure 2 illustrates the ash deposition phenomena in utility boilers. Ash particle accumulations occur via transport of particles to the fireside surfaces (heat transfer, ceramic materials, support materials, SCR catalysts, baghouse materials, and ESP wires and plates) and sticking of the particles. The transport mechanisms important for ash deposition include small-particle mechanisms for particles less than 10 μm that involve thermophoresis, electrophoresis, and vapor-phase and small-particle diffusion; and large-particle mechanisms for particles greater than 10 μm that involve inertial impaction. The ability of larger particles to stick depends upon the quantity and viscosity of the liquid phase on the particle surface.

Thermophoresis is a phenomenon that involves the transport of very small particles as a result of a thermal gradient from hot gases to cooler surfaces. Electrophoresis is the transport of particles because of a difference in charge. Vapor-phase and small-particle diffusion occurs in the boundary layer next to the surface and results in transport of ash to the surface. Inertial impaction is a larger-particle phenomenon where the particles are of a sufficient size and density to leave airflow patterns around the tube and impinge upon the surface of a tube or deposit. Deposits that form in high-temperature regions of the boiler, such as the radiant section, are called slag deposits. Deposits that form in lower-temperature regions of the boiler, such as in the convective pass on steam tubes and lower-temperature surfaces such as SCR catalysts, are called fouling deposits. Slag deposits are usually associated with a high level of liquid-phase components and are exposed to radiation from the flame. This is a description that many researchers use to aid in classification of deposits since some engineers call any type of deposit "slag". Slag deposits are typically dominated by silicate liquid phases, but may also contain moderate to high levels of reduced iron phases such as FeO and FeS. The liquid characteristics of the silicates are highly dependent upon the quantities of Na, Mg, Ca, K, and Fe ash on the silicates. In addition, the initiating layers of slag deposits may consist of very fine particulate and can produce a reflective ash layer. This phenomenon is especially evident when high organically associated calcium subbituminous coal is fired. These coals produce small CaO particles that usually form the initiating layers.

Fouling deposits form in the lower-temperature regions of the boilers and, in most cases, do not contain the high levels of liquid phases that are usually associated with slagging-type deposits. Fouling deposits contain lower levels of liquid phases as compared to slag deposits. The fouling deposit liquid phases usually consist mainly of sulfates that bind the particles together. Fouling deposits typically form as a result of the reaction of gas-phase sulfur oxide species with particles rich in alkali and alkaline-earth elements.

ASH-RELATED EXPERIENCES AT MRY FACILITY

The MRY is a minemouth electrical generating plant located near Center, North Dakota. The station consists of two units: Unit 1, rated at 276 MWg, began production in 1970; Unit 2, rated at 506 MWg, began production in 1977. Both Units 1 and 2 are equipped with B&W cyclone-fired boilers; the Unit 1 boiler has seven cyclones, and the Unit 2 boiler has twelve cyclones. Annual station gross generation is approximately 5.5 million MWh.

BNI Coal Ltd. is the sole coal supplier for the MRY Station. Coal is mined from the nearby Center mine, which consists of three distinct seams varying from 2½–9 feet thick. Coal is strip-mined using two draglines and is loaded with front-end loaders and delivered to the plant with bottom-dump haul trucks. Annual coal production is 4.3 million tons per year.

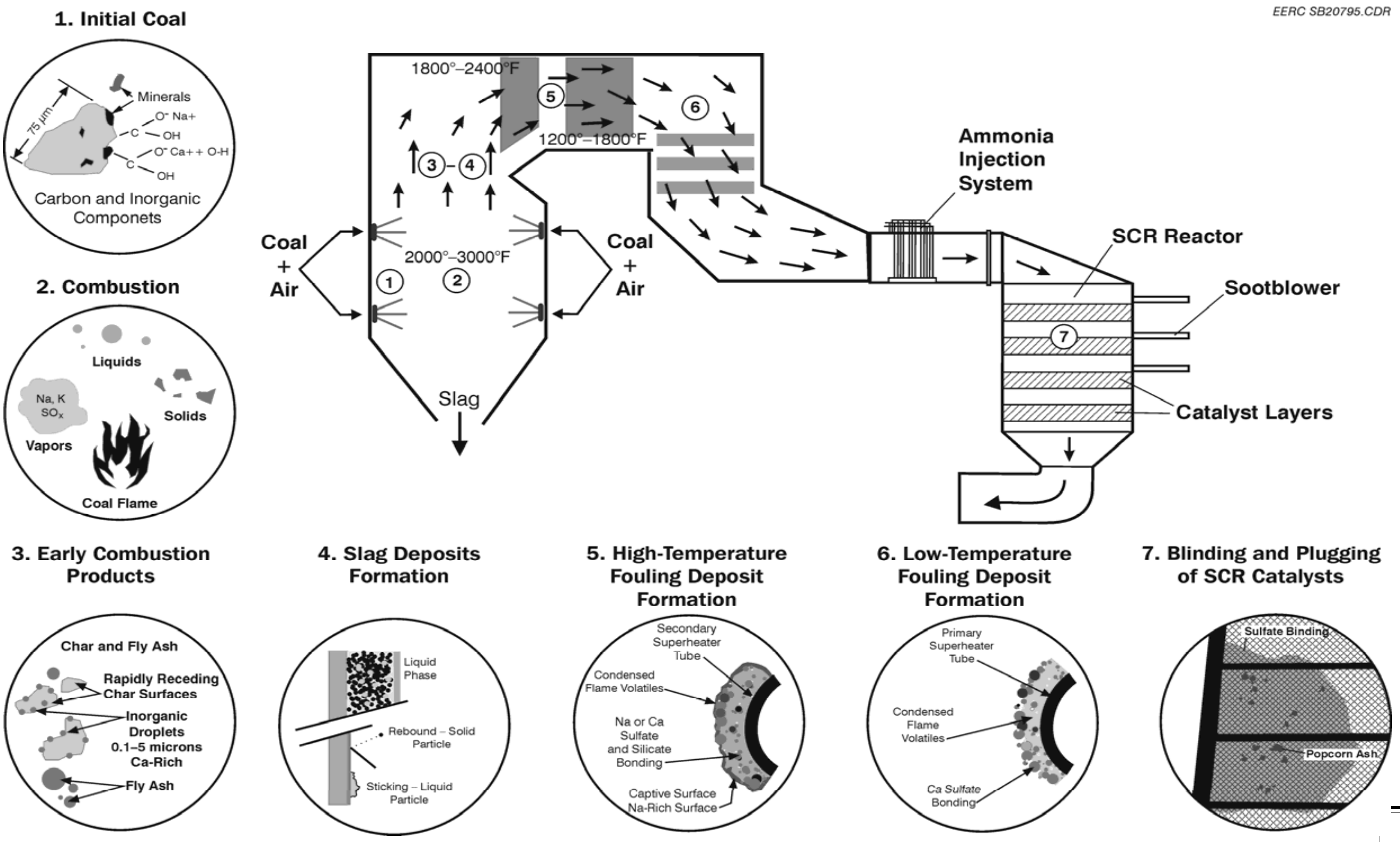


Figure 2. Overall processes of ash deposition typical of a lignite- or subbituminous-fired boiler.

History of Furnace Slagging/Fouling

Prior to 1991, besides annual maintenance outages, load reductions and forced outages due to furnace slagging/fouling were the largest cause of production loss. In 1985, operating guidelines were established that reduced furnace slagging/fouling, including deslagging outages scheduled every six months.

In 1991, a 3-month boiler cleaning cycle was proposed and initiated. The goal of this program was to increase annual generation by running the units at higher sustained loads and scheduling boiler-cleaning outages at 3-month intervals. However, furnace slagging/fouling continued to have a significant impact on plant operations. Success was measured in the number of production days between boiler-cleaning outages.

During the mid-1990s, a major outage every third year was scheduled for each unit. In addition, Unit 1 cleaning outages were scheduled for 80–90-day runs (four cleaning outages per year), and Unit 2 cleaning outages were scheduled for 65–75-day runs (five cleaning outages per year). The problem was that furnace and convection-pass surfaces gradually become coated with ash deposits, which, over time, sootblowers cannot remove. Some of the contributors to the ash deposits were as follows:

- Organically associated sodium is a primary contributor to deposition problems. Sodium is vaporized in the cyclones and condenses on other ash particles, causing them to become sticky and deposit at the furnace exit. The problem is associated with sulfate formation and occurs in the convective pass, including the economizer. Samples show that sodium in the ash varies from 0.6%–13.0%.

- Organically associated calcium is another component that causes deposition problems. Unlike sodium, calcium does not produce a vapor-phase component. Calcium does react with silicate (derived from clays) to cause low-melting-point phases that produce wall deposits and deposits in the high-temperature regions of the convective pass. Calcium also produces very small particles that will be transported to heat-transfer surfaces, resulting in the formation of thin, light-colored layers called reflective ash. These small particles of ash are carried through to the back passes where they are sulfated and can combine with sodium to cause the formation of strongly bonded sulfate-based deposits. Samples show that calcium in the ash varies from 6.8%–24.0%.

- Clay minerals and quartz – Center lignite can contain high levels of illite, which has a 1:3 Al:Si ratio and high levels of potassium, both of which cause wall slagging and high-temperature fouling. Quartz and other clays can significantly contribute to the mass of the deposits. Samples show that ash content varies from 5.0%–25.5%.

Advanced Boiler Performance Indices

Advanced indices are used to relate the coal characteristics as determined by computer-controlled scanning electron microscopy (CCSEM) and chemical fractionation to ash behavior in a coal-fired utility boiler (12). Fuel performance is estimated in terms of slag flow behavior,

abrasion and erosion wear, wall slagging, high-temperature silicate-based convective pass fouling, and low-temperature sulfate-based convective pass fouling. The following indices are used to assess the effects of ash behavior on utility boiler performance:

- Convective-Pass Fouling Indices

  Sulfation Index: Indicates the propensity of deposit to form in the convective pass of the utility boiler in the temperature range from 1000°–1750°F. This index is based on the availability of alkali (Na and K) and alkaline-earth (Ca and Mg) elements to react with SO_2 and SO_3 to form sulfates. The sulfates are the primary materials that cause particle-to-particle bonding in high-calcium coals. The sulfates are thermodynamically stable at temperatures below about 1650°F. Index values range from 1 (low) to 10 (severe).

  Silicate Index: Indicates the propensity of deposits to form from 1600°–2400°F. This index is related to the formation of deposits in which the silicate material is the primary component that bonds the deposits together. The information used to derive the index includes the size of the minerals such as quartz and clay minerals, availability of alkali and alkaline-earth elements, and viscosity of the silicate liquid phase. Index values range from 1 (low) to 200 (severe).

- Waterwall Slagging

  Slagging Index: Indicates the propensity of a deposit to form on the radiant walls from 2000°–3000°F. The basis of the slagging index is the size of the minerals (especially the illite, quartz, and pyrite), association of the calcium (calcite can contribute to slagging), and viscosity of the silicate-based liquid phase. Index values range from 1 (low) to 20 (severe).

- Wear Indices

  Abrasion Index: This index indicates the potential for wear of fuel preparation and handling equipment. The wear is related to the hardness of minerals in the coal. The primary minerals of concern include quartz and pyrite. The index values range from 0.1 (low) to 10 (severe).

  Erosion Index: This index indicates the potential for wear of boiler parts due to the impaction of fly ash particles. The erosion index is dependent upon the size of the ash/mineral particle, size of the particle, and velocity of the particle. The index values range from 0.1 (low) to 1.0 (severe).

- Cyclone Slagging Index: This index provides information on the slag flow behavior in cyclones. The factors that are included in this index include the partitioning of the ash in the cyclone based on size and association of the ash-forming components in the coal. The partitioning of the ash between the slag and entrained ash can significantly influence the flow behavior of the slag. Standard partitioning criteria have been developed to provide the composition of the slag. The composition is used to estimate the viscosity of the slag as a function of temperature. The index values have several ranges as follows: 1 (low viscosity), 1.5–2.5 (optimum viscosity), >3.0 (slag freezing).

- Strength Development Index: The strength index is based on the ability of the deposited material to develop strength. Strength development is primarily dependent upon the abundance and viscosity of the liquid-phase components in the deposits. Index values less than 0.25 indicate that the material will produce weak deposits; index values of 0.25–0.34 indicate weak-to-moderate-strength deposits; index values of 0.34–0.41 indicate high-strength deposits; and index values >0.41 indicate flowing slag.

Indices were calculated for a range of coals from the Center mine, and the propensity for ash deposition in various portions of the boiler indicates wide variations, as shown in Table 1. The BNI numbers indicate the location in the seams where the coal originated: Kinneman Creek seam (KC), Hagel A (HA), and Hagel (HB). Each seam has a different distribution of minerals and organically associated elements that can have a significant impact on the formation of deposits in the system. Comparison of Center lignite to subbituminous and bituminous coals from other regions of the United States, shown in Table 2, indicates significant differences in the potential to form deposits in the boilers. In all cases, the lignite (not the worst coal from Center mine) from the Center mine has a high propensity to produce deposits as compared to the other coals.

Another indication of the variability of lignites can be illustrated based on the calculation of the temperature where the slag flow would occur. This is defined as the T250 temperature, where the slag viscosity is 250 poise. Frequency distributions of the T250 values for all the data for coals analyzed are illustrated in Figure 3. Calculations of T250 values for 1212 samples obtained from the Center mine database (17) were made using empirical relations derived from CCSEM and chemical fractionation data and knowledge of how ash partitions in the cyclone. Figure 3 shows a bimodal distribution in the T250 based on the Urbain equation calculations. The primary mode was at a value of 2000°F. The secondary mode was at about 2700°F. The results indicate that many of the coals have a sufficiently low T250 for good slag flow. However, coals with T250 at 2700°F are not suitable for maintaining good slag flow.

Figures 4 through 6 illustrate the variations in T250 for the various seams of coals characterized. The HA and HB seam coals appear to have large numbers of samples, with T250 values at or near 2000°F. The KC seam coal, as illustrated in Figure 6, has extremely high T250 values. Based on these data, the KC coals are not favored relative to the slag flow behavior of the ash.

Frequency distributions of cyclone slagging index values indicated significant variations in slagging potentials of coals mined from the three seams, KC, HA, and HB. This information proved particularly useful in planning the mining and firing of coal from the KC seam.

During a July 1999 test burn, the composition of the cores was used to examine and illustrate the variability of the delivered coal quality based on base-to-acid ratio calculated from the ash composition. Figure 7 shows the variation in the base-to-acid-ratio and the seam where the coal was loaded. The base-to-acid ratios were calculated from core data that corresponded to the location in the seam where the coal was mined. There is a significant variation in the base-to-acid ratio for the coals. The coals that have the highest base-to-acid ratio are typically from the HA seam. HB seam coals generally have an intermediate base-to-acid ratio. KC or top-seam coal has the lowest base-to-acid ratio. Lower base-to-acid-ratio coals typically produce slag with high viscosities.

Table 1. Characteristics and Indices Calculated for Selected Center Lignite Samples

BNI No.	41-132HB	41-44KC	41-144HA	41-144HB	41-168KC	41-168HA	41-168HB	41-180KC	41-180HA	41-180HB	41-192KC	41-192HA
Mineral wt%, mineral basis												
Total Quartz Content			18.8	9.8	30.3	8.7	8.8	11.4	20.0	3.9	15.0	17.4
Quartz <10 microns		10.8		6.4	24.6	4.4	4.0	6.8	3.3	2.6	9.7	12.7
Total Kaolinite Content		10.6		10.8	7.7	6.4	1.7	9.5	4.4	2.4	14.3	28.0
Kaolinite Content <10 microns		5.1		6.3	4.5	2.6	0.9	4.8	1.1	0.9	10.2	20.8
Total Montmorillonite		10.7		2.7	6.5	1.7	6.1	7.0	2.3	2.4	7.6	5.1
Total Illite		14.1		9.3	6.6	0.2	28.0	19.1	10.2	1.6	6.8	1.9
Total Pyrite		8.0		26.7	18.9	67.1	19.7	9.1	10.9	57.2	22.6	32.3
Pyrite Content <10 microns		4.5		10.5	2.8	9.8	4.7	2.5	2.5	17.0	6.6	7.0
Gypsum Content		6.5		0.0	1.6	2.7	0.8	5.4	0.0	16.1	2.2	0.0
Proximate (wt% as received)												
Moisture		30.95		41.66	36.24	38.23	37.50	37.90	37.99	38.21	37.85	39.52
Volatile Matter		27.26		25.74	26.32	25.90	24.55	25.11	24.42	25.88	26.13	24.27
Fixed Carbon		26.56		27.97	28.18	29.65	30.37	27.94	29.53	31.54	29.15	30.30
Ash		10.30		4.63	9.26	6.22	7.58	9.05	8.1	4.37	6.88	5.91
Total Sulfur (% as received)		0.94		0.55	1.49	1.08	0.75	0.99	0.64	0.86	0.90	0.85
Btu/lb		6597		6593	6791	6957	6806	6584	6653	7194	6881	6835
% Ash (dry basis)	11.64	10.30		7.94	14.52	10.07	12.13	14.57	13.00	7.07	11.07	9.77
Ash Comp. (wt% equiv. Oxide)												
Na_2O		0.50		10.65	0.82	9.25	8.02	0.46	8.15	11.99	1.48	9.69
MgO		3.30		5.74	3.72	4.90	4.45	3.90	5.00	4.59	6.13	5.10
Al_2O_3		11.90		10.37	9.34	5.64	11.81	12.12	10.19	5.23	10.59	7.46
SiO_2		30.60		14.70	33.71	8.47	30.74	35.57	36.25	5.31	25.80	13.06
P_2O_5		0.20		0.06	0.15	0.42	0.25	0.07	0.26	0.23	0.25	0.24
SO_3		23.00		25.50	21.28	35.25	21.05	18.32	15.93	35.75	24.15	32.75
K_2O		1.20		0.96	0.47	0.62	1.52	1.03	1.22	0.47	0.55	0.60
CaO		16.80		21.00	15.31	18.94	12.10	17.15	14.87	15.43	20.01	18.98
TiO_2		1.30		0.39	0.72	0.29	0.40	0.51	0.29	0.16	0.48	0.28
MnO		0.20		0.03	0.07	0.05	0.04	0.10	0.07	0.04	0.07	0.12
Fe_2O_3		10.30		8.43	14.87	15.95	10.44	7.80	6.84	18.88	10.12	13.29
Cyclone Slagging Index		2.77		1.28	2.5	1.1	2.6	3.3	2.9	0.4	2.2	1.3
Silicate		10.71		102.43	29.47	108.33	109.93	16.29	176.22	137.49	14.19	149.54
Sulfate		9.43		3.57	2.2	5.01	3.46	1.75	3.98	4.4	2.21	3.24
Wall Slagging Index		1.18		11	2.67	10.68	9.27	1.79	8.83	12.63	2.2	10.53
Erosion Index		0.19		0.15	0.17	0.19	0.22	0.21	0.27	0.17	0.17	0.17
Abrasion Index		2.14		0.71	6.46	1.55	1.41	2.25	1.93	0.83	1.75	1.68
Strength Index		0.32		0.66	0.35	1.11	0.35	0.3	0.33	1.32	0.43	0.63

Continued . .

Table 2. Advanced Index Values for Other Coals (12)

Advanced Indices	Lignite North Dakota	Powder River Basin	Bituminous Illinois	Bituminous Appalachian
Cyclone Slagging Index	1.6	2.1	3.5	3.2
Convective Pass Fouling				
Silicate	61.8	23.99	10.36	14.21
Sulfate	4.09	2.88	0	0
Wall Slagging Index	9.28	1.85	1.53	1.66
Erosion Index	0.15	0.17	0.14	0.17
Abrasion Index	0.71	1.96	3.94	1.96

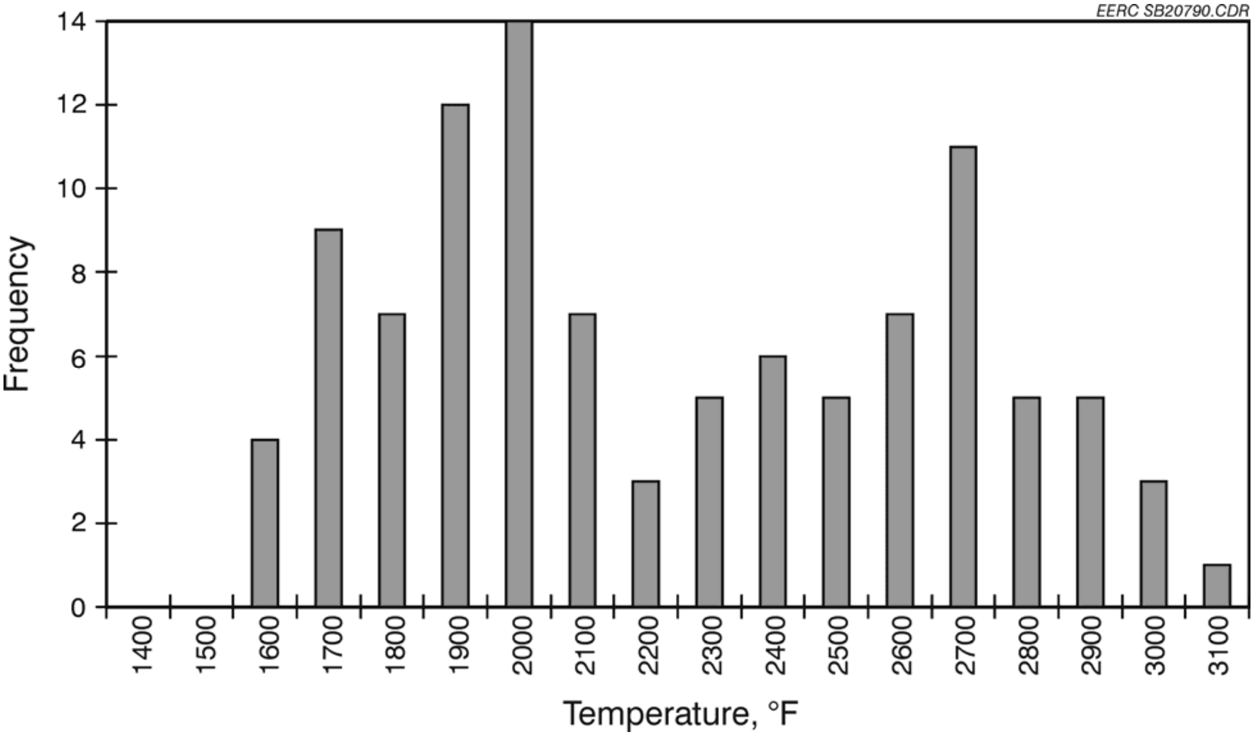


Figure 3. T_{250} frequency distribution for all Coal Quality Management System (CQMS) data, °F.

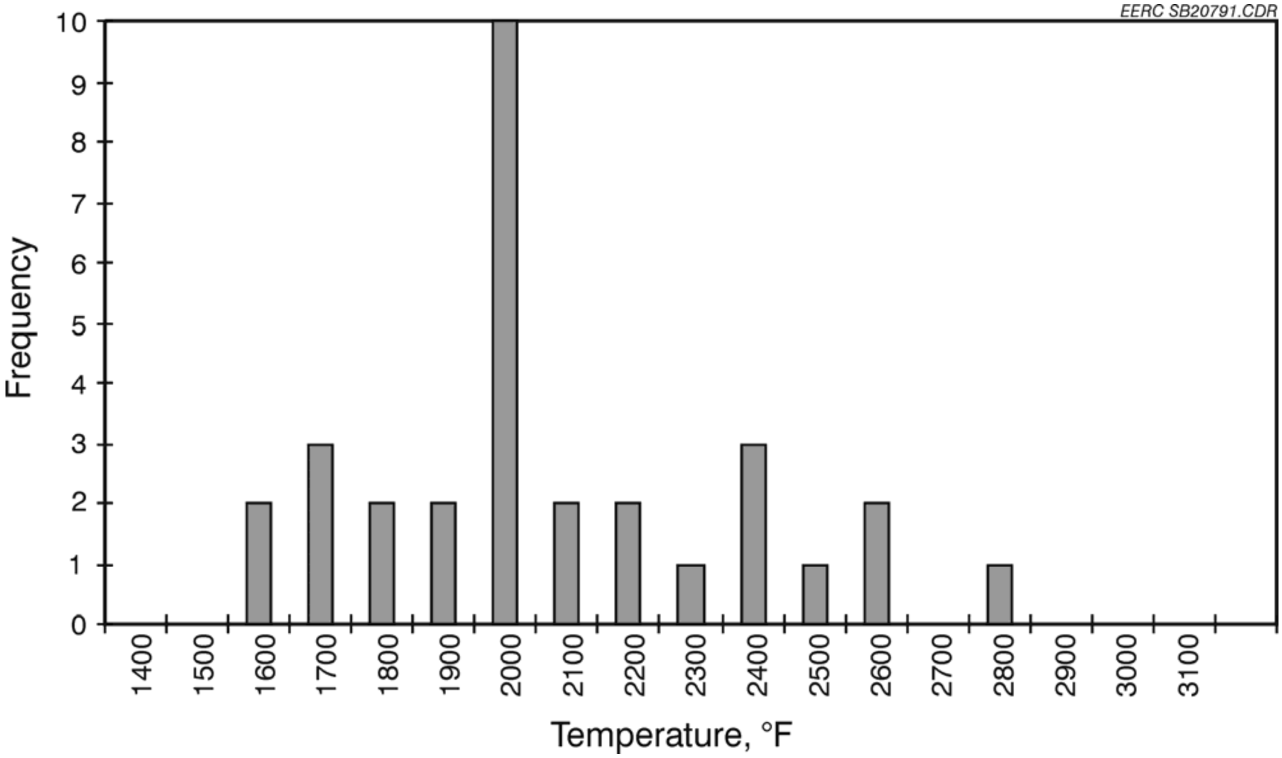


Figure 4. T_{250} distribution for HA seam coal.

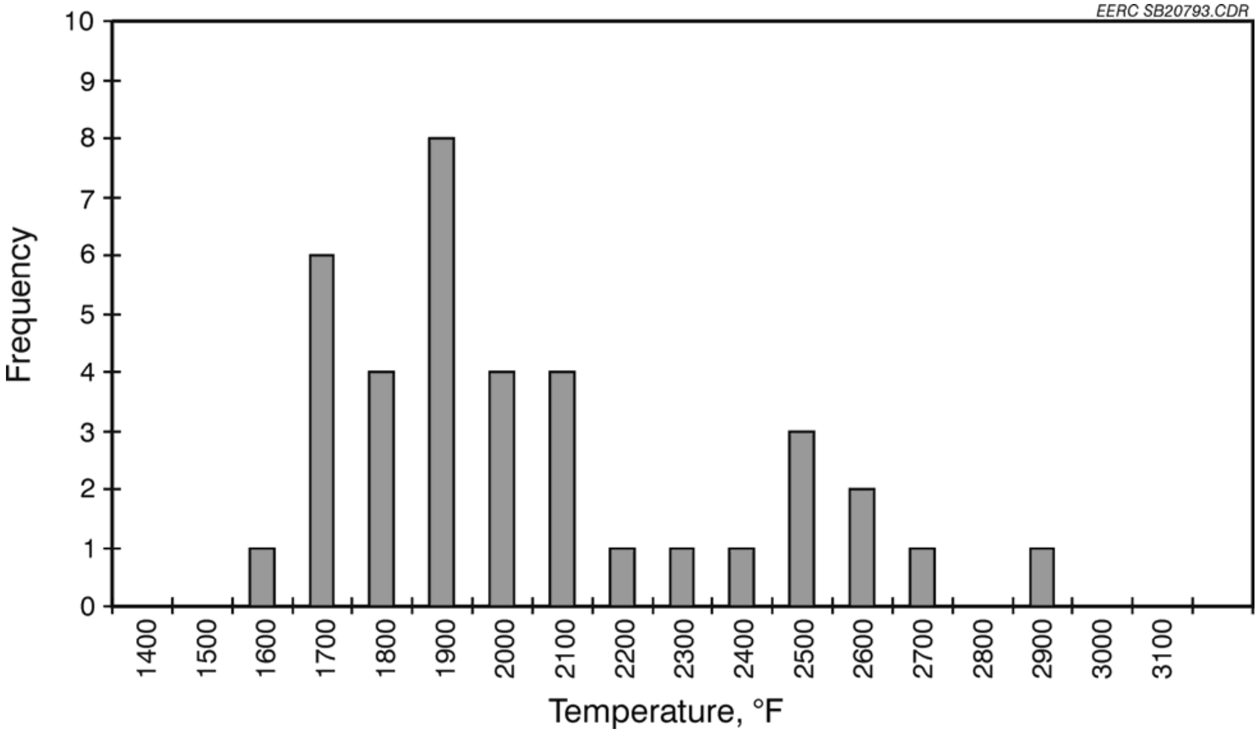


Figure 5. T_{250} distribution for HB seam coal.

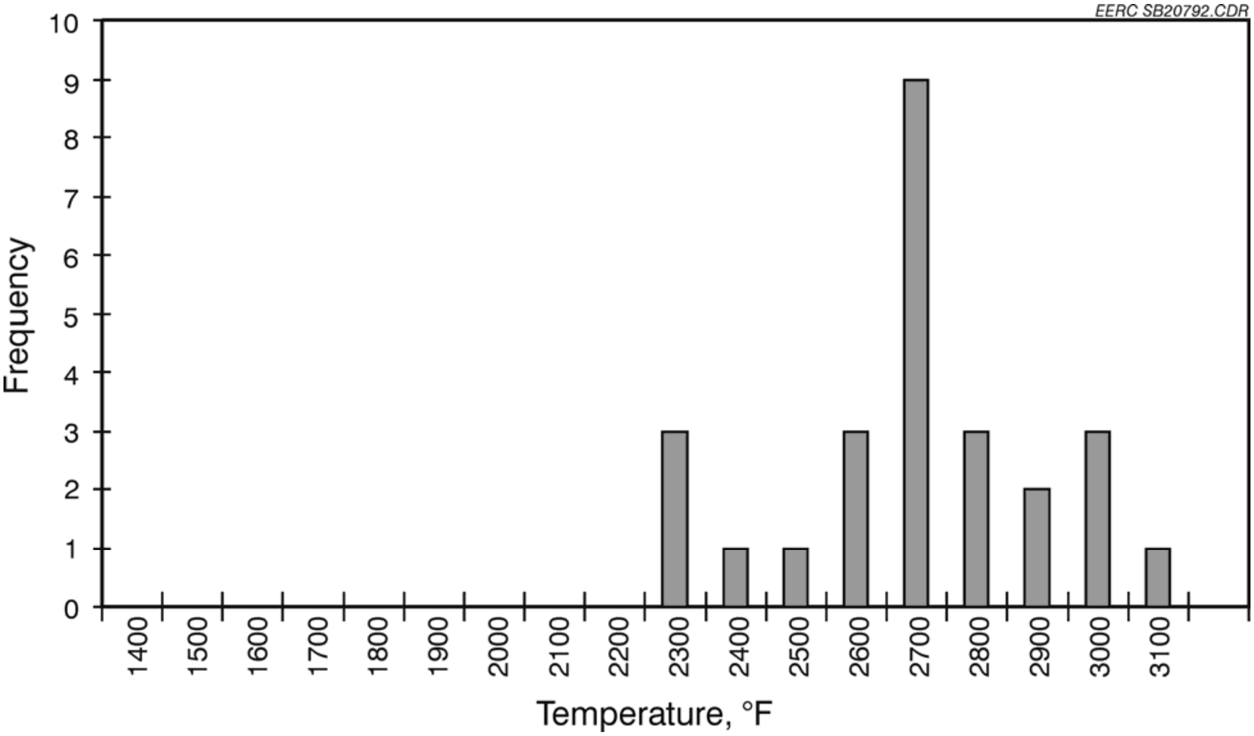


Figure 6. T_{250} distribution for KC seam coal.

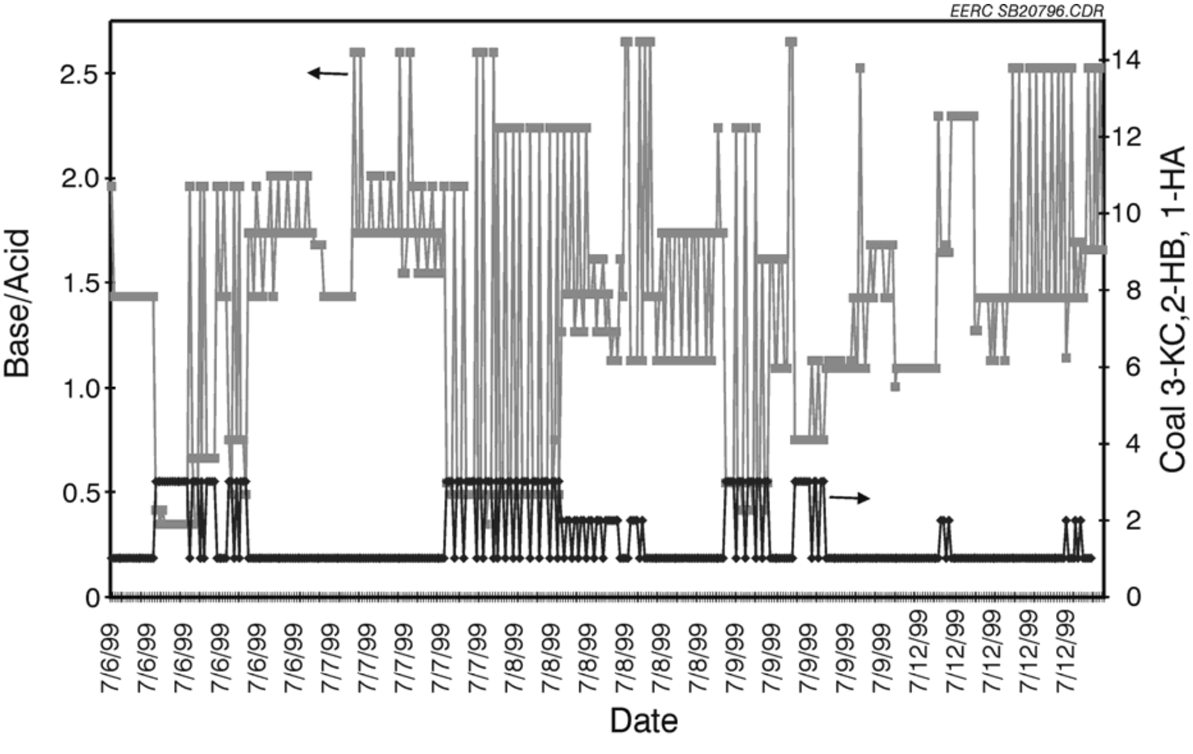


Figure 7. Variations in the delivered coal quality during a test burn period.

Figure 7 shows the sequence of deliveries beginning on July 6 and ending on July 12, 2004. During this period, the majority of the coal delivered was from the HA seam, followed by KC, and HB. Most of the deliveries alternated between KC and HA. Figure 6 shows several instances where significant quantities of KC coal were delivered, on July 6 through July 9. The quantity of KC coal delivered will have the potential to increase the viscosity of the slag and result in poor slag flow from the cyclones.

ASH-RELATED IMPACTS ON SCR CATALYST PERFORMANCE

Ash-related impacts on SCR catalyst performance will depend upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (14–16, 22). The problems currently being experienced on SCR catalysts include the following:

- Formation of sulfate- and phosphate-based blinding materials on the surface of catalysts.
- Carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing on top of the SCR catalysts.

Licata and others (14) conducted tests on a South African and German Ruhr coal and found that the German Ruhr coal significantly increased the pressure drop across the catalyst because of the accumulation of ash. They found that the German coal produced a highly adhesive ash consisting of alkali (K and Na) sulfates. In addition, they reported that the alkali elements are in a water-soluble form and highly mobile and will migrate throughout the catalyst material, reducing active sites. The water-soluble form is typical of organically associated alkali elements in coals. The German Ruhr Valley coal has about 9.5% ash and 0.9 % S on an as-received basis, and the ash consists mainly of Si (38.9%), Al (23.2%), Fe (11.6%), and Ca (9.7%), with lower levels of K (1.85%) and Na (0.85%) (15). Cichanosicz and Muzio (16) summarized the experience in Japan and Germany and indicated that the alkali elements (K and Na) reduced the acidity of the catalyst sites for total alkali content (K+Na+Ca+Mg) of 8%–15% of the ash in European power plants. They also found that alkaline-earth elements such as calcium react with SO_3 on the catalyst, resulting in plugging of pores and a decrease in the ability of NH_3 to bond to catalyst sites. The levels of calcium in the coals that caused blinding ranged from 3%–5% of the ash.

The mechanisms for this type of low-temperature deposition have been examined and modeled in detail at the Energy & Environmental Research Center (EERC) in work termed Project Sodium and Project Calcium in the early 1990s; however, the focus of those projects was specific to primary superheater and economizer regions of boilers and not SCR systems (22, 23). Deposit buildup of this type can effectively blind or mask the catalyst, diminishing its reactivity for converting NO_2 to N_2 and water and potentially creating increased ammonia slip (14). Arsenic and phosphates, which are not uncommon in low-rank coals, may also play a role in catalyst degeneration. Arsenic is a known catalyst poison (14) in applications such as catalytic oxidation for pollution control. Phosphates can occur in low-temperature ash deposits to create blinding effects, and they also occur with arsenic and can cause catalyst poisoning (23).

Lignite and subbituminous coals produce ash that plugs and blinds catalysts (25–28). The problems currently experienced with SCR catalysts include the formation of sulfate- and phosphate-based blinding materials on the surface of catalysts and the carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing them on top of the SCR catalysts (14). The most significant problem that limits the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates, phosphates, and possibly carbonates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16, 27–28). The degree of the ash-related impacts on SCR catalyst performance depends upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (15–16, 24, 27–28).

In studies (7) the impacts of temperature and the presence of catalyst on the ability of ash to sulfate were examined. The tests were conducted using a thermogravimetric analyzer (TGA). TGA testing was conducted using a <5-µm-size fraction of ash produced from Powder River Basin (PRB) coals and lignites and exposing them to vapor-phase sulfur dioxide with and without catalyst at several temperatures. The aim of the testing was to determine the potential of the formation of sulfates to cause particle-to-particle bonding that leads to the formation of deposits in the temperature range where SCR catalysts are used. The TGA testing is focused on determining the reactivity of the <5-µm ash produced from selected PRB and blends to sulfur dioxide and gas-phase phosphorus species as a function of temperature. Testing was conducted to determine the weight gain with flue gas containing ammonia. The impact temperature on the weight gain due to the formation of sulfates for a PRB blend is shown in Figure 8. The rates of sulfation were found to increase with increased temperature. The results show an increase in the weight gains when ammonia and phosphorus were added. Ground catalyst was mixed with PRB and placed in the TGA. Increases in weight gain were observed when catalyst was added as compared to baseline cases for 100% PRB, as shown in Figures 8 and 9, respectively. The presence of catalyst enhances the formation of sulfates.

Full-Scale Slipstream Testing

More recently (8), the behavior of ash and mercury in flue gas produced from the combustion of lignite and subbituminous coals from the United States of America in selective catalytic reduction (SCR) systems for nitrogen oxide removal has been examined. Typically, these coals contain ash-forming components that consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, these coals produce ash that has an abundance of alkali and alkaline-earth-rich oxide particles (<5 µm) that are carried into the backpasses of the combustion system and react with flue gas to form sulfates and possibly carbonates. The forms of mercury in the flue gas produced from the lignite and subbituminous coals are dominated by the elemental form. Slipstream testing was conducted at two subbituminous-fired power plants and one lignite-fired power plant to determine the impacts of ash on SCR plugging, blinding, and mercury oxidation.

The SCR slipstream system consists of two primary components: the control room and the SCR reactor. The reactor section consists of a catalyst section, an ammonia injection system, and sampling ports for NO_x at the inlet and exit of the catalyst section. The control room houses a computer system that logs data and controls the gas flow rates, temperatures, pressure drop across the catalyst, and sootblowing cycles. The computer is programmed to maintain constant temperature of the catalyst, gas flow rates, sootblowing cycles, and ammonia injection. The computer is equipped with a modem that allows for downloading of data and modification of the operation of the reactor from a remote computer located at the EERC.

Flue gas is isokinetically extracted from the convective pass of the boiler upstream of the air heater. The temperature is typically about 790°F. The flue gases pass through a 4-inch pipe equipped with sampling, thermocouple, and pressure ports. Ammonia is injected into the piping upstream of the reactor section. The reactor consists of a steel housing that is approximately 8.5 inches square and 8 feet long. The reactor section has three components, including a flow straightener, a pulse section or sootblower, and a catalyst test section. A metal honeycomb is used as a flow straightener upstream of the catalyst section and is about 6 inches long. A purge section was installed ahead of the catalyst test section to remove accumulated dust and deposits. The catalyst test section is located downstream of the purge section. The entire catalyst section is insulated and equipped with strip heaters for temperature control. The catalyst test section is 3.28 ft (1 m) in length and houses three catalyst sections. Thermocouple and pressure taps are located in the purge sections for measurements before and after each section.

The induced-draft fan is used to extract approximately 400 acfm (200 scfm) of flue gas from the convective pass of the utility boiler to achieve an approach velocity of 5.2 m/s (17.0 ft/s). The gas velocity is similar to that found in full-scale applications. The total gas flow through the reactor represents a thermal load of approximately 300 kW.

The range of operating conditions for the reactor is listed below:

- Gas temperature: ~700°–800°F
- Gas flow rate: 400–500 acfm
- Approach velocity range: 5.0–5.5 m/sec
- Ammonia injection rate: 0.5:1 with NO_x level
- Tempering air for fan: ~ 50–200 scfm
- Catalyst dP: 0.5–1.0 inches water column
- Fan sized for up to 30 inches water column

The catalyst installed at the Baldwin and Coyote Stations was the Haldor Topsoe catalyst. Topsoe's DNX-series of catalysts comprises SCR DENOX catalysts tailored to suit a comprehensive range of process requirements. DNX-series catalysts are based on a corrugated, fiber-reinforced titanium dioxide (TiO_2) carrier impregnated with the active components vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels. The unique catalyst design provides a highly porous structure with a large surface area and an ensuing large number of active sites. The pitch of the catalyst was approximately 6 mm.

The catalyst installed at the Columbia Station was a Babcock Hitachi plate-type catalyst. This catalyst is a TiO_2-based plate catalyst, developed and manufactured by Hitachi. The pitch of the catalyst was approximately 10 mm.

The coals produced ash that had significant accumulations of ash on the catalyst on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation.

The deposits on the surfaces and within the pores of the catalyst consisted of mainly alkali and alkaline-earth element-rich phases that have been sulfated. The results of this testing found that the <5-µm ash rich in alkali and alkaline-earth elements is captured on the surface and within the catalyst pores. These materials react with SO_2/SO_3 in the flue gas, resulting in the formation of a continuous phase that blinds the catalyst. The ability of elemental mercury to be oxidized across the SCR catalyst was investigated at a North Dakota lignite-fired plant. These results showed no oxidation of mercury across the SCR catalyst.

The reactor was installed at the Baldwin Station and operated for a 6-month time period on the Haldor Topsoe catalyst. The information obtained from testing included pressure drop, sootblowing cycles, and reactor temperatures. Figure 10 show the pressure drop across the catalyst test periods from 0 to 2 months. During the first two months of operation, the pressure was about 0.5 inches of water; at the end of two months, the pressure drop was about 0.8 inches of water, indicating plugging had occurred. The air was pulsed a minimum of every 8 hours in an attempt to maintain cleanliness. The reactor was monitored on a daily basis, and adjustments in pulsing cycles were made in order to minimize deposit accumulation. However, for the first two months, the pressure drop steadily increased. There are several periods where the unit was taken off-line; during those times, the temperature of the catalyst was maintained. At 2-month intervals, a section of catalyst was removed and replaced with a new one.

For Months 2 through 4, the pressure drop was highly variable initially but was about 0.8 inches of water. From Months 4 through 6, the pressure drop was maintained between 0.6 and 0.8 inches of water. This is due to the installation of a fresh catalyst section and leaving two thirds of the catalysts in place that were partially plugged. The gas velocity in the single section of new, clean catalyst was high because of channeling, and the result of the high gas flow was less deposition and accumulation. Gas velocity has a significant impact on the potential for deposits to form. However, at high gas velocity, low NO_x conversion is likely.

The reactor was installed at the Columbia Station and operated for a 6-month period of time with the Babcock Hitachi catalyst. The information obtained from the testing included pressure drop information, sootblowing cycles, and reactor temperature. Figure 11 shows the test periods from 0 to 2 months. The pressure drop across the SCR upon installation was about 0.4 inches of water and increased to an average of about 0.5 inches of water, but ranged from less than 0.4 to greater than 0.8 inches of water. The pressure drop for Months 2 to 4 increased from about 0.5 to 0.7 inches of water because of accumulation of ash. After cleaning the reactor and replacing one catalyst section, the pressure drop was about 0.3 but increased to over 0.6 inches of water up to about 4100 hours. There was an outage at the plant, and aggressive pulsing of the reactor was conducted; the pressure drop was brought back down to 0.3 but rapidly increased to over 0.5 inches of water within 500 hours.

The same reactor that was installed at the Baldwin Station was moved and installed at the Coyote Station. In addition, the same Haldor Topsoe catalyst type was used in the reactor. The reactor was operated for a 6-month period of time. Figure 12 shows the test periods from 0 to 2 months. As this paper is being prepared, the reactor is still operating on-site. The pressure drop across the catalyst upon installation was about 0.4 inches of water. After only 750 hours, the pressure drop was 1.5 inches of water, indicating significant plugging and blinding. Very aggressive air pulsing was conducted, with little success in removing the deposits. The pressure drop for the catalyst was over two times greater than the pressure drop observed for the Baldwin Station utilizing the same reactor and same catalyst. At about 1700 hours, the reactor was cleaned, and a section of catalyst was removed for characterization. The pressure drop after cleaning was about 0.8 to 1.0 inches of water. The pressure drop did not increase as rapidly because of the higher velocities through the clean section of the catalyst.

The tops of the catalysts were photographed during inspection and sampling of the catalyst sections. Figure 13 shows the ash materials that accumulated on the catalyst inlet after 2 months of operation. The most significant accumulation was noted for the Coyote Station, followed by Columbia and Baldwin. The Coyote Station had some larger pieces of ash deposit material on the surface as well as plugging of the catalyst passages. The Baldwin Station showed some obvious deposition along the walls of the reactor and some accumulation on the inlet sections. The Columbia Station showed more significant accumulation and plugging than the Baldwin Station.

After 4 months, the tops of the catalysts were photographed during inspection and sampling of the catalyst sections, as shown in Figure 14. The most significant accumulation was noted for the Coyote Station and some accumulation for the Baldwin Station.

SCR Ash Deposit Characterization

The characteristics of the ash materials that collected on the catalyst surfaces and pores were characterized by SEM and x-ray microanalysis and, in selected cases, XRD was used to determine the crystalline phases present. The catalysts were sampled after 2, 4, and 6 months. The sections were sampled, and approximately 2.5-cm squares were mounted for SEM analysis on double-stick tape and in epoxy resin. The double-stick tape samples allowed for characterization of the external morphology of the particles and catalyst surface. The samples mounted in resin were cross-sectioned and polished, which allowed for more detailed and quantitative analysis of the bonding materials and materials that accumulated in the pores of the catalyst. Detailed information on all the samples can be found elsewhere (add FPT reference). Examples of two deposit and catalyst analysis are presented here.

The 6-month sample from the Baldwin Station showed extensive sulfation of the alkaline-earth elements present in the deposits. Figures 15a and 15b show regions of the catalyst where all the pores were blocked and a minimal amount of deposit on the surface of the catalyst. Figure 15c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical compositions of selected points that indicate the presence of high levels of calcium and sulfur are listed in Table 3. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample. In addition, there are some regions of high levels of calcium, aluminum, and sulfur present. The calcium aluminum materials are likely derived from the calcium aluminum phosphate minerals found in the coal fired at this plant.

The 4-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst. Figure 16 shows the 4-month sample from the Coyote Station. The catalyst showed particles adhering to the surface and completely filling and masking the pores in the catalyst. The external morphology of the catalyst surface shows the masking of the catalyst surface. Chemical compositions of selected points are shown in Table 4. The 4-month sample shows more sulfation than the two months of exposure samples. Figures 16b and 16c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of sodium-, calcium-, and sulfur-rich material, likely in the form of calcium sulfate. Significant sodium was found in the deposits, as shown in Table 4. The sample shows significant evidence of sulfation after 4 months of exposure and was much more pronounced than the samples for the Baldwin and Columbia Stations that are fired on PRB coals. The presence of sodium enhances the bonding and sulfation of the particles to form a strongly bonded matrix (22).

SCR Deposit Formation Mechanisms

The mechanism for the formation of deposits that blind SCR catalysts involves the transport of very small particles rich in alkali and alkaline-earth elements, the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. The formation of SO_3 from SO_2 is catalyzed by the SCR; this, in turn, increases the reaction rate of SO_3 to form sulfates. In some cases, the alkali and alkaline-earth elements will also react with CO_2 to form carbonates. XRD analysis identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements including sodium, magnesium, calcium, and potassium, in addition to mineral phases. The primary minerals present in these coals include quartz, clay minerals, carbonates, sulfates, sulfides, and phosphorus-containing minerals (6).

During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component, their association in the coal, and combustion system design and operating conditions. Significant research has been conducted on ash formation mechanisms and relationships to impacts on power plant performance (1–6, 9–13, 19–21, 29). During combustion, the inorganic components associated with western subbituminous and lignite coal typically are distributed into various size fractions of ash. The smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. These ash particles are largely derived from the organically associated cations in the coal. The larger size fraction has higher levels of aluminum and silicon derived from the mineral fraction of the ash-forming component of the coal. Entrained ash was extracted from the Columbia Station at the point of the inlet to the SCR reactor and was aerodynamically classified and analyzed. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst, as shown in Figure 17. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-µm size fraction. The deposited material shows significantly more sulfation than the entrained-ash size fraction, indicating that the sulfation process occurs after the particles are deposited in the catalyst.

The mechanism of SCR catalyst blinding when firing lignite or subbituminous coals is shown in Figure 18 (30). The requirements for the formation of deposits that blind SCR catalyst include firing a coal that produces significant levels of <5-µm-sized particles. The particles are transported into the pores of the catalyst and subsequently react with SO_3 to form sulfates. The sulfate forms a matrix that bonds other ash particles. The SCR catalyzes the formation of SO_3 and thereby increases the rate of sulfation (24, 25). The sulfation of CaO increases the molar volume, resulting in the filling of the pore. For coals that have high sodium contents, formation of low-melting-point phases such as pyrosulfates is possible (31). Pyrosulfate materials can melt at temperatures as low as 535°F in coal-fired power systems.

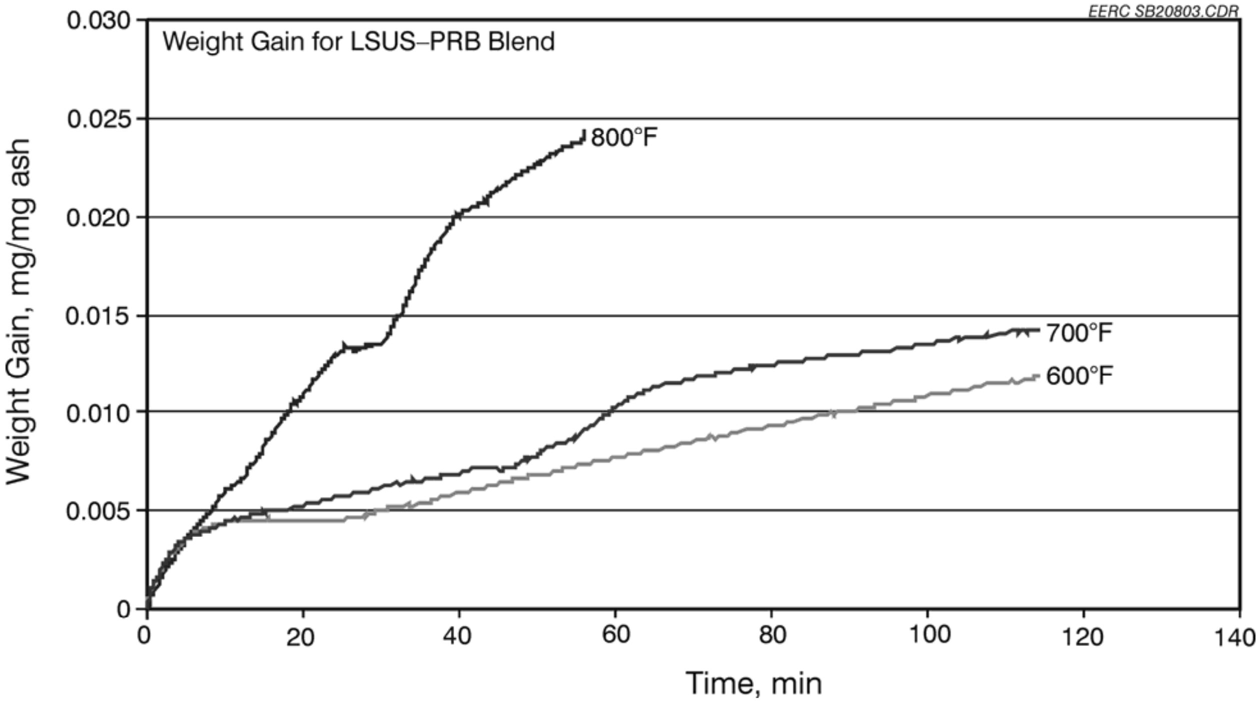


Figure 8. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia at three temperatures.

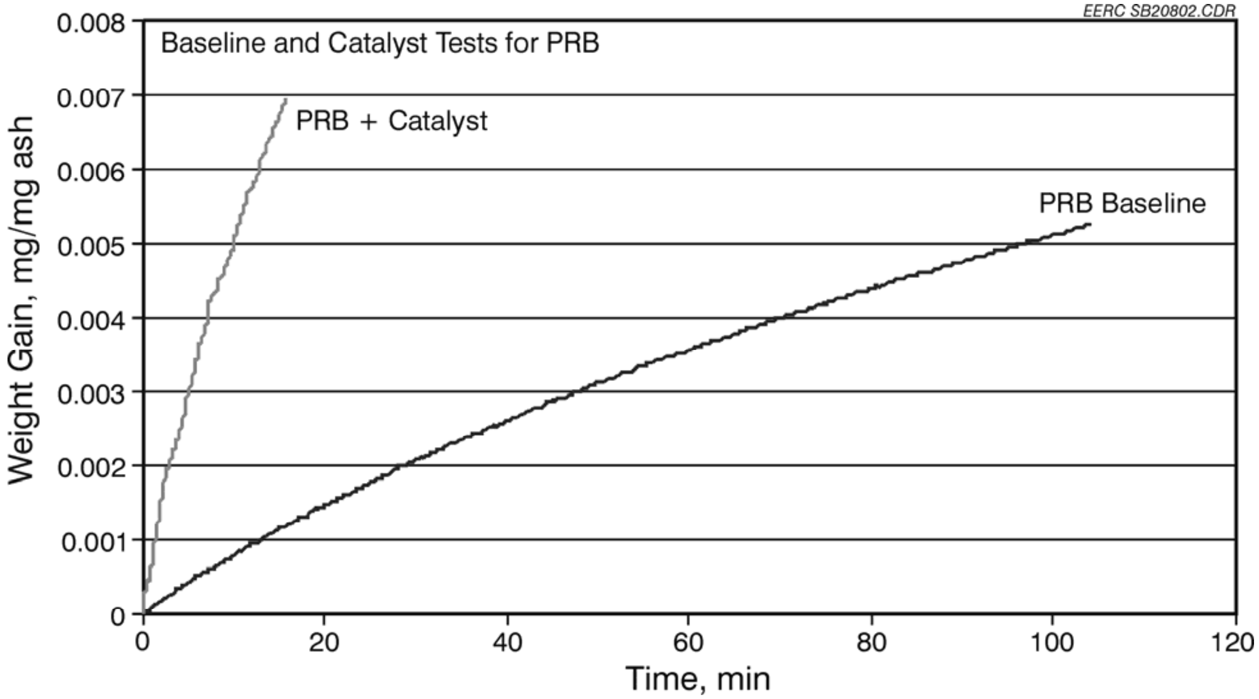


Figure 9. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia with and without SCR catalyst present.

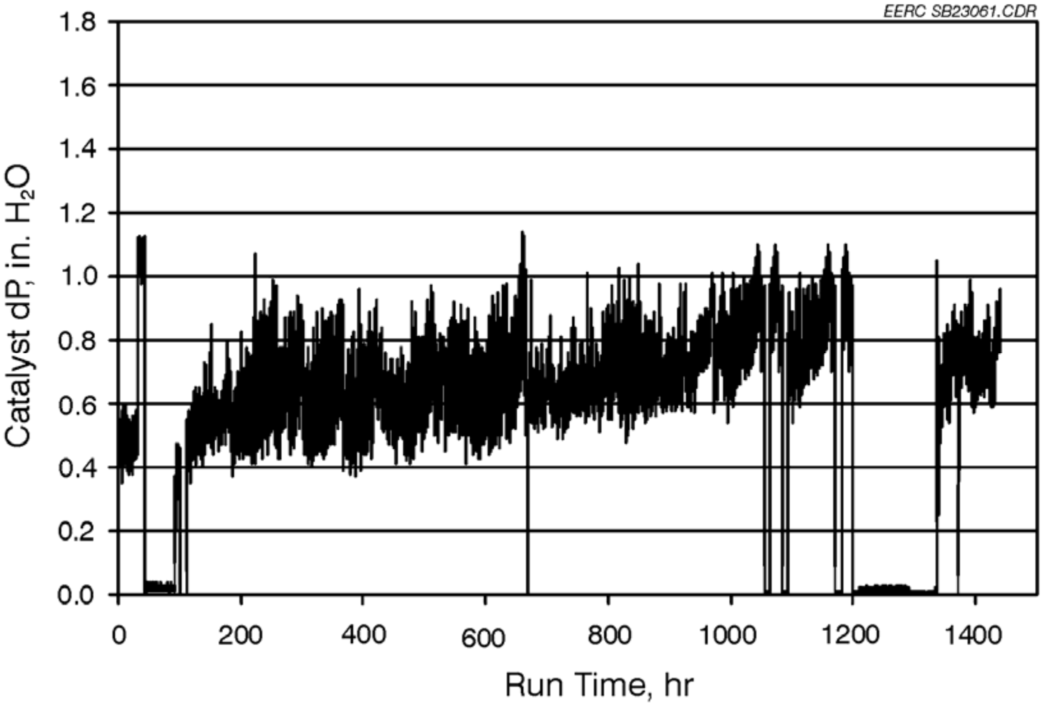


Figure 10. Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.

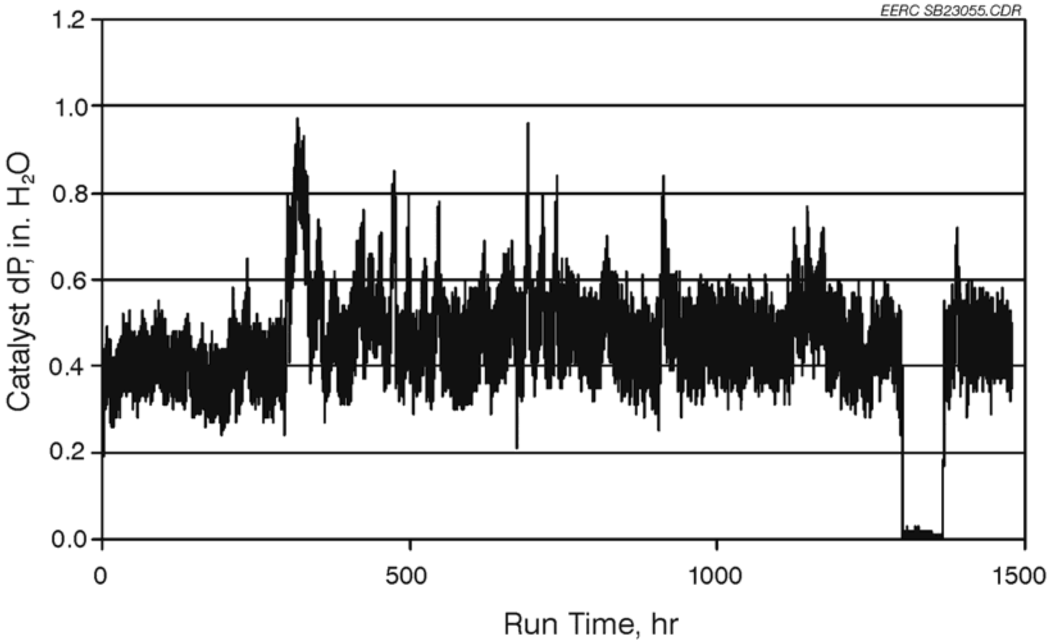


Figure 11. Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.

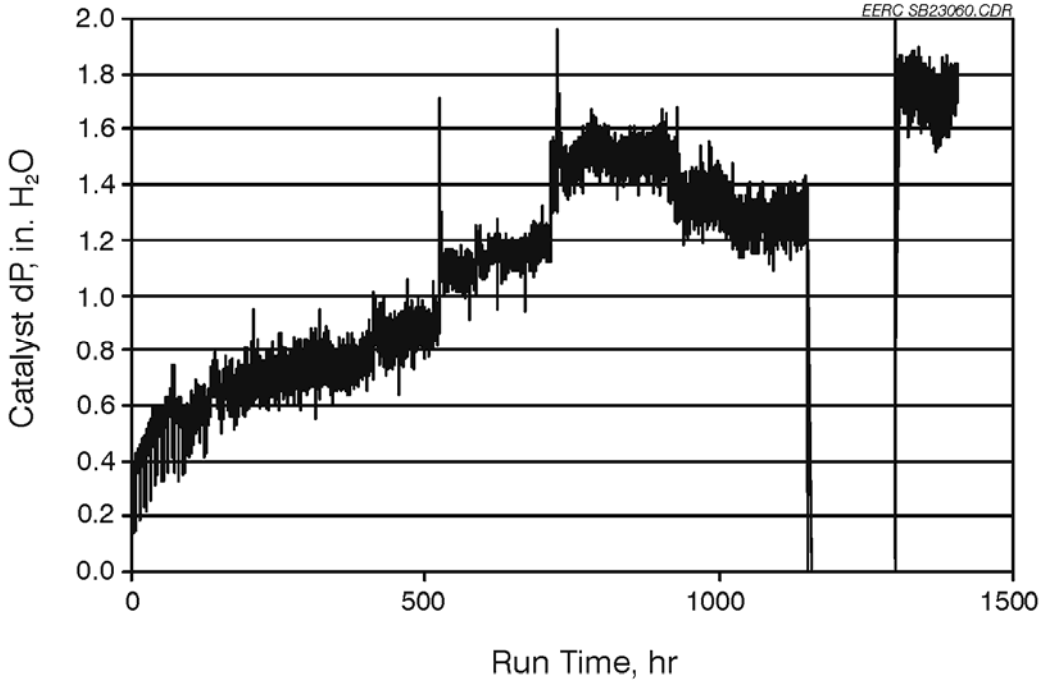
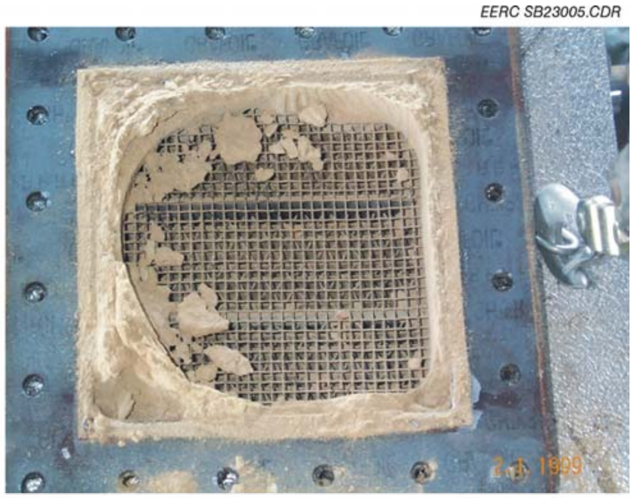


Figure 12. Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.



Baldwin Station after 2 months

Coyote Station after 2 months

Columbia Station after 2 months

Figure 13. Pictures of catalyst inlet after about 2 months of testing at each plant.

EERC SB23004.CDR

Baldwin Station after 4 months

Coyote Station after 4 months

Figure 14. Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.

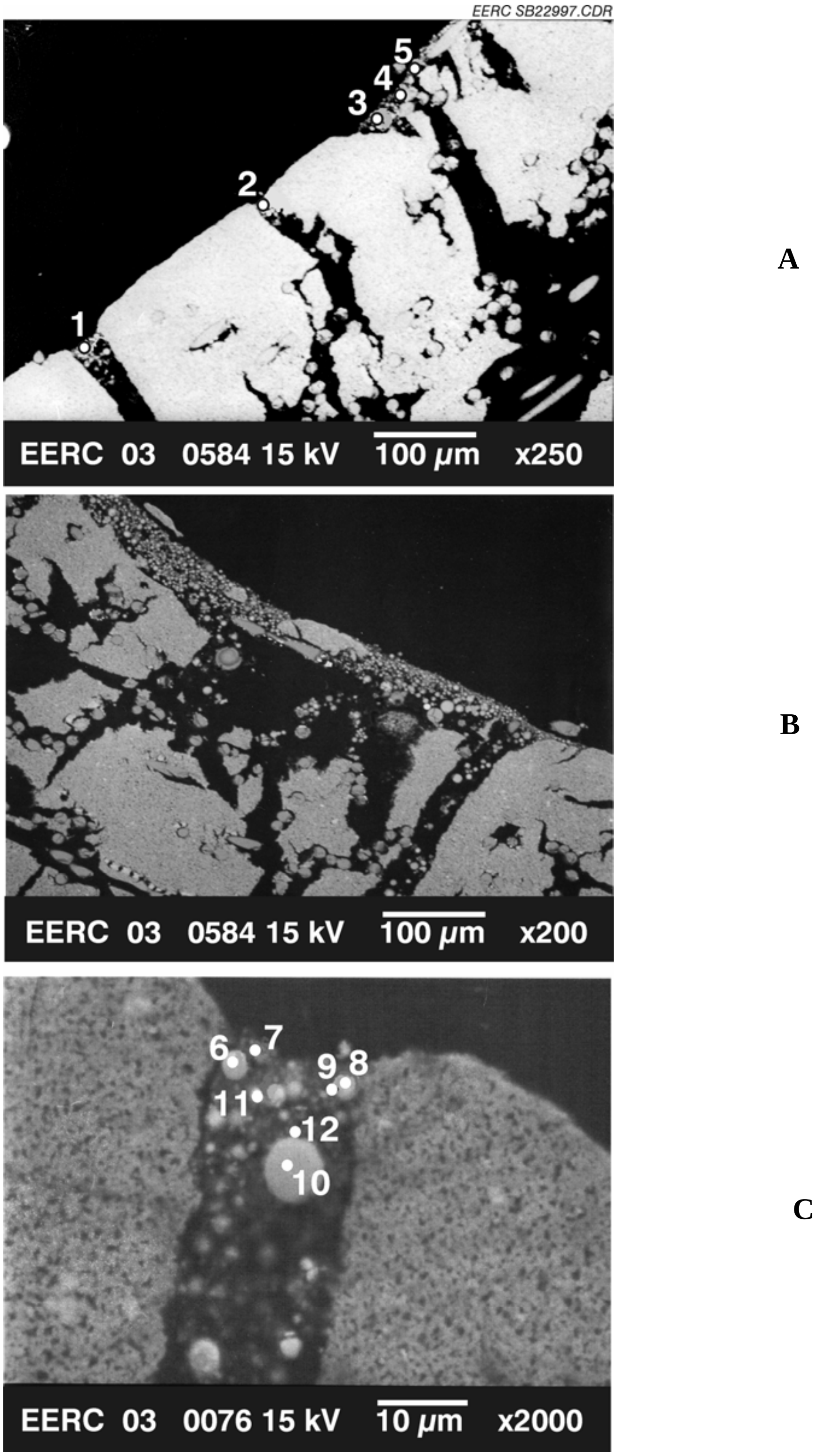


Figure 15. SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure. A) and B) low-magnification images of ash deposit on catalyst surface and C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

Table 3. Chemical Composition of Selected Points and Areas in Figure 15

Chemical composition (normalized wt% equivalent oxide)						
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6
2.1.3						
	0.6	1.0	2.1	0.3	0.5	2.7
Na_2O	4.3	2.5	6.3	0.7	1.6	7.6
MgO	14.8	16.0	15.6	15.5	14.7	0.9
Al_2O_3	3.3	7.8	18.8	57.7	7.7	47.3
SiO_2	2.3	2.1	0.5	0.6	1.8	0.0
P_2O_5	30.7	20.4	17.7	0.0	29.0	0.8
SO_3	0.7	0.0	1.0	0.4	0.9	0.9
K_2O	28.8	28.7	28.1	22.5	34.9	28.4
CaO	2.0	7.2	2.2	0.3	1.3	1.1
TiO_2	11.4	12.9	6.2	0.0	7.6	7.9
Fe_2O_3	1.1	1.4	1.4	2.0	0.0	2.5
BaO						
Total	100	100	100	100	100	100
Oxide	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
2.1.4						
	1.7	0.4	0.5	2.2	1.3	1.7
Na_2O	4.5	6.4	5.9	5.0	3.4	6.4
MgO	5.0	2.4	3.0	19.2	10.8	3.8
Al_2O_3	8.4	18.4	18.5	31.0	17.9	16.7
SiO_2	1.8	0.9	1.0	0.0	1.7	1.2
P_2O_5	37.9	1.7	5.3	0.0	22.5	13.9
SO_3	0.4	0.0	0.0	0.9	0.8	0.0
K_2O	31.4	52.6	49.0	28.9	30.6	45.4
CaO	1.9	6.9	7.4	2.4	2.0	1.1
TiO_2	7.1	5.7	6.0	6.3	6.1	6.5
Fe_2O_3	0.0	4.6	3.5	4.2	2.9	3.3
BaO						
Total	100	100	100	100	100	100

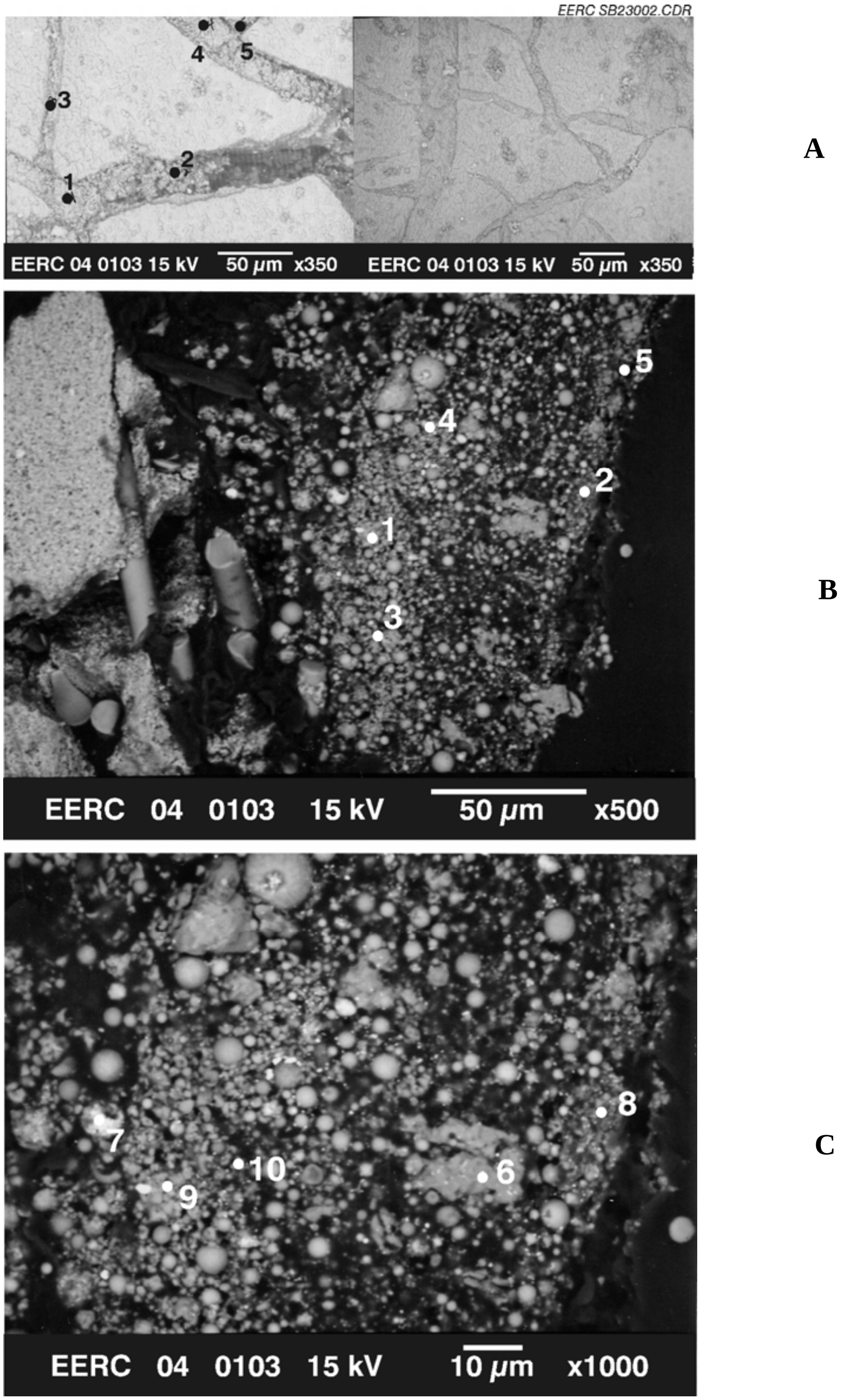


Figure 16. SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure. A) low-magnification image of ash deposit on catalyst surface, B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

2.1.4.1 Table 4. Chemical Composition of Selected Points and Areas in Figure 16

	Chemical composition (normalized wt% equivalent oxide)				
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5
2.1.5					
	6.7	1.9	7.1	6.2	3.1
Na_2O	1.1	1.7	1.1	2.6	3.2
MgO	2.6	8.8	4.0	4.8	10.5
Al_2O_3	7.0	21.1	11.3	5.6	32.2
SiO_2	0.2	2.4	0.0	0.2	0.9
P_2O_5	54.7	38.5	56.4	57.5	30.4
SO_3	2.0	2.8	0.7	2.8	2.4
K_2O	18.0	3.4	15.8	9.3	2.3
CaO	0.6	0.8	1.1	1.3	1.5
TiO_2	5.8	5.1	2.1	6.5	9.8
Fe_2O_3	1.4	13.5	0.5	3.4	3.6
BaO					
Total	100	100	100	100	100

Oxide	Point 6	Point 7	Point 8	Point 9	Point 10
2.1.6					
	9.5	2.6	10.4	8.9	4.4
Na_2O	1.2	1.9	1.3	3.0	3.7
MgO	2.6	8.6	4.2	4.9	10.6
Al_2O_3	6.3	18.2	10.5	5.0	28.9
SiO_2	0.1	1.9	0.0	0.1	0.7
P_2O_5	41.8	28.4	44.9	44.5	23.4
SO_3	3.2	4.3	1.2	4.4	3.8
K_2O	24.5	4.4	22.5	12.8	3.1
CaO	0.6	0.8	1.3	1.5	1.8
TiO_2	7.7	6.6	2.9	8.9	13.2
Fe_2O_3	2.4	22.3	0.9	5.9	6.3
BaO					
Total	100	100	100	100	100

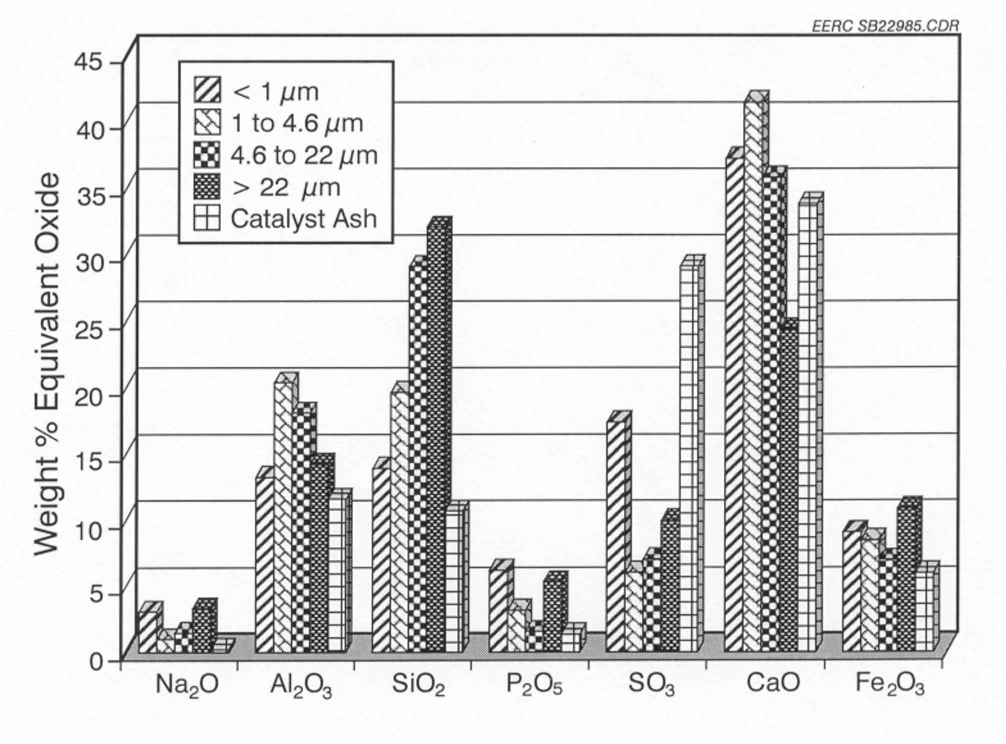


Figure 17. Comparison of entrained ash and deposited ash on catalyst for Columbia Station.

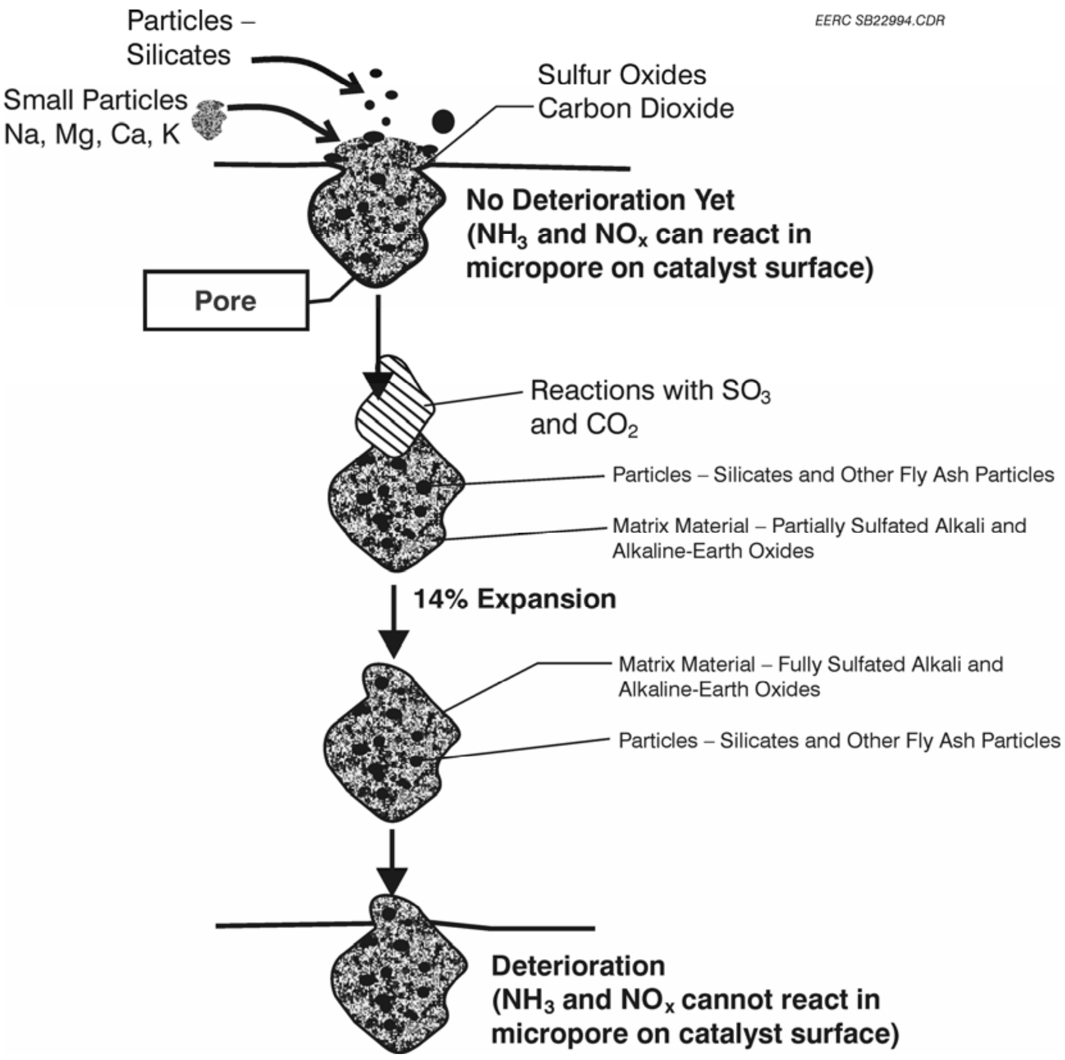


Figure 18. Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard and others [30]).

Low-Temperature Pyrosulfates

The presence of sodium sulfate in the flue gas exiting a scrubber will cause problems to low-dust and tail-end devices such as selective catalytic reduction (SCR) systems for NO_x reduction. There are two problems associated with the fine particulate rich in sodium sulfate on downstream devices. These include accumulation of fine particles on the SCR that, when sootblown, will cause opacity problems, and that the fine particles on the SCR will form pyrosulfates such as $(K_{1.5}Na_{0.5})S_2O_7$ that have melting points as low as 535°F (31) that will blind the catalyst. The presence of these compounds in low-temperature corrosion deposits is well known (32). In addition, the presence of SO_3 enhances the formation of the low-melting-point pyrosulfates (31). The sodium sulfate materials will cause opacity and SCR catalyst blinding problems that limit the feasibility of the low-dust or tail-end SCR technology for use with high-sodium lignite coals.

The sodium sulfate materials will be transported to the catalyst surfaces by diffusion, electrophoresis, and, possibly, inertial impaction. The particles are held in place by weak electrostatic and van der Waals forces. Once accumulation takes place, the sodium sulfate particles will react with flue gas components, resulting in the formation of pyrosulfates. The formation of pyrosulfates involves the following processes (31):

1. Formation of sulfates such as Na_2SO_4 and K_2SO_4
2. Conversion of SO_2 to SO_3 in the bulk gas phase – catalytically active surface such as an SCR catalyst – $SO_2 + \frac{1}{2} O_2 \rightarrow SO_3$
3. Pyrosulfate formation – $Na_2SO_4 + SO_3 \rightarrow Na_2S_2O_7$

The melting points of selected pyrosulfate phases are shown in Table 5.

Table 5. Melting Points of Selected Pyrosulfate Compounds

Compound	Temperature, °C	Temperature, °F
$K_3Fe(SO_4)_3$	618	1144
$K_3Al(SO_4)_3$	654	1209
$KFe(SO_4)_2$	694	1281
$Na_3Fe(SO_4)_3$	624	1155
$Na_3Al(SO_4)_3$	646	1195
$NaFe(SO_4)_2$	690	1274
$Na_2S_2O_7$	401	754
$K_2S_2O_7$	300	572
$(K_{1.5}Na_{0.5})S_2O_7$	279	535

Melting points for pyrosulfates between 535° and 770°F have been reported in the literature. Much of the past work has focused on the formation of these phases on tube surfaces. These species contribute to the corrosion of heat-transfer surfaces in coal-fired power plants. The exact melting point depends on the relative amounts of sodium and/or potassium.

There is significant evidence for the formation of sodium-rich fine particulate in full-scale power plants when firing high-sodium-containing coals. For example, Minnesota Power's Boswell Energy Station found that when it fired high-sodium, lower-ash subbituminous coal, it experienced increases in opacity. Hurley and Katrinak (33) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with an electrostatic precipitator and a wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using an impactor and multicyclone. The sized fractions were analyzed to determine the composition of the submicron-sized fraction.

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of one of the coals. Vapor-phase sodium condenses in the convective pass to form fine sodium sulfate particles or other Na species that later react with ash particles. Pure Na_2SO_4 particles are too small to be removed by scrubbing.

CONCLUSION: SCR IS NOT FEASIBLE FOR NO_X REDUCTION AT MILTON R. YOUNG

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be impossible because of the formation of sodium calcium sulfates in the pores of the catalyst. Following is a list of the key roadblocks associated with lignites which have not been overcome and, in our opinion, make the installation of SCR catalyst at the MRY plant technically infeasible for NO_x control.

- High alkali and alkaline-earth elements present in the coal fired at the MRY plant form sulfates that blind the catalyst.
    - Cyclone-firing partitions the ash during combustion. As a result the level of sodium and calcium in the fly ash is enhanced and will increase the SCR catalyst blinding.
    - Sulfate reactions increase with increasing temperature, and the suggested temperature of installation at the MRY facility is higher than typical installations; therefore, sulfation problems are enhanced.
    - Sulfate formation is also enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.
    - The high levels of sodium in the coals combined with calcium produces low-melting-point eutectic compounds that will melt on the surface.
    - Sulfates form on the surfaces of catalysts firing PRB coals. Lignites will be several orders of magnitude worse because of the higher levels of sodium.

- The ash components to impact SCR performance in Japan and Europe (14–16) include alkali and alkaline-earth elements that result in sulfate formation. The total calcium content and the sum of the calcium, magnesium, potassium, and sodium provide an indication of the problems that occur. For the coals fired at the MRY power plant, the CaO content ranges from 6.8%–19.99%, and the sum of the alkali and alkaline-earth elements range from 9.33%–29.87% of the ash. The levels of calcium in Center lignite are 2 to 4 times higher than the problematic coals in Japan and Europe.

- The finding or work conducted in Germany and Japan were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-rich sulfate formation that fill and plug the catalyst at both lignite (North Dakota)- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or popcorn ash, plugging the top of the SCR catalyst with deposit fragments, is a significant problem because of the extremely high deposition potential of the coal. The formation of deposits in various parts of the boiler requires continuous sootblowing. The deposit fragments are likely going to be carried with the bulk gas flow to the SCR catalyst, resulting in plugging.

- The variability of the lignite is a problem of unique concern at MRY. The deposition potential of the coal is always changing rapidly, resulting in rapid growth and formation of deposits in various sections of the boiler. Aggressive sootblowing of all fireside surfaces is already required to maintain full-load operation. The sootblowing of upstream heat exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, and during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

The ash-related impacts of the lignites from North Dakota are the most complex and severe of any coals in the world, and installation of tail-end SCR systems for NO_x reduction will not be possible. The key problems associated with lignites that have not been overcome and, in our opinion, make the installation of tail-end SCR systems at the MRY plant technically infeasible for NO_x control at MRY's Units 1 and 2 are listed below:

X High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces extreme levels of homogeneously condensed sodium sulfate that pass through the wet scrubber. In addition, the cyclone-firing system captures much of the ash as slag, resulting in a decrease in ash that is available for providing condensation sites for vapor-phase sodium compounds upon gas cooling. This results in an increased homogeneous condensation of sodium sulfate.

X These small particles pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials cannot feasibly be resolved through conventional sootblowing and cleaning technologies to remove the particulate.

X Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

The formation of liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems catalyze the formation of SO_3 from SO_2. The presence of SO_3 significantly enhances the formation of the pyrosulfates at MRY to an extreme level that cannot be dealt with effectively using cleaning technologies that exist today.

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APPENDIX B

Technical Description of SO_2 Controls (B1)

Coal Data for Future PTE Case (B2)

B1 Technical Description of SO_2 Controls

B1.0 Fuel Switching

Fuel switching can be a viable method of fuel sulfur content reduction in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. One such fuel is lignite, which is a low Btu content, high ash, high moisture, medium sulfur content fuel. A typical lignite boiler is physically larger than a similarly rated unit designed for bituminous or sub-bituminous fuel due to the lower heat content of the lignite. The lignite fueled boiler must burn a greater mass of coal each hour to achieve the same heat input due to the lower heat content of the lignite fuel. Therefore, ancillary equipment such as coal crushers/dryers and conveyors, ductwork, etc. are designed larger to handle the greater quantities of coal and flue gas. For this analysis, fuel switching would consist of changing from North Dakota lignite to Powder River Basin (PRB) sub-bituminous.

Firing sub-bituminous fuels such as PRB coal in boilers designed for lignite fuel results in a significantly lower coal feed rate for the same heat input, and lower flue gas quantities. If a lignite fired boiler is switched to PRB coal, gas velocities would slow approximately 20% in the boiler for similar heat inputs. Slowing the flue gas velocity affects heat transfer characteristics and steam generation capabilities. While the slower gas velocities may seem to enable additional heat extraction due to a lengthier gas residence time in the boiler, this is somewhat counterbalanced by the fact that the boiler operator must also maintain a minimum outlet temperature. Lower flue gas velocity, with the same flue gas heat capacity (PRB flue gas approx. 1.5% less than lignite), also translates into higher initial flue gas temperatures in the combustion zone, which might mean greater heat absorption in the waterwall portion of the furnace. However, an actual test burn is required to determine the exact effects.

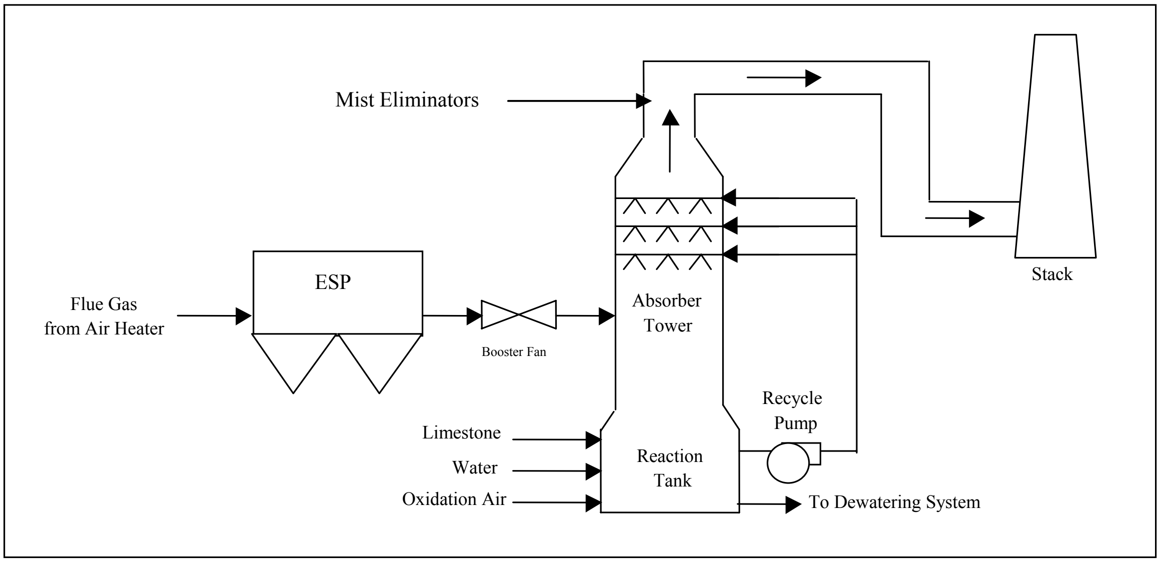
Switching to a fuel such as PRB coal will achieve significant SO_2 emission reductions. However, additional SO_2 control measures, such as post combustion controls might be required to achieve BART. Unfortunately, the removal efficiency of the post combustion technologies would be negatively affected by lower inlet flue gas SO_2 content. While a modern wet FGD system may readily achieve 95% SO_2 control on a medium or high sulfur fuel, when coupled with lower sulfur western fuels, the problem becomes one of diminishing returns. This should be easily understandable as one of the principal process variables affecting the performance of these systems is the inlet SO_2 concentration.

B2.0 Wet Flue Gas Desulfurization

Wet FGD technology utilizing lime or limestone as the reagent and employing forced oxidation to produce gypsum (calcium sulfate dihydrate, $CaSO_4{\cdot}2H_2O$) as the byproduct, is commonly applied to coal-fired boilers. The gypsum byproduct is either landfilled or sold for commercial reuse.

A flow diagram of the wet FGD process is provided in Figure B-1. In the wet FGD process, a slurry of finely ground limestone ($CaCO_3$) in water is recirculated through an absorber tower where it is brought into turbulent contact with the flue gas. The contact between the flue gas and the slurry cools and saturates the gas via evaporation of water from the slurry. SO_2 is simultaneously absorbed into the slurry where it forms sulfurous acid which reacts with the limestone, forming calcium sulfite hemihydrate ($CaSO_3{\bullet}½H_2O$) which can then be disposed of as a waste product or oxidized to calcium sulfate dihydrate or gypsum ($CaSO_4{\bullet}2H_2O$) before disposal or for commercial reuse. No commercial uses for sulfite waste products have been identified.

Figure B-1. Wet FGD Process Flow Diagram



Chemical reactions between the limestone and the absorbed SO_2 take place within the slurry in the absorber, and in the absorber reaction tank, resulting in the formation of particles of $CaSO_3{\cdot}½\,H_2O$. Some of the oxygen in the flue gas may participate in the reaction, resulting in the formation of particles of $CaSO_4{\bullet}2H_2O$ as well. Air may be injected into the absorber sump to promote the formation of gypsum and minimize the formation of calcium sulfite solids where a gypsum product is desired, either for ease of disposal or commercial use. The resultant slurry is then processed in a dewatering system prior to disposal or commercial use.

As the limestone reagent in the recirculating slurry is depleted, it is replenished with fresh slurry prepared by wet grinding of crushed limestone using reclaimed liquid from the dewatering system. Fresh water is also required to replace water lost to evaporation in the flue gas cooling process. Fresh water is often used to wash the mist eliminators, devices located at the scrubber exit to capture slurry droplets entrained in the exiting flue gas stream and return them to the scrubber. The mist eliminator wash removes accumulated materials from the mist eliminator chevrons, thus preventing solids buildup and pluggage. In addition, depending upon the mineral content of the coal, a portion of the reclaimed liquid from the dewatering process may be blown down, or disposed of, to prevent excessive accumulation of mineral salts in the slurry which could result in mineral scaling within the absorber equipment. The blow down rate varies with each plant. Fresh water makeup, both through the mist eliminator wash system and in the limestone grinding process, replaces the blow down and evaporative losses.

Lime scrubbers are very similar to limestone scrubbers. The use of lime rather than limestone can reduce the liquid-to-gas ratio and/or absorber size required to achieve a given SO_2 removal rate. Lime is sometimes used in wet FGD systems where extremely high SO_2 removal rates are desired or where limestone is not readily available. However, since lime is more expensive than limestone, the reagent cost is much higher for a lime system. Therefore, the vast majority of wet FGD systems are designed to use limestone as the neutralizing reagent.

Advantages of the wet FGD systems include lower operating costs, primarily due to the ability to use limestone instead of lime as a reagent, the production of a salable by-product and high removal efficiency. Also, wet FGD systems have a high turndown capability and plant operational flexibility is not hindered to the same degree as the semi-dry, CFB and FDA processes. This last advantage is important where wet FGD systems are applied to load following units. Disadvantages of wet FGD systems include corrosion due to a wet environment with corrosive chemicals including salts of sulfurous and sulfuric acid and hydrochloric acid. Also, because the wet systems are more mechanically complex, they typically require larger maintenance staff than the semi-dry, CFB and FDA alternatives. The greater mechanical complexity also contributes to a greater capital cost for wet FGD systems. Finally, because wet FGD systems completely saturate the flue gas stream, nearly all the SO_3 or H_2SO_4 vapor in the entering flue gas is condensed into aerosol droplets which are too small to be efficiently captured in the scrubber. Fifty percent or more of these droplets pass right through the scrubber. Where units are burning high sulfur fuels, this can cause a plume opacity problem. Wet FGD systems commonly achieve 95% percent SO_2 removal efficiencies in commercial applications.

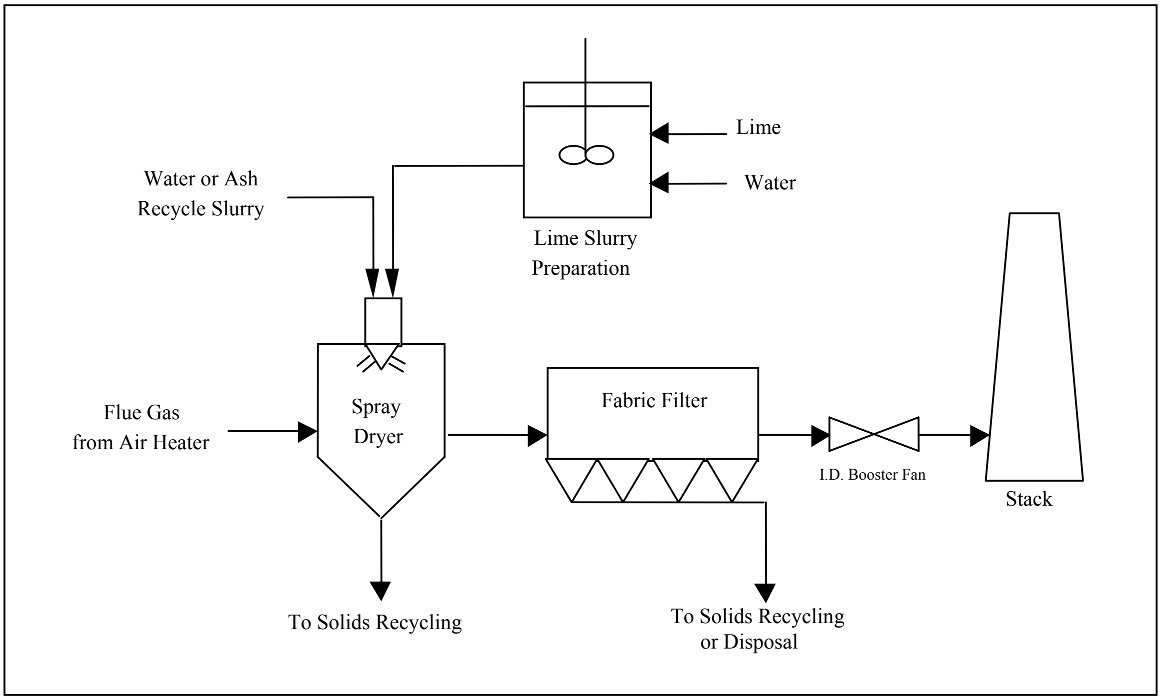
B3.0 Semi-Dry Flue Gas Desulfurization

As an alternative to wet FGD technology, the control of SO_2 emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection. The semi-dry FGD process became popular in the U.S. beginning in the late 1970s as a way to comply with the New Source Performance Standards (NSPS) for electric utility steam generating units for which construction commenced after September 18, 1978 (40 CFR Part 60, Subpart Da). These standards require that all new coal-fired electric utility boilers be equipped with a “continuous system of emission reduction” for SO_2. However, the standards allowed SO_2 removal efficiency as low as 70 percent for facilities burning low-sulfur coal. The semi-dry FGD process could meet this requirement, and was often selected as the SO_2 control technology for many new coal-fired power plants that were built in the 1970s and 1980s and designed to burn low-sulfur western coal. In the late 1980s and through the 1990s, most of the new coal-fired boilers built in the U.S. were for small Independent Power Producer (IPP) projects, and many of these also selected the semi-dry/lime FGD process.

There are several variations of the semi-dry process in use today. This section addresses the spray dryer FGD process. Two other variations, the Flash Dryer Absorber and Circulating Fluidized Bed absorber are addressed in following sections. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling.

A schematic diagram of the spray dryer FGD process is provided in Figure B-2. In the spray dryer FGD process, boiler flue gas is introduced into a Spray Dryer Absorber (SDA) into which hydrated lime (calcium hydroxide, $Ca(OH)_2$) and water are added as dispersed droplets. The $Ca(OH)_2$ reacts with SO_2 that has been absorbed into the water to form primarily calcium sulfite and some calcium sulfate. The heat from the flue gas causes the water to evaporate, cooling the gas and drying the reaction products. Because the total water feed rate is much lower than that of the wet FGD process, the reaction products are dried in the SDA and the flue gas is only partially saturated. The amount of water added to the process is carefully controlled so that the flue gas temperature is maintained well above the saturation, or dewpoint, temperature (typically 30-40 ^{0}F above saturation) to avoid corrosion problems. Cooling the gas to this point significantly increases the SO_2 control efficiency over injection into hot, dry flue gas. The reaction product leaves the SDA as fine dry particles entrained in the flue gas. The flue gas enters the SDA at the top and flows downward, cocurrent with the introduced neutralizing agent. This characteristic is the opposite of the wet FGD system which introduces flue gas into the bottom of the absorber, countercurrent to the falling slurry spray.

Figure B-2 Spray Dryer FGD Process Flow Diagram



In the lime spray drying process, quicklime (CaO) is slaked with water to form lime slurry which is then injected into the SDA along with additional water through a rotary atomizer or dual fluid nozzle or similar apparatus. Recycled PM from the PM control equipment downstream of the SDA is often mixed with the lime slurry before injection into the SDA to provide additional surface area for SO_2 absorption. The flue gas is introduced into the SDA in a manner designed to maximize the contact between the gas and the droplets and to prevent slurry impingement on the walls of the SDA. The turbulent mixing of the flue gas and the slurry droplets promotes rapid absorption of SO_2 into the water of the slurry droplets. The chemical reactions between the absorbed SO_2 and the calcium hydroxide take place within the droplet as the flue gas moves through the SDA. The flue gas is cooled and partially humidified as the water evaporates, leaving a mixture of fly ash and dry powdered reaction product entrained in the flue gas. Some of the solid particles fall to the bottom of the reactor and are collected by a waste handling system. Entrained particles are collected in an electrostatic precipitator (ESP) or fabric filter (FF) downstream of the SDA.

An additional distinguishing characteristic of the SDA is that it must be located upstream of a particulate control device, as opposed to the wet FGD process which is normally the last flue gas treatment process before discharge to the stack. For new plants, this point is not of such great importance. However, when retrofitting FGD equipment to an existing coal-fired plant, which already has particulate control equipment installed, this becomes an important point. If a suitable location exists for the insertion of a new SDA upstream of an existing PM control device, and if the performance of the existing PM control device would not be overly degraded by the additional PM loading, then the retrofit process would consist only of installation of the SDA, reagent preparation and waste handling systems. However, many times one, or both, of these conditions do not exist and the choice to utilize an SDA requires the installation of a new PM control device, such as an ESP or fabric filter. Where this situation exists, the capital cost of the SDA option increases significantly.

Semi-dry processes have some notable advantages compared to wet FGD processes including a dry byproduct which can be handled with conventional ash handling systems. Because the semi-dry system does not have a truly wet zone, corrosion problems in the SDA are eliminated, or significantly reduced, to the point exotic materials of construction are not required. Spray dryer systems utilize less complex equipment resulting in a reduced capital cost and allowing somewhat smaller operations and maintenance staff. Where a fabric filter is utilized as the downstream particulate control device for a semi-dry process, the lime content of the filter cake on the fabric filter reacts with condensed SO_3 in the flue gas stream capturing and neutralizing the acid aerosol. Consequently, semi-dry FGD options, paired with a fabric filter for PM control, have virtually zero emissions of acid aerosols.

The primary disadvantages of the lime spray dryer process make it less likely to be applied to large power plant boilers, especially those firing high-sulfur coal. The lime spray dryer requires the use of lime, which is much more expensive than limestone. While lime contains approximately 1.8 times more calcium than limestone on a mass basis, lime can cost up to five times more than limestone on a mass basis. Therefore, reagent costs for a lime based process are typically higher than a limestone-based process for a given application.

Wastes from semi-dry processes have very limited possibility for reuse due to fly ash contamination. Also, where fly ash might be sold for other uses, contamination with the semi-dry FGD reaction products typically eliminates commercial options for reuse. Where fly ash sales are to be maintained, a second PM control device would be required for the semi-dry FGD system exhaust stream, increasing both capital and O&M costs.

SDAs have much more stringent size limitations than wet FGD scrubbers. Typically units larger than 250 to 300 MW will require at least two SDAs, thus driving up capital costs and system complexity for larger units, while wet FGD systems can handle up to 1000 MW in a single absorber module. SDAs do not have the same turndown capabilities as wet FGD absorbers, further limiting applicability for load following units. Finally, lime spray dryer systems do not have the same level of experience with high SO_2 removal requirements in high sulfur applications that wet FGD systems have.

No variation of semi-dry FGD systems has clearly demonstrated the ability to achieve SO_2 removal levels similar to wet FGD systems in the U.S. Table B-1 lists many of the recent lime spray dryer system installations in the U.S. The information in Table B-1 was obtained from the RACT/BACT/LAER Clearing House. As can be seen in the column titled Efficiency, two units were permitted with an SO_2 removal efficiency of 94.5% and one with 95%. However, these units typically use a lower sulfur fuel and achieve an emissions limit in the range of 0.12 to 0.17 lb SO_2/mmBtu.

Table B-1 – Recent Dry FGD Permits From RBLC

RBLC ID	Facility	Process	Fuel	Size	Unit	Control Device	Emission Limit (lb/mmBtu)	Estimated Efficiency	Permit Date
*NE-0018	Whelan Energy Center	Unit 2 Utility Boiler	PRB coal	2,210	mmBtu/hr	Spray Dryer Absorber (SDA)	0.12	NA	3/30/2004
AR-0074	Plum Point Energy	Boiler , Unit 1 - SN-01	Bituminous Coal	800	MW	Dry Flue Gas Desulfurization	0.16	NA	8/20/2003
MT-0022	Bull Mountain, No. 1, LLC - Roundup Power Project	Boiler, PC No. 1	Coal	390	MW	Dry Flue Gas Desulfurization (FGD)	0.12	94.5	7/21/2003
MT-0022		Boiler, PC No. 2	Coal	390	MW	Dry Flue Gas Desulfurization (FGD)	0.12	94.5	7/21/2003
IA-0067	MidAmerican Energy Company	CBEC 4 Boiler	PRB Coal	7,675	mmBtu/hr	Lime Spray Dryer Flue Gas Desulfurization	0.1	92	6/17/2003
KS-0026	Holcomb Unit #2	Boiler, PC	Subbituminous Coal	660	MW	Dry Flue Gas Desulfurization	0.12	94	10/08/2002
WY-0057	WYGEN 2	500 MW PC Boiler	Subbituminous Coal	500	MW	Semi-Dry Lime Spray Dryer Absorber	0.1	NA	9/25/2002
MO-0050	Kansas City Power & Light Co. - Hawthorn Station	PC Boiler,	Coal	384	T/H	Dry Flue Gas Desulfurization	0.12	NA	8/17/1999
WY-0039	Two Elk Generation Partners, Limited Partnership	PC Fired Boiler	Coal	250	MW	Lime Spray Dry Scrubber	0.17	91	2/27/1998
WY-0047	Encoal Corporation-Encoal North Rochelle Facility	PC Fired Boiler	Subbituminous Coal	3,960	mmBtu/hr	Lime Spray Dryer	0.2	73	10/10/1997
WY-0048	Wygen, Inc. - Wygen Unit One	Boiler, PC	Subbituminous Coal	80	MW	Circulating Dry Scrubber	0.2	92	9/6/1996
PA-0133	Mon Valley Energy Limited Partnership	PC Fired Boiler	Bituminous Coal	966	mmBtu/hr	Spray Dry Absorption	0.25	92	8/8/1995

Table B-1 – Recent Dry FGD Permits From RBLC (cont.)

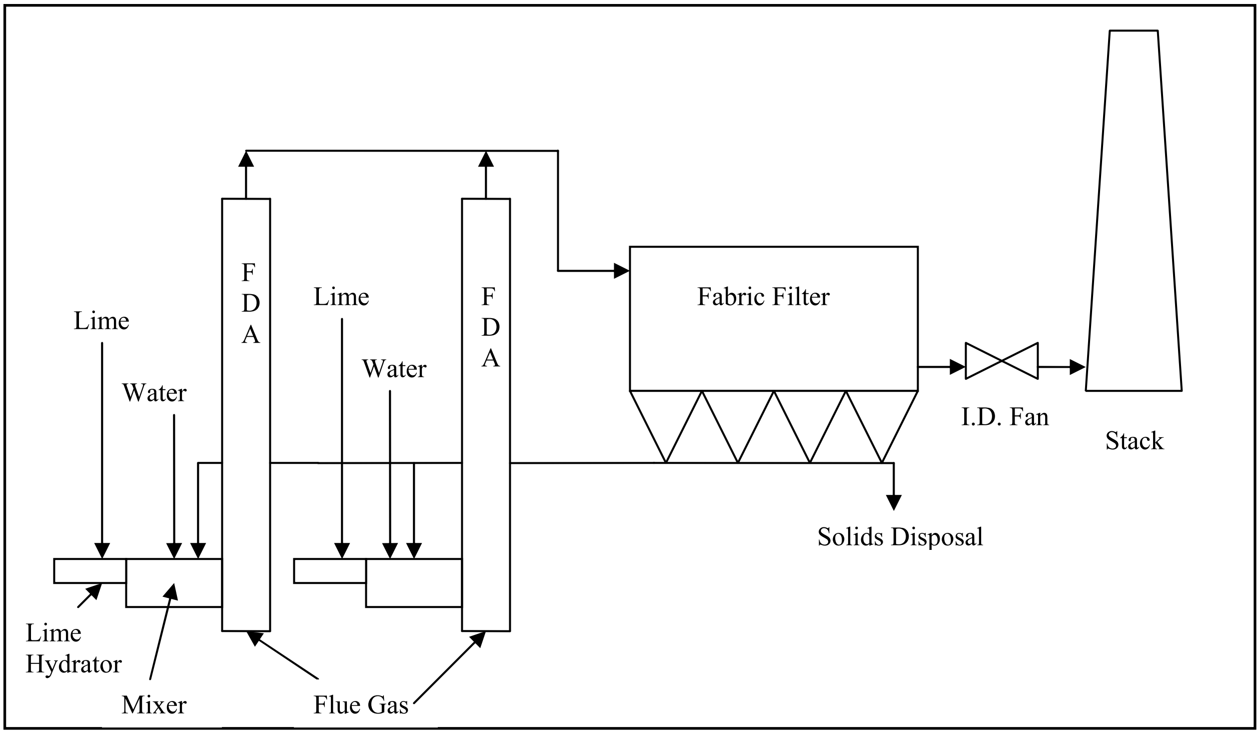
RBLC ID	Facility	Process	Fuel	Size	Unit	Control Device	Emission Limit (lb/mmBtu)	Estimated Efficiency	Permit Date
VA-0213	SEI Birchwood, Inc.	PC Fired Boiler	Coal	2,200	mmBtu/hr	Lime Spray Drying System (FGD System)	220	94	8/23/1993
WY-0046	Black Hills P&L Neil Simpson U	PC Fired Boiler	Coal	80	MW	Circulating Dry Scrubber	0.17	95	4/14/1993
MI-0228	Indelk Energy Services Of Otsego	Boiler (Coal)	Coal	778	mmBtu/hr	Dry Scrubber	0.32	90	3/16/1993
NC-0057	Roanoke Valley Project Ii	Boiler, PC-Fired	Coal	517	mmBtu/hr	Dry Lime Scrubbing	0.187	93	12/7/1992
SC-0027	South Carolina Electric And Gas Company	Boiler, PC-Fired Unit No. 1	Coal	385	MW	Spray Dryer Absorber	0.25	93	7/15/1992
SC-0027		PC-Fired Boiler, Unit No. 2	Coal	385	MW	Spray Dryer Absorber	0.17	93	7/15/1992
SC-0027		PC-Fired Boiler, Unit No. 3	Coal	385	MW	Spray Dryer Absorber	0.17	93	7/15/1992
NJ-0015	Keystone Cogeneration Systems, Inc.	PC-Fired Boiler	Coal, Bituminous	2,116	mmBtu/hr	Spray Dryer Absorber	0.16	93	9/6/1991
NC-0054	Roanoke Valley Project	Boiler, PC-Fired	Coal	1,700	mmBtu/hr	Dry Lime FGD	0.213	92	1/24/1991
NJ-0014	Chambers Cogeneration Limited Partnership	2 PC-Fired Boilers	Coal	1,389	mmBtu/hr (each)	Spray Dryer Absorber	0.22	93	12/26/1990
VA-0176	Hadson Power 13	Boiler	Coal	30,228	lb/hr coal	Lime Spray Dryer	0.162	92	8/17/1990
VA-0171	Mecklenburg Cogeneration Limited Partnership	PC Fired, Boiler, 4 Units	Bituminous Coal	834.5	mmBtu/hr	Spray Dryer, Fabric Filter	0.172	92	5/9/1990

B4.0 Flash Dryer Absorber Flue Gas Desulfurization

The Flash Dryer Absorber (FDA) is a further development of the lime spray dryer process. The approach is similar in that the flue gas is only partially saturated during the process and thus corrosion problems are either reduced or eliminated. Like the SDA, waste solids from the particulate control process are added to the reagent feed stream to the reactor. Similar to the SDA, the FDA mixes lime, water and recycled PM for enhanced surface area. Recycled PM, along with absorption products and unreacted lime, are collected downstream of the FDA and a sizable fraction recycled to the FDA. Unlike the SDA, the FDA recycles a very high fraction of the captured PM. Because of this, the ratio of solids to liquid in the reagent stream injected into the FDA reactor is much higher than the SDA. The ratio is so much higher that the wetted recycled solids are still a relatively dry free flowing stream after wetting in the mixing stage[2]. Because the reagent stream starts off much higher in solids, the liquid film thickness on the wetted solids is much thinner and the drying time for the injected solids is much shorter than a typical SDA. This allows the FDA to function with a significantly smaller reactor compared to the typical SDA absorber vessel. Like the SDA, the water injection rate of the FDA is controlled to lower the flue gas temperature to optimize the SO_2 control efficiency while avoiding saturation and the accompanying corrosion problems. Unlike the SDA, the flue gas is flows vertically upward in the FDA. Figure B-3 is a schematic presentation of the FDA design.

The FDA utilizes quicklime (CaO) instead of hydrated lime as a reagent. The reasoning given for this by the designers is that when purchasing lime, although the price per ton is similar, the quicklime has 32% more calcium (SO_2 neutralization component) per ton than hydrated lime. Also, because quicklime is denser (900-1,200 kg/m^3 for quicklime vs. 450-640 kg/m^3 for hydrated lime), both transport and onsite storage capacity requirements can be smaller. However, direct injection of quicklime has resulted in less efficient reagent utilization compared to hydrated lime use. This is theorized to be due to hot spots created in the reaction zone by the hydration of the quicklime. The heat of hydration of quicklime is approximately 1.1 mmBtu/ton, so there is considerable heat evolved during the hydration step. To avoid adding this heat to the flue gas or creating hot spots that could reduce lime utilization, the FDA design incorporates a separate lime hydration stage where more than the stoichiometrically required amount of water is added to the quicklime in stages. The super stoichiometric water is heated during the slaking process and evaporates, leaving dry hydrated lime. The hydrated lime, recycled solids and water are then combined in a mixing vessel just prior to injection into the reactor.

Figure B-3 Flash Dryer Absorber FGD Process Flow Diagram



Like the SDA, the FDA must be followed by a PM control device to capture the dry solids in the FDA exhaust. The great majority of these solids are recycled back to the FDA. The non recycled fraction is a mixture of calcium sulfite/sulfate solids and fly ash for which limited possibilities for reuse exist. Also, in those instances where fly ash sales produce an income for the power plant, addition of the FDA solids to the fly ash will likely render the waste solids stream valueless. Where the plant receives revenue from fly ash sales, the lost revenue would be an additional cost of FDA implementation because the fly ash is used as a surface area enhancer in FDA operation.

The FDA is a relatively recent modification of the semi-dry FGD concept and as such, has not established a significant field record at this time. In their paper on FDA technology in 2002[3], Alstom cited a 280 MW plant in China with an 85% SO_2 removal efficiency. This plant had an FDA installed upstream of an ESP. Dry and semi-dry scrubbers installed upstream of a fabric filter have been consistently shown to achieve approximately 5-10% greater acid gas removal efficiency due to absorption and neutralization taking place in the filter cake of the fabric filter. Typically ESPs downstream of an FDA or other dry or semi-dry SO_2 scrubbing system are attributed no more than 5% SO_2 removal efficiency.

Advantages of the FDA over wet FGD systems are similar to those described for the semi-dry process described previously, including ease of byproduct handling, much less aggressive corrosion conditions allowing the use of more common, less expensive materials of construction, less complex equipment, and potentially enhanced SO_3 control when combined with a fabric filter. FDA advantages also include a significantly smaller reactor/absorber which translates into a lower area requirement than either wet or semi-dry FGD systems, though manufacturers often provide multiple FDA's, even on smaller units.

Disadvantages of the FDA, when compared to the wet FGD system are similar to those described for the semi-dry process, including reactor size limitations, lower turndown ratio, more expensive reagent, and lack of byproduct market value.

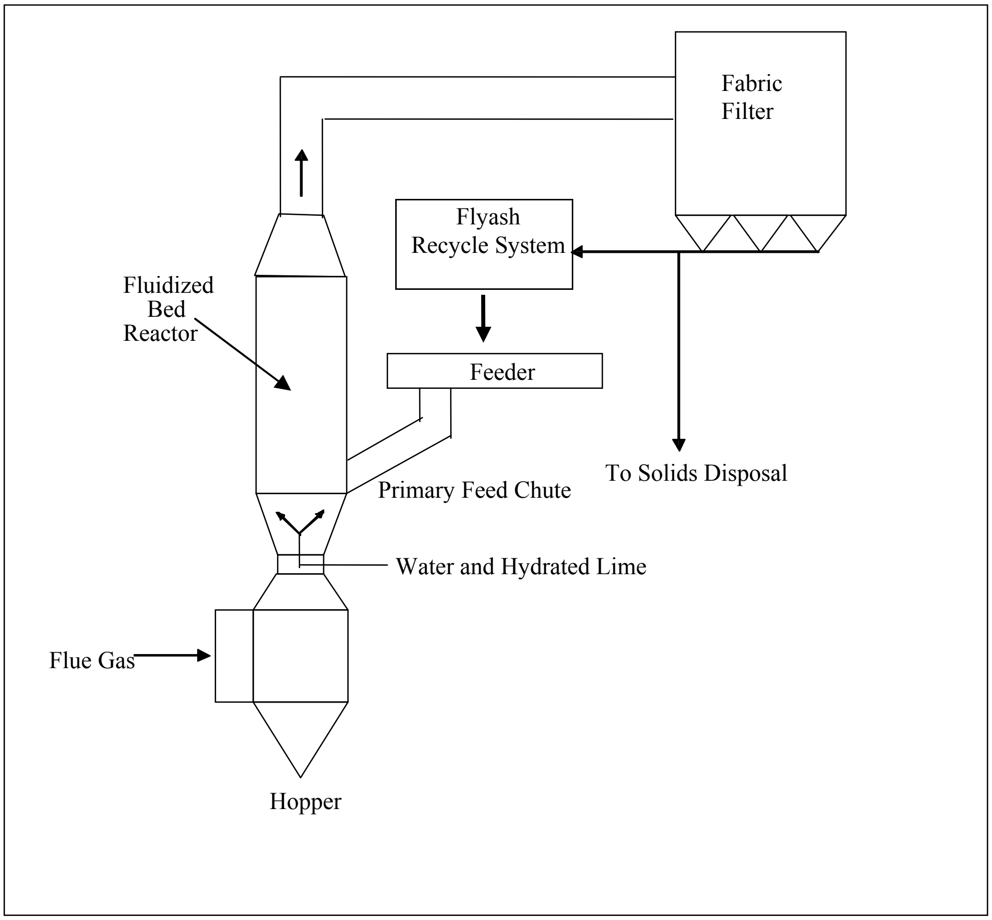
B5.0 Circulating Fluidized Bed Absorber Flue Gas Desulfurization

In the fluidized bed dry scrubbing process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle, and mixed with water, hydrated lime, recycled flyash and FGD reaction products. High velocity movement of the gas through the reactor suspends the solids creating a fluidized bed. A CFB absorber vessel would be a smaller diameter than the SDA discussed previously in this report. A schematic representation of the CFB process is shown in Figure B-4. The smaller diameter absorber helps maintain higher flue gas velocities required to maintain the fluidized bed. Water injected into the venturi throat cools the flue gas and wets the recycled solids similar to the process described previously for the FDA. Dry, powdered, hydrated lime is injected into the bed near the bottom of the absorber vessel, above the venturi and dissolves in the thin water film on the recycled solids. SO_2 from the flue gas is also absorbed into the evaporating water film and reacts with the lime to produce both calcium sulfite and sulfate reaction products. Flue gas temperatures are typically reduced from 300 ^{0}F to approximately 160 ^{0}F to optimize SO_2 removal efficiency. The evaporation of the water cools and partially humidifies the flue gas and maintains the bed in a slightly moist, powdery condition. The continuous motion of the bed helps prevent solids deposition inside the absorber and promotes regeneration of the particle surfaces, exposing additional lime to react with absorbed SO_2. Particles that are entrained in the flue gas leaving the top of the reactor are collected in an ESP or fabric filter downstream of the CFB absorber. A large portion of the collected particles is recycled to the reactor, sustaining the bed and improving lime utilization. CFB absorbers have been installed with both fabric filters and ESPs for particulate control.

The CFB absorber dry scrubbing process utilizes a bed of fluidized particles to provide an extended surface area for wetting, evaporation and SO_2 absorption. The extended surface decreases the time required for SO_2 absorption. Even though the gas velocity is higher than a wet FGD absorber or an SDA, the CFB absorber is not taller than either of these vessels.

The CFB has many of the same advantages of the SDA and FDA such as a dry byproduct, simplified waste handling systems and conventional materials of construction.
CFBs also have less rotating equipment than wet FGD or SDA systems, thus simplifying maintenance requirements somewhat. Like the SDA and FDA, the CFB application with a fabric filter for particulate collection will also achieve very good acid aerosol control. Unlike the SDA the CFB does not require dual fluid nozzles or atomizers in the absorber. This feature simplifies the absorber maintenance of a CFB over that of the SDA. Also, because lime and water are injected separately into the CFB, increased reagent requirements can be met without increasing saturation of the flue gas.

Figure B-4 – Circulating Fluidized Bed FGD System



Disadvantages of the CFB process include higher reagent cost and lower utilization than SDAs in similar applications and more limited turndown capability. In a recent study[2] the National Lime Association determined that compared to CFB's in similar applications, the SDA achieved slightly lower SO_2 removal with slightly better reagent utilization. Because CFBs must maintain gas velocities within a fluidizing range, a recycle duct from the absorber exhaust to the inlet is sometimes included to allow for partial recycle of flue gas to maintain bed velocity and improve the turndown ratio. Similar to the SDA and FDA processes, CFBs are size limited and multiple absorbers are required for applications larger than 250-300 MW.

An additional disadvantage the CFB has over the SDA is pressure drop. Because the CFB must maintain the fluidized bed condition, the pressure drop over the absorber is typically 8-10 in. w.g. compared to an SDA at 6-8 in. w.g. and a wet FGD system at approximately 6.0 in. w.g.

B6.0 Powerspan Electro Catalytic Oxidation (ECO™) Technology

The Powerspan Electro-Catalytic Oxidation (ECO™) system is a multipollutant control technology designed to control emissions of NO_X, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO™ process has two main process vessels, a barrier discharge reactor and a multi-level wet scrubber. The barrier discharge reactor utilizes an electrical discharge to create oxygen and hydroxide radicals which then react with NO_X, SO_2, and mercury to produce sulfur trioxide (SO_3), sulfuric acid (H_2SO_4), nitric acid (HNO_3) and oxidized metallic species (e.g., mercury). The flue gas stream then enters the bottom of the ECO™ scrubber where the lower loop cools the flue gas and removes a portion of the SO_2, acid gasses produced in the barrier reactor (H_2SO_4 & HNO_3) and oxidized metals such as mercury, with a low pH aqueous ammonia reagent. A second scrubbing loop is then entered where additional SO_2, NO_2, acid gases and oxidized metals are removed with an aqueous ammonia reagent, though at a higher pH. Above the second scrubber loop is an absorber section for absorbing fugitive ammonia from the first and second scrubbing loops. The final step in the ECO™ process is a wet electrostatic precipitator (WESP) which collects fine particulate matter, aerosols generated in the scrubber and additional mercury.

As a reagent the system utilizes aqueous ammonia in two scrubber loops, with varying pH to control collection efficiency in the lower and upper loops. The ammonia reacts with the collected SO_2 in aqueous solution to produce ammonium sulfate as a byproduct. The ammonium sulfate is then salable as fertilizer, thus turning byproduct disposal into a profitable venture for system operators. Captured mercury and other oxidized metals are removed from the scrubber bleed stream with activated carbon and disposed of as a hazardous waste. Ash and insoluble metals are filtered from the scrubber bleed stream before fertilizer production and disposed of with other particulate wastes from upstream particulate control equipment. The ammonium sulfate can be either, sold as an aqueous product, or crystallized, granulated and sold.

In addition to high removal efficiencies for SO_2, NO_X, and mercury, the ECO™ process claims to achieve high levels of fine particulate control in the WESP. Powerspan claims a routine SO_2 removal efficiency of >98% with inlet concentrations up to approximately 2,000 ppm. SO_2 levels at LOS Unit 2 are commonly about 1,399 parts per million. NO_X removal is stated to be up to 90% with a 0.05 lb NO_X/mmBtu outlet condition achievable. Mercury removal of 75-85% is also reported by Powerspan for the ECO™ process.

Powerspan performed an extended pilot plant demonstration at R.E. Burger Station Units 4&5. The pilot demonstration project treated a slipstream of approximately 110,000 scfm and demonstrated performance, reliability and economics. The demonstration program started in January, 2004. Powerspan recently indicated that they are scaling the reactor and scrubber for optimum cost and space arrangement and incorporating lessons learned from the pilot plant operation. It is important for the purposes of this BART study to note that coproduct crystallization and granulization equipment was not included in the pilot plant operation. The coproduct stream that would normally feed into the crystallization and granulation processes was collected and transported offsite for this process step during pilot plant operation. Because crystallization and granulation of ammonium sulfate from an ammonia scrubber solution is not a new technological process, this was not considered a deficiency in the pilot plant program. For instance, the Dakota Gasification Company (DGC) in Beulah, ND currently operates an SO_2 scrubber utilizing ammonia as a reagent. Following the generation of ammonium sulfate, DGC crystallizes and granulates a fertilizer product on site. No full size commercial scale ECO™ systems have been installed or operated at the time of this report.

1. http://www.coaleducation.org/Ky_Coal_Facts/coal_resources/coal_properties.htm

2. "Economics of Lime and Limestone for Control of Sulfur Dioxide"; DePriest, William & Gaikwas, Rajendra P. ; National Lime Association (www.lime.org/NLADryFGD.PDF); September, 2002.

3. "Alstom Power's Flash Dryer Absorber For Flue Gas Desulfurization", Ahman, Barranger and Marin, Proceedings of IJPGC '02, June 24-26, 2002.

B2 – Coal Data for Future PTE Case

COTEAU
THE COTEAU PROPERTIES COMPANY

A SUBSIDIARY OF THE NORTH AMERICAN COAL CORPORATION

FREEDOM MINE
204 County Road 15
Beulah, ND 58523-9475
(701) 873-2281 • Fax (701) 873-7226

January 13, 2006

Mr. Robert J. Bartosh
Senior Vice President and Chief Operating Officer
Dakota Coal Company
P.O. Box 5540
Bismarck, ND 58506-5540

Dear Mr. Bartosh:

Enclosed is the Freedom Mine's long-range coal quality projection for the Leland Olds Station, as requested by Dakota Coal Company.

If you have any questions, please contact me.

Sincerely,

THE COTEAU PROPERTIES COMPANY

Mark V Haugen

Mark V. Haugen
Engineering Manager

MVH:lr
Enc.

cc: w/enc.
Karl Lemmerman
Dean Bray

THE COTEAU PROPERTIES COMPANY

PROJECTED COAL QUALITY--AS RECEIVED BASIS

LELAND OLDS STATION
UNITs I & II

	AS DELIVERED COAL QUALITY	
Year	**Sulfur**	**Btu**
2012	0.83	6,778
2013	0.79	6,787
2014	0.99	6,764
2015	1.02	6,751
2016	0.99	6,735
2017	1.12	6,774
2018	1.09	6,733
2019	1.13	6,766
2020	1.12	6,780
2021	1.00	6,799
2022	0.99	6,830
2023	1.06	6,829
2024	1.06	6,735
2025	0.96	6,673
2026	0.94	6,548
2027	0.74	6,777
2028	0.83	6,678
2029	0.78	6,666
2030	0.75	6,630
2031	0.78	6,753
2032	0.87	6,689
2033	0.74	6,610
2034	0.70	6,747
2035	0.70	6,754
2036	0.70	6,760
2037	0.70	6,762
2038	0.71	6,756
2039	0.71	6,751
2040	0.73	6,752
TOT / AVE	0.88	6,736
MINIMUM	0.70	6,548
MAXIMUM	1.13	6,830

1/12/06

APPENDIX C

Technical Description of Particulate Matter Controls (C1)

Appendix C1 – Technical Description of Particulate Matter Controls

C1.0FUEL SWITCHING

Fuel switching along with flue gas conditioning is a viable method of reducing particulate matter emissions in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. One such fuel is lignite, which is a low Btu content, high ash, high moisture, and medium sulfur content fuel. A typical lignite boiler is physically larger than a similarly rated unit designed for bituminous or sub-bituminous fuel due to the lower heat content of the lignite. The lignite fueled boiler must burn a greater quantity of coal per hour to achieve the same heat input due to the lower heat content of the lignite fuel. Therefore, ancillary equipment such as pulverizers, coal conveyors, ductwork, etc. are designed larger to handle the greater quantities of coal and flue gas.

Firing sub-bituminous fuels such as PRB in boilers designed for lignite fuel result in a significantly lower coal feed rate for the same heat input, and lower flue gas quantities. If a lignite fired boiler is switched to PRB coal, gas velocities would slow approximately 20% in the boiler for similar heat inputs. Lower flue gas velocity, with the same flue gas heat capacity (PRB flue gas is approximately 1.5% less than lignite), also translates into higher initial flue gas temperatures in the combustion zone, which might mean greater heat absorption in the waterwall portion of the furnace. However, an actual test burn is required to determine the exact effects.

Fly ash conditioning methods installed upstream of an ESP usually involve the injection of a chemical into the flue gas stream to control the electrical resistivity of the fly ash. Conditioning systems can also be used to cause coagulation of the dust particles, agglomeration, and improve the cohesiveness of the fly ash in order to improve the collection efficiency of an ESP. Two of the main factors that determine the resistivity are the sulfur content of the coal and the elemental composition of the ash. Low amounts of sulfur in the coal will limit the concentration of sulfur dioxide in the flue gas and thus the extent of its oxidation to sulfur trioxide. The low sulfur PRB coal limits the amount of available sulfur trioxide and water vapor that can be absorbed on a non-conductive fly ash particle, which would lower the resistivity of the fly ash. The low sulfur content and the high alkaline ash both contribute to high resistivity. The low sulfur content limits the amount of sulfur trioxide that is formed while the calcium oxide will preferentially react with the acid and form a non-conducting ash.

The most common types of flue gas conditioning systems for this application include humidification of the flue gas, sulfur trioxide injection, ammonia injection, or a combination of these conditioning methods. Humidification of the flue gas was one of the first methods used to lower the resistivity of the fly ash. However, many of these systems have been replaced with sulfur trioxide and/or ammonia conditioning systems. It is common for facilities with flue gas conditioning systems to utilize sulfur trioxide and/or ammonia injection. Ammonia injection is typically used in retrofits where an existing ESP is undersized and sulfur trioxide alone is not able to effectively reduce the resistivity. However, if sulfur trioxide can effectively reduce the resistivity, then ammonia injection and thus ammonia storage on-site is avoided. Switching to a fuel such as PRB and adding a flue gas conditioning system to achieve lower PM emission rates will achieve significant PM emission reductions assuming that the control efficiency of the existing ESP can be restored.

C2.0FABRIC FILTER (FF)

A fabric filter or baghouse removes particulate by passing flue gas through filter bags. A pulse-jet fabric filter (PJFF) unit consists of isolatable compartments with common inlet and outlet manifolds containing rows of fabric filter bags. The filter bags are made from a synthetic felted material that are suspended from a tube sheet mounted at the top of each fabric filter compartment. The tube sheet separates the particulate laden flue gas from the clean flue gas. This tube sheet is a flat sheet of carbon steel with holes designed to accommodate filter bags through which the bags are hung. The flue gas passes through the PJFF by flowing from the outside of the bag to the inside, up the center of the bag through the hole in the tube sheet and out the PJFF. Fly ash particles are collected on the outside of the bags, and the cleaned gas stream passes through the fabric filter and on to the chimney. A long narrow wire cage is located within the bag to prevent collapse of the bag as the flue gas passes through it. Each filter bag alternates between relatively long periods of filtering and short periods of cleaning. During the cleaning period, fly ash that has accumulated on the bags is removed by pulses of air and then falls into a hopper for storage and subsequent disposal.

Cleaning is either initiated at a preset differential pressure across the tubesheet or based on a maximum time between cleanings. Bags in a PJFF are cleaned by directing a pulse of pressurized air down the filter bag countercurrent to the flue gas flow to induce a traveling ripple (pulse) in the filter bag. This pulse travels the length of the bag, deflecting the bag outward and separating the dust cake as it moves.

An advantage of a fabric filter over an ESP is that a fabric filter is not dependent on the resistivity of the fly ash. Since the fabric filter uses bags instead of an electric charge to remove the particles, the resistivity of the particles is not an issue. Fabric filters also have a lower dependence on particle size than ESPs. A disadvantage of fabric filters is that they have a tendency to corrode and clog with high sulfur coal applications. The high sulfur coals produce more SO_3, which tends to create problems with the fabric filters. Therefore, ESPs are typically used on high sulfur coal applications instead of fabric filters. Another disadvantage of fabric filters is the associated pressure drop. The bags, which collect a cake of particles, create an obstruction to the gas path. Fabric filters typically have approximately three times the pressure drop of an ESP. Fabric filters have been proven to control PM removal efficiency in excess of 99%.

C3.0ELECTROSTATIC PRECIPITATOR (ESP)

ESPs are commonly used as the primary filterable PM control device on coal fired units. The ESP discharge electrodes generate a high voltage electrical field that gives the particulate matter an electric charge (positive or negative). The charged particles will then be collected on a collection plate. A rapper or hammer system will be utilized to vibrate the collected particles off of the plates so they can fall into the hoppers for storage and subsequent disposal.

The advantages of an ESP include the fact that an ESP can be applied to high sulfur coals, and the pressure drop across an ESP is relatively low compared to other alternatives such as a fabric filter. Unlike the fabric filter, which uses bags as the filter media, an ESP does not contain elements that can plug in the presence of SO_3. The unobstructed design of the ESP results in a pressure drop that is approximately 1/3 of a corresponding fabric filter. The disadvantage of the ESP is that its effectiveness to remove particulate is dependant on the resistivity of the fly ash and particle size. ESPs have been proven to control PM removal efficiency in excess of 99%.

APPENDIX D

Visibility Modeling and Impairment Improvement Analysis Details (D1)

Emission Parameters for Basin Electric Power Cooperative
BART Modeling Analysis
Leland Olds Station Unit 1 & Unit 2

Scenario/ Unit Number	Stack Height		Stack Diameter		Exit Velocity		Exit Temperature		Emission Rate			
	Feet	Meters	Feet	Meters	feet/sec	meters/sec	F	K	SO_2	NO_X	PM Fine	PM Coarse
Precontrol												
Unit 1	350	106.7	17.40	5.30	64.60	19.70	350.6	450.00	5970	813	16.5	138.7
Unit 2	500	152.4	22.00	6.71	82.00	25.00	348	448.60	12205	3959	26.9	226.3
Run 1												
Unit 1	350	106.7	17.40	5.30	64.60	19.70	174	351.89	905	760.4	NA	NA
Unit 2	500	152.4	26.25	8.00	55.00	16.77	144	335.22	885.3	343.7	NA	NA
Unit1pm	350	106.7	17.4	5.30	64.60	19.70	350.6	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22	6.71	82.00	25.00	348	448.60	NA	NA	45.6	383
Run 2												
Unit 1	350	106.7	17.40	5.30	64.60	19.70	174	351.89	633.5	760.4	NA	NA
Unit 2	500	152.4	26.25	8.00	55.00	16.77	144	335.22	885.3	1359.5	NA	NA
Unit1pm	350	106.7	17.4	5.30	64.60	19.70	350.6	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22	6.71	82.00	25.00	348	448.60	NA	NA	45.6	383
Run 3												
Unit 1	500	152.4	18.60	5.67	55.00	16.77	144	335.22	452.5	760.4	NA	NA
Unit 2	500	152.4	26.25	8.00	55.00	16.77	144	335.22	885.3	1559.5	NA	NA
Unit1pm	350	106.7	17.40	5.30	64.60	19.70	351	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22.00	6.71	82.00	25.00	348	448.60	NA	NA	45.6	383
Run 4												
Unit 1	350	106.7	17.40	5.30	64.60	19.70	174	351.89	905	603.1	NA	NA
Unit 2	500	152.4	26.25	8.00	55.00	16.77	144	335.22	885.3	2462	NA	NA
Unit1pm	350	106.7	17.40	5.30	64.60	19.70	351	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22	6.71	82.00	25.00	348	448.6	NA	NA	45.6	383
Run 5												
Unit 1	350	106.7	17.40	5.30	64.60	19.70	174	351.89	633.5	603.1	NA	NA
Unit 2	500	152.4	26.25	8.00	55.00	16.77	144	335.22	NA	NA	NA	NA
Unit1pm	350	106.7	17.40	5.30	64.60	19.70	351	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22	6.71	82.00	25.00	348	448.6	NA	NA	NA	NA
Run 6												
Unit 1	500	152.4	18.60	5.67	55.00	16.77	144	335.22	452.5	603.1	NA	NA
Unit 2	500	152.4	26.25	8.00	55	16.77	144	335.22	NA	NA	NA	NA
Unit1pm	350	106.7	17.40	5.30	64.60	19.70	350.6	450.00	NA	NA	23.1	194
Unit2pm	500	152.4	22	6.71	82.00	25.00	348	448.6	NA	NA	NA	NA

Basin Electric Power Cooperative
Leland Olds Station Unit 1
BART Screening Analysis
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	5.037	7.271	2.234	2000	74	48	102	2.8	69.68	30.17	0.10	0.06
98th %tile Delta-DV	1.781	4.036	2.255	2000	11	51	105	2.9	55.70	44.09	0.12	0.09
90th %tile Delta-DV	0.449	2.577	2.127	2000	109	49	103	2.3	20.47	78.45	0.86	0.22
2001												
Largest Delta-DV	2.644	4.878	2.234	2001	64	52	106	2.8	88.34	11.50	0.12	0.04
98th %tile Delta-DV	1.286	3.392	2.106	2001	257	51	105	2.2	90.00	9.20	0.64	0.16
90th %tile Delta-DV	0.300	2.534	2.234	2001	43	52	106	2.8	86.90	12.90	0.11	0.08
2002												
Largest Delta-DV	5.618	7.851	2.234	2002	73	51	105	2.8	83.93	15.71	0.27	0.09
98th %tile Delta-DV	2.539	4.645	2.106	2002	233	53	107	2.2	90.14	9.39	0.36	0.11
90th %tile Delta-DV	0.519	2.752	2.234	2002	49	54	108	2.8	69.19	29.93	0.65	0.23
TRNP NORTH UNIT												
2000												
Largest Delta-DV	5.165	7.398	2.234	2000	36	82	71	2.8	52.34	47.24	0.30	0.13
98th %tile Delta-DV	2.175	4.408	2.234	2000	44	71	60	2.8	43.57	55.98	0.34	0.11
90th %tile Delta-DV	0.417	2.545	2.127	2000	137	82	71	2.3	83.17	16.58	0.18	0.07
2001												
Largest Delta-DV	3.847	6.102	2.255	2001	12	83	112	2.9	88.87	10.65	0.38	0.10
98th %tile Delta-DV	1.793	3.899	2.106	2001	260	86	115	2.2	97.10	2.52	0.29	0.09
90th %tile Delta-DV	0.464	2.634	2.170	2001	179	83	112	2.5	94.92	4.81	0.20	0.08
2002												
Largest Delta-DV	6.414	8.647	2.234	2002	73	89	118	2.8	79.45	19.99	0.45	0.11
98th %tile Delta-DV	2.047	4.195	2.149	2002	199	71	60	2.4	89.35	8.85	1.49	0.32
90th %tile Delta-DV	0.468	2.638	2.170	2002	178	83	112	2.5	97.10	2.47	0.34	0.09
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	6.000	8.233	2.234	2000	74	90	72	2.8	72.72	27.12	0.10	0.06
98th %tile Delta-DV	1.123	3.250	2.127	2000	110	90	72	2.3	9.98	88.97	0.83	0.22
90th %tile Delta-DV	0.371	2.647	2.276	2000	336	90	72	3	39.36	60.09	0.44	0.11
2001												
Largest Delta-DV	2.647	4.881	2.234	2001	64	90	72	2.8	88.72	11.12	0.12	0.04
98th %tile Delta-DV	1.046	3.322	2.276	2001	328	90	72	3	87.82	12.04	0.09	0.05
90th %tile Delta-DV	0.211	2.445	2.234	2001	55	90	72	2.8	80.67	19.16	0.10	0.08
2002												
Largest Delta-DV	6.145	8.379	2.234	2002	73	90	72	2.8	82.04	17.55	0.32	0.09
98th %tile Delta-DV	1.999	4.233	2.234	2002	39	90	72	2.8	85.12	14.37	0.34	0.17
90th %tile Delta-DV	0.278	2.511	2.234	2002	67	90	72	2.8	61.92	36.64	1.15	0.29
LOSTWOOD NWA												
2000												
Largest Delta-DV	6.396	8.672	2.275	2000	47	97	79	2.9	89.84	9.92	0.17	0.07
98th %tile Delta-DV	1.974	4.249	2.275	2000	88	93	75	2.9	18.46	80.97	0.40	0.16
90th %tile Delta-DV	0.883	3.093	2.211	2000	171	91	73	2.6	16.34	82.87	0.59	0.21
2001												
Largest Delta-DV	7.362	9.702	2.340	2001	326	91	73	3.2	92.10	7.54	0.27	0.09
98th %tile Delta-DV	2.018	4.314	2.297	2001	12	91	73	3	86.63	13.08	0.24	0.05
90th %tile Delta-DV	0.557	2.724	2.167	2001	235	99	81	2.4	64.88	31.34	2.99	0.79
2002												
Largest Delta-DV	3.736	6.011	2.275	2002	74	97	79	2.9	86.44	13.35	0.15	0.06
98th %tile Delta-DV	1.774	4.070	2.297	2002	29	97	79	3	83.32	16.39	0.23	0.07
90th %tile Delta-DV	0.476	2.816	2.340	2002	362	99	81	3.2	83.91	15.88	0.17	0.04

Duration Events
TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 37
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 33
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 57
Number of days with Delta-Deciview > 1.00: 31
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 39
Number of days with Delta-Deciview > 1.00: 24
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4

Basin Electric Power Cooperative
Leland Olds Station Unit 1
BART Run 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.402	3.636	2.234	2000	74	48	102	2.8	51.80	47.22	0.62	0.35
98th %tile Delta-DV	0.401	2.677	2.276	2000	335	53	107	3	37.54	58.33	3.32	0.81
90th %tile Delta-DV	0.096	2.224	2.127	2000	287	46	46	2.3	59.13	38.53	1.70	0.64
2001												
Largest Delta-DV	0.777	2.883	2.106	2001	258	4	4	2.2	28.15	66.77	4.20	0.87
98th %tile Delta-DV	0.393	2.521	2.127	2001	92	51	105	2.3	33.42	64.26	1.75	0.57
90th %tile Delta-DV	0.091	2.197	2.106	2001	266	4	4	2.2	14.12	83.42	2.02	0.44
2002												
Largest Delta-DV	1.972	4.206	2.234	2002	73	49	103	2.8	44.52	53.78	1.27	0.43
98th %tile Delta-DV	0.832	3.066	2.234	2002	67	28	28	2.8	15.25	80.25	3.71	0.79
90th %tile Delta-DV	0.133	2.239	2.106	2002	240	51	105	2.2	88.91	9.47	1.23	0.39
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.581	3.815	2.234	2000	36	82	71	2.8	34.54	63.12	1.65	0.69
98th %tile Delta-DV	0.563	2.690	2.127	2000	98	84	113	2.3	26.41	69.82	3.05	0.72
90th %tile Delta-DV	0.109	2.215	2.106	2000	265	67	56	2.2	52.96	44.45	1.89	0.70
2001												
Largest Delta-DV	1.704	3.959	2.255	2001	12	83	112	2.9	50.99	47.26	1.39	0.36
98th %tile Delta-DV	0.470	2.598	2.127	2001	112	85	114	2.3	32.47	63.23	3.56	0.73
90th %tile Delta-DV	0.110	2.343	2.234	2001	89	82	71	2.8	52.71	46.43	0.49	0.38
2002												
Largest Delta-DV	2.733	4.967	2.234	2002	73	89	118	2.8	37.20	60.56	1.79	0.45
98th %tile Delta-DV	0.720	2.954	2.234	2002	83	71	60	2.8	24.29	71.93	2.90	0.88
90th %tile Delta-DV	0.135	2.390	2.255	2002	30	82	71	2.9	53.65	45.76	0.36	0.24
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.695	3.928	2.234	2000	74	90	72	2.8	53.38	45.66	0.59	0.37
98th %tile Delta-DV	0.378	2.484	2.106	2000	247	90	72	2.2	86.21	8.52	4.17	1.11
90th %tile Delta-DV	0.087	2.321	2.234	2000	71	90	72	2.8	38.89	58.89	1.69	0.54
2001												
Largest Delta-DV	0.767	3.022	2.255	2001	12	90	72	2.9	50.46	49.03	0.36	0.15
98th %tile Delta-DV	0.328	2.561	2.234	2001	84	90	72	2.8	39.77	58.04	1.65	0.54
90th %tile Delta-DV	0.059	2.186	2.127	2001	98	90	72	2.3	15.65	81.71	2.12	0.52
2002												
Largest Delta-DV	2.340	4.573	2.234	2002	73	90	72	2.8	41.70	56.46	1.43	0.42
98th %tile Delta-DV	0.670	2.904	2.234	2002	39	90	72	2.8	45.10	52.61	1.51	0.78
90th %tile Delta-DV	0.094	2.200	2.106	2002	241	90	72	2.2	89.44	9.32	0.90	0.34
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.293	4.569	2.275	2000	47	97	79	2.9	49.48	49.36	0.82	0.34
98th %tile Delta-DV	0.433	2.600	2.167	2000	217	93	75	2.4	74.23	19.53	4.95	1.29
90th %tile Delta-DV	0.169	2.401	2.232	2000	197	99	81	2.7	20.47	76.51	2.13	0.88
2001												
Largest Delta-DV	2.532	4.872	2.340	2001	326	91	73	3.2	51.00	47.13	1.41	0.46
98th %tile Delta-DV	0.650	2.926	2.275	2001	41	91	73	2.9	39.94	58.48	1.10	0.47
90th %tile Delta-DV	0.218	2.363	2.145	2001	270	99	81	2.3	24.10	68.90	5.62	1.38
2002												
Largest Delta-DV	1.117	3.392	2.275	2002	74	97	79	2.9	50.35	48.49	0.82	0.34
98th %tile Delta-DV	0.544	2.883	2.340	2002	363	97	79	3.2	43.82	55.42	0.51	0.25
90th %tile Delta-DV	0.127	2.294	2.167	2002	234	97	79	2.4	77.90	17.85	3.00	1.24

Duration Events
TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative
Leland Olds Station Unit 1
BART Run2
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.197	3.430	2.234	2000	74	48	102	2.8	42.93	55.92	0.73	0.42
98th %tile Delta-DV	0.357	2.632	2.276	2000	335	53	107	3.0	29.60	65.74	3.75	0.91
90th %tile Delta-DV	0.082	2.231	2.149	2000	199	53	107	2.4	61.89	27.55	8.29	2.28
2001												
Largest Delta-DV	0.715	2.821	2.106	2001	258	36	36	2.2	18.57	75.76	4.70	0.97
98th %tile Delta-DV	0.355	2.482	2.127	2001	92	51	105	2.3	26.00	71.42	1.94	0.63
90th %tile Delta-DV	0.072	2.178	2.106	2001	230	45	45	2.2	20.18	72.24	6.24	1.33
2002												
Largest Delta-DV	1.731	3.964	2.234	2002	73	49	103	2.8	35.96	62.08	1.47	0.49
98th %tile Delta-DV	0.796	3.029	2.234	2002	67	28	28	2.8	11.19	84.09	3.89	0.83
90th %tile Delta-DV	0.110	2.216	2.106	2002	220	51	105	2.2	55.28	43.10	1.03	0.60
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.429	3.663	2.234	2000	36	82	71	2.8	26.96	70.43	1.83	0.77
98th %tile Delta-DV	0.496	2.602	2.106	2000	247	82	71	2.2	32.53	62.98	3.35	1.13
90th %tile Delta-DV	0.092	2.198	2.106	2000	265	67	56	2.2	44.05	52.87	2.25	0.84
2001												
Largest Delta-DV	1.462	3.717	2.255	2001	12	83	112	2.9	42.12	55.81	1.64	0.42
98th %tile Delta-DV	0.426	2.553	2.127	2001	112	85	114	2.3	25.18	70.07	3.94	0.81
90th %tile Delta-DV	0.102	2.230	2.127	2001	302	68	57	2.3	15.59	77.64	5.52	1.25
2002												
Largest Delta-DV	2.463	4.697	2.234	2002	73	89	118	2.8	29.30	68.18	2.02	0.50
98th %tile Delta-DV	0.670	2.903	2.234	2002	83	71	60	2.8	18.34	77.58	3.13	0.95
90th %tile Delta-DV	0.114	2.284	2.170	2002	155	82	71	2.5	51.04	48.31	0.39	0.26
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.442	3.675	2.234	2000	74	90	72	2.8	44.48	54.37	0.71	0.44
98th %tile Delta-DV	0.282	2.388	2.106	2000	247	90	72	2.2	81.19	11.72	5.61	1.49
90th %tile Delta-DV	0.070	2.303	2.234	2000	56	90	72	2.8	39.56	58.69	1.27	0.48
2001												
Largest Delta-DV	0.655	2.909	2.255	2001	12	90	72	2.9	41.62	57.78	0.42	0.17
98th %tile Delta-DV	0.272	2.378	2.106	2001	260	90	72	2.2	73.47	22.63	2.98	0.92
90th %tile Delta-DV	0.045	2.194	2.149	2001	195	90	72	2.4	86.34	11.45	1.57	0.64
2002												
Largest Delta-DV	2.076	4.309	2.234	2002	73	90	72	2.8	33.35	64.54	1.63	0.48
98th %tile Delta-DV	0.584	2.817	2.234	2002	39	90	72	2.8	36.43	60.94	1.74	0.90
90th %tile Delta-DV	0.081	2.187	2.106	2002	220	90	72	2.2	71.39	26.20	1.47	0.94
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.985	4.261	2.275	2000	47	97	79	2.9	40.66	57.98	0.96	0.40
98th %tile Delta-DV	0.380	2.677	2.297	2000	14	91	73	3.0	30.00	67.46	2.01	0.54
90th %tile Delta-DV	0.147	2.293	2.145	2000	137	91	73	2.3	33.90	61.77	3.45	0.89
2001												
Largest Delta-DV	2.187	4.527	2.340	2001	326	91	73	3.2	42.08	55.71	1.66	0.55
98th %tile Delta-DV	0.575	2.850	2.275	2001	41	91	73	2.9	31.76	66.45	1.25	0.53
90th %tile Delta-DV	0.191	2.530	2.340	2001	345	99	81	3.2	17.54	78.59	3.04	0.83
2002												
Largest Delta-DV	1.005	3.345	2.340	2002	337	91	73	3.2	10.12	86.30	2.46	1.12
98th %tile Delta-DV	0.474	2.814	2.340	2002	363	97	79	3.2	35.32	63.81	0.58	0.29
90th %tile Delta-DV	0.110	2.320	2.211	2002	178	97	79	2.6	76.02	19.82	3.34	0.81

Duration Events

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative
Leland Olds Station Unit 1
BART Run 3
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	0.973	3.207	2.234	2000	72	6	6	2.8	23.24	74.15	2.00	0.61
98th %tile Delta-DV	0.298	2.553	2.255	2000	11	51	105	2.9	24.70	73.57	1.01	0.72
90th %tile Delta-DV	0.073	2.200	2.127	2000	287	46	46	2.3	41.38	55.53	2.25	0.85
2001												
Largest Delta-DV	0.513	2.747	2.234	2001	64	46	46	2.8	37.89	60.81	0.95	0.35
98th %tile Delta-DV	0.276	2.552	2.276	2001	338	48	102	3.0	20.29	74.19	4.22	1.31
90th %tile Delta-DV	0.060	2.208	2.149	2001	211	53	107	2.4	78.75	13.84	5.46	1.96
2002												
Largest Delta-DV	1.538	3.771	2.234	2002	78	46	46	2.8	27.91	70.28	1.24	0.57
98th %tile Delta-DV	0.627	2.903	2.276	2002	336	53	107	3.0	9.57	86.23	3.40	0.81
90th %tile Delta-DV	0.124	2.251	2.127	2002	105	45	45	2.3	10.64	83.47	4.43	1.46
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.215	3.449	2.234	2000	36	82	71	2.8	20.96	75.94	2.18	0.92
98th %tile Delta-DV	0.309	2.415	2.106	2000	247	71	60	2.2	35.55	56.75	5.78	1.92
90th %tile Delta-DV	0.066	2.321	2.255	2000	31	85	114	2.9	22.89	74.75	1.71	0.66
2001												
Largest Delta-DV	0.904	3.158	2.255	2001	12	83	112	2.9	35.10	61.46	2.74	0.71
98th %tile Delta-DV	0.336	2.569	2.234	2001	63	82	71	2.8	48.08	50.81	0.74	0.37
90th %tile Delta-DV	0.085	2.255	2.170	2001	175	82	71	2.5	76.76	8.28	12.02	2.94
2002												
Largest Delta-DV	2.003	4.236	2.234	2002	73	89	118	2.8	23.59	73.24	2.54	0.63
98th %tile Delta-DV	0.569	2.844	2.276	2002	337	58	47	3.0	20.45	77.66	1.29	0.60
90th %tile Delta-DV	0.092	2.219	2.127	2002	110	82	71	2.3	38.92	58.39	2.10	0.60
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.131	3.365	2.234	2000	74	90	72	2.8	36.53	61.99	0.92	0.56
98th %tile Delta-DV	0.210	2.316	2.106	2000	247	90	72	2.2	76.34	14.06	7.58	2.01
90th %tile Delta-DV	0.062	2.295	2.234	2000	47	90	72	2.8	33.95	65.44	0.28	0.33
2001												
Largest Delta-DV	0.506	2.739	2.234	2001	64	90	72	2.8	38.81	59.87	0.98	0.34
98th %tile Delta-DV	0.215	2.321	2.106	2001	260	90	72	2.2	66.03	29.01	3.78	1.17
90th %tile Delta-DV	0.034	2.161	2.127	2001	99	90	72	2.3	43.07	55.86	0.56	0.52
2002												
Largest Delta-DV	1.759	3.993	2.234	2002	73	90	72	2.8	26.76	70.71	1.96	0.57
98th %tile Delta-DV	0.472	2.706	2.234	2002	39	90	72	2.8	28.72	68.00	2.16	1.12
90th %tile Delta-DV	0.066	2.172	2.106	2002	220	90	72	2.2	64.25	32.77	1.82	1.16
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.732	4.007	2.275	2000	47	97	79	2.9	32.48	65.94	1.12	0.46
98th %tile Delta-DV	0.349	2.624	2.275	2000	72	97	79	2.9	32.04	66.53	1.07	0.36
90th %tile Delta-DV	0.125	2.292	2.167	2000	239	93	75	2.4	37.43	54.55	6.16	1.85
2001												
Largest Delta-DV	2.009	4.348	2.340	2001	326	91	73	3.2	35.26	62.31	1.83	0.60
98th %tile Delta-DV	0.511	2.786	2.275	2001	41	91	73	2.9	24.59	73.39	1.42	0.60
90th %tile Delta-DV	0.136	2.476	2.340	2001	345	93	75	3.2	13.72	80.86	4.29	1.14
2002												
Largest Delta-DV	0.999	3.338	2.340	2002	337	93	75	3.2	7.42	88.97	2.46	1.14
98th %tile Delta-DV	0.396	2.736	2.340	2002	363	93	75	3.2	28.29	70.67	0.69	0.35
90th %tile Delta-DV	0.098	2.330	2.232	2002	188	97	79	2.7	30.17	57.49	9.75	2.58

Duration Events
TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative
Leland Olds Station Unit 1
BART Run 4
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.272	3.505	2.234	2000	74	48	102	2.8	57.50	41.42	0.69	0.39
98th %tile Delta-DV	0.354	2.629	2.276	2000	335	53	107	3	42.66	52.64	3.78	0.92
90th %tile Delta-DV	0.089	2.216	2.127	2000	287	46	46	2.3	64.25	33.20	1.85	0.70
2001												
Largest Delta-DV	0.673	2.779	2.106	2001	258	4	4	2.2	32.66	61.45	4.88	1.01
98th %tile Delta-DV	0.347	2.581	2.234	2001	63	53	107	2.8	65.68	33.50	0.56	0.25
90th %tile Delta-DV	0.083	2.189	2.106	2001	224	46	46	2.2	88.70	3.24	6.62	1.44
2002												
Largest Delta-DV	1.768	4.001	2.234	2002	73	49	103	2.8	50.20	47.88	1.43	0.48
98th %tile Delta-DV	0.703	2.937	2.234	2002	74	49	103	2.8	54.38	44.15	1.06	0.42
90th %tile Delta-DV	0.126	2.232	2.106	2002	220	51	105	2.2	68.92	29.66	0.90	0.52
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.388	3.622	2.234	2000	36	82	71	2.8	39.73	57.58	1.89	0.80
98th %tile Delta-DV	0.483	2.611	2.127	2000	98	84	113	2.3	30.87	64.72	3.57	0.84
90th %tile Delta-DV	0.097	2.224	2.127	2000	101	82	71	2.3	46.88	49.15	3.06	0.90
2001												
Largest Delta-DV	1.549	3.804	2.255	2001	12	83	112	2.9	56.55	41.51	1.54	0.40
98th %tile Delta-DV	0.436	2.542	2.106	2001	258	85	114	2.2	81.70	14.63	2.87	0.80
90th %tile Delta-DV	0.108	2.214	2.106	2001	247	58	47	2.2	87.26	3.01	7.23	2.51
2002												
Largest Delta-DV	2.424	4.658	2.234	2002	73	89	118	2.8	42.63	54.81	2.05	0.51
98th %tile Delta-DV	0.620	2.769	2.149	2002	199	79	68	2.4	58.24	34.62	5.85	1.28
90th %tile Delta-DV	0.127	2.297	2.170	2002	155	82	71	2.5	65.23	34.19	0.35	0.23
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.544	3.777	2.234	2000	74	90	72	2.8	59.04	39.89	0.66	0.41
98th %tile Delta-DV	0.372	2.478	2.106	2000	247	90	72	2.2	87.74	6.89	4.24	1.13
90th %tile Delta-DV	0.076	2.310	2.234	2000	71	90	72	2.8	44.47	52.99	1.93	0.61
2001												
Largest Delta-DV	0.691	2.946	2.255	2001	12	90	72	2.9	56.26	43.18	0.40	0.16
98th %tile Delta-DV	0.295	2.422	2.127	2001	112	90	72	2.3	42.86	53.15	3.28	0.70
90th %tile Delta-DV	0.053	2.329	2.276	2001	310	90	72	3	38.28	57.72	2.33	1.67
2002												
Largest Delta-DV	2.089	4.323	2.234	2002	73	90	72	2.8	47.31	50.60	1.62	0.47
98th %tile Delta-DV	0.601	2.834	2.234	2002	39	90	72	2.8	50.50	46.94	1.69	0.87
90th %tile Delta-DV	0.089	2.259	2.170	2002	178	90	72	2.5	79.36	17.37	2.52	0.74
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.077	4.352	2.275	2000	47	97	79	2.9	55.26	43.45	0.92	0.38
98th %tile Delta-DV	0.391	2.666	2.275	2000	72	97	79	2.9	54.51	44.22	0.95	0.32
90th %tile Delta-DV	0.150	2.382	2.232	2000	192	99	81	2.7	57.00	37.60	4.35	1.06
2001												
Largest Delta-DV	2.312	4.651	2.340	2001	326	91	73	3.2	56.50	41.42	1.56	0.51
98th %tile Delta-DV	0.572	2.847	2.275	2001	41	91	73	2.9	45.61	52.60	1.26	0.54
90th %tile Delta-DV	0.187	2.333	2.145	2001	270	99	81	2.3	28.08	63.76	6.55	1.61
2002												
Largest Delta-DV	1.007	3.283	2.275	2002	74	97	79	2.9	56.13	42.58	0.91	0.38
98th %tile Delta-DV	0.482	2.822	2.340	2002	363	97	79	3.2	49.57	49.57	0.57	0.29
90th %tile Delta-DV	0.122	2.289	2.167	2002	234	97	79	2.4	81.01	14.57	3.12	1.29

Duration Events
TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative
Leland Olds Station Unit 1
BART Run 5
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.064	3.297	2.234	2000	74	48	102	2.8	48.64	50.06	0.83	0.48
98th %tile Delta-DV	0.309	2.585	2.276	2000	335	53	107	3	34.24	60.37	4.33	1.06
90th %tile Delta-DV	0.073	2.200	2.127	2000	109	50	104	2.3	14.74	76.32	7.05	1.89
2001												
Largest Delta-DV	0.609	2.715	2.106	2001	258	4	4	2.2	25.34	68.13	5.40	1.12
98th %tile Delta-DV	0.300	2.428	2.127	2001	92	51	105	2.3	30.79	66.15	2.30	0.75
90th %tile Delta-DV	0.068	2.217	2.149	2001	195	46	46	2.4	82.05	15.28	1.98	0.69
2002												
Largest Delta-DV	1.521	3.754	2.234	2002	73	49	103	2.8	41.37	56.38	1.69	0.57
98th %tile Delta-DV	0.662	2.895	2.234	2002	67	28	28	2.8	13.55	80.74	4.71	1.01
90th %tile Delta-DV	0.100	2.206	2.106	2002	220	51	105	2.2	60.81	37.40	1.13	0.66
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.233	3.467	2.234	2000	36	82	71	2.8	31.56	65.39	2.15	0.90
98th %tile Delta-DV	0.433	2.539	2.106	2000	247	82	71	2.2	37.39	57.45	3.85	1.30
90th %tile Delta-DV	0.082	2.188	2.106	2000	265	67	56	2.2	49.44	47.10	2.52	0.94
2001												
Largest Delta-DV	1.303	3.558	2.255	2001	12	83	112	2.9	47.65	50.01	1.86	0.48
98th %tile Delta-DV	0.365	2.493	2.127	2001	112	85	114	2.3	29.44	65.00	4.61	0.95
90th %tile Delta-DV	0.086	2.213	2.127	2001	302	68	57	2.3	18.55	73.40	6.57	1.48
2002												
Largest Delta-DV	2.145	4.379	2.234	2002	73	89	118	2.8	34.21	62.85	2.35	0.59
98th %tile Delta-DV	0.565	2.798	2.234	2002	83	71	60	2.8	21.87	73.27	3.73	1.13
90th %tile Delta-DV	0.101	2.355	2.255	2002	30	82	71	2.9	50.48	48.72	0.48	0.32
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.287	3.521	2.234	2000	74	90	72	2.8	50.22	48.49	0.80	0.49
98th %tile Delta-DV	0.276	2.382	2.106	2000	247	90	72	2.2	83.19	9.54	5.74	1.53
90th %tile Delta-DV	0.062	2.211	2.149	2000	187	90	72	2.4	93.17	2.98	2.79	1.05
2001												
Largest Delta-DV	0.578	2.832	2.255	2001	12	90	72	2.9	47.37	51.96	0.48	0.20
98th %tile Delta-DV	0.249	2.483	2.234	2001	84	90	72	2.8	36.75	60.36	2.18	0.71
90th %tile Delta-DV	0.043	2.277	2.234	2001	82	90	72	2.8	51.20	46.79	1.44	0.58
2002												
Largest Delta-DV	1.818	4.052	2.234	2002	73	90	72	2.8	38.58	58.98	1.89	0.55
98th %tile Delta-DV	0.513	2.747	2.234	2002	39	90	72	2.8	41.58	55.41	1.98	1.03
90th %tile Delta-DV	0.074	2.202	2.127	2002	128	90	72	2.3	11.49	80.11	6.60	1.80
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.761	4.037	2.275	2000	47	97	79	2.9	46.35	52.09	1.10	0.45
98th %tile Delta-DV	0.328	2.603	2.275	2000	72	97	79	2.9	45.61	52.86	1.14	0.38
90th %tile Delta-DV	0.129	2.275	2.145	2000	98	91	73	2.3	37.69	59.14	2.38	0.78
2001												
Largest Delta-DV	1.958	4.298	2.340	2001	326	91	73	3.2	47.56	49.94	1.88	0.62
98th %tile Delta-DV	0.496	2.771	2.275	2001	41	91	73	2.9	36.99	60.93	1.46	0.62
90th %tile Delta-DV	0.170	2.315	2.145	2001	117	99	81	2.3	20.42	74.99	2.08	2.51
2002												
Largest Delta-DV	0.845	3.120	2.275	2002	74	97	79	2.9	47.24	51.21	1.09	0.46
98th %tile Delta-DV	0.412	2.752	2.340	2002	363	97	79	3.2	40.76	58.23	0.67	0.34
90th %tile Delta-DV	0.098	2.244	2.145	2002	134	97	79	2.3	14.60	75.52	7.69	2.19

Duration Events
TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative
Leland Olds Station Unit 1
BART Run 6
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	0.825	3.059	2.234	2000	72	6	6	2.8	27.61	69.29	2.38	0.72
98th %tile Delta-DV	0.253	2.508	2.255	2000	11	51	105	2.9	29.15	68.81	1.20	0.85
90th %tile Delta-DV	0.065	2.214	2.149	2000	187	45	45	2.4	82.68	12.97	3.22	1.13
2001												
Largest Delta-DV	0.448	2.682	2.234	2001	64	46	46	2.8	43.50	55.00	1.10	0.40
98th %tile Delta-DV	0.249	2.355	2.106	2001	260	52	106	2.2	65.57	29.07	4.17	1.20
90th %tile Delta-DV	0.054	2.329	2.276	2001	310	53	107	3	29.20	66.04	2.78	1.98
2002												
Largest Delta-DV	1.325	3.559	2.234	2002	78	46	46	2.8	32.75	65.12	1.46	0.66
98th %tile Delta-DV	0.524	2.652	2.127	2002	136	53	107	2.3	17.26	72.95	7.90	1.89
90th %tile Delta-DV	0.102	2.230	2.127	2002	105	45	45	2.3	12.90	79.96	5.37	1.77
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.034	3.267	2.234	2000	36	82	71	2.8	24.87	71.45	2.59	1.09
98th %tile Delta-DV	0.273	2.379	2.106	2000	247	71	60	2.2	40.25	51.03	6.55	2.17
90th %tile Delta-DV	0.057	2.227	2.170	2000	165	58	47	2.5	50.04	46.35	2.61	1.00
2001												
Largest Delta-DV	0.793	3.047	2.255	2001	12	83	112	2.9	40.24	55.81	3.14	0.81
98th %tile Delta-DV	0.299	2.532	2.234	2001	63	82	71	2.8	54.15	44.60	0.83	0.42
90th %tile Delta-DV	0.077	2.311	2.234	2001	85	84	113	2.8	15.75	79.66	3.59	1.00
2002												
Largest Delta-DV	1.718	3.952	2.234	2002	73	89	118	2.8	27.90	68.35	3.00	0.75
98th %tile Delta-DV	0.479	2.755	2.276	2002	337	58	47	3	24.39	73.36	1.54	0.72
90th %tile Delta-DV	0.081	2.208	2.127	2002	110	82	71	2.3	44.43	52.49	2.39	0.68
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	0.991	3.224	2.234	2000	74	90	72	2.8	42.00	56.29	1.05	0.65
98th %tile Delta-DV	0.204	2.310	2.106	2000	247	90	72	2.2	78.62	11.51	7.80	2.07
90th %tile Delta-DV	0.054	2.287	2.234	2000	36	90	72	2.8	24.77	72.98	1.53	0.72
2001												
Largest Delta-DV	0.443	2.676	2.234	2001	64	90	72	2.8	44.47	54.02	1.12	0.39
98th %tile Delta-DV	0.202	2.308	2.106	2001	260	90	72	2.2	70.31	24.41	4.03	1.25
90th %tile Delta-DV	0.030	2.179	2.149	2001	190	90	72	2.4	87.28	2.25	8.24	2.24
2002												
Largest Delta-DV	1.516	3.750	2.234	2002	73	90	72	2.8	31.44	65.59	2.30	0.67
98th %tile Delta-DV	0.408	2.642	2.234	2002	39	90	72	2.8	33.34	62.86	2.51	1.30
90th %tile Delta-DV	0.061	2.209	2.149	2002	189	90	72	2.4	81.52	6.96	8.88	2.64
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.506	3.782	2.275	2000	47	97	79	2.9	37.77	60.39	1.30	0.54
98th %tile Delta-DV	0.300	2.576	2.275	2000	72	97	79	2.9	37.30	61.04	1.24	0.42
90th %tile Delta-DV	0.111	2.278	2.167	2000	239	93	75	2.4	42.23	48.73	6.95	2.09
2001												
Largest Delta-DV	1.772	4.112	2.340	2001	326	91	73	3.2	40.47	56.74	2.10	0.69
98th %tile Delta-DV	0.433	2.708	2.275	2001	41	91	73	2.9	29.12	68.49	1.68	0.71
90th %tile Delta-DV	0.121	2.332	2.211	2001	175	93	75	2.6	86.28	6.19	5.80	1.74
2002												
Largest Delta-DV	0.822	3.162	2.340	2002	337	93	75	3.2	9.10	86.48	3.02	1.40
98th %tile Delta-DV	0.338	2.678	2.340	2002	363	93	75	3.2	33.20	65.58	0.81	0.41
90th %tile Delta-DV	0.082	2.228	2.145	2002	134	99	81	2.3	10.92	77.74	8.74	2.61

Duration Events
TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0
2002
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 0
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 0
2002
Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

Basin Electric Power Cooperative
Leland Olds Station Unit 2
BART Screening Analysis
2000-2002

						SEQ	ND	% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	5.555	7.789	2.234	2000	72	3	3	2.8	64.50	35.23	0.20	0.06
98th %tile Delta-DV	2.340	4.573	2.234	2000	71	45	45	2.8	63.17	36.53	0.23	0.07
90th %tile Delta-DV	0.674	2.780	2.106	2000	217	51	105	2.2	72.89	26.84	0.19	0.08
2001												
Largest Delta-DV	5.384	7.618	2.234	2001	64	46	46	2.8	75.27	24.62	0.08	0.03
98th %tile Delta-DV	2.339	4.466	2.127	2001	92	51	105	2.3	54.75	44.89	0.27	0.09
90th %tile Delta-DV	0.586	2.713	2.127	2001	131	53	107	2.3	65.85	33.92	0.15	0.08
2002												
Largest Delta-DV	9.117	11.351	2.234	2002	73	49	103	2.8	76.50	23.23	0.20	0.06
98th %tile Delta-DV	4.924	7.030	2.106	2002	233	53	107	2.2	81.37	18.31	0.24	0.08
90th %tile Delta-DV	1.161	3.288	2.127	2002	95	46	46	2.3	50.63	48.95	0.31	0.11
TRNP NORTH UNIT												
2000												
Largest Delta-DV	5.115	7.349	2.234	2000	72	82	71	2.8	66.02	33.73	0.20	0.05
98th %tile Delta-DV	2.430	4.705	2.276	2000	316	85	114	3	63.24	36.55	0.17	0.05
90th %tile Delta-DV	0.681	2.787	2.106	2000	238	85	114	2.2	93.64	5.82	0.41	0.13
2001												
Largest Delta-DV	6.501	8.734	2.234	2001	64	82	71	2.8	74.84	25.02	0.10	0.03
98th %tile Delta-DV	2.954	5.209	2.255	2001	12	83	112	2.9	73.21	26.59	0.16	0.04
90th %tile Delta-DV	0.827	3.061	2.234	2001	62	82	71	2.8	80.29	19.62	0.06	0.03
2002												
Largest Delta-DV	9.937	12.170	2.234	2002	73	89	118	2.8	64.99	34.69	0.26	0.06
98th %tile Delta-DV	3.958	6.085	2.127	2002	293	58	47	2.3	69.27	29.98	0.58	0.16
90th %tile Delta-DV	0.761	3.016	2.255	2002	30	82	71	2.9	74.64	25.29	0.05	0.03
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	6.879	9.113	2.234	2000	74	90	72	2.8	84.55	15.32	0.07	0.05
98th %tile Delta-DV	1.581	3.814	2.234	2000	54	90	72	2.8	78.53	21.22	0.19	0.06
90th %tile Delta-DV	0.553	2.680	2.127	2000	101	90	72	2.3	58.05	41.44	0.37	0.14
2001												
Largest Delta-DV	5.192	7.426	2.234	2001	64	90	72	2.8	76.26	23.63	0.08	0.03
98th %tile Delta-DV	2.288	4.521	2.234	2001	84	90	72	2.8	62.27	37.42	0.23	0.07
90th %tile Delta-DV	0.434	2.540	2.106	2001	230	90	72	2.2	87.77	10.96	1.05	0.22
2002												
Largest Delta-DV	9.852	12.086	2.234	2002	73	90	72	2.8	70.69	29.03	0.22	0.06
98th %tile Delta-DV	3.450	5.725	2.276	2002	336	90	72	3	65.33	34.31	0.29	0.06
90th %tile Delta-DV	0.617	2.723	2.106	2002	270	90	72	2.2	52.16	47.06	0.60	0.18
LOSTWOOD NWA												
2000												
Largest Delta-DV	8.438	10.714	2.275	2000	47	99	81	2.9	95.78	4.03	0.14	0.06
98th %tile Delta-DV	2.419	4.587	2.167	2000	231	93	75	2.4	85.81	13.16	0.76	0.27
90th %tile Delta-DV	1.109	3.342	2.232	2000	209	99	81	2.7	77.75	21.00	0.94	0.31
2001												
Largest Delta-DV	9.179	11.518	2.340	2001	326	99	81	3.2	91.22	8.47	0.24	0.07
98th %tile Delta-DV	4.158	6.303	2.145	2001	261	99	81	2.3	90.60	8.78	0.50	0.12
90th %tile Delta-DV	1.032	3.178	2.145	2001	260	97	79	2.3	87.32	12.53	0.11	0.04
2002												
Largest Delta-DV	6.803	9.078	2.275	2002	74	97	79	2.9	72.69	27.16	0.12	0.04
98th %tile Delta-DV	3.609	5.949	2.340	2002	337	93	75	3.2	33.34	65.90	0.59	0.17
90th %tile Delta-DV	0.796	2.942	2.145	2002	100	91	73	2.3	74.33	25.51	0.10	0.06

Duration Events

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 46
Number of days with Delta-Deciview > 1.00: 28
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 56
Number of days with Delta-Deciview > 1.00: 39
Max number of consecutive days with Delta-Deciview > 0.50: 5

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 26
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 54
Number of days with Delta-Deciview > 1.00: 31
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 50
Number of days with Delta-Deciview > 1.00: 31
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 39
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 33
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 65
Number of days with Delta-Deciview > 1.00: 41
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 64
Number of days with Delta-Deciview > 1.00: 37
Max number of consecutive days with Delta-Deciview > 0.50: 6
2002
Number of days with Delta-Deciview > 0.50: 51
Number of days with Delta-Deciview > 1.00: 34
Max number of consecutive days with Delta-Deciview > 0.50: 4

Basin Electric Power Cooperative
Leland Olds Station Unit 2
BART Run 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.616	3.850	2.234	2000	72	4	4	2.8	25.56	72.54	1.44	0.46
98th %tile Delta-DV	0.492	2.768	2.276	2000	335	53	107	3.0	29.71	62.67	6.12	1.50
90th %tile Delta-DV	0.124	2.252	2.127	2000	109	7	7	2.3	10.46	85.42	3.12	1.00
2001												
Largest Delta-DV	0.893	3.126	2.234	2001	64	46	46	2.8	39.58	59.07	0.99	0.36
98th %tile Delta-DV	0.484	2.738	2.255	2001	13	6	6	2.9	22.66	73.36	3.22	0.75
90th %tile Delta-DV	0.104	2.252	2.149	2001	195	46	46	2.4	74.42	22.72	2.08	0.78
2002												
Largest Delta-DV	2.526	4.759	2.234	2002	78	46	46	2.8	30.14	68.08	1.22	0.57
98th %tile Delta-DV	0.961	3.195	2.234	2002	74	49	103	2.8	34.66	63.38	1.49	0.48
90th %tile Delta-DV	0.201	2.328	2.127	2002	105	46	46	2.3	11.63	83.74	3.45	1.18
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.472	3.706	2.234	2000	36	82	71	2.8	23.43	75.62	0.69	0.26
98th %tile Delta-DV	0.502	2.778	2.276	2000	316	85	114	3.0	26.09	71.95	1.54	0.42
90th %tile Delta-DV	0.107	2.340	2.234	2000	46	68	57	2.8	7.81	87.77	3.63	0.79
2001												
Largest Delta-DV	1.202	3.436	2.234	2001	64	82	71	2.8	39.09	59.26	1.23	0.41
98th %tile Delta-DV	0.609	2.843	2.234	2001	42	82	71	2.8	36.93	61.83	0.87	0.37
90th %tile Delta-DV	0.132	2.407	2.276	2001	316	82	71	3.0	24.19	74.80	0.75	0.26
2002												
Largest Delta-DV	3.070	5.304	2.234	2002	73	89	118	2.8	26.09	71.35	2.04	0.52
98th %tile Delta-DV	0.991	3.224	2.234	2002	50	71	60	2.8	20.70	76.66	1.97	0.67
90th %tile Delta-DV	0.147	2.253	2.106	2002	241	82	71	2.2	79.82	17.85	1.72	0.62
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.650	3.884	2.234	2000	74	90	72	2.8	39.15	59.66	0.68	0.51
98th %tile Delta-DV	0.334	2.568	2.234	2000	69	90	72	2.8	20.06	76.02	3.13	0.79
90th %tile Delta-DV	0.104	2.274	2.170	2000	152	90	72	2.5	27.73	62.31	7.77	2.19
2001												
Largest Delta-DV	0.859	3.093	2.234	2001	64	90	72	2.8	40.75	57.88	1.01	0.36
98th %tile Delta-DV	0.317	2.571	2.255	2001	12	90	72	2.9	36.15	62.11	1.34	0.39
90th %tile Delta-DV	0.057	2.163	2.106	2001	224	90	72	2.2	85.00	4.89	8.12	1.98
2002												
Largest Delta-DV	2.741	4.974	2.234	2002	73	90	72	2.8	29.16	68.30	1.99	0.55
98th %tile Delta-DV	0.767	3.001	2.234	2002	39	90	72	2.8	31.04	66.08	1.90	0.98
90th %tile Delta-DV	0.101	2.207	2.106	2002	233	90	72	2.2	31.69	58.45	8.17	1.69
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.653	4.929	2.275	2000	47	99	81	2.9	34.78	63.77	1.04	0.41
98th %tile Delta-DV	0.606	2.773	2.167	2000	233	99	81	2.4	52.67	45.27	1.46	0.60
90th %tile Delta-DV	0.215	2.447	2.232	2000	209	99	81	2.7	34.43	54.11	8.62	2.85
2001												
Largest Delta-DV	3.302	5.641	2.340	2001	326	97	79	3.2	38.39	59.61	1.57	0.43
98th %tile Delta-DV	0.909	3.249	2.340	2001	333	99	81	3.2	25.62	70.86	2.41	1.12
90th %tile Delta-DV	0.224	2.370	2.145	2001	107	97	79	2.3	16.30	79.89	2.88	0.93
2002												
Largest Delta-DV	1.645	3.985	2.340	2002	337	93	75	3.2	8.19	88.69	2.42	0.70
98th %tile Delta-DV	0.589	2.734	2.145	2002	111	99	81	2.3	33.04	62.70	3.45	0.81
90th %tile Delta-DV	0.135	2.280	2.145	2002	134	99	81	2.3	10.24	80.95	7.15	1.66

Duration Events
TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

Basin Electric Power Cooperative
Leland Olds Station Unit 2
BART Run 2
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.781	4.015	2.234	2000	72	4	4	2.8	23.00	75.29	1.30	0.41
98th %tile Delta-DV	0.536	2.811	2.276	2000	335	53	107	3.0	27.23	65.78	5.61	1.38
90th %tile Delta-DV	0.135	2.284	2.149	2000	199	53	107	2.4	53.49	34.41	9.54	2.56
2001												
Largest Delta-DV	0.970	3.203	2.234	2001	64	46	46	2.8	36.29	62.47	0.91	0.33
98th %tile Delta-DV	0.526	2.632	2.106	2001	260	52	106	2.2	59.53	35.29	4.02	1.15
90th %tile Delta-DV	0.114	2.242	2.127	2001	302	1	1	2.3	6.70	90.51	2.28	0.51
2002												
Largest Delta-DV	2.753	4.986	2.234	2002	78	46	46	2.8	27.33	71.05	1.10	0.52
98th %tile Delta-DV	1.050	3.283	2.234	2002	74	49	103	2.8	31.60	66.61	1.35	0.44
90th %tile Delta-DV	0.225	2.353	2.127	2002	105	46	46	2.3	10.34	85.54	3.07	1.05
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.623	3.856	2.234	2000	36	82	71	2.8	21.10	78.05	0.62	0.23
98th %tile Delta-DV	0.556	2.832	2.276	2000	316	85	114	3.0	23.49	74.75	1.39	0.38
90th %tile Delta-DV	0.121	2.354	2.234	2000	46	68	57	2.8	6.92	89.17	3.21	0.70
2001												
Largest Delta-DV	1.307	3.540	2.234	2001	64	82	71	2.8	35.78	62.72	1.13	0.37
98th %tile Delta-DV	0.658	2.891	2.234	2001	63	82	71	2.8	45.58	53.25	0.79	0.39
90th %tile Delta-DV	0.146	2.421	2.276	2001	316	82	71	3.0	21.73	77.36	0.68	0.23
2002												
Largest Delta-DV	3.353	5.587	2.234	2002	73	89	118	2.8	23.54	74.16	1.84	0.47
98th %tile Delta-DV	1.091	3.324	2.234	2002	75	82	71	2.8	27.07	70.28	1.91	0.75
90th %tile Delta-DV	0.151	2.257	2.106	2002	241	82	71	2.2	77.68	20.05	1.67	0.60
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.786	4.019	2.234	2000	74	90	72	2.8	35.92	62.99	0.63	0.47
98th %tile Delta-DV	0.372	2.606	2.234	2000	69	90	72	2.8	18.00	78.49	2.81	0.71
90th %tile Delta-DV	0.114	2.284	2.170	2000	152	90	72	2.5	25.41	65.47	7.12	2.00
2001												
Largest Delta-DV	0.932	3.166	2.234	2001	64	90	72	2.8	37.42	61.33	0.93	0.33
98th %tile Delta-DV	0.346	2.601	2.255	2001	12	90	72	2.9	33.04	65.37	1.23	0.36
90th %tile Delta-DV	0.057	2.185	2.127	2001	101	90	72	2.3	45.96	53.12	0.57	0.35
2002												
Largest Delta-DV	2.986	5.220	2.234	2002	73	90	72	2.8	26.42	71.27	1.80	0.50
98th %tile Delta-DV	0.836	3.070	2.234	2002	39	90	72	2.8	28.38	68.99	1.74	0.90
90th %tile Delta-DV	0.109	2.215	2.106	2002	233	90	72	2.2	29.20	61.71	7.53	1.56
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.876	5.152	2.275	2000	47	99	81	2.9	31.71	66.97	0.95	0.37
98th %tile Delta-DV	0.647	2.814	2.167	2000	233	99	81	2.4	49.26	48.81	1.37	0.56
90th %tile Delta-DV	0.238	2.513	2.275	2000	70	93	75	2.9	19.43	78.10	1.81	0.65
2001												
Largest Delta-DV	3.540	5.880	2.340	2001	326	97	79	3.2	35.35	62.80	1.44	0.40
98th %tile Delta-DV	0.999	3.338	2.340	2001	333	99	81	3.2	23.22	73.59	2.18	1.01
90th %tile Delta-DV	0.232	2.400	2.167	2001	235	99	81	2.4	14.42	81.94	3.00	0.65
2002												
Largest Delta-DV	1.841	4.181	2.340	2002	337	93	75	3.2	7.25	90.00	2.14	0.62
98th %tile Delta-DV	0.643	2.789	2.145	2002	111	99	81	2.3	30.17	65.93	3.15	0.74
90th %tile Delta-DV	0.149	2.294	2.145	2002	122	99	81	2.3	21.01	77.00	1.26	0.74

Duration Events
TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 5
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2

Basin Electric Power Cooperative
Leland Olds Station Unit 2
BART Run 3
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.503	4.736	2.234	2000	72	4	4	2.8	15.77	83.06	0.89	0.28
98th %tile Delta-DV	0.728	3.004	2.276	2000	335	53	107	3	19.84	75.06	4.09	1.00
90th %tile Delta-DV	0.178	2.284	2.106	2000	241	36	36	2.2	11.25	84.26	2.94	1.54
2001												
Largest Delta-DV	1.316	3.550	2.234	2001	64	46	46	2.8	26.27	72.83	0.66	0.24
98th %tile Delta-DV	0.660	2.936	2.276	2001	338	47	101	3	13.57	82.61	3.07	0.75
90th %tile Delta-DV	0.148	2.275	2.127	2001	101	45	45	2.3	32.11	67.07	0.53	0.28
2002												
Largest Delta-DV	3.723	5.957	2.234	2002	78	46	46	2.8	19.19	79.67	0.77	0.36
98th %tile Delta-DV	1.445	3.679	2.234	2002	74	49	103	2.8	22.50	76.23	0.96	0.31
90th %tile Delta-DV	0.336	2.463	2.127	2002	105	46	46	2.3	6.89	90.36	2.05	0.70
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.268	4.502	2.234	2000	36	82	71	2.8	14.60	84.81	0.43	0.16
98th %tile Delta-DV	0.800	3.076	2.276	2000	316	85	114	3	16.13	82.65	0.95	0.26
90th %tile Delta-DV	0.146	2.295	2.149	2000	187	87	116	2.4	71.86	24.74	2.38	1.02
2001												
Largest Delta-DV	1.790	3.917	2.127	2001	98	84	113	2.3	13.07	83.85	2.45	0.64
98th %tile Delta-DV	0.877	3.110	2.234	2001	63	82	71	2.8	33.86	65.27	0.58	0.29
90th %tile Delta-DV	0.181	2.415	2.234	2001	89	82	71	2.8	25.44	73.76	0.47	0.33
2002												
Largest Delta-DV	4.549	6.782	2.234	2002	73	89	118	2.8	16.28	82.12	1.27	0.32
98th %tile Delta-DV	1.496	3.730	2.234	2002	75	82	71	2.8	19.33	78.77	1.36	0.53
90th %tile Delta-DV	0.212	2.487	2.276	2002	352	71	60	3	10.30	88.72	0.76	0.22
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	2.380	4.613	2.234	2000	74	90	72	2.8	26.14	73.07	0.46	0.34
98th %tile Delta-DV	0.471	2.705	2.234	2000	32	90	72	2.8	14.28	84.16	1.08	0.47
90th %tile Delta-DV	0.142	2.269	2.127	2000	98	90	72	2.3	20.09	78.39	1.06	0.46
2001												
Largest Delta-DV	1.261	3.495	2.234	2001	64	90	72	2.8	27.20	71.89	0.67	0.24
98th %tile Delta-DV	0.477	2.732	2.255	2001	12	90	72	2.9	23.72	75.14	0.89	0.26
90th %tile Delta-DV	0.076	2.204	2.127	2001	101	90	72	2.3	34.65	64.67	0.43	0.26
2002												
Largest Delta-DV	4.036	6.269	2.234	2002	73	90	72	2.8	18.49	79.89	1.26	0.35
98th %tile Delta-DV	1.134	3.367	2.234	2002	39	90	72	2.8	20.63	77.46	1.26	0.65
90th %tile Delta-DV	0.142	2.376	2.234	2002	82	90	72	2.8	10.75	86.87	1.94	0.44
LOSTWOOD NWA												
2000												
Largest Delta-DV	3.831	6.106	2.275	2000	47	99	81	2.9	22.64	76.42	0.68	0.27
98th %tile Delta-DV	0.830	2.998	2.167	2000	233	99	81	2.4	38.00	60.51	1.05	0.44
90th %tile Delta-DV	0.307	2.474	2.167	2000	226	99	81	2.4	34.63	59.20	4.91	1.26
2001												
Largest Delta-DV	4.528	6.868	2.340	2001	326	97	79	3.2	26.24	72.39	1.07	0.30
98th %tile Delta-DV	1.391	3.730	2.340	2001	333	99	81	3.2	16.35	81.41	1.54	0.71
90th %tile Delta-DV	0.339	2.506	2.167	2001	235	99	81	2.4	9.83	87.69	2.04	0.44
2002												
Largest Delta-DV	2.675	5.015	2.340	2002	337	93	75	3.2	4.78	93.41	1.41	0.41
98th %tile Delta-DV	0.886	3.031	2.145	2002	111	99	81	2.3	21.64	75.57	2.26	0.53
90th %tile Delta-DV	0.209	2.549	2.340	2002	362	99	81	3.2	20.31	79.25	0.36	0.07

Duration Events

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 15
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 14
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 3

IMPACT ANALYSIS of Basic SOFA with SNCR ALTERNATIVE for LELAND OLDS UNIT 1

This document is being provided in response to the North Dakota Department of Health's request issued in a December 1, 2006 letter to Basin Electric Power Cooperative regarding the NDDH's comments from their review of the final draft report of the BEPC LOS BART DETERMINATION STUDY for LELAND OLDS STATION UNIT 1 and 2 (August 2006).

This is intended to be in addition to the following sections:

2.4.2 Energy Impacts of NO_X Control Alternatives – LOS Unit 1;

2.4.3 Non Air Quality and Other Environmental Impacts of NO_X Control Alternatives – LOS Unit 1;

2.4.4 Visibility Impairment Impacts of Leland Olds Station NO_X Controls – Unit 1;

2.4.5 Summary of Impacts of LOS NO_X Controls – Unit 1;

CORRECTIONS:

Included in this document are replacements to the following sections of the August 2006 BEPC BART Determination Study report:

2.4.1.2 Operating and Maintenance Cost Estimates for NO_X Controls – LOS Unit 1;

2.4.1.3 Cost Effectiveness for NO_X Controls – LOS Unit 1;

The following describes corrections to Section 2.4.1.2 O&M costs, and Section 2.4.1.3 Cost Effectiveness, for those LOS Unit 1 alternatives that involve a chemical reagent injected for NOx control. These corrections are included in front of the updated impacts evaluation added for the basic SOFA with SNCR NO_X Control alternative for LOS Unit 1.

Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water should be included in the O&M costs; this follows EPA OAQPS convention. For the purposes of this study, this additional coal consumption has been included in the annual O&M costs provided in the August 2006 final draft of the BEPC LOS BART Report. For example, the cost of this extra coal consumption was incorrectly calculated as $10 per year for LOS Unit 1's basic SOFA + SNCR alternative for both the historic and PTE cases in the August 2006 final draft of the BEPC LOS BART Report, assuming $0.91/mmBtu. It should have been 53,645 mmBtu/yr x $0.91/mmBtu = $48,600/yr annual O&M cost for LOS Unit 1's basic SOFA + SNCR alternative.

Similarly, included in this document are replacements to the following sections of the August 2006 BEPC BART Determination Study report:

2.5.1.2 Operating and Maintenance Cost Estimates for NO_X Controls – LOS Unit 2;

2.5.1.3 Cost Effectiveness for NO_X Controls – LOS Unit 2;

The following describes corrections to Section 2.5.1.2 O&M costs, and Section 2.5.1.3 Cost Effectiveness, for those LOS Unit 2 alternatives that involve a chemical reagent injected for NO_X control. These corrections are also included at the back of this updated impacts evaluation.

The cost of this extra coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water was incorrectly calculated as $20 per year for LOS Unit 2's SNCR + ASOFA alternative and $40 per year for RRI+SNCR with ASOFA alternative for both the historic and PTE cases in the August 2006 final draft of the BEPC LOS BART Report, assuming $0.91/mmBtu. It should have been 204,807 mmBtu/yr x $0.91/mmBtu = $185,400/yr annual O&M cost for LOS Unit 2's SNCR + ASOFA alternative, and 389,490 mmBtu/yr x $0.91/mmBtu = $352,700/yr annual O&M cost for LOS Unit 2's RRI+SNCR with ASOFA alternative.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study report)

2.4.1.2 OPERATING AND MAINTENANCE COST ESTIMATES FOR NO_X CONTROLS – LOS UNIT 1

The operation and maintenance costs to implement the NO_X control technologies evaluated for LOS Unit 1 were largely estimated from cost factors established in the EPA's Air Pollution Control Cost Manual[1] (OAQPS), and from engineering judgment applied to that control technology. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's Levelized Total Annual Costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR alternatives; and
- Reagent dilution water consumption and unit cost for SNCR alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.
- Reductions in revenue expected to result from loss of unit availability, i.e. outages attributable to the control option, which reduce annual net electrical generation available for sale (revenue).

Table 2.4-3 and Table 2.4-4 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the NO_X control options evaluated for LOS Unit 1. The cost methodology summarized in Section 1.3.5 provides more details for the levelized annual O&M cost calculations and cost factors. The annual operating and maintenance costs of the control options in Table 2.4-3 is based on LOS Unit 1 operation with the control options at 2,622 mmBtu/hr heat input and 8,760 hrs/yr operation. These O&M costs are relative to unit pre-control baseline operation at 0.285 lb/mmBtu for the highest 24-month NOx emission summation at 2,443 mmBtu/hr heat input for 8,510 hrs/yr operation of LOS Unit 1 with existing close-coupled overfire air and low-NO_X burners.

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[1] See Basin LOS BART Determination Study report NO_X Section Reference number 49.

TABLE 2.4-3 – Estimated O&M Costs for NO_X Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

NO_X Control Alternative	Annual O&M Cost(1) ($1,000)	Levelized Annual O&M Cost(2) ($1,000)
SNCR (using urea) w/ boosted SOFA (Rotamix)	2,518	3,004
SNCR (using urea) w/ basic SOFA	2,142	2,556
SNCR (using urea) w/ CCOFA	2,461	2,936
Coal Reburn (conventional, pulverized) w/ boosted SOFA	3,072(3)	3,665(3)
Coal Reburn (conventional, pulverized) w/ basic SOFA	2,420(3)	2,887(3)
Boosted Separated Overfire Air (ROFA)	626	747
Separated Overfire Air (SOFA, basic)	21	25
Baseline, based on annual operation at historic 24-mo average pre-control emission rate	0	0

(1) – Annual O&M cost figures in 2005 dollars.
(2) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(3) – Costs for increased PM collection capacity included in coal reburn option are $901,000 for annual O&M cost, and $1,074,000/yr levelized annual O&M cost.

The annual operating and maintenance costs of the control options in Table 2.4-4 are based on LOS Unit 1 operation with the control option at 2,622 mmBtu/hr heat input and 8,760 hrs/yr operation. These O&M costs are relative to unit baseline operation at 0.29 lb/mmBtu for the highest 24-month NO_X emission summation at 2,622 mmBtu/hr heat input for 8,760 hrs/yr operation of LOS Unit 1 with existing close-coupled overfire air and low-NO_X burners.

TABLE 2.4-4 – Estimated O&M Costs for NO_X Control Options (Relative to Presumptive BART Annual Emission Baseline – Future PTE Case)

LOS Unit 1

NO_X Control Alternative	Annual O&M Cost[1] ($1,000)	Levelized Annual O&M Cost[2] ($1,000)
SNCR (using urea) w/ boosted SOFA (Rotamix)	2,518	3,004
SNCR (using urea) w/ basic SOFA	2,142	2,556
SNCR (using urea) w/ CCOFA	2,461	2,936
Coal Reburn (conventional, pulverized) w/ boosted SOFA	3,072[3]	3,665[3]
Coal Reburn (conventional, pulverized) w/ basic SOFA	2,420[3]	2,887[3]
Boosted Separated Overfire Air (ROFA)	626	747
Separated Overfire Air (SOFA, basic)	21	25
Baseline, based on annual operation at future PTE case pre-control emission rate	0	0

(1) – Annual O&M cost figures in 2005 dollars.
(2) – Levelized annual O&M cost = Annual O&M cost x 1.19314 O&M cost factor.
(3) – Costs for increased PM collection capacity included in coal reburn option are $901,000 for annual O&M cost, and $1,074,000/yr levelized annual O&M cost.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.4.1.3 COST EFFECTIVENESS FOR NO_X CONTROLS – LOS UNIT 1

In order to compare a particular NO_X emission reduction alternative during the cost of compliance impact analysis portion of the BART determination process, the basic methodology defined in the BART Guidelines was followed [70 FR 39167-39168]. The sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which is referred to as “Levelized Total Annual Cost” (LTAC) of each alternative, was calculated. The LTAC for all NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Section 1.3.5 for cost methodology details).

The Average Cost Effectiveness (also called Unit Control Cost) was then determined as the LTAC divided by annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. There are two different NO_X emission baselines; the first assumes the highest historic 24-month average NO_X emission rate expressed in tons per year. The second baseline derives tons per year from the maximum future PTE case average NO_X emission rate.

This approach results in two different average cost effectiveness values for the control options evaluated for LOS Unit 1. The annual NO_X emission reduction is the difference between the pre-control baseline and post-control emissions in tons per year. Average control cost for a particular technology is LTAC divided by annual tons of expected emission reduction. A summary of the annual emissions, reductions, control and levelized annual costs for the two LOS Unit 1 baselines are presented in Table 2.4-5 and 2.4-6.

TABLE 2.4-5 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

Alt. No.(1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
G	Coal Reburn with boosted SOFA (future PTE case)	1,666	1,301	7,032(5)	5,404(5)
F	Coal Reburn with basic SOFA (future PTE case)	1,746	1,221	5,983(5)	4,898(5)
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	1,782	1,185	3,819	3.223
D	SNCR with basic SOFA (future PTE case)	1,883	1,084	3,099	2,858
C	SNCR with Close-Coupled OFA (future PTE case)	2,450	517	3,361	6,504
B	Boosted Separated Overfire Air (ROFA), (future PTE case)	2,483	484	1,137	2,347
A	Separated Overfire Air (SOFA, basic)	2,642	325	144	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	2,967	0	0	

(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.

(2) – NO_X emissions and control level reductions relative to the highest historic 24-month average pre-control annual baseline for LOS Unit 1.

(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #2 for Tables 2.4-2 and 2.4-3 for annualized cost factors.

(4) – Annualized cost figures in 2005 dollars.

(5) – LTAC for increased PM collection capacity included in coal reburn option are $1,372,000 for annualized capital cost plus $1,074,000 for annualized O&M cost, for a total of $2,446,000/yr. This results in an average control cost of $1,762/ton with boosted SOFA and $1,870/ton with basic SOFA.

TABLE 2.4-6 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Presumptive BART Annual Emission Baseline – Future PTE Case)

LOS Unit 1

Alt. No.(1)	NO_X Control Alternative	Annual NO_X Emissions(2) Tons/yr	Annual NO_X Emissions Reduction(2) Tons/yr	Levelized Total Annual Cost(3),(4) $1,000	Average Control Cost(4) $/ton
G	Coal Reburn with boosted SOFA (future PTE case)	1,693	1,638	7,032(5)	4,293(5)
F	Coal Reburn with basic SOFA (future PTE case)	1,774	1,557	5,983(5)	3,844(5)
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	1,811	1,519	3,819	2,513
D	SNCR with basic SOFA (future PTE case)	1,913	1,417	3,099	2,187
C	Boosted Separated Overfire Air (ROFA), (future PTE case)	2,469	862	1,137	1,319
B	SNCR with Close-Coupled OFA (future PTE case)	2,490	841	3,362	4,000
A	Separated Overfire Air (SOFA, basic)	2,641	689	144	208
	Baseline, based on annual operation at future PTE scenario pre-control emission rate	3,330	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

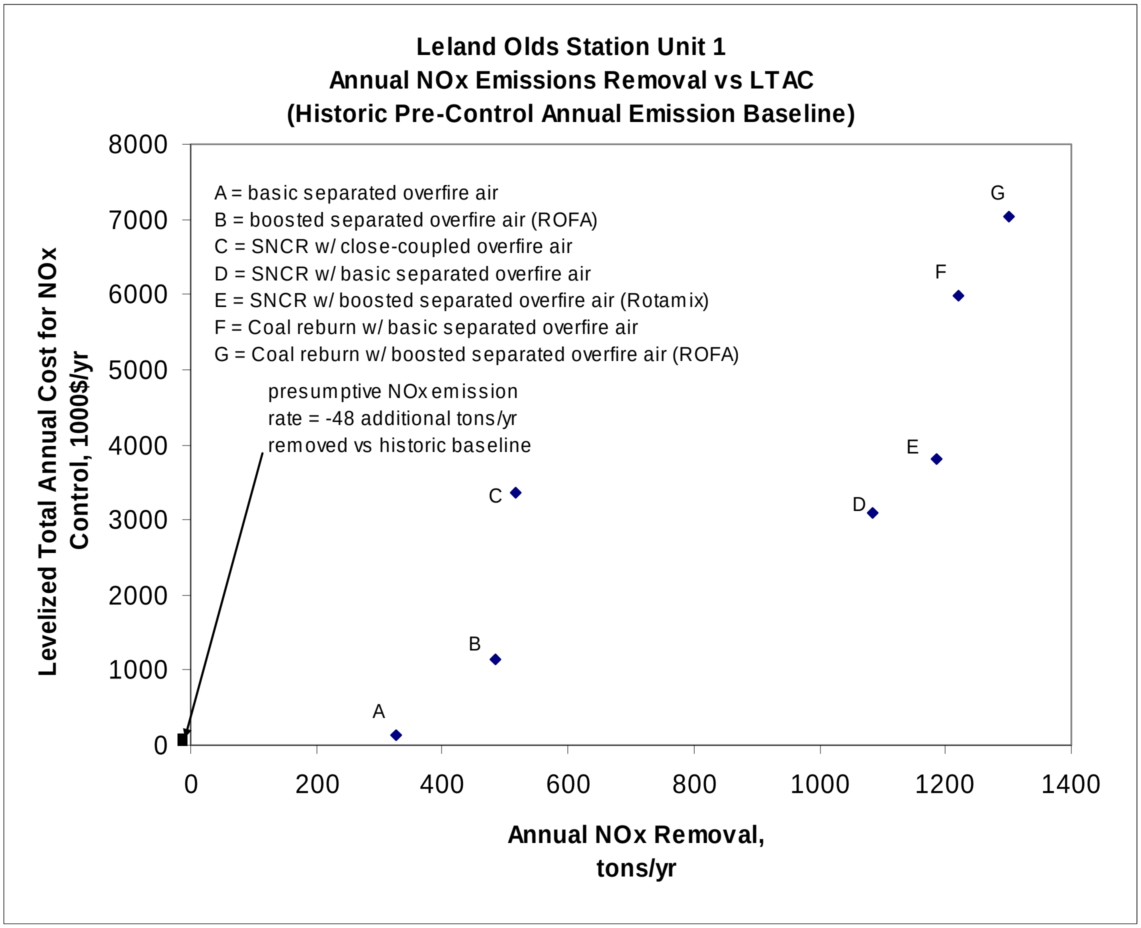
(2) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE scenario applied to LOS Unit 1.

(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #2 for Tables 2.4-2 and 2.4-4 for annualized cost factors.

(4) – Annualized cost figures in 2005 dollars.

(5) – LTAC for increased PM collection capacity included in coal reburn option are $1,372,000 for annualized capital cost plus $1,074,000 for annualized O&M cost, for a total of $2,446,000/yr. This results in an average control cost of $1,493/ton with boosted SOFA and $1,571/ton with basic SOFA.

Figure 2.4-1 – NO_X Control Cost Effectiveness – LOS Unit 1 (Historic Pre-Control Annual Emission Baseline)(1)



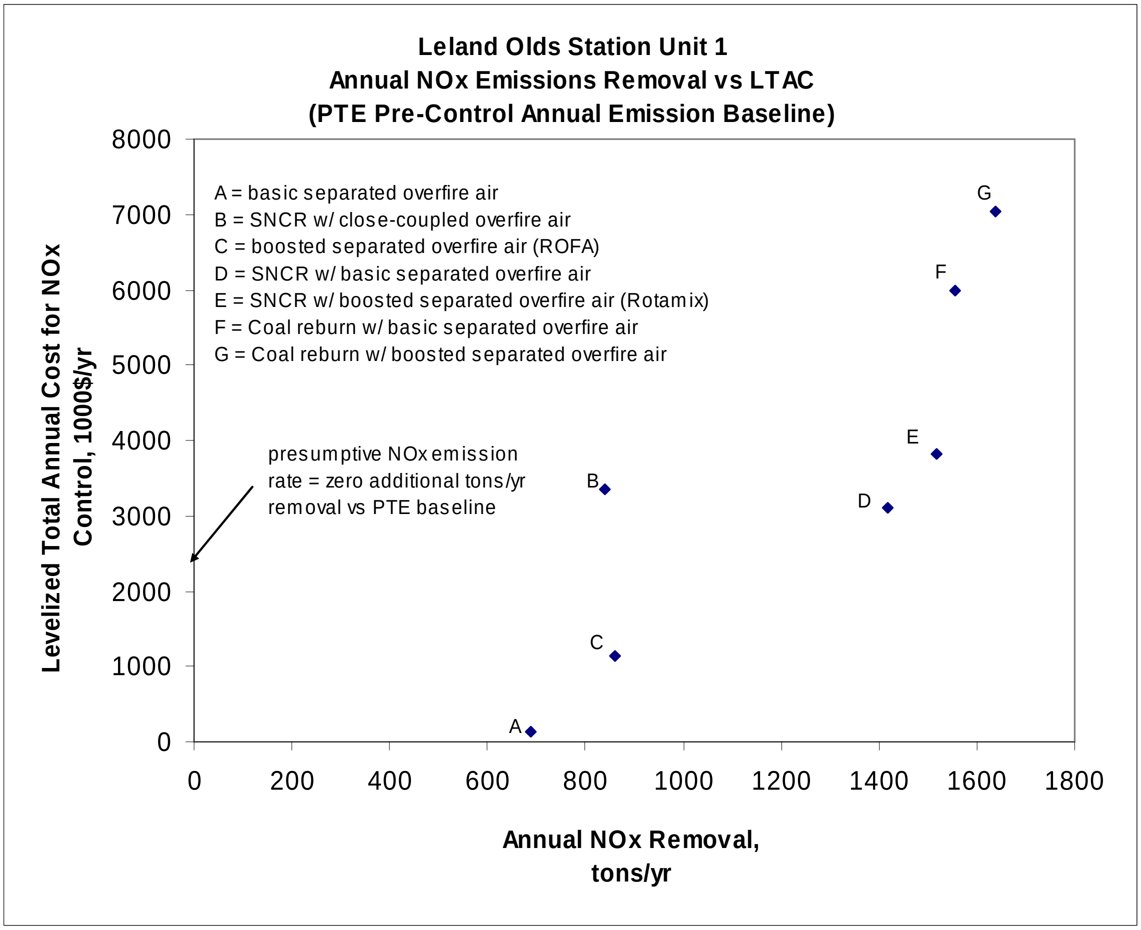
(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-5.

The comparison of the cost-effectiveness of the control options evaluated for LOS Unit 1 relative to two different NO_X emission baselines was made and is shown in Figures 2.4-1 and 2.4-2. The estimated annual amount of NO_X removal (emission reduction) in tons per year is plotted on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis).

Figure 2.4-1 is for the control options evaluated relative to the baseline historic pre-control annual baseline, compared to the post-control maximum annual NO_X emissions for operation of LOS Unit 1 under the future PTE case.

Figure 2.4-2 plots estimated levelized total annual costs versus estimated annual amount of NO_X removal (emission reduction) for the control options evaluated relative to the maximum pre-control annual baseline and future potential-to-emit post-control NO_X emissions for operation of LOS Unit ` under the future PTE case.

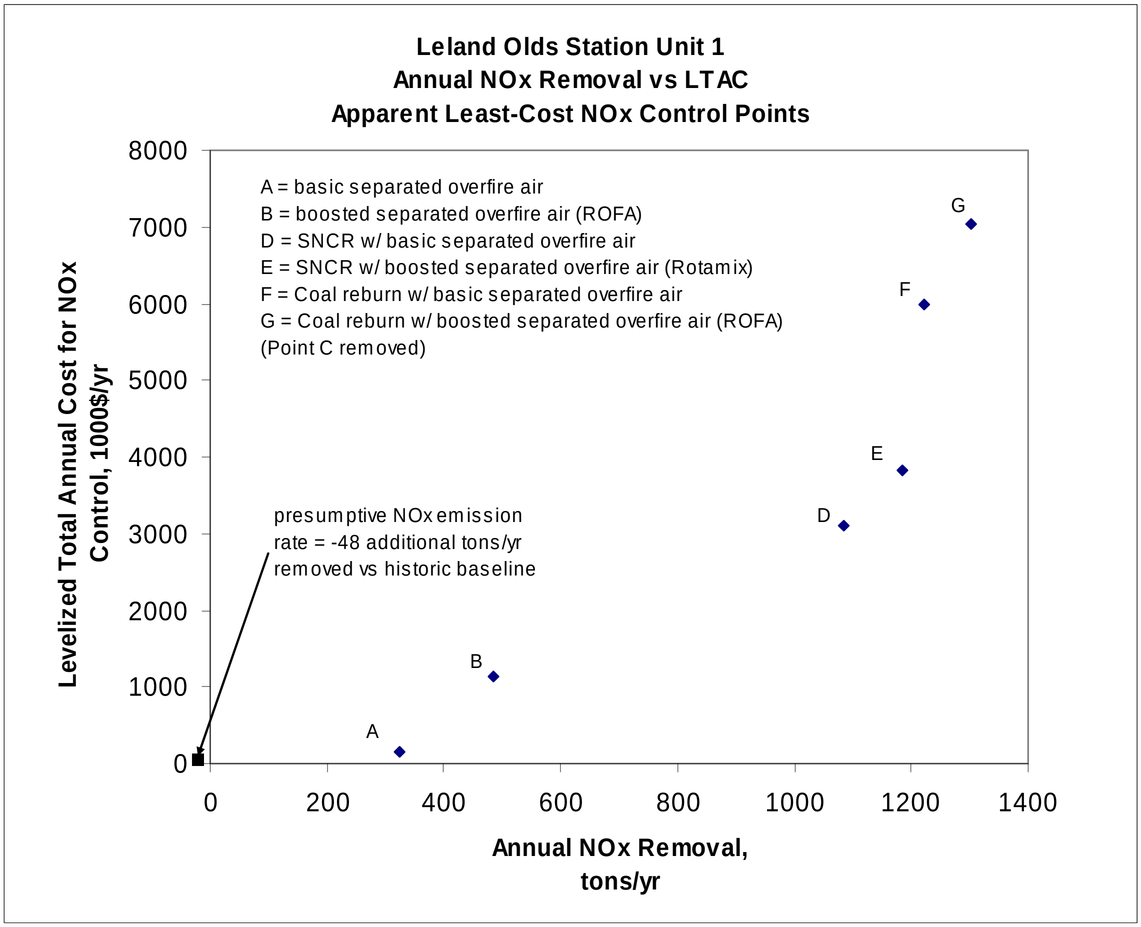
Figure 2.4-2 – NO_X Control Cost Effectiveness – LOS Unit 1 (PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-6.

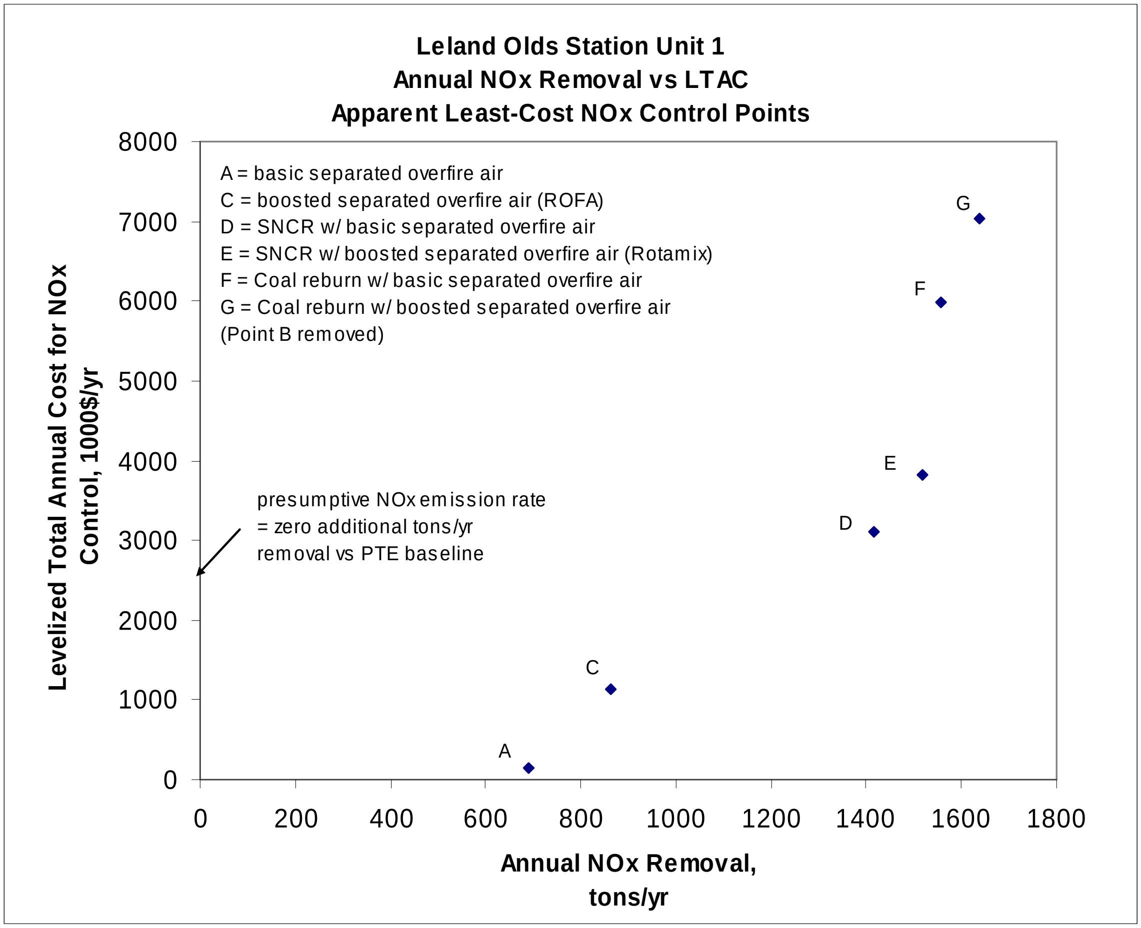
The purpose of Figures 2.4-1 and 2.4-2 is to show the range of control and cost for the evaluated NO_X reduction alternatives and identify the least-cost controls so that the Dominant Controls Curve can be created. The Dominant Controls Curve is the best fit line through the points forming the lower rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual NO_X removal tonnage for the various remaining BART alternatives. Points distinctly to the left of and above this curve are inferior control alternatives per the BART Guidelines and BART Guidelines on a cost effectiveness basis. Following a “bottom-up” graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope should be excluded from further analysis on a cost efficiency basis. Of the highest-performing versions of the technically feasible LOS Unit 1 NO_X control alternatives evaluated for cost-effectiveness, the data point for SNCR with close-coupled OFA is seen to be more costly for fewer tons of NO_X removed than for boosted separated overfire air (ROFA). SNCR with CCOFA appears to be an inferior control, and thus should not be included on the least cost and Dominant Controls Curve boundary. Note that cost-effectiveness points for conventional gas reburn and fuel-lean gas reburn alternatives would be distinctly left and significantly above the least cost-control envelope, so these options were not included in the cost-effectiveness analysis. Figures 2.4-3 and 2.4-4 show the revised least-cost control points without SNCR with CCOFA.

Figure 2.4-3 – NO_X Control Cost Effectiveness – LOS Unit 1
Apparent Least-Cost NOx Control Points
(Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-5.

Figure 2.4-4 – NO_X Control Cost Effectiveness – LOS Unit 1 Apparent Least-Cost NOx Control Points (PTE Pre-Control Annual Emission Baseline – Future PTE Case)[(1)]



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-6.

The next step in the cost effectiveness analysis for the BART NO_X control alternatives is to review the incremental cost effectiveness between remaining least-cost alternatives. Figure 2.4-5 and Figure 2.4-6 contain a repetition of the levelized total annual cost and NO_X control information from Figure 2.4-3 and Figure 2.4-4 with SNCR with CCOFA removed (Point C in Figure 2.4-1, and Point B in Figure 2.4-2), and shows the incremental cost effectiveness between each successive set of least-cost NO_X control alternatives. The incremental NO_X control tons per year, divided by the incremental levelized annual cost, yields an incremental average unit cost ($/ton). This represents the slope of a line, if drawn, from one least-cost point as compared with another least-cost point.

TABLE 2.4-7 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

Alt. No.(1)	**NO_X Control Technique**	**Levelized Total Annual Cost(2),(3) ($1,000)**	**Annual Emission Reduction(4) (Tons/yr)**	**Incremental Levelized Total Annual Cost(3),(5) ($1,000)**	**Incremental Annual Emission Reduction(4),(5) (Tons/yr)**	**Incremental Control Cost Effectiveness ($/ton)(3),(6)**
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,301	1,049	80	13,130
F	Coal Reburn with basic SOFA (future PTE case)	5,983	1,221	2,164	37	58,972
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,819	1,185	719	100	7,173
D	SNCR with basic SOFA (future PTE case)	3,099	1,084	1,962	600	2,271
B	Boosted Separated Overfire Air (ROFA), (future PTE case)	1,137	484	993	159	6,249
A	Separated Overfire Air (SOFA, basic)	144	325	144	325	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.

(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors. Costs for increased PM collection efficiency are included in coal reburn options.

(3) – Annualized cost figures in 2005 dollars.

(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 1.

(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

TABLE 2.4-8 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case)

LOS Unit 1

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,638	1,049	81	12,921
F	Coal Reburn with basic SOFA (future PTE case)	5,983	1,557	2,164	37	58,035
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,819	1,519	719	102	7,058
D	SNCR with basic SOFA (future PTE case)	3,099	1,417	1,462	556	3,532
C	Boosted Separated Overfire Air (ROFA), (future PTE case)	1,137	862	993	172	5,763
A	Separated Overfire Air (SOFA, basic)	144	689	144	689	208
--	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection capacity are included in coal reburn options.

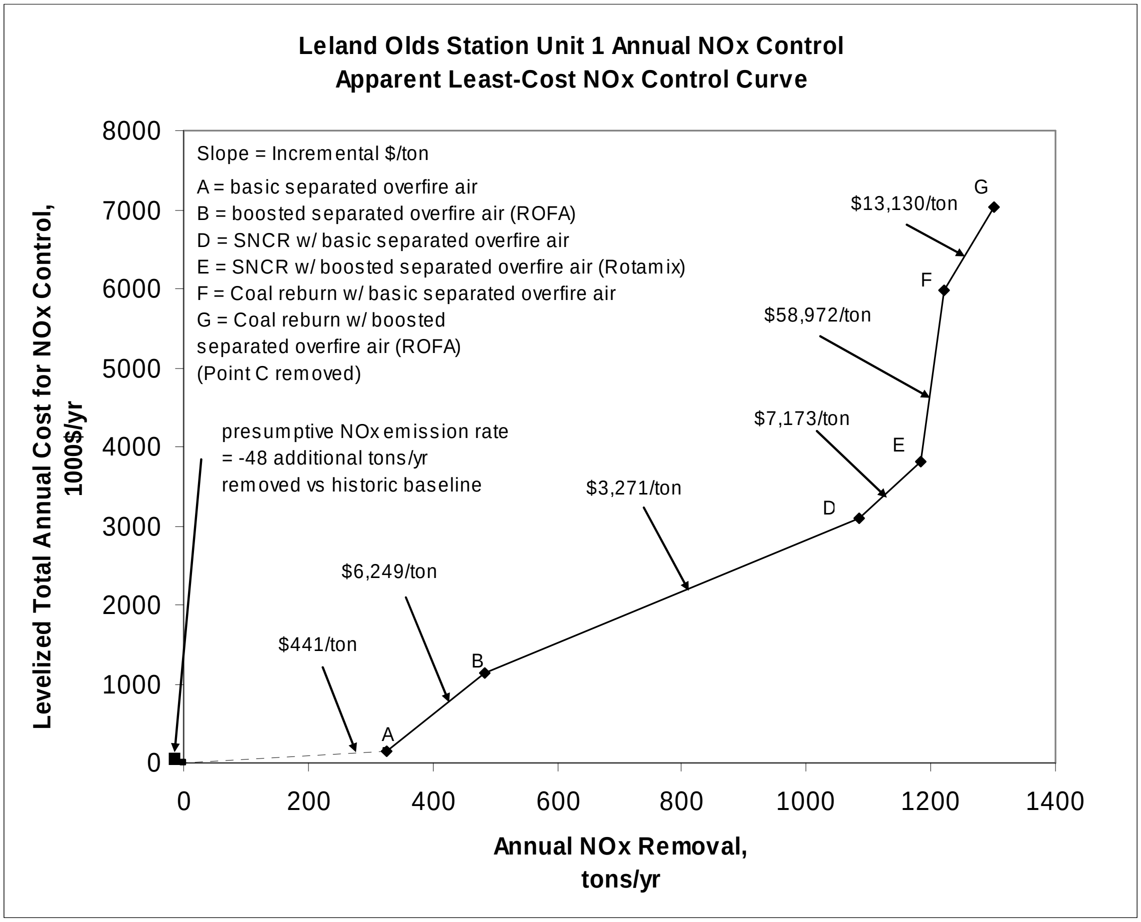
(3) – Annualized cost figures in 2005 dollars.

(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 1.

(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

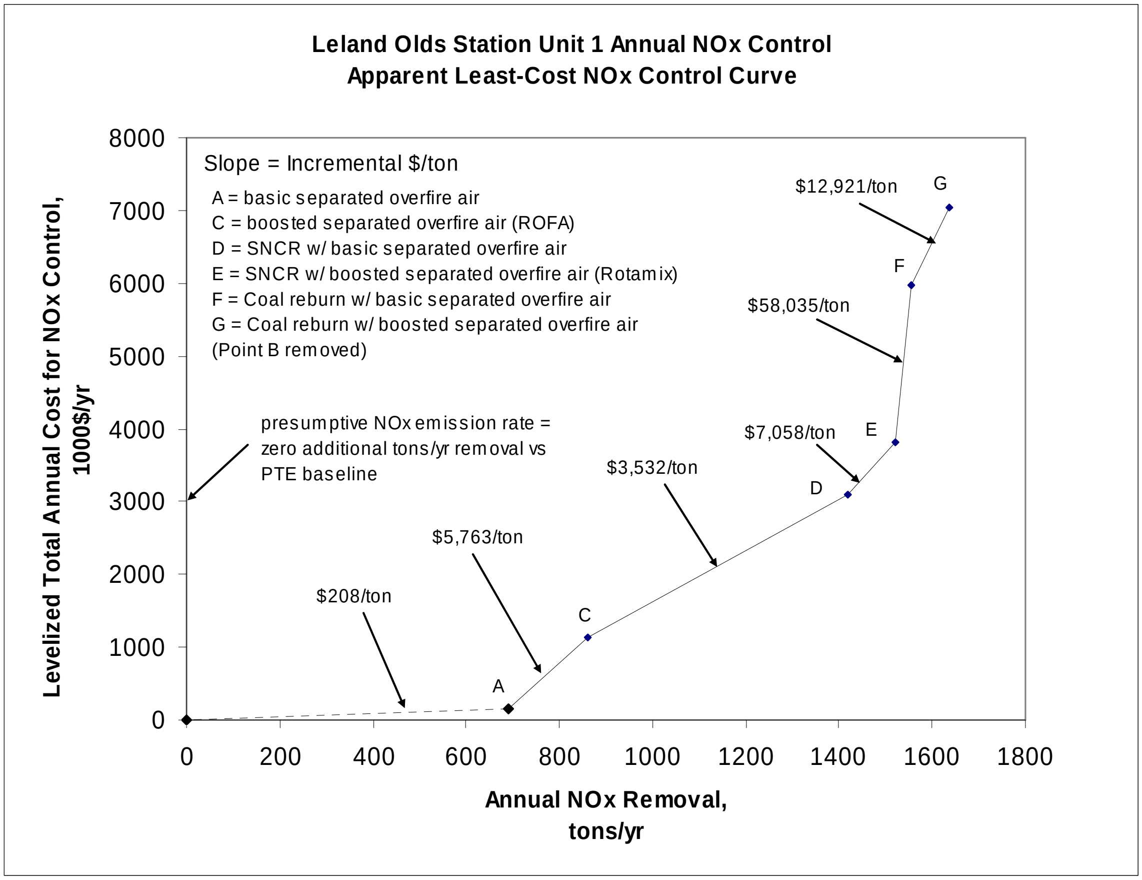
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

Figure 2.4-5 – NO_X Control Cost Effectiveness – LOS Unit 1 Apparent Least-Cost Controls Curve (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-7.

Figure 2.4-6 – NO_X Control Cost Effectiveness – LOS Unit 1 Apparent Least-Cost Controls Curve (PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)

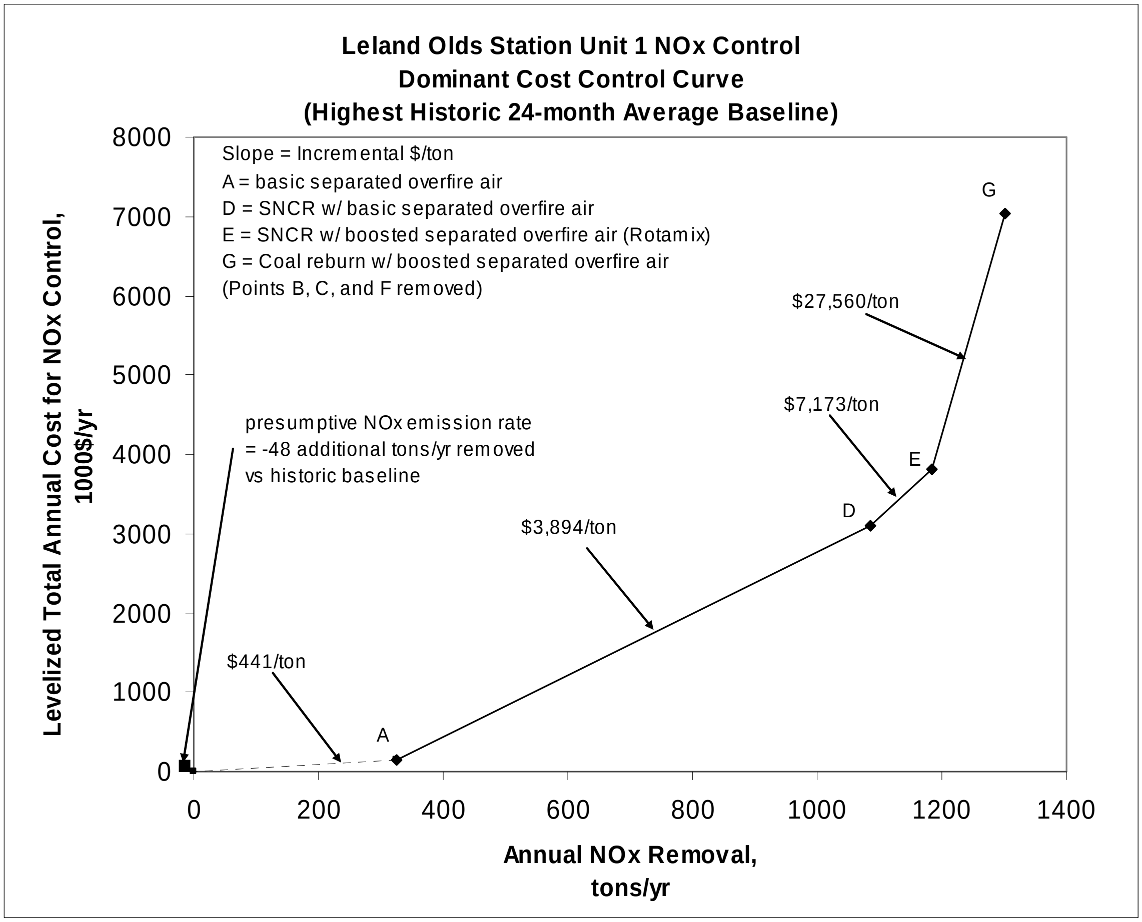


(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-8.

In the comparison displayed in Figure 2.4-5 and Figure 2.4-6, for the data shown in Table 2.4-7 and Table 2.4-8, the boosted SOFA (ROFA) NO_X control alternative (Point B in Figure 2.4-5, Point C in Figure 2.4-6) had a significantly higher incremental unit NO_X control cost (slope, $6,249/ton and $5,763/ton, respectively) compared against basic SOFA alternative (Point A) versus SNCR with basic SOFA (Points D) compared against ROFA. Also, Coal Reburn with basic SOFA (Points F) was significantly more incrementally expensive ($58,972/ton and $58,035/ton) compared against SNCR with boosted SOFA (Points E) versus Coal Reburn with boosted SOFA (Points G) compared against Coal Reburn with basic SOFA alternatives (Point F) ($13,130/ton and $12,921/ton). This indicates that Points C and Points F are inferior controls and do not occupy the Dominant Cost Control Curves.

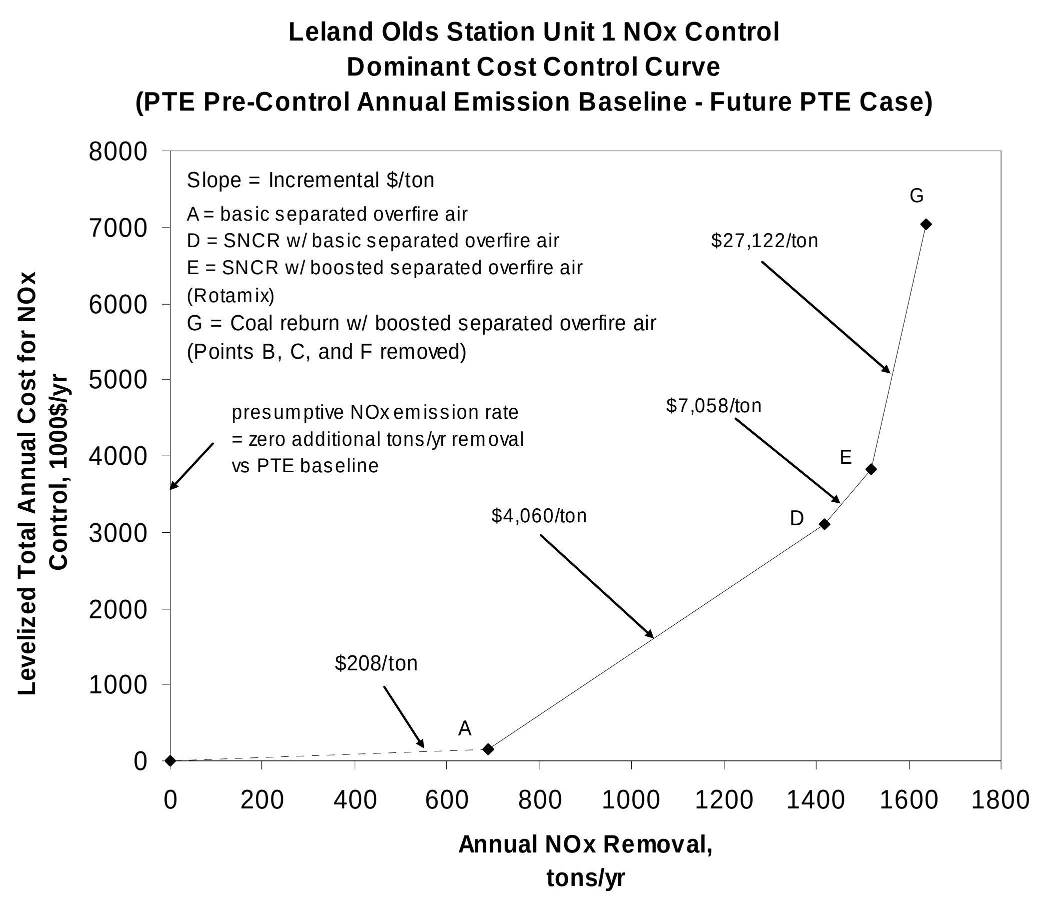
After removal of Points C and F, the modified least-cost controls curve is the Dominant Cost Control Curve for NO_X emissions alternatives for each of the LOS Unit 1 pre-control baselines evaluated.

Figure 2.4-7 – NO_X Control Cost Effectiveness – LOS Unit 1 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-9.

Figure 2.4-8 – NO_X Control Cost Effectiveness – LOS Unit 1 Dominant Cost Control Curve(1) (PTE Pre-Control Annual Emission Baseline – Future PTE Case)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-10.

TABLE 2.4-9 – Estimated Incremental Annual Emissions and LTAC for Dominant Cost Control Alternatives
(Historic Pre-Control Annual Emission Baseline) – LOS Unit 1 NO_X Control

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,301	3,213	117	27,560
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,819	1,185	719	100	7,173
D	SNCR with basic SOFA (future PTE case)	3,099	1,084	2,956	759	3,894
A	Separated Overfire Air (SOFA, basic)	144	325	144	325	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.

(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection efficiency are included in coal reburn option.

(3) – Annualized cost figures in 2005 dollars.

(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 1.

(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

TABLE 2.4-10 – Estimated Incremental Annual Emissions and LTAC for Dominant Cost Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) – LOS Unit 1 NO_X Control

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,638	3,213	118	27,122
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,819	1,519	719	102	7,058
D	SNCR with basic SOFA (future PTE case)	3,099	1,417	2,956	728	4,060
A	Separated Overfire Air (SOFA, basic)	144	689	144	689	208
--	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors. Costs for increased PM collection capacity are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

The cost impact analysis for historic and PTE baseline conditions identifies those control alternatives that are on the Dominant Controls Cost Curve. Those alternatives are scrutinized for cost-effectiveness on both relative and absolute bases. In the comparison displayed in Figure 2.4-7 and Figure 2.4-8, for the data shown in Table 2.5-9 and Table 2.5-10, the SNCR with basic SOFA NO_X control alternative (Points D) had a significantly higher incremental unit NO_X control cost (slope, $3,894/ton and $4,060/ton, respectively, for historic and PTE baseline conditions) compared against basic SOFA alternative (Point A) versus baseline ($441/ton and $208/ton, respectively). The incremental cost-effectiveness of the least-cost SNCR alternative on the Dominant Cost Control Curve is on the order of eight to nineteen times the magnitude of basic SOFA. SNCR with boosted SOFA (Point E) had a significantly higher incremental unit NO_X control cost compared against the SNCR with basic SOFA alternative (Point D) ($7,173/ton and

$7,058/ton, vs $3,894/ton and $4,060/ton respectively). Coal Reburn with boosted SOFA (Points G) was even more incrementally costly versus SNCR with boosted SOFA (Points E) ($27,560/ton and $27,122/ton, vs $($7,173/ton and $7,058/ton respectively).

In the final BART Guidelines, the EPA neither proposes hard definitions for reasonable or unreasonable Unit Control Costs nor for incremental cost effectiveness values. As can be seen from a review of Table 2.4-5, the average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the highest 24-hour historic baseline NO_X emission ranges from $441/ton to $6,504/ton. Table 2.4-6 shows average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the presumptive NO_X emission level ranges from $208/ton to $4,293/ton. The latter has lower costs per ton of NO_X emission removal due to the higher number of tons removed for the maximum emissions for pre-control baseline and additional controls under the future PTE case.

Various combinations of NO_X control technologies evaluated for control and cost-effectiveness are considered to be technically feasible for LOS Unit 1, but have much higher installation and operating costs compared with basic SOFA alone. This confirms the analysis performed by the EPA for establishing the presumptive limits for BART NO_X emissions from pulverized coal-fired EGUs: that the application of current combustion control technology, [primarily low-NOx burners and overfire air] is generally, but not always, more cost-effective than post-combustion controls. Based on the cost impact analysis and the premise that LOS Unit 1's historic and PTE annual average baseline emissions already meet the presumptive BART NO_X level of 0.29 lb/mmBtu, only the least-cost alternative of basic separated overfire air was considered for further impact and visibility impairment evaluations for LOS Unit 1 NO_X emissions control.

The other elements of the fourth step of a BART analysis after the cost impact analysis include evaluating the following impacts:

- Energy impacts.
- Non-air quality environmental impacts.
- Remaining useful life of the source.

For the purposes of this BART analysis, the remaining useful life of the source was assumed to exceed the 20-year project life utilized in the levelized annual cost impact estimates. The other impacts for the single LOS Unit 1 NO_X emissions control alternative chosen to be evaluated further are discussed in Section 2.4.2 and Section 2.4.3. Visibility impairment impacts evaluated for selected LOS Unit 1 NO_X emissions controls are summarized in Section 2.4.4.

(The following article is an addition to the August 2006 BEPC BART Determination Study report.)

[The same basic kinds of energy impacts for NO_X emissions controls described in the August 2006 BEPC LOS BART Report were evaluated for the SOFA with SNCR alternative for LOS Unit 1.]

2.4.2.1 ENERGY IMPACTS OF SOFA with SNCR NO_X CONTROL ALTERNATIVE – LOS UNIT 1

Another feasible NO_X control alternative was reviewed for significant or unusual energy penalties or benefits associated with its use on LOS Unit 1.

Basic SOFA with SNCR operation on LOS Unit 1 may require slightly higher forced draft fan power consumption resulting from higher fan discharge pressure, with combustion air damper actuators' electrical power demand expected to be an insignificant (+ 1 kW) change in net electrical power consumption from LOS Unit 1. Higher windbox pressure and ductwork pressure drop impacts of the SOFA system on the forced draft fans' and induced draft fans' auxiliary electrical power consumption are expected to be negligible (less than 1% of the annual auxiliary power consumed by these fans).

The SNCR portion of this layered alternative involves a chemical reagent injected for NO_X control, assumed to be aqueous urea. The injection of a diluted urea solution requires some additional auxiliary power for heating and pumping the liquid, and using compressed air for atomization and cooling the reagent injection nozzles/lances. Heat is required for urea reagent storage, assumed to be applied to outside concentrated aqueous urea storage tank(s). For the basic SOFA with SNCR alternative, the source of heat is assumed to be auxiliary electrical power. Together, the addition of SNCR to LOS Unit 1 is estimated to consume 35.8 kW, which was calculated following EPA OAQPS convention[2]. Based on operation for the entire year with the assumed 99% availability factor, this would consume approximately 310,000 kW-hr/yr of additional auxiliary electrical power.

Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water; this follows EPA OAQPS convention[1], but is not accepted practice by an experienced SNCR vendor (Fuel Tech) who claims that the heat produced from the exothermic reaction of urea and NO_X is approximately equal to the heat required to evaporate the dilution water. Reagent dilution water for those SNCR alternatives that involve a chemical reagent injected for NOx control were assumed to be four times the amount of delivered aqueous urea solution consumption (assumes urea is a 50% solution as delivered and is

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[2]. See Basin LOS BART Determination Study report NO_X Section Reference number 49, page 1-34.

injected as a 10% solution); this also follows EPA OAQPS convention[3]. This was estimated to be approximately 6.2 million Btu per hour, or 53,645 mmBtu/yr.

Likewise, operation of a basic SOFA with SNCR alternative may cause a small increase in levels of unburned carbon in the flyash emitted from the LOS Unit 1 boiler compared with current operation. This represents a slight amount of lost potential electrical power generation from the incompletely burned fuel, so this inefficiency could have a small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr). This impact was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

As discussed above, SNCR operation will cause a slight decrease (approximately 0.2%) on the LOS Unit 1 plant unit heat rate (higher Btu/kW-hr), primarily to higher flue gas moisture with corresponding sensible and latent heat losses which would require a slightly higher gross heat input to evaporate the extra dilution water input. This ignores the slight increase in induced draft fan horsepower and auxiliary electrical power consumption to handle the extra coal combustion products, urea and dilution water flows that will result in increased flue gas mass flow during SNCR operation.

LOS Unit 1 boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures is not expected to change significantly, as a slight increase during air-staged burner operation with SOFA may be offset by a slight depression from the injection of the urea dilution water. This impact on the boiler’s operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This impact on the LOS Unit 1 boiler’s thermal conversion efficiency and steam cycle impacts from small steam temperature changes was not quantified, but is not expected to be significant.

SOFA and SNCR are not expected to significantly reduce LOS Unit 1 reliability and availability to generate electrical power. There may be some changes in the degradation rate of the boiler’s furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion of the steel waterwall tubes by sulfur compounds in the furnace gases being created above the burners and below the SOFA injection ports. Due to the moderate sulfur content in the lignite and modest amount of air-staging during firing of the existing low-NO_X burners expected during SOFA operation, this potential change in corrosion rate of the boiler tubes is expected to be minor. This degradation is expected to occur

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[3] See Basin LOS BART Determination Study report NO_X Section Reference number 49, page 1-35.

over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes and superheater/reheater tube banks to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube and superheater/reheater tube failures and changeouts is difficult to estimate, and has not been quantified. SNCR with SOFA operation of LOS Unit 1 may also cause a slight increase in fireside deposit accumulation, especially in the primary and possibly secondary superheater and reheater tube banks. This is expected to be minor, and removed during periodic scheduled outages of LOS Unit 1.

Table 2.4-11 summarizes the gross demand and usage of auxiliary electrical power estimated for the two NO_X control alternatives evaluated for impacts on LOS Unit 1. This assumes annual operation for 8,760 hours at a heat input rate of 2,622 mmBtu/hr at the future PTE case conditions.

TABLE 2.4-11 – Expected Auxiliary Electrical Power Impacts for NO_X Controls – LOS Unit 1

		NO_X Control Equipment Estimated Annual Average Auxiliary Electrical Power Demand and Usage (future PTE case)		
Alt. No.	**NO_X Control Technique**	**Aux. Power Demand (1) (kW)**	**Generation Reduction from Aux. Power Demand(2) (kW-hrs/yr)**	**Generation Reduction from Reduced Unit Availability(3) (kW-hrs/yr)**
D	SNCR with basic SOFA	36.8	318,749	18,893
A	Separated OFA	1	8,760	0

(1) – The NO_X control equipment gross auxiliary electrical power demand is estimated.

(2) – The annual change in NO_X equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.

(3) – The estimated total hours per year of unit unavailability multiplied by average gross generation multiplied by annual running plant capacity factor for the particular control alternative. For this analysis, SOFA was not expected to reduce annual hours of possible operation.

(The following article is an addition to the August 2006 BEPC BART Determination Study report)

[The same basic kinds of non-air environmental impacts for NO_X emissions controls described in the August 2006 BEPC LOS BART Report were evaluated for the SOFA with SNCR alternative for LOS Unit 1.]

2.4.3.2 NON AIR QUALITY AND OTHER ENVIRONMENTAL IMPACTS OF SOFA with SNCR – LOS UNIT 1

Operation of an SNCR-related system will normally create a small amount of unreacted urea or ammonia to be emitted. The amount of ammonia slip produced by SNCR depends on the amount of reagent utilization and location of the injection points. Higher SNCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

Ammonia slip is typically controlled to less than 10 ppmvd, especially since the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates. Boiler combustion air heaters, whether tubular or rotary regenerative types, can become fouled with such sulfate compounds. An extension of scheduled unit outages or forced outages (unlikely) could occur as a result of these sulfate deposit accumulations and the time spent to remove them. This could reduce unit operating time (annual availability), but for LOS Unit 1 is expected to be very small, estimated to be 1% of the annual operating time possible.

Some of the unreacted ammonia from SNCR operation will be collected with the flyash in the electrostatic precipitator. This is not expected to pose any significant hazards in the subsequent disposal of the flyash in the nearby permitted landfill currently used by BEPC for this coal combustion byproduct material.

Storage of urea or ammonia reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Regulation of storage and containment of such reagents as hazardous substances will be under the requirements of various federal Acts, which are not part of this BART impact analysis.

The amount of unburned carbon in the flyash produced by the boiler, collected for disposal or potentially emitted to the atmosphere may increase by small increments due to operation of LOS Unit 1 using separated overfire air for NO_X emissions control. The potential changes in the annual amounts of flyash disposal rates are expected to be inconsequential, and have not been quantified. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

The operation of a system using a basic form of separated overfire air for NO_X emissions control may increase carbon monoxide concentrations in the stack flue gas emitted from the LOS Unit 1 boiler. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

The operation of a conventional SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs). The chemical form of the reagent will affect the amount of carbon dioxide emitted, since urea contains CO which is readily converted to CO_2 in the boiler-furnace and convection sections by combining with available free oxygen. One mole of carbon dioxide (CO_2) will be created and emitted for every mole of urea injected for reaction with NO_X. This is a relatively small increase in the total amount of CO_2 produced as part of the combustion of carbon-based fossil fuel in the form of lignite. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be emitted from the stack as an aerosol or condensable particulate. This has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition. Although the predicted amount of such potential impact from ammonia slip emissions has not been determined, it is expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO_X emission reductions from the use of SNCR-related alternatives. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

There were no other adverse or significant changes in non-air quality environmental impacts identified for LOS Unit 1 as a result of using separated overfire air with SNCR for NO_X emissions control. Predicted visibility impairment improvement impacts from the reduction in nitrogen oxides emissions predicted to result from operation of LOS Unit 1 with SOFA and SNCR are discussed in the next section.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study report)

2.4.4 VISIBILITY IMPAIRMENT IMPACTS OF LELAND OLDS STATION NO_X CONTROLS –UNIT 1

The fifth step in a BART analysis is to conduct a visibility improvement determination for the source.

For this BART analysis, there were two baseline NO_X emission rates modeled for LOS Unit 1 – one for the historic pre-control NO_X emission rate listed in the NDDH BART protocol[3], and one applying the presumptive BART NO_X emission rate. The historic pre-control emission baseline was the 24-hour average actual NO_X emission rate from the highest emitting day of the years 2000-2002 (meteorological period modeled per the NDDH BART protocol[3]). The historic (protocol) NO_X baseline condition emission rate was modeled simultaneously with the highest 24-hour average SO_2 emission rate, and the highest 24-hour average PM emission rate of the 2000-2002 time period.

The historic (protocol) baseline hourly NO_X emission rate used for modeling visibility impacts due to LOS Unit 1 under the conditions stated above was 813 lb/hr. Visibility impact modeling was performed using the CALPUFF model with the difference between the impacts from historic pre-control baseline and post-control average hourly NO_X emission rates representing the visibility impairment impact reduction. One CALPUFF model run was performed with the LOS Unit 1's basic SOFA NO_X emission rate and another run was subsequently conducted with LOS Unit 1's SOFA with SNCR NO_X emission rate, constant PM emissions, and BART level of SO_2 control assuming the Potential-To-Emit (PTE) boiler design rating for heat input (2,622 mmBtu/hr). The unit NO_X emission rate of 0.168 lb/mmBtu multiplied by the boiler PTE heat input rating of 2,622 mmBtu/hr yields 441 lb/hr for LOS Unit 1 under the future PTE case. This compares to the visibility model using an average post-control hourly future PTE LOS Unit 1 NO_X emission rate of 0.23 lb/mmBtu with the PTE boiler heat input rating to yield 603 lb/hr for operation with basic SOFA.

In keeping with the NDDH BART visibility impairment impact modeling protocol, the BART NO_X post-control future PTE presumptive emission rate (760 lb/hr), basic SOFA, and SOFA with SNCR alternatives all have a different boiler heat input basis than the LOS Unit 1 historic highest 24-hour pre-control NO_X emission baseline (813 lb/hr). The post-control conditions for LOS Unit 1 all assume operation at the boiler PTE heat input capacity rating (future PTE case) of 2,622 mmBtu/hr.

The results of the historic LOS Unit 1 pre-control baseline, presumptive BART NO_X PTE baseline, and future post-control PTE NO_X emission rates for basic SOFA alternatives with and without SNCR-enhancement, modeled with the PTE 90% sulfur emission control rate for LOS Unit 1, are shown in Table 2.4-12. The results of the visibility impairment modeling at the pre-control (protocol) baseline emission rate for LOS Unit 1 showed that Lostwood National Wildlife Refuge exceeded 0.5 deciView for the highest predicted visibility impairment impact (90th percentile, averaged for 2000-2002). Average predicted visibility impairment impacts decreased significantly for the presumptive BART NO_X PTE baseline emission rate, and improved slightly with post-control SOFA with and without SNCR-enhanced PTE NO_X emission rates, modeled with the 90% PTE sulfur emission control rates for LOS Unit 1. The comparison of the incremental average visibility impairment impacts that are predicted for the three PTE sulfur emission control rates for LOS Unit 1 is shown elsewhere in Section 3.4.4.

TABLE 2.4-12 – Average Visibility Impairment Impacts from NO_X Controls – LOS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts(1)			
	Historic Pre-Control (Protocol) Baseline(2) (dV)	Presumptive BART NO_X PTE Baseline(3) (dV)	PTE Emissions with basic SOFA NO_X Control(4) (dV)	PTE Emissions with basic SOFA+SNCR NO_X Control(5) (dV)
TRNP-South Unit	0.423	0.107	0.099	0.091
TRNP-North Unit	0.450	0.118	0.111	0.102
TRNP-Elkhorn Ranch	0.287	0.080	0.073	0.066
Lostwood NWR	0.639	0.171	0.153	0.132

(1) - Average predicted visibility impairment impacts (90th percentile) relative to background for years 2000-2002. Pre-control baseline impacts are from highest historic 24-hour NO_X, SO_2, and PM emission rates (NDDH BART protocol). Presumptive BART NO_X emission limit, basic SOFA NO_X and basic SOFA + SNCR NO_X emission rate impacts are from PTE heat input conditions. A summary of the initial modeling scenarios was provided in the August 2006 BART Determination Study final draft report Table 1.4-1 and the modeling results were presented in Appendix D. SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case.

(2) - Average of year 2000-2002 (annual) predicted visibility impairments modeled at historic pre-control NO_X emission baseline of 813 lb/hr.

(3) - Average of year 2000-2002 (annual) predicted visibility impairments modeled at presumptive BART post-control PTE NO_X mass emission hourly rate of 760.4 lb/hr (0.29 lb/mmBtu x 2,622 mmBtu/hr).

(4) - Average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA control alternative's post-control PTE NO_X mass emission hourly rate of 603.1 lb/hr (0.23 lb/mmBtu x 2,622 mmBtu/hr).

(5) - Average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA with SNCR control alternative's post-control PTE NO_X mass emission hourly rate 441 lb/hr (0.168 lb/mmBtu x 2,622 mmBtu/hr).

The results of the visibility impairment modeling at the presumptive BART NO_X PTE emission rate (760 lb/hr) with the PTE 90% sulfur emission control rate for LOS Unit 1 again showed that Lostwood National Wildlife Refuge had the highest predicted improvement in visibility impairment compared to the pre-control (protocol) baseline levels. Average predicted visibility impairment reduction also increased with basic SOFA with and without SNCR-enhanced post-control NO_X PTE emission rates from LOS Unit 1 for Lostwood NWR (approximately 0.5 deciView reduction). This is shown in Table 2.4-13.

TABLE 2.4-13 – Average Visibility Impairment Impact Reductions from NO_X Controls – LOS Unit 1 (Post-Control PTE Emissions vs Historic Baseline)

Federal Class 1 Area	Visibility Impairment Reductions(1)		
	Presumptive BART NO_X PTE Baseline(2) (dV)	**PTE Emissions, basic SOFA NO_X Control(3) (dV)**	**PTE Emissions with basic SOFA+SNCR NO_X Control(4) (dV)**
TRNP-South Unit	0.316	0.323	0.332
TRNP-North Unit	0.332	0.339	0.348
TRNP-Elkhorn Ranch	0.207	0.214	0.220
Lostwood NWR	0.467	0.486	0.507

(1) - Average predicted visibility impairment impact reductions (90th percentile) relative to historic pre-control emission rates (NDDH BART protocol) for years 2000-2002. Presumptive BART NO_X and SOFA NO_X impacts are from PTE heat input emission rates. SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case scenario.

(2) - Difference of average of year 2000-2002 (annual) predicted visibility impairments modeled at historic pre-control NO_X emission baseline of 813 lb/hr minus average of year 2000-2002 (annual) predicted visibility impairments modeled at presumptive BART post-control PTE NO_X mass emission hourly rate of 760.4 lb/hr (0.29 lb/mmBtu x 2,622 mmBtu/hr).

(3) - Difference of average of year 2000-2002 (annual) predicted visibility impairments modeled at historic pre-control NO_X emission baseline of 813 lb/hr minus average of year 2000-2002 (annual)

predicted visibility impairments modeled at basic SOFA control alternative's post-control PTE NO_X mass emission hourly rate of 603.1 lb/hr (0.23 lb/mmBtu x 2,622 mmBtu/hr).

(4) - Difference of average of year 2000-2002 (annual) predicted visibility impairments modeled at historic pre-control NO_X emission baseline of 813 lb/hr minus average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA with SNCR control alternative's post-control PTE NO_X mass emission hourly rate 441 lb/hr (0.168 lb/mmBtu x 2,622 mmBtu/hr).

This analysis includes calculation of the average incremental reduction of the predicted visibility impairment impact for basic SOFA with and without SNCR-enhanced alternatives' PTE emission levels evaluated for the future PTE case operation of LOS Unit 1 compared to presumptive BART NO_X control effectiveness. The results are shown in Table 2.4-14.

TABLE 2.4-14 –Visibility Impairment Reduction from NO_X Controls (vs Presumptive BART NO_X Baseline Emissions) – LOS Unit 1

Federal Class 1 Area	Incremental Visibility Impairment Reduction PTE Emissions, basic SOFA NO_X Control[1] (dV)	Incremental Visibility Impairment Reduction PTE Emissions with basic SOFA+SNCR NO_X Control[2] (dV)	Additional Incremental Visibility Impairment Reduction PTE Emissions with basic SOFA+SNCR NO_X Control[3] (dV)
TRNP-South Unit	0.00733	0.0157	0.00833
TRNP-North Unit	0.00733	0.0160	0.00867
TRNP-Elkhorn Ranch	0.00733	0.0137	0.00633
Lostwood NWR	0.0183	0.0393	0.0210

(1) - Incremental average predicted visibility impairment impact reductions (90th percentile) relative to presumptive BART post-control PTE NO_X mass emission hourly rate for years 2000-2002. SOFA NO_X post-control impacts are from PTE heat input emission rates, with SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case.

(2) - Incremental average predicted visibility impairment impact reductions (90th percentile) relative to presumptive BART post-control PTE NO_X mass emission hourly rate for years 2000-2002. SOFA + SNCR post-control NO_X impacts are from PTE heat input emission rates, with SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case.

(3) - Additional incremental average predicted visibility impairment impact reductions (90th percentile) relative to basic SOFA post-control PTE NO_X mass emission hourly rate for years 2000-2002. SOFA + SNCR post-control NO_X impacts are from PTE heat input emission rates, with SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case.

Table 2.4-14 shows that incremental visibility impairment improvements predicted to result from applying the basic SOFA with and without SNCR-enhanced alternatives to the presumptive BART NO_X PTE emission rate for LOS Unit 1 are very small. The amount of visibility impairment predicted for natural background conditions is much greater in magnitude than the amount predicted from LOS Unit 1's post-control NO_X PTE emissions contribution alone. The data also shows that reductions in predicted visibility impairment impacts that result from a combination of presumptive

BART NO_X PTE emissions and SO_2 PTE emissions at the 90 percent (or better) control levels compared to the pre-control (protocol) emission conditions are much greater in significance than the incremental improvements of predicted visibility impairment from additional reductions in NO_X emissions.

This analysis also includes a determination of the incremental cost-effectiveness of reducing predicted visibility impairment impact for the SOFA with and without SNCR-enhanced alternatives being evaluated for LOS Unit 1. The estimated LTAC for reducing NO_X emissions from LOS Unit 1 expected to result from separated overfire air (SOFA) for the future PTE case are shown in Table 2.4-6. The comparison in Table 2.4-15 shows that the ratio of the estimated additional annualized costs of installing and operating SOFA with and without SNCR-enhanced alternatives for the future PTE conditions to the average predicted visibility impairment improvement relative to the presumptive BART NO_X PTE baseline emission rate for the future PTE case applied to LOS Unit 1 would result in millions of dollars per deciView of visibility impairment improvement.

TABLE 2.4-15 – Cost Effectiveness of Visibility Impairment Reduction from NO_X Controls (vs Presumptive NO_X Baseline Emissions) – LOS Unit 1

Federal Class 1 Area	Incremental Visibility Impairment Reduction Unit Cost PTE Emissions, basic SOFA NO_X Control(1) ($/dV-yr)	Incremental Visibility Impairment Reduction Unit Cost PTE Emissions, basic SOFA + SNCR NO_X Control(2) ($/dV-yr)	Additional Incremental Visibility Impairment Reduction Unit Cost PTE Emissions, basic SOFA + SNCR vs SOFA NO_X Control(3) ($/dV-yr)
TRNP-South Unit	19,640,000	197,800,000	354,600,000
TRNP-North Unit	19,640,000	193,700,000	341,000,000
TRNP-Elkhorn Ranch	19,640,000	226,800,000	466,600,000
Lostwood NWR	7,860,000	78,800,000	140,700,000

(1) - Average predicted visibility impairment impact reductions (90th percentile) relative to presumptive BART NO_X PTE baseline emission rates for years 2000-2002 with SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case. Basic SOFA NO_X impacts are from PTE heat input emission rates. Control costs are levelized annual values for installed capital + O&M for basic SOFA NO_X control. All cost figures in 2005 dollars. See Table 2.4-6 for details.

(2) - Average predicted visibility impairment impact reductions (90th percentile) relative to presumptive BART NO_X PTE baseline emission rates for years 2000-2002 with SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case. Basic SOFA+SNCR NO_X impacts are from PTE heat input emission rates. Control costs are levelized annual values for

installed capital + O&M for basic SOFA+ SNCR NO_X control. All cost figures in 2005 dollars. See Table 2.4-6 for details.

(3) - Average predicted incremental visibility impairment impact reductions (90th percentile) relative to basic SOFA NO_X PTE emission rates for years 2000-2002 with SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case. Basic SOFA and basic SOFA with SNCR NO_X impacts are from PTE heat input emission rates. Incremental control costs are levelized annual values for installed capital + O&M for basic SOFA with SNCR control vs basic SOFA NO_X control. All cost figures in 2005 dollars. See Table 2.4-6 for details.

The number of days predicted to have visibility impairment due to LOS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the historic pre-control (protocol) hourly NO_X, SO_2, and PM emission rates described previously in this Section. The results are summarized and presented in the Screening Analysis Table of Appendix D. Similarly, the same information for the post-control SO_2 and PM alternatives for LOS Unit 1 with presumptive BART NO_X PTE emission rates was summarized and is shown in Table 3.4-15. The differences in average visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between presumptive BART NO_X emission rates versus basic SOFA-controlled LOS Unit 1 NO_X emission rates with post-control SO_2 and PM alternatives are summarized and shown in Table 2.4-16. The reductions in the average visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between presumptive BART NO_X emission rates versus basic SOFA with SNCR-controlled NO_X emission rates with post-control SO_2 and PM alternatives for LOS Unit 1 are also summarized and shown in Table 2.4-16.

The magnitude of predicted visibility impairment impacts and number of days predicted to have visibility impairment impact greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 area. The highest number of days in which the predicted visibility impairment impact above background exceeded 0.5 deciViews was for the pre-control (protocol) emission case in year 2000 for Lostwood NWR. A series of bar charts showing the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for both the pre-control and post-control model results is included in Section 3.4. The post-control SO_2 and PM alternatives with SOFA for NO_X control were only slightly lower for the predicted visibility impairment impacts and number of days predicted to have visibility impairment impacts greater than 0.50 and 1.00 deciViews compared to the same post-control SO_2 and PM conditions with presumptive BART NO_X PTE emission rates. The number of days are presented in Appendix D. A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the SOFA-controlled PTE emission rates compared to presumptive BART NO_X PTE emission rates with post-control SO_2 and PM alternatives is included in Figures 2.4-9, 2.4-10, and 2.4-11.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.4.5 SUMMARY OF IMPACTS OF LOS NO_X CONTROLS – UNIT 1

Table 2.4-17 summarizes the various quantifiable impacts discussed in Sections 2.4.1 through 2.4.4 for the single BART NO_X alternative evaluated for LOS Unit 1.

Table 2.4-16 – Visibility Impairment Reductions – Basic SOFA and Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls

LOS Unit 1

Class 1 Area	NO_X Control Technique(1)	Visibility Impairment Reduction (ΔdV)	ΔDays(2) Exceeding 0.5 dV in 2000	ΔDays(2) Exceeding 0.5 dV in 2001	ΔDays(2) Exceeding 0.5 dV in 2002	ΔDays(2) Exceeding 1.0 dV in 2000	ΔDays(2) Exceeding 1.0 dV in 2001	ΔDays(2) Exceeding 1.0 dV in 2002	ΔConsecutive Days(2) Exceeding 0.5 dV 2000	ΔConsecutive Days(2) Exceeding 0.5 dV 2001	ΔConsecutive Days(2) Exceeding 0.5 dV 2002
TRNP South	Basic SOFA	0.00733(3)	1	0	0	0	0	0	0	0	0
TRNP North	Basic SOFA	0.00733(3)	2	3	2	0	0	0	0	1	0
TRNP Elkhorn	Basic SOFA	0.00733(3)	1	0	1	1	0	1	0	0	0
Lostwood NWR	Basic SOFA	0.0183(3)	0	0	2	0	2	0	0	0	0
TRNP South	Basic SOFA+SNCR	0.0157(4)	2	2	3	1	0	0	0	1	0
TRNP North	Basic SOFA+SNCR	0.0160(4)	3	3	4	1	0	2	0	1	0
TRNP Elkhorn	Basic SOFA+SNCR	0.0137(4)	1	0	1	1	0	1	0	0	0
Lostwood NWR	Basic SOFA+SNCR	0.0393(4)	1	4	4	0	3	2	0	0	0

1 - SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

2 - Difference in number of days is 100th percentile level for predicted visibility impacts in Table 3.4-15.

3 - Average predicted visibility impairment reductions (90th percentile) from all PTE emissions for SO_2 and PM post-control alternatives with basic SOFA NO_X control at 0.23 lb/mmBtu relative to presumptive NO_X emission level of 0.29 lb/mmBtu with PTE heat input emission rates (future PTE case), years 2000-2002.

4 - Average predicted visibility impairment reductions (90th percentile) from all PTE emissions for SO_2 and PM post-control alternatives with basic SOFA + SNCR NO_X control at 0.168 lb/mmBtu relative to presumptive NO_X emission level of 0.29 lb/mmBtu with PTE heat input emission rates (future PTE case), years 2000-2002.

Figure 2.4-9 – Days of Visibility Impairment Reductions – 0.5 dV
Basic SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

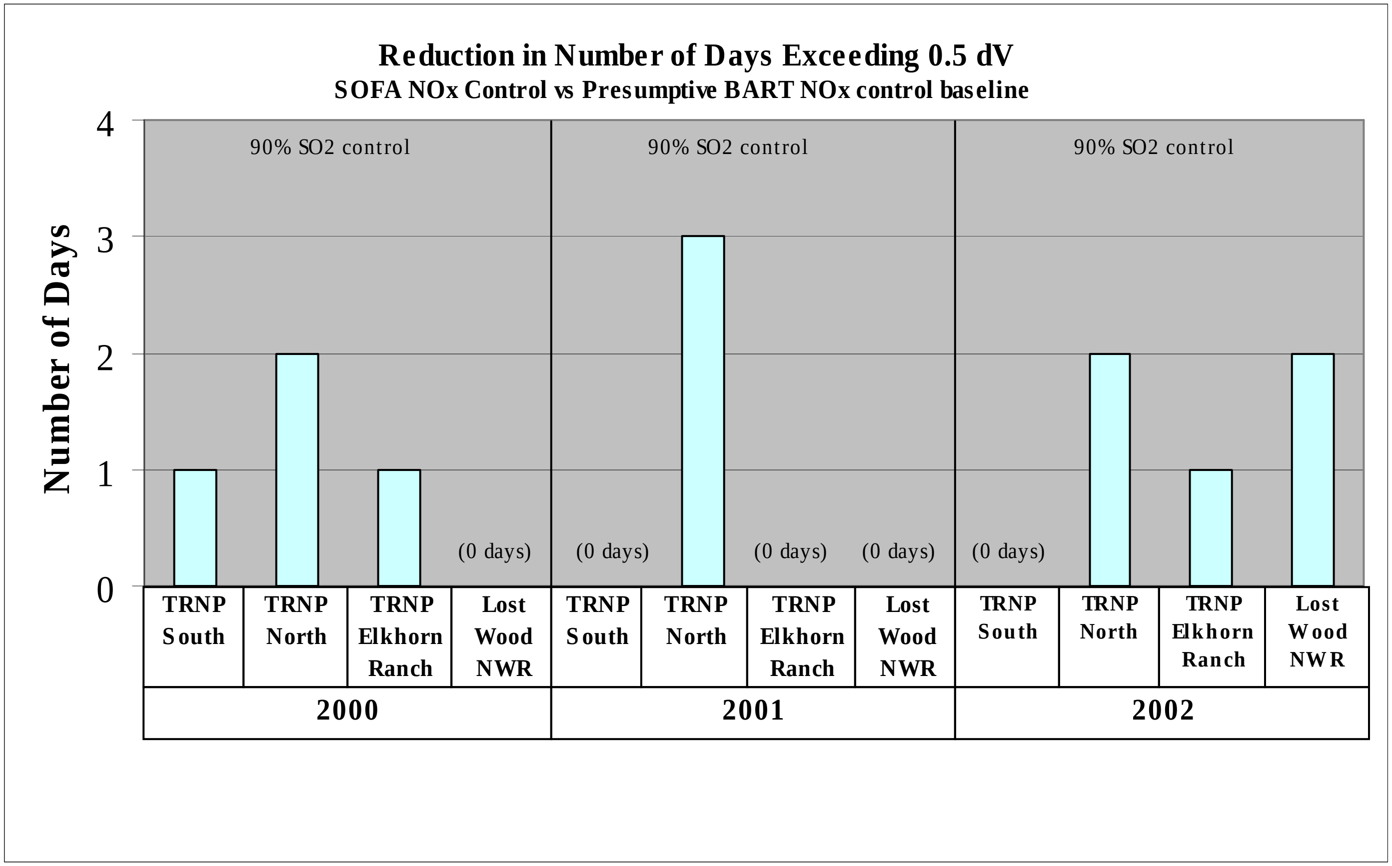


Figure 2.4-10 – Days of Visibility Impairment Reductions – 1.0 dV
Basic SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

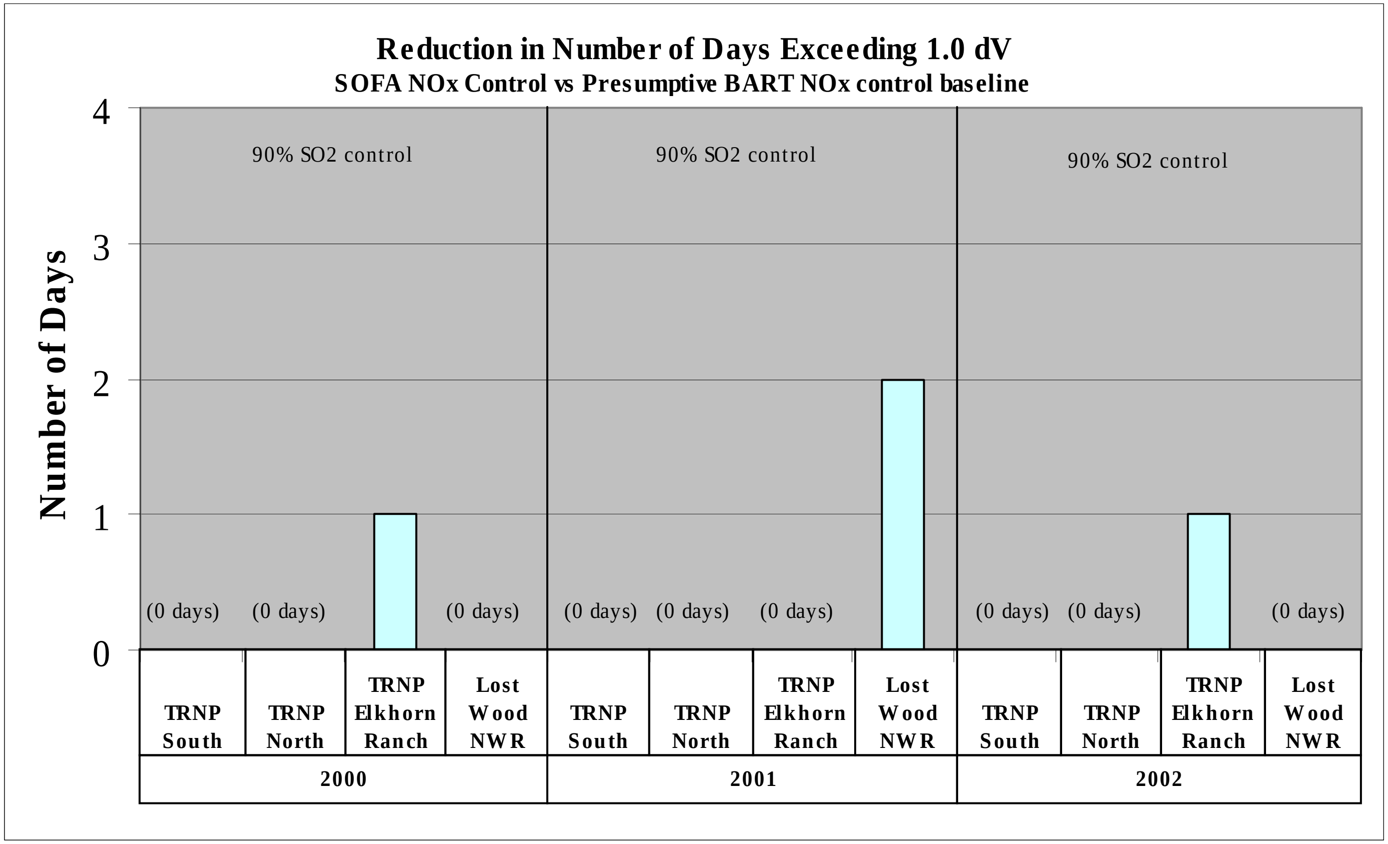


Figure 2.4-11 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV
Basic SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

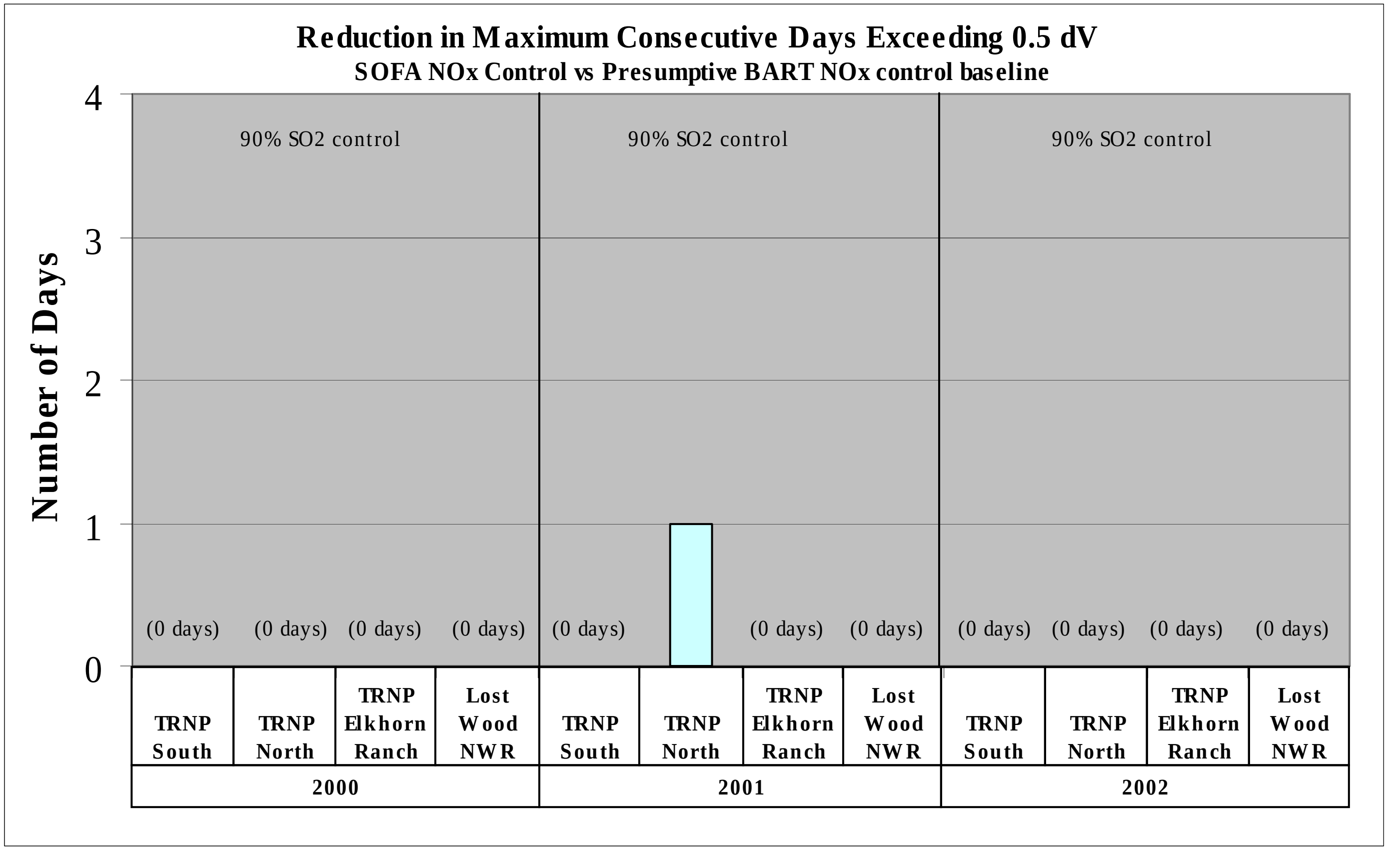


Figure 2.4-12 – Days of Visibility Impairment Reductions – 0.5 dV
Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

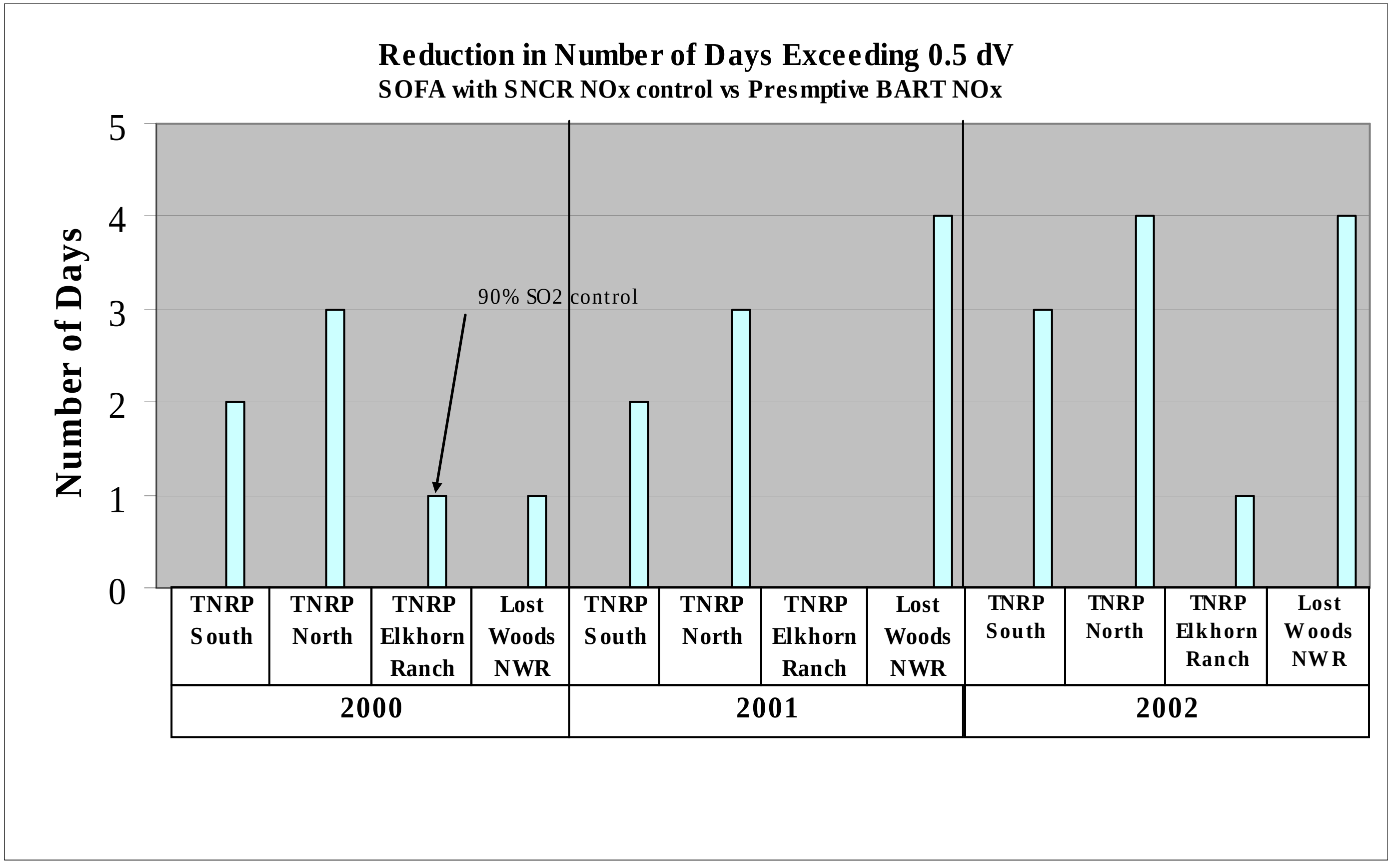


Figure 2.4-13 – Days of Visibility Impairment Reductions – 1.0 dV
Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

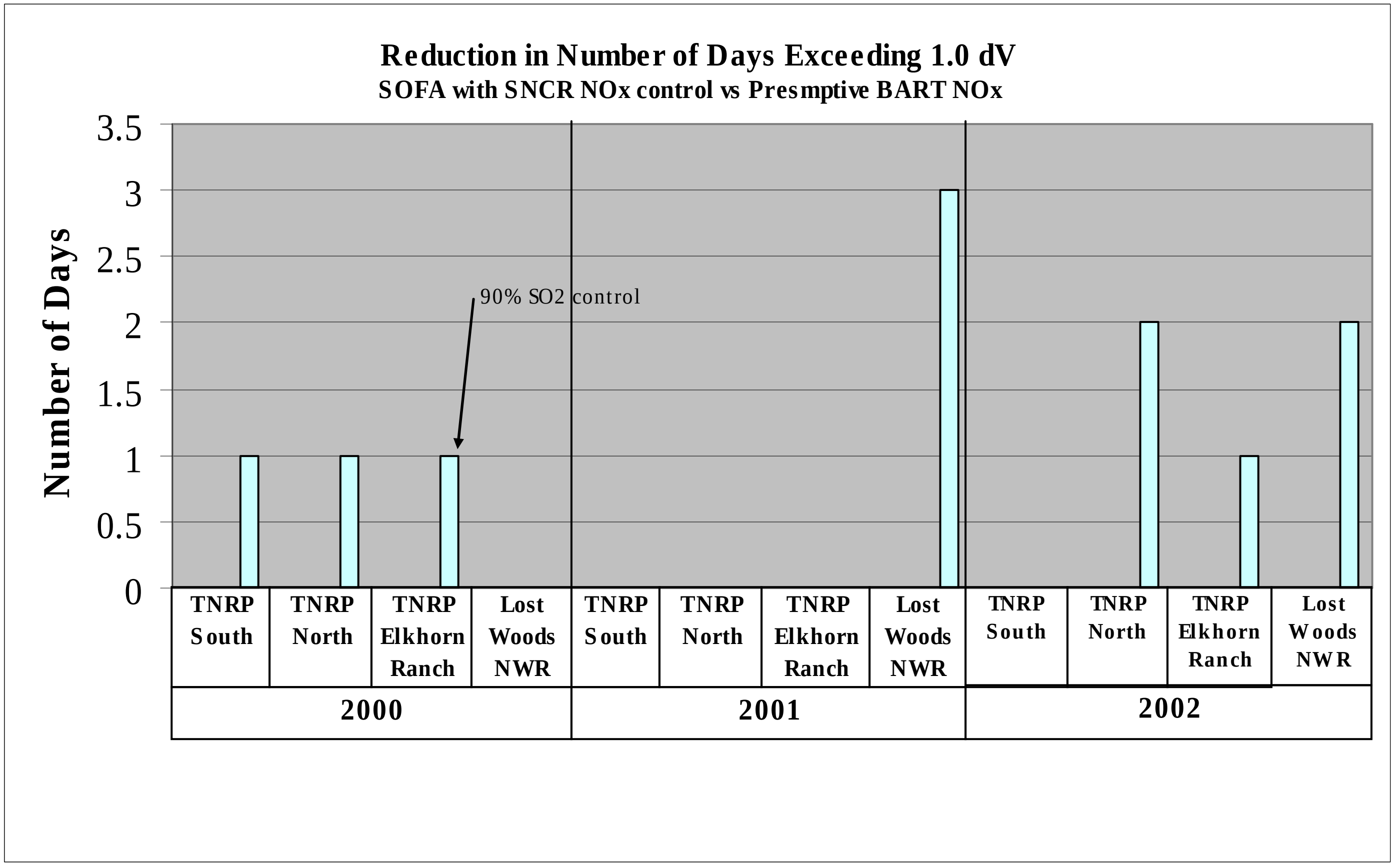


Figure 2.4-14 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls LOS Unit 1

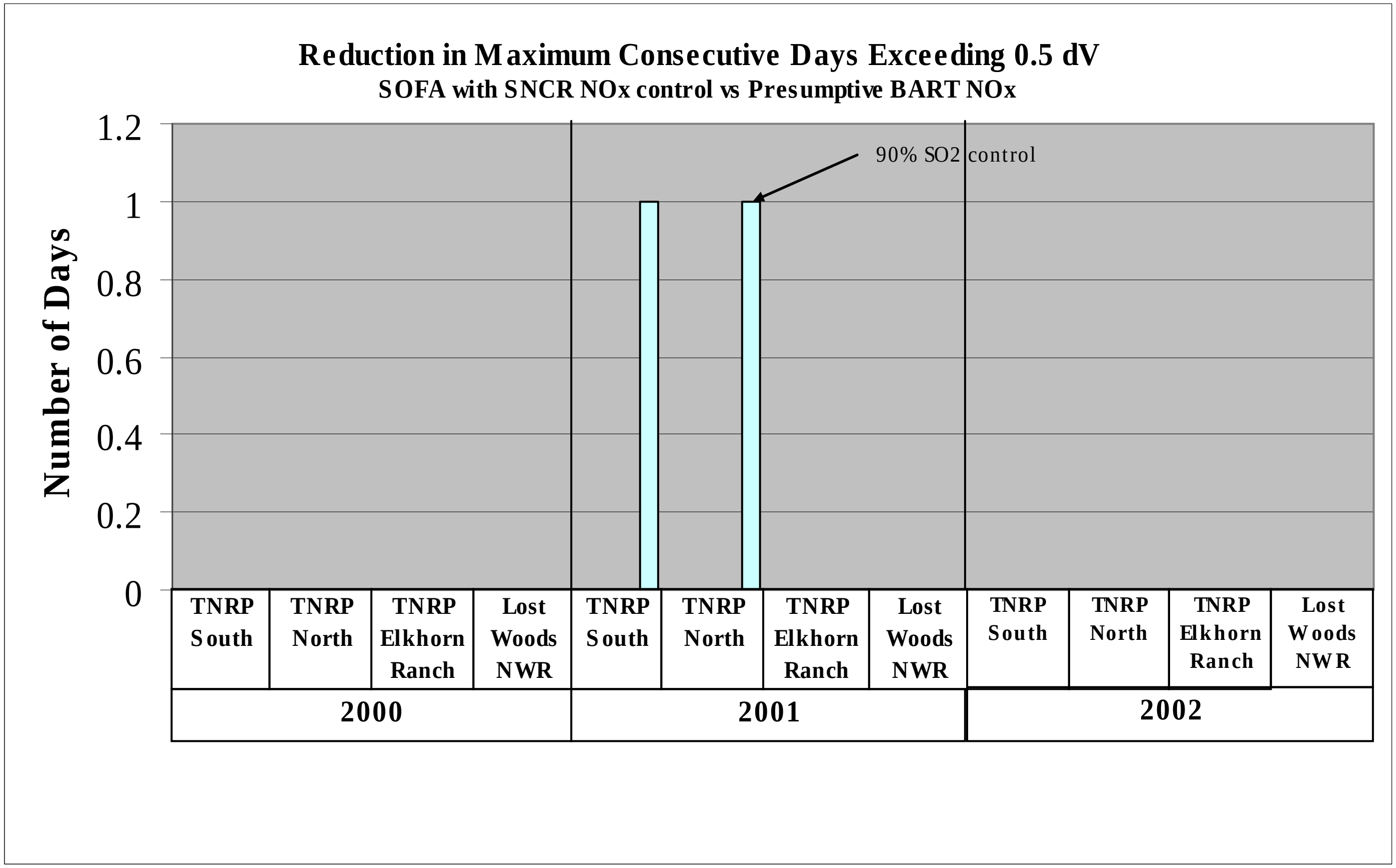


Figure 2.4-15 – Days of Visibility Impairment Reductions – 0.5 dV
Basic SOFA + SNCR Control vs SOFA NO_X Control with SO_2 and PM Controls
LOS Unit 1

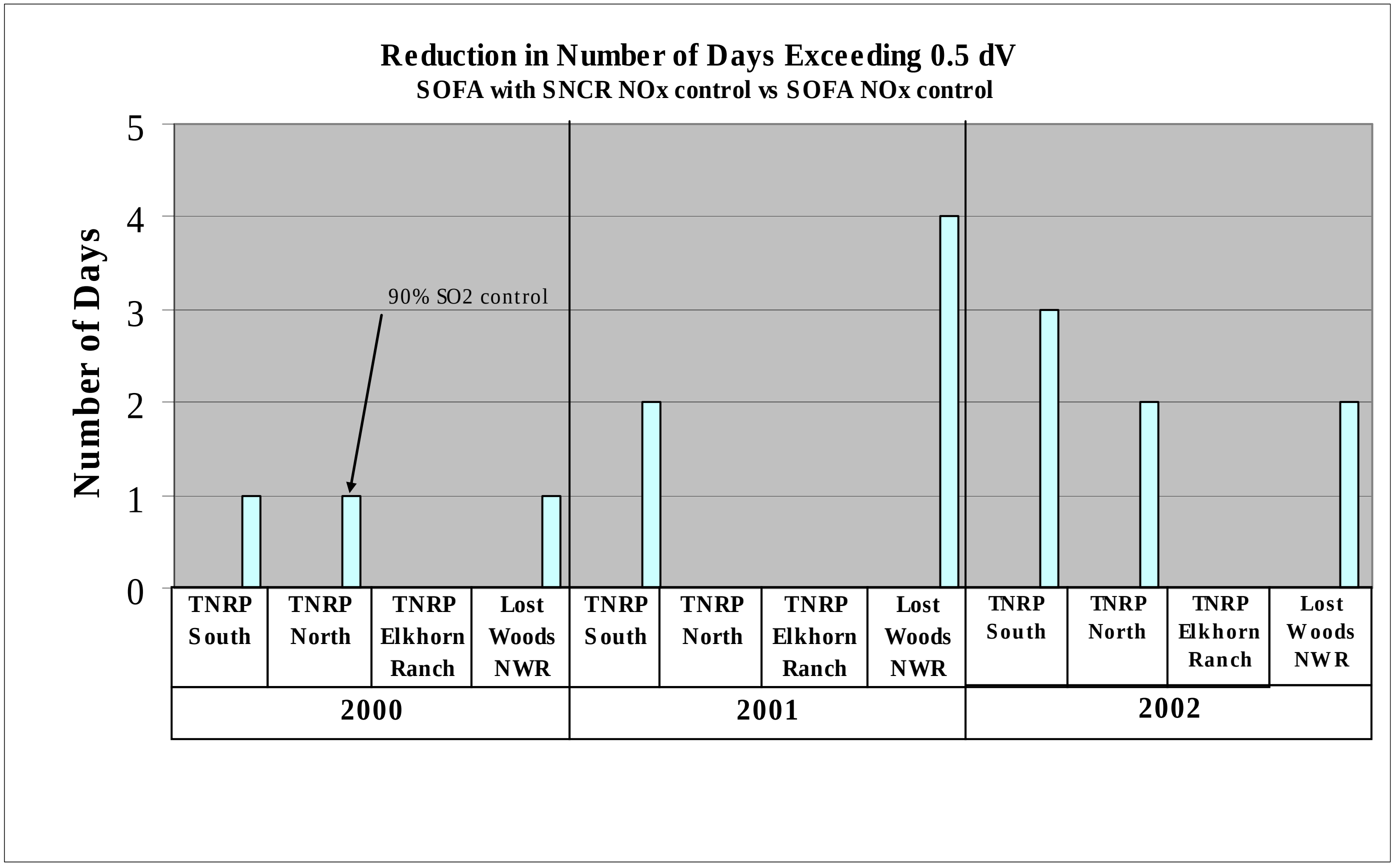


Figure 2.4-16 – Days of Visibility Impairment Reductions – 1.0 dV
Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

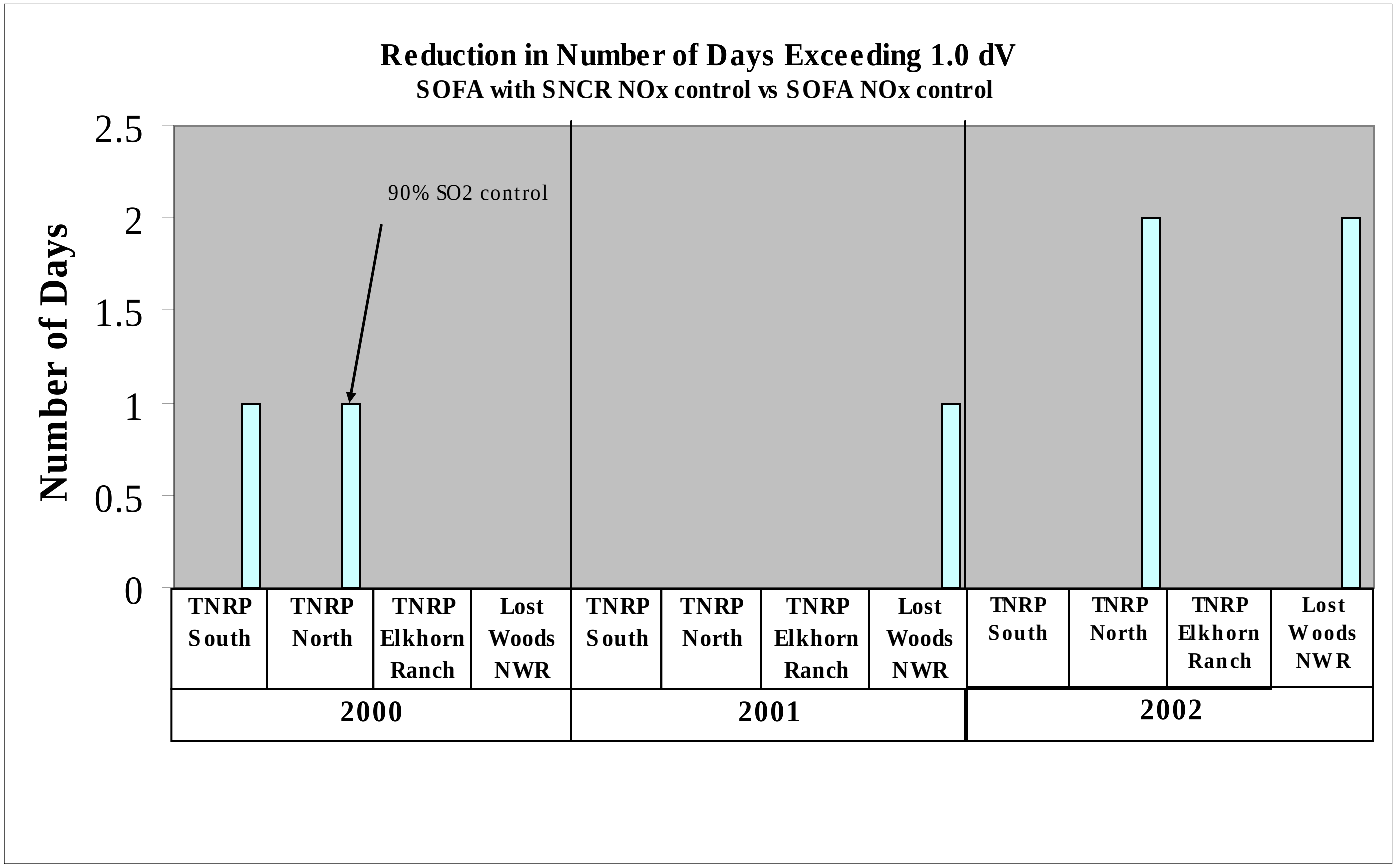


Figure 2.4-17 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV Basic SOFA + SNCR vs Presumptive BART NO_X Control with SO_2 and PM Controls LOS Unit 1

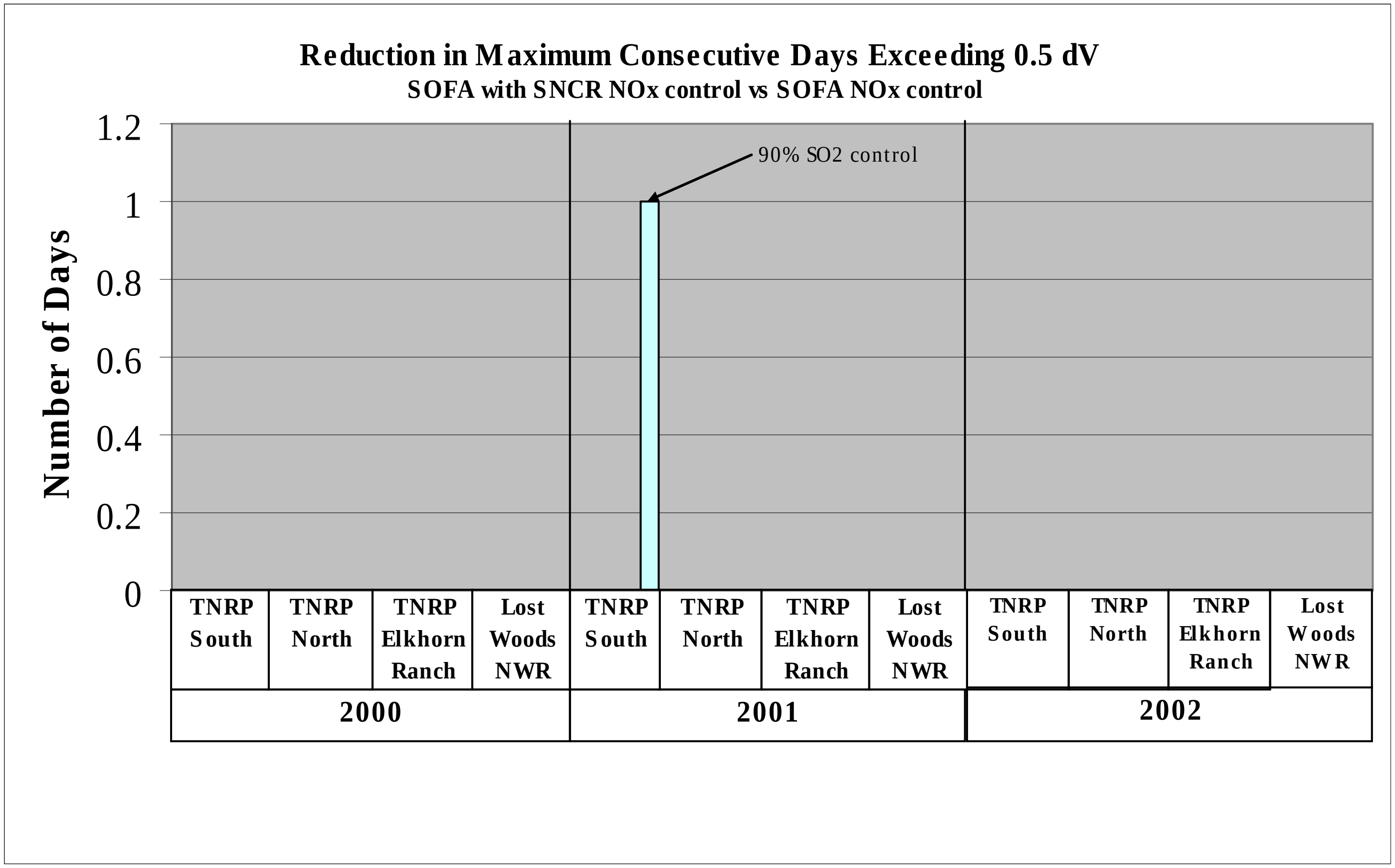


Table 2.4-17 – Impacts Summary for LOS Unit 1 NO_X Controls (vs Presumptive BART NO_X PTE Emissions)

NO_X Control Technique w/ SO_2 Control Level	NO_X Control Efficiency (%)	Annual NO_X Emissions Reduction (tpy)	Levelized Total Annual Cost(1) ($)	Unit Control Cost(1) ($/ton)	Visibility Impairment Impact Reduction		Incremental Visibility Impairment Reduction Unit Cost(1), (2) ($/dV)	Energy Impact (kW)	Non Air Quality Impacts
					Class 1 Area	Incremental ΔdV			
Basic SOFA w/ 90% SO_2 Control	20.7%	689	$144,000	$208	TRNP-S	0.00733(3)	$19,640,000	1	Flyash unburned carbon increase
					TRNP-N	0.00733(3)	$19,640,000		
					TRNP-Elk	0.00733(3)	$19,640,000		
					LNWR	0.0183(3)	$7,860,000		
Basic SOFA + SNCR w/ 90% SO_2 Control	42.0%	1,417	$3,100,000	$2,187	TRNP-S	0.0157(4)	197,800,000	36.8	Flyash unburned carbon increase, ammonia in flyash
					TRNP-N	0.0160(4)	193,700,000		
					TRNP-Elk	0.0137(4)	226,800,000		
					LNWR	0.0393(4)	78,800,000		
Basic SOFA + SNCR vs basic SOFA, w/ 90% SO_2 Control	26.8(5)	728(5)	$2,955,000 (5)	$4,059	TRNP-S	0.00833(5)	354,600,000(5)	35.8(5)	ammonia in flyash
					TRNP-N	0.00867(5)	341,000,000(5)		
					TRNP-Elk	0.00633(5)	466,600,000(5)		
					LNWR	0.0210(5)	140,700,000(5)		

(1) - All cost figures in 2005 dollars. See Table 2.4-6 for details.

(2) - LTAC for post-control NO_X control alternative divided by Incremental ΔdV.

(3) - Average predicted visibility impairment impact improvements (incremental, 90th percentile) for years 2000-2002 (annual) modeled at presumptive BART post-control PTE NO_X mass emission hourly rate of 760.4 lb/hr (0.29 lb/mmBtu x 2,622 mmBtu/hr) minus average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA control alternative's post-control PTE NO_X mass emission hourly rate of 603.1 lb/hr (0.23 lb/mmBtu x 2,622 mmBtu/hr) with SO_2 and PM post-control alternatives at PTE heat input emission rates (future PTE case) for both cases. This case assumes 90% SO_2 control over pre-control baseline.

(4) - Average predicted visibility impairment impact improvements (incremental, 90th percentile) for years 2000-2002 (annual) modeled at presumptive BART post-control PTE NO_X mass emission hourly rate of 760.4 lb/hr (0.29 lb/mmBtu x 2,622 mmBtu/hr) minus average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA with SNCR control alternative's post-control PTE NO_X mass emission hourly rate 441 lb/hr (0.168 lb/mmBtu x 2,622 mmBtu/hr) with SO_2 and PM post-control alternatives at PTE heat input emission rates (future PTE case) for both cases. This case assumes 90% SO_2 control over pre-control baseline.

(5) - Average predicted incremental visibility impairment impact improvements (incremental, 90th percentile) for years 2000-2002 (annual) modeled at SOFA post-control PTE NO_X mass emission hourly rate of 603.1 lb/hr (0.23 lb/mmBtu x 2,622 mmBtu/hr) minus average of year 2000-2002 (annual) predicted visibility impairments modeled at basic SOFA with SNCR control alternative's post-control PTE NO_X mass emission hourly rate 441 lb/hr (0.168 lb/mmBtu x 2,622 mmBtu/hr) with SO_2 and PM post-control alternatives at PTE heat input emission rates (future PTE case) for both cases. This case assumes 90% SO_2 control over pre-control baseline.

(The following article is a copy of the same section in the August 2006 BEPC BART Determination Study final draft report. It is included here for continuity from the corrected and amended Unit 1 portion of the BEPC BART Determination Study report and the corrected Unit 2 portion that follows)

2.5 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS – LOS UNIT 2

The fourth step of a BART analysis is to evaluate the following impacts of feasible emission controls:

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

The purpose of the impacts evaluation is to determine if there are any energy, economic, non-air quality environmental reasons, or aspects of the remaining useful life of the source, which would eliminate the control technologies from consideration for Leland Olds Station Unit 2.

2.5.1 COST IMPACTS OF NO_X CONTROLS – LOS UNIT 2

An evaluation was performed to determine the compliance costs of installing various feasible NO_X control alternatives on LOS Unit 2 boiler. This evaluation included estimates for:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 2.5-1 through 2.5-8. From Step 3 of the BART analysis, compared with other similarly-effective NO_X controls, conventional gas reburn alternatives would have high expected capital costs for a natural gas supply pipeline and on-going natural gas costs. Thus, otherwise technically feasible gas-consuming alternatives are considered economically unattractive for application at LOS on the Unit 2 boiler.

Although the BART Guidelines prescribes following a “top down” analysis approach for BART determination, the development of a least cost envelope with dominant controls[1] [70 FR 39168] clearly labels points with lower emissions reductions and total annual costs first, i.e. “A”, “B”, etc. then proceeding with labeling and connecting points plotted further away from the zero emission reduction point. This “bottom-up” approach is for plotting the least-cost (dominant) control curve. The labeling of each unit’s NO_X control technique alternative has followed this approach.

2.5.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROLS - LOS UNIT 2

The capital costs to implement the various NO_X control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. In the cases involving SNCR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

A review of the unit capital cost factor range and single point unit capital cost factor for the feasible NO_X emission reduction technology evaluated for LOS Unit 2 are presented in Table 2.5-1.

TABLE 2.5-1 – Unit Capital Cost Factors of Feasible NO_X Control Options for LOS Unit 2

Alt. No. (1)	**NO_X Control Technique**	**Range(2) ($/kW)**	**Single Point Unit Capital Cost Factor(3), ($/kW) LOS Unit 2**
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	20 + ?(4)	46(4),(5),(6)
C	SNCR (using urea) w/ ASOFA	20-35(7)	38(5),(6)
B	Coal Reburn (conventional, pulverized) w/ ASOFA	30-60(7)	153(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	23(6)

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ due to positive or negative synergistic effects. Range based on published values or vendor proposals.

(3) – Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on existing nameplate rating. Single point cost figures in 2005 dollars.

(4) – No published RRI unit capital cost factor was found in available technical literature. The installed capital costs for RRI are expected to be similar to SNCR. If both RRI and SNCR are installed together, capital cost of the RRI+SNCR portion was assumed to be 1.5x the capital cost of SNCR alone, due to commonality between the two systems sharing certain equipment and systems.

(5) – Estimated capital cost for SNCR point estimate derived from December 2004 budgetary proposal by Fuel Tech. See Appendix A for details.

(6) – The single point unit capital cost factor shown for the “advanced” version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(7) – NESCAUM 2005 Technical Paper, posted at their website for basic SOFA. See Appendix A for details.

(8) – The single point unit capital cost factor shown for a coal reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report, posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in coal reburn options is 57.5 $/kW. See Appendix A for details.

Annualized capital cost, which includes the time value of capital monies and its recovery, is determined from the estimated capital cost and the methodology described in Section 1. Table 2.5-2 shows the estimated installed capital cost and annualized capital cost values for the highest-performing form of the various feasible NO_X emission reduction technologies applied to LOS Unit 2. These were developed by multiplying the unit capital cost single point factors for the control option by the nameplate output capacity rating of the respective unit. These are listed in order of control effectiveness, with the highest ranked options at the top.

TABLE 2.5-2 – Installed and Annualized Capital Costs Estimated for NO_X Control Alternatives - LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Installed Capital Cost(2) ($1,000)	Annualized Capital Cost(3) ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	20,200	1,760
C	SNCR (using urea) w/ ASOFA	16,800	1,470
B	Coal Reburn (conventional, pulverized) w/ ASOFA	67,400(4)	5,880(4)
A	Advanced Separated Overfire Air (ASOFA)	10,100	883
	Baseline	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – Installed capital cost is estimated for determination of total capital cost for a control technology, assuming maximum unit output capacity is based on existing nameplate rating of 440,000 kW. Installed capital cost figures in 2005 dollars.

(3) – Annualized capital cost = Installed capital cost x 0.08718 Capital Recovery Factor.

(4) – Costs for increased PM collection capacity included in coal reburn option are $25,300,000 for installed capital cost, and $2,200,000/yr annualized capital cost.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.5.1.2 OPERATING AND MAINTENANCE COST ESTIMATES FOR NO_X CONTROLS – LOS UNIT 2

The operation and maintenance costs to implement the various NO_X control technologies were largely estimated from cost factors (percentages of installed capital costs) established in the EPA's Air Pollution Control Cost Manual (OAQPS), and from engineering judgment applied to that control technology. In the cases including various forms of SNCR, preliminary vendor quotes were obtained and used in place of, or to adjust the OAQPS cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's Levelized Total Annual Costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR and RRI alternatives; and
- Reagent dilution water consumption and unit cost for SNCR and RRI alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.
- Reductions in revenue expected to result from loss of unit availability, i.e. outages attributable to the control option, which reduce annual net electrical generation available for sale (revenue).

Table 2.5-3 and Table 2.5-4 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the highest-performing form of the various feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Section 1.3.5 provides more details for the levelized annual O&M cost calculations and cost factors.

TABLE 2.5-3 – Estimated O&M Costs for NO_X Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual O&M Cost(2) ($1,000)	Levelized Annual O&M Cost(3) ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	11,340	13,530
C	SNCR (using urea) w/ ASOFA	6,750	8,060
B	Coal Reburn (conventional, pulverized) w/ ASOFA	5,900(4)	7,040(4)
A	Advanced Separated Overfire Air (ASOFA)	152	182
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Annual O&M cost figures in 2005 dollars.
(3) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $1,740,000 for annual O&M cost, and $2,080,000/yr levelized annual O&M cost.

Annual operating and maintenance costs of the NO_X control options in Table 2.5-3 and Table 2.5-4 are based on LOS Unit 2 operation with the control option at 5,130 mmBtu/hr heat input and 8,760 hrs/yr operation. The Table 2.5-3 O&M costs are relative to unit pre-control baseline operation at 0.667 lb/mmBtu for the highest 24-month NO_X emission summation at 4,478 mmBtu/hr heat input for 8,050 hrs/yr operation of LOS Unit 2. The Table 2.5-4 O&M costs are relative to unit pre-control baseline operation at 0.667 lb/mmBtu for the maximum NO_X emissions associated with the future PTE case at 5,130 mmBtu/hr heat input for 8,760 hrs/yr operation of LOS Unit 2.

TABLE 2.5-4 – Estimated O&M Costs for NO_X Control Options (Relative to PTE Pre-Control Annual Emission Baseline – Future PTE Case) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual O&M Cost(2) ($1,000)	Levelized Annual O&M Cost(3) ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	11,340	13,530
C	SNCR (using urea) w/ ASOFA	6,750	8,060
B	Coal Reburn (conventional, pulverized) w/ ASOFA	5,900(4)	7,040(4)
A	Advanced Separated Overfire Air (ASOFA)	152	182
	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Annual O&M cost figures in 2005 dollars.
(3) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $1,740,000 for annual O&M cost, and $2,080,000/yr levelized annual O&M cost.

The majority of the annual operating and maintenance costs for the alternatives using chemical reagent injection (urea) for NO_X emissions control are for the delivered reagent and dilution water. Both RRI and SNCR are assumed to dilute the 50% aqueous urea solution as-received to a 10% aqueous urea concentration for direct injection into the targeted furnace areas. Higher than theoretical normalized (molar) stoichiometric ratios (NSRs) for the moles of equivalent reagent injected (urea) per mole of inlet NO_X emission were assumed for SNCR with ASOFA, and for RRI+SNCR with ASOFA due to inefficiencies inherent in their use. These annual costs reflect a significant increase in reagent consumption above the theoretical rates based on expected amounts of reagent utilization.

In order to compare a particular NO_X emission reduction alternative during the cost of compliance impact analysis portion of the BART selection process, the basic methodology defined in the BART Guidelines was followed [70 FR 39167-39168]. The sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which in this analysis is referred to as "Levelized Total Annual Cost" (LTAC) of expected pollutant removal incurred by implementing that alternative, was calculated. The LTAC for these NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Section 1.3.5 of this BART evaluation for methodology details).

The Average Cost Effectiveness (also called Unit Control Cost) was then determined as the LTAC divided by baseline annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. The feasible control alternatives were also compared by calculating the change in LTAC per incremental ton of pollutant removed for the next most stringent alternative (incremental cost effectiveness). This identified which alternatives produced the highest increment of expected pollutant reduction for the estimated lowest average LTAC increment compared with the pre-control baseline emission rate. The expected annual number of tons of pollutant removed versus estimated LTAC for each remaining control alternative was then plotted. These incremental and average control costs relative to the historic pre-control annual NO_X emission baseline for LOS Unit 2 are shown in Table 2.5-5. The incremental and average control costs relative to the PTE pre-control annual NO_X emission baseline for LOS Unit 2 are shown in Table 2.5-6.

TABLE 2.5-5 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	5,895	6,128	15,290	2,500
C	SNCR (using urea) w/ ASOFA	6,762	5,261	9,520	1,810
B	Coal Reburn (conventional, pulverized) w/ ASOFA	7,115	4,908	12,920[5]	2,630[5]
A	Advanced Separated Overfire Air (ASOFA)	10,796	1,227	1,060	867
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	12,023	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.

(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.

(4) – Annualized cost figures in 2005 dollars.

(5) – LTAC for increased PM collection capacity included in coal reburn option are $2,200,000 for annualized capital cost plus $2,080,000 for annualized O&M cost, for a total of $4,280,000/yr. This results in an average control cost of $873 per ton of NO_X removed.

TABLE 2.5-6 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case)
LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	5,895	9,094	11,340	1,680
C	SNCR (using urea) w/ ASOFA	6,762	8,226	6,750	1,160
B	Coal Reburn (conventional, pulverized) w/ ASOFA	7,115	7,873	5,900(4)	1,640[5]
A	Advanced Separated Overfire Air (ASOFA)	10,796	4,193	1,060	254
	Baseline, based on annual operation at future PTE case pre-control emission rate	14,989	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 2.

(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-4 for annualized cost factors.

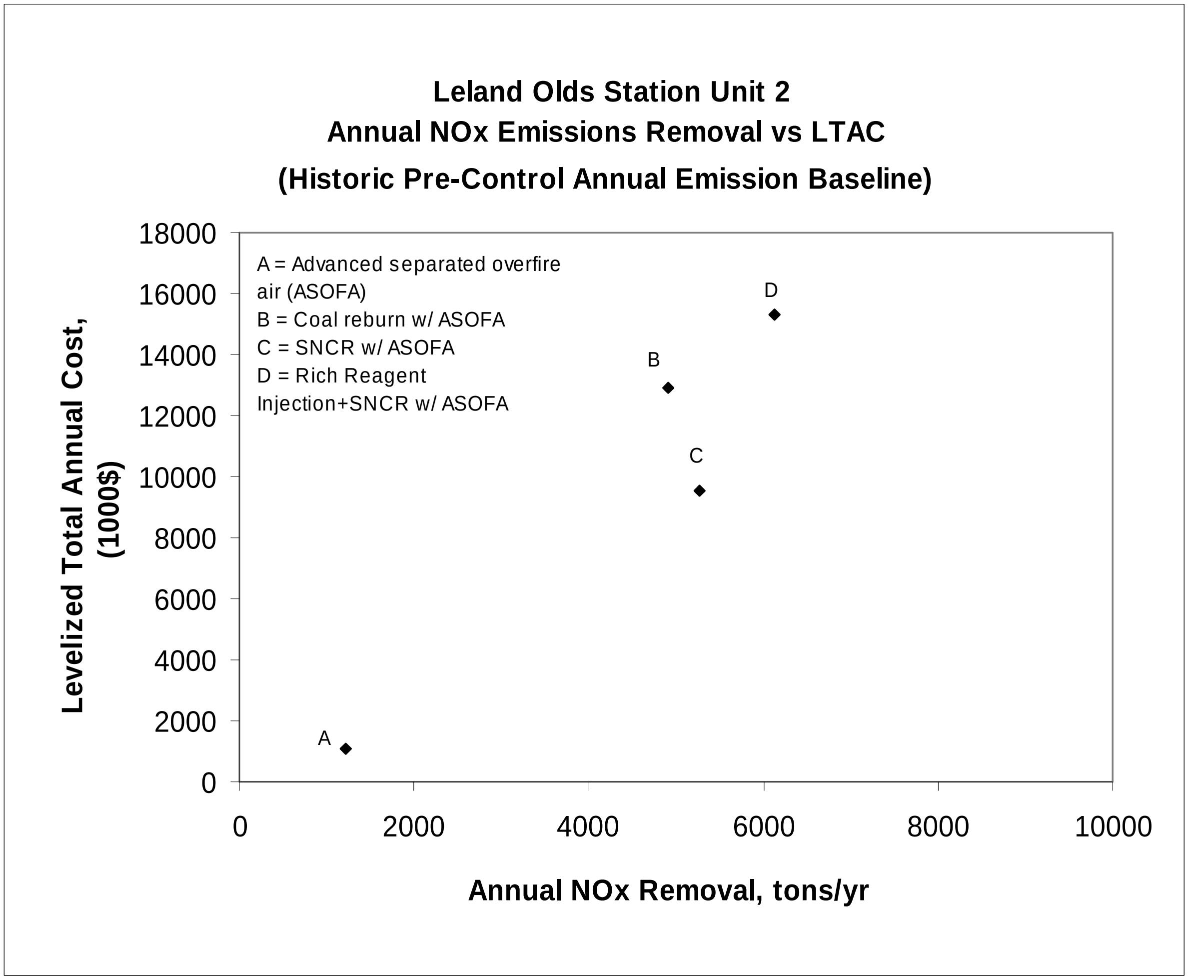
(4) – Annualized cost figures in 2005 dollars.

(5) – LTAC for increased PM collection capacity included in coal reburn option are $2,200,000 for annualized capital cost plus $2,080,000 for annualized O&M cost, for a total of $4,280,000/yr. This results in a average control cost of $544 per ton of NO_X removed.

The comparison of the cost-effectiveness of the control options evaluated for LOS Unit 2 relative to two different NO_X emission baselines was made and is shown in Figures 2.5-1 and 2.5-2. The estimated annual amount of NO_X removal (emission reduction) in tons per year is plotted on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis).

Figure 2.5-1 is for the control options evaluated relative to the baseline historic pre-control annual baseline, compared to the post-control maximum annual NO_X emissions for operation of LOS Unit 2 under the future PTE case.

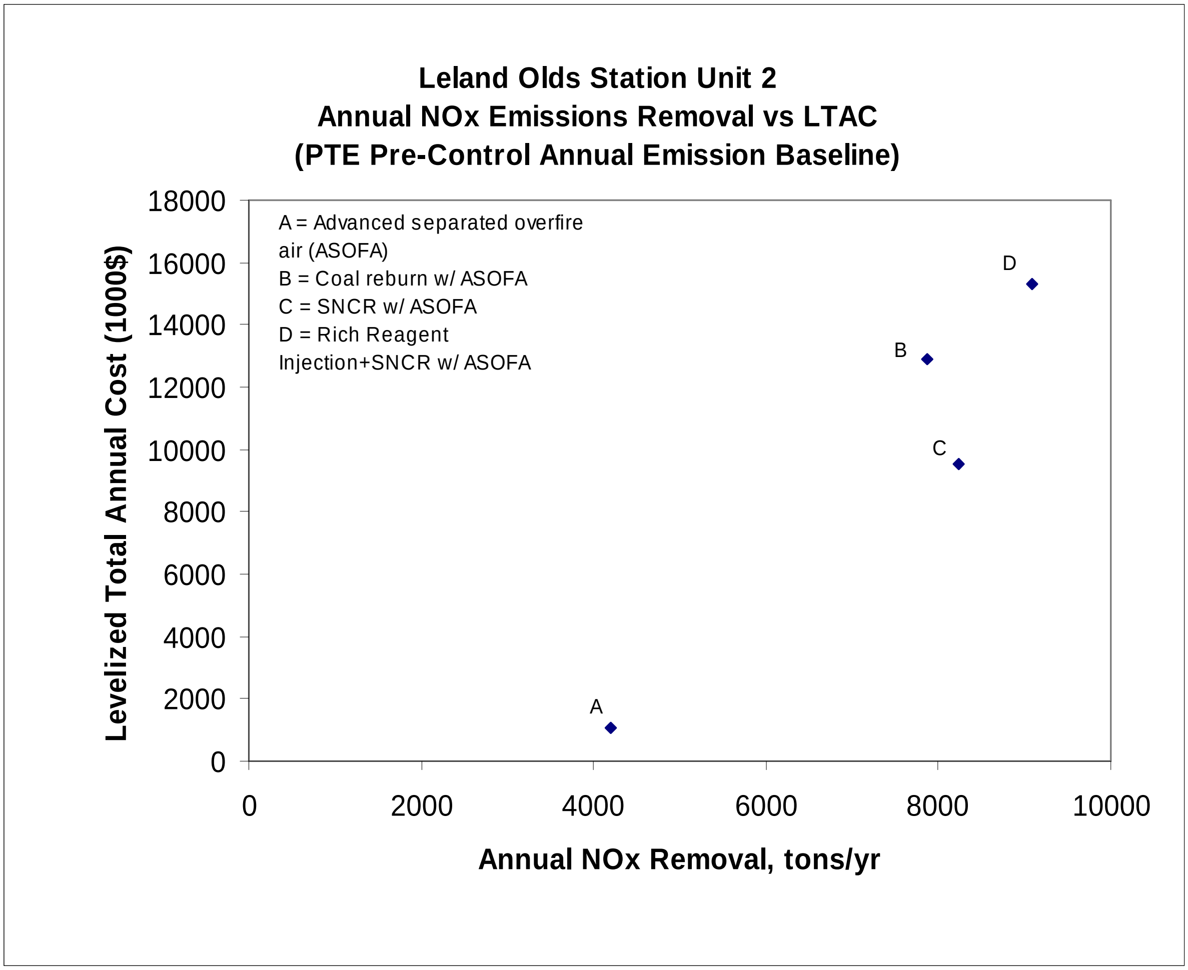
Figure 2.5-1 – NO_X Control Cost Effectiveness – LOS Unit 2 (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-5.

Figure 2.5-2 plots estimated levelized total annual costs versus estimated annual amount of NO_X removal (emission reduction) for the control options evaluated relative to the maximum pre-control annual baseline and future potential-to-emit post-control NO_X emissions for operation of LOS Unit 2 under the future PTE case.

Figure 2.5-2 – NO_X Control Cost Effectiveness – LOS Unit 2
(PTE Pre-Control Annual Emission Baseline – Future PTE Case)$^{(1)}$



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-6.

The purpose of Figures 2.5-1 and 2.5-2 is to show the range of control and cost for the evaluated NO_X reduction alternatives and identify the least-cost controls so that the Dominant Controls Curve can be created. The Dominant Controls Curve is the best fit line through the points forming the lower rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual NO_X removal tonnage for the various remaining BART alternatives. Points distinctly to the left of and above this curve are inferior control alternatives per the BART Guidelines and BART Guidelines on a cost effectiveness basis. Following a “bottom-up” graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope should be excluded from further analysis on a cost efficiency basis. Of the highest-performing versions of the technically feasible LOS Unit 2 NO_X control alternatives evaluated for cost-effectiveness, the data point for coal reburn with ASOFA is seen to be more costly for fewer tons of NO_X removed than for SNCR with ASOFA. This appears to be an inferior control, and thus should not be included on the least cost and Dominant Controls Curve boundary. Note that cost-effectiveness points for conventional gas reburn and fuel-lean gas reburn alternatives would be distinctly left and significantly above the least cost-control envelope, so these options were not included in the cost-effectiveness analysis.

The next step in the cost effectiveness analysis for the BART NO_X control alternatives is to review the incremental cost effectiveness between remaining least-cost alternatives. Figure 2.5-3 and Figure 2.5-4 contains a repetition of the levelized total annual cost and NO_X control information from Figure 2.5-1 and Figure 2.5-2 with Point B removed, and shows the incremental cost effectiveness between each successive set of least-cost NO_X control alternatives. The incremental NO_X control tons per year, divided by the incremental levelized annual cost, yields an incremental average unit cost ($/ton). This represents the slope of a line, if drawn, from one least-cost point as compared with another least-cost point. This modified least-cost controls curve is the Dominant Controls Cost Curve for NO_X emissions alternatives for each of the LOS Unit 2 pre-control baselines evaluated.

TABLE 2.5-7 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No.[(1)]	**NO_X Control Technique**	**Levelized Total Annual Cost**(2),(3) **($1,000)**	**Annual Emission Reduction**(4) **(Tons/yr)**	**Incremental Levelized Total Annual Cost**(3),(5) **($1,000)**	**Incremental Annual Emission Reduction**(4),(5) **(Tons/yr)**	**Incremental Control Cost Effectiveness ($/ton)**(3),(6)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	15,290	6,128	5,770	867	6,650
C	SNCR (using urea) w/ ASOFA	9,520	5,261	8,460	4,034	2,100
A	Advanced SOFA (ASOFA)	1,060	1,227	1,060	1,227	867
	Baseline, based on annual operation at historic 24-month average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.
Costs for increased PM collection efficiency are included in coal reburn option.

(3) – Annualized cost figures in 2005 dollars.

(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.

(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

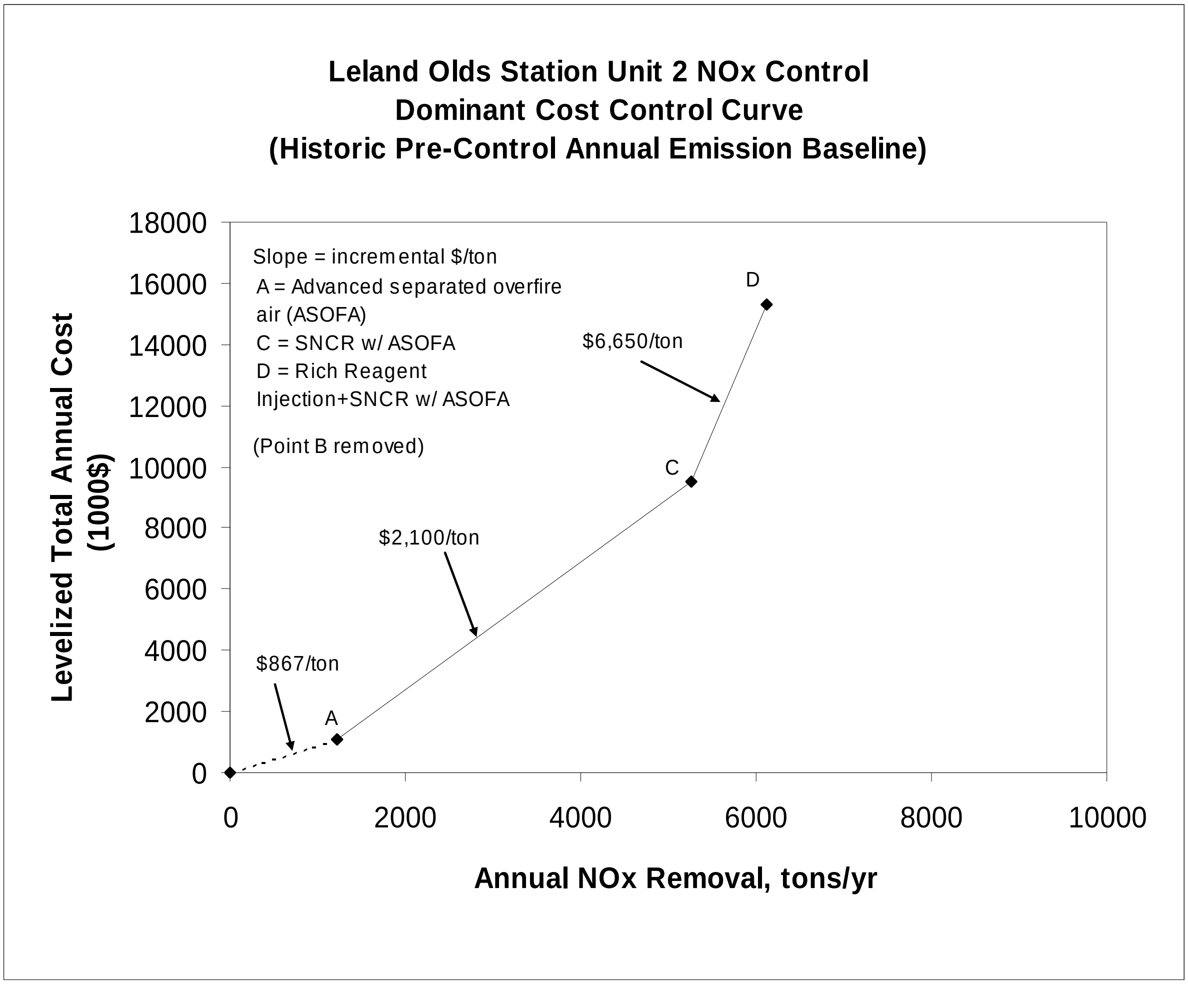
TABLE 2.5-8 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) LOS Unit 2

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	11,340	9,094	5,770	867	6,650
C	SNCR (using urea) w/ ASOFA	6,750	8,226	8,460	4,034	2,100
A	Advanced SOFA (ASOFA)	1,060	4,193	1,060	4,193	254
	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.
Costs for increased PM collection capacity are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 2.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

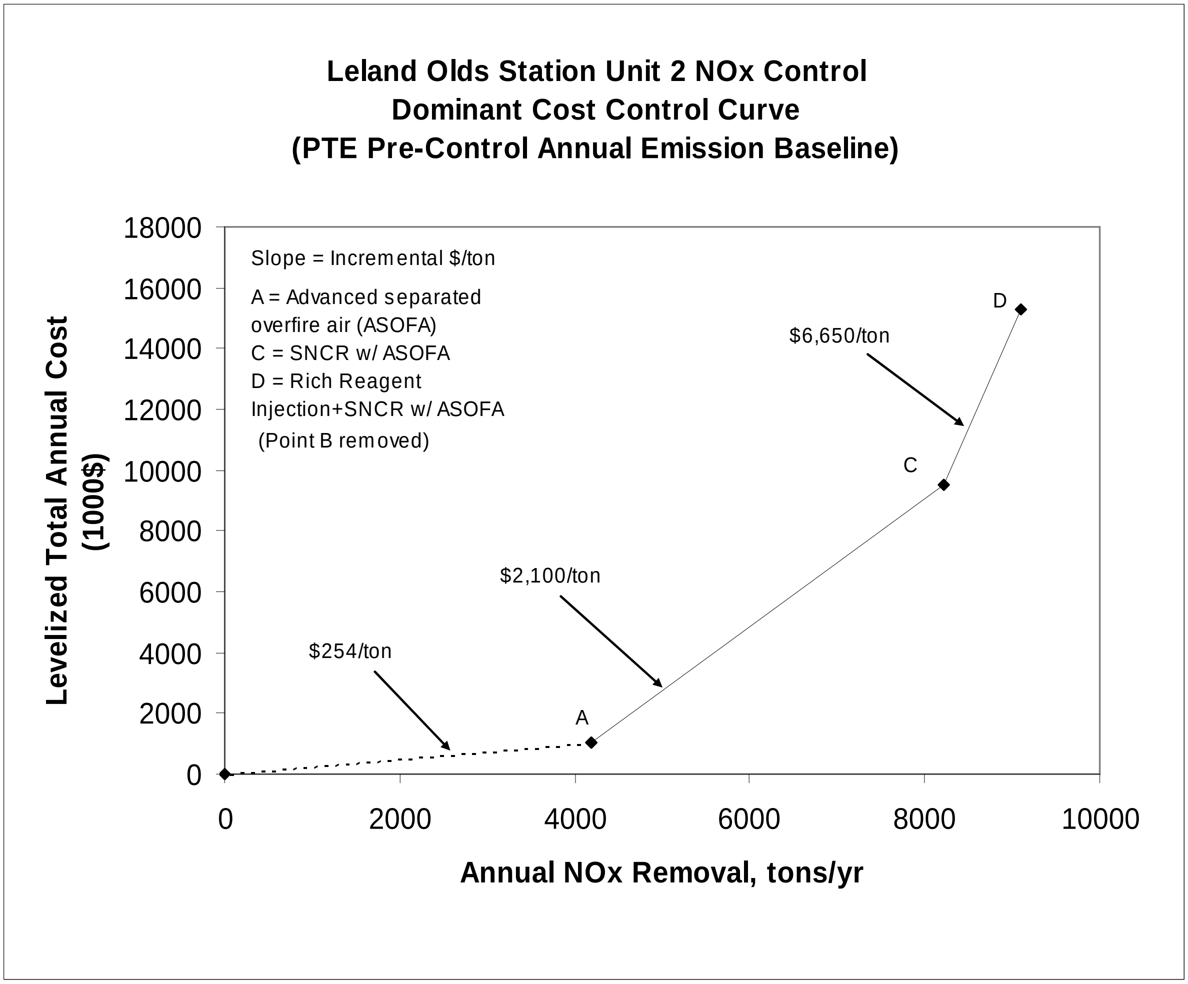
In the comparison displayed in Figure 2.5-3 and Figure 2.5-4, for the data shown in Table 2.5-7 and Table 2.5-8, the RRI+SNCR with Advanced SOFA NO_X control alternative (Point D) had a significantly higher incremental unit NO_X control cost (slope, $6,650/ton) compared against SNCR with ASOFA alternative (Point C) versus SNCR with ASOFA (Point C) compared against the ASOFA alternative (Point A) ($2,100/ton).

Figure 2.5-3 – NO$_X$ Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-7.

Figure 2.5-4 – NO_X Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-8.

In the final BART Guidelines, the EPA neither proposes hard definitions for reasonable, or unreasonable Unit Control Costs nor for incremental cost effectiveness values. As can be seen from a review of Table 2.5-5, the average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the highest 24-hour historic baseline NO_X emission ranges from $867/ton to $2,630/ton. Table 2.5-6 shows average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the presumptive NO_X emission level ranges from $254/ton to $1,680/ton. The latter has lower costs per ton of NO_X emission removal due to the higher number of tons removed for the maximum emissions for pre-control baseline and additional controls under the future PTE case.

The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the Dominant Control Cost Curve) between successively more effective alternatives. The incremental cost analysis indicates that from a cost effectiveness viewpoint, the highest performing alternative is Rich Reagent Injection + SNCR with ASOFA (Point D). This control option is considered technically feasible for Leland Olds Station Unit 2 boiler, incurs a significant annual (levelized) incremental cost compared to the next highest feasible NO_X control technique, SNCR with ASOFA (Point C, slope from C to D =6,650 $/ton) compared against the next lowest alternative, ASOFA (Point A, slope from A to C = 2,100 $/ton).

The other elements of the fourth step of a BART analysis following cost of compliance are to evaluate the following impacts of feasible emission controls:

- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

For the purposes of this BART analysis, the remaining useful life of the source was assumed to exceed the 20-year project life utilized in the cost impact estimates. The other impacts for the LOS Unit 2 NO_X emissions control alternatives from the Dominant Control Cost Curve are discussed in Section 2.5.2 and Section 2.5.3. Visibility impairment impacts for these LOS Unit 2 NO_X emissions controls are summarized in Section 2.5.4.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.4.6 ENERGY IMPACTS OF NO_X CONTROL ALTERNATIVES – LOS UNIT 2

Operation of the top NO_X control technologies considered feasible for potential application at the Leland Olds Station impose direct impacts on the consumption of energy required for the production of electrical power at the facility. The details of estimated energy usage and costs for the various LOS Unit 2 NO_X control alternatives are summarized in Appendix A.

Control alternatives for reduction of NO_X emissions were reviewed to determine if the use of the technique or technology will result in any significant or unusual energy penalties or benefits. There are several basic kinds of energy impacts for NO_X emissions controls:

- Potential increase or decrease in power plant energy consumption resulting from a change in thermal (heat) energy to net electrical output conversion efficiency of the unit, usually expressed as an hourly unit heat rate (Btu/kW-hr) or the inverse of pounds of pollutant per unit electrical power output (MW-hr). This may or may not change the net electrical output (MW) capacity of the EGU, depending on if there are physical or imposed limits on the total heat input to the boiler or electrical power output.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in physical operational limitations imposed on the ability to sustain a fuel heat input rate (mmBtu/hr) which results in a potentially lower or higher unit net electrical output (MW) capacity. This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in auxiliary electrical power demand and usage (kW, kW-hrs). This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in reliability and availability to generate electrical power. This results in a change to the number of hours of annual operation, not necessarily a change in net electrical output (MW) capacity of the EGU.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.5.2.1 ENERGY IMPACTS OF SOFA ALTERNATIVES – LOS UNIT 1

There should not be a major impact on energy consumption by the operation of the advanced variation of a separated overfire air system. ASOFA was the only NO_X control technology common to all four alternatives evaluated for LOS Unit 2. SOFA does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. Combustion air damper actuators' electrical power demand would be insignificant (+ 1 kW) change in net electrical power consumption from LOS Unit 2. For cyclone boilers, providing effective volumes and velocities of separated overfire air at the injection ports should not require higher forced draft fan power consumption resulting from higher fan discharge pressure. Higher lignite drying system vent ductwork pressure drop impacts of the advanced SOFA system on the forced draft fans' auxiliary electrical power consumption are expected to be negligible (less than 1% of the annual auxiliary power consumed by these fans) so that unit net electrical output (MW) capacity is essentially the same as the current nameplate rating.

Operation of a SOFA system may cause a small increase in levels of unburned carbon in the flyash emitted from the boiler compared with current operation. This represents a slight amount of lost potential electrical power generation from the incompletely burned fuel, so this inefficiency could have a small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kw-hr). This impact was not quantified, as the historical variation in coal heat content that influences plant unit heat rate may be more significant.

Boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures may be slightly elevated during air-staged cyclone operation with SOFA. This impact on the boiler's operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr) was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

SOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, once the amount of secondary combustion air that can be withdrawn from the cyclones is established for consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for LOS Unit 2. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion from sulfur compounds in the furnace gases being created above the cyclones and below the SOFA injection ports. Due to the relatively moderate amounts of sulfur content in the lignite, modest amount of air-staging of the existing cyclones during SOFA operation, and the potential use of recirculated flue gas along the lower furnace walls, the expected change in corrosion rate of the boiler tubes should be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube failures and changeouts is difficult to estimate, and has not been quantified.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.5.2.2 ENERGY IMPACTS OF SNCR ALTERNATIVES – LOS UNIT 2

The SNCR portion of this layered alternative involves a chemical reagent injected for NO_X control, assumed to be aqueous urea. For SNCR-related NO_X control alternatives (with or without Rich

Reagent Injection), the injection of a diluted urea solution requires some additional auxiliary power for heating and pumping the liquid, and using compressed air for atomization and cooling the reagent injection nozzles/lances. Heat is required for urea reagent storage. For the Advanced SOFA + SNCR with and without RRI alternatives, the source of heat is assumed to be auxiliary electrical power, on the order of 150 to 300 kW, which was calculated following EPA OAQPS convention[4]. Based on operation for the entire year with the assumed 99% availability factor, this would consume approximately 310,000 kW-hr/yr of additional auxiliary electrical power.

Advanced SOFA + SNCR with and without RRI alternatives' operation is not expected to require higher forced draft fan power consumption. Combustion air damper actuators' electrical power demands are expected to be an insignificant (+ 1 kW) change in net electrical power consumption from LOS Unit 2.

Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water; this follows EPA OAQPS convention[1], but is not accepted practice by an experienced SNCR vendor (Fuel Tech) who claims that the heat produced from the exothermic reaction of urea and NO_X is approximately equal to the heat required to evaporate the dilution water. Reagent dilution water for those SNCR alternatives that involve a chemical reagent injected for NOx control were assumed to be four times the amount of delivered aqueous urea solution consumption (assumes urea is a 50% solution as delivered and is injected as a 10% solution); this also follows EPA OAQPS convention[5]. This was estimated to be approximately 23.7 million Btu per hour for Advanced SOFA + SNCR, or 204,800 mmBtu/yr and approximately 45.0 million Btu per hour for Advanced SOFA + SNCR with RRI, or 389,500 mmBtu/yr for LOS Unit 2.

Likewise, operation of a Advanced SOFA + SNCR with and without RRI alternatives may cause a small increase in levels of unburned carbon in the flyash emitted from the boiler compared with current operation. This represents a slight amount of lost potential electrical power generation from the incompletely burned fuel, so this inefficiency could have a small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr). This impact was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

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[4] See Basin LOS BART Determination Study report NO_X Section Reference number 49, page 1-34.
[5] See Basin LOS BART Determination Study report NO_X Section Reference number 49, page 1-35.

As discussed above, SNCR operation will cause a slight decrease (approximately 0.5-0.9%) on the plant unit heat rate (higher Btu/kW-hr), primarily to higher flue gas moisture with corresponding sensible and latent heat losses which would require a slightly higher gross heat input to evaporate the extra dilution water input. This ignores the slight increase in induced draft fan horsepower and auxiliary electrical power consumption to handle the extra coal combustion products, urea and dilution water flows that will result in increased flue gas mass flow during SNCR/RRI operation. The impact of additional flue gas created by operation of an SNCR-related system on induced draft fan power consumption should be insignificant.

Boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures is not expected to change significantly, as a slight increase during air-staged burner operation with SOFA may be offset by a slight depression from the injection of the urea dilution water. This impact on the boiler's operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This impact on the LOS Unit 2 boiler's thermal conversion efficiency and steam cycle impacts from small steam temperature changes was not quantified, but is not expected to be significant.

ASOFA and SNCR/RRI are not expected to significantly reduce unit reliability and availability to generate electrical power. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion of the steel waterwall tubes by sulfur compounds in the furnace gases being created above the burners and below the SOFA injection ports. Due to the moderate sulfur content in the lignite and modest amount of air-staging during firing of the existing cyclone burners expected during ASOFA operation, this potential change in corrosion rate of the boiler tubes is expected to be minor. SNCR/RRI may cause a slight increase in fireside deposit accumulation, especially in the primary and possibly secondary superheater and reheater tube banks. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes and superheater/reheater tube banks to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube and superheater/reheater tube failures and changeouts is difficult to estimate, and has not been quantified.

Table 2.5-9 summarizes the gross demand and usage from auxiliary electrical power estimated for the NO_X control alternatives evaluated for LOS Unit 2.

TABLE 2.5-9 – Expected Auxiliary Electrical Power Impacts for NO_X Controls – LOS Unit 2

		NO_X Control Equipment Estimated Annual Average Auxiliary Electrical Power Demand and Usage		
Alt. No.(1)	**NO_X Control Technique**	**Aux. Power Demand (2) (kW)**	**Generation Reduction from Aux. Power Demand(2),(3) (kW-hrs/yr)**	**Generation Reduction from Reduced Unit Availability(4) (kW-hrs/yr)**
D	RRI + SNCR (using urea) w/ ASOFA	285	2,464,300	38,500,000
C	SNCR (using urea) w/ ASOFA	156	1,349,600	38,500,000
A	Advanced Separated Overfire Air (ASOFA)	1	8,760	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – The NO_X control equipment gross auxiliary electrical power demand is estimated.
(3) – The annual change in NO_X equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.
(4) – The estimated total hours per year of unit unavailability multiplied by average gross generation multiplied by annual running plant capacity factor for the particular control alternative. For this analysis, SOFA was not expected to reduce annual hours of possible operation.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.5.4 VISIBLITY IMPAIRMENT IMPACTS OF LELAND OLDS STATION NO_X CONTROLS – UNIT 2

The fifth step in a BART analysis is to conduct a visibility improvement determination for the source. For this BART analysis, there were two baseline NO_X emission rates assumed for LOS Unit 2 – one for the historic pre-control NO_X emission rate listed in the NDDH BART protocol[3], and one applying the Potential-To-Emit (PTE) pre-control annual NO_X emission rate associated with the future PTE case. The historic pre-control emission baseline was the 24-hour average NO_X emission rate from the highest emitting day of the years 2000-2002 (meteorological period modeled per the NDDH protocol[3]). The historic (protocol) NO_X baseline condition emission rate was modeled simultaneously with the highest 24-hour average SO_2 emission rate, and the highest 24-hour average PM emission rate of the 2000-2002 time period. The historic (protocol) baseline hourly NO_X emission rate used for modeling visibility impacts due to LOS Unit 2 under the conditions stated above was 3,959 lb/hr.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from historic (protocol) pre-control baseline and post-control average hourly emission rates representing the visibility impairment impact reduction for LOS Unit 2. Three post-control CALPUFF model runs for LOS Unit 2 were conducted with the same presumptive BART SO_2 emission baseline rate of 95%, constant PM emissions, and various levels of NO_X control assuming the same boiler design rating for heat input (5,130 mmBtu/hr). For the three post-control alternatives representing LOS Unit 2 PTE annual emissions associated with the future PTE case, the model used average unit NO_X emission rates of 0.48, 0.304, and 0.265 lb/mmBtu (corresponding to the design parameter in Table 1.2-1 and control rates in Table 1.4-1) multiplied by the boiler heat input rating of 5,130 mmBtu/hr to yield average hourly NO_X emission rates 2,462, 1,560, and 1,360 lb/hr. The boiler heat input basis for LOS Unit 2's historic highest 24-hour pre-control NO_X emission baseline, in keeping with the NDDH BART visibility impairment impact modeling protocol, is different than assumed for the PTE annual post-control conditions of the NO_X control alternatives evaluated for visibility impairment impacts.

The results of the visibility impairment modeling at the historic pre-control (protocol) baseline NO_X emission rate for LOS Unit 2 showed that all four of the designated Class 1 areas exceeded 0.5 deciView for highest predicted visibility impairment impact (90th percentile, averaged for 2000-2002). Lostwood National Wildlife Refuge (LNWR) showed the biggest predicted visibility impairment impact, which averaged 0.98 dV for the three years modeled (2000-2002). Average predicted visibility impairment impacts decreased significantly with presumptive BART SO_2 emission rate combined with constant PM emissions and various post-control ASOFA-enhanced NO_X emission rates for LOS Unit 2. This is shown in Table 2.5-10.

TABLE 2.5-10 – Average Visibility Impairment Impacts from Emission Controls – LOS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts(1) (deciView)			
	Historic Pre-Control Baseline	PTE Emissions, ASOFA(2)	PTE Emissions, SNCR w/ ASOFA(2)	PTE Emissions, RRI+SNCR w/ ASOFA(2)
TRNP-South Unit	0.807	0.221	0.158	0.143
TRNP-North Unit	0.756	0.180	0.139	0.129
TRNP-Elkhorn Ranch	0.535	0.120	0.093	0.087
Lostwood NWR	0.979	0.285	0.206	0.191

(1) - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection.

Analysis of the reduction in visibility impairment impact included a comparison of the emission controls' effectiveness of reducing predicted visibility impairment impacts for the conditions of the future PTE case operation of LOS Unit 2 versus the historic pre-control (protocol) baseline that was modeled. LNWR again showed the highest average predicted visibility impairment impact reduction resulting from LOS Unit 2 emissions controls during PTE (future PTE case) heat inputs versus historic pre-control baseline emissions. These comparisons are shown in Table 2.5-11.

TABLE 2.5-11 –Average Visibility Impairment Impact Reductions From Emission Controls – LOS Unit 2 (vs Historic Maximum 24-Hour Average Hourly Emission Baseline)

Federal Class 1 Area	Visibility Impairment Reductions(1) (deciView)		
	PTE Emissions, ASOFA(2)	PTE Emissions, SNCR w/ ASOFA(2)	PTE Emissions, RRI+SNCR w/ ASOFA(2)
TRNP-South Unit	0.586	0.649	0.664
TRNP-North Unit	0.577	0.617	0.628
TRNP-Elkhorn Ranch	0.415	0.441	0.447
Lostwood NWR	0.694	0.773	0.788

(1) - Difference of average 90th percentile predicted post-control visibility impairment impact versus historic pre-control (protocol) baseline visibility impairment impact. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection.

The comparison in Table 2.5-12 shows the reduction of average visibility impairment impact from LOS Unit 2 NO_X emissions expected to result from ASOFA combined with SNCR with and without RRI relative to the average visibility impairment impact from post-control ASOFA NO_X emission rates applied to LOS Unit 2.

TABLE 2.5-12 – Incremental Average Visibility Impairment Reductions from NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission Visibility Impairment Impact)

	Incremental Visibility Impairment Impact Reductions, from NO_X Emission Controls(1)	
Federal Class 1 Area	**PTE Emissions, SNCR w/ ASOFA (dV)**	**PTE Emissions, RRI+SNCR w/ ASOFA (dV)**
TRNP-South Unit	0.063	0.078
TRNP-North Unit	0.040	0.051
TRNP-Elkhorn Ranch	0.027	0.033
Lostwood NWR	0.079	0.094

(1) - Incremental average 90th percentile predicted post-control visibility impairment impact, compared to ASOFA for NO_X control with 95% SO_2 emissions control and existing ESP for PM emissions control at PTE heat input rate (future PTE case). A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

This analysis included a determination of the cost-effectiveness of reducing predicted visibility impairment impact for a particular NO_X emission rate associated with the control alternatives evaluated on LOS Unit 2. The basis of comparison was the average predicted visibility impairment impact and estimated levelized total annual cost (LTAC) for the advanced form of separated overfire air (ASOFA) alone under the future PTE case conditions. The estimated additional annualized costs of installing and operating each NO_X control alternative with PTE heat input (future PTE case) relative to the LTAC from post-control ASOFA NO_X emission rates applied to LOS Unit 2 are shown in Table 2.5-13.

TABLE 2.5-13 – LTAC for NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission LTAC)

Incremental LTAC Change for NO_X Emission Reduction(1)	
PTE Emissions, SNCR w/ ASOFA ($/yr)	**PTE Emissions, RRI+SNCR w/ ASOFA ($/yr)**
8,460,000	13,230,000

(1) - Incremental Levelized Total Annual Cost for NO_X control alternatives compared to ASOFA for PTE heat input rate (future PTE case). All cost figures in 2005 dollars. See Table 2.5-8 for details.

The comparison in Table 2.5-14 shows that the additional annualized costs of installing and operating each NO_X control alternative with PTE heat input (future PTE case) divided by the additional average predicted visibility impairment impact reduction relative to the post-control ASOFA NO_X emission rates and LTAC applied to LOS Unit 2 would result in hundreds of millions of dollars per deciview of control cost visibility impairment impact effectiveness.

TABLE 2.5-14 – Cost Effectiveness for Incremental Average Visibility Impairment Reductions from NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission LTAC and Visibility Impacts)

	Incremental Visibility Impairment Reduction Unit Cost, from NO_X Emission Controls(1)	
Federal Class 1 Area	**PTE Emissions, SNCR w/ ASOFA ($/deciView-yr)**	**PTE Emissions, RRI+SNCR w/ ASOFA ($/deciView-yr)**
TRNP-South Unit	135,000,000	183,000,000
TRNP-North Unit	210,000,000	279,000,000
TRNP-Elkhorn Ranch	317,000,000	436,000,000
Lostwood NWR	108,000,000	152,000,000

(1) - Incremental Levelized Total Annual Cost divided by incremental average 90th percentile predicted post-control visibility impairment impact, compared to ASOFA for NO_X control with 95% SO_2 emissions control and existing ESP for PM emissions control at PTE heat input rate (future PTE case). All cost figures in 2005 dollars.

The number of days predicted to have visibility impairment due to LOS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the historic pre-control (protocol) NO_X, SO_2, and PM emission rates described previously in this Section. The results were summarized and presented in Table 2.4-15. Similarly, the same information for the post-control SO_2 and PM alternatives with presumptive BART NO_X PTE emission rates was summarized and is shown in Table 2.5-16. The differences in average visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between post-control SO_2 and PM alternatives with SNCR with ASOFA-controlled and RRI+ SNCR with ASOFA-controlled NO_X emission rates versus ASOFA-controlled NO_X emission rates are summarized and shown in Table 2.5-15.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 area. The highest number of days in which the predicted visibility impairment impact above background exceeded 0.5 deciViews was for the pre-control (protocol) emission case in year 2002 for TRNP's South Unit. A series of bar charts showing the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the pre-control model results is included in Section 3.5. The pair of post-control SO_2 and PM alternatives combined with SNCR with ASOFA or RRI+SNCR with ASOFA for NO_X control were only slightly lower for the predicted visibility impairment impacts and number of days predicted to have visibility impairment impacts greater than 0.50 and 1.00 deciViews compared to the same pair of post-control SO_2 and PM conditions with ASOFA-controlled NO_X emission rates. A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the RRI+SNCR with ASOFA-controlled PTE emission rates and SNCR with ASOFA-controlled PTE emission rates compared to ASOFA NO_X PTE emission rates with post-control SO_2 and PM alternatives is included in Figures 2.5-5, 2.5-6, and 2.5-7.

(The following article is a replacement of the same section in the August 2006 BEPC BART Determination Study final draft report)

2.5.5 SUMMARY OF IMPACTS OF LELAND OLDS STATION NO_X CONTROLS – UNIT 2

Table 2.5-16 summarizes the various quantifiable impacts discussed in Sections 2.5.1 through 2.5.4 for the NO_X control alternatives evaluated for LOS Unit 2.

Table 2.5-15 – Visibility Impairment Improvements – Post Control vs ASOFA NO_X Control with SO_2 and PM Controls
LOS Unit 2

Class 1 Area	NO_X Control Technique w/ SO_2 Control Level(1)	Visibility Impairment Reduction(2) (ΔdV)	ΔDays(3) Exceeding 0.5 dV in 2000	ΔDays(3) Exceeding 0.5 dV in 2001	ΔDays(3) Exceeding 0.5 dV in 2002	ΔDays(3) Exceeding 1.0 dV in 2000	ΔDays(3) Exceeding 1.0 dV in 2001	ΔDays(3) Exceeding 1.0 dV in 2002	ΔConsecutive Days(3) Exceeding 0.5 dV 2000	ΔConsecutive Days(3) Exceeding 0.5 dV 2001	ΔConsecutive Days(3) Exceeding 0.5 dV 2002
TRNP South	RRI+SNCR w/ ASOFA	0.078	4	8	9	2	2	8	0	1	0
	SNCR w/ ASOFA	0.063	3	7	6	2	2	7	0	1	0
TRNP North	RRI+SNCR w/ ASOFA	0.051	6	8	4	2	2	8	0	0	0
	SNCR w/ ASOFA	0.040	4	6	4	2	2	6	0	0	0
TRNP Elkhorn	RRI+SNCR w/ ASOFA	0.033	2	3	3	0	1	2	0	1	0
	SNCR w/ ASOFA	0.027	2	2	3	0	1	2	0	1	0
Lostwood NWR	RRI+SNCR w/ ASOFA	0.094	12	10	6	5	7	2	0	0	1
	SNCR w/ ASOFA	0.079	9	6	6	5	5	2	0	0	1

(1) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - Difference in average predicted visibility impairment impacts (90th percentile) for 2000-2002 for alternatives' post-control NO_X emission levels versus ASOFA-controlled NO_X emission level with same PTE heat input SO_2 and PM post-control alternatives' emission rate (future PTE case).

(3) - Difference in number of days is 100th percentile level for predicted visibility impairment impacts provided in Appendix D1.

Figure 2.5-5 – Days of Visibility Impairment Reductions – 0.5 dV
NO_X Controls versus ASOFA with SO_2 and PM Controls
LOS Unit 2

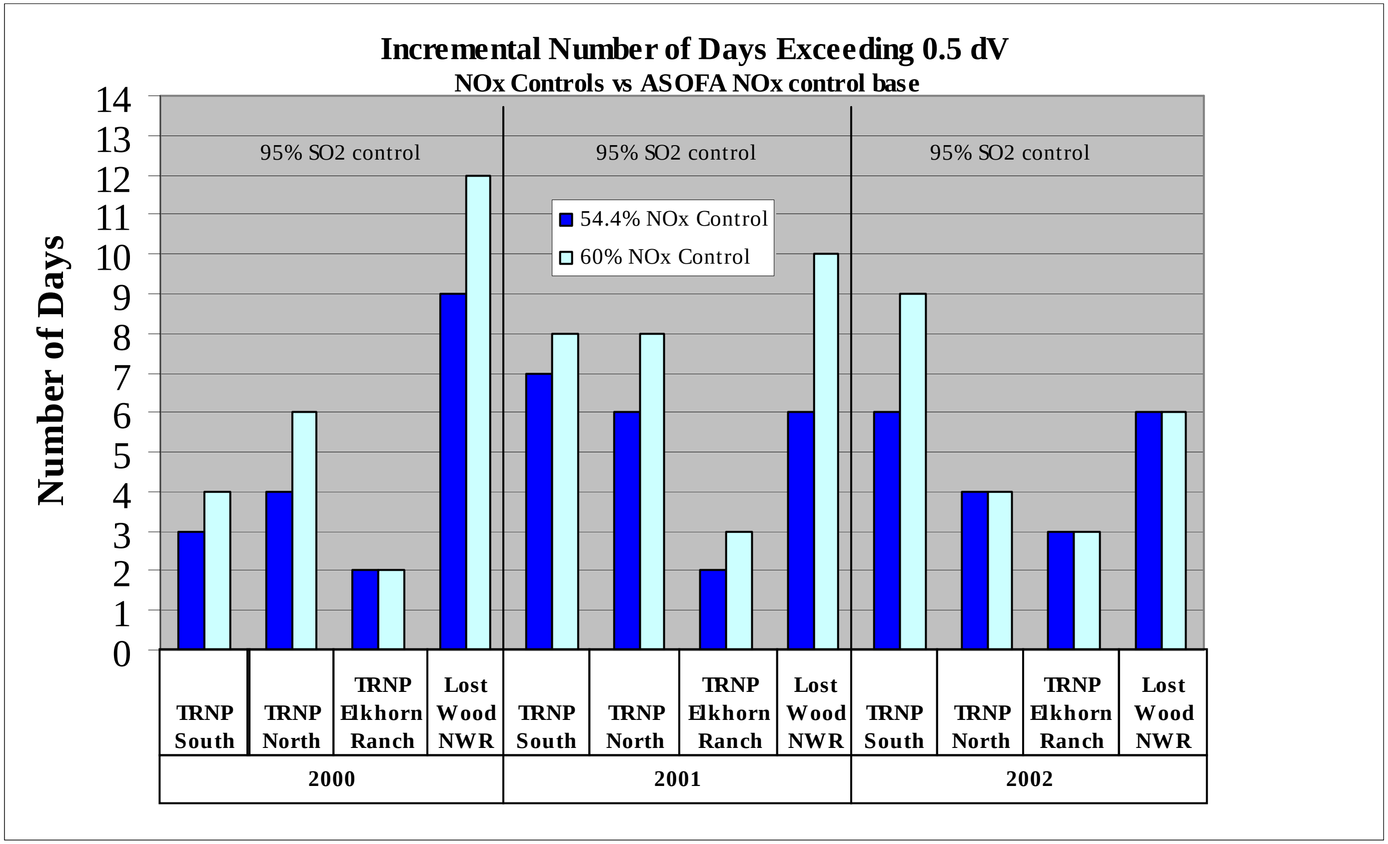

Figure 2.5-6 – Days of Visibility Impairment Reductions – 1.0 dV NO_X Controls versus ASOFA with SO_2 and PM Controls LOS Unit 2

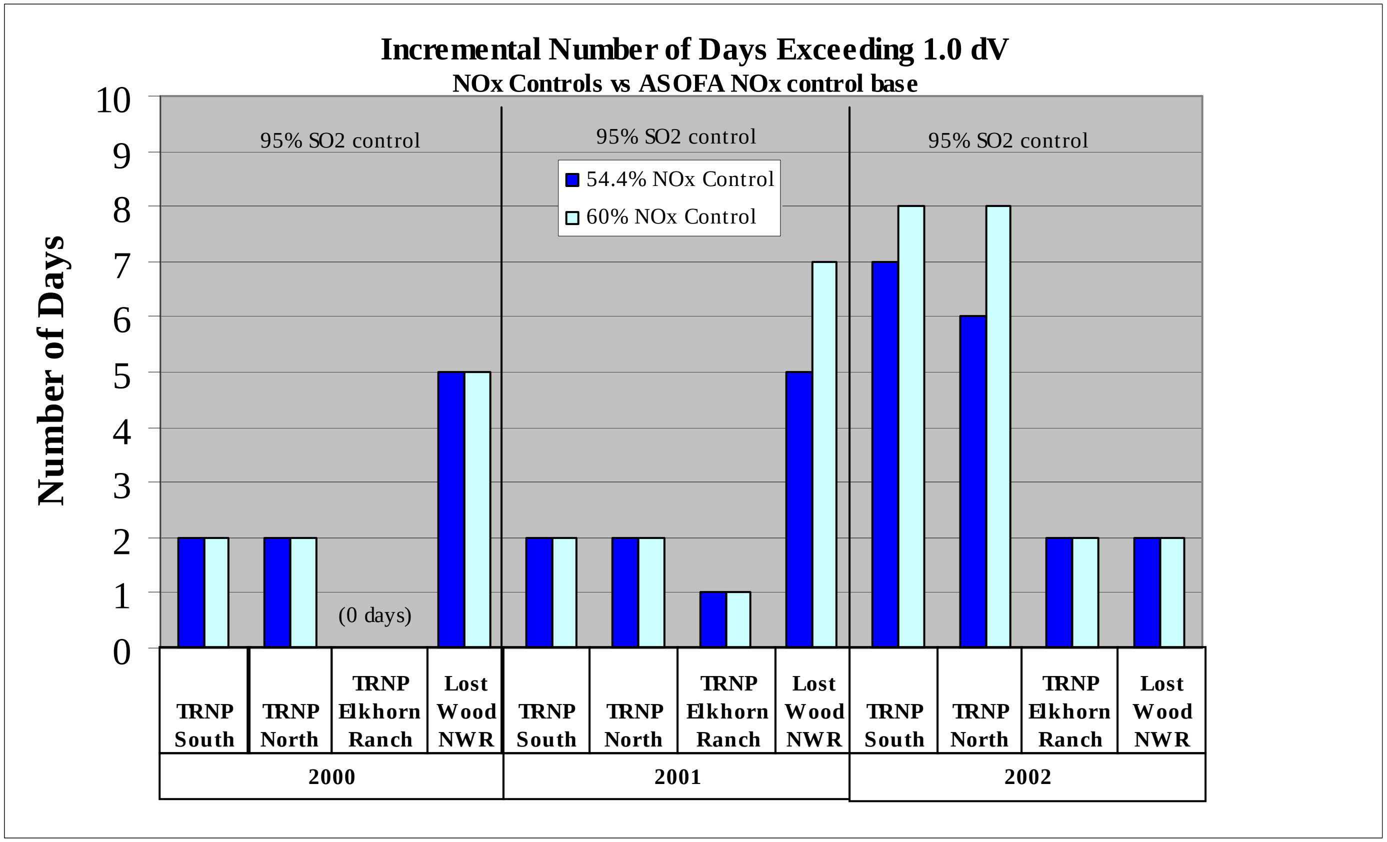

Figure 2.5-7 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV NO_X Controls versus ASOFA with SO_2 and PM Controls LOS Unit 2

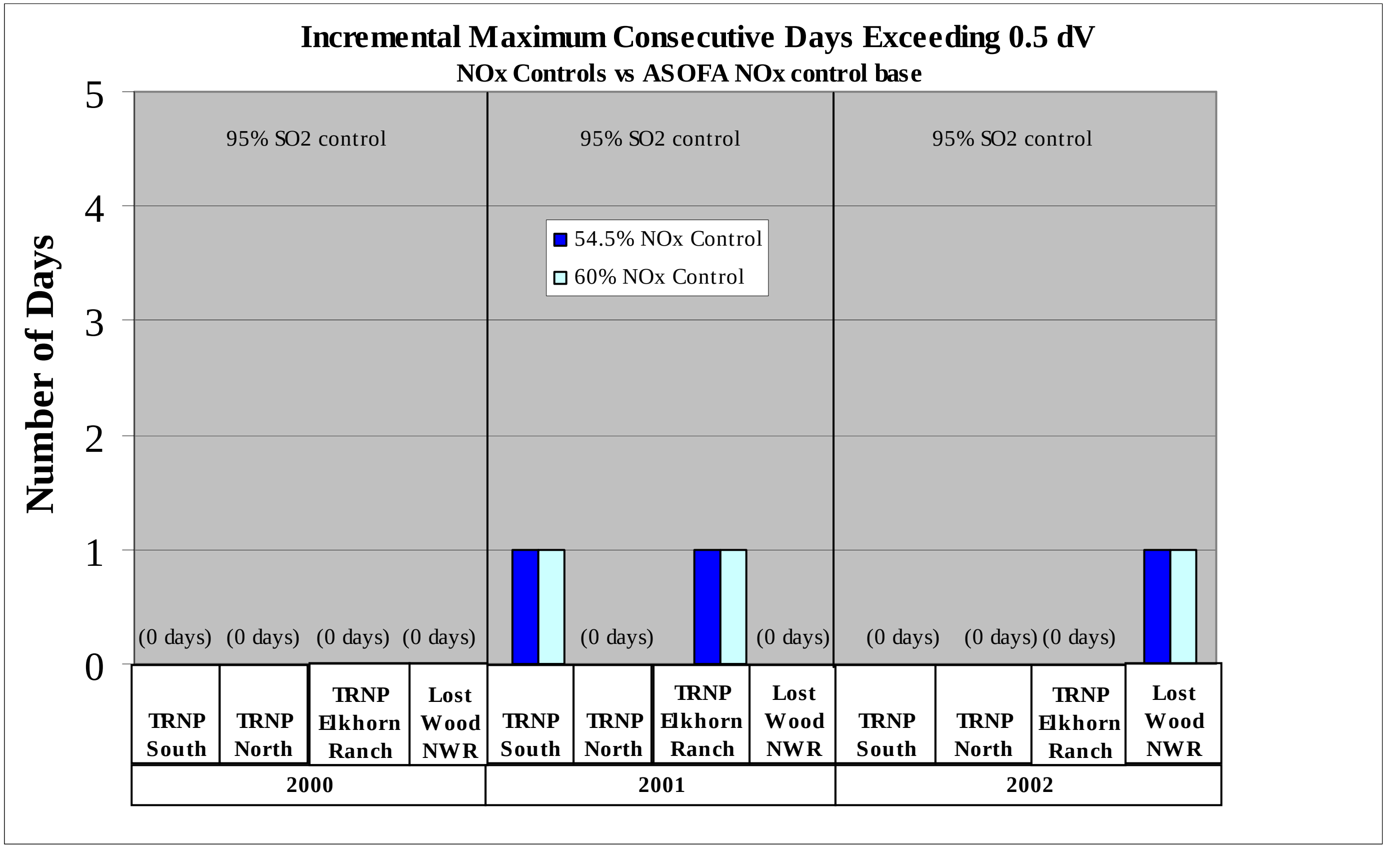

Table 2.5-16 – Impacts Summary for LOS Unit 2 NO_X Controls
(vs Pre-Control PTE NO_X Emissions)

NO_X Control Technique w/ SO_2 Alternative	NO_X Control Efficiency (%)	Annual NO_X Emissions Reduction (tpy)	Levelized Total Annual Cost(1) ($)	Unit Control Cost ($/ton)	Visibility Impairment Impact Reduction		Incremental Visibility Impairment Reduction Unit Cost(1),(3) ($/dV-yr)	Energy Impact (kW)	Non Air Quality Impacts
					Class 1 Area	Incremental(2) ΔdV			
RRI+SNCR w/ ASOFA	60.3%	9,094	13,230,000	1,680	TRNP-S	0.078	183,000,000	284	Flyash unburned carbon increase, ammonia in flyash
					TRNP-N	0.051	279,000,000		
					TRNP-Elk	0.033	436,000,000		
					LNWR	0.094	152,000,000		
SNCR w/ ASOFA	54.5%	8,226	8,460,000	1,160	TRNP-S	0.063	135,000,000	155	Flyash unburned carbon increase, ammonia in flyash
					TRNP-N	0.040	210,000,000		
					TRNP-Elk	0.027	317,000,000		
					LNWR	0.079	108,000,000		
ASOFA	28%	4,193	1,060,000	254	TRNP-S	base	base	1	Flyash unburned carbon increase
					TRNP-N	base	base		
					TRNP-Elk	base	base		
					LNWR	base	base		

(1) - All cost figures in 2005 dollars.

(2) - Average predicted visibility impairment impact improvements (incremental, 90th percentile) from PTE post-control NO_X emission levels relative to ASOFA post-control NO_X emission levels; all cases have 95% control SO_2 emission level and same PM post-control level at 5,130 mmBtu/hr heat input and 8,760 hours per year operation for the future PTE case, for 2000-2002.

(3) - Incremental LTAC for RRI+SNCR w/ ASOFA = $13,230k/yr; SNCR w/ ASOFA = $8,460k/yr; vs ASOFA = $0k/yr (base), divided by incremental ΔdV. See Table 2.5-14 for details.

NO$_X$ SECTION REFERENCES:

(see pages 127 -131 in the August 2006 BEPC BART Determination Study final draft report)

BASIN ELECTRIC POWER COOPERATIVE
LELAND OLDS STATION
COMBINED UNIT 1 AND 2 MODELING ANALYSIS

The U.S. Environmental Protection Agency (EPA) finalized the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations in July 2005. The final regulations require eligible sources to be analyzed to determine a BART emission limit for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). The North Dakota Department of Health (NDDH) determined that Basin Electric Power Cooperative, Inc.'s (BEPC's) Leland Olds Station (LOS) Units 1 and 2 are subject to a BART evaluation.

The NDDH prepared an air dispersion modeling protocol as a guideline to evaluate potential changes in visibility at nearby Class I Areas[1]. The NDDH modeling protocol requires that pre-control and post-control changes in visibility due to individual emission units be evaluated, and after the individual changes in visibility are determined, the entire facility's change in visibility is evaluated[2]. This document summarizes the facility change in visibility, and should be read in conjunction with the "BART DETERMINATION STUDY for Leland Olds Station Unit 1 and 2 Basin Electric Cooperative" Final Draft dated August 2006[3].

DEFINITION OF VISIBILITY IMPAIRMENT

Visibility impairment is caused by a combination of particles and gases in the atmosphere. Some particles and gases scatter light, others absorb light. The combined effect of scattering and absorption is called "light extinction" which is most commonly seen as haze. This haze is related to a haze index (HI) that is measured in deciview units; this haze index is related to light extinction coefficient by the following equation:

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[1] A Class I Area has special national or regional value from a natural, scenic, recreational, or historic perspective. The EPA affords Class I Areas special protection against degradation of these values.

[2] NDDH "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final), November 2005, page 53.

[3] The details of the BART modeling methodology, and changes in visibility from individual sources are summarized in the "BART DETERMINATION STUDY for Leland Olds Station Unit 1 and 2 Basin Electric Cooperative" Final Draft, August 2006.

$$HI = 10 \ln(b_{ext}/10)$$

Where HI is the haze index, and b_{ext} is light extinction coefficient in inverse megameters. An HI of 0.5 or more is considered a noticeable change in haziness, but not necessarily a visibility impairment.

Visibility impairment is a function of light extinction. Light extinction occurs when light energy is either scattered or absorbed by particles in the air. The amount of moisture in the air also plays a role in light extinction. Certain gases combine with moisture in the air to form small light scattering particles. These gases, most notably SO_2 and NO_X, are major components of coal-fired power plant emissions. Particulate matter (PM) also contributes to light extinction. In the final BART Determination Guidelines (70 FR 39160), EPA states that:

> "You may use PM_{10} as an indicator for particulate matter. [Note that we do not recommend the use of Total Suspended Particulates (TSP) as an indicator for particulate matter.]. As emissions of PM10 include the components of $PM_{2.5}$ as a subset, there is no need to have separate 250 ton thresholds for PM_{10} and $PM_{2.5}$. 250 tons of PM_{10} represents at most 250 tons of $PM_{2.5,}$ and at most 250 tons of any individual particulate species such as elemental carbon, crustal material, etc".

MODELING METHODOLOGY

The NDDH recommended using the current guideline version of the CALPUFF modeling system as modified by the NDDH to specifically address terrain, climate, and emission characteristics of the LOS[4]. One of the NDDH modifications is the CALBART post-processing program. CALBART uses the Federal Land Mangers' Air Quality Related Values Workgroup (FLAG) Method 6 for calculating light extinction. Along with the CALPUFF modeling system, the NDDH also provided the RUC2-MM5 gridded wind field data (2000-2002), the surface, upper air, and precipitation files, and the CALMET and CALPUFF input files. These input files contained the specific coordinate grid

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[4] CALMET and CALPUFF were recompiled by the NDDH while the CALPOST executable used for this visibility analysis was the EPA guideline executable

points, wind field options, terrain, dispersion options, receptor coordinates, plume characteristics, and other model parameters that the NDDH has determined best represents the region.

The NDDH confirmed that the two Class I areas to be considered for visibility impairment analysis are the Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWWA).

BEPC performed an analysis to determine what emission levels would constitute BART. Those emission rates are listed in the attached Table 1[5]. In order to predict the change in light extinction at the TRNP and LWWA areas, SO_2, NO_x, and PM were modeled with CALPUFF using the emission controls determined to be BART. Even though other pollutants are emitted during coal combustion, the BART guidelines focus on SO_2, NO_x, and PM. The NDDH identified 104 receptors allocated over both the TRNP and the LWWA. These receptors are the points for which CALPUFF was used to perform a visibility calculation.

A BART visibility impact analysis measures visibility improvement over the worst 2 percent (98th percentile) and 20 percent (90th percentile) visibility days at each receptor. The 98th percentile is the 8th worst visibility day (2 percent times 365 days equals about eight days). Since visibility is a 24-hour averaged analysis, the 90th percentile is calculated where each receptor was tabulated for each day and the worst 73 days (365 days times 0.2 equals about 73 days) were averaged together to determine the worst 20 percent visibility days.

DEGREE OF VISIBILITY IMPROVEMENT

The NDDH does not have a target threshold for visibility improvement for BART analyses. The BART determination takes into account the following parameters:

1. The cost of compliance.

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[5] Details of the controls and emission limits are found in the "BART DETERMINATION STUDY for Leland Olds Station Unit 1 and 2 Basin Electric Cooperative" Final Draft, August 2006.

2. The energy and non-air quality environmental impacts.
3. Any pollution control equipment in use at the source.
4. The remaining useful life of the source.
5. The visibility that may reasonably be anticipated to result from the use of such technology.

Parameter number five does not set a target threshold for visibility. As a result, Units 1 and 2 were combined to fulfill parameter number five, and to show the improvement in visibility from the LOS facility. The pre-control emissions were taken from the NDDH modeling protocol. The post-control emissions are the expected emissions after employing BART.

Table 2a presents the pre-control visibility impacts while Table 2b shows the post-control visibility impacts when employing BART. Both Tables 2a and 2b are the direct output from CALPUFF's CALBART post-processor. The tables show the change in deciview when compared to background values, the total deciview (background and LOS sources), and the year, day, and location of the occurrence (SEQ RECP, and ND RECP columns in Table 2a and 2b). The final four columns in both tables breakdown the contribution of the haziness into its components: sulfates, nitrates, fine particulate, and coarse particulate.[6]

Table 3a shows that the three-year average improvement in visibility ranged from 56 percent to over 77 percent when the largest, 98th percentile, and 90th percentile deciview changes are compared to pre-control levels. Table 3b shows that the average number of hazy days over 0.5 deciview decreased about 65 percent when compared to pre-control levels. The number of hazy days is the total number of hazy days over 0.5 and 1.0 change in deciview.

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[6] Details of the CALPUFF modeling methodology are found in the "BART DETERMINATION STUDY for Leland Olds Station Unit 1 and 2 Basin Electric Cooperative" Final Draft, August 2006, pgs. 85, 116, 217, 227.

CONCLUSION

A BART analysis does not need to meet a target threshold for visibility improvement; in other words, the LOS does not need for a BART to achieve a certain HI value. The visibility values listed in Tables 2b, 3a and 3b should be considered the visibility that may reasonably be anticipated to result from the use of the BART controls.

REFERENCES

Burns & McDonnell. August 2006. *BART DETERMINATION STUDY for Leland Olds Station Unit 1 and 2 Basin Electric Cooperative Final Draft*. Kansas City: Burns & McDonnell.

North Dakota Department of Health. November 2005. *Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final)*. Bismarck, North Dakota: North Dakota Department of Health.

Table 2b
Basin Electric Power Cooperative
Leland Olds Station Combined Unit 1 & 2
BART Post-Control 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.807	5.041	2.234	2000	72	6	6	2.8	28.51	69.11	1.82	0.56
98th %tile Delta-DV	0.897	3.067	2.17	2000	152	53	107	2.5	19.51	72.64	6.3	1.54
90th %tile Delta-DV	0.241	2.347	2.106	2000	241	44	44	2.2	22.25	66.77	7.84	3.14
2001												
Largest Delta-DV	1.618	3.851	2.234	2001	64	46	46	2.8	44.07	54.81	0.82	0.3
98th %tile Delta-DV	0.909	3.037	2.127	2001	112	53	107	2.3	28.4	67.52	3.32	0.76
90th %tile Delta-DV	0.197	2.473	2.276	2001	310	53	107	3	30.73	65.45	2.24	1.58
2002												
Largest Delta-DV	4.252	6.485	2.234	2002	78	46	46	2.8	33.88	64.51	1.11	0.51
98th %tile Delta-DV	1.756	3.99	2.234	2002	74	49	103	2.8	38.85	59.54	1.18	0.44
90th %tile Delta-DV	0.36	2.488	2.127	2002	105	45	45	2.3	13.35	78.93	5.93	1.8
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.997	5.231	2.234	2000	36	82	71	2.8	27.55	69.58	2.02	0.85
98th %tile Delta-DV	0.981	3.087	2.106	2000	247	71	60	2.2	43.87	48.78	5.44	1.91
90th %tile Delta-DV	0.212	2.467	2.255	2000	16	82	71	2.9	11.98	85.66	1.56	0.8
2001												
Largest Delta-DV	2.649	4.904	2.255	2001	12	83	112	2.9	44.51	52.89	2.06	0.54
98th %tile Delta-DV	1.09	3.323	2.234	2001	63	82	71	2.8	53.53	45.51	0.64	0.32
90th %tile Delta-DV	0.259	2.407	2.149	2001	205	58	47	2.4	77.67	10.8	9.4	2.14
2002												
Largest Delta-DV	5.385	7.618	2.234	2002	73	89	118	2.8	29.53	67.74	2.18	0.54
98th %tile Delta-DV	1.814	4.047	2.234	2002	75	82	71	2.8	34.39	63.32	1.59	0.7
90th %tile Delta-DV	0.295	2.401	2.106	2002	248	82	71	2.2	48.72	47.57	2.32	1.4

Table 2b (Continued)
Basin Electric Power Cooperative
Leland Olds Station Combined Unit 1 & 2
BART Post-Control 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.226	5.459	2.234	2000	74	90	72	2.8	44.34	54.42	0.76	0.48
98th %tile Delta-DV	0.669	2.903	2.234	2000	66	90	72	2.8	42.14	56.24	1.07	0.54
90th %tile Delta-DV	0.199	2.369	2.17	2000	155	90	72	2.5	48.36	49.73	1.13	0.78
2001												
Largest Delta-DV	1.575	3.808	2.234	2001	64	90	72	2.8	45.26	53.6	0.84	0.3
98th %tile Delta-DV	0.745	2.851	2.106	2001	260	90	72	2.2	72.87	22.99	3.16	0.98
90th %tile Delta-DV	0.115	2.221	2.106	2001	224	90	72	2.2	86.94	4.19	7.13	1.74
2002												
Largest Delta-DV	4.767	7	2.234	2002	73	90	72	2.8	33.05	64.74	1.71	0.5
98th %tile Delta-DV	1.433	3.666	2.234	2002	39	90	72	2.8	36.37	60.73	1.92	0.98
90th %tile Delta-DV	0.197	2.324	2.127	2002	125	90	72	2.3	22.46	76.56	0.11	0.86
LOSTWOOD NWR												
2000												
Largest Delta-DV	4.539	6.814	2.275	2000	47	98	80	2.9	40.51	58.05	1.03	0.41
98th %tile Delta-DV	1.051	3.326	2.275	2000	48	99	81	2.9	38.62	60.37	0.69	0.33
90th %tile Delta-DV	0.412	2.644	2.232	2000	192	99	81	2.7	40.51	53.52	4.81	1.16
2001												
Largest Delta-DV	5.222	7.562	2.34	2001	326	94	76	3.2	42.44	55.25	1.74	0.57
98th %tile Delta-DV	1.61	3.885	2.275	2001	41	91	73	2.9	30.19	67.84	1.38	0.58
90th %tile Delta-DV	0.45	2.661	2.211	2001	175	93	75	2.6	87.98	5.82	4.78	1.42
2002												
Largest Delta-DV	2.702	5.041	2.34	2002	337	93	75	3.2	9.51	86.82	2.59	1.07
98th %tile Delta-DV	1.081	3.421	2.34	2002	350	99	81	3.2	25.46	71.28	1.91	1.34
90th %tile Delta-DV	0.303	2.643	2.34	2002	362	99	81	3.2	37.44	61.45	0.92	0.2

Table 2b (Continued)
Basin Electric Power Cooperative
Leland Olds Station Combined Unit 1 & 2
BART Post-Control 1
2000-2002

Duration Events

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > .50: 2
2001
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > .50: 2
2002
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > .50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > .50: 1
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > .50: 2
2002
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > .50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > .50: 1
2001
Number of days with Delta-Deciview > 0.50: 011
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > .50: 2
2002
Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > .50: 2

LOSTWOOD NWR
2000
Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > .50: 2
2001
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > .50: 3
2002
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > .50: 3

Table 2b (Continued)
Basin Electric Power Cooperative
Leland Olds Station Combined Unit 1 & 2
BART Post-Control 1
2000-2002

DELTA-DV: Change in Haze Index due to source
DV(Total): Change in Haze Index due to the source and background sources
DV(BKG): Change in Haze Index due to background sources
SEQ RECEP: Sequentially numbered receptor as listed in CALPOST
ND RECEP: Receptor number as listed in North Dakota BART Protocol
F(RH): Relative humidity factor (i.e., amount of moisture in the air)
%SO4: Percent of Haze Index due to sulfates
%NO3: Percent of Haze Index due to nitrates
%PMC: Percent of Haze Index due to coarse particulates
%PMF: Percent of Haze Index due to fine particulates

Burns & McDonnell
SINCE 1898

January 29, 2007

Mr. Cris Miller
Senior Environmental Projects Administrator
Basin Electric Power Cooperative
1717 E. Interstate Ave
Bismarck, ND 58503-0564

Re: Revisions to BEPC BART Determination Study report,
LOS 1 with basic SOFA and SNCR NOx Control impacts, and
LOS Unit 1 and Unit 2 SNCR Cost Effectiveness Corrections

Dear Cris:

Burns & McDonnell has completed a supplemental report to the August 2006 final BART Determination Study report for Basin's Unit 1 and Unit 2 at Leland Olds Station.

This supplemental report includes expected impacts of LOS Unit 1 with basic SOFA and SNCR for NOx control. This document is being provided in response to the North Dakota Department of Health's request issued in a December 1, 2006 letter to Basin Electric Power Cooperative regarding the NDDH's comments from their review of the final draft report of the BEPC LOS BART DETERMINATION STUDY for LELAND OLDS STATION UNIT 1 and 2 (August 2006).

This is intended to be in addition to the following sections:

2.4.2 Energy Impacts of NO_X Control Alternatives – LOS Unit 1;
2.4.3 Non Air Quality and Other Environmental Impacts of NO_X Control Alternatives – LOS Unit 1;
2.4.4 Visibility Impairment Impacts of Leland Olds Station NO_X Controls – Unit 1;
2.4.5 Summary of Impacts of LOS NO_X Controls – Unit 1;

Included in this document are replacements to the following sections of the August 2006 BEPC BART Determination Study report:

2.4.1.2 Operating and Maintenance Cost Estimates for NO_X Controls – LOS Unit 1;
2.4.1.3 Cost Effectiveness for NO_X Controls – LOS Unit 1;

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Section 2.4.1.2 O&M Costs, and Section 2.4.1.3 Cost Effectiveness, were corrected for the costs of additional coal consumption for those LOS Unit 1 alternatives that involve a chemical reagent injected for NOx control alternatives to compensate for the heat of vaporization of the reagent dilution water.

Similarly, included in this document are replacements to the following sections of the August 2006 BEPC BART Determination Study report:

2.5.1.2 Operating and Maintenance Cost Estimates for NO_X Controls – LOS Unit 2;

2.5.1.3 Cost Effectiveness for NO_X Controls – LOS Unit 2;

Section 2.5.1.2 O&M costs, and Section 2.5.1.3 Cost Effectiveness, were corrected for the costs of additional coal consumption for those LOS Unit 2 alternatives that involve a chemical reagent injected for NOx control alternatives to compensate for the heat of vaporization of the reagent dilution water.

An electronic copy of the document has been sent to you via email.

As always, please contact Bob Blakley at (816) 822-3842 rblakley@burnsmcd.com, or Carl Weilert at (816) 822-3103 or cweilert@burnsmcd.com if questions arise.

Carl V. Weilert

Carl V. Weilert, P.E.
Project Manager
Plant Services Department

Robert D. Blakley

Robert D. Blakley, P.E
Project Engineer
Plant Services Department

cc: C. Weilert
Project File 37640

Rb/rb

REGISTERED PROFESSIONAL ENGINEER
ROBERT D. BLAKLEY
PE - 5658
DATE
NORTH DAKOTA
1/29/2007

Burns & McDonnell

January 29, 2007

Mr. Cris Miller
Senior Environmental Projects Administrator
Basin Electric Power Cooperative
1717 E. Interstate Ave
Bismarck, ND 58503-0564

Leland Olds Station Unit 1and Unit 2
NDDH Comments December 1, 2006
BART Determination Study

Dear Mr. Miller:

Burns & McDonnell has reviewed the letter issued by the North Dakota Department of Health (NDDH) to Basin Electric Power Cooperative (BEPC) dated December 1, 2006[1]. This letter report addresses the issues raised by the NDDH and refers to the results of additional visibility impairment improvement modeling for Unit 1 (submitted as separate documents under separate cover letters) as requested.

Burns & McDonnell was retained by BEPC to perform the previously issued BART Determination Study[2]. Basin Electric Power Cooperative's (BEPC's) Units 1 and 2 at the Leland Olds Station (LOS) were determined to be BART eligible by the NDDH. The referenced BART analysis was conducted in accordance with the eligibility conclusion made by NDDH and follows the steps outlined in the finalized Regional Haze Regulations [RHR] and Guidelines for Best Available Retrofit Technology (BART) Determinations[3] (July 6, 2005) to determine a BART emission limit for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). The NDDH protocol[4] (November 2005) provided a state specific modeling protocol for use in the analysis.

Burns & McDonnell responses are in the form of reiterating the NDDH's comments verbatim followed by a brief reply to address the issues raised.

NDDH Comment #1 *The National Park Service has indicated that 98% SO_2 control has been proposed on several other projects such as Thoroughbred, LGE-Trimble and Mustang. Although the Department recognizes that such sources have not been built, and that they will be firing coal not common to our region, we ask that Basin provide comments on this issue.*

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[1] See Reference number 1.
[2] See Reference number 2.
[3] See Reference number 3.
[4] See Reference number 4.

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B&McD Response #1 This issue has been addressed by the EPA in the New Source Performance Standards (NSPS) recently promulgated as final rule amendments to 40 CFR part 60, subparts Da, Db, and Dc emission standards effective February 27, 2006[5].

In establishing the final SO_2 emission standards for EUSGUs, in specific response to the issue of reflecting best demonstrated technology (BDT) for SO_2 removal greater than 98 percent, the "EPA has concluded that 98 percent control is possible with certain control and boiler configurations under ideal conditions. The amended SO_2 standard is based on a 30-day average that includes the variability that occurs from non-ideal operating conditions".[6]

Basin Electric has provided information regarding predicted future coal quality that indicates a higher level and variability of sulfur content that will be required to be controlled. Burns & McDonnell believes that it would not be possible to operate the units at Leland Olds Station continuously under ideal operating conditions such that an average 98% level of SO_2 emissions control could be sustained for every 30-day rolling period. The projects mentioned by the National Park Service have not been constructed and have not demonstrated the ability to achieve and sustain 98% SO_2 emissions control for every 30-day rolling period.

Burns & McDonnell believes that a 30-day rolling average requirement of 98 percent control suggested by the National Park Service as BART for SO_2 removal is inappropriate for the EUSGUs at Leland Olds Station. The referenced BART Determination Study report[7] analysis for Unit 1 and Unit 2 evaluated available technologies and recommended effective levels of SO_2 removal considered suitable for the determination of BART appropriate for this facility given the statutory factors required for the analysis.

NDDH Comment #2 *With respect to the 90% and 95% SO_2 control options, emission rates were provided that are based on coal-to-stack control efficiencies. We believe a wet scrubber is capable of achieving 95% control of the inlet concentration to the scrubber and dry scrubber is capable of achieving 90%. Emission rates that reflect 90% and 95% inlet to outlet control efficiencies should be provided.*

B&McD Response #2 The BART SO_2 emission rates provided in the BART Determination Study report were calculated based upon 100% of the sulfur input in the coal assumed to be converted to SO_2 in the boiler and emitted in the flue gas. The FGD scrubber SO_2 removal efficiencies for Leland Olds Station boilers were assumed to be relative to the inlet mass rate and type of scrubber for the respective boilers: 90% for Unit 1's dry scrubber, and 95% for Unit 2's wet scrubber. Likewise, the recommended 30-day rolling average SO_2 BART emission limits were calculated similarly, with sulfur and heat contents of the lignite coal being changed to be reflective of expected

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[5] See Reference number 5.

[6] Ibid Reference 5, pg 9870.

[7] Ibid Reference 2.

higher short-term future variability in the sulfur concentration and lower fuel heat content[8]. The analysis did not assume any reduction of lignite sulfur input assumed due to fuel processing or boiler firing, and this is consistent with normally accepted practice for estimating emissions at the inlet of an SO_2 control device. This also agrees with the EPA's recommended method for calculating Potential To Emit emission rates as defined in the NSR Manual[9]. Burns & McDonnell believes that the appropriate method to calculate outlet emissions for the BART Determination Study analysis of the Leland Olds Station units is to assume that 100% of the calculated sulfur predicted to be contained in the future coal feed to the boiler is converted to sulfur oxides. The presumed level of SO_2 control was applied across the FGD scrubber to the inlet mass emissions, and subsequently resulted in the amount of SO_2 mass emissions released to the atmosphere that was included in the referenced study report.

NDDH Comment #3 *For Unit 1, basic separated overfire air (SOFA) with selective non-catalytic reduction (SNCR) was evaluated for costs. However, no modeling was conducted to show the effects on visibility for this alternative. The Department believes that close examination of all factors associated with this alternative will be necessary before such an alternative can be eliminated. As we have indicated in the past, BART selection is made using the top-down approach considering all the statutory factors including visibility improvement. Although the presumptive level factor will be weighed in our BART determination, we also believe it is necessary to conduct a complete evaluation of more efficient technologies that may be cost-effective. Therefore, the Department requests that modeling be conducted for the basic SOFA plus SNCR alternative and the results submitted for review. In addition, the remaining factors (i.e., energy impacts, non-air quality environmental impacts, etc.) should be addressed.*

B&McD Response #3 There is published and regulatory agency-provided information associated with the RHR that conflicts with the premise that all technically feasible control alternatives that are cost-effective and have minimal energy and non-air environmental impacts must be evaluated for visibility impairment impact as part of a BART Determination process. The BART Stakeholder Meeting with the NDDH on July 27, 2005 included an NDDH verbal response to the question (paraphrased) "If a source agrees to presumptive limits even though they are at a facility that is less than 750 MW, would a BART Determination be required along with Air Quality Modeling? The NDDH verbal response referenced the RHR BART Guideline (presumably pg 68 of the final July 6, 2005 FR version of the RHR) which, when paraphrased, essentially states that if a source applies the most stringent applicable technology, then it is not required to perform the Air Quality modeling. Also, the NDDH is believed to have asked EPA Region 8 this (or a similar) question and their quick answer was basically that if a utility accepted presumptive BART not only would they not perform the AQ modeling they would not have to perform a BART determination for that unit for that pollutant.

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[8] Ibid Reference 2, pages 158 and 233 for Unit 1; pages 188 and 236 for Unit 2.

[9] See Reference number 6, Article II.B.6, page A.19.

In the EPA's corrected RHR Comment Response Document, the EPA provided a response to a commenter (0215) that said "if an EGU is achieving the default/presumption for NOx, it should not be required to do a BART determination for that pollutant" [10]. The EPA's response in this same document was "We agree that a streamlined BART process is warranted for such sources"[11].

Because the EPA established the presumptive BART NO_X emission limits based on combustion controls for boilers other than cyclone-fired ones, post-combustion controls for sources without existing post-combustion controls, including selective non-catalytic reduction (SNCR) technology "are generally not cost-effective except in very limited applications and therefore were not included in EPA's analysis"[12].

LOS Unit 1's highest 24-month rolling average NO_X emission rate during the years 2000-2004 was 0.285 lb/mmBtu. This was slightly below the presumptive BART level of 0.29 lb/mmBtu for a lignite-fired dry-bottom pulverized coal boiler greater than 200 MW located at a power plant with a generating capacity of more than 750 MW. The BART Determination Study report recommended a 30-day rolling average BART NO_X emission rate for LOS Unit 1 of 0.29 lb/mmBtu[13]. The RHR leaves it up to the individual states to determine whether to apply the EPA's presumptive BART NO_X emission rate limits for units greater than 200 MW operating at power plants with a total generating capacity of less than 750 MW.

Thus, due to the EPA's comment response coupled with direct feedback from NDDH regarding the specific relevant issue, there was reason to believe that if BEPC accepted the presumptive BART NO_X emission limit of 0.29 lb/mmBtu for a lignite-fired dry bottom pulverized coal boiler greater than 200 MW located at a power plant with a generating capacity of more than 750 MW for Unit 1, that a BART analysis and visibility modeling of all feasible NO_X reduction technologies including post-combustion alternatives would not be required for LOS Unit 1. Basin's BART Determination Study report analysis for Unit 1 did, however, include the technical feasibility analysis of appropriate, available NO_X reduction technologies, along with visibility modeling and impairment improvement evaluation for a single combustion control-based alternative with the next lowest emission rate (basic SOFA).

As shown in Table 2.4-14 of Basin's BART Determination Study report[14] analysis for Unit 1, the incremental visibility impairment reduction of SOFA vs. presumptive NO_X emissions based on future PTE heat input conditions was typically less than 0.01 at three TRNP Class 1 areas, and was below 0.02 at Lostwood NWR. The corrected incremental control cost increases significantly from basic SOFA to the SNCR with basic SOFA alternative ($4,060/ton) vs $208/ton for basic SOFA versus presumptive NO_X emissions for the future PTE pre-control case. The expected incremental

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[10] See Reference 7, page 238.
[11] Ibid Reference 7, page 238.
[12] Ibid Reference 3, page 39134.
[13] Ibid Reference 2, page ES-4 and page 241.
[14] Ibid Reference 2, page 88.

visibility impairment reduction of SNCR with SOFA vs. basic SOFA was found to be of a similar very small magnitude (maximum 0.021 dV) because the NO_X emission rate change of 0.062 lb/mmBtu (0.230-0.168 lb/mmBtu) between these alternatives was comparable to the NO_X emission rate change of 0.060 lb/mmBtu (0.290-0.230 lb/mmBtu) from presumptive NO_X to basic SOFA.

While the RHR BART Guidelines[15] do not use the words "top-down", it is left up to the states to establish the appropriate approach for the BART analysis and determination. The referenced BART Determination Study report[16] analysis for Unit 1 evaluated available technologies and recommended effective levels of NO_X emissions considered suitable for the determination of BART appropriate for this facility given the statutory factors required for the analysis.

In a spirit of cooperation, the visibility improvement modeling and analysis of the impacts, including the other statutory factors required for a BART determination for the SNCR with basic SOFA alternative applied to LOS Unit 1's pre-control NO_X emissions are being provided to the NDDH as a separate document[17].

NDDH Comment #4 *We would like a better explanation of how the estimated emissions for the various alternatives for NO_X control were estimated. The discussion should include emissions achieved at other facilities based on these alternatives and how those numbers compare to proposed emission rates for Leland Olds Station.*

B&McD Response #4 The referenced BART Determination Study report[18] provided numerous references on pages 127-131 and an extensive list summarizing recent NO_X reduction projects in the United States in Appendix A3. Although there is a significant amount of experience with certain commonly applied techniques and technologies for NO_X control on coal-fired boilers, such as low-NO_X burners (LNBs) and separated overfire air, there is a noticeable lack of such experience on wall-fired pulverized coal and cyclone boilers designed and built for firing North Dakota lignite.

For LOS Unit 1, the long-term average pre-control NO_X levels with original burners but without close-coupled overfire air (CCOFA, prior to 1995) were estimated to be much higher than 0.29 lb/mmBtu. The EPA's Technical Support Document for BART NO_X Limits[19] published with the RHR Guidelines established a Pre-Control rate of 0.74 lb/mmBtu and an Effective Control Case 1a NO_X Emission Rate of 0.23 lb/mmBtu for LOS Unit 1. This would be a pre-to-post control reduction of approximately 69 percent, which is higher than the example low-NOx burner retrofits summarized in Appendix A3 (pages A3-13 though A3-15) of the referenced BART Determination Study report. The EPA's Case 1a assumed installation of current NO_X combustion

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[15] Ibid Reference 3.
[16] Ibid Reference 2.
[17] See Impacts Analysis of Basic SOFA with SNCR Alternative for Leland Olds Unit 1, 1/29/2007.
[18] Ibid Reference 2.
[19] See Reference 8, Excel Spreadsheet page 270.

controls (LNBs and SOFA) for units with no prior controls, or which have controls installed before 1997. This is the situation applicable to Leland Olds Station Unit 1.

Considering the information included above and in other available technical literature, the referenced BART Determination Study report established 0.23 lb/mmBtu as the estimated post-control 24-month rolling average NO$_X$ emission rate for LOS Unit 1 when retrofitted with SOFA in combination with low-NOx burners. This was a 20.7% reduction from the presumptive BART NO$_X$ rate of 0.290 lb/mmBtu[20]. The referenced BEPC LOS BART study's Unit 1 visibility improvement modeling and impact analysis also assumed a 20.7% reduction from the average NO$_X$ rate of 760.4 lbs/hr (presumptive BART) to 603.1 lbs/hr for the highest 24-hour (daily) post-control condition with low-NOx burners and SOFA[21]. SNCR with basic SOFA assumed an additional 26.8 percent reduction beyond the 0.23 lb/mmBtu basic SOFA control level, estimated to be 0.168 lb/mmBtu or 42 percent below the presumptive BART baseline of 0.29 lb/mmBtu[22]. This estimated additional reduction percentage for SNCR performance applied to LOS Unit 1 is similar to the levels achieved by other wall-fired boilers retrofitted with this technology as summarized in Appendix A3 (pages A3-21 though A3-26) of the referenced BART Determination Study report. It is also 77.3% lower than the EPA's Pre-Control NO$_X$ emission rate of 0.74 lb/mmBtu.

For LOS Unit 2, the long-term average pre-control NO$_X$ levels with previous firing practices was estimated to be much higher than the pre-control future PTE baseline of 0.67 lb/mmBtu established in the referenced BART Determination Study report[23]. The EPA's Technical Support Document for BART NO$_X$ Limits[24] published with the RHR Guidelines established a Pre-Control rate of 1.03 lb/mmBtu and an Effective Control Case 1a NO$_X$ Emission Rate of 0.52 lb/mmBtu for LOS Unit 2. This would be a pre-to-post control reduction of approximately 50 percent, which is similar or higher than some of the cyclone SOFA retrofits with modest amounts of substoichiometric combustion summarized in Appendix A3 (pages A3-1 though A3-2) of the referenced BART Determination Study report. The EPA's Case 1a assumed installation of current NO$_X$ combustion controls for units with no prior controls, or which have controls installed before 1997. The current combustion control technology analyzed by the EPA for cyclone units is coal reburning[25]. This is the situation applicable to Leland Olds Station Unit 2.

Considering the information included above and in other available technical literature, the referenced BART Determination Study report established 0.48 lb/mmBtu as the estimated post-control 24-month rolling average NO$_X$ emission rate for LOS Unit 2 with the advanced form of SOFA, which was a 28% reduction from the pre-control

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[20] Ibid Reference 2, Table 2.3-2 on page 58.

[21] Ibid Reference 2, Table 1.4-1 on page 19, and pages 85-95.

[22] Ibid Reference 2, Table 2.3-2 on page 58.

[23] Ibid Reference 2, Table 2.3-4 on page 61.

[24] Ibid Reference 8, Excel Spreadsheet page 270.

[25] Ibid Reference 3, page 39134, footnote 63.

future PTE baseline rate of 0.67 lb/mmBtu[26]. The referenced BART study's LOS Unit 2 visibility improvement modeling and impact analysis also assumed a 0.48 lb/mmBtu NO_X emission rate with the advanced form of SOFA, which represents a reduction of nearly 38 percent from the average NO_X rate of 3,959 lbs/hr for the highest 24-hour (daily) post-control condition without ASOFA[27]. The referenced BART study also assumed an additional 36.7 percent reduction beyond the 0.48 ASOFA control level for the 24-month rolling average NO_X emission rate of LOS Unit 2's SNCR with ASOFA alternative, estimated to be 0.304 lb/mmBtu or 54.5 percent below the future PTE pre-control baseline of 0.67 lb/mmBtu[28].

The expected post-control SNCR NO_X emission rate depends on the NO_X inlet concentration, type of reagent (aqueous urea), the amount of time that the flue gas is within the optimum temperature window for the SNCR process, and the amount of ammonia slip that is considered acceptable. Generally, the higher the NO_X inlet concentration and/or allowable ammonia slip in the boiler outlet flue gas, the higher the NOx reduction percentage that can be achieved. This estimated additional reduction performance for SNCR applied to LOS Unit 2 is similar to or better than the percentage reductions achieved by other cyclone-fired boilers retrofitted with this technology as summarized in Appendix A3 (pages A3-7 though A3-9) of the referenced BART Determination Study report. The amount of ammonia slip emitted was not always disclosed in the technical literature or vendor experience summaries for SNCR projects, and this has a significant influence on the resulting NO_X reduction expected.

The Alliant Edgewater Unit 4 and AmerenUE Sioux Unit 1 cyclone SOFA retrofits were operated with substantially more substoichiometric combustion conditions (below 0.90) than expected to be sustainable at LOS for Unit 2. Therefore, those NO_X reduction projects summarized in the referenced BART Determination Study report have reported greater percentage NO_X emission rate reductions resulting from deeply-staged cyclones and SOFA than are anticipated for LOS Unit 2 for operation with modestly-staged cyclones and ASOFA. As described in the referenced BART study, there is significant concern about the ability to control and sustain adequate ash slag fluidity, coverage, and tapping during deeply-staged cyclone operation for LOS Unit 2 when firing lignite coal. This means that the subsequent estimates for NO_X emission rates when ASOFA is considered alone and when combined with other technically-feasible technologies at LOS for Unit 2 will not reach the low levels of NO_X emission rates that were demonstrated on subbituminous coals at these other cyclone-fired boilers[29].

NDDH Comment #5 *We ask that you address the use of combustion optimization systems (COS) for the reduction of* NO_X *emissions from both units.*

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[26] Ibid Reference 2, Table 2.3-4 on page 61.

[27] Ibid Reference 2, Table 1.4-1 on page 19, and pages 116-126.

[28] Ibid Reference 2, Table 2.3-4 on page 61.

[29] Ibid Reference 2, Appendix A3, pages A1, and A3-7 through A3-9.

B&McD Response #5 When establishing presumptive NO_X emission limits for BART-eligible coal-fired units, the RHR Guidelines did not include combustion optimization systems as "types of current combustion [NO_X] control technology options assumed include low NO_X burners, over-fire air, and coal reburning"[30]. All boilers that fire fuel to generate steam include some form of combustion control, primarily to safeguard personnel and equipment from inappropriate operation that could result in explosions. "Combustion optimization systems (COS) refers to the active control of combustion. These active combustion control measures seek to find an optimum combustion efficiency and to control combustion (and hence emissions) at that efficiency. Another approach uses a neural network computer software program to find the optimum control point. Still another approach is to use software to optimize inputs for the defined output"[31].

COS have been developed over the past ten years to manipulate boiler fuel/air combustion hardware adjustments to reduce NO_X and minimize CO emissions, increase boiler thermal efficiency, decrease flyash combustibles loss (also called LOI or loss-on-ignition), and decrease flue gas temperature variations within the furnace. There are two major aspects to COS:

- the control system with its software and hardware controllers; and
- the field devices, which include actuators and sensors.

COS can be operated on a stand-alone basis or combined with other optimization systems for furnace sootblowers, boiler steam cycle efficiency and capacity, and post-combustion NO_X reduction and reagent injection control.

A reference technical paper summarizing combustion controls for the western region of the United States stated that the number of neural networks installed at any of the 110 coal-fired EGUs in the WRAP paper was "unknown but significant". It also stated that "at least 35 installations of GNOCIS have been identified, and Pegasus [NeuSIGHT, by NeuCo, Inc.] has many more, however, the total number of installations of neural networks with enhanced monitoring could not be identified. However, enhanced monitoring has been in use for a number of years and it is expected that many units do utilize some form of it to optimize performance"[32]. It should be noted that neural networks were listed as an addition to low NO_X burners, close-coupled and separated overfire air combustion controls for state-of-the-art NO_X reduction techniques, but not for cyclone-firing.

One COS vendor offers technology "to integrate existing controls, control systems, sensors and computer hardware with advanced optimization techniques in a proprietary software environment to reduce emissions, increase efficiency, and increase availability. [This technology] literally learns on-line the interrelationships between important process control settings and real-time performance, constantly searching for overall performance improvements and make adjustments automatically and in real-

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[30] Ibid Reference 3, page 39134.

[31] See Reference 9, page 16.

[32] See Reference 10, Table 3 on page 3-7, and page 3-11.

time"[33]. One of the COA projects mentioned in the referenced technical literature is a 2003-2007 U.S. DOE Clean Coal Power Initiative (CCPI) project at Dynegy Midwest Generation's Baldwin Energy Complex[34]. The initial potential benefits expected from the implementation of this demonstration project identified "NO_X emissions reductions of 5%"[35].

According to data presented in a early 2006 technical journal, the average NO_X concentration at the inlets to the Baldwin Unit 1 cyclone boilers' SCR reactors can be reduced by approximately 7.7% from non-optimized baseline[36]. Total Project Funding is budgeted at $19 million, and this does not "entail the addition of process equipment" to the host facility[37]. It should be mentioned that a significant amount of field instrumentation and distributed control systems and local area networks already installed at Baldwin Station were likely the main reasons why this latter statement was made. Unfortunately, it is not possible to determine the actual installed cost of the NO_X emission reduction portion of this project that would normally be attributable to the scope of the neural network COS, and how this might relate to the cost of a commercially-available, dedicated COS for each cyclone or tangentially-fired boiler at Baldwin.

Another technical paper from April 2005 describes some improvements made to the neural control software model initially used for controlling NO_X by controlling cyclone combustion air/fuel stoichiometry at Baldwin Station. It is unclear that the claimed NO_X reductions achieved fairly early in the demonstration project (15-20%) were sustainable or that they represent only those gains strictly due to the COS. There were aspects of the COS methods that were incomplete or had detrimental effects to other operations that led to further changes in the tuning of the optimizer[38].

Several referenced technical papers have been written summarizing another COS called Generic NO_X Control Intelligence System (GNOCIS), applied at Southern Company's Georgia Power - Plant Hammond Unit 4. "GNOCIS is a software package designed to improve utility boiler efficiency and reduce NO_X emissions through careful control of operating parameters. GNOCIS can operate on units that burn gas, oil, or coal and is available for all combustion firing geometries". Also, "GNOCIS uses a neural network to model the combustion characteristics of a boiler. In one of the more common forms, a neural network (computer code that models a system's responses) consists of three layers: an input layer, a hidden layer, and an output layer. The input layer receives signals from monitored variables and transmits them to the hidden layer, which contains interconnected neurons for pattern recognition. After processing, signals are sent to the output layer, which outputs recommend settings for the control variables. Thus, a neural network is, in effect, a sophisticated curve-fitting tool. Neural networks

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[33] See Reference 11.
[34] See Reference 12.
[35] See Reference 12 Fact Sheet and Reference 13 background sheet.
[36] See Reference 14, Figure 3, page 3.
[37] Ibid Reference 12, page 2 and page 1.
[38] See Reference 15.

can recognize patterns in input data, but before the network can associate a particular pattern with a corresponding plant state, it must be "trained". The training phase can be time consuming and usually involves feeding historical data to the program. However, once a network has been trained, it can respond very rapidly to new inputs. An advantage of a neural network is that, if any inputs are faulty, prediction capability degrades only gradually compared to most other modeling techniques. In order for GNOCIS to function effectively, a properly designed and installed control system is essential"[39].

The vast majority of these COS are believed to have been applied to pulverized coal-fired boilers with low-NO_X burners and SOFA[40]. The reference technical literature stated that testing with the GNOCIS program set to control boiler operations, full-load NO_X emissions were reduced from between 14 percent and 10 percent over baseline, depending on the mode that the COS was operating in. The COS mode for minimizing NO_X emissions at full load produced the 14% reduction, maximizing efficiency operating mode showed a 12% decrease, while the minimize flyash LOI mode resulted in the 10% drop over full-load baseline emissions[41].

In regards to the cost of this COS, "If a distributed control system (DCS) is present, installing GNOCIS on the boiler is relatively inexpensive and can significantly improve plant operations".[42] Also, "Estimates by the participant for costs that could be used for planning a retrofit a 500-MWe power plant similar to Hammond Unit 4 are: GNOCIS \$0.25 million (\$0.50/kW). These estimates are based upon actual Hammond Unit 4 costs, as well as cost data available from EPRI and other sources. Of course, site-specific factors, such as boiler size, age, design, furnace configuration, windbox design, and condition, plant layout, etc., can significantly affect these estimates. Insufficient data are available to allow estimation of installing full unit optimization hardware and software"[43].

Due to the time span from the actual installation of the digital control system in June 1994 followed by GNOCIS testing starting in February 1996, until the date of the reference technical report (March 2004) and then to the present (January 2007), the expected cost of installing this COS at Hammond Unit 4 is difficult to estimate in today's dollars from a review of the available technical literature.
There have been few published technical papers or articles in utility trade journals/magazines that document COS applied to cyclone-fired boilers. One 2002 technical reference provided an implementation cost range between \$30 and \$60/kW, claiming fuel and operating flexibility for low NO_X emission rates from tangentially-fired, wall-fired, and cyclone-fired boilers[44]. The exact details of such modifications have not been published, although the general scope of this referenced firm's COS

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[39] See Reference 16, pages 17 and 18.
[40] Ibid Reference 10, pages 3-11 and 3-12.
[41] Ibid Reference 16, page 8.
[42] Ibid Reference 16, page 9.
[43] Ibid Reference 16, pages 43 and 44.
[44] See Reference 17, page 4.

involved changes that went well beyond what is typically included for these kinds of retrofit projects in terms of field instrumentation and controls hardware. Unfortunately, it is not possible to determine the actual installed cost of the portion and the amount of NO_X emission reductions for these projects that would normally be attributable to the scope of traditional COS "neural network" retrofit projects.

Basin has already implemented improvements to the Leland Olds Station Unit 2 boiler distributed controls system in spring 2006, and plans on installing similar DCS control upgrades on Unit 1 in fall 2007. It is difficult to estimate the amount of potential NO_X emission reductions and costs of adding available commercial COS to either LOS unit due to the site-specific nature of such installations. The need to identify the levels of field instrumentation and control devices for integration with the COS and the fact that the alternatives recommended as BART for NO_X control have not been installed would require further detailed investigation. The opportunity to make significant additional NO_X emission reductions strictly from adopting and adapting neural networks to the LOS boilers is uncertain but is believed to be limited due to the improvements already planned and/or incorporated by the installation of the DCS upgrades and other operational procedures in effect.

An electronic copy of this document has been sent to you via email. The referenced "Impacts Analysis of Basic SOFA with SNCR Alternative for Leland Olds Unit 1, 1/29/2007" has been sent to you via email with a separate cover letter.

As always, please contact Bob Blakley at (816) 822-3842 rblakley@burnsmcd.com, or Carl Weilert at (816) 822-3103 or cweilert@burnsmcd.com if questions arise.

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Rb/rb

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References:

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12 – "Demonstration of Integrated Optimization Software at the Baldwin Energy Complex", 2003 CCPI Program project brief available at http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/project_briefs/Neuco.pdf, and

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May 29, 2009

Received
Air Quality
MAY 2009

Mr. Terry L. O'Clair, P.E.
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Dear Terry:

Per your request, Basin Electric Power Cooperative (Basin Electric) has developed a hypothetical cost effectiveness determination to supplement our previously submitted BART Determination Study for Leland Olds Unit's 1 and 2. This specific work product is a continuation of information surrounding the discussion of the applicability of selective catalytic reduction (SCR) and specifically the tail-end selective catalytic reduction (TE-SCR) to Leland Olds Unit 2.

As Sargent & Lundy has explained both in its March 11, 2009 presentation and in earlier communications with the Department, cyclone boilers burning North Dakota lignite coal have unique challenges that may make SCRs unfeasible because of the high alkalis (mainly sodium and potassium) levels combined with the high temperature and other properties that are uniquely found in cyclone boilers which vaporizes the alkalis into the flue gas stream. This high level of vaporized alkali products in the flue gas stream is known to cause deactivation and poisoning of the catalyst. The design issues for North Dakota lignite have not been addressed by Powder River Basin (PRB), Texas lignite, or other brown coals that do not have the same high alkali content and other chemical properties of North Dakota lignite. Extensive pilot testing is needed to resolve catalyst deactivation and other issues.

Sargent & Lundy developed the first application of SCRs on PRB coal. As they noted in their March 11 presentation to you, the following problems would have arisen for PRB if extensive pilot testing had not been done prior to the first commercial application of SCRs on facilities using PRB coal (slide 59):

- ✓ Catalyst would not have performed
- ✓ Reactors would have been too small
- ✓ Operation would have been problematic

TE-SCRs are a higher cost and much less applied technology than other SCRs. Based on the factors discussed in the March 11th presentation, Sargent & Lundy concluded (slide 68):

> There are attributes of this fuel [ND Lignite] in a tail-end SCR environment that are not well understood today and need more investigation to predict it's performance to make it commercially available technology.

Because of these uncertainties, and the huge potential consequences to our company and the North Dakota lignite resource if an SCR were installed and did not work, Basin Electric committed to completing pilot testing for the SCR technology on cyclone boilers using ND lignite before the next review period for Regional Haze. We ask that you allow us that opportunity, and emphasize that these highly hypothetical estimates are nothing more than an educated guess based on hypothetical performance levels (with a very high probability of being wrong) until pilot testing is completed. We emphasize that point, because there is a risk that these estimates will be cited as if they have the same degree of accuracy as estimates of costs for commercially available technologies. The law is clear that when pilot testing is needed, a technology is not considered "available." One of the reasons for doing this is to avoid putting on extremely expensive technologies such as SCRs, with no assurance that they will work.

Thus, we are supplying you with these cost estimates with the caveats and commitments just described, and ask that the estimates not be misused.

The hypothetical cost effectiveness determination for TE-SCR was performed by Sargent & Lundy, who as you know has significant technical expertise for all application of SCRs. This study indicates that the TE-SCR has numerous unknowns as to its applicability to a North Dakota lignite-fired cyclone boiler for NOx control. Specifically, unknown is the reactivity loss of the catalyst, design factors of the SCR (catalyst volume and surface area), reagent injection rates, reagent slip and economic volatility of the re-heat fuel. These areas need to be more defined prior to placing a pollution control technology on such an unlike flue gas stream that a North Dakota lignite-fired cyclone boiler represents.

Basin Electric's BART Determination submittal included the visibility impairment at the Class I areas in North Dakota using the Departments modeling Calpuff protocol. With the addition of a wet scrubber for SO_2 control and selective non-catalytic reduction (SNCR) technology for NOx control on both Leland Olds units there was significant visibility improvement on the Class I areas. It is expected that the ammonia slip from the TE-SCR may be greater than a SNCR control since it will be located beyond the wet scrubber. This increased ammonia slip in the presence of SO_3 may require additional controls such as a wet electrostatic precipitator (WESP) or other technologies such as sorbent injection in order to minimize potential plume blight issues and PSD requirements.

Based on this hypothetical economic analysis, the Department should consider both the high initial cost and large risk of failure of installing an unproven control technology.

Should you have questions or require additional information, please contact me at (701) 355-5635.

Sincerely,

Cris Miller

Cris Miller
Senior Environmental Project Administrator

/gmj
Enclosure
cc: Lyle Witham

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Sargent & Lundy LLC

May 27, 2009

Mr. Cris Miller
Senior Environmental Project Administrator
Basin Electric Power Cooperative
1717 E. Interstate Avenue
Bismark, ND 58503-0564

Project: Basin Electric Power Cooperative – Leland Olds Station
Subject: BART Evaluation Update – Tail End SCR

Dear Mr. Miller:

Per your request as a follow-up to our presentation to the North Dakota Department of Health (NDDH/Department) on March 11, 2009, this letter report has been prepared to provide supplemental information in support of Basin Electric Power Cooperative's (BEPC's) BART Determination Study for Leland Olds Station Units 1 and 2, which was submitted to the NDDH in August 2006 (the "BART Determination Study").

The BART Determination Study identified tail-end selective catalytic reduction (TE-SCR) as a potentially available post-combustion NOx retrofit control technology. However, the study determined that TE-SCR on Leland Olds Station (LOS) Unit 2 would be susceptible to unacceptable catalyst deactivation from soluble alkalis in the lignite (most notably sodium) not removed by the particulate matter and flue gas desulfurization control systems. The study concluded that TE-SCR was not a technically feasible NOx retrofit control technology due to the flue gas characteristics associated with the North Dakota lignite fired in LOS Unit 2.

Although there continue to be significant technical issues associated with the operation of a TE-SCR control system on a unit firing North Dakota lignite, NDDH has requested that BEPC provide a cost effectiveness evaluation for the TE-SCR control system on LOS Unit 2 recognizing the high level of uncertainty in doing so due to the lack of design and operational knowledge surrounding the application of a TE-SCR on a ND lignite–fired cyclone boiler. Cost estimates included in this letter report were prepared in response to the Department's request for a cost effectiveness evaluation. However, as we concluded in our presentation to the Department on March 11, 2009, significant pilot testing will be needed to understand the effect of lignite-derived flue gas on the SCR catalyst and evaluate the technical feasibility and effectiveness of TE-SCR on LOS Unit 2 with any degree of certainty. Without information developed from a testing program, cost estimates included herein should be considered hypothetical case studies based on technical judgment. More accurate estimates cannot be developed without first performing pilot tests, and, without that information, the actual cost effectiveness of the TE-SCR system (assuming it proves to be technically feasible) could be higher or lower than the costs identified below.

In addition, as described below, we still have significant concerns regarding the technically feasibility and effectiveness of a TE-SCR control system on a lignite-fired cyclone boiler. We concur with the conclusions included in the BART Determination Study that, at this point, TE-SCR is not a technically feasible or commercially available Best Available Retrofit Technology (BART) for LOS Unit 2. Again, pilot testing would be required to conclude, with any degree of certainty, that TE-SCR is a technically feasible and economically viable NOx retrofit control technology.

Nevertheless, to support BEPC's response to the Department's request, Sargent & Lundy (S&L) is providing the following supplemental information: (1) a brief technical description of the TE-SCR control system; (2) a hypothetical cost effectiveness evaluation of TE-SCR on LOS Unit 2 accounting for some of the uncertainty associated with the effectiveness and operation of the system; and (3) updated cost effectiveness tables and figures that were originally included in the BART Determination Study.

Tail-E SCR Application at Leland Olds Unit 2

LOS Unit 2 is a Babcock & Wilcox (B&W) cyclone-fired unit with a turbine-generator nameplate rating of 440 MW. LOS Unit 2 is equipped with two parallel electrostatic precipitators (ESPs) for particulate matter control. The unit is not currently equipped with a flue gas desulfurization (FGD) control system, but BEPC is in the process of installing a wet FGD control system for sulfur dioxide (SO_2) control. The wet FGD control system is anticipated to be operational in the fall of 2010. The primary fuel for LOS Unit 2 is North Dakota lignite from the Freedom Coal Mine in Beulah, ND.

Selective catalytic reduction (SCR) was evaluated in the BART Determination Study as a potentially available NOx retrofit control technology. SCR involves injecting ammonia (NH_3) into boiler flue gas in the presence of a catalyst to reduce NOx to nitrogen (N_2) and water. The overall SCR reactions can be shown as follows:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

The performance of an SCR system is influenced by several factors including flue gas temperature, SCR inlet NOx concentration, catalyst surface area, volume and age of the catalyst, and the amount of ammonia slip that is acceptable. SCR control systems on coal-fired power plants are typically located at the economizer outlet, where the flue gas temperature is most suitable for the NH_3/NOx reactions. However, flue gas characteristics at the economizer outlet can also have detrimental affects on the SCR catalyst. Studies suggest that these flue gas characteristics can be especially troublesome with North Dakota lignite, where the ash chemistry is highly alkaline and contact with the catalyst can lead to significant catalyst deactivation and a shorter catalyst life.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst. Recovery of catalyst activity from the reversible phenomenon (i.e., inhibition) is controlled by the economics of new catalyst replacement and is highly dependent on the actual mechanism of deactivation.

In a North Dakota lignite application, SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances (e.g., Li, Na, K, and Ca) in flue gas. Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium (Na) and potassium (K) are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium (Ca), can react with SO_3 absorbed within the catalyst to form $CaSO_4$ and blind the catalyst. North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, Ca, K, and magnesium.

Sodium levels in North Dakota lignite are typically 5 to 20 times higher than sodium levels in bituminous and subbituminous coals, and sodium compounds can represent between 5% and 11% of the ash generated from firing North Dakota lignite. These sodium levels, occurring in both the vapor phase and particulate phase, along with relatively high levels of potassium and calcium, significantly increase the potential for catalyst deactivation, plugging, and erosion. Based on the ash chemistry, a conventional high dust SCR arrangement (i.e., SCR located at the economizer outlet) would experience unacceptable catalyst deactivation rates, and, as concluded in the BART Determination Study, high dust SCR is, therefore, not a technically feasible NOx retrofit control option on units firing North Dakota lignite.

One option that has been studied to address these technical issues is to locate the SCR after the particulate and FGD control systems (if present). SCR control systems located downstream of the particulate and SO_2 controls are generally referred to as tail-gas or tail-end SCRs (TE-SCR). The idea is to remove the alkaline elements that cause unacceptable catalyst deactivation upstream of the SCR. The TE-SCR would still have to be designed to handle vapor phase sodium and fine particulates that are not collected by the ESP and wet FGD.

The TE-SCR configuration requires the flue gas to be re-heated for effective NOx control. Flue gas exiting the wet FGD at approximately 140 °F is directed to a gas-gas heat exchanger (GGHE) to raise its temperature to approximately 550 °F. After the GGHE the flue gas is directed to either an in-duct gas burner or steam heat exchanger to raise its temperature an additional 50 °F. From the duct burner or steam heat exchanger the flue gas would enter the TE-SCR reactor at approximately 600 °F. Ammonia is injected and mixed into the flue gas stream as it enters the SCR reactor, where it reacts with NOx to form nitrogen and water as shown above. Flue gas exiting the TE-SCR is returned to the other side of the GGHE to recover the waste heat before it is exhausted through the stack.

Due to the limited effectiveness of the GGHE, the outlet temperature from the TE-SCR system will be approximately 50 °F to 60 °F higher than the flue gas inlet temperature, resulting in a stack temperature of approximately 190 °F. This stack temperature is about 50 °F higher that the stack gas expected from the wet FGD system currently being installed on LOS Unit 2. The existing stack liner is guaranteed to withstand only 150 °F temperature, thus, the liner may have to be replaced or coated to withstand the higher stack gas temperatures.

TE-SCR has not been demonstrated on a lignite-fired boiler, and there are still significant technical concerns associated with the viability of existing SCR catalysts on a lignite-fired unit. For example, it is not known whether the comparatively high level of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream ESP and wet FGD. Furthermore, the potential exists for sodium and potassium compounds remaining in the flue gas as fine particulates to re-vaporize as the flue gas is re-heated in the aforementioned duct burners. The fine particulates remaining in the flue gas would also have tendency to get into the catalyst pores, forming water soluble salts and reducing catalyst activity, as the flue gas passes through the water dew point. SCR catalyst in a TE-SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation. In order to understand the effect of lignite-derived flue gas on the SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of TE-SCR on LOS Unit 2 with any degree of certainty, pilot testing will be needed as summarized in the PowerPoint presentation to the Department on March 11, 2009.

<u>TE-SCR Cost Estimate</u>

Notwithstanding the remaining technical issues and uncertainties, S&L prepared a cost estimate to install and operate a TE-SCR on LOS Unit 2. Given the technical uncertainties and limited amount of available cost information, the TE-SCR cost estimate should be considered a hypothetical case study based on technical judgment. This cost estimate is designed to supplement the NOx control cost effectiveness evaluation included in the BART Determination Study. To be consistent with cost estimates included in the BART Determination Study, S&L followed the cost estimating methodologies and assumptions outlined in Section 1.3.5 of the study. S&L did not reevaluate costs for the other potentially feasible NOx retrofit control technologies, but relied on costs included in the BART Determination Study. Capital costs for the other NOx retrofit control technologies were brought up to 2009 dollars using an average annual escalation rate of 4.0%.

Order of magnitude capital costs were developed for the TE-SCR control system. Capital costs include the equipment, material, labor, and all other direct costs needed to retrofit LOS Unit 2 with the control technology. An allowance was included into the capital cost estimate for the Unit 2 stack liner modifications. Fixed and variable O&M costs were also developed for the TE-SCR control system. Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables associated with operating the system, such as reagent usage (e.g., ammonia), auxiliary power requirements, secondary fuel and catalyst replacement.

<u>Accounting for Uncertainty</u>

As discussed above, significant technical issues remain unresolved regarding the effectiveness of a TE-SCR control system on LOS Unit 2. Without pilot scale testing it is not possible to know definitively how the flue gas chemistry will affect the SCR catalyst, and it is very difficult to estimate with any certainty the catalyst deactivation rate (required to estimate annual operating costs of the system). In addition to the catalyst deactivation issues, the cost effectiveness of a TE-SCR control system will be particularly sensitive to the cost of natural gas and ammonia. The TE-SCR control system will require significant quantities of both natural gas and ammonia, and the cost of these consumables will directly affect the cost effectiveness of the system. Finally, installation of the TE-SCR could trigger the necessity to install additional pollution controls to address resulting increases in sulfuric acid mist emissions (another PSD regulated pollutant). Methods used to account for these uncertainties are described below:

Catalyst Replacement Frequency

Based on our engineering judgment, an accelerated catalyst deactivation rate is anticipated with the lignite derived flue gas; therefore, we developed capital and O&M costs for the two most likely scenarios: (1) a catalyst deactivation rate that necessitates catalyst replacement every 12 months; and (2) a catalyst deactivation rate that necessitates catalyst replacement every 6 months. More frequent catalyst replacement requires more frequent shutdown of the unit. Typical catalyst replacement activities require the unit to be shutdown for a two week outage. Because planned major outages are only scheduled every three years, costs associated with the additional catalyst replacement outages were included in the annual O&M estimates.

Consumable Costs

The cost effectiveness of the TE-SCR will also be sensitive to the cost of consumables used in the system including natural gas and ammonia. As described above, effective NOx control with a TE-SCR requires re-heating the flue gas from approximately 140 °F to approximately 600 °F. Based on preliminary engineering calculations, re-heating the flue gas will consume approximately 115 mmBtu/hr natural gas. The cost of firing natural gas to re-heat the flue gas will have a significant impact on the cost effectiveness of the system.

Natural gas prices have been subject to significant volatility over the past several years. Volatility in natural gas prices are subject to short-term supply and demand shifts, coupled with the significant lead time required to bring additional natural gas supplies to market and expand pipeline capacity.[2] Natural gas prices are also sensitive to market factors such as weather swings and supply disruptions. Based on information published by the U.S. Energy Information Administration, the price of natural gas for electricity production is currently in the range of $6.60 to $8.00/mmBtu. As recently as 2007 natural gas prices for electricity production reached almost $14/mmBtu. Future swings in natural gas prices will directly affect the cost of operating the TE-SCR control system.

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[2] See, e.g., "An Analysis of Price Volatility in Natural Gas Markets," U.S. Energy Information Administration, Office of Oil and Gas, August 2007.

Similarly, the TE-SCR will consume significant quantities of ammonia. Based on preliminary engineering calculations the TE-SCR will consume approximately 873 lb/hr of ammonia. Operating costs of the TE-SCR control system are directly related to the cost of ammonia. Ammonia prices are directly related to the price of natural gas. Approximately 33 mmBtu of natural gas are needed to produce one ton of ammonia, and natural gas accounts for approximately 80% of the ammonia production cost. Anhydrous ammonia costs are currently in the range of approximately $450/ton, but have historically been as high as $700/ton.

To account for potential swings in the cost of natural gas and ammonia, and to envelope potential O&M costs associated with the TE-SCR control system, annual O&M costs were calculated using natural gas prices of $8 and $12/mmBtu and ammonia costs of $450 and $700/ton.

Acid Mist Control

Finally, it is possible that the installation of the TE-SCR will trigger New Source Review (NSR) permitting and additional pollution control requirements for sulfuric acid mist (SAM). In addition to oxidizing NOx to N_2 and water, undesirable reactions can occur in an SCR system including the oxidation of SO_2 and formation of SAM. A fraction of the remaining SO_2 in the flue gas (approximately 1%) will oxidize to SO_3 in the presence of the SCR catalyst. SO_3 can react with water in the flue gas to form SAM. Assuming a controlled SO_2 emission rate of 35 ppmvd @ 15% O_2 and 1% SO_2 to SO_3 conversion across the SCR, SAM emissions from LOS Unit 2 would increase by approximately 24.1 tpy, a quantity in excess of the PSD significant level.

PSD would require increased SAM emissions to be controlled using BACT. Although it is possible that BACT could require the installation of a wet ESP control system after the TE-SCR (which would be very expensive), it is more likely that increased SAM emissions could be addressed using an upstream sorbent injection system. Sorbent injection involves the injection of a powdered absorbent directly into the flue gas exhaust stream upstream of the particulate control device. To address the potential need for SAM control, S&L prepared one cost estimate that includes the capital and O&M costs associated with a sorbent injection system.

The following TE-SCR with advanced separated overfire system (ASOFA) scenarios were developed for direct comparison with the scenarios A-D in the BART Determination Study. Five TE-ASOFA scenarios were developed to account for uncertainty regarding: (1) catalyst deactivation rate; (2) sorbent injection control requirements; and (3) the cost of natural gas and ammonia.

Scenario E: TE-SCR with ASOFA
12-month catalyst replacement frequency
$8/mmBtu natural gas
$450/ton ammonia
No sorbent injection system to address increased acid gas emissions

Scenario F: TE-SCR with ASOFA
6-month catalyst replacement frequency

$8/mmBtu natural gas
$450/ton ammonia
No sorbent injection system to address increased acid gas emissions

Scenario G: TE-SCR with ASOFA
6-month catalyst replacement frequency
$12/mmBtu natural gas
$450/ton ammonia
No sorbent injection system to address increased acid gas emissions

Scenario H: TE-SCR with ASOFA + Sorbent Injection System
6-month catalyst replacement frequency
$12/mmBtu natural gas
$450/ton ammonia
Sorbent injection system installed to address increased acid gas emissions

Scenario I: TE-SCR with ASOFA + Sorbent Injection System
6-month catalyst replacement frequency
$12/mmBtu natural gas
$700/ton ammonia
Sorbent injection system installed to address increased acid gas emissions

Unit costs used to develop annual O&M costs associated with each scenario are summarized below:

Parameter	**Units**	**Scenario E**	**Scenario F**	**Scenario G**	**Scenario H**	**Scenario I**
Inlet NOx Rate	lb/mmBtu	0.48	0.48	0.48	0.48	0.48
NOx Control System		TE-SCR	TE-SCR	TE-SCR	TE-SCR	TE-SCR
SAM Control		na	na	na	Sorbent Injection	Sorbent Injection
Total Initial Catalyst	m^3	530	530	530	530	530
Controlled NOx Rate	lb/mmBtu	0.07	0.07	0.07	0.07	0.07
Catalyst Replacement	frequency	12 months	6 months	6 months	6 months	6 months
Capacity Factor	%	96.2	92.3	92.3	92.3	92.3
Catalyst Cost	$\$/m^3$	7,500	7,500	7,500	7,500	7,500
Power Cost	$/MWh	50	50	50	50	50
Natural Gas Cost	$/mmBtu	8.0	8.0	12.0	12.0	12.0
Ammonia Cost	$/ton	450	450	450	450	700

Updated Cost Evaluation

Provided below are several tables updating the NOx retrofit cost effectiveness evaluation originally included in the Section 2.5.1 of the BART Determination Study. These tables include costs associated with potential NOx control technologies for LOS Unit 2. The control cost estimates included in the 2006 study have been updated to reflect 2009 dollars (costs were originally given as 2005 dollars). The tables also include estimates associated with the installation of TE-SCR and ASOFA on Unit 2. The table numbers included below are intended to match the table numbers used in the BART Determination Study.

Further, the TE-SCR/ASOFA cost effectiveness calculation is consistent with the methods and assumptions used in the BART Determination Study. Consistent with the approach used in the 2006 study, future potential-to-emit (PTE) annual emissions with the TE-SCR/ASOFA system were reduced to account for an annual outage requirement of 2 weeks for Scenario E (catalyst replacement every 12 months) and 4 weeks for Scenarios F thru I (catalyst replacement every 6 months). Levelized total annual costs for Scenarios F thru I vary depending the cost of natural gas and ammonia and the installation/operation of a sorbent injection control system. The following equation was used to calculate the cost effectiveness:

$$\text{Cost Effectiveness (\$/ton)} = \frac{\text{Levelized Total Annual Cost}}{\text{(Historic Pre-Control Annual Baseline Emissions – Future PTE Annual Emissions)}}$$

The following tables and figures were updated from the BART Determination Study to include the TE-SCR Scenarios:

Table / Figure No.	**Description**
Table 2.5-1	Unit Capital Cost Factors of Feasible NOx Control Options for LOS Unit 2
Table 2.5-2	Installed and Annualized Capital Costs Estimated for NOx Control Alternatives – LOS Unit 2
Table 2.5-3	Estimated O&M Costs for NOx Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 2
Table 2.5-5	Estimate Annual Emissions and LTAC for NOx Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2
Figure 2.5-1	NOx Control Effectiveness – LOS Unit 2 (Historic Pre-Control Annual Emission Baseline)
Table 2.5-7	Estimated Incremental Annual Emissions and LTAC for NOx Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2
Figure 2.5-3	NOx Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)

TABLE 2.5-1 – Unit Capital Cost Factors of Feasible NO_X Control Options for LOS Unit 2

Alt. No. (1)	NO_X Control Technique	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3) ($/kW) LOS Unit 2
I	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $700/ton Sorbent Injection Control System	> 300	387
H	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton Sorbent Injection Control System	> 300	387
G	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	> 300	376
F	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	> 300	376
E	Tail-End SCR + ASOFA (1 yr catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	> 300	376
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	20 + ?(4)	53(4),(5),(6)
C	SNCR (using urea) w/ ASOFA	20-35(7)	44(5),(6)
B	Coal Reburn (conventional, pulverized) w/ ASOFA	30-60(7)	178(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	26(6)

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ due to positive or negative synergistic effects. Range based on published values or vendor proposals.

(3) – Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on existing nameplate rating. Single point cost figures in 2009 dollars.

(4) – No published RRI unit capital cost factor was found in available technical literature. The installed capital costs for RRI are expected to be similar to SNCR. If both RRI and SNCR are installed together, capital cost of the RRI+SNCR portion was assumed to be 1.5x the capital cost of SNCR alone, due to commonality between the two systems sharing certain equipment and systems.

(5) – Estimated capital cost for SNCR point estimate derived from December 2004 budgetary proposal by Fuel Tech. See Appendix A for details.

(6) – The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(7) – NESCAUM 2005 Technical Paper, posted at their website for basic SOFA. See Appendix A for details.

(8) – The single point unit capital cost factor shown for a coal reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report, posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in coal reburn options is 57.5 $/kW. See Appendix A for details.

TABLE 2.5-2 – Installed and Annualized Capital Costs Estimated for NO_X Control Alternatives - LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Installed Capital Cost(2) ($1,000)	Annualized Capital Cost(3) ($1,000)
I	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $700/ton Sorbent Injection Control System	170,800	14,890
H	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton Sorbent Injection Control System	170,800	14,890
G	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	165,800	14,450
F	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	165,800	14,450
E	Tail-End SCR + ASOFA (1 yr catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	165,800	14,450
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	23,600	2,060
C	SNCR (using urea) w/ ASOFA	19,600	1,710
B	Coal Reburn (conventional, pulverized) w/ ASOFA	78,800(4)	6,870(4)
A	Advanced Separated Overfire Air (ASOFA)	11,800	1,030
	Baseline	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – Installed capital cost is estimated for determination of total capital cost for a control technology, assuming maximum unit output capacity is based on existing nameplate rating of 440,000 kW. Installed capital cost figures in 2009 dollars.

(3) – Annualized capital cost = Installed capital cost x 0.08718 Capital Recovery Factor.

(4) – Costs for increased PM collection capacity included in coal reburn option are $29,500,000 for installed capital cost, and $2,570,000/yr annualized capital cost.

TABLE 2.5-3 – Estimated O&M Costs for NO_X Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual O&M Cost(2) ($1,000)	Levelized Annual O&M Cost(3) ($1,000)
I	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $700/ton Sorbent Injection Control System	40,470	48,280
H	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton Sorbent Injection Control System	39,590	47,230
G	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	39,210	46,780
F	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	35,490	42,340
E	Tail-End SCR + ASOFA (1 yr catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	24,630	29,380
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	12,860	15,340
C	SNCR (using urea) w/ ASOFA	7,680	9,160
B	Coal Reburn (conventional, pulverized) w/ ASOFA	6,700(4)	7,990(4)
A	Advanced Separated Overfire Air (ASOFA)	177	211
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Annual O&M cost figures in 2009 dollars.
(3) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $2,030,000 for annual O&M cost, and $2,420,000/yr levelized annual O&M cost.

TABLE 2.5-5 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
I	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $700/ton Sorbent Injection Control System	1,452	10,571	63,170	5,976
H	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton Sorbent Injection Control System	1,452	10,571	62,12	5,876
G	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	1,452	10,571	61,230	5,792
F	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	1,452	10,571	56,790	5,372
E	Tail-End SCR + ASOFA (1 yr catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	1,512	10,511	43,830	4,170
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	5,895	6,128	17,400	2,839
C	SNCR (using urea) w/ ASOFA	6,762	5,261	10,870	2,066
B	Coal Reburn (conventional, pulverized) w/ ASOFA	7,115	4,908	14,860[5]	3,027[5]
A	Advanced Separated Overfire Air (ASOFA)	10,796	1,227	1,241	1,011
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	12,023	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

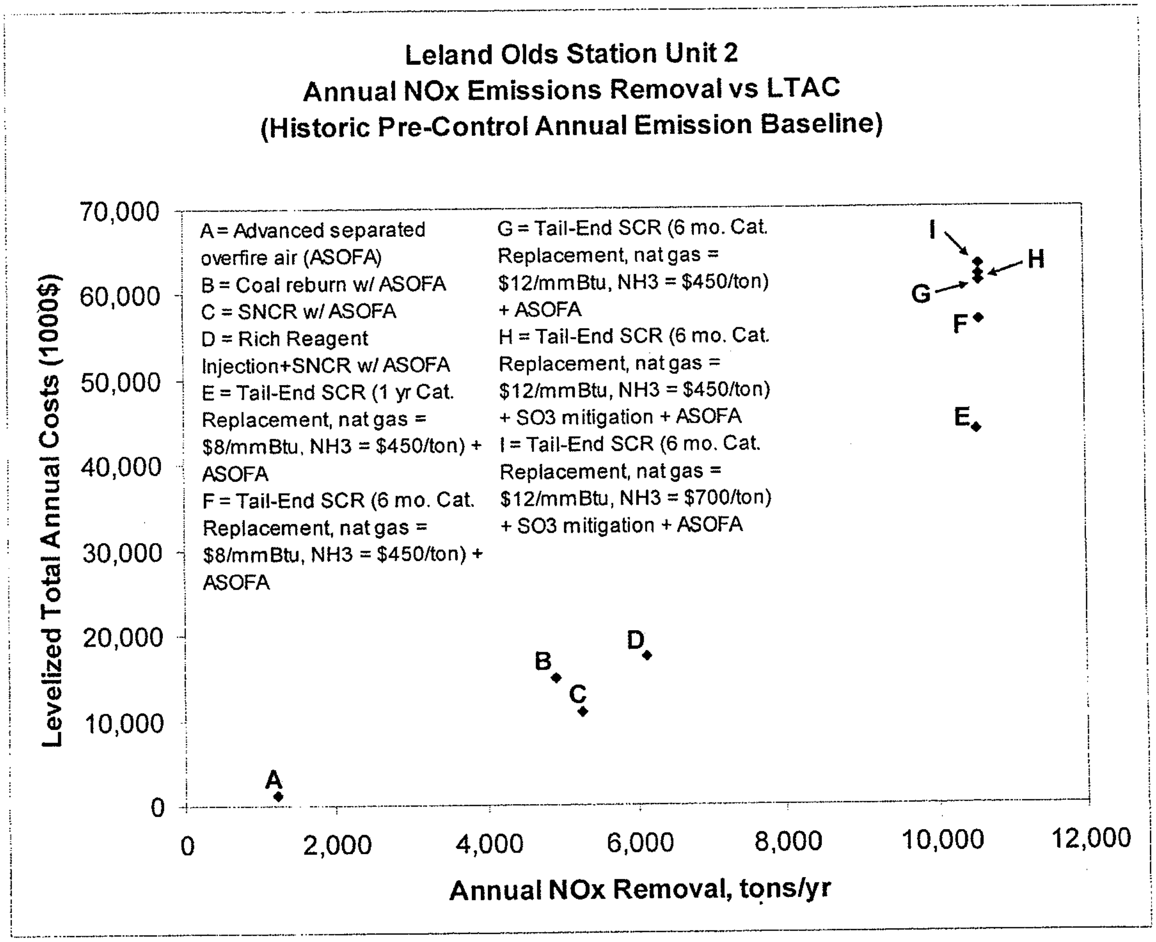
(2) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.

(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.

(4) – Annualized cost figures in 2009 dollars.

(5) – LTAC for increased PM collection capacity included in coal reburn option are $2,570,000 for annualized capital cost plus $2,420,000 for annualized O&M cost, for a total of $4,990,000/yr. This results in an average control cost of $1,016 per ton of NO_X removed.

Figure 2.5-1 – NO_X Control Cost Effectiveness – LOS Unit 2 (Historic Pre-Control Annual Emission Baseline)(1)



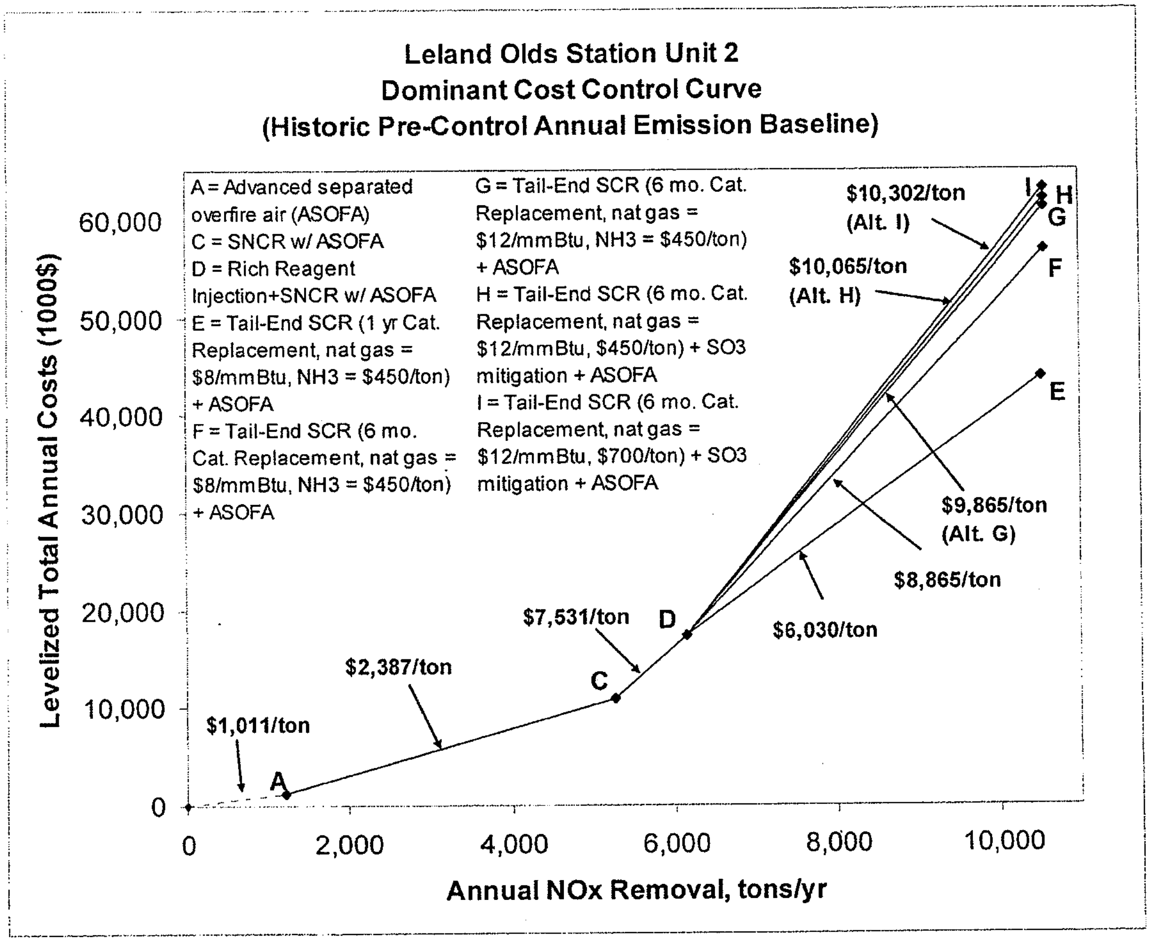
(1) - All cost figures in 2009 dollars. Numbers are listed and qualifiers are noted in Table 2.5-5.

TABLE 2.5-7 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
I(7)	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $700/ton Sorbent Injection Control System	63,170	10,571	45,770	4,443	10,302
H(7)	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton Sorbent Injection Control System	62,120	10,571	44,720	4,443	10,065
G(7)	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $12/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	61,230	10,571	43,830	4,443	9,865
F(7)	Tail-End SCR + ASOFA (6 mo catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	56,790	10,571	39,390	4,443	8,865
E(7)	Tail-End SCR + ASOFA (1 yr catalyst replacement) gas = $8/mmBtu / NH_3 = $450/ton No Sorbent Injection Control	43,830	10,511	26,430	4,383	6,030
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	17,400	6,128	6,530	867	7,531
C	SNCR (using urea) w/ ASOFA	10,870	5,261	9,629	4,034	2,387
A	Advanced SOFA (ASOFA)	1,241	1,227	1,241	1,227	1,011
	Baseline, based on annual operation at historic 24-month average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors. Costs for increased PM collection efficiency are included in coal reburn option.
(3) – Annualized cost figures in 2009 dollars.
(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).
(7) – Incremental costs for Alternatives E, F, G, H, and I are both relative to Alternative D.

Figure 2.5-3 – NO_X Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2009 dollars. Numbers are listed and qualifiers are noted in Table 2.5-7.

Conclusions

Significant technical issues remain unresolved regarding the installation of a TE-SCR on a unit firing North Dakota lignite. The flue gas characteristics from firing North Dakota lignite could rapidly accelerate catalyst deactivation due to potentially elevated sodium levels that are not captured in the ESP and wet FGD. Without pilot scale testing it is not possible to know how the flue gas chemistry will affect the SCR catalyst, and it is very difficult to estimate with any certainty the catalyst deactivation rate (required to design the SCR reactor and estimate annual operating costs of the system).

Despite the significant uncertainties surrounding the potential for accelerated catalyst deactivation on Unit 2 TE-SCR, a cost evaluation was performed for a TE-SCR on LOS Unit 2 (a North Dakota lignite fired cyclone furnace). Given the technical uncertainties and limited amount of available cost information, the TE-SCR cost estimate prepared for this evaluation should be considered hypothetical case studies based on technical judgment, and may not be representative of the actual costs associated with the control system. To account for uncertainties in the catalyst deactivation rate, natural gas and ammonia costs, and the need to provide additional acid mist control, S&L prepared costs for several operating scenarios.

The total levelized annual cost for the TE-SCR/ASOFA control systems is estimated to range from approximately $43.8 million per year (based on a 12-month catalyst replacement frequency and lower natural gas and ammonia costs) to approximately $61.2 million per year (based on a 6-month catalyst replacement frequency and assuming higher natural gas and ammonia costs). Levelized annual costs for the control system increases to approximately $63.2 million per year assuming sorbent injection control is needed to address increases in acid gas emissions. Assuming an average controlled NOx emission rate of 0.07 lb/mmBtu, the average annual cost effectiveness of the TE-SCR/ASOFA control system, based on the historic pre-control annual emission baseline, is estimated to range from approximately $4,200 to $6,000/ton, depending on the catalyst replacement frequency and cost of consumables.

The incremental cost effectiveness of the TE-SCR/ASOFA technology over the next lower-cost retrofit control option (RRI/SNCR/ASOFA) ranges from approximately $6,000/ton (assuming a 12-month catalyst replacement frequency and lower consumable costs) to more than $10,000/ton (assuming a 6-month catalyst replacement frequency, higher consumable costs, and the need to address increased SAM emissions).

Again, this economic analysis was based on a hypothetical engineering analysis of what we know today. A more accurate estimate cannot be developed without first performing significant pilot testing as suggested in our March 11, 2009 presentation to the Department. The actual cost effectiveness of the control system could therefore be higher or lower than those identified from this effort.

Should you need additional information, please do not hesitate to contact me.

Sincerely,

Wm. DePriest

William DePriest
Senior Vice President
Environmental Services

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

Coal Creek Station Units 1 and 2

Best Available Retrofit Technology Analysis

Revised December 12, 2007

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Executive Summary

This report describes the background and methods for the selection of the Best Available Retrofit Technology (BART) as proposed by Great River Energy (GRE) for the Coal Creek Station (CCS) located in Underwood, ND. CCS is a two unit, 1100 megawatt mine-mouth plant. Commercial operation commenced on CCS Unit 1 in 1979 and Unit 2 in 1980. The CCS steam generators are Combustion Engineering Controlled Circulation tangentially fired lignite boilers. Preliminary visibility modeling conducted by the North Dakota Department of Health (NDDH) found that the Coal Creek units cause or contribute to visibility impairment in a federally protected Class 1 area, therefore making the facility subject to BART.

Guidelines included in 40 CFR §51 Appendix Y were used to determine BART for the Coal Creek units. The existing pollution control equipment for each unit includes: ESP for particulate matter, low NOx burners (LNB) with a level of separated overfire air (SOFA) for NOx, and partially bypassed wet scrubbing for SO_2. The CALMET/CALPUFF/CALBART dispersion modeling sequence was used to assess the post-BART visibility impacts associated with the proposed BART emission limits. Based on the results of visibility modeling, economic impacts analysis and consideration for other non-air quality energy and environmental factors, GRE proposes the following as BART:

- Particulate matter (PM) emissions will continue to be controlled by the existing ESP for each unit. Additional PM controls, including condensable PM (CPM) controls, would provide little visibility improvement and require significant capital expenditures. Existing and proposed SO_2 controls may provide additional CPM reductions, primarily in the form of sulfuric acid mist (SAM). Therefore, the current PM performance standard of 0.1 lb/MMBtu will be maintained.

- NOx emissions will be reduced to the presumptive BART level of 0.17 lb/MMBtu on a 30-day rolling average. This will be achieved through the installation of an additional level of SOFA.

- SO_2 emissions will be reduced to the presumptive BART level of 0.15 lb/MMBtu on a station wide 30-day rolling average. This will be achieved through the use of coal drying, and the installation of trays or new liquid distribution rings (LDRs) and high flow mist eliminators (MEs)

The proposed BART emission rates will result in an overall visibility improvement of over 50% for Coal Creek Station.

It is GRE's goal to install controls that will meet or perform below the presumptive BART levels for both NOx and SO_2. In an effort to utilize the best available technology at the time of purchase, GRE will continue to evaluate which technology will provide the requisite removal efficiencies to meet presumptive BART emission limits and provide GRE with greatest operational flexibility. GRE was awarded a collaborative agreement for a Lignite Fuel Enhancement project under the Clean Coal Power Initiative DOE Solicitation DE-PS26-02NT41428. Phase I of the DOE project included a 75 ton/hour lignite drying system with a segregator for beneficiation of the fuel was designed and constructed in 2005. The drying system has been performance tested, and an evaluation of the benefits of the drying system was completed. A public version of this evaluation is included in Appendix J. Coal drying results in two major benefits to the station; first is a decrease in lignite moisture content resulting in higher boiler efficiency and a lower flue gas volume, subsequently resulting in increased scrubbing efficiency; and second is a decrease in fuel combustion quantities resulting in lower emissions.

1.0 Introduction

On July 15, 2005, the U.S. Environmental Protection Agency (EPA) published the final rules for regional haze and best available retrofit technology (BART). The BART rules[1], originally promulgated in September 1999, were in effect as of September 6, 2005.

The rules require that each state subject to BART, develop a Regional-Haze State Implementation Plan (RH SIP) to improve visibility impairment in federally-protected national parks and wilderness areas (Class I areas). The SIP must require BART on all BART-eligible sources and mandate a plan to achieve natural background visibility by 2064. Figure 1-1 illustrates the 6 BART eligible units and 4 Class 1 areas in North Dakota. Each state must submit an RH SIP by December 17, 2007 that includes milestones for establishing reasonable progress towards the visibility improvement goals, and plans for the first five-year period. Upon submission of the SIP, states must make the requirements for BART sources enforceable through rules, administrative orders or Title V permit amendments.

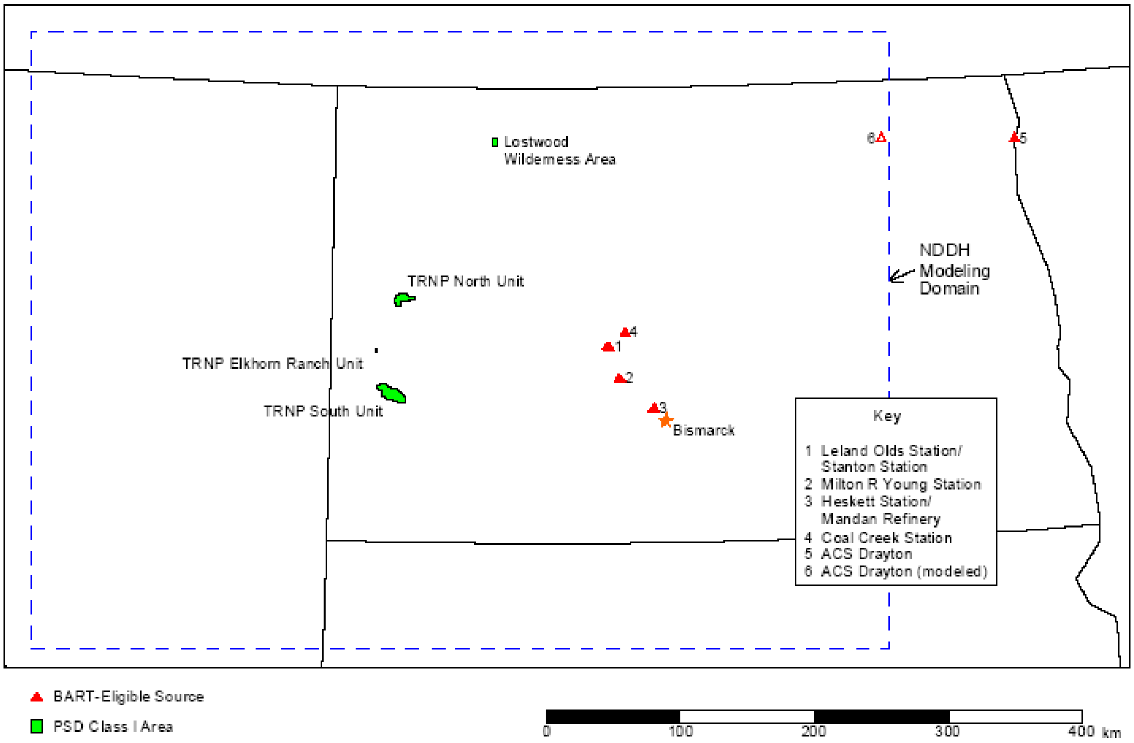

Figure 1-1 North Dakota's BART Geography: The North Dakota SIP will address the 4 PSD Class I Areas and 6 BART Eligible Units illustrated above. (Source *Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota, Final version)*

Expressly, reasonable progress means that the 20 best-visibility days must get no worse, and the 20 worst-visibility days must become as good as the 20 worst days under natural

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[1] 40 CFR §51 and Clean Air Act §169A and 169B

conditions. Assuming a uniform rate of progress the default glide path, illustrated in Figure 1-2, would require 1 to 2 percent improvement per year in visibility on the 20 worst days. The state must submit progress reports every five years to establish their advancement toward the Class 1 area natural visibility backgrounds. If a state feels it may be unable to adopt the default glide path, a slower rate of improvement may be proposed on the basis of cost or time required for compliance and non-air quality impacts.

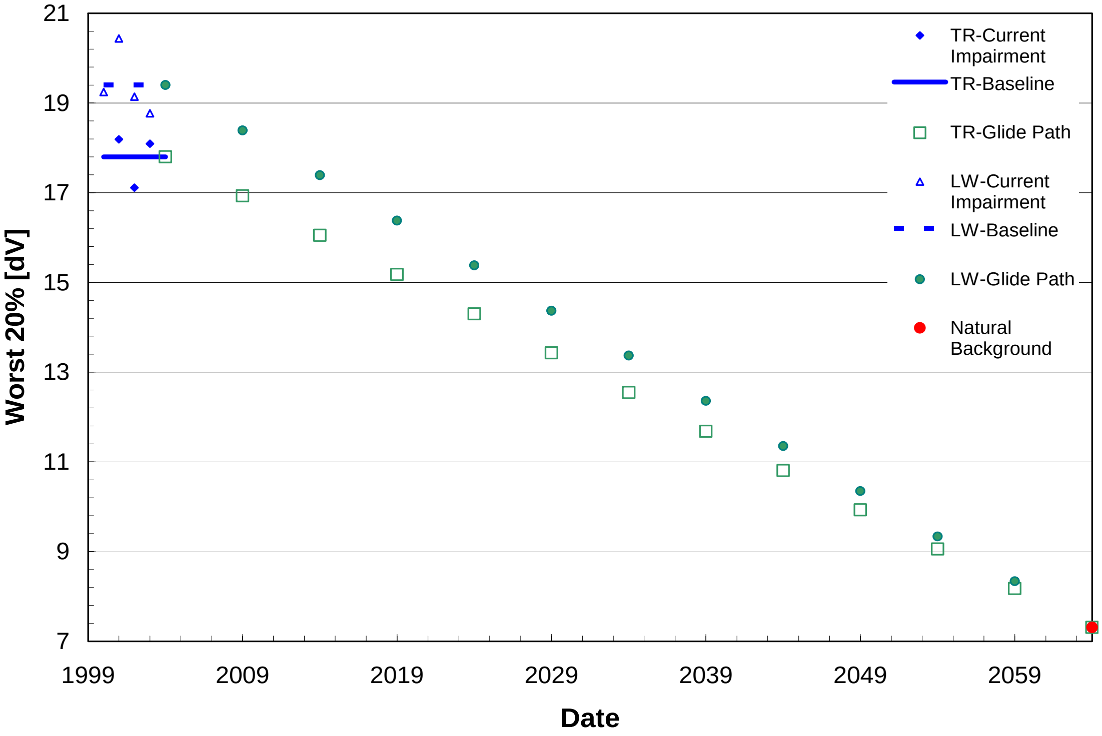

Figure 1-2 Theodore Roosevelt NP and Lostwood WA, ND. Current impairment includes both natural and anthropogenic contributions. (Data from VIEWS database trend analyzer, http://vista.cira.colostate.edu/views/web/AnnualSummaryDev/Trends.aspx DOA 06 Dec 2005)

1.1 BART Eligibility

Under the BART rules, large sources that have previously installed pollution-control equipment required under another standard (e.g., MACT, NSPS and BACT) will be required to conduct visibility analyses. Installation of additional controls may be required to further reduce emissions of visibility impairing pollutants such as PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and possibly VOCs and ammonia. Sources built before the implementation of the Clean Air Act (CAA) which had previously been grandfathered may also have to conduct such analyses and possibly install controls, even though they have been exempt to date from any other CAA requirements.

BART eligibility is established on the basis of 3 criteria. Sources that are BART-eligible must meet all three conditions described below:

1. Contain emission units in one or more of the 26 listed source categories under the PSD rules (e.g., fossil-fuel-fired steam electric plants larger than 250 MMBtu/hr,

fossil-fuel boilers larger than 250 MMBtu/hr, petroleum refineries, coal cleaning plants, sulfur recovery plants)

2. Were in existence on August 7, 1977, but were not in operation before August 7, 1962
3. Have total potential emissions from the emission units meeting the two criteria above greater than 250 tons per year for at least one visibility-impairing pollutant

If emissions from a BART-eligible source cause or contribute to visibility impairment at any Class I area, then that source is subject to BART. Visibility modeling conducted with CALPUFF or another EPA-approved visibility model is necessary to make a definitive visibility impairment determination. Sources that do not cause or contribute to visibility impairment are exempt from BART requirements, even if they are BART-eligible.

1.2 BART Determinations

Each BART-eligible source that is not exempt must determine BART on a case-by-case basis. Even if a source was previously part of a group BART determination, individual BART determinations must be made for each source. The analysis takes into account six criteria and is analyzed using five steps. The six criteria that comprise the engineering analysis include: the availability of the control technology, existing controls at a facility, the cost of compliance, the remaining useful life of a source, the energy and non-air quality environmental impacts of the technology and finally, the visibility impacts.[2] The five steps of a BART analysis are:

Step 1 - Identify all Control Technologies
The first step in the analysis is to identify all available retrofit control technologies for each applicable emission unit.

Step 2 - Eliminate Technically Infeasible Options
In the second step, the technical feasibility of each control option identified in step one is evaluated with respect to source-specific factors. Technologies which are determined to be technically infeasible are eliminated from further consideration.

Step 3 - Evaluate Control Effectiveness
In step three, rank the remaining controls based on the control efficiency at the expected emission rate as compared to the emission rate before addition of controls for the pollutant of concern.

Step 4 - Evaluate Impacts and Document Results
The fourth step utilizes an engineering analysis to document the impacts of each remaining control technology option. The economic analysis included in this step includes a dollar per ton of pollutant removed cost for each

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[2] 40 CFR 51 Appendix Y

technology in addition to an incremental cost analysis to illustrate the economic effectiveness of one technology in relation to the others evaluated. Step four also includes an assessment of energy impacts and other non-air quality environmental impacts.

Economic impacts were analyzed using the procedures found in the EPA Air Pollution Control Cost Manual-Sixth Edition (EPA 452/B-02-001). Vendor cost estimates for this project were used when applicable. Equipment cost estimates from the EPA Control Cost Manual or EPA's Air Compliance Advisor (ACA) Air Pollution Control Technology Evaluation Model version 7.5 were used if no vendor data were available. The source of the control equipment cost data are noted in each of the control cost analysis worksheets as found in Appendix A.

Step 5 - *Evaluate Visibility Impacts*

The fifth step requires a modeling analysis conducted with EPA-approved models such as CALPUFF. The modeling protocol[3], including receptor grid, meteorological data, and other factors used for this part of the analysis were provided by the North Dakota Department of Health. The model outputs, including 98th and 90th percentile visibility impairment days are used to establish the degree of improvement that can be reasonably attributed to each technology.

The proposed BART was selected based on the results of information obtained in Steps 4 and 5.

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[3] *Protocol for BART-Related Visibility Modeling Analyses in North Dakota*, Final Version, November, 2005.

2.0 Coal Creek Station BART Determination

As defined by federal guidance and ND 33-25-25-01, a source "causes or contributes to visibility impairment" if the 98th percentile of any year's modeling results meets or exceeds the threshold of five-tenths of a deciview (dV) at a Class I area receptor. The pre-BART modeled emission rates for eligible sources represent the highest 24-hour average emissions from the years 2000 through 2002. Pre-BART evaluations conducted by the North Dakota Department of Health using the CALPUFF[3] visibility model identified 6 BART eligible sources, including Coal Creek Station, that cause or contribute to visibility impairment in North Dakota.

Using a streamline method for BART determination, BART eligible sources at Coal Creek Station can be divided into groups based on function, utilization and actual emissions.

2.1 BART Eligible Units

Great River Energy's (GRE) Coal Creek Station, located in Underwood, ND, contains two main units. Both are tangentially fired lignite boilers with ratings of 6015 and 6022 MMBtu/hr respectively for a combined facility output of 1,100 megawatts. The two units have identical permit emission limits, and for the purpose of this analysis, identical characteristics. The BART analysis for each pollutant has been performed on the basis of a single unit with a rating of 6019 MMBtu/hr, meaning that the total impact with respect to economics or other environmental concerns should be doubled to encompass the entire facility. PM is currently controlled with an electrostatic precipitator (ESP). Low NOx burners (LNB) are used in combination with a level of separated over-fire air (SOFA) for NOx control. Each unit currently controls SO_2 emissions with a wet scrubber, with approximately 25% of the flow bypassing the scrubber. Continued operation of the station is predicted for the long term foreseeable future, therefore the remaining useful life of the source as defined by EPA guidance [4] was not used as an element of impact assessment.

At least three sets of emission parameters must be considered to successfully determine BART. The current Title V permitted emission limits represent the maximum allowable emission rates. The baseline actual emissions represent historical emissions inventories and are used in comparison with design basis emission rates for potential retrofit technologies. This emission rate is the long term (30-day or annual average) average expectation, and is used in the economic analysis. Finally, the pre-BART screening emission rate, which represents the maximum 24-hour average emission rate as mentioned above, is used as a baseline for visibility impacts analysis. Table 2-1 describes these three data parameters for Coal Creek Station.

Table 2-1 Single Unit Emission Bases

Pollutant	Permit Limit	Baseline Actual	BART Screen
PM	0.10 lb/MMBtu 528 lb/hr	0.03 lb/MMBtu 181 lb/hr	0.04 lb/MMBtu 250 lb/hr
NOx	0.4 lb/MMBtu 5,104 lb/hr	0.22 lb/MMBtu 1,294 lb/hr	0.29 lb/MMBtu 1,772 lb/hr
SO_2	1.2 lb/MMBtu 6,336 lb/hr	0.56 lb/MMBtu 3,356 lb/hr	0.95 lb/MMBtu 5,734 lb/hr

The BART analysis, as described in Section 1.2 of this document, will be presented on a pollutant by pollutant basis for the above units with the exception of the assessment of visibility impacts for SO_2 and NOx (Step 5). The visibility analysis for SO_2 and NOx was performed using a multi pollutant approach, and can be found in Section 7.0 of this document.

2.2 Other BART Eligible Units

The remaining BART eligible emission units at Coal Creek are exempt from BART analysis because they do not cause or contribute to visibility impairment, and are included under one of the two following categories.

i. *Low Utilization Units*

Based on the hours of operation, some emission units can be classified as low emitters. Table 2-2 lists the emergency and auxiliary units at Coal Creek and their four year average actual emissions. The limited expected operations of these units makes additional controls economically infeasible, and no further BART analysis is required.

Table 2-2 Coal Creek Station Low Utilization Units

Emission Unit Identification and Description	Fuel	Maximum Heat Input	2001-2004 Average, Actual				
			Hours of Operation	NOx (tpy)	SO_2 (tpy)	PM (tpy)	PM_{10} (tpy)
EUI 3 Auxiliary Boiler No. 91	Fuel oils	172 lb/MMBtu	25	0.06	0.02	4.23E-03	2.96E-03
EUI 4 Auxiliary Boiler No. 92	Fuel oils	173 lb/MMBtu	6	0.10	0.33	1.62E-01	3.23E-02
EUI 5 Emergency Generator	Nos. 1 and 2 fuel oils	3,500 hp	95	2.89	0.27	6.91E-02	4.78E-02
EUI 6 Fire Pump Engine	Nos. 1 and 2 fuel oils	200 hp	14	0.11	0.01	6.06E-03	5.98E-03

ii. Material Handling and Fugitive Sources

All material handling units (EUI 7 through EUI 26), including coal and lime handling operations and fly ash silos, are controlled through the use of fabric filter baghouses. Baghouses are currently recognized as the best available control technology (BACT) for PM emitting sources. No further BART analysis is required for emission units employing BACT or equivalent controls.

In step three of the BART guidance, the Federal Register[4] states, "Fugitive emissions, to the extent quantifiable, must be counted." The emissions from the sources listed in Table 2-3 consist of PM only, and because sulfates and nitrates are the primary contributors to visibility impairment, PM sources will not significantly contribute to visibility impairment in Class I areas. For this reason, these sources will not be considered further.

Table 2-3 Coal Creek Station Fugitive Sources

Fugitive Source Name
FS 1 Cooling towers No. 91, No. 92, and No. 93
FS 2 Boombelt conveyor (stackout)
FS 3 Conveyor 909 (stackout)
FS 4 Scrubber building flyash silo (stackout)
FS 5 Coal pile maintenance

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[4] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Rules and Regulations.

3.0 Particulate Matter (PM) BART Analysis

Historical emissions inventories show that under normal operation, Coal Creek Station units emit PM at less than one third of their permitted limit. The existing ESP provides a great deal of filterable particulate control, and pre-BART modeling showed that the PM contribution to visibility impairment for Units 1 and 2 was almost negligible in comparison to the impairment attributed to sulfates and nitrates. EPA has interpreted 'total particulate' to include condensable particulate matter (CPM) and NDDH has requested that CPM be addressed as part of the BART analysis. As such, Section 6 below provides an estimation of CPM and concludes that CPM emissions from Units 1 and 2 do not significantly impact visibility impairment and will be reduced by the proposed SO_2 BART control. As illustrated in Section 7.0, post-BART modeling of Unit 1 alone shows a 1.6 Δ-dV improvement in visibility impairment while particulate controls can provide an improvement of only 0.06 Δ-dV as described in Section 3.5.

3.1 Identify PM Control Options

Table 3-1 lists the available retrofit PM options for Coal Creek Units 1 and 2.

Table 3-1 Available PM Control Technologies

PM Control Options
ESP – Current Control
WESP
Mechanical Collector (Multiclone)
Fabric Filter/Baghouse

3.2 Eliminate Infeasible PM Control Options

3.2.1 Electrostatic Precipitator (ESP)

An electrostatic precipitator applies electric forces to separate suspended particles from the flue gas stream. In an ESP, an intense electrostatic field is maintained between high-voltage discharge electrodes, typically wires or rigid frames, and grounded collecting electrodes, typically plates. A corona discharge from the discharge electrodes ionizes the gas passing through the precipitator, and gas ions subsequently ionize the particles. The electric field drives the negatively charged particles to the collecting electrodes. Periodically, the collecting electrodes are rapped mechanically to dislodge collected particulate matter, which falls into hoppers for removal. Collector dust is removed from the precipitator for disposal or recycling.

ESP control efficiency under normal loading conditions is typically in the range of 98% to 99%+. Reduced efficiencies will occur when the inlet particle concentration is low. Outlet particle concentrations can be reduced to as much as 0.005 gr/dscf. The actual outlet concentration will depend on the size range and nature of the particles. An ESP is currently used to control particulate emissions from the Coal

Creek units, making ESP replacement or modification a technically feasible control option.

3.2.2 Wet Electrostatic Precipitator (WESP)

A wet electrostatic precipitator operates in the same manner as a dry ESP; it applies electric forces to separate suspended particles from the flue gas stream. In a WESP, an intense electrostatic field is maintained between high-voltage discharge electrodes, typically wires or rigid frames, and grounded collecting electrodes, typically plates. A corona discharge from the discharge electrodes ionizes the gas passing through the precipitator, and gas ions subsequently ionize the particles. The electric field drives the negatively charged particles to the collecting electrodes. Particle removal in a WESP is accomplished with water sprays instead of mechanical cleaning methods. As a result of using water sprays, WESP's generate wastewater which must be treated to remove suspended particles and dissolved solids.

Since WESP's use electrical forces for particle collection, the electrical properties of the particles can adversely impact WESP operation. Particles with high resistivity may not readily accept an electric charge and will be difficult to collect. Particles with high conductivity or magnetic properties will strongly adhere to the collection plates and be difficult to remove; WESP water sprays may reduce this problem. However, WESP water spray systems will require more maintenance than dry ESP's in order to keep the waster spray system working properly.

WESP control efficiency under normal loading conditions is typically in the range of 98% to 99%+. Reduced efficiencies will occur when the inlet particle concentration is low. Outlet particle concentrations can be reduced to as much as 0.005 gr/dscf. The actual outlet concentration will depend on the size range and nature of the particles. WESP technology has been demonstrated on similar coal-fired boilers, making it a technically feasible option for the Coal Creek units.

3.2.3 Mechanical Collector

Cyclone separators are designed to remove particles by inducing a vortex as the gas stream enters the chamber, causing the exhaust gas stream to flow in a spiral pattern. Centrifugal forces cause the larger particles to concentrate on the outside of the vortex and consequently slide down the outer wall and fall to the bottom of the cyclone, where they are removed. The cleaned gas flows out of the top the cyclone. There are two principal types of cyclones: tangential entry and axial entry. In tangential entry cyclones, the exhaust gas enters an opening located on the tangent at the top of the unit. In axial flow cyclones, the exhaust gases enter at the middle of one end of a cylinder and flows through vanes that cause the gas to spin. A peripheral stream removes collected particles while the cleaned gas exits at the center of the opposite end of the cylinder.

Overall cyclone control efficiencies range from 50% to 99% with higher efficiencies being achieved with large particles and low efficiencies for smaller particles (< PM_{10}). Mechanical separators are often used upstream of other PM control devices to reduce the loading on the primary control device. This improves overall control efficiency and may reduce the overall cost of the control system when the waste gas is heavily laden with particulate matter.

According to a report prepared by EPRI[5] on the current controls used for coal-fired only power plants, this technology has only been permitted for use on one similar unit which is not yet operational. Due to the fact that a multiclone has not been successfully demonstrated on a comparable unit, it is infeasible for a retrofit at Coal Creek and will not be considered further in this analysis.

3.2.4 Fabric Filter/Baghouse

A fabric filter or baghouse consists of a number of fabric bags placed in parallel inside of an enclosure. Particulate matter is collected on the surface of the bags as the gas stream passes through them. The dust cake which forms on the filter from the collected particulate can contribute significantly to increasing the collection efficiency.

Two major fabric filter types are the reverse-air fabric filter and the pulse-jet fabric filter. In a reverse-air fabric filter, the flue gas flows upward through the insides of vertical bags which open downward. The particulate matter thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the fabric filter is taken off-line, and the gas flow in this compartment is reversed. This causes the bags to collapse, and collected dust to fall from the bags into hoppers. Shaking or other methods are sometimes employed to dislodge the dust from the bags. The cleaning cycle in a reverse-air fabric filter typically lasts about three minutes per compartment. Because reverse-air cleaning is gentle, reverse-air fabric filters typically require a low air-to-cloth ratio of 2 ft/min. In a pulse-jet fabric filter, dirty air flows from the outside of the bags inward, and the bags are mounted on cages to keep them from collapsing. Dust that collects on the outsides of the bags is removed by a reverse pulse of high-pressure air. This cleaning does not require isolation of the bags from the flue gas flow, and thus may be done on-line.

The main operating limitation of a baghouse is that its operating temperature is limited by the bag material. Most filter materials are limited to 200ºF – 300º F. Some materials like glass fiber or nomex may be operated at 400ºF, but are more expensive.

Baghouse control efficiency under normal loading conditions is typically in the range of 98% to 99%+. Reduced efficiencies will occur when the inlet particle concentration is low. Outlet particle concentrations can be as low as 0.005 gr/dscf; however, outlet concentrations achieved will depend on the size range and nature of the particles being filtered. Baghouses are commonly used to control particulate

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[5] *Status and Performance of Best Available Control Technologies*, EPRI, Palo Alto, CA: 2005. 1008114 (Appendix H)

emissions from coal-fired boilers, making it a viable control option for Coal Creek's BART.

3.3 Evaluate the Effectiveness of Feasible PM Options

Based on the current degree of control being achieved on Units 1 and 2, ESP, WESP and baghouse technologies can only reasonably provide a 50% reduction in actual emissions each from existing emissions. Table 3-2 describes the expected emissions from each of the three remaining control options.

Table 3-2 Control Effectiveness of Technically Feasible PM Control Options

Control Technology	Expected Control Efficiency[6]	Controlled Emissions lb/MMBtu
Dry ESP	50%	0.015
Polishing WESP	50%	0.015
Baghouse	50%	0.015

3.4 Evaluate the Impacts of Feasible PM Options

As illustrated above in Table 3-2, the three technically feasible options provide identical degrees of control. To differentiate the options, the economic and environmental impacts of each are presented below.

3.4.1 Economic Impacts

Each technology is expected to provide controlled emissions of roughly 388 tons per year, a 50% improvement from the pre-BART historical baseline. Table 3-3 details the expected costs associated with each technology based on the EPA cost model and site specific information. Due to space considerations, the retrofit of PM controls at Coal Creek Station would require significant additional expenses that were not included in the control cost evaluation below.

Table 3-3 PM Control Cost Summary, per Unit Basis

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)
Polishing WESP	$7.23	$1.92	$4,969
Baghouse	$37.37	$7.67	$19,864
Dry ESP	$38.51	$10.06	$26,056

Because the technologies provide identical levels of control, an incremental analysis of the costs is not beneficial. All three options require significant capital investments and large increases in expected operation and maintenance costs. The

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[6] Control efficiency reflects improvement beyond the performance of the existing ESP.

pollution control costs indicate that additional particulate control would involve an excessive investment for only a 50% reduction in already low particulate emissions.

3.4.2 Energy and Environmental Impacts

There are no energy or non-air quality environmental impacts that would discourage the use of an ESP, WESP or baghouse as BART. All three options would require energy usage comparable to the existing ESP. The flyash systems needed to handle the solid waste generated by particulate controls are already in place at Coal Creek.

3.5 PM Visibility Impacts

Figure 3-1 illustrates the visibility improvement of particulate controls. Reducing PM emissions from the existing permit limit of 0.1 lb/MMBtu to 0.015 lb/MMBtu results in visibility improvement of only 0.06 Δ-dV; negligible in comparison to the improvement attributed to SO_2 and NOx control as illustrated in Section 7.0.

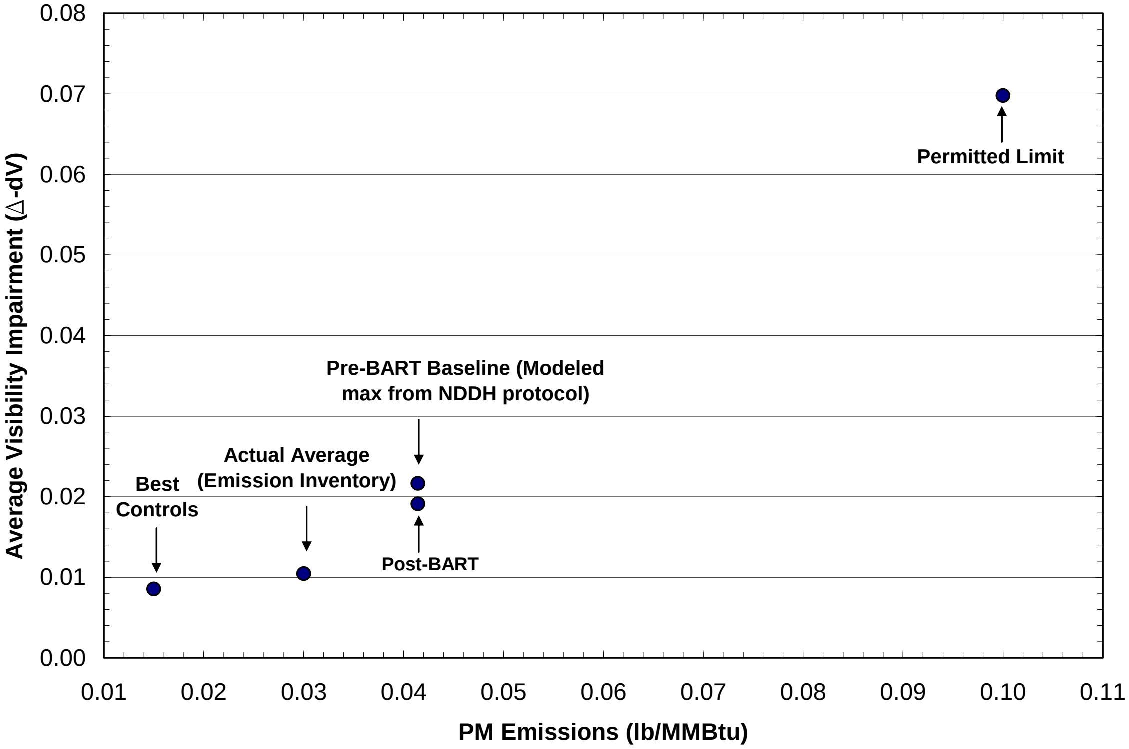

Figure 3-1 PM Visibility Contribution. Four modeled scenarios for Coal Creek Unit 1, modeled year 2002, 98th percentile, illustrate the negligible visibility impacts attributed to particulate matter. All scenarios except for "Pre-BART" were modeled with NOx and SO_2 at the presumptive levels of 0.17 lb/MMBtu and 0.15 lb/MMBtu respectively.

Table 3-4 PM Visibility Modeling Parameters

				Emission Rate Input								
	Description			Stack Velocity	PM_{10}		$PM_{2.5}$ (fine)	PM (coarse)	SO_2		NOx	
Scenario	**PM**	**SO_2/NOx**	**Units**	**m/s (ft/s)**	**% reduction**	**lb/hr**	**lb/hr**	**lb/hr**	**% reduction**	**lb/hr**	**% reduction**	**lb/hr**
0	Pre-BART Protocol		1	25.9 (85)	NA - base	249.2	101.9	147.3	NA - base	5,733.5	NA - base	1,772.3
			1& 2	25.9 (85)	NA - base	465.3	190.3	275.0	NA - base	10,702.8	NA - base	3,594.7
1	Pre-BART Protocol	Presumptive BART [1]	1	25.9 (85)	0%	249.2	101.9	147.3	84%	902.0	42%	1,022.6
			1& 2	25.9 (85)	0%	465.3	190.3	275.0	83%	1,805.0	43%	2,046.3
2	Permit Limit	Presumptive BART	1	25.9 (85)	-141%	601.5	246.0	355.5	84%	902.0	42%	1,022.6
			1& 2	25.9 (85)	-1.6	1,203.7	492.3	711.4	83%	1,805.0	43%	2,046.3
3	Average Actual	Presumptive BART	1	25.9 (85)	28%	180.5	73.8	106.6	84%	902.0	42%	1,022.6
			1& 2	25.9 (85)	22%	361.1	147.7	213.4	83%	1,805.0	43%	2,046.3
4	Best Control	Presumptive BART	1	25.9 (85)	64%	90.2	36.9	53.3	84%	902.0	42%	1,022.6
			1& 2	25.9 (85)	61%	180.6	73.8	106.7	83%	1,805.0	43%	2,046.3

[1] Presumptive levels of 0.15 lb SO_2/MMBtu and 0.17 lb NOx/MMBtu were assumed for modeling purposes.

Table 3-5 PM Modeling, Year 2002

				Visibility Impairment[1]															
	Description				TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA					
Scenario	**PM**	**SO_2/NOx**	**Units**	**Avg. PM Contr.**	**98th % Δ-dV**	**% PM_{10} [3]**	**PM_{10} Δ-dV Contr.**	**98th % Δ-dV**	**% PM_{10} [3]**	**PM_{10} Δ-dV Contr.**	**98th % Δ-dV**	**% PM_{10} [3]**	**PM_{10} Δ-dV Contr.**	**98th % Δ-dV**	**% PM_{10} [3]**	**PM_{10} Δ-dV Contr.**			
0	Pre-BART Protocol		1	0.022	2.559	0.75%	0.019	2.113	1.28%	0.027	1.703	1.03%	0.018	1.814	1.26%	0.023			
			1& 2	0.034	4.475	0.73%	0.033	3.557	1.61%	0.057	3.039	0.99%	0.030	3.190	0.53%	0.017			
1	Pre-BART Protocol	Presumptive BART [2]	1	0.019	0.749	3.48%	0.026	0.695	3.10%	0.022	0.586	3.16%	0.019	0.536	1.92%	0.010			
			1& 2	0.045	1.434	3.27%	0.047	1.338	3.53%	0.047	1.129	5.91%	0.067	1.050	1.80%	0.019			
2	Permit Limit	Presumptive BART	1	0.070	0.784	7.99%	0.063	0.731	11.72%	0.086	0.611	7.29%	0.045	0.578	14.93%	0.086			
			1& 2	0.135	1.503	8.04%	0.121	1.402	11.81%	0.166	1.181	7.26%	0.086	1.125	14.85%	0.167			
3	Average Actual	Presumptive BART	1	0.010	0.742	0.72%	0.005	0.689	2.26%	0.016	0.581	2.31%	0.013	0.533	1.40%	0.007			
			1& 2	0.035	1.425	2.56%	0.036	1.328	2.76%	0.037	1.115	4.64%	0.052	1.046	1.40%	0.015			
4	Best Control	Presumptive BART	1	0.009	0.733	1.29%	0.009	0.681	1.14%	0.008	0.570	2.32%	0.013	0.529	0.70%	0.004			
			1& 2	0.017	1.408	1.29%	0.018	1.311	1.39%	0.018	1.090	2.38%	0.026	1.039	0.70%	0.007			

[1] Year 2002 modeled only, to illustrate worst case year in modeling.
[2] Presumptive levels of 0.15 lb SO_2/MMBtu and 0.17 lb NOx/MMBtu were assumed for modeling purposes.
[3] Percentage attributed to PM emissions calculated from model output data (Appendix D).

3.6 Proposed BART for PM

Based on the above analysis and the visibility impacts found in Section 7.0, GRE is proposing the existing ESP and its current PM limit as BART for particulate emissions at Coal Creek's Unit 1 and Unit 2. Current actual emissions reflect a large degree of control and are below the current performance standard of 0.1 lb/MMBtu. A modification to the existing ESP or the retrofit of a baghouse is not cost effective on a dollar per ton basis[7], and additional controls will provide negligible improvement from a visibility standpoint.

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[7] Comparisons of the cost guidelines from CAIR, NSPS, WRAP, EPA and court decisions indicates that a cost threshold of under $1500 per ton of pollutant removed is a reasonable estimate for BART (Appendix B).

4.0 Nitrogen Oxides (NOx) BART Analysis

There are three mechanisms by which NOx production occurs: thermal, fuel and prompt NOx. Fuel bound NOx is a primary concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. The secondary mechanism of NOx production is through thermal NOx formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air. The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

Downstream of the flame, significant amounts of NO_2 can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \qquad (2)$$

Thermal oxidation is a function of the residence time, free oxygen, and peak reaction temperature. Prompt NOx is a form of thermal NOx which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of NOx are emitted as prompt NOx.

Coal Creek Station's NOx emissions are currently controlled to an average of 0.22 lb/MMBtu through the use of low NOx burners (LNB) with a level of separated overfire air (SOFA).

4.1 NOx Control Options

Table 4-1 lists the available retrofit NOx options for Coal Creek Units 1 and 2.

Table 4-1 Available NOx Control Technologies

NOx Control Options
Combustion Controls
• External Flue Gas Recirculation
• Overfire Air
• Low NOx Burners
Post Combustion Controls
• Selective Catalytic Reduction - High Dust - Low Dust
• Selective Non- Catalytic Reduction - NOxOUT®
• Low Temperature Oxidation - Tri-NOx® - LoTOx
• Non Selective Catalytic Reduction
• Novel Multi-pollutant Controls - Electro-Catalytic Oxidation - Pahlman Process

4.2 Eliminate Infeasible NOx Control Options

4.2.1 Combustion Controls

Various combustion controls exist for NOx reduction from combustion units. A few feasible examples of these controls include overfire air (OFA) and low NOx burners (LNB).

External Flue Gas Recirculation (FGR)

Flue gas recirculation is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizer or air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through adsorption of the combustion heat by the relatively inert flue gas, and to reduce the oxygen concentration in the combustion zone. FGR reduces thermal NOx generation in high-temperature emission sources.

Additional ductwork and a blower would be required to recirculate flue gas. These elements must fit in the limited space around the burner's coal mill. The space constraints and the lowered flame temperature created by FGR make it incompatible with the existing combustion controls on Units 1 and 2. The addition of FGR could further result in reduced boiler capacity. Flue gas recirculation is therefore a technically infeasible control option and will not be considered further.

Overfire Air (OFA)

Overfire air diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. OFA is the typical NOx control technology used in lignite-fired boilers and is primarily geared to thermal NOx reductions. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NOx by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NOx is most likely to be formed.

OFA technology is currently used to control NOx emissions on both Coal Creek units. Based on engineering analyses[8] performed on Unit 1, additional levels of separated overfire air (SOFA) are a technically feasible option for further NOx reduction.

Low NOx Burners (LNB)

LNB technology utilizes advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the

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[8] *TLN3 System Assessment and Recommendations for Lower NOx Operation*. Foster Wheeler North America Corporation. September 9, 2005 (Appendix F).

primary zone, NOx formation is limited by either one of two methods. Under staged air rich (high fuel) condition, low oxygen levels limit flame temperatures resulting in less NOx formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel lean (low fuel) conditions, excess air will reduce flame temperature to reduce NOx formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOx formation. Low NOx burners typically achieve NOx emission reductions of 25% - 50%.

LNB is currently used to control NOx emissions from both Coal Creek units. In combination with SOFA, LNB is a technically feasible option to further reduce emissions. Based on the currently achieved emission rates, reduction in the range of 25%-30% would be expected.

4.2.2 Post Combustion Controls

NOx can be reduced to molecular nitrogen (N_2) in add-on systems located downstream of the furnace area of the combustion process. The two main techniques in commercial service include the selective non-catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process. There are a number of different process systems in each of these categories of control techniques.

In addition to these treatment systems, there are a large number of other processes being developed and tested on the market. These approaches involve innovative techniques of chemically reducing, absorbing, or adsorbing NOx downstream of the combustion chamber. One example of these alternatives is nonselective catalytic reduction (NSCR).

Selective Catalytic Reduction (SCR)

Selective catalytic reduction is a post combustion NOx control technology in which ammonia (NH_3) is injected into the flue gas stream in the presence of a catalyst. SCR control efficiency is typically 70% - 90%. NOx is removed through the following chemical reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_20 \qquad (1)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_20 \qquad (2)$$

The catalyst bed lowers the activation energy required for NOx decomposition. The catalyst contains an active phase of such as vanadium pentoxide on a carrier such as titanium dioxide, and these are used for their ability to lower the activation energy required for NOx decomposition. SCR requires an optimum temperature range of 650-800°F.

High-dust SCR (upstream of particulate control) applications typically required soot blowers for catalyst cleaning. Firing lignite coal results in a stream heavily laden with particulate matter containing catalyst poisons such as sodium. The catalyst plugging observed at the lignite-fired boiler at Coyote Station [9] was caused by materials which could not be cleaned by a soot blower system. Due to the likelihood of catalyst surface plugging caused by high sodium concentrations, a high-dust SCR is technically infeasible on both Units 1 and 2. A low-dust SCR (downstream of particulate control), would require reheat to bring the stream temperature back to the effective range after it is cooled for particulate removal, but is a technically feasible option for NOx reduction. Based on current NOx emissions, an SCR could provide additional reduction in the range of 70%-80%.

Selective Non-Catalytic Reduction (SNCR)

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N_2, and water. SNCR control efficiency is typically 25% - 50%. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

$$NO + NH_3 + \frac{1}{4}O_2 \rightarrow N_2 + 3/2 H_2O \qquad (1)$$

$$NH_3 + \frac{1}{4}O_2 \rightarrow NO + 3/2 H_2O \qquad (2)$$

At temperature ranges of 1470 to 1830°F reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate.

NOxOUT®

NOxOUT® is a commercially available urea based SNCR process for the reduction of NOx from stationary sources. The process requires injection of stabilized urea liquid into the combustion flue gas in a location where the temperature range is 1,600 - 2,000 °F.

SNCR is a technically feasible NOx control option for Units 1 and 2. Based on the current level of NOx control, an emissions reduction of approximately 50% would be expected.

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[9] *SCR catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals.* Steven A. Benson; Jason D. Laumb; Charlene R. Crocker; John H. Pavlish. 7/1/2004 (Appendix G)

Low Temperature Oxidation (LTO)

The LTO system utilizes an oxidizing agent such as ozone to oxidize various pollutants including NOx. In the system, the NOx in the flue gas is oxidized to form nitrogen pentoxide (equations 1, 2, and 3). The nitrogen pentoxide forms nitric acid vapor as it contacts the water vapor in the flue gas (4). Then the nitric acid vapor is absorbed as dilute nitric acid and is neutralized by the sodium hydroxide or lime in the scrubbing solution forming sodium nitrate (5) or calcium nitrate. The nitrates are removed from the scrubbing system and discharged to an appropriate water treatment system. Commercially available LTO systems include Tri-NOx® and LoTOx.

$$NO + O_3 \rightarrow NO_2 + O_2 \qquad (1)$$

$$NO_2 + O_3 \rightarrow NO_3 + O_2 \qquad (2)$$

$$NO_3 + NO2 \rightarrow N_2O_5 \qquad (3)$$

$$N_2O_5 + H_2O \rightarrow 2HNO_3 \qquad (4)$$

$$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O \qquad (5)$$

LTO systems represent a technically feasible control option for Units 1 and 2, with an expected control efficiency of 80%-90%.

Tri-NOx®

This technology uses an oxidizing agent such as ozone or sodium chlorite to oxidize NO to NO_2 in a primary scrubbing stage. Then NO_2 is removed through caustic scrubbing in a secondary stage. The reactions are as follows:

$$O_3 + NO \rightarrow O_2 + NO_2 \qquad (1)$$

$$2NaOH + 2NO_2 + \tfrac{1}{2} O_2 \rightarrow 2NaNO_3 + H_2O \qquad (2)$$

Tri-NOx® is a commercially available multi-staged wet scrubbing process in industrial use. Several process columns, each assigned a separate processing stage, are involved. In the first stage, the incoming material is quenched to reduce its temperature. The second, oxidizing stage, converts NO to NO_2. Subsequent stages reduce NO_2 to nitrogen gas, while the oxygen becomes part of a soluble salt. A major advantage of the Tri-NOx® process is that concurrent scrubbing of SO_2 can be achieved. Tri-NOx is typically applied at small to medium sized sources with high NOx concentration in the exhaust gas (1,000 ppm NOx). Under these conditions control efficiencies of 99% can be achieved.

LoTOx

BOC Gases' Lo-TOx is an example of a commercially available version of an LTO system. LoTOx technology uses ozone to oxidize NO to NO_2 and NO_2 to N_2O_5 in a wet scrubber (absorber). This can be done in the same scrubber used for particulate or sulfur dioxide removal. The N_2O_5 is converted to HNO_3 in a scrubber, and is removed with lime or caustic. Ozone for LoTOx is generated on site with an electrically powered ozone generator. The ozone generation rate is controlled to match the amount needed for NOx control. Ozone is generated from pure oxygen. In order for LoTOx to be economically feasible, a source of low cost oxygen must be available from a pipeline or on site generation. The normal NOx control efficiency range for Lo-TOx is 80% to 95%.

Non-Selective Catalytic Reduction (NSCR)

A non-selective catalytic reduction (NSCR) system is a post combustion add-on exhaust gas treatment system. NSCR is often referred to as a three-way conversion catalyst because it simultaneously reduces NOx, unburdened hydrocarbons (UBH), and CO. Typically, NSCR can achieve NOx emission reductions of 90 percent. In order to operate properly, the combustion process must be near stoichiometric conditions. Under this condition, in the presence of a catalyst, NOx is reduced by CO, resulting in nitrogen (N_2) and carbon dioxide (CO_2). The most important reactions for NOx removal are:

$$2CO + 2NO \rightarrow 2CO_2 + N_2 \qquad (1)$$

$$[UBH] + NO \rightarrow N2 + CO_2 + H_2O \quad (2)$$

NSCR catalyst has been applied primarily in natural gas combustion applications. This is due in large part to the catalyst being very sensitive to poisoning, making it infeasible to apply this technology to the lignite-fired boilers at Coal Creek.

Novel Multi-Pollutant Controls

Electro-Catalytic Oxidation (ECO)

ECO technology utilizes a reactor in which SO_2 and NOx and mercury are oxidized to nitrogen dioxide (NO_2), sulfuric acid and mercuric oxide respectively using non-thermal plasma. The NO_2 and remaining SO_2 are then removed and concentrated in a scrubber with ammonia injection. This technology is intended for use on low-dust streams and must be located downstream of existing particulate controls.

Pahlman Process

The Pahlman process involves the treatment of flue gas with a sorbent containing magnesium oxide. Using the solubility properties of magnesium at different ionization states, SO_2 and NOx are captured and dissolved in a spray dry system. The sorbent is then captured at a downstream baghouse and can be regenerated.

Both ECO and the Pahlman process technologies are still in the testing and development phase. They are therefore not currently considered commercially available and are not considered further.

4.3 Evaluate the Effectiveness of Feasible NOx Options

Based on the current degree of control being achieved on Units 1 and 2, Table 4-2 describes the expected emissions from each of the remaining feasible control options.

Table 4-2 Control Effectiveness of Technically Feasible NOx Control Options

Control Technology	Expected Control Efficiency	Controlled Emissions lb/MMBtu	Controlled Emissions ton/year
LTO	90%	0.022	556
SCR with Reheat	80%	0.043	1,111
SNCR	50%	0.108	2,779
Foster Wheeler SOFA/LNB Option 1	30%	0.15	3,877
Foster Wheeler SOFA/LNB Option 2	21%	0.17	4,394

4.4 Evaluate the Impacts of Feasible NOx Options

As illustrated above in Table 4-2, the five technically feasible options each provide a different level of control. The economic and environmental impacts are presented below.

4.4.1 Economic Impacts

Table 4-3 details the expected costs associated with each technology based on pre-BART historical baseline emissions, the EPA cost model and site specific information. As required by ASTM International designation C618-05, the presence of ammonia in the ash caused by the use of SNCR or SCR would make it ineligible for beneficial use. The cost for SNCR and SCR technologies includes the predicted ash sales revenue losses. The results of the engineering analysis performed by Foster Wheel presented two options with different levels of control for SOFA/LNB control. The detailed cost analysis for each technology is provided in Appendix A.

Table 4-3 NOx Control Cost Summary, per Unit Basis

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
LTO	$44.33	$58.07	$11,610	$31,799
SCR with Reheat	$70.36	$40.40	$9,087	$19,862
SNCR	$6.16	$7.28	$2,621	$6,027
Foster Wheeler SOFA/LNB Option 1[*]	$5.26	$0.66	$395	$868
Foster Wheeler SOFA/LNB Option 2	$2.63	$0.34	$291	NA-Base

The incremental control cost listed in Table 4-3 represents the incremental value of each technology as compared to the technology with the next highest level of control. In this analysis, dominant controls are located on the least cost envelope, as illustrated graphically in Figure 4-1.

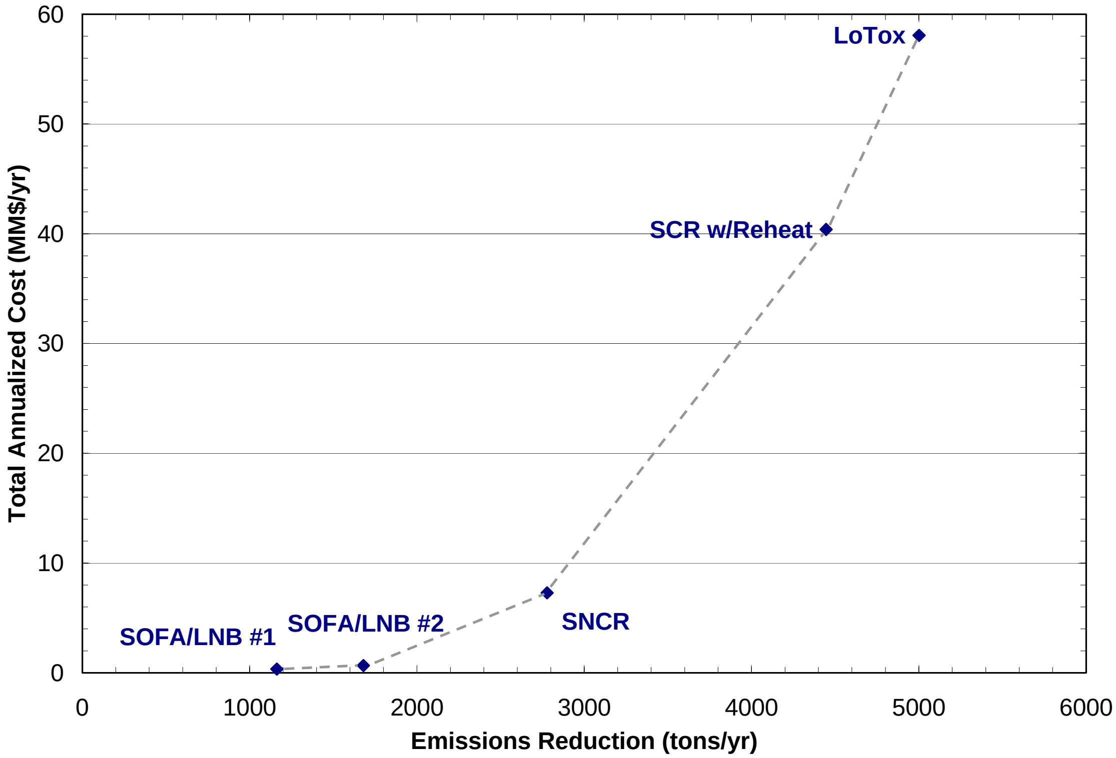

Figure 4-1 Incremental NOx Analysis The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year.

Based on the BART final rule and other similar regulatory programs like CAIR, cost-effective NOx controls are in the range of $1,300 to $1,800 per ton removed as

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[*] Installation costs revised based on an updated Foster Wheeler proposal. The updated proposal is included in Appendix K.

illustrated in Appendix B. Accordingly, SNCR, SCR with reheat, and LTO should all be precluded from BART consideration on the basis of cost effectiveness. All three technologies represent significant capital investments that are not justified on a cost per ton or incremental cost basis.

4.4.2 Energy and Environmental Impacts

The energy and non-air quality environmental impacts for SOFA/LNB options, SNCR, SCR, and LTO are described in Table 4-4.

Table 4-4 NOx Control Technology Impacts Assessment

Control Option	Energy Impacts	Other Impacts
LTO	- The blower, circulation pump and wastewater discharge require additional electrical usage.	- Additional waste water generated by LTO technologies requires biotreatment.
SCR with Reheat	- The reheat required to make SCR technically feasible will result in high energy use and associated costs.	- Reheat would require additional natural gas use which is not currently available and would require installation of a larger natural gas line. - Ammonia slip concerns.
SNCR	- Minimal additional energy impacts.	- Ash would no longer be eligible for beneficial use options. Over $27 million has already been invested in the infrastructure for ash sales. Ash must be landfilled if beneficial use options are not available. - Ammonia slip concerns.
SOFA/LNB	- Minimal energy impacts.	- Potential for tube wastage.

4.5 Proposed BART for NOx

Based on the above analysis and the visibility impacts found in Section 7.0, GRE is proposing an additional level of separated overfire air (SOFA) as BART for NOx emissions at Coal Creek's Unit 1 and Unit 2. A comparison of the visibility modeling results for the two SOFA/LNB control options shows little difference in visibility improvement between the two. Regardless of this fact, the proposed BART will be the more stringent of the two options with a design emission rate of 0.15 lb/MMBtu. While this design emission rate may be achieved on a long term of annual average basis, a shorter term limit of 0.17 lb/MMBtu is required to account for potential variability due to operational conditions.

With tangential firing, the lateral impingement of the horizontally adjacent fuel and air streams produces a furnace vortex with a single flame envelope. The entire furnace acts as the burner; therefore, precise proportioning of fuel and air at each of the individual fuel and air admission points is not required. Locally fuel-rich or air-rich streams are mixed in passing through the furnace, resulting in complete combustion of the fuel. The furnace vortex produces a large amount of internal recirculation of bulk gas, which, couples with the longer residence time for burning, provides a combustion system inherently low in NOx production and virtually eliminates hydrocarbon and CO emissions.

Further reductions of NOx emissions are achieved through the use of close coupled and separated overfire air. Close coupled overfire air compartments are provided as extensions of the windboxes and the separated overfire air compartments are above the windboxes. Overfire reduces NOx formation by reducing the peak and bulk flame temperatures by extending the combustion zone and time necessary for fuel burnout. The close coupled overfire air is directed into the furnace through two elevations of separately tiled windbox registers and the separated overfire air is directed into the furnace through two additional elevations of registers that are separated above the main windbox. Optimum damper and tilt positions are established by field testing.

Current actual emissions reflect a large degree of control and are below the current permit limit of 5,104 lb/hr (0.85 lb/MMBtu) per unit on a 12-month rolling average. The additional level of SOFA/OFA presented in Foster Wheeler's Option 2 represents a cost effective method of further controlling NOx emissions. As stated above, the installed SOFA will be designed to meet an emission rate of 0.15 lb/MMBtu, but a design basis cannot be directly translated into an operational limit. With consideration for operational variability and potential emission spikes, the proposed BART emissions limit for both Unit 1 and Unit 2 is 0.17 lb/MMBtu on a 30-day rolling average, which corresponds to the presumptive limit established by EPA. The revised Foster Wheeler proposal included in Appendix J states an emission guarantee of 0.17 lb/MMBtu. An optimization study will be performed after the implementation of the full scale coal dryers and the installation of the upgraded NOx control system to determine actual performance levels, but at this time, an emission limit lower than the vendor guarantee will not be proposed.

5.0 Sulfur Dioxide (SO_2) BART Analysis

5.1 SO_2 Control Options

Coal Creek Units 1 and 2 are currently controlled using wet flue gas desulfurization scrubbers that operate at a dry stack condition with approximately 27% of the flue gas bypassing the scrubber. The remaining 73% of the gas from each unit is routed through an existing four-module scrubber with a removal efficiency of approximately 94%. The overall control efficiency for each unit is approximately 68%. Based on the current removal efficiency, only systems that can achieve greater than 68% overall control efficiency are evaluated. Table 5-1 lists the available SO_2 control options for Coal Creek Units 1 and 2.

Table 5-1 Available SO_2 Control Technologies

SO_2 Control Options
Pre-Combustion Controls
Flue Gas Desulfurization
Dry Sorbent Injection
Spray Dry Absorber
Wet Lime/Limestone Absorber
Novel Control: TurboSorp®

5.2 Eliminate Infeasible SO_2 Control Options

The pollutant SO_2 is formed when sulfur present in fuels is oxidized by either process conditions or by combustion. Pre-combustion controls utilize methods for improving the physical or chemical properties of the fuel before it is combusted. Existing methods for post-combustion SO_2 control can be categorized as either dry or wet flue gas desulfurization.

5.2.1 Pre-Combustion Controls

Coal impurities can be reduced through pretreatment options such as coal washing and coal drying. No information could be located in support of the effectiveness of washing lignite coal, but coal drying was explored and is a viable option. In this process, raw coal is crushed and screened to remove rocks and other impurities. Subsequently, the crushed coal is thermally processed to remove excess moisture. Coal drying is a technically feasible control option, and a full scale DOE project is beginning construction in the spring of 2007 at Coal Creek Station.

The lignite coal supplied to Coal Creek Station by the Falkirk Mining Company typically has a higher heating value of 6200 Btu/lb and a moisture content of 38%. A 75 ton/hour lignite drying system with a segregator for beneficiation of the lignite was designed and constructed in 2005. The drying system utilizes plant waste heat to process the coal at under 200ºF resulting in water evaporation with no additional volatiles production. The prototype dryer was built and tested to determine the final design for the full scale lignite coal drying demonstration project, beginning construction the spring of 2007. The major benefit of drying lignite is a decrease in the lignite moisture content which results in a higher boiler efficiency and a reduction in flue gas volume of up to 30%. Other benefits include reduced SO_2, NOx, CO_2 and Hg emissions (roughly 5%), reduced station power consumption by about 18%, and reduced water used by about 2.5%.

5.2.2 Flue Gas Desulfurization (FGD)

The FGD systems commonly used to control SO_2 emissions can be classified as either wet or dry systems. Both systems rely on creating turbulence in the gas stream to increase contact with the absorbing medium. Wet systems are commonly capable of achieving higher removal efficiencies than dry systems because it is easier to mix a gas with a liquid than a solid. FGD requires the use of an alkali powder of slurry, and lime (or limestone) is the most widely used compound for acid gas absorption. Sodium based reagents are also available, and while they provide better SO_2 solubility, they are significantly more expensive.

Wet FGD systems may discard all of the waste by-product streams or regenerate and reuse them. Wet systems generally require more extensive networks of pumps and piping than dry systems to recirculate, collect and treat the scrubbing liquid. As implied by the name, dry scrubbers require less water than wet systems but also require higher temperatures to ensure that all moisture has been evaporated before leaving the scrubber. There are many available FGD systems including wet scrubbing, spray dryer absorption, and dry sorbent injection.

Dry Sorbent Injection (DSI)

Dry sorbent injection involves the injection of a lime or limestone powder into the exhaust gas stream. The stream is then passed through a baghouse to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 50% and 70%. It should be noted that the maximum expected removal efficiency of this technology (70%) is very close to the existing scrubber removal of 68% for both units. While dry sorbent injection is a technically feasible retrofit option, it will provide only minimal improvement over the existing removal efficiency.

Spray Dry Absorption

Spray dry absorption is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the droplets. The absorption of the SO_2 leads to the formation of calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate ($CaSO_4$) within the droplets as illustrated by equations 1 and 2 below.

$$SO_2 + CaO + 1/2\ H_2O \rightarrow CaSO_3 \bullet 1/2\ H_2O \qquad (1)$$

$$CaSO_3 + ½O_2 + 2H_2O \rightarrow CaSO_4 \bullet 2H_2O \qquad (2)$$

The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter. Spray dryer absorption control efficiency is typically in the 70% to 90% range. A spray dry scrubber is a technically feasible retrofit control option.

Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime (CaO) or limestone ($CaCO_3$) in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. Similarly to the chemistry illustrated above for spray dry absorption, the SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite ($CaSO_3 \cdot 2H_2O$) and calcium sulfate ($CaSO_4$). Wet lime scrubbing is capable of achieving 98+% control. Wet scrubbing is currently used on approximately 73% of exhaust gas at both Coal Creek units. A new replacement wet scrubber is a technically feasible retrofit option. Modifications to the existing scrubbers in order to improve its capture and/or control efficiency are also technically feasible. Both options, entire replacement of and upgrades to the existing scrubbers, are considered separately in this evaluation.

Novel Multi-Pollutant Control: TurboSorp®

TurboSorp® is a dry FGD technology in which the flue gas is pushed through an open chamber reactor. The flue gas enters the reactor through a nozzle with venturi geometry for optimum distribution of gas flow. The fluidized bed of particles circulates above the venturi inlet inside the vessel and water is injected to maintain outlet temperatures in the range of 45ºF to 55ºF above saturation temperature. Recycled particles from the baghouse along with hydrated lime are injected at this location to control outlet SO_2. The stream is then passed through a fabric filter or ESP to remove large particulate and finally exits through the stack.

This technology has been considered for Coal Creek as a potential method for treating the current scrubber bypass streams from Units 1 and 2. TurboSorp® could provide the benefits of a dry stack and additional particulate control. A booster fan would be required at the outlet to control the gas flow rate, and the system would also require installation of a hydrator or pug mill to facilitate the lime hydration process. Test plants are currently operating in Europe, but TurboSorp® has not been commercially demonstrated in the United States. Though not considered technically feasible due to its lack of commercial availability at this time, TurboSorp® may be considered further in future control technology assessments.

Additional novel controls including ECO and the Pahlman process for NOx and SO_2 are included in Section 4.2.2.

5.3 Evaluate the Effectiveness of Feasible SO_2 Options

Based on the degree of SO_2 emissions control currently achieved at Units 1 and 2, Table 5-2 describes the expected emissions from each of the remaining feasible control options.

Table 5-2 Control Effectiveness of Technically Feasible SO_2 Control Options

Control Technology	Expected Control Efficiency	Controlled Emissions lb/MMBtu	Controlled Emissions ton/year
Scrubber Replacement[10]	95%	0.106	2,735.7
Scrubber Modification + Coal Drying	94%	0.128	3,310.2
Spray Dry Baghouse	90.0%	0.212	5,471.4
Existing Scrubber + Coal Dryer	83.1%	0.358	9,263.1
DSI Baghouse	70.0%	0.635	16,414.3

With respect to scrubber modifications, a variety of upgrades have been evaluated for the Units 1 and 2 scrubbers. They range in efficiency from 93.9% to 96.0% as illustrated in Appendix I, and include options that will meet the presumptive SO_2 limit of 0.15 lb/MMBtu. Many of the technically feasible options require the replacement or upgrade of the stacks due to the demands of wet stack conditions. A wet stack is a technically feasible option as illustrated in Appendix E, and the evaluated modifications represent both wet and dry stack options. In addition to being evaluated individually, coal drying was incorporated into some of the evaluated scrubber modification options.Full scale coal drying ~~is~~ will be implemented (see Appendix K for detailed analysis report), and as a results, the volume of the flue gas will be significantly reduced, thus requiring fewer modifications to accommodate the currently bypassed gas flow. Appendix I includes information on scrubber modification options provided by URS Corporation. Other modification options include:

- Replacement/addition of spray headers
- Replacement/addition of nozzles
- Installation of trays or liquid distribution rings (LDRs)
- Addition of a fifth scrubber module
- Expansion of the existing absorbers

Treatment of the existing bypass with a separate control was also considered. All of the modifications will require new mist eliminators in the absorbers and all wet scrubbing options will necessitate stack modifications. These options and the applicable combinations have been evaluated individually, and the economic details are included in

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[10] *Survey of State-of-the-Art Emissions Control Systems* (1010762) published in 2006 by EPRI states that new absorbers can achieve control efficiencies of 98+%. However, given the type of coal and necessary retrofit the existing plant, 95% control could be expected from a new scrubber at Coal Creek. (See 2/23/07 letter for additional justification).

Appendix A. For the sake of clarity, the range of control efficiencies and impacts of the eight evaluated modifications are referred to under the classification of "scrubber modifications."

A number of operational variables can affect the performance of SO_2 control technologies. Gas velocities, duct and stack geometry all play a role in determining deposition in the stack and scrubber modules, resulting in varied removal efficiencies. As a result of existing plant configurations, retrofit scrubber modifications may not achieve the optimum velocities and geometries. Therefore, the control efficiencies and emission rates presented above are design rates only and represent best case operational expectations. Coal sulfur content[11], equipment reliability and maintenance will also play a large part in the control of actual emissions.

Due to the fact that Coal Creek Station is a mine-mouth plant, there are limited opportunities for coal blending. SO_2 emissions will depend heavily on mine operations which introduces a high degree of variability. While coal sulfur content may seem to vary little over short periods of time, a change in mining area could produce a drastic and immediate change. On an annual basis, the average may remain low if only one or two months out of twelve have a high sulfur content, but 30-day rolling average limits must account for the potential of a high sulfur content on the short term basis. This variability must be considered when determining an appropriate emission limit. The technology evaluations presented in Section 5.4 are based on recent emission inventories and design removal efficiencies. When compared to more historical or future predicted coal sulfur contents for Falkirk Mine, the recent sulfur content has been in the mid range. Any future SO_2 emission limit needs to account for the higher end of the expected sulfur content, and realistic operational conditions that can result in removal efficiencies lower than the design basis.

5.4 Evaluate the Impacts of Feasible SO_2 Options

The economic and environmental/non-air quality impacts of the remaining controls are illustrated below.

5.4.1 Economic Impacts

Table 5-3 details the expected costs associated with each technology based on pre-BART historical baseline emissions, the EPA cost model and site specific information. The detailed cost analysis for each technology is provided in Appendix A[12].

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[11] See section 6.2 and Appendix C for further coal sulfur content and emission rate documentation.

[12] Cost estimates do not represent detailed engineering estimates. Based on market prices and site specific conditions, cost can vary by 20+%.

Table 5-3 SO_2 Control Cost Summary, per Unit Basis

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
Scrubber Replacement	$204.72	$30.76	$2,114	$33,498
Scrubber Modification + Coal Drying*	$76.22	$11.52	$824	$281
Spray Dry Baghouse	$181.18	$29.22	$2,472	Inferior
Existing Scrubber + Coal Dryer	$71.20	$9.84	$1,226	NA-Base
DSI Baghouse	$48.75	$12.52	$14,313	Inferior

The incremental control costs listed in Table 5-3 represents the incremental value of each technology as compared to the technology with the next highest level of control. Control technologies listed as "inferior" do not represent cost effective options in comparison to the dominant control technologies on an incremental dollar per ton basis. In this analysis, dominant controls are located on the least cost envelope, as illustrated graphically in Figure 5-1.

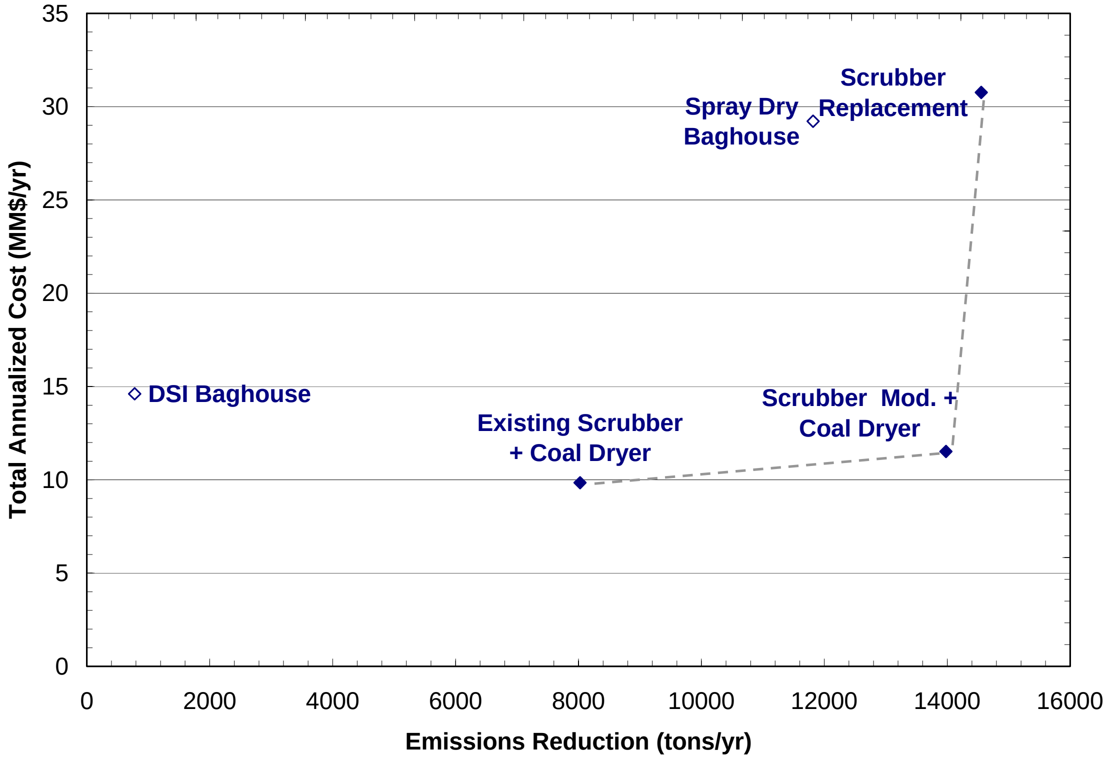

Figure 5-1 Incremental SO_2 Analysis The remaining feasible technologies are illustrated on the basis of emission reduction in tons per year and total cost in millions of dollars per year. Dominant and inferior controls are represented by darkened or empty diamonds respectively. The average cost and emission reduction are show for scrubber modifications.

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* Cost of options involving coal drying revised to reflect the installed capital and annualized O&M costs of full scale dryer operation.

Based on the BART final rule and other similar regulatory programs like CAIR, cost-effective SO_2 controls are in the range of $1,000 to $1,300 per ton removed as illustrated in Appendix B. Accordingly, the retrofit options of DSI baghouse, spray dry baghouse, and scrubber replacement should be precluded from BART consideration on the basis of both average cost effectiveness and incremental cost effectiveness. All three technologies represent significant capital investments that are not justified on a cost per ton or incremental cost basis.

5.4.2 Energy and Environmental Impacts

The energy and non-air quality impacts for scrubber replacement and modification, dry scrubbing options, and coal drying are presented in Table 5-4.

Table 5-4 SO_2 Control Technology Impacts Analysis

Control Option	Energy Impacts	Other Impacts
Scrubber Replacement	- Additional blower capacity requires increased energy use.	- Extensive process downtime for installation, requiring replacement power. - Stack modifications required. - Additional water consumption and wastewater generation.
Scrubber Modification with Coal Drying	- Minimal energy impacts.	- Stack modifications required. - Outage/replacement power required for installation. - Additional water consumption and wastewater generation.
Dry Scrubbing (Spray Dry/DSI Baghouse)	- Additional blower capacity requires increased energy use.	- Extensive process downtime for installation, requiring replacement power[13].

5.5 Proposed BART for SO_2

Based on the above analysis and the visibility impacts found in Section 7.0**,** GRE is proposing to eliminate the current bypass and scrub 100% of the flue gas stream, with the potential to maintain wet stack operation. This scenario results in a proposed BART emission limit of 0.15 lb/MMBtu station wide cap per unit on a 30-day rolling average period. Compliance with the proposed BART limit will be demonstrated using the existing continuous emissions monitoring system (CEMS).

The proposed emission limit is intended to account for a short term range of operational conditions and coal sulfur content. On an annual basis, it is likely that both Units will operate below the 0.15 lb/MMBtu limit. The visibility modeling results support the proposed BART on dollar per deciview and total deciview improvement bases. Section 7.3 shows that aside from the addition of a new scrubber which has been ruled out by the factors described in Section 5.4, the proposed BART is the most cost effective

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[13] Replacement power is only required for fully retrofit dry controls designed to handle the full flue gas flow. Control options designed to treat only the current scrubber bypass (including TurboSorp) will not have this requirement.

option and provides a large degree of visibility improvement. For the year 2002, the 98th percentile total visibility improvement for the two stations combined will be over 1.8 Δ-dV compared to baseline.

It must be noted that while modifications to the existing scrubber modules can achieve control efficiencies near what is expected from a newly designed scrubber, a number of operational differences still exist. New scrubbers have a great deal of redundancy and flexibility built into their design. For example, multiple levels of spray headers allow operators to put individual spray headers into service or take them out of service as conditions dictate. In contrast, the Coal Creek Station scrubbers have fewer redundancies and are therefore more likely to experience emission spikes caused by operational configuration.

Coal Creek Station requires room for operational changes that may occur between outages. The scrubbers are designed to minimize operational upsets, however all control technologies, including scrubbers, can experience operational degradation between outage opportunities. Examples such as scaling of the mist eliminators, nozzle breakage, and plugging or scaling of spray pumps and lime slurry equipment can all result in a removal efficiency less than the design removal. Additionally, Coal Creek scrubber modification design will be limited by space constraints of the existing module and building, namely, no footprint exists for additional spray pumps. These factors indicate that while the existing modules will be upgraded, their design and resulting operation will not be the same as would typically be expected from a new scrubber. This implies that a design emission rate cannot be directly translated into an operational emission limit.

Based on the results of the coal dryer study (Appendix J), the final SO_2 control strategy for Coal Creek will include coal drying in addition to the installation of trays or new LDRs and high flow MEs. GRE's goal is to meet or operate below BART presumptive levels while maintaining the highest degree of operational flexibility. In an effort to utilize the best available technology at the time of purchase, GRE will continue to evaluate which technology will provide the requisite removal efficiencies to meet the BART presumptive levels and provide GRE with greatest operational flexibility. Coal drying will provide the benefit of reducing the coal moisture content by about 8%. A decreased flue gas volume coupled with the separation of the heavier material in the 1st stage of the drying process has provided evidence of additional pollutant reductions. (CO_2, NOx, Hg) These numbers have been extrapolated from the prototype experiment but the full scale demonstration project will provide the final refined values.

6.0 Condensable Particulate Matter (CPM) BART Analysis

Based on EPA's interpretation that 'total particulate' includes condensable particulate matter (CPM) and at NDDH's request, GRE provides an estimate of CPM from Units 1 and 2 at Coal Creek Station. It is important to note that ND utilities are not required to test for CPM. They are only required to test for particulate using Methods 5 or 17, depending on plant permit requirements. Coal Creek's Title V permit includes a particulate limit for Units 1 and 2 and compliance is demonstrated based on a correlation curve with opacity that was developed using EPA Method 17. Since GRE does not have stack test data for CPM, a literature review was conducted to estimate CPM emissions based on a correlation to tested filterable values. Unfortunately, there is wide variability in CPM emissions when correlated to filterable emissions, regardless of the methodology selected. Some of the variability it associated with Method 202 and sulfate interference. Since CPM exists in several forms such as ammonia salts and sulfur containing particles, Method 202 cannot compensate for sulfate levels, and consequently overestimates CPM emissions. AP-42 is another methodology that provides a linear relationship between sulfur content and CPM emissions, which is arguably inaccurate, especially at higher sulfur concentrations. Nevertheless, for the purpose of this BART analysis, CPM emissions are approximated and assessed according to BART requirements.

6.1 Identify CPM Control Options

It is generally accepted that CPM is largely formed by ammonia salts and sulfur containing particles. In the absence of ammonia from NO_X controls, no ammonium salts are expected in Unit 1or 2, indicating that the majority of CPM is in the form of sulfuric acid mist (SAM). In general, the inorganic portion of CPM far exceeds the organic portion and is composed primarily of sulfates, which emanate from SO_2. Sulfuric acid mist is formed from sulfur trioxide (SO_3) reacting with water in exhaust streams. SO_3 (and SO_2) is formed when sulfur present in the coal is oxidized by either process conditions or by combustion. Accordingly, the majority of control options for CPM are the SO_2 control technologies described previously in Section 5.0 and listed in Table 6-1 below.

Table 6-1 Available CPM Control Technologies.

CPM Control Options
Wet Electrostatic Precipitator
Dry Sorbent Injection
Spray Dry Absorber
Wet Lime/Limestone Absorber

6.2 Eliminate Infeasible CPM Control Options

Wet Electrostatic Precipitator

In applications where a wet electrostatic precipitator (WESP) is used for particulate removal, it may also be used for SAM removal. A WESP uses a water spray to remove particulate matter from the ESP collection plates. For SAM removal, caustic is added to the water spray system, allowing the spray system to function as an SAM absorber. As indicated in Section 3.0, WESP control is a technically feasible but economically infeasible control option. CPM emissions do not significantly change the economic analysis. As such, WESP is economically infeasible for CPM control. If added to the particulate analysis in Section 3, CPM emissions do not significantly change the economic impacts. No additional PM controls are necessary.

Dry Sorbent Injection (DSI)

Dry sorbent (pulverized lime or limestone) is directly injected into the duct upstream of the fabric filter. SAM reacts with sorbent and the solid particles are collected with a fabric filter. This process was developed as a lower cost option to conventional spray dry absorption (SDA) technology. DSI is technically feasible for controlling CPM. However, as indicated in Section 5.0, DSI represents a lower degree of control than will be achieved by the proposed SO_2 BART controls for Coal Creek Station.

Spray Dry Absorption

Spray dryer absorption is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the pollutants (SO_2 and SAM) are absorbed by the droplets. The absorption of the SO_2 and SAM leads to the formation of calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate ($CaSO_4$) within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter. Dry scrubbing presents a lower degree of control than will be achieved by the proposed SO_2 BART controls for Coal Creek Station.

Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing flue gas stream with a slurry comprised of lime (CaO) or limestone ($CaCO_3$) in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO_2 and SAM in the gas stream reacts with the lime or limestone slurry to form calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate ($CaSO_4$). Coal Creek Station currently uses wet scrubbing for SO_2 control, and modifications to the existing scrubber system are the proposed BART control. Coal Creek's scrubber modifications will also provide a corresponding reduction to CPM.

6.3 Evaluate the Effectiveness of Feasible CPM Options

A number of methods exist with which to estimate CPM emissions. However, consistent and accurate CPM estimates vary widely due in large part to the uncertainties currently associated with CPM emissions measurements as presented below.

EPA's AP-42 emission factor uses a linear relationship between CPM and the sulfur content of coal. Historical coal sulfur contents have ranged 0.29% to 1.21% for Coal Creek Station with an average of 0.63%. There are two issues relevant to the uncertainty associated with using AP-42 emission factors: how well they represent the results of Method 202 measurements and the known artifacts in the inorganic portion of Method 202. (Namely, condensable sulfates are formed in the aqueous measurement process that would not otherwise form CPM in the atmosphere. These sulfates are generally termed "pseudo particulates" and their formation results in inflated CPM values when using Method 202[14].)

Five tests from coal-burning boilers in various locations provide some indication of the relationship between Method 202 measurements and AP-42 calculations. These sites all used wall fired boilers and pulverized coal and were equipped with a particulate control (ESP or fabric filter) but had no NO_X or SO_2 controls.

In the AP-42 calculations, CPM varies linearly with sulfur content. However, Method 202 measurements do not yield such a linear relationship. This suggests that the AP-42 correlation with coal sulfur is not appropriate. There is not sufficient data to assess if CPM measurements corrected for pseudo particulates would have a linear relationship with coal sulfur content. At higher sulfur contents, AP-42 calculations appear to overestimate CPM compared to Method 202, which already overestimates CPM. For very low sulfur content coal Method 202 may provide the more conservative estimate.

Since GRE does not have Method 202 test data from its boilers, CPM emissions are estimated by using a ratio of 4:1 for CPM to filterable PM (Method 5) based on the literature data presented in both Figure 6-1 and Table 6-2 below. The bar graph and table below summarizes the sulfur content, Method 202 CPM and AP-42 CPM, as well as the ratio of condensable to filterable PM using these two techniques from these five sites. The tests give a range of condensable to filterable PM ratios of 1.44-6.69 using Method 202, with an average ratio of 3.61.

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[14] A comparison of Method 202 with a modified version to correct for pseudo particulates was performed at the Xcel Energy (previously Northern States Power) Black Dog Station, which at the time of the test fired pulverized coal at 0.25% sulfur content with wall-fired burners. The boilers were equipped with electrostatic precipitators for particulate control, but did not have ammonia-based NOX controls or SO2 controls. The comparison was accomplished by measuring CPM with standard Method 5 and Method 202 techniques and then repeating the measurements using a cold filter in the Method 5 train to simulate conditions for formation of CPM in the atmosphere. At Method 5 temperatures, sulfate based CPM can pass through the collection filter. A cold filter will capture these sulfate and sulfuric acid particulates so that any sulfate measured in the impingers of Method 202 may be considered pseudo particulates. This comparison indicates as much as an 83% overestimation of CPM using Method 202.

Table 6-2 Filterable and Condensable PM Comparison[17,18]

Source	Average Coal Sulfur Content	AP-42 CPM (lb/MMBtu)	Method (M) 202 CPM (lb/MMBtu)	Ratio of Condensable (M 202) to Filterable, (M 5) PM	Ratio of Condensable (AP-42) to Filterable, (M 5) PM
Logan Generating Company, L.P. Cogen Facility	1.13	0.083	0.0208	4.56	18.20
PSE & G - Mercer Station Unit 1	0.75	0.045	0.0373	3.00	3.61
PSE & G- Mercer Station Unit 2	0.75	0.045	0.0563	6.69	5.34
Deseret Generation and Trans. Coop.- Bonanza Power Plant	0.47	0.017	0.0096	1.44	2.55
Xcel Energy Black Dog Station	0.25	0.01	0.0437	2.36	0.54
Xcel Energy Black Dog Station – corrected for pseudo particulates (Modified M 202)	*0.25*	*0.01*	*0.0076*	*0.41*	*0.05*
Average Ratio CPM: Filterable				**3.61**	**6.05**

As described above, the existing methodologies for approximating CPM emissions all have their limitations. The Electric Power Research Institute (EPRI) is currently working with the EPA to revise Method 202 in an effort to produce more accurate CPM emission estimates. For the sole purpose of approximating (CPM) from its lignite-fired boilers for this BART analysis, GRE has chosen to multiply its filterable particulate matter (PM), as determined using EPA Method 5 test data, by a factor of 4. This ratio is based on literature data comparing the results of CPM measured by EPA Method 202[15] to filterable particulates as measured by EPA Method 5. It is also reflective of recent BACT permit limits[16], which show a range of CPM ratios from roughly 2 to 4 times the corresponding PM limit. Accordingly, the proposed CPM emission factor will conservatively estimate CPM emissions for the purposes of this BART evaluation.

As shown in Figure 6-1, a modified Method 202 can correct for pseudo-particulates. It is shown that Method 202 alone can overestimate CPM by as much as 83%, on a relatively low sulfur coal.

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[15] CPM may be directly measured using EPA Method 202, or it may be estimated using EPA's AP-42 emissions factor document. Method 202 measures the amount of particulates that condense in water-filled impingers in the "back half" of a Method 5 stack sampling system.

[16] CPM information sources for CFB boiler emission limit determinations. Email from Tom Bachman <tbachman@nd.gov> of NDDH, 15 June 2006.

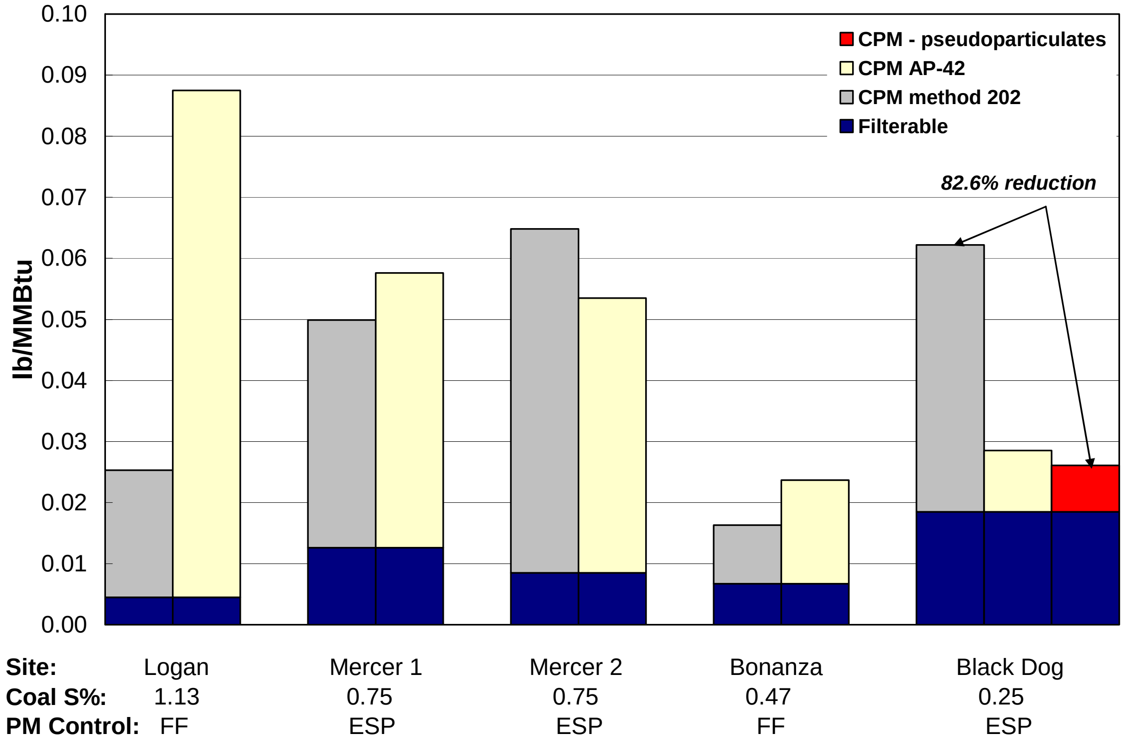

Figure 6-1. Comparison of Method 202 and AP-42. Breakdown of particulate matter is illustrated for 5 power plants[17,18].

Table 6.2 provides CPM estimates using Method 202 and also attempts to correct for pseudo-particulate.

Table 6-3 Annual CPM Emissions Estimate Based on Modified Method 202 Approximation

Unit 1 Method 5 Result (lb/MMBtu)	PM (filterable) Emissions	CPM w/ pseudo-particulates (lb/MMBtu)	CPM w/o pseudo-particulate (lb/MMBtu)	CPM w/ pseudo-particulates (ton/yr)	CPM w/o pseudo-particulate (ton/yr)
0.03	799.0 tpy[19]	0.12	0.02	3,196.0 tpy	556.1

6.4 Evaluate the Impacts of Feasible CPM Options

Uncontrolled SO_2 emissions for a single unit are calculated to be 56,435 tons per year. As illustrated in Table 6-3 CPM emissions are estimated at approximately

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[17] "In Stack Condensible Particulate Matter Measurements and Issues" by Louis A. Corio and John Sherwell in the Journal of Air & Waste Management Association: 50:207-218.

[18] "Measurement of Condensible Particulate Matter: A Review of Alternatives to EPA Method 202, EPRI, Palo Alto, CA: 1998. Report TR-111327.

[19] Annual emissions are based on past actual operations for Coal Creek Units 1 and 2. 8,856 annual operating hours with a utilization rate of 100%. (0.03 lb/MMBtu x 6019 MMBtu/hr x 8856 hr/yr/2000 = 799.0 tpy)

3,196 tons per year, only 5.7% of the SO_2 emissions. If corrected for pseudo-particulates, CPM emissions may be as low as 556.1 tons per year, or only 1% of the SO_2 emissions. Detailed economic and environmental impacts for the available control technologies have been presented in Section 5.4. With either the corrected or uncorrected value, the incorporation of CPM will not significantly change the SO_2 economic evaluation. Further, as discussed in Section 3 and as modeled in Section 7, existing PM controls at the permit limit of 0.1 lb/MMBtu are considered BART. With an uncorrected CPM emission rate (0.12 lb/MMBtu) estimated at 4 times filterable PM (0.03 lb/MMBtu), both units are operating only slightly above the filterable emission rate (0.1 lb/MMBtu), which has been modeled and contributes only 0.06 Δ-dV per unit to regional haze (see Section 7.5). Therefore, comparable to the SO_2 determination, CPM emissions do not significantly change the PM determination in Section 3.

6.5 CPM Visibility Impacts

As illustrated in Section 3.5, visibility impairment due to particulate matter is negligible in comparison to the contributions attributed to sulfates and nitrates. A comparison of Coal Creek's Unit 1 Method 5 results (0.03 lb/MMBtu) and permitted emission rate (0.1 lb/MMBtu) showed a 0.06 Δ-dV 98th percentile addition to visibility impairment. As stated above, it is assumed that total particulate emissions (uncorrected condensable + filterable) will be 5 times the filterable contribution, or in this case, 0.15 lb/MMBtu, given the uncertainties with the methodologies. Extrapolation from the existing data points indicates that the total visibility impairment attributed to CPM is less than 0.08 Δ-dV. These results indicate that total particulate emissions (uncorrected condensable + filterable) will have a negligible influence on overall visibility impacts. Therefore, even if CPM emissions are as high 4 times filterable PM, the modeled visibility impairment would not be significant and additional SO_2 and PM controls are not economically justifiable.

6.6 Proposed BART for CPM

GRE has reviewed, summarized and discussed the limitations of various methodologies for estimating CPM emissions. GRE proposes no additional control for CPM as supported by the visibility analysis in Section 6.5. It is recognized that proposed BART SO_2 controls will reduce CPM, or specifically, sulfuric acid mist (SAM) as the major component of CPM. Coal Creek Station will reduce SAM emissions by as much as 98% through proposed scrubber improvements.

7.0 Visibility Impacts Analysis

As indicated in EPA's final BART guidance[20], states are required to consider the degree of visibility improvement resulting from the retrofit technology in combination with other factors, such as economics and technical feasibility, when determining BART for an individual source.

The CALPUFF program models how a pollutant contributes to visibility impairment with consideration for the background atmospheric ammonia, ozone and meteorological data. Additionally, the interactions between the visibility impairing pollutants NOx, SO_2 and PM_{10} can play a large part in predicting impairment. It is therefore important to take a multi-pollutant approach when assessing visibility impacts.

7.1 Assessing Visibility Impairment

The visibility impairment contribution for different emission rate scenarios can be determined using the CALMET, CALPUFF, POSTUTIL, and CALBART modeling templates provided by the North Dakota Department of Health (NDDH). The North Dakota BART modeling protocol[21] describes the CALPUFF model inputs including the meteorological data set and background atmospheric ammonia and ozone concentrations along with the functions of the POSTUTIL and CALBART post processing elements. The CALBART output files provide three methods with which to assess the expected post-BART visibility improvement: the 98th percentile, 90th percentile, and the number of days on which a source exceeds an impairment threshold.

As defined by federal guidance and Section 33-15-25-01 of the North Dakota Air Pollution Control Rules, [22] a source "contributes to visibility impairment" if the 98th percentile of any year's modeling results meets or exceeds the threshold of five-tenths of a deciview (dV) at a Federally protected Class I area receptor. The pre-BART evaluation of this criterion conducted by the North Dakota Department of Health identified Coal Creek Station as a BART eligible source[23] that does cause or contribute to visibility impairment at the four North Dakota Class I areas. In addition to establishing whether or not a source contributes to impairment on the 98th percentile, the severity of the visibility impairment contribution or reasonably attributed visibility impairment can be gauged by assessing the number of days on which a source exceeds 0.5 dV. Finally, the determination of reasonable progress along the predicted glide path can be assessed using the 90th percentile prediction.

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[20] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Rules and Regulations p. 39106.

[21] *Protocol for BART-Related Visibility Modeling Analyses in North Dakota*, Final Version, November, 2005.

[22] Chapter 33-15-25 is a new rule on public notice through May 15, 2006.

[23] Subject to BART notification from NDDH is included in Appendix D.

7.2 Predicting 24-Hour Maximum Emission Rates

Pursuant to verbal guidance from NDDH staff and to be consistent with use of the highest daily emissions for pre-BART visibility impacts, the post-BART emissions to be used for the visibility impacts analysis should reflect a maximum 24-hour average basis.

The highest daily emissions for PM/PM_{10} were maintained from pre-BART modeling. The highest predicted NOx emission rate is based on pre-BART average emission rates and highest day variability. The pre-BART NOx modeled emission rate (0.29 lb/MMBtu) was approximately 30% higher than the average NOx emissions from historical emission inventories (0.22 lb/MMBtu). As illustrated in , the highest expected emission rate for the proposed BART control of an additional level of SOFA was assessed by adding a 20% variability factor to the design emission rate of 0.15 lb/MMBtu.

Table 7-1 NOx Predicted 24-hour Maximum Emission Rates

Control Strategy	Design Rate (lb/MMBtu)	30-day Rolling Emission Rate (lb/MMBtu)	24-hour Max. Emission Rate		Basis[24]
			Unit 1 (lb/hr)	Units 1 & 2 (lb/hr)	
Pre-BART Baseline	--	--	1,772.3	3,594.7	Actual emissions data from 2000 – 2002. Represents the highest NOx emission rate per calendar day.
Foster Wheeler SOFA/LNB Option 2	0.17	0.19	1,227.6	2,456.5	Design emission rate with 10% variability for 30-day rolling and 20% variability for 24-hr max.
Foster Wheeler SOFA/LNB Option 1	0.15	0.17	1,083.1	2,167.5	
SNCR	0.11	0.12	776.2	1,553.4	
SCR with Reheat	0.04	0.05	310.5	621.4	
LTO	0.02	0.02	155.2	310.7	

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[24] Emission rates for Unit 1 calculated using 6,015 MMBtu/hr rating. Unit 1 & 2 emissions use 12,037 MMBtu/hr combined rating.

SO_2 emission rates are highly dependant on coal sulfur content. Accordingly, an analysis of past actual and future predicted sulfur content is used to determine expected SO_2 emission rates. Figure 7-1 indicates that 2.6 lb/MMBtu is the maximum expected SO_2 emission rate with respect to 30- day block averages.

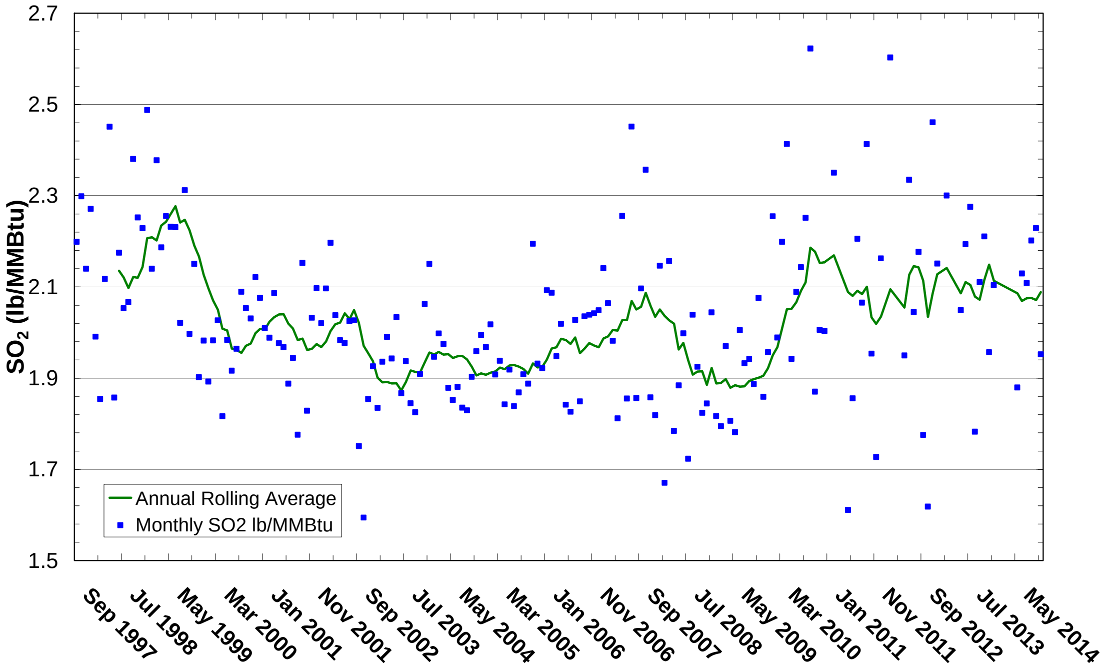

Figure 7-1 Past Actual and Future Predicted Monthly lb SO_2/MMBtu. Coal Creek sampling data is used to determine the 30-day block monthly average sulfur content from 1997 through 2006 and the Falkirk Mine Plan provides monthly predicting for future sulfur content from 2006 through 2014.

A statistical comparison of 30-day block and 30-day rolling past actual data (Appendix C) demonstrates that 14% variability should be used to determine a rolling emission rate based on a block average. This information, in combination with the design emission rates for both a new scrubber and scrubber modifications[25] is used to establish the 30-day rolling emission rates.

Since the SO_2 BART solution will be some modification of the existing scrubber, it is logical to utilize existing operational and maintenance parameters to predict the highest daily emissions. The scrubber is currently cleaned once every 7 days for a period of 4 hours during which time emissions are approximately 1.0 lb/MMBtu. Figure 7-2 illustrates the post-BART operational pattern that will be required to maintain 30-day rolling average emissions of 0.15 lb/MMBtu under current scrubber cleaning conditions. This indicates that under normal operation, the scrubber will be performing below the proposed limit of 0.15 lb/MMBtu.

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[25] SO_2 modeling was performed for scrubber replacement and scrubber modifications only because scrubber replacement is the only evaluated SO_2 control which will provide lower emissions than the proposed BART control.

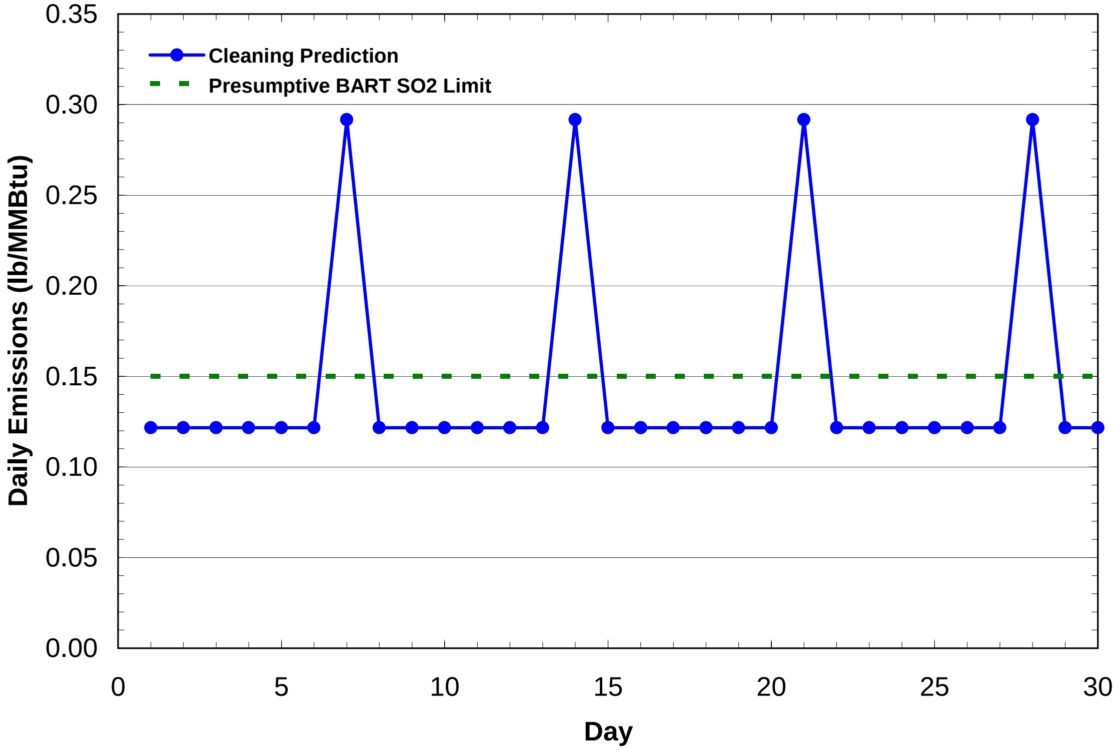

Figure 7-2 Maximum SO_2 Emission Prediction Emissions required to maintain 0.15lb/MMBtu on a 30 day rolling average based on current scrubber maintenance procedures.

A 70% variability was added to the 30-day rolling emission rate for a new scrubber to predict the 24-hour maximum emission rate. This is an engineering estimate based on a comparison of Coal Creek's pre-BART actual annual emissions and 24-hour maximum emissions. Table 7-2 presents a summary of SO_2 emission rates.

Table 7-2 SO_2 Predicted 24-hour Maximum Emission Rates

Control Strategy	Design Reduction	30-day Rolling Emission Rate (lb/MMBtu)	24-hour Maximum Emission Rate		Basis
			Unit 1 (lb/hr)	Unit 1 & 2 (lb/hr)	
Pre-BART Baseline	--	--	5,733.5	10,702.8	Actual emissions data from 2000 – 2002. Represents the highest SO_2 emission rate per calendar day.
Scrubber Modification	95.1%[26]	0.06	1,756.4	3,514.8	Resign reduction at 2.6 lb/MMBtu block 30-day sulfur content + 14% variability for 30-day rolling. Individual methods for determining 24-hour max emissions are described above.
Scrubber Replacement	98.0%	0.15	610.8	1,222.4	

Table 7-3 describes the pre and post-BART model input parameters. Other stack parameters such as exit temperature, height, elevation and diameter were not changed and can be found in the protocol[21].

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[26] Average percent reduction for evaluated scrubber modifications.

Table 7-3 Visibility Modeling Parameters

Scenario	Description			Emission Rate Input								
				Stack Velocity	PM$_{10}$		PM$_{2.5}$ (fine)	PM (coarse)	SO$_2$		NOx	
	SO$_2$	NOx	Units	m/s (ft/s)	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr
0	Pre-BART Protocol		1	25.9 (85)	NA - base	249.2	101.9	147.3	NA - base	5733.5	NA - base	1772.3
			1& 2	25.9 (85)	NA - base	465.3	190.3	275.0	NA - base	10702.8	NA - base	3594.7
1	Scrubber Modifications	SOFA/LNB #2	1	16.8 (55)	0%	249.2	101.9	147.3	69%	1756.4	31%	1227.6
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	67%	3514.8	32%	2456.5
2	Scrubber Modifications	SOFA/LNB #1	1	16.8 (55)	0%	249.2	101.9	147.3	69%	1756.4	39%	1083.1
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	67%	3514.8	40%	2167.5
3	Scrubber Modifications	SNCR	1	16.8 (55)	0%	249.2	101.9	147.3	69%	1756.4	56%	776.2
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	67%	3514.8	57%	1553.4
4	Scrubber Modifications	SCR	1	16.8 (55)	0%	249.2	101.9	147.3	69%	1756.4	82%	310.5
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	67%	3514.8	83%	621.4
5	Scrubber Modifications	LTO	1	16.8 (55)	0%	249.2	101.9	147.3	69%	1756.4	91%	155.2
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	67%	3514.8	91%	310.7
6	New Scrubber	SOFA/LNB #2	1	16.8 (55)	0%	249.2	101.9	147.3	89%	610.8	31%	1227.6
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	89%	1222.4	32%	2456.5
7	New Scrubber	SOFA/LNB #1	1	16.8 (55)	0%	249.2	101.9	147.3	89%	610.8	39%	1083.1
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	89%	1222.4	40%	2167.5
8	New Scrubber	SNCR	1	16.8 (55)	0%	249.2	101.9	147.3	89%	610.8	56%	776.2
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	89%	1222.4	57%	1553.4
9	New Scrubber	SCR	1	16.8 (55)	0%	249.2	101.9	147.3	89%	610.8	82%	310.5
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	89%	1222.4	83%	621.4
10	New Scrubber	LTO	1	16.8 (55)	0%	249.2	101.9	147.3	89%	610.8	91%	155.2
			1& 2	16.8 (55)	0%	465.3	190.3	275.0	89%	1222.4	91%	310.7

7.3 Modeled Results

Visibility impairment was modeled using the meteorological data for the years 2000, 2001 and 2002 for the predicted post-BART emission scenario. To illustrate the individual in cumulative visibility impacts, Unit 1 alone and Units 1 and 2 in combination were modeled. As indicated by the results, reaction chemistry caused by limited background atmospheric ammonia results in a Δ-dV reduction for Units 1 and 2 together that is less than double the dV reduction for Unit 1 alone. Results for the 90th, 98th and number of days above 0.5 dV at Lostwood Wilderness Area (WA) and Theodore Roosevelt National Park (TRNP) North, South and Elkhorn Ranch units are included in

Table 7-4 through Table 7-6. Additionally, Figure 7-3 illustrates scenarios 1 through 15 on a $/dV basis. The figure focuses on year 2002 modeling results because it is the year that showed the most severe pre-BART visibility impairment.

Table 7-4 Year 2000 Modeling Results

					Visibility Impairment											
	Description				TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
Scenario	SO_2	NOx	Units	Average Improvement [1]	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
0	Pre-BART Protocol		1	--	24	0.299	1.229	21	0.318	0.941	18	0.212	0.777	37	0.503	1.183
			1& 2	--	41	0.553	2.176	41	0.586	1.836	35	0.401	1.391	58	0.945	2.157
1	Scrubber Modifications	SOFA/LNB #2	1	59%	7	0.125	0.494	6	0.124	0.446	2	0.088	0.314	7	0.215	0.499
			1& 2	78%	7	0.125	0.494	6	0.124	0.446	2	0.088	0.314	7	0.215	0.499
2	Scrubber Modifications	SOFA/LNB #1	1	61%	7	0.119	0.467	6	0.118	0.416	2	0.082	0.300	6	0.207	0.469
			1& 2	79%	7	0.119	0.467	6	0.118	0.416	2	0.082	0.300	6	0.207	0.469
3	Scrubber Modifications	SNCR	1	65%	6	0.106	0.410	6	0.105	0.352	2	0.072	0.270	4	0.180	0.417
			1& 2	81%	6	0.106	0.410	6	0.105	0.352	2	0.072	0.270	4	0.180	0.417
4	Scrubber Modifications	SCR	1	71%	6	0.081	0.338	4	0.097	0.255	2	0.067	0.224	3	0.139	0.371
			1& 2	84%	6	0.081	0.338	4	0.097	0.255	2	0.067	0.224	3	0.139	0.371
5	Scrubber Modifications	LoTOx	1	73%	5	0.073	0.296	4	0.095	0.229	2	0.057	0.220	3	0.128	0.341
			1& 2	86%	5	0.073	0.296	4	0.095	0.229	2	0.057	0.220	3	0.128	0.341
6	New Scrubber	SOFA/LNB #2	1	75%	5	0.081	0.328	3	0.072	0.326	2	0.053	0.186	1	0.134	0.336
			1& 2	86%	5	0.081	0.328	3	0.072	0.326	2	0.053	0.186	1	0.134	0.336
7	New Scrubber	SOFA/LNB #1	1	77%	4	0.076	0.301	2	0.066	0.296	2	0.049	0.174	1	0.124	0.306
			1& 2	87%	4	0.076	0.301	2	0.066	0.296	2	0.049	0.174	1	0.124	0.306
8	New Scrubber	SNCR	1	80%	2	0.062	0.243	1	0.055	0.233	1	0.044	0.147	1	0.106	0.246
			1& 2	89%	2	0.062	0.243	1	0.055	0.233	1	0.044	0.147	1	0.106	0.246
9	New Scrubber	SCR	1	86%	0	0.041	0.157	0	0.042	0.138	0	0.029	0.103	1	0.069	0.166
			1& 2	93%	0	0.041	0.157	0	0.042	0.138	0	0.029	0.103	1	0.069	0.166
10	New Scrubber	LoTOx	1	88%	0	0.034	0.141	0	0.038	0.105	0	0.026	0.086	0	0.060	0.145
			1& 2	94%	0	0.034	0.141	0	0.038	0.105	0	0.026	0.086	0	0.060	0.145

[1] Average improvement represents the 90^{th} percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.

Table 7-5 Year 2001 Modeling Results

Scenario	Description			Average Improv-ement [1]	Visibility Impairment											
					TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
	SO_2	NOx	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
0	Pre-BART Protocol		1	--	21	0.251	1.209	27	0.372	1.154	16	0.192	1.056	40	0.503	1.183
			1& 2	--	34	0.466	2.181	46	0.694	2.094	27	0.365	1.949	56	0.945	2.157
1	Scrubber Modifications	SOFA/LNB #2	1	58%	8	0.116	0.509	9	0.142	0.547	8	0.076	0.505	21	0.215	0.499
			1& 2	56%	19	0.230	0.986	25	0.282	1.069	14	0.151	0.984	34	0.215	0.499
2	Scrubber Modifications	SOFA/LNB #1	1	60%	7	0.108	0.482	8	0.136	0.512	6	0.076	0.473	18	0.207	0.469
			1& 2	58%	19	0.214	0.936	24	0.270	1.002	13	0.151	0.923	33	0.207	0.469
3	Scrubber Modifications	SNCR	1	64%	6	0.096	0.437	6	0.127	0.436	4	0.069	0.405	15	0.180	0.417
			1& 2	62%	18	0.194	0.854	20	0.253	0.858	12	0.137	0.793	31	0.180	0.417
4	Scrubber Modifications	SCR	1	70%	2	0.075	0.373	5	0.106	0.353	2	0.058	0.319	13	0.139	0.371
			1& 2	69%	16	0.150	0.730	16	0.212	0.693	11	0.114	0.625	28	0.139	0.371
5	Scrubber Modifications	LoTOx	1	72%	2	0.070	0.356	5	0.101	0.333	1	0.056	0.283	13	0.128	0.341
			1& 2	70%	13	0.139	0.700	15	0.202	0.656	10	0.110	0.557	25	0.128	0.341
6	New Scrubber	SOFA/LNB #2	1	76%	2	0.062	0.340	3	0.079	0.412	1	0.039	0.309	12	0.134	0.336
			1& 2	75%	15	0.123	0.668	13	0.156	0.811	9	0.077	0.602	23	0.134	0.336
7	New Scrubber	SOFA/LNB #1	1	77%	1	0.062	0.310	2	0.075	0.376	1	0.038	0.294	9	0.124	0.306
			1& 2	76%	11	0.123	0.609	12	0.149	0.741	8	0.076	0.573	23	0.124	0.306
8	New Scrubber	SNCR	1	81%	1	0.054	0.248	2	0.069	0.299	1	0.032	0.259	7	0.106	0.246
			1& 2	79%	6	0.108	0.484	9	0.136	0.592	8	0.064	0.509	18	0.106	0.246
9	New Scrubber	SCR	1	86%	0	0.037	0.170	1	0.048	0.184	0	0.027	0.157	5	0.069	0.166
			1& 2	85%	2	0.074	0.335	5	0.098	0.365	1	0.053	0.311	12	0.069	0.166
10	New Scrubber	LoTOx	1	88%	0	0.031	0.149	0	0.044	0.147	0	0.022	0.123	4	0.060	0.145
			1& 2	87%	1	0.062	0.294	5	0.087	0.290	1	0.044	0.242	10	0.060	0.145

[1] Average improvement represents the 90th percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.

Table 7-6 Year 2002 Modeling Results

	Description				**Visibility Impairment**											
					TRNP South Unit			**TRNP North Unit**			**TRNP Elkhorn Ranch**			**Lostwood WA**		
Scenario	**SO_2**	**NOx**	**Units**	**Average Improvement [1]**	**Days Above 0.5 Δ-dV**	**90th % Δ-dV**	**98th % Δ-dV**	**Days Above 0.5 Δ-dV**	**90th % Δ-dV**	**98th % Δ-dV**	**Days Above 0.5 Δ-dV**	**90th % Δ-dV**	**98th % Δ-dV**	**Days Above 0.5 Δ-dV**	**90th % Δ-dV**	**98th % Δ-dV**
0	Pre-BART Protocol		1	--	38	0.540	2.559	30	0.385	2.113	23	0.310	1.703	32	0.385	1.814
			1& 2	--	50	0.971	4.475	45	0.706	3.557	42	0.581	3.039	45	0.707	3.190
1	Scrubber Modifications	SOFA/LNB #2	1	57%	22	0.219	1.181	15	0.158	0.987	12	0.136	0.789	13	0.178	0.832
			1& 2	54%	32	0.433	2.218	26	0.313	1.880	18	0.269	1.524	26	0.350	1.601
2	Scrubber Modifications	SOFA/LNB #1	1	59%	20	0.207	1.140	15	0.151	0.918	12	0.129	0.746	13	0.165	0.783
			1& 2	56%	32	0.410	2.145	26	0.298	1.755	18	0.256	1.443	25	0.325	1.510
3	Scrubber Modifications	SNCR	1	64%	20	0.186	1.052	14	0.131	0.813	11	0.118	0.654	11	0.141	0.680
			1& 2	61%	30	0.371	1.991	24	0.260	1.536	17	0.234	1.271	23	0.279	1.318
4	Scrubber Modifications	SCR	1	70%	13	0.160	0.799	11	0.121	0.677	8	0.090	0.515	10	0.114	0.569
			1& 2	68%	25	0.316	1.537	17	0.239	1.290	14	0.180	1.006	23	0.224	1.105
5	Scrubber Modifications	LoTOx	1	72%	11	0.140	0.706	8	0.119	0.632	7	0.084	0.468	8	0.106	0.510
			1& 2	70%	23	0.281	1.364	17	0.235	1.206	14	0.167	0.917	17	0.207	0.992
6	New Scrubber	SOFA/LNB #2	1	74%	13	0.140	0.695	12	0.095	0.727	9	0.088	0.531	9	0.096	0.561
			1& 2	72%	29	0.278	1.344	19	0.188	1.382	17	0.176	1.033	21	0.193	1.088
7	New Scrubber	SOFA/LNB #1	1	76%	11	0.129	0.640	12	0.087	0.675	7	0.085	0.487	9	0.088	0.520
			1& 2	87%	11	0.129	0.640	12	0.087	0.675	7	0.085	0.487	9	0.088	0.520
8	New Scrubber	SNCR	1	80%	8	0.106	0.546	9	0.069	0.529	5	0.073	0.393	2	0.080	0.414
			1& 2	78%	23	0.210	1.057	16	0.137	1.029	11	0.145	0.772	13	0.158	0.812
9	New Scrubber	SCR	1	86%	3	0.070	0.406	2	0.049	0.325	3	0.047	0.250	1	0.059	0.261
			1& 2	85%	11	0.139	0.792	11	0.098	0.627	7	0.093	0.494	9	0.115	0.513
10	New Scrubber	LoTOx	1	26%	32	0.382	2.055	24	0.273	1.601	17	0.243	1.342	24	0.292	1.397
			1& 2	87%	8	0.123	0.651	8	0.092	0.536	7	0.075	0.401	4	0.096	0.444

[1] Average improvement represents the 90th percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.

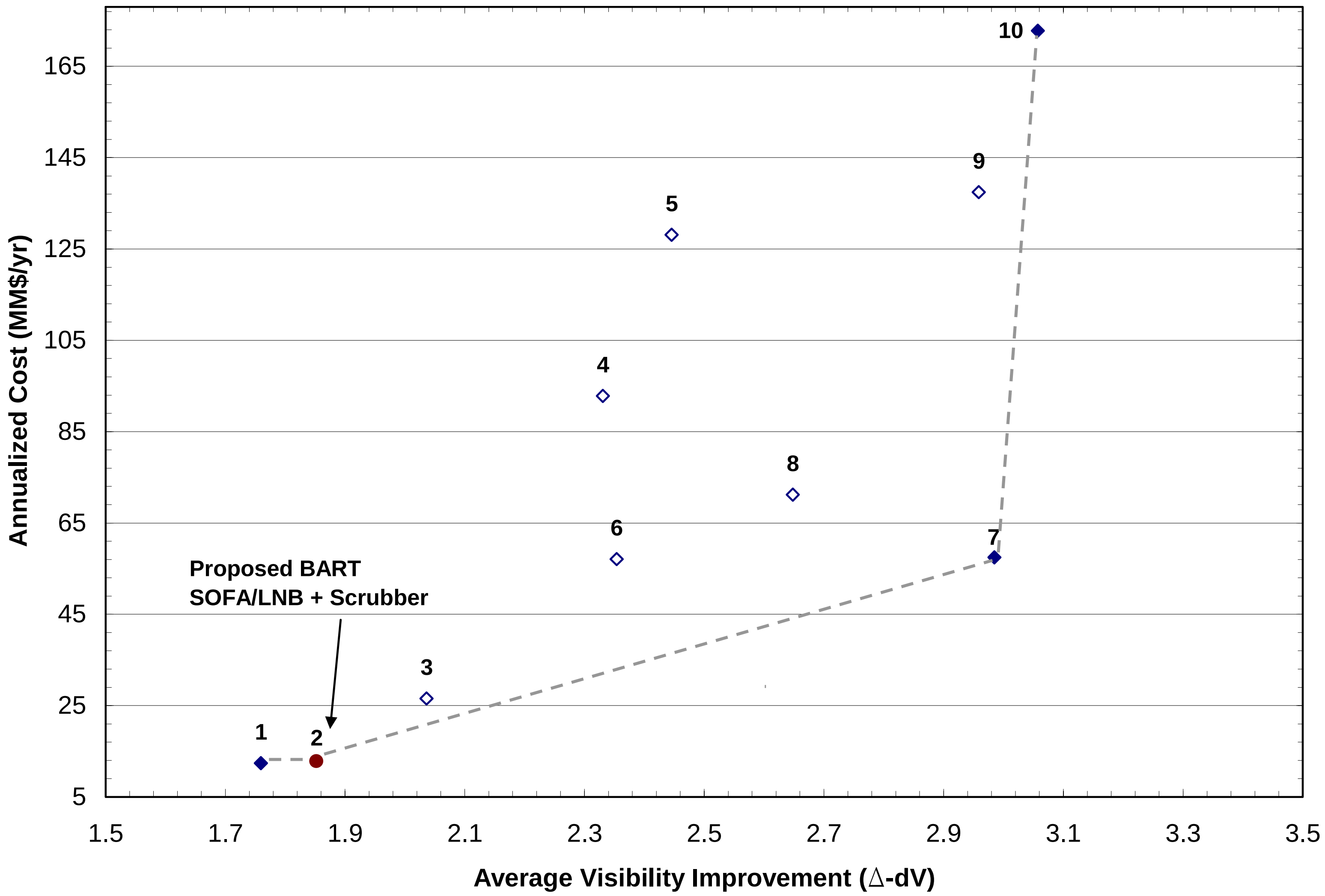

Figure 7-3 Dollar per Deciview Analysis. Scenarios 1 through 10 are plotted for the 98th percentile of 2002 based on the total annualized cost for installation and operation on both Units and the average visibility improvement for the 4 Class 1 areas. Dominant controls are presented as filled icons and inferior controls are represented as empty icons.

As illustrated by the dollar per deciview analysis in Figure 7-3, the proposed BART of scrubber modifications with an additional level of SOFA (Scenario 2) is support by the visibility modeling results. This graph also indicates that a change in NOx emission rate of 0.02 lb/MMBtu (comparison of Scenarios 1 and 2) only results in a change of about 0.1 Δ-dV on a 98th percentile comparison. As noted in Section 5.4.1, scrubber replacement (Scenarios 7 and 10) does not represent a feasible control option, therefore, from a visibility standpoint, Scenario 2 if the next best control.

7.4 Visibility Impacts of the Proposed BART

Scenario 2 represents a significant reduction in modeled visibility impairment in the four Class 1 Areas. As one example, on average, for 2002 98th percentile, the total visibility improvement for the two stations combined will be over 1.8 Δ-dV. Figure 7-4 illustrates the expected visibility improvement for the proposed BART of using current PM_{10} emissions in addition to meeting presumptive NOx and SO_2 limits as compared to the pre-BART baseline (Scenarios 0 and 2). The year 2002 results were used because the highest degree of impairment was demonstrated in that year.

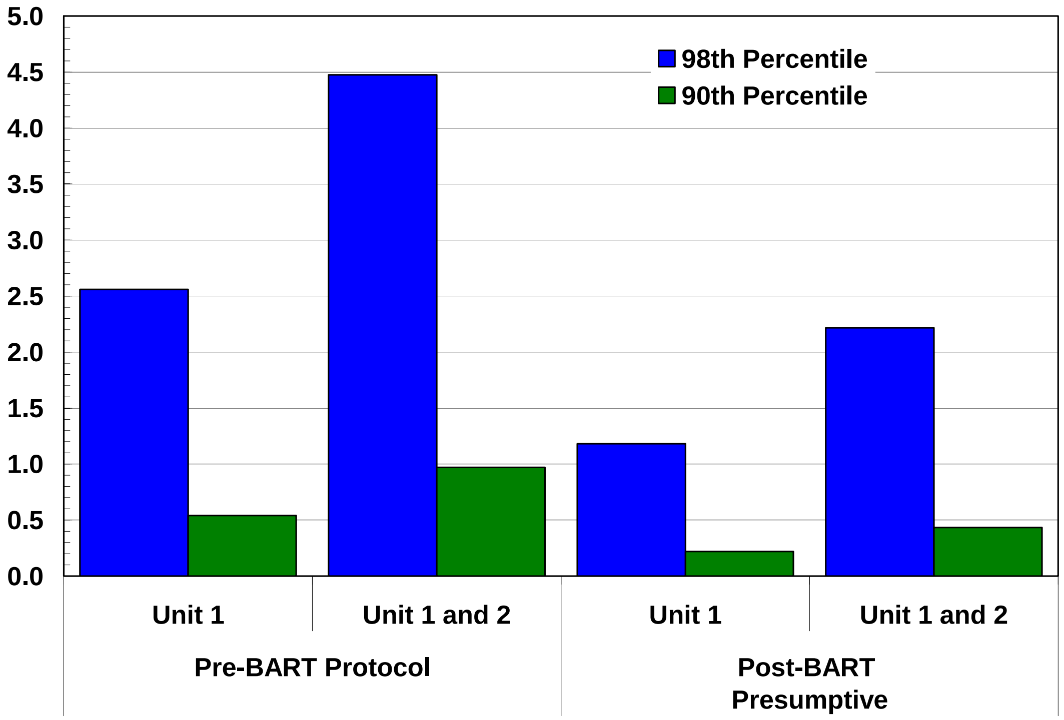

Figure 7-4 Visibility Improvement Predicted visibility improvement at post-BART presumptive emissions illustrated on a 90th and 98th percentile comparison to post-BART emissions at TRNP's South Unit.

8.0 Summary of Proposed BART

Based on the evaluations presented above, Scenario 2 is considered BART for Coal Creek Station. With respect to particulate controls, GRE will maintain the current PM performance standard of 0.1 lb/MMBtu for the existing ESP. The PM analysis presented in Section 3.0 confirms that additional PM controls are not economically justified and would provide negligible deciview reductions in Class 1 areas.

For NOx controls, GRE establishes LNB with and additional level of SOFA as described in Section 4.0. SNCR, SCR and LTO are ruled out on cost per ton bases along with operational, energy and environmental impacts. The LNB/SOFA combination will provide 20% to 30% reduction on a 30-day and annual basis at an emission rate of 0.17 lb/MMBtu.

For SO_2, GRE proposes to modify the existing scrubbers. The proposed emission limit of 0.15 lb/MMBtu on a 30-day rolling average is based on historical and future predicted operation and fuel sulfur content variability. A final decision on the scrubber modifications required to achieve the presumptive BART emission rate of 0.15 lb/MMBtu will be made pursuant to the evaluation of coal drying as applied to Coal Creek Unit 1.

In combination, the proposed BART controls will provide an average visibility improvement of over 1.8 Δ-dV compared to the pre-BART baseline that will significantly contribute to the state's effort in meeting its reasonable progress goals under the Regional Haze Rule.

Appendices

Appendix A. Economic Evaluations

Appendix B. Cost Threshold Documentation

Appendix C. Coal Sulfur Content Variability

Appendix D. Visibility Modeling Output Files

Appendix E. Wet Stack Study

Appendix F. Foster Wheeler SOFA/LNB Analysis

Appendix G. SCR catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals

Appendix H. EPRI SO_2 Control Support Documentation

Appendix I. URS SO_2 Control Evaluation

Appendix J. Revised Foster Wheeler Proposal

Appendix K. Coal Drying Study

Appendix A

Economic Evaluations

Revised Pages September 2007

Great River Energy Coal Creek
BART Emission Control Cost Analysis

Table A-1: Cost Summary
Revised September 2007

PM/PM_{10} Control Cost Summary

Baseline 0.030 lb/MMBtu

Case	Control Technology	Controlled Emissions lb/MMBtu	Control Eff %	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	PM Polishing WESP	**0.015**	**50%**	**387.6**	**1**	**385.9**	**$7,232,000**	**$1,917,697**	**$4,969**	**D**	**NA-Base**	**A-4**
2	PM Baghouse	**0.015**	**50%**	**387.6**	**--**	**385.9**	**$37,370,845**	**$7,665,813**	**$19,864**	**I**	**NA**	**A-5**
3	Dry ElectroStatic Precipitator (ESP)	**0.015**	**50%**	**387.6**	**--**	**385.9**	**$38,510,903**	**$10,055,112**	**$26,056**	**I**	**NA**	**A-6**

SO_2 Control Cost Summary

Baseline 2.12 lb/MMBtu

Case	Control Technology	Designed Emissions lb/MMBtu	Control Eff %	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Scrubber Replacement	**0.106**	**95%**	**2735.7**	**3**	**14553.4**	**$204.72**	**$30.76**	**$2,114**	**D**	**$33,498**	**A-7**
2	Scrubber Mod. + Coal Dryer	**0.128**	**94%**	**3310.2**	**2**	**13978.9**	**$76.22**	**$11.52**	**$824**	**D**	**$281**	**A-8**
3	Spray Dry Baghouse	**0.212**	**90%**	**5471.4**	**--**	**11817.7**	**$181.18**	**$29.22**	**$2,472**	**I**	**NA**	**A-9**
4	Existing Scrubber + Coal Dryer	**0.358**	**83%**	**9263.1**	**1**	**8026.0**	**$71.20**	**$9.84**	**$1,226**	**D**	**NA-Base**	**A-10**
5	DSI Baghouse	**0.635**	**70%**	**16414.3**	**--**	**874.9**	**$48.75**	**$12.52**	**$14,313**	**I**	**NA**	**A-11**

NO_x Control Cost Summary

Baseline 0.22 lb/MMBtu

Case	Control Technology	Designed Emissions lb/MMBtu	Control Eff %	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Low Temperature Oxidation (LoTOx)	**0.022**	**90%**	**556**	**3**	**5001.5**	**$44.33**	**$58.07**	**$11,610**	**D**	**$17,283**	**A-12**
2	Selective Catalytic Reduction (SCR) w/Reheat	**0.043**	**80%**	**1111**	**--**	**4445.8**	**$84.11**	**$56.15**	**$12,631**	**I**	**NA**	**A-13 and A-14**
3	Selective Non-Catalytic Reduction (SNCR)	**0.108**	**50%**	**2779**	**--**	**2778.6**	**$19.91**	**$22.90**	**$8,240**	**I**	**NA**	**A-15**
4	SOFA/LNB #2	**0.150**	**30%**	**3877**	**2**	**1680.1**	**$5.26**	**$0.66**	**$395**	**D**	**$629**	**A-16**
5	SOFA/LNB #1	**0.170**	**21%**	**4394**	**1**	**1163.2**	**$2.63**	**$0.34**	**$291**	**D**	**NA-Base**	**A-17**

[1] Control Technology Classification- D=Dominant, I=Inferior. Only dominant costs are used to calculate incremental cost effectiveness.

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Equipment Information: GRE Coal Creek Unit I			6015	MMBtu/hr	590 MW		**Baseline Emis**	
Year	2004	2003	2002	2001	2000	03 -'04 Avg	**Avg Units I & II**	
Hours of Operation	8,480	8,574	7,851	8,546	8,610	8,527	**8,586**	
Fuels Used:								
Quanity of Lignite - Tons	3,927,641	3,966,578	3,602,970	3,979,416	3,920,779	3,947,110	**3,983,234**	
Percent Ash (Coal Only) Average	10.77	10.63	10.93	11.30	11.28	10.70	**10.74**	
Percent Sulfur in Coal Average	0.61	0.61	0.60	0.61	0.62	0.61	**0.61**	
BTU per Unit of Coal Average	6,297	6,261	6,203	6,196	6,201	6,279	**6,257**	
% Sodium in Lignite Ash Average	2.39	2.63	2.66	2.17	2.27	2.51	**2.57**	
Quanity of No. 6 Fuel Oil Gal		76,159	258,263	125,059	87,694	76,159		
Quanity of No. 2 Fuel Oil Gal	190,025	18,593	N/A	N/A		104,309	**189,654**	
Percent Sulfur in Fuel Oil Average	0.04	0.92	1.39	1.32	1.63	0.48	**0.04**	
BTU per Unit of Fuel Oil Average	140,141	151,509	154,030	153,557	152,035	145,825	**147,281**	
Quanity of Used Oil/Solvent on Coal Gal	49,155	21,637	17,327	723	904	35,396	**35,396**	
Percent Sulfur in Used Oil Average	0.47	0.38	0.23	0.38	0.61	0	**0.42**	
BTU per Unit of Used Oil Average	15,893	19,156	19,598	19,350	19,192	17,524	**17,524**	
Heat Input	4.947E+07	4.967E+07	4.470E+07	4.931E+07	4.862E+07	4.957E+07	**4.984E+07**	
MMBtu/hr	5,833	5,793	5,694	5,770	5,647	5,813	**5,805**	
% of Capacity	97.0%	96.3%	94.7%	95.9%	93.9%	96.6%	**96.5%**	
SO2 lb/MMbtu	0.636	0.556	0.533	0.593	0.589	0.596	**0.558**	
PM lb/MMBtu	0.005	0.003	0.058	0.020	0.026	0.004	**0.030**	
NOx lb/MMBtu	0.217	0.204	0.210	0.212	0.214	0.211	**0.215**	
Total Stack Emissions:							**T/yr (1)**	**lb/hr**
Particulate Emitted Tons Per Year:	116.3	72.6	1,305.1	491.6	632.9	94.4	**750.2**	**181.1**
PM10 Emitted Tons Per Year:	78.7	48.6	874.5	329.4	424.1	63.7	**69.5**	**16.8**
PM2.5 Emitted Tons Per Year:	32.2						**32.2**	**7.8**
SO2 Emitted Tons Per Year:	15,741.6	13,816.9	11,910.0	14,630.3	14,331.7	14,779.3	**13,905.9**	**4027.3**
NOx Emitted Tons Per Year:	5,370.1	5,071.8	4,689.6	5,234.6	5,209.7	5,221.0	**5,363.5**	**1294.5**
CO Emitted Tons Per Year:	982.4	991.9	901.4	995.2	980.4	987.1	**996.1**	**240.4**
TOC Emitted Tons Per Year:	78.6	79.4	72.2	79.6	78.4	79.0	**79.7**	**19.2**
Stack Emissions --- Lignite:								
Particulate Rate from Test lb/MMBtu	0.005	0.003	0.058	0.020	0.026	0.004	**0.004**	
SO2 CEM Annual Average lb/MMBtu	0.609	0.538	0.508	0.561	0.563	0.573	**0.543**	
NOX CEM Annual Average lb/MMBtu	0.217	0.204	0.210	0.212	0.214	0.211	**0.215**	

(1) Emission rate for 1 unit

SO2 Scrubber Control Eff	**93.7%**
Percent Bypass	**27%**
Overall Control Efficiency	**68.4%**
Uncontrolled SO2 lb/hr	**12,745**

Equipment Information: GRE Coal Creek Unit II			6022	MMBtu/hr		
Year	2004	2003	2002	2001	2000	02 -'03 Avg
Hours of Operation	7,963	8,621	8,669	8,028	8,366	8,645
Fuels Used:						
Quanity of Lignite - Tons	3,650,697	4,014,476	4,024,241	3,642,488	3,866,225	4,019,358
Percent Ash (Coal Only) Average	10.80	10.63	10.95	11.28	11.26	10.79
Percent Sulfur in Coal Average	0.60	0.61	0.61	0.61	0.62	0.61
BTU per Unit of Coal Average	6,293	6,260	6,209	6,199	6,201	6,235
% Sodium in Lignite Ash Average	2.38	2.63	2.63	2.18	2.27	2.63
Quanity of No. 6 Fuel Oil Gal		26,179	76,391	139,020	216,520	51,285
Quanity of No. 2 Fuel Oil Gal	189,282	52,291	N/A	N/A		N/A
Percent Sulfur in Fuel Oil Average	0.04	0.42	1.58	1.32	1.62	1.00
BTU per Unit of Fuel Oil Average	140,141	143,194	154,279	153,163	153,839	148,736
Quanity of Used Oil/Solvent on Coal Gal	N/A	N/A	N/A	N/A	N/A	N/A
Percent Sulfur in Used Oil Average	N/A	N/A	N/A	N/A	N/A	N/A
BTU per Unit of Used Oil Average	N/A	N/A	N/A	N/A	N/A	N/A
Heat Input	4.595E+07	5.026E+07	4.997E+07	4.516E+07	4.795E+07	5.012E+07
MMBtu/hr	5,771	5,830	5,765	5,626	5,732	5,797
% of Capacity	95.9%	96.9%	95.8%	93.5%	95.3%	96.4%
SO2 lb/MMbtu	0.499	0.539	0.501	0.517	0.535	0.520
PM lb/MMBtu	0.002	0.003	0.034	0.019	0.023	0.019
NOx lb/MMBtu	0.236	0.221	0.218	0.230	0.222	0.220
Total Stack Emissions:						
Particulate Emitted Tons Per Year:	80.4	120.9	1,267.5	649.1	829.1	694.2
PM10 Emitted Tons Per Year:	54.5	81.0	849.2	434.9	555.6	465.1
PM2.5 Emitted Tons Per Year:	22.3					
SO2 Emitted Tons Per Year:	11,468.8	13,547.3	12,517.7	11,682.5	12,816.5	13,032.5
NOx Emitted Tons Per Year:	5,429.3	5,557.5	5,454.4	5,190.1	5,323.0	5,506.0
CO Emitted Tons Per Year:	913.1	1,003.8	1,006.3	911.0	967.1	1,005.0
TOC Emitted Tons Per Year:	73.1	80.3	80.5	72.9	77.4	80.4
Stack Emissions --- Lignite:						
Particulate Rate from Test lb/MMBtu	0.004	0.005	0.051	0.029	0.035	0.028
SO2 CEM Annual Average lb/MMBtu	0.498	0.533	0.494	0.505	0.531	0.514
NOX CEM Annual Average lb/MMBtu	0.236	0.221	0.218	0.230	0.222	0.220

Adjust Particulate Matter Emissions
Method 5 Average Results
2000 - 2003
0.030 lb PM/MMBtu

Notes
Fuel Oil Use Avg '04 No 2 FO
PM/PM10 Avg Unit 1 '03, '04 & Unit II '03
PM lb/MMBtu Avg Unit 1 '03, '04 & Unit II '03, '04

Uncontrolled PM Emission Rate Using AP-42 - For SW Disposal Rates

	Total	Filterable	Condensable
T/yr	214,719	213,950	769
lb/Hr	50,016	49,837	179

Filterable PM Emission Factor	107.4	lb/ton coal
Condensable PM Emission Factor	0.031	lb/MMBtu

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit: Unit 1 or 2 **Study Year** 2005
Emission Unit Number NA
Stack/Vent Number NA

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37	$/hr	26.25	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.051	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Natural Gas	6.85	$/kscf		2005	Average natural gas spot price July 04 - June 05, Henry La Hub.,	WTRG Economics, WWW.wtrg.com/daily/small/ngspot.gig
Water	0.31	$/kgal	0.79	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.27	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.31	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.64	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.15	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal	5.00	$/ton		2005	GRE D Stockdill 2/9/2006	GRE landfill cost for ash
Hazardous Waste Disposal	273.18	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.55	$/ton-mi	0.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
Ash Sales	36.00	$/ton	5.00	2006	GRE D Stockdill 4/27/2007	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	2005	GRE per Diane Stockdill 12/6/05 email	
Caustic	305.21	$/ton		2005	GRE per Diane Stockdill 12/6/05 email	
Urea	405	$/ton		2005	Hawkins Chemical	50% solution of urea in water, includes delivery
Soda Ash		$/ton				
Oxygen	15.00	kscf	15.00	2005	Get cost from Air Prod Website	
EPA Urea	179.1	$/ton				
Ammonia	0.92	$/lb			GRE per Diane Stockdill	
Nahcolite	233.52	$/ton	195.57	1999	Integrated Air Pollution Control System Program Version 5a, EPA May 1999	
Catalyst & Replacement Parts						
SCR Catalyst	500	$/ft^3			Not used, get vendor quote if needed	
CO Catalyst	650	$/ft^3			Not used, get vendor quote if needed	
Catalyst #3						
Catalyst #4						
Catalyst #5						
Filter Bags	160.00	$/bag	33.71	2002	GRE cost per Steve Smokey	
Tower Packing	100	$/ft^3				
Replacement Parts						
Replacement Parts						
Replacement Parts						
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%
Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal						
Operating Information						
Annual Op. Hrs	8,586	Hours			2002 - 2004 Coal Creek Emissions Inventory	
Utilization Rate	100.0%				GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	yrs				Engineering Estimate
Coal Ash	10.74	wt % ash			2003-2004 Coal Creek Emissions Inventory	
Coal Moisture	37.30	% Coal Moisture Content				
Coal Sulfur	0.73	% Coal Sulfur Content			2003-2004 Coal Creek Emissions Inventory	
Coal Heating Value	6,257	Btu/lb of coal			2003-2004 Coal Creek Emissions Inventory	
Design Capacity	6,019	MMBtu/hr				
ID Fan Flow Rates	No Coal Drying	Coal Drying				
Standardized Flow Rate	965,316	866,294	scfm @ 32º F			
Temperature	330	330	Deg F		GRE per G. Riveland 4/5/06 email	
Moisture Content	15.3%	13.3%			GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,488,000	2,234,300	acfm		GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,550,000	1,391,000	scfm @ 330º F		GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,312,850	1,205,997	dscfm @ 330º F			
	Max Emis	**Baseline Emiss**				
Pollutant	**Lb/Hr**	**lb/MMBtu**				
PM10	180.2	0.030			PM10 99.5% of PM per ND Dept of Health Guidelines (Per Stanton EI)	
Total Particulates	181.1	0.030			2000 - 2002 Coal Creek Emissions Inventory Average Method 5 PM lb/MMBtu and most recent hourly average duty (MMBtu	
Nitrous Oxides (NOx)	1,294	0.215			2002 - 2004 Coal Creek Emissions Inventory	
Sulfur Dioxide (SO_2)	4,027	0.669			2002 - 2004 Coal Creek Emissions Inventory	

Enter this data for each unit
Enter data for this study (applies to all units)

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-4: PM Control - Polishing Wet ESP

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

Chemical Engineering Chemical Plant Cost Index	
1997	386.5
2005	465
Inflation Adj	1.20

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs						1997		
Purchased Equipment (A)						2005	5,408,000	2,782,609
Purchased Equipment Total (B)	15%	of control device cost (A)						**3,200,000**
Installation - Standard Costs	69%	of purchased equip cost (B)						2,208,000
Installation - Site Specific Costs								NA
Installation Total								2,208,000
Total Direct Capital Cost, DC								5,408,000
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)						1,824,000
Total Capital Investment (TCI) = DC + IC								**7,232,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						832,575
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,085,122
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**1,917,697**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost (6) $/Ton Rem**
PM10	180.2	773.5		0.015	lb/MMBtu	387.6	385.9	4,969
Total Particulates	181.1	777.4		0.015	lb/MMBtu	387.6	389.8	4,920
Nitrous Oxides (NOx)	1,294.5	5,557.3				5557.3	-	NA
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1. Total Direct Capital Cost per GRE cost estimate (CCS BART Evaluation.xls). Assumed no indirect capital cost included in estimate.
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3
3. ESP Maintenance costs Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
4. ESP Maintenance Materials Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
5. Existing PM emission rate per avg Method 5 test results of 0.030 lb/MMBtu, projected PM emission rate is at typical BACT limit 0f 0.015 lb/MMBtu per RBLC
6. Used an ESP SCA grid factor of 553 ft^2/1000 acfm per GRE, D. Stockdill.
7. Assumed WESP size is 20% of IAPCS model calculated size for electricity and spray water use.
8. Process, emissions and cost data listed above is for one unit.
9. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-4: PM Control - Polishing Wet ESP

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**2,782,609**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	278,261
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	139,130
Purchased Equipment Total (B)	15%		**3,200,000**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	128,000
Handling & erection	50%	of purchased equip cost (B)	1,600,000
Electrical	8%	of purchased equip cost (B)	256,000
Piping	3%	of purchased equip cost (B)	96,000
Insulation	2%	of purchased equip cost (B)	64,000
Painting	2%	of purchased equip cost (B)	64,000
Installation Subtotal Standard Expenses	69%		**2,208,000**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**2,208,000**
Total Direct Capital Cost, DC			**5,408,000**
Indirect Capital Costs			
Engineering, supervision	20%	of purchased equip cost (B)	640,000
Construction & field expenses	20%	of purchased equip cost (B)	640,000
Contractor fees	10%	of purchased equip cost (B)	320,000
Start-up	1%	of purchased equip cost (B)	32,000
Performance test	1%	of purchased equip cost (B)	32,000
Model Studies	2%	of purchased equip cost (B)	64,000
Contingencies	3%	of purchased equip cost (B)	96,000
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)	**1,824,000**
Total Capital Investment (TCI) = DC + IC			**7,232,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**7,232,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr	39,710
Supervisor	48%	% of Operator Costs.	19,061
Maintenance			
Maintenance Labor	275,173	ft2 grid area, 0.8 $/ft2 of grid area	227,018
Maintenance Materials	1	1% of purchased equipment cost	32,000
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 982 kW-hr, 8586 hr/yr, 100% utilization	426,953
NA	NA		-
Water	0.31	$/kgal, 498 gpm, 8586 hr/yr, 100% utilization	79,467
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization	8,367
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**832,575**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,673
Administration (2% total capital costs)	2%	of total capital costs (TCI)	144,640
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	72,320
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	72,320
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	605,169
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,085,122**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**1,917,697**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-4: PM Control - Polishing Wet ESP

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$\$/\mathrm{ft}^3$
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Laboı	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cosl	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower Baghouse & ESI	497,600		4.48			403.5	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.46
	Liq flow	Liquid SPGR	D P ft H2O	Efficiency	Hp	kW	
WESP Pump	2488 gpm	1.000	40	0.5		37.4	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
WESP H2O WW Disch	498 gpm	1.000	40	0.5		7.5	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
SCA Factor	553	ft^2/1000 acfm					
ESP Grid	275,173	ft^2	1.94E-03	kW/ft^2		533.8	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.48
Total						982.3	

Reagent Use & Other Operating Costs					
WESP Pump	497,600 acfm	5	gpm/kacfm	2,488 gpm	EPA Cost Cont Manual 6th ed Section 6 Chapter 3.4.1.9
WESP Water Makeup Rate/WW Discl		20%	of circulating water rate =	498 gpm	

Operating Cost Calculations

Annual hours of operation: 8,586

Utilization Rate: 100%

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	1.0	hr/8 hr shift	1,073	39,710	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	48%	of Operator Costs.			NA	19,061	% of Operator Costs.
	Maintenance							
	Maint Labor	275,173	ft2 grid area	0.825	$\$/\mathrm{ft}^2$ of grid area		227,018	ft2 grid area, 0.8 $/ft2 of grid area
	Maint Mtls	1	% of purchased equipment cost			NA	32,000	1% of purchased equipment cost
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	982.3	kW-hr	8,433,718	426,953	$/kwh, 982 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	497.6	gpm	256,344	79,467	$/kgal, 498 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.2	ton/hr	1,673	8,367	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	Mi	0	0	$/ton-mi, 0 Mi, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-5: PM Control -Baghouse

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

Chemical Engineering Chemical Plant Cost Index	
1997	386.5
2005	465
Inflation Adj	1.20

Year		
1997	24,679,400	DC from IAPCS program
2005	29,691,904	Inflation Adjusted DC

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			14,838,533
Purchased Equipment Total (B)	15%	of control device cost (A)	**17,064,313**
Installation - Standard Costs	74%	of purchased equip cost (B)	12,627,591
Installation - Site Specific Costs			NA
Installation Total			12,627,591
Total Direct Capital Cost, DC			29,691,904
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	7,678,941
Total Capital Investment (TCI) = DC + IC			**37,370,845**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	2,944,403
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	4,721,410
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,665,813**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost (5) $/Ton Rem**
PM10	180.2	773.5		0.015	lb/MMBtu	387.6	385.9	19,864
Total Particulates	181.1	777.4		0.015	lb/MMBtu	387.6	389.8	19,666
Nitrous Oxides (NOx)	1,294.5	5,557.3				5557.3	-	NA
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1. Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3. Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4. Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5. High control cost is due to the small additional decrease in emissions as compared to existing controls.
6. Existing PM emission rate per avg Method 5 test results of 0.030 lb/MMBtu, projected PM emission rate is at typical BACT limit 0f 0.015 lb/MMBtu per RBLC
7. Process, emissions and cost data listed above is for one unit.
8. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-5: PM Control -Baghouse

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**14,838,533**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,483,853
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	741,927
Purchased Equipment Total (B)	15%		**17,064,313**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	682,573
Handling & erection	50%	of purchased equip cost (B)	8,532,156
Electrical	8%	of purchased equip cost (B)	1,365,145
Piping	1%	of purchased equip cost (B)	170,643
Insulation	7%	of purchased equip cost (B)	1,194,502
Painting	4%	of purchased equip cost (B)	682,573
Installation Subtotal Standard Expenses	74%		**12,627,591**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**12,627,591**
Total Direct Capital Cost, DC			**29,691,904**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,706,431
Construction & field expenses	20%	of purchased equip cost (B)	3,412,863
Contractor fees	10%	of purchased equip cost (B)	1,706,431
Start-up	1%	of purchased equip cost (B)	170,643
Performance test	1%	of purchased equip cost (B)	170,643
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	511,929
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**7,678,941**
Total Capital Investment (TCI) = DC + IC			**37,370,845**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**37,334,469**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr	79,421
Supervisor	15%	15% of Operator Costs	11,913
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr	39,710
Maintenance Materials	100%	of maintenance labor costs	39,710
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization	1,957,404
NA	NA		-
NA	NA		-
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization	788,176
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization	8,367
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	33.71	$/bag, 795 bags, 8586 hr/yr, 100% utilization	19,702
Total Annual Direct Operating Costs			**2,944,403**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	102,452
Administration (2% total capital costs)	2%	of total capital costs (TCI)	747,417
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	373,708
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	373,708
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	3,124,123
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,721,410**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,665,813**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-5: PM Control -Baghouse

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	\$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	2	years	
CRF	0.5416		
Rep part cost per unit	33.711	\$/bag	
Amount Required	795		
Total Rep Parts Cost	28,140	Cost adjusted for freight & sales tax	
Installation Labor	8,236	10 min per bag, Labor + Overhead (68% = \$29.65/hr	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**36,376**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag
Annualized Cost	**19,702**		

Electrical Use	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	2,488,000	10			4503.3	
Baghouse Shaker	0.0	Gross fabric area ft^2			0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other						
Other						
Other						
Other						
Other						
Total					4503.3	

Baghouse Filter Cost						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	10,661	ft^2				
Cages	10 ft long	5 in dia	13.42	area/cage ft^2 795 Cages	11.036	\$/cage
Bags	1.69	\$/ft2 of fabric			22.68	\$/bag
Total					33.711	
Lime Use	0.00	lb/hr SO2	0.96	lb Lime/lb SO2	0.00	lb/hr Lime

Operating Cost Calculations **Annual hours of operation:** **8,586**
Utilization Rate: **100%**

	Item	Unit Cost \$	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	\$/Hr	2.0	hr/8 hr shift	2,147	79,421	\$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	11,913	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	\$/Hr	1.0	hr/8 hr shift	1,073	39,710	\$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	39,710	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	\$/kwh	4503.3	kW-hr	38,665,162	1,957,404	\$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	\$/kscf	0	scfm	0	0	\$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	\$kgal	0.0	gpm	0	0	\$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	\$/kscf	2	scfm/kacfm	2,563,436	788,176	\$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralization	1.64	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatmen	4.15	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	\$/ton	0.2	ton/hr	1,673	8,367	\$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	\$/ton-mi	0.0	ton/hr	0	0	\$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	\$/ft3	0	ft^3	0	0	\$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	33.71	\$/bag	795	bags	NA	19,702	\$/bag, 795 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-6: PM Control - Dry ESP

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F		
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

Year		
1997	23,864,300	DC from IAPCS program
2005	28,711,254	Inflation Adjusted DC

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			14,949,885
Purchased Equipment Total (B)	15%	of control device cost (A)	**17,192,367**
Installation - Standard Costs	67%	of purchased equip cost (B)	11,518,886
Installation - Site Specific Costs			NA
Installation Total			11,518,886
Total Direct Capital Cost, DC			28,711,254
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)	9,799,649
Total Capital Investment (TCI) = DC + IC			**38,510,903**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	4,472,639
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	5,582,472
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,055,112**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost (6) $/Ton Rem**
PM10	180.2	773.5		0.015	lb/MMBtu	387.6	385.9	26,056
Total Particulates	181.1	777.4		0.015	lb/MMBtu	387.6	389.8	25,796
Nitrous Oxides (NOx)	1,294.5	5,557.3				5557.3	-	NA
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3
3 ESP Maintenance costs Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
4 ESP Maintenance Materials Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
5 Existing PM emission rate per avg Method 5 test results of 0.030 lb/MMBtu, projected PM emission rate is at typical BACT limit 0f 0.015 lb/MMBtu per RBLC
6 Used an ESP SCA grid factor of 553 ft^2/1000 acfm per GRE, D. Stockdill.
7 Process, emissions and cost data listed above is for one unit.
8 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-6: PM Control - Dry ESP

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**14,949,885**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,494,988
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	747,494
Purchased Equipment Total (B)	15%		**17,192,367**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	687,695
Handling & erection	50%	of purchased equip cost (B)	8,596,184
Electrical	8%	of purchased equip cost (B)	1,375,389
Piping	1%	of purchased equip cost (B)	171,924
Insulation	2%	of purchased equip cost (B)	343,847
Painting	2%	of purchased equip cost (B)	343,847
Installation Subtotal Standard Expenses	67%		**11,518,886**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**11,518,886**
Total Direct Capital Cost, DC			**28,711,254**
Indirect Capital Costs			
Engineering, supervision	20%	of purchased equip cost (B)	3,438,473
Construction & field expenses	20%	of purchased equip cost (B)	3,438,473
Contractor fees	10%	of purchased equip cost (B)	1,719,237
Start-up	1%	of purchased equip cost (B)	171,924
Performance test	1%	of purchased equip cost (B)	171,924
Model Studies	2%	of purchased equip cost (B)	343,847
Contingencies	3%	of purchased equip cost (B)	515,771
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)	**9,799,649**
Total Capital Investment (TCI) = DC + IC			**38,510,903**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**38,510,903**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr	39,710
Supervisor	48%	% of Operator Costs.	19,061
Maintenance			
Maintenance Labor	1,375,864	ft2 grid area, 0.8 $/ft2 of grid area	1,135,088
Maintenance Materials	1	1% of purchased equipment cost	171,924
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 4,687 kW-hr, 8586 hr/yr, 100% utilization	2,037,107
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 25 ton/hr, 8586 hr/yr, 100% utilization	1,069,750
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**4,472,639**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	819,470
Administration (2% total capital costs)	2%	of total capital costs (TCI)	770,218
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	385,109
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	385,109
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	3,222,567
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,582,472**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**10,055,112**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-6: PM Control - Dry ESP

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$\$/\text{ft}^3$
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		ΔP ft H2O	Efficiency	Hp	kW	
Blower Baghouse & ESP	2,488,000		4.48			2017.5	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.46
	Liq flow	Liquid SPGR	ΔP ft H2O	Efficiency	Hp	kW	
WESP Pump	0 gpm	1.000	40	0.5		0.0	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
WESP H2O WW Disch	0 gpm	1.000	40	0.5		0.0	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
SCA Factor	553	ft^2/1000 acfm					
ESP Grid	1,375,864	ft^2	1.94E-03	kW/ft^2		2669.2	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.48
Total						4686.6	

Reagent Use & Other Operating Costs					
WESP Pump	acfm	5	gpm/kacfm	0 gpm	EPA Cost Cont Manual 6th ed Section 6 Chapter 3.4.1.9
WESP Water Makeup Rate/WW Disch	20%	of circulating water rate =	0 gpm		

Operating Cost Calculations **Annual hours of operation:** **8,586**
Utilization Rate: **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	1.0	hr/8 hr shift	1,073	39,710	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr
Supervisor	48%	of Operator Costs.			NA	19,061	% of Operator Costs.
Maintenance							
Maint Labor	1,375,864	ft2 grid area	0.825	$\$/\text{ft}^2$ of grid area		1,135,088	ft2 grid area, 0.8 $/ft2 of grid area
Maint Mtls	1	% of purchased equipment cost			NA	171,924	1% of purchased equipment cost
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	4686.6	kW-hr	40,239,539	2,037,107	$/kwh, 4,687 kW-hr, 8586 hr/yr, 100% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
SW Disposal	5.00	$/ton	24.9	ton/hr	213,950	1,069,750	$/ton, 25 ton/hr, 8586 hr/yr, 100% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
Waste Transport	0.55	$/ton-mi	0.0	Mi	0	0	$/ton-mi, 0 Mi, 8586 hr/yr, 100% utilization
Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1 Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-7: SO2 Control - Wet Scrubber

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

Chemical Engineering Chemical Plant Cost Index	
1997	386.5
2005	465
Inflation Adj	1.20

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs				DC from IAPCS program		1997	71,051,700	
Purchased Equipment (A)				Inflation Adjusted DC		2005	85,482,640	40,179,854
Purchased Equipment Total (B)	15%	of control device cost (A)						**46,206,833**
Installation - Standard Costs	85%	of purchased equip cost (B)						39,275,808
Installation - Site Specific Costs								103,067,200
Installation Total								142,343,008
Total Direct Capital Cost, DC								188,549,840
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B						16,172,391
Total Capital Investment (TCI) = DC + IC								**204,722,232**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						5,404,793
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						25,357,435
Total Annual Cost (Annualized Capital Cost + Operating Cost								**30,762,227**

Uncontrolled SO2 Emission Rate	12,745	lb/hr
Scrubber Control Efficiency	95.0%	[7]
Scrubber Bypass	0.0%	

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180	773				773	-	NA
Total Particulates	181	777				777	-	NA
Nitrous Oxides (NOx)	1,294	5,557				5,557	-	NA
Sulfur Dioxide (SO_2)	4,027	17,289	95.0%			2,736	14,553	2,114

Notes & Assumptions

1 Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1
3 Liquid/Gas ratio = 38 L/G = Gal/1,000 acf
4 Water Makeup Rate/Wastewater Discharge = 20% of circulating water rate
5 Process, emissions and cost data listed above is for one unit.
6 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
7 EPRI, current technology expectation for new scrubber, GRE 3/21/06
8 Per GRE 2/12/07 cost estimate $40/MW-hr, 540 MW
9 Per GRE 2/19/07 demolition cost estimate.

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-7: SO2 Control - Wet Scrubber

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**40,179,854**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	4,017,985
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	2,008,993
Purchased Equipment Total (B)	15%		**46,206,833**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,544,820
Handling & erection	40%	of purchased equip cost (B)	18,482,733
Electrical	1%	of purchased equip cost (B)	462,068
Piping	30%	of purchased equip cost (B)	13,862,050
Insulation	1%	of purchased equip cost (B)	462,068
Painting	1%	of purchased equip cost (B)	462,068
Installation Subtotal Standard Expenses	85%		**39,275,808**
Site Preparation, as required		Demolition [9]	6,000,000
Buildings, as required		Bypass duct modification	2,200,000
Site Specific - Other		Replacement Power- 6 months (183 days) [8]	94,867,200
Total Site Specific Costs			103,067,200
Installation Total			**142,343,008**
Total Direct Capital Cost, DC			**188,549,840**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,620,683
Construction & field expenses	10%	of purchased equip cost (B)	4,620,683
Contractor fees	10%	of purchased equip cost (B)	4,620,683
Start-up	1%	of purchased equip cost (B)	462,068
Performance test	1%	of purchased equip cost (B)	462,068
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	1,386,205
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**16,172,391**
Total Capital Investment (TCI) = DC + IC			**204,722,232**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**204,722,232**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr	19,855
Supervisor	15%	15% of Operator Costs	2,978
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr	19,855
Maintenance Materials	100%	of maintenance labor costs	19,855
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 5,189 kW-hr, 8586 hr/yr, 100% utilization	2,255,516
NA	NA		-
Water	0.31	$/kgal, 6,836 gpm, 8586 hr/yr, 100% utilization	1,091,719
NA	NA		-
NA	NA		-
WW Treat Neutralization	1.64	$/kgal, 1,891 gpm, 8586 hr/yr, 100% utilizatio	1,596,647
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 1,031 lb/hr, 8586 hr/yr, 100% utilization	398,366
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**5,404,793**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	37,526
Administration (2% total capital costs)	2%	of total capital costs (TCI)	4,094,445
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	2,047,222
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	2,047,222
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	17,131,019
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**25,357,435**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**30,762,227**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-7: SO2 Control - Wet Scrubber

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$\$/\text{ft}^3$
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160.00	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		**ΔP in H2O**	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,488,000		8.55	0.7	-	3,555.5	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**ΔP ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	94,544 gpm	1	60	0.7	-	1,523.4	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	6836 gpm	1	60	0.7	-	110.2	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
Other							
Other							
Other							
Total						5189.1	

Reagent Use & Other Operating Costs								
Caustic Use	1071.22	lb/hr SO2			2.50	lb NaOH/lb SO2	2678.05	lb/hr Caustic
Lime Use	1071.22	lb/hr SO2			0.96	lb Lime/lb SO2	1031.05	lb/hr Lime
Baseline scrubber bypass:			27.0%					
Baseline scrubber efficiency:			93.7%					
Liquid/Gas ratio	38.0	* L/G = Gal/1,000 acf					6836 gpm	
Circulating Water Rate	94,544	gpm						
Water Makeup Rate/WW Disch =			2%	of circulating water rate + evap. loss =				
Evaopration Loss =			72%					

Operating Cost Calculations **Annual hours of operation:** **8,586**
Utilization Rate: **100%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	0.5	hr/8 hr shift	537	19,855	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	2,978	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	537	19,855	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	19,855	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	5189.1	kW-hr	44,553,851	2,255,516	$/kwh, 5,189 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	6,836.1	gpm	3,521,675	1,091,719	$/kgal, 6,836 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	Mscfm	0	0	$/kscf, 0 Mscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	1,890.9	gpm	974,106	1,596,647	$/kgal, 1,891 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	1031.0	lb/hr	4,426	398,366	$/ton, 1,031 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-8: SO2 Control - Option 1, Existing Absorber + Mist Eliminator + Liquid Distribution Ring + Fan Upgrade + Modify Stack + Coal Drying

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

Chemical Engineering Chemical Plant Cost Index	
2004	442
2005	465
Inflation Adj	1.05

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								51,000,000
Purchased Equipment Total (B)	15%	of control device cost (A)						**58,650,000**
Installation - Standard Costs	85%	of purchased equip cost (B)						49,852,500
Installation - Site Specific Costs								32,235,200
Installation Total								82,087,700
Total Direct Capital Cost, DC								55,695,200
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)						20,527,500
Total Capital Investment (TCI) = DC + IC								**76,222,700**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,090,296
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						9,427,172
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**11,517,469**

Uncontrolled SO2 Emission Rate	12,745	lb/hr
Scrubber Control Efficiency	94%	
Scrubber Bypass	0.0%	

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180	773				773	-	NA
Total Particulates	181	777				777	-	NA
Nitrous Oxides (NOx)	1,294	5,557				5,557	-	NA
Sulfur Dioxide (SO_2)	4,027	17,289	94.0%			3,310	13,979	824

Notes & Assumptions

1 Total installed cost per URS Proposal 10/26/04 & Chimney Consultants Proposal 9/22/04
MM$51 for coal drying addition from Coal Drying Incremental Benefit and Cost Model spread sheet 02/05/2007
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1
3 Liquid/Gas ratio = 10 L/G = Gal/1,000 acf
4 Water Makeup Rate/Wastewater Discharge = 20% of circulating water rate
5 Process, emissions and cost data listed above is for one unit.
6 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
7 Per "Gary's BART analysis" spreadsheet and phone conversation with D. Stockdill 02/14/2006
8 Per GRE 2/12/07 cost estimate $40/MW-hr, 540 MW
9 Installed capital cost per G. Riveland 04/13/06

Great River Energy Coal Creek
BART Emission Control Cost Analysis

Table A-8: SO2 Control - Option 1, Existing Absorber + Mist Eliminator + Liquid Distribution Ring + Fan Upgrade + Modify Stack + Coal Drying

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**51,000,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	5,100,000
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	2,550,000
Purchased Equipment Total (B)	15%		**58,650,000**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	7,038,000
Handling & erection	40%	of purchased equip cost (B)	23,460,000
Electrical	1%	of purchased equip cost (B)	586,500
Piping	30%	of purchased equip cost (B)	17,595,000
Insulation	1%	of purchased equip cost (B)	586,500
Painting	1%	of purchased equip cost (B)	586,500
Installation Subtotal Standard Expenses	85%		**49,852,500**
Option 1 Modifications		Mist Eliminator, Liquid Distrubution Ring, Fan Upgrade [7]	5,020,000
Buildings, as required		Stack Modifications, Installed Cost [9], bypass duct modificatio	12,700,000
Site Specific - Other		Replacement Power - two 14 day outages [8]	14,515,200
Total Site Specific Costs			32,235,200
Installation Total			**82,087,700**
Total Direct Capital Cost, DC			**55,695,200**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	5,865,000
Construction & field expenses	10%	of purchased equip cost (B)	5,865,000
Contractor fees	10%	of purchased equip cost (B)	5,865,000
Start-up	1%	of purchased equip cost (B)	586,500
Performance test	1%	of purchased equip cost (B)	586,500
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	1,759,500
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**20,527,500**
Total Capital Investment (TCI) = DC + IC			**76,222,700**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**76,222,700**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.3 hr/8 hr shift, 8586 hr/yr	50,700
Maintenance Materials	100%	of maintenance labor costs	50,700
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 2,188 kW-hr, 8586 hr/yr, 100% utilization	951,126
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 2 ton/hr, 8586 hr/yr, 100% utilization	96,370
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 2,437 lb/hr, 8586 hr/yr, 100% utilization	941,400
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**2,090,296**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	NA
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,524,454
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	762,227
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	762,227
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	6,378,264
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**9,427,172**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**11,517,469**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-8: SO2 Control - Option 1, Existing Absorber + Mist Eliminator + Liquid Distribution Ring + Fan Upgrade + Modify Stack + Coal Drying

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160.00	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		**D P in H2O**	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,488,000		5.38	0.6464	-	2,188.2	Incremental ID fan power increase, GRE G. Riveland 4/5/06 email
	Flow	**Liquid SPGR**	**D P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
Other							
Other							
Other							
Total						2188.2	

Reagent Use & Other Operating Costs						
Caustic Use	0.00	lb/hr SO2	2.50	lb NaOH/lb SO2	0.00	lb/hr Caustic
Lime Use	0.00	lb/hr SO2	0.96	lb Lime/lb SO2	0.00	lb/hr Lime

Liquid/Gas ratio 0.0 * L/G = Gal/1,000 acf
Circulating Water Rate 0 gpm
Water Makeup Rate/WW Disch = 20% of circulating water rate = 0 gpm

Operating Cost Calculations **Annual hours of operation:** **8,586**
Utilization Rate: **100%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	0	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.3	hr/8 hr shift	1,370	50,700	$/Hr, 1.3 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	50,700	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	2188.2	kW-hr	18,787,866	951,126	$/kwh, 2,188 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	2.2	ton/hr	19,274	96,370	$/ton, 2 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	2436.5	lb/hr	10,460	941,400	$/ton, 2,437 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-9: SO2 Control - Spray Dryer and Baghouse

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

Chemical Engineering Chemical Plant Cost Index	
1997	386.5
2005	465
Inflation Adj	1.20

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs				DC from IAPCS program		1997	55,548,000	
Purchased Equipment (A)				Inflation Adjusted DC		2005	66,830,065	33,398,333
Purchased Equipment Total (B)	15%	of control device cost (A)						**38,408,083**
Installation - Standard Costs	74%	of purchased equip cost (B)						28,421,982
Installation - Site Specific Costs								97,067,200
Installation Total								125,489,182
Total Direct Capital Cost, DC								163,897,265
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)						17,283,637
Total Capital Investment (TCI) = DC + IC								**181,180,902**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						6,709,521
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						22,507,741
Total Annual Cost (Annualized Capital Cost + Operating Cost								**29,217,263**

Uncontrolled SO2 Emission Rate	12,745	lb/hr
Scrubber Control Efficiency	90.0%	
Scrubber Bypass	0.0%	

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5	0%			773.5	-	NA
Total Particulates	181.1	777.4	0%			777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	0%			5557.3	-	NA
Sulfur Dioxide (SO_2)	4,027.3	17,289.1	90.0%			5,471	11,817.7	2,472

Notes & Assumptions

1 Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Process, emissions and cost data listed above is for one unit.
6 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
7 Solid waste disposal cost is only for spent lime.
8 Per GRE 2/12/07 cost estimate $40/MW-hr, 540 MW

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-9: SO2 Control - Spray Dryer and Baghouse

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**33,398,333**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	3,339,833
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	1,669,917
Purchased Equipment Total (B)	15%		**38,408,083**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,536,323
Handling & erection	50%	of purchased equip cost (B)	19,204,042
Electrical	8%	of purchased equip cost (B)	3,072,647
Piping	1%	of purchased equip cost (B)	384,081
Insulation	7%	of purchased equip cost (B)	2,688,566
Painting	4%	of purchased equip cost (B)	1,536,323
Installation Subtotal Standard Expenses	74%		**28,421,982**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Bypass duct modification	2,200,000
Site Specific - Other		Replacement Power- 6 months (183 days) [8]	94,867,200
Total Site Specific Costs			97,067,200
Installation Total			**125,489,182**
Total Direct Capital Cost, DC			**163,897,265**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	3,840,808
Construction & field expenses	20%	of purchased equip cost (B)	7,681,617
Contractor fees	10%	of purchased equip cost (B)	3,840,808
Start-up	1%	of purchased equip cost (B)	384,081
Performance test	1%	of purchased equip cost (B)	384,081
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	1,152,242
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**17,283,637**
Total Capital Investment (TCI) = DC + IC			**181,180,902**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**181,144,526**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr	79,421
Supervisor	15%	15% of Operator Costs	11,913
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr	39,710
Maintenance Materials	100%	of maintenance labor costs	39,710
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization	1,957,404
NA	NA		-
Water	0.31	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization	545,860
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization	788,176
WW Treat Neutralization	1.64	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilizatio	2,886,172
NA	NA		-
SW Disposal	5.00	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization	17,971
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 837 lb/hr, 8586 hr/yr, 100% utilization	323,482
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	33.71	$/bag, 795 bags, 8586 hr/yr, 100% utilization	19,702
Total Annual Direct Operating Costs			**6,709,521**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	102,452
Administration (2% total capital costs)	2%	of total capital costs (TCI)	3,623,618
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,811,809
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,811,809
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	15,158,053
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**22,507,741**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**29,217,263**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-9: SO2 Control - Spray Dryer and Baghouse

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	\$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	2	years	
CRF	0.5416		
Rep part cost per unit	33.711	\$/bag	
Amount Required	795		
Total Rep Parts Cost	28,140	Cost adjusted for freight & sales tax	
Installation Labor	8,236	10 min per bag, Labor + Overhead (68% = \$29.65/hr	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**36,376**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag
Annualized Cost	**19,702**		

Electrical Use	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	2,488,000		10			4503.3	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						4503.3	

Baghouse Filter Cost							See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	10,661	ft^2					
Cages	10 ft long	5 in dia	13.42	area/cage ft^2	795 Cages	11.036	\$/cage
Bags	1.69	\$/ft2 of fabric				22.68	\$/bag
Total						33.711	
Lime Use	869.85	lb/hr SO2	0.96	lb Lime/lb SO2		837.23	lb/hr Lime
Water Makeup Rate/WW Disch =	3418 gpm						
Baseline scrubber bypass:	27.0%						
Baseline scrubber efficiency:	93.7%						

Operating Cost Calculations — **Annual hours of operation:** **8,586**
Utilization Rate: **100%**

	Item	Unit Cost \$	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	\$/Hr	2.0	hr/8 hr shift	2,147	79,421	\$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	11,913	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	\$/Hr	1.0	hr/8 hr shift	1,073	39,710	\$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	39,710	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	\$/kwh	4503.3	kW-hr	38,665,162	1,957,404	\$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	\$/kscf	0	scfm	0	0	\$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	\$/kgal	3,418.0	gpm	1,760,837	545,860	\$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	\$kgal	0.0	gpm	0	0	\$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	\$/kscf	2	scfm/kacfm	2,563,436	788,176	\$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	\$/kgal	3,418.0	gpm	1,760,837	2,886,172	\$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	\$/ton	0.4	ton/hr	3,594	17,971	\$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	\$/ton-mi	0.0	ton/hr	0	0	\$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	\$/ton	837.2	lb/hr	3,594	323,482	\$/ton, 837 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	\$/ft3	0	ft^3	0	0	\$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	33.71	\$/bag	795	bags	NA	19,702	\$/bag, 795 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Existing Wet Scrubber + Coal Drying

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
			Dry Std Flow Rate	1,205,997	dscfm @ 330º F

Chemical Engineering Chemical Plant Cost Index	
2004	442
2005	465
Inflation Adj	1.05

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								51,000,000
Purchased Equipment Total (B)	15%	of control device cost (A)						**58,650,000**
Installation - Standard Costs	85%	of purchased equip cost (B)						49,852,500
Installation - Site Specific Costs								27,215,200
Installation Total								77,067,700
Total Direct Capital Cost, DC								50,675,200
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B						20,527,500
Total Capital Investment (TCI) = DC + IC								**71,202,700**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,037,198
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						8,806,302
Total Annual Cost (Annualized Capital Cost + Operating Cost								**9,843,501**

Uncontrolled SO2 Emission Rate	12,745	lb/hr
Scrubber Control Efficiency	92.3%	
Scrubber Bypass	10.0%	

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180	773				773	-	NA
Total Particulates	181	777				777	-	NA
Nitrous Oxides (NOx)	1,294	5,557				5,557	-	NA
Sulfur Dioxide (SO_2)	4,027	17,289	83.1%			9,263	8,026	1,226

Notes & Assumptions

1. Total installed cost per URS Proposal 10/26/04 & Chimney Consultants Proposal 9/22/04.
   MM$51 for coal drying addition from Coal Drying Incremental Benefit and Cost Model spread sheet 02/05/2007
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1
3. Liquid/Gas ratio = 10 L/G = Gal/1,000 acf
4. Water Makeup Rate/Wastewater Discharge = 20% of circulating water rate
5. Process, emissions and cost data listed above is for one unit.
6. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
7. Per GRE 2/12/07 cost estimate $40/MW-hr, 540 MW
8. Installed capital cost per G. Riveland 04/13/06

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Existing Wet Scrubber + Coal Drying

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**51,000,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	5,100,000
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	2,550,000
Purchased Equipment Total (B)	15%		**58,650,000**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	7,038,000
Handling & erection	40%	of purchased equip cost (B)	23,460,000
Electrical	1%	of purchased equip cost (B)	586,500
Piping	30%	of purchased equip cost (B)	17,595,000
Insulation	1%	of purchased equip cost (B)	586,500
Painting	1%	of purchased equip cost (B)	586,500
Installation Subtotal Standard Expenses	85%		**49,852,500**
Site Preparation, as required		Bypass duct modification	2,200,000
Buildings, as required		Stack Modifications, Installed Cost [8]	10,500,000
Site Specific - Other		Replacement Power - two 14-day outage [7]	14,515,200
Total Site Specific Costs			27,215,200
Installation Total			**77,067,700**
Total Direct Capital Cost, DC			**50,675,200**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	5,865,000
Construction & field expenses	10%	of purchased equip cost (B)	5,865,000
Contractor fees	10%	of purchased equip cost (B)	5,865,000
Start-up	1%	of purchased equip cost (B)	586,500
Performance test	1%	of purchased equip cost (B)	586,500
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	1,759,500
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**20,527,500**
Total Capital Investment (TCI) = DC + IC			**71,202,700**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**71,202,700**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.3 hr/8 hr shift, 8586 hr/yr	50,700
Maintenance Materials	100%	of maintenance labor costs	50,700
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, -235 kW-hr, 8586 hr/yr, 100% utilization	-101,972
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 2 ton/hr, 8586 hr/yr, 100% utilization	96,370
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 2,437 lb/hr, 8586 hr/yr, 100% utilization	941,400
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**1,037,198**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	NA
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,424,054
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	712,027
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	712,027
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	5,958,194
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**8,806,302**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,843,501**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Existing Wet Scrubber + Coal Drying

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/$ft^3$
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160.00	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,234,300		3.28		-	-234.6	Incremental ID fan power increase, GRE G. Riveland 4/5/06 email
	Flow	**Liquid SPGR**	**D P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
Other							
Other							
Other							
Total						-234.6	

Reagent Use & Other Operating Costs						
Caustic Use	0.00	lb/hr SO2	2.50	lb NaOH/lb SO2	0.00	lb/hr Caustic
Lime Use	0.00	lb/hr SO2	0.96	lb Lime/lb SO2	0.00	lb/hr Lime

Liquid/Gas ratio 0.0 * L/G = Gal/1,000 acf
Circulating Water Rate 0 gpm
Water Makeup Rate/WW Disch = 2% of circulating water rate = 0 gpm

Operating Cost Calculations **Annual hours of operation:** **8,586**
Utilization Rate: **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8586 hr/yr
Supervisor	15%	of Op.			NA	0	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	1.3	hr/8 hr shift	1,370	50,700	$/Hr, 1.3 hr/8 hr shift, 8586 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	50,700	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	-234.6	kW-hr	-2,014,276	-101,972	$/kwh, -235 kW-hr, 8586 hr/yr, 100% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
SW Disposal	5.00	$/ton	2.2	ton/hr	19,274	96,370	$/ton, 2 ton/hr, 8586 hr/yr, 100% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1 Lime	90.0	$/ton	2436.5	lb/hr	10,460	941,400	$/ton, 2,437 lb/hr, 8586 hr/yr, 100% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Dry Sorbent Injection and Baghouse

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

Chemical Engineering Chemical Plant Cost Index	
1997	386.5
2005	465
Inflation Adj	1.20

Year		
1997	32,195,800	DC from IAPCS program
2005	38,734,921	Inflation Adjusted DC

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								19,357,782
Purchased Equipment Total (B)	15%	of control device cost (A)						**22,261,449**
Installation - Standard Costs	74%	of purchased equip cost (B)						16,473,472
Installation - Site Specific Costs								2,200,000
Installation Total								18,673,472
Total Direct Capital Cost, DC								38,734,921
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)						10,017,652
Total Capital Investment (TCI) = DC + IC								**48,752,573**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						6,393,346
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						6,129,094
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**12,522,440**

Uncontrolled SO2 Emission Rate	12,745	lb/hr
Scrubber Control Efficiency	70.0%	
Scrubber Bypass	0.0%	

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	773.5	0%			773.5	-	NA
Total Particulates	181.1	777.4	0%			777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	0%			5557.3	-	NA
Sulfur Dioxide (SO_2)	4,027.3	17,289.1	70.0%			16,414	874.9	14,313

Notes & Assumptions

1 Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6 Process, emissions and cost data listed above is for one unit.
7 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
8 Solid waste disposal cost is only for spent lime.

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Dry Sorbent Injection and Baghouse

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**19,357,782**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,935,778
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	967,889
Purchased Equipment Total (B)	15%		**22,261,449**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	890,458
Handling & erection	50%	of purchased equip cost (B)	11,130,724
Electrical	8%	of purchased equip cost (B)	1,780,916
Piping	1%	of purchased equip cost (B)	222,614
Insulation	7%	of purchased equip cost (B)	1,558,301
Painting	4%	of purchased equip cost (B)	890,458
Installation Subtotal Standard Expenses	74%		**16,473,472**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Bypass duct modification	2,200,000
Total Site Specific Costs			2,200,000
Installation Total			**18,673,472**
Total Direct Capital Cost, DC			**38,734,921**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,226,145
Construction & field expenses	20%	of purchased equip cost (B)	4,452,290
Contractor fees	10%	of purchased equip cost (B)	2,226,145
Start-up	1%	of purchased equip cost (B)	222,614
Performance test	1%	of purchased equip cost (B)	222,614
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	667,843
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**10,017,652**
Total Capital Investment (TCI) = DC + IC			**48,752,573**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**48,716,197**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr	79,421
Supervisor	15%	15% of Operator Costs	11,913
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr	39,710
Maintenance Materials	100%	of maintenance labor costs	39,710
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization	1,957,404
NA	NA		-
Water	0.31	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization	545,860
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization	788,176
WW Treat Neutralization	1.64	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilizatio	2,886,172
NA	NA		-
SW Disposal	5.00	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization	1,330
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 62 lb/hr, 8586 hr/yr, 100% utilization	23,948
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	33.71	$/bag, 795 bags, 8586 hr/yr, 100% utilization	19,702
Total Annual Direct Operating Costs			**6,393,346**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	102,452
Administration (2% total capital costs)	2%	of total capital costs (TCI)	975,051
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	487,526
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	487,526
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	4,076,539
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,129,094**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**12,522,440**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Dry Sorbent Injection and Baghouse

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	2	years	
CRF	0.5416		
Rep part cost per unit	33.711	$/bag	
Amount Required	795		
Total Rep Parts Cost	28,140	Cost adjusted for freight & sales tax	
Installation Labor	8,236	10 min per bag, Labor + Overhead (68% = $29.65/hr	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**36,376**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag
Annualized Cost	**19,702**		

Electrical Use	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	2,488,000	10			4503.3	
Baghouse Shaker	0.0	Gross fabric area ft^2			0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other						
Other						
Other						
Other						
Other						
Total					4503.3	

Baghouse Filter Cost							
Gross BH Filter Area	10,661	ft^2					See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Cages	10 ft long	5 in dia	13.42	area/cage ft^2	795 Cages	11.036	$/cage
Bags	1.69	$/ft2 of fabric				22.68	$/bag
Total						33.711	
Lime Use	64.40	lb/hr SO2	0.96	lb Lime/lb SO2		61.98	lb/hr Lime
Water Makeup Rate/WW Disch =		3418 gpm					
Baseline scrubber bypass:		27.0%					
Baseline scrubber efficiency:		93.7%					

Operating Cost Calculations — **Annual hours of operation: 8,586** — **Utilization Rate: 100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	$/Hr	2.0	hr/8 hr shift	2,147	79,421	$/Hr, 2.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	11,913	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	1,073	39,710	$/Hr, 1.0 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	39,710	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	4503.3	kW-hr	38,665,162	1,957,404	$/kwh, 4,503 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	3,418.0	gpm	1,760,837	545,860	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	2,563,436	788,176	$/kscf, 2 scfm/kacfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	3,418.0	gpm	1,760,837	2,886,172	$/kgal, 3,418 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	266	1,330	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	62.0	lb/hr	266	23,948	$/ton, 62 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	33.71	$/bag	795	bags	NA	19,702	$/bag, 795 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-12: NOx Control - LoTOx - (Low Temperature Oxidation)

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								9,653,165
Purchased Equipment Total (B)	15%	of control device cost (A)						**11,101,139**
Installation - Standard Costs	98%	of purchased equip cost (B)						10,879,116
Installation - Site Specific Costs								NA
Installation Total								10,879,116
Total Direct Capital Cost, DC								21,980,256
Total Indirect Capital Costs, IC	25%	of purchased equip cost (B)						2,775,285
Total Capital Investment (TCI) = DC + IC								**44,328,337**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						52,548,709
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						5,520,025
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**58,068,734**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	90%			555.7	5,001.5	11,610
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1. Sept 2005 Cost Estimate Procedure from **BOC Gases**
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1 (absorbers)
3. Liquid/Gas ratio = 10 L/G = Gal/1,000 acf
4. Water Makeup Rate/Wastewater Discharge = 20% of circulating water rate
5. Check O2 Prices
6. Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART.
7. Flow rate, duty and costs listed above for one unit.
8. Process, emissions and cost data listed above is for one unit.
9. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-12: NOx Control - LoTOx - (Low Temperature Oxidation)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**9,653,165**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	965,316
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	482,658
Purchased Equipment Total (B)	15%		**11,101,139**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,332,137
Handling & erection	40%	of purchased equip cost (B)	4,440,456
Electrical	10%	of purchased equip cost (B)	1,110,114
Piping	30%	of purchased equip cost (B)	3,330,342
Insulation	5%	of purchased equip cost (B)	555,057
Painting	1%	of purchased equip cost (B)	111,011
Installation Subtotal Standard Expenses	98%		**10,879,116**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**10,879,116**
Total Direct Capital Cost, DC			**21,980,256**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,110,114
Construction & field expenses	10%	of purchased equip cost (B)	1,110,114
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	111,011
Performance test	1%	of purchased equip cost (B)	111,011
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	333,034
Total Indirect Capital Costs, IC	25%	of purchased equip cost (B)	**2,775,285**
Ozone Generator, Installed Cost			**19,572,797**
Total Capital Investment (TCI) = DC + IC			**44,328,337**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**44,328,337**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr	19,855
Supervisor	15%	15% of Operator Costs	2,978
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr	19,855
Maintenance Materials	100%	of maintenance labor costs	19,855
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 15,125 kW-hr, 8586 hr/yr, 100% utilization	6,574,275
NA	NA		-
Water	0.31	$/kgal, 4,976 gpm, 8586 hr/yr, 100% utilization	794,665
Cooling Water	0.27	$kgal, 5,825 gpm, 8586 hr/yr, 100% utilization	806,235
NA	NA		-
NA	NA		-
WW Treat Biotreatement	4.15	$/kgal, 4,976 gpm, 8586 hr/yr, 100% utilization	10,644,316
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Oxygen	15.00	kscf, 261 kscf/hr, 8586 hr/yr, 100% utilization	33,666,674
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**52,548,709**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	37,526
Administration (2% total capital costs)	2%	of total capital costs (TCI)	886,567
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	443,283
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	443,283
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	3,709,366
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,520,025**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**58,068,734**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-12: NOx Control - LoTOx - (Low Temperature Oxidation)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,488,000		10	0.7	-	4,158.5	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**D P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	24,880 gpm	1	60	0.7	-	400.9	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	4976 gpm	1	60	0.7	-	80.2	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				10,485	
Other							
Total						15125.0	

Reagent Use & Other Operating Costs							
Ozone Needed	1.8	lb O3/lb NOx	2,330.1	lb/hr O3			
Oxygen Needed	10%	wt O2 to O3 conversion	23,301	lb/hr O2	261,408	scfh O2	
LTO Cooling Water	150	gal/lb O3	5,825	gpm			
Liquid/Gas ratio	10.0	* L/G = Gal/1,000 acf					
Circulating Water Rate	24,880	gpm					
Water Makeup Rate/WW Disch =		20%	of circulating water rate =	4976 gpm			
Scrubber Cost	10	$/scfm Gas	$9,653,165		Incremental cost per BOC. Need to increase vessel size over standard absorber.		
Ozone Generator	$350	lb O3/day	$19,572,797	Installed	Installed cost factor per BOC.		

Operating Cost Calculations — **Annual hours of operation:** **8,586**; **Utilization Rate:** **100%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	0.5	hr/8 hr shift	537	19,855	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	2,978	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	537	19,855	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	19,855	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	15125.0	kW-hr	129,863,497	6,574,275	$/kwh, 15,125 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	4,976.0	gpm	2,563,436	794,665	$/kgal, 4,976 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	5,825.2	gpm	3,000,929	806,235	$kgal, 5,825 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	4,976.0	gpm	2,563,436	10,644,316	$/kgal, 4,976 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	261.4	kscf/hr	2,244,445	33,666,674	kscf, 261 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

Chemical Engineering Chemical Plant Cost Index	
1998/1999	390
2005	465
Inflation Adj	1.19

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation		6019	80.0%	0.22		1998	40,904,723
Purchased Equipment (A)							2005	48,771,016
Purchased Equipment Total (B)	0%	of control device cost (A)					SCR Only	**48,771,016**
Installation - Standard Costs	15%	of purchased equip cost (B)					SCR Only	8,778,783
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC							SCR + Reheat	**70,360,657**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					SCR + Reheat	34,405,374
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					SCR + Reheat	5,991,799
Total Annual Cost (Annualized Capital Cost + Operating Cost)							SCR + Reheat	**40,397,172**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	80%			1111.5	4,445.8	9,087
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
3 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.36 -2.43
4 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.32 - 2.35
5 SCR Catalyst Volume per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.18 - 2.24
6 SCR Reactor Size per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.25 - 2.31
7 SCR Catalyst Replacement per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.50 - 2.53
8 SCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.48
9 SCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.46
10 Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART
11 Reheat cost based on 180 F temperature from scrubber exhaust
12 Process, emissions and cost data listed above is for one unit.
13 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**48,771,016**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0.0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**48,771,016**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	2,438,551
Engineerin & Home Office	10%	of purchased equip cost (A)	4,877,102
Process Contingency	5%	of purchased equip cost (A)	2,438,551
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**9,754,203**
Project Contingeny (C)	15%	of (A + B)	**8,778,783**
Total Plant Cost D		A + B + C	**67,304,002**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**1,346,080**
Inventory Capital		Reagent Vol * $/gal	**47,079**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**68,697,161**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**NA**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	1,030,457
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 5,177 kW-hr, 8586 hr/yr, 100% utilization	2,250,322
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Ammonia	0.92	$/lb, 1,387 lb/hr, 8586 hr/yr, 100% utilization	10,958,450
NA	NA		-
SCR Catalyst	500.00	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization	1,391,800
NA	NA		-
Total Annual Direct Operating Costs			**15,631,029**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	5,748,532
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,748,532**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**21,379,562**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation		6019	80.0%	0.22		1998	40,904,723
Purchased Equipment (A)							2005	48,771,016
Purchased Equipment Total (B)	0%	of control device cost (A)					SCR Only	**48,771,016**
Installation - Standard Costs	15%	of purchased equip cost (B)					SCR Only	8,778,783
Installation - Site Specific Costs								0
Installation Total								13,750,000
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC							SCR + Reheat	**84,110,657**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					SCR + Reheat	49,011,624
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					SCR + Reheat	7,142,389
Total Annual Cost (Annualized Capital Cost + Operating Cost)							SCR + Reheat	**56,154,013**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	80%			1111.5	4,445.8	12,631
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
3 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.36 -2.43
4 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.32 - 2.35
5 SCR Catalyst Volume per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.18 - 2.24
6 SCR Reactor Size per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.25 - 2.31
7 SCR Catalyst Replacement per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.50 - 2.53
8 SCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.48
9 SCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.46
10 Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART
11 Reheat cost based on 180 F temperature from scrubber exhaust
12 Process, emissions and cost data listed above is for one unit.
13 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**48,771,016**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**48,771,016**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	2,438,551
Engineering & Home Office	10%	of purchased equip cost (A)	4,877,102
Process Contingency	5%	of purchased equip cost (A)	2,438,551
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**9,754,203**
Project Contingeny (C)	15%	of (A + B)	**8,778,783**
Total Plant Cost D		A + B + C	**67,304,002**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Sunk Capital Investmet (F)		Flyash sales infrastructure loss	**13,750,000**
Pre Production Costs (G)	2%	of (D+E))	**1,346,080**
Inventory Capital		Reagent Vol * $/gal	**47,079**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**82,447,161**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**NA**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	1,236,707
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 5,177 kW-hr, 8586 hr/yr, 100% utilization	2,250,322
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Lost Ash Sales	36.00	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization	14,400,000
NA	NA		-
Ammonia	0.92	$/lb, 1,387 lb/hr, 8586 hr/yr, 100% utilization	10,958,450
NA	NA		-
SCR Catalyst	500.00	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization	1,391,800
NA	NA		-
Total Annual Direct Operating Costs			**30,237,279**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	6,899,123
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,899,123**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**37,136,403**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst				
Equipment Life	24,000	hours		
FCW	0.3157			
Rep part cost per unit	500	$/ft^3	# of Layers	12
Replacement Factor	12	Layers replaced per year =		1
Amount Required	8,819	ft^3		
Catalyst Cost	4,409,257			
Y catalyst life factor	3	Years		
Annualized Cost	**1,391,800**			

SCR Capital Cost per EPRI Method			**40,904,723**				
Duty	6,019	MMBtu/hr	Catalyst Area	2,904	ft^2	360	*f* (h SCR)
Q flue gas	2,787,396	acfm	Rx Area	3,339		-24	*f* (h NH_3)
NOx Cont Eff	80%	(as faction)	Rx Height	57.8	ft	-728	*f* (h New) new= -728, Retrofit = 0
NOx in	0.22	lb/MMBtu	n layer	12	layers	Y	Bypass? Y or N
Ammina Slip	2	ppm	h layer	13.1	ft	127	*f* (h Bypass)
Fuel Sulfur	0.67	wt % (as %)	n total	13	layers	25,397,317	*f* (vol catalyst)
Temperature	330	Deg F	h SCR	90	ft		*f* (h SCR)
Catalyst Volume	**105,822**	ft^3	New/Retrofit	N	N or R		

Electrical Use				
Duty	6,019	MMBtu/hr		kW
NOx Cont Eff	80%	(as faction)	Power	5,177.2
NOx in	0.22	lb/MMBtu		
n catalyst layers	13	layers		
Press drop catalyst	1	in H_2O per layer		
Press drop duct	3	in H_2O		
Total				5177.2

Reagent Use & Other Operating Costs			Ammonia Use				
NOx in	0.22	lb/MMBtu		402	lb/hr Neat		
Efficiency	80%			29%	solution	56.0	lb/ft^3 Density
Duty	6,019	MMBtu/hr		1387	lb/hr	185.3	gal/hr
			Volume 14 day inventory	62,270	gal	$47,079	Inventory Cost

Operating Cost Calculations

Annual hours of operation: **8,586**
Utilization Rate: **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	1.5	% of Total Capital Investment				1,236,707	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	5177.2	kW-hr	44,451,242	2,250,322	$/kwh, 5,177 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gph	0	0	$/kgal, 0 gph, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	36.00	$/ton	46.6	ton/hr	400,000	14,400,000	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
7	Ammonia	0.92	$/lb	1387	lb/hr	11,911,359	10,958,450	$/lb, 1,387 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	1,391,800	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-14: Cost of Flue Gas Re-Heating (Thermal Oxidizer)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:	**Catalyst**	
Equipment Life	2	years
CRF	0.5416	
Rep part cost per unit	650	\$/ft^{3}
Amount Required	39	ft^{3}
Catalyst Cost	26,618	Cost adjusted for freight & sales tax
Installation Labor	3,993	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Thermal	2,488,000		19	0.6		9,218.0	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	2,488,000		23	0.6		11,158.7	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				9218.0	

Reagent Use & Other Operating Costs Oxidizers - NA

	Operating Cost Calculations			**Annual hours of operation:**			**8,586**	
				Utilization Rate:			**100%**	
	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	0.5	hr/8 hr shift	537	19,855	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	2,978	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	537	19,855	$/Hr, 0.5 hr/8 hr shift, 8586 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	19,855	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	9218.0	kW-hr	79,146,091	4,006,731	$/kwh, 9,218 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	4,167	scfm	2,146,725	14,705,069	$/kscf, 4,167 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
2	CO Catalyst	650	$/ft3	0	ft^{3}	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-14: Cost of Flue Gas Re-Heating (Thermal Oxidizer)

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

Auxiliary Fuel Use Equation 3.19

T_{wi}	180	Deg F - Temperature of waste gas into heat recovery
T_{fi}	450	Deg F - Temperature of Flue gas into of heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	70%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	369	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	261	Deg F - Temperature of flue gas into of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2684	Btu/lb - Deg F Heat Capacity of waste gas (air)
p_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
p_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	1,550,000	scfm - Flow of waste gas
Q_{af}	4,167	scfm - Flow of auxiliary fuel

Year 2005 Inflation Rate 3.0%

Cost Calculations 1,554,167 scfm Flue Gas Cost in 1989 $'s $753,546

Current Cost Using CHE Plant Cost Index $898,458

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Indurator Flue Gas Heat Capacity - Basis Typical Composition

100 scfm 359 scf/lbmole

		Gas Composition		lb/hr f	wt %	Cp Gas	Cp Flue
28	mw CO	0	v %	0			
44	mw CO2	15	v %	184	22.0%	0.24	0.0528
18	mw H2O	10	v %	50	6.0%	0.46	0.0276
28	mw N2	60	v %	468	56.0%	0.27	0.1512
32	mw O2	15	v %	134	16.0%	0.23	0.0368
Cp Flue Gas		100	v %	836	100.0%		0.2684

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators
(EPA 453/B-96-001)

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F		
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s		6019	50.0%	0.22		1998	3,627,729
Purchased Equipment (A)							2005	4,325,369
Purchased Equipment Total (B)	0%	of control device cost (A)						**4,325,369**
Installation - Standard Costs	15%	of purchased equip cost (B)						778,566
Installation - Site Specific Costs								0
Installation Total								13,750,000
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**19,909,069**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						21,231,102
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,665,978
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**22,897,080**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	50.0%			2778.6	2,778.6	8,240
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1
2 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.19
3 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
4 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
5 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
6 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
7 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
8 Lignite Coal Assumptions 6,054 Btu/lb (wet) Ash 6.2% 42% moisture $10.20/ton delivered
9 Control Efficiency = % reduction needed to meet presumptive BART of 0.29 lb/MMBtu
10 Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART
11 Process, emissions and cost data listed above is for one unit.
12 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**4,325,369**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**4,325,369**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	216,268
Engineering & Home Office	10%	of purchased equip cost (A)	432,537
Process Contingency	5%	of purchased equip cost (A)	216,268
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**865,074**
Project Contingeny (C)	15%	of (A + B)	**778,566**
Total Plant Cost D		A + B + C	**5,969,009**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Sunk Capital Investmet (F)		Flyash sales infrastructure loss	**13,750,000**
Pre Production Costs (G)	2%	of (D+E))	**119,380**
Inventory Capital		Reagent Vol * $/gal	**70,680**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**19,909,069**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**19,909,069**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	15.00	% of Total Capital Investment	2,986,360
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 79 kW-hr, 8586 hr/yr, 100% utilization	34,178
NA	NA		-
Water	0.31	$/kgal, 498 gph, 8586 hr/yr, 100% utilization	1,325
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization	2,003,101
NA	NA		-
NA	NA		-
Lost Ash Sales	36.00	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization	14,400,000
NA	NA		-
Urea	405.00	$/ton, 1 ton/hr, 8586 hr/yr, 100% utilization	1,806,138
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**21,231,102**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	1,665,978
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,665,978**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**22,897,080**

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		
		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	500	$\$/\mathrm{ft}^3$
Amount Required	12	ft^3
Packing Cost	6,300	Cost adjusted for freight & sales tax
Installation Labor	945	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	160	$\$/\mathrm{ft}^3$	
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.22	lb/MMBtu	kW
NSR	1.23		
Power			78.6
Total			78.6

Reagent Use & Other Operating Costs			Urea Use				
NOx in	0.22	lb/MMBtu		519	lb/hr Neat		
Efficiency	50%			50%	solution	71.0	lb/ft^3 Density 50% Solution
Duty	6,019	MMBtu/hr		1039	lb/hr	109.5	gal/hr
		Volume 14 day inventory		36,777	gal	$70,680	Inventory Cost
Water Use	498	gal/hr	Inject at 10% solution				
						10.74	wt % ash
Fuel Use	8.41	MMBtu/hr				37.30	% Coal Moisture Content
						0.73	% Coal Sulfur Content
Ash Generation	144.47	lb/hr				6,257	Btu/lb of coal

Operating Cost Calculations — **Annual hours of operation: 8,586** — **Utilization Rate: 100%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8586 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	15	% of Total Capital Investment				2,986,360	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	78.6	kW-hr	675,122	34,178	$/kwh, 79 kW-hr, 8586 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
	Water	0.31	$/kgal	497.9	gph	4,275	1,325	$/kgal, 498 gph, 8586 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8586 hr/yr, 100% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	46.7	ton/hr	400,620	2,003,101	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
	Lost Ash Sales	36.00	$/ton	46.6	ton/hr	400,000	14,400,000	$/ton, 47 ton/hr, 8586 hr/yr, 100% utilization
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
3	Urea	405	$/ton	0.5194	ton/hr	4,460	1,806,138	$/ton, 1 ton/hr, 8586 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								1,000,000
Purchased Equipment Total (B)	5%	of control device cost (A)						**1,050,000**
Installation - Standard Costs	0%	of purchased equip cost (B)						4,000,000
Installation - Site Specific Costs								NA
Installation Total								4,000,000
Total Direct Capital Cost, DC								5,050,000
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)						210,000
Total Capital Investment (TCI) = DC + IC								**5,260,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,942
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						655,319
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**663,261**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	30%			3877.2	1,680.1	395
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1 Sept 2005 Cost Estimate from Foster Wheeler, Option 1. Assumed price listed is for one unit. Costs in spreadsheet are for one unit
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)
3 Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4 Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART
5 Process, emissions and cost data listed above is for one unit.
6 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,000,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	0%	of control device cost (A)	0
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	50,000
Purchased Equipment Total (B)	5%		**1,050,000**
Installation			
Foundations & supports		of purchased equip cost (B)	0
Handling & erection		of purchased equip cost (B)	0
Electrical	10%	of purchased equip cost (B)	105,000
Piping		of purchased equip cost (B)	0
Insulation	15%	of purchased equip cost (B)	157,500
Painting		of purchased equip cost (B)	0
Installation Subtotal Standard Expenses (1)			**4,000,000**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**4,000,000**
Total Direct Capital Cost, DC			**5,050,000**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	52,500
Construction & field expenses	10%	of purchased equip cost (B)	105,000
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	10,500
Performance test	1%	of purchased equip cost (B)	10,500
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	31,500
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**210,000**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC			**5,260,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**5,260,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr	3,971
Maintenance Materials	100%	of maintenance labor costs	3,971
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,942**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,765
Administration (2% total capital costs)	2%	of total capital costs (TCI)	105,200
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	52,600
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	52,600
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	440,153
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**655,319**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**663,261**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,488,000		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**D P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion	0	lb/hr O2	0	scfh O2
LTO Cooling Water	150	gal/lb O3	0	gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	0	gpm				
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0	gpm		
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0	Installed	Installed cost factor per BOC.	

Operating Cost Calculations **Annual hours of operation:** **8,586**
Utilization Rate: **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	0	$/Hr	0.1	hr/8 hr shift	107	0	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	107	3,971	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,971	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8586 hr/yr, 100% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1 Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,586	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330º F
			Dry Std Flow Rate	1,312,850	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								500,000
Purchased Equipment Total (B)	5%	of control device cost (A)						**525,000**
Installation - Standard Costs	0%	of purchased equip cost (B)						2,000,000
Installation - Site Specific Costs								NA
Installation Total								2,000,000
Total Direct Capital Cost, DC								2,525,000
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)						105,000
Total Capital Investment (TCI) = DC + IC								**2,630,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,942
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						330,042
Total Annual Cost (Annualized Capital Cost + Operating Cost								**337,984**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	180.2	773.5				773.5	-	NA
Total Particulates	181.1	777.4				777.4	-	NA
Nitrous Oxides (NOx)	1,294.5	5,557.3	21%			4394.1	1,163.2	291
Sulfur Dioxide (SO_2)	4,027.3	17,289.1				17289.1	-	NA

Notes & Assumptions

1. Sept 2005 Cost Estimate from Foster Wheeler, Option 1. Assumed price listed is for one unit. Costs in spreadsheet are for one unit
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)
3. Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4. Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART
5. Process, emissions and cost data listed above is for one unit.
6. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**500,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	0%	of control device cost (A)	0
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	25,000
Purchased Equipment Total (B)	5%		**525,000**
Installation			
Foundations & supports		of purchased equip cost (B)	0
Handling & erection		of purchased equip cost (B)	0
Electrical		of purchased equip cost (B)	0
Piping		of purchased equip cost (B)	0
Insulation		of purchased equip cost (B)	0
Painting		of purchased equip cost (B)	0
Installation Subtotal Standard Expenses (1)			**2,000,000**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**2,000,000**
Total Direct Capital Cost, DC			**2,525,000**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	26,250
Construction & field expenses	10%	of purchased equip cost (B)	52,500
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	5,250
Performance test	1%	of purchased equip cost (B)	5,250
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	15,750
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**105,000**
Total Capital Investment (TCI) = DC + IC			**2,630,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**2,630,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr	3,971
Maintenance Materials	100%	of maintenance labor costs	3,971
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,942**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,765
Administration (2% total capital costs)	2%	of total capital costs (TCI)	52,600
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	26,300
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	26,300
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	220,077
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**330,042**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**337,984**

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,488,000		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**D P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion	0	lb/hr O2	0	scfh O2
LTO Cooling Water	150	gal/lb O3	0	gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	0	gpm				
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0	gpm		
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0	Installed	Installed cost factor per BOC.	

Operating Cost Calculations — **Annual hours of operation:** **8,586**
Utilization Rate: **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	0	$/Hr	0.1	hr/8 hr shift	107	0	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	107	3,971	$/Hr, 0.1 hr/8 hr shift, 8586 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,971	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8586 hr/yr, 100% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8586 hr/yr, 100% utilization
Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8586 hr/yr, 100% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8586 hr/yr, 100% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
WW Treat Biotreatement	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8586 hr/yr, 100% utilization
SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8586 hr/yr, 100% utilization
Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8586 hr/yr, 100% utilization
1 Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8586 hr/yr, 100% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8586 hr/yr, 100% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8586 hr/yr, 100% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8586 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix C

Coal Sulfur Content Variability

Sulfur Content Statistical Variability Analysis

For the purpose of establishing representative SO_2 emission rate predictions, past actual and future predicted coal sulfur content data for Falkirk Mine was analyzed. Table 1 presents an analysis of Coal Creek Station's past actual daily coal sulfur content. The analyzed data set includes 3,136 daily readings covering the time period from September 1997 through mid-May 2006, and is used to illustrate the variability between a 30-day rolling and 30-day block average. Past actual and future predicted mine plan 30-day block data presented in Section 7.2 of the report are recreated below in Figure 1. In order to include at least 98% of expected scenarios and appropriately determine an operational limit on a 30-day rolling average from the 30-day block averages, 14% variability must be assessed. This provides a degree of comfort with the operational limit and expected variability determined from past operational data.

The data presented in Figure 1 is calculated from core samples using a Falkirk mine plan modeling program. The predicted as delivered (AD) pounds of SO_2 per MMBtu is derived from the model. Consequently, the predicted AD pounds of SO_2 per MMBtu will change as the mine plan changes. The mine planning model uses grids generated from drilling and coring data. The in situ sulfur and Btu grids are built using the quality analysis from core samples. Once this is complete, a dilution factor is added in to get the AD sulfur and AD Btu. The dilution factor is needed to account for non-coal (clay) material which is present in the delivered coal as a result of the mining process. The amount of dilution used in the model is periodically adjusted by comparing the model predictions to past actual delivered quality reported by GRE.

The statistical analysis presented in Figure 1 is based on the 2004 mine plan which was available at the time of initial BART analysis submittal. Mine plans are variable in nature, and are therefore used only as an estimation tool, not a definitive statement of future emissions. The individual core sample IDs and characteristics will not be provided as supporting information to this graphic. It is virtually impossible to obtain a representative sample of the coal characteristics using core samples, and this model is only used to plan the mining operation and not to certify the sulfur content or heating values of future coal deliveries. The core samples cannot provide guaranteed estimates for quantities of the coal that will possess the specific characteristics of that core sample; only that some quantity of coal underground has those characteristics. The data provided by the mine plan model is used to incorporate a prediction of future worst case conditions, which in combination with past actual data, assists with the evaluation of SO_2 control technologies.

Table 1. Variability between 30-Day Rolling and 30-Day Block Calendar Month Averages

% Variability	Count	Cumulative %
0%	582	18.6%
1%	666	39.8%
2%	524	56.5%
3%	342	67.4%
4%	284	76.5%
5%	181	82.2%
6%	104	85.6%
7%	74	87.9%
8%	74	90.3%
9%	66	92.4%
10%	70	94.6%
11%	32	95.6%
12%	42	97.0%
13%	25	97.8%
14%	12	98.2%
15%	7	98.4%
16%	8	98.6%
17%	6	98.8%
18%	13	99.2%
19%	6	99.4%
20%	5	99.6%
21%	1	99.6%
22%	1	99.6%
23%	0	99.6%
24%	1	99.7%
25%	1	99.7%
26%	0	99.7%
27%	1	99.7%
28%	0	99.7%
29%	2	99.8%
30%	3	99.9%
31%	3	100.0%

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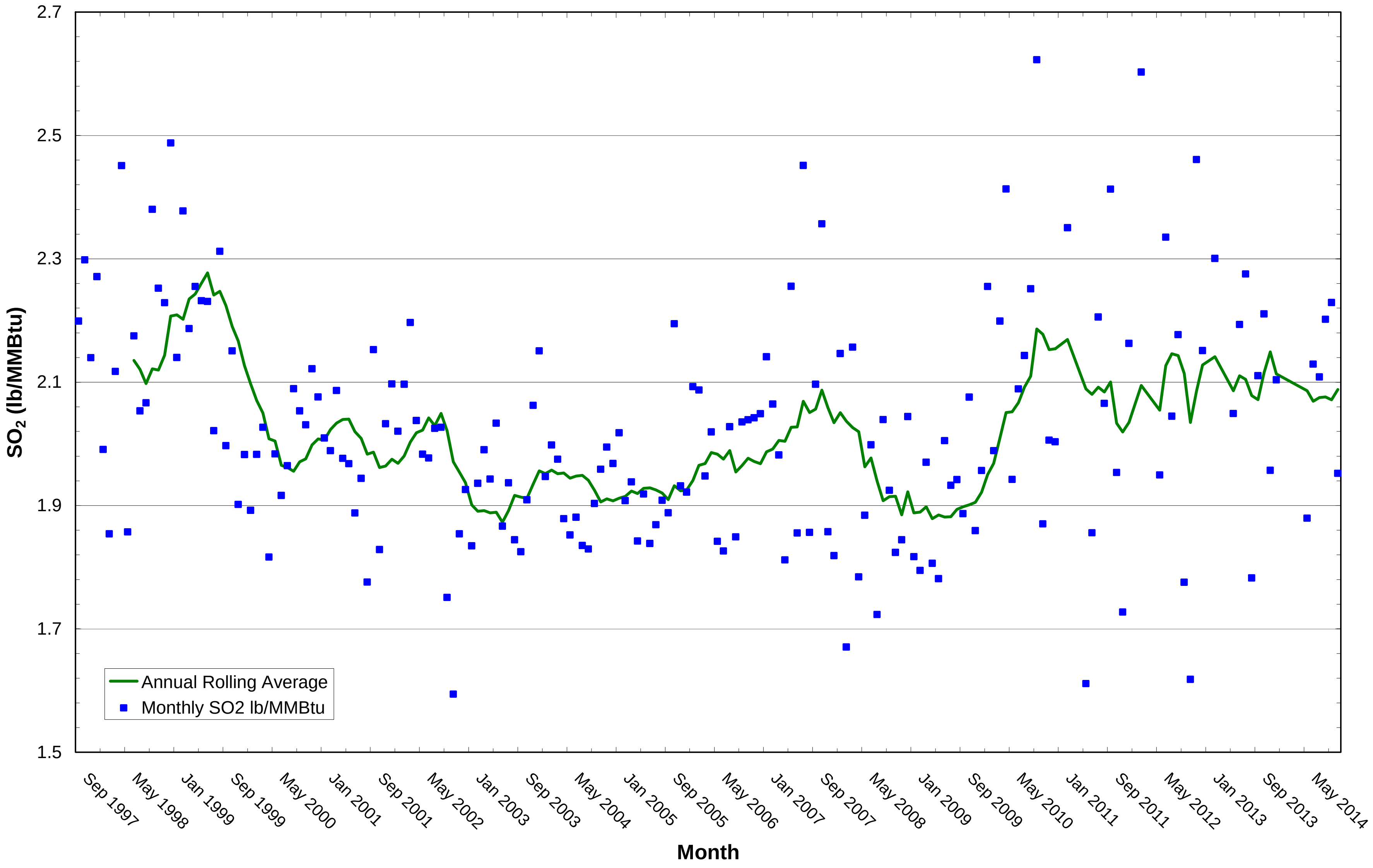

Figure 1. Past Actual and Future Predicted Monthly lb SO_2/MMBtu. Coal Creek sampling data is used to determine the 30-day block monthly average sulfur content from 1997 through 2006 and the Falkirk Mine Plan provides monthly predicting for future sulfur content from 2006 through 2014.

Appendix B

Cost Threshold Documentation

Summary of Relevant Economic Feasibility ($/ton) Control Costs

		Avg. Expected Values ($/ton)		Limiting/Marginal values ($/ton)		
Reference	**Regulatory Body/Rule**	**SO_2**	**NOx**	**SO_2**	**NOx**	**Comments**
FR Notice 6JULY05 Final Rule	BART	100 - 1000	100 - 1000			70 FR 39135
	BART		281 - 1296			70 FR 39135 Table 3
	BART	919				70 FR 39133
	BART					Guidelines disparagingly reference "thousands of dollars per ton" in commenting on the need to exceed MACT and its general unreasonableness.
70 FR 25210 CAIR	CAIR		1300			Estimated Marginal cost 2009
FR Notice 5MAY04 Proposed Rule	BART(proposed rule)	200-1000				BART proposed lists this as values for 90-95% SO2 control, which is still assumed, or .1 to .15 lb/MMBtu. Dropped from final to give states flexibility to require more. Says for scrubbers, bypasses aren't BART, only 100% scrubbing is BART.
	BART(proposed rule)					0.2 lb/MMBtu for NOx is assumed reasonable. Recognizes that some sources may need SCR to get this level. For those, state discretion of the cost vs. visibility value is necessary.
Midwest RPO Report Referencing CAIR	CAIR(using IPM)			1000	1500	
	CAIR (2009 in 1999$)		900		2400	
	CAIR (2015 in 1999$)		1800		3000	
	CAIR (depending on Nat'l emissions)			1200 - 3000	1400- 2100	This was modeled with TRUM (Technology Retrofitting Updating Model) to develop the marginal values.
Kammer EPA Decision	Kammer Decision			> 1000	> 1000	
LADCO Midwest RPO Boiler Analysis	LADCO/Midwest RPO	1240 - 3822	607 - 4493			
MANE-VU BART Control Assessment	MANE-VU			200 - 500	200 - 1500	
Bowers vs. SWAPCA	Bowers vs. SWAPCA	300	300	1000	1000	954-1134 was ruled too much, in favor of 256-310 for SO2. This did consider incremental value. Sections XVII to XIX
WRAP Trading Program Methodology	WRAP			3000		
	EPA - Referenced by Wrap					References EPA-600S\7-90-018. Low is <$500/ton, Moderate is $500-3000/ton, High is over $3000/ton

The dollars per ton estimates cited above were obtained from BART guidance, documentation of similar regulatory programs such as CAIR, and relevant court decisions. These materials indicate that most EPA sanctioned documents, including the final BART ruling, concretely support an average expected reasonable cost range of $1,300 to $1,800 per ton of NOx removed and a range of $1,000 to $1,300 per ton of SO_2 removed. The BART presumptive limits were set based on cost effective controls that were on average less than these ranges. As an example, the presumptive SO_2 limit was established based on an average cost effectiveness of less than $1,000/ton. As the cost analysis extends into RPO, WRAP and other regional planning documentation, the cost ranges become more variable and difficult to predict. For ease of comparison, the federally established ranges for NOx and SO_2 were used as a BART cost threshold basis.

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GREAT RIVER
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July 3, 2007

Mr Terry O'Clair
North Dakota Department of Health
Division of Air Quality
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

RE: Great River Energy – Coal Creek and Stanton Stations
Supplemental Information for Cost Effectiveness under BART

Dear Mr O'Clair:

As follow-up to our June 4, 2007, meeting with you and Mr. David Glatt, this document serves to outline information relevant to determining an appropriate cost effectiveness threshold for evaluations under Best Available Retrofit Technology (BART). Great River Energy (GRE) submits this information as an addendum to the BART analyses and proposal documents that have been submitted to the North Dakota Department of Health (NDDH) for GRE's Coal Creek and Stanton stations. This information and proposal is for your consideration, and we look forward to continuing our dialogue with you on this matter.

Cost effectiveness is one of several important factors evaluated to determine BART in accordance with U.S. Environmental Protection Agency (EPA) rules and guidance. The EPA is specific in its assignment of presumptive BART emission rates and cost effectiveness expectations.[1] Alternative cost effectiveness values referenced through Section 309 of the Clean Air Act are of interest, but are not as specifically tailored to the goals of the BART rules.

The NDDH has suggested a value deemed cost effective for purposes of economic impacts under BART. This value stems from a reference in the 2004 proposed rule for BART determinations.[2] Specifically, the proposed BART Rule references a draft technical support document[3] (TSD) for

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[1] Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking – Setting BART SO_2 Limits for Electric Generating Units: Control Technology and Cost Effectiveness, April 2005. Note that scatter plot evaluations for NOx and SO_2 illustrate that presumptive levels are established from large electricity generating units (EGUs) to ensure the highest visibility reduction.

[2] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule; F.R. Vol. 69, No. 87, May 5, 2004, p. 25198

[3] Western Regional Air Partnership Regional Haze BART (Trading Program Option) TSD 6A, Draft: July 16, 1999

the Western Regional Air Partnership's (WRAP) Annex[4] to a report submitted to the EPA by the Grand Canyon Visibility Transport Commission (GCVTC) in 1996.[5]

The cost effectiveness ranges stated in this WRAP TSD reference an EPA assessment of NOx and SO_2 controls for coal-fired boilers that was published in 1990.[6,7] While the information presented is of interest to BART, a straight inflation adjustment from an analysis performed in the late 1980s and published in 1990 does not provide an accurate reflection of current pollution control technologies and associated capital and operating cost effectiveness.

The 1990 EPA document presents a range of control costs that vary by coal sulfur content, boiler type, and generating capacity. It further states that cost estimates rely heavily on site-specific parameters and that both cost and pollutant removal efficiency should be balanced when selecting a control technology for a given boiler. At the time of the report, many technologies considered for BART, including selective non-catalytic reduction (SNCR) for NOx, were not commercially available and are therefore not reflected in the analysis. With the wide variety of specific control costs presented in the document, the range of $500 to $3,000 presented as moderate in the WRAP TSD is a subjective number that broadly incorporated all NOx and SO_2 costs for every type and size of utility.

The document states that $3,000 was used as an approximation to exclude controls that meet BACT level emissions. While BACT controls have been accepted as BART in many cases, the opposite is not necessarily true. Therefore, while BACT average and incremental cost effectiveness thresholds may be reviewed while determining BART cost effectiveness, the EPA's BART Rule and TSDs as well as associated visibility improvements should ultimately be the determinative guidance.

The WRAP TSD was produced under the assumption that BART may not be required for EGUs, which is the premise of the WRAP trading program. Further, in the executive summary to the WRAP annex, it is explained that the goal of WRAP is to employ reductions that are "better than BART" to achieve greater reductions than dictated by reasonable progress goals.

For these reasons, WRAP cost estimates include more than just "BART-eligible sources." As a final WRAP comment, note that the WRAP Annex explicitly sets program penalties at $5,000/ton of excess emissions.[8] This penalty is established at "three to four times greater than the expected market trading price," which is, by definition, an expected cost effectiveness of approximately $1,200/ton to $1,600/ton.

---

[4] Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and A Backstop Market Trading Program, September 29, 2000

[5] Report from Grand Canyon Visibility Transport Commission to the United States Environmental Protection Agency, June 1996

[6] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule; F.R. Vol. 69, No. 87, May 5, 2004, p. 25198.

[7] Assessment of Control Technologies for Reducing Emissions of SO_2 and NOx from Existing Coal-Fired Utility Boilers, EPA-600/7-90-018, September 1990

[8] Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and A Backstop Market Trading Program, September 29, 2000, p. 47

Given the outdated nature of the EPA control assessment that is at the root of WRAP's $500 to $3,000/ton range, it is critically important to rely on more recent cost documentation as provided by the EPA in the BART Rule and associated technical support documents and as provided in GRE's BART analyses reports to the NDDH.

With respect to cost effectiveness as defined in the BART Final Rule,[9] the expected control costs range from $900/ton to $2,400/ton for SO_2 removal and from $300/ton to $1,300/ton for NOx, with most NOx estimates at less than $1,000/ton. Again, these estimates rely heavily on boiler type, capacity, and the fuel burned. The following two excerpted figures illustrate not only the EPA's intent to evaluate BART cost effectiveness on the type and size of boiler, but also confirms that average cost effectiveness is established at a much lower level than that suggested by the NDDH. As an example, highlighted in the two excerpted figures are the rows that would apply to Stanton Station.

FIGURE 1

Unit capacity (MW)	Tons (K) of SO_2 emitted in 2001	Percent of BART eligible coal-fired unit's 2001 emissions	Calculated average cost effectiveness for MW grouping ($/ton SO_2 removed)	Percent of estimated removable BART SO_2 emissions from coal-fired units*
<50 MW	26	0.4	1962	0.9
50–100 MW	93	1.4	2399	1.6
100–150 MW	171	2.5	1796	2.2
150–200 MW	235	3.5	1324	3.4
200–250 MW	253	3.8	1282	3.1
250–300 MW	281	3.2	1128	4.0
>300 MW	5712	85.2	......	84.8
All Units	6707	100	984	100
BART Units (>200MW)	6246	92.2	919	91.9

TABLE 3.—AVERAGE COST-EFFECTIVENESS OF NOx CONTROLS FOR BART-ELIGIBLE COAL-FIRED UNITS

Unit type	Coal type	Number units nation-wide	National average ($/ton)
Dry-bottom wall-fired	Bituminous	114	1229
	Sub-bituminous	66	576
	Lignite	3	1296
Tangential-fired	Bituminous	105	567
	Sub-bituminous	72	281
	Lignite	9	614
Cell Burners	Bituminous	32	1287
	Sub-bituminous	3	1021
Dry-turbo-fired	Bituminous	7	775
	Sub-bituminous	7	599
Wet-bottom	Bituminous	6	378
Cyclones (with SCR)	All	56	900

In the determination of NOx control cost effectiveness the NDDH should also be cognizant of determinations made by other states in EPA Region 8. As an example, in Colorado's final BART guidance[10] it has been stated that no post-combustion NOx controls will be required, precluding the need to consider SNCR and selective catalytic reduction (SCR) as potential control options.

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[9] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule; F.R. Vol. 70, No. 128, July 6, 2005, p. 39133-39135

[10] Colorado BART, March 16, 2006

In the proposed BART Rule[11] the EPA also states that post-combustion NOx controls should not be necessary, other than on cyclone units.

The BART Final Rule further supports that visibility impacts are a key component of the BART determination. If one control technology provides a significant improvement in visibility over another, the State may and should consider this information in its BART determination Under this assumption, one cost effectiveness threshold would not be appropriate for all units because there would be varying degrees of visibility improvements.

In terms of visibility improvement, a 0.5 deciview (dV) level has already been determined by the EPA to be a "contribution threshold" for states in determining BART-eligible sources that cause or contribute to visibility impairment and thus become "subject to BART." It can be asserted that any change in impairment from an individual facility with BART-eligible sources less than 0.5 dV can and should be deemed insignificant by a state. In the 2005 document from the NDDH addressing regional haze status[12] the NDDH determined that a newly permitted coal-fired ethanol production facility and a new 175-MW power plant that will be located closer to Class I areas than GRE's facilities would not adversely affect visibility in the North Dakota Class I areas. The fact that these two projects have already been deemed insignificant supports a *de minimis* contribution threshold.

We understand that regional-scale dispersion modeling for BART is pending. Until this analysis is completed it is unknown whether North Dakota will meet its reasonable further progress goals Accordingly, before requiring emission controls beyond BART, the regional-scale dispersion modeling analysis should be completed with source attribution assessments including those from North Dakota, other contributing states and Canadian sources with their projected reductions. If it can be shown that sources outside the United States are preventing North Dakota Class I areas from meeting their glide path goals, consideration should be given to revising the natural background goal to account for sources that cannot be controlled under the EPA regional haze rules.

Cost effectiveness thresholds have been determined for many other regulatory programs similar to BART. However, BART has the distinct goal of improving/reducing regional haze and is unique in its consideration of visibility impacts. Regardless of the references used to determine cost effectiveness thresholds, it is obvious that pollutant specific thresholds are supported by the EPA. GRE maintains that based on the EPA BART Rule with ranges of $900/ton to $2,400/ton for SO_2 removal and $300/ton to $1,300/ton for NOx removal, and associated references presented in this document, a value of $1,500/ton or less is appropriate for determining cost effectiveness for both NOx and SO_2 control technologies under BART.

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[11] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule; F.R. Vol 69, No. 87, May 5, 2004, p 25202

[12] Report on Progress Made Toward the National Visibility Goal, November 2005.

Should you have any questions regarding this submittal, please contact me or Greg Archer at 763-241-2278.

Sincerely,

GREAT RIVER ENERGY

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

c: David Glatt – NDDH
Greg Archer – GRE
Deb Nelson – GRE
Steve Smokey – GRE, Stanton
Diane Stockdill – GRE, Coal Creek
Joel Trinkle – Barr Engineering Co.

Appendix D

Visibility Modeling Output Files

Revised Pages February 2007

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
1200 Missouri Avenue, Bismarck, ND 58504-5264
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701.328.5200 (fax)
www.ndhealth.gov

November 30, 2005

Ms. Dianne Stockdill
Environmental Coordinator
Great River Energy
2875 Third Street SW
Underwood, ND 58576

Dear Ms. Stockdill:

As specified in the June 15, 2005 final amendments to the EPA July, 1999 regional haze rule, the Department has completed visibility modeling to determine which North Dakota BART-eligible (Best Available Retrofit Technology) sources are subject to BART. The Department's visibility analysis for this BART screening followed the protocol outlined in "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota" (North Dakota Department of Health, November, 2005).

As you are aware, the Great River Energy Coal Creek Generating Station Units 1 and 2 are BART-eligible sources. Completed visibility modeling for the Coal Creek Station (Units 1 and 2 combined) indicates that the maximum 98th percentile delta-deciview prediction for the facility exceeds the BART screening threshold of 0.5 deciviews. Therefore, Coal Creek Units 1 and 2 are subject to BART.

Two summaries of modeling results are enclosed. Attachment A provides a summary of 98th percentile predictions for the worst-case meteorological year for all BART-eligible facilities. Attachment B provides more detailed results specific to the Coal Creek Generating Station. Included in Attachment B are results for all delta-deciview metrics recommended in the North Dakota protocol, for each year of meteorological data. Also provided are worst-case day and receptor, and the percent contribution for each species.

If you have any questions regarding these results, please contact Steve Weber or Rob White of my staff at (701)328-5188. We look forward to working with you to develop appropriate BART control strategies for Coal Creek Units 1 and 2.

Sincerely,

Steve Weber for

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/SW:csc
Enc:
xc/enc: Deb Nelson - Great River Energy

Attachment A

Summary of BART Screening Results
98th Percentile Prediction for Worst-case Met. Year (2000-2002)
(24-hr Delta-Deciview)

	TRNP South	TRNP North	TRNP Elk. Ranch	Lostwood NWA
Leland Olds Station	6.22	5.32	4.49	5.42
Milton R Young Station	6.69	5.58	6.10	4.88
Coal Creek Station	4.48	3.56	3.04	4.04
Stanton Station Unit 1	1.68	1.54	1.43	1.35
Heskett Station Unit 2	0.82	0.54	0.61	0.58
Mandan Refinery	0.05	0.04	0.04	0.04

29-Nov-05

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CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 0, Pre-BART) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND        % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        2.915     5.149     2.234    2000   72     53    107   2.80    68.34   30.91    0.26
      0.49
  98th %tile Delta-DV     1.229     3.399     2.170    2000  164     51    105   2.50    96.84    1.72    0.53
      0.91
  90th %tile Delta-DV     0.299     2.405     2.106    2000  214     46     46   2.20    96.52    1.60    0.79
      1.08

  Number of days with Delta-Deciview > 0.50:    24
  Number of days with Delta-Deciview > 1.00:    11
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.851     5.085     2.234    2000   74     67     56   2.80    76.95   22.60    0.06
      0.39
  98th %tile Delta-DV     0.941     3.175     2.234    2000   36     82     71   2.80    60.35   38.73    0.25
      0.67
  90th %tile Delta-DV     0.318     2.424     2.106    2000  214     82     71   2.20    97.68    1.05    0.31
      0.96

  Number of days with Delta-Deciview > 0.50:    21
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        2.918     5.152     2.234    2000   74     90     72   2.80    76.04   23.52    0.06
      0.39
  98th %tile Delta-DV     0.777     3.010     2.234    2000   54     90     72   2.80    77.58   21.66    0.25
      0.51
  90th %tile Delta-DV     0.212     2.361     2.149    2000  199     90     72   2.40    92.17    5.82    0.68
      1.33

  Number of days with Delta-Deciview > 0.50:    18
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.941     6.216     2.275    2000   47     99     81   2.90    72.86   26.64    0.16
      0.33
  98th %tile Delta-DV     1.183     3.415     2.232    2000  196     99     81   2.70    89.63    8.06    0.71
      1.61
  90th %tile Delta-DV     0.503     2.735     2.232    2000  185     99     81   2.70    91.19    7.65    0.34
      0.82

  Number of days with Delta-Deciview > 0.50:    37
  Number of days with Delta-Deciview > 1.00:    17
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 0, Pre-BART) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                     SEQ     ND          % of Modeled Extinction by
                                                                            Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        5.024     7.258     2.234    2000   72     53    107   2.80    66.43   32.84    0.25
      0.48
  98th %tile Delta-DV     2.176     4.346     2.170    2000  164     51    105   2.50    97.09    1.47    0.53
      0.92
  90th %tile Delta-DV     0.553     2.680     2.127    2000  100     51    105   2.30    63.30   35.11    0.55
      1.04

  Number of days with Delta-Deciview > 0.50:    41
  Number of days with Delta-Deciview > 1.00:    22
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        4.550     6.783     2.234    2000   74     67     56   2.80    82.48   17.04    0.06
      0.42
  98th %tile Delta-DV     1.836     4.069     2.234    2000   36     82     71   2.80    58.41   40.68    0.25
      0.66
  90th %tile Delta-DV     0.586     2.734     2.149    2000  183     82     71   2.40    93.83    4.90    0.41
      0.86

  Number of days with Delta-Deciview > 0.50:    41
  Number of days with Delta-Deciview > 1.00:    19
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        4.813     7.046     2.234    2000   74     90     72   2.80    78.69   20.85    0.07
      0.40
  98th %tile Delta-DV     1.391     3.497     2.106    2000  265     90     72   2.20    87.87   11.21    0.28
      0.64
  90th %tile Delta-DV     0.401     2.635     2.234    2000   56     90     72   2.80    74.35   24.92    0.22
      0.51

  Number of days with Delta-Deciview > 0.50:    35
  Number of days with Delta-Deciview > 1.00:    15
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        5.654     7.930     2.275    2000   47     99     81   2.90    86.27   13.15    0.19
      0.39
  98th %tile Delta-DV     2.157     4.432     2.275    2000   72     97     79   2.90    69.75   29.78    0.16
      0.30
  90th %tile Delta-DV     0.945     3.177     2.232    2000  204     96     78   2.70    66.55   32.48    0.34
      0.63

  Number of days with Delta-Deciview > 0.50:    58
  Number of days with Delta-Deciview > 1.00:    33
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

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CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 1) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND          % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        1.383     3.616     2.234    2000   72     53     107   2.80    53.98   43.94    0.70
      1.38
  98th %tile Delta-DV     0.439     2.673     2.234    2000   75     56     110   2.80    59.78   38.65    0.23
      1.34
  90th %tile Delta-DV     0.109     2.237     2.127    2000  101     46      46   2.30    51.59   45.04    0.87
      2.50

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.219     3.452     2.234    2000   74     67      56   2.80    66.62   32.12    0.17
      1.10
  98th %tile Delta-DV     0.493     2.768     2.276    2000  316     85     114   3.00    55.05   43.38    0.60
      0.96
  90th %tile Delta-DV     0.117     2.350     2.234    2000   48     82      71   2.80    67.15   32.12    0.12
      0.61

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.292     3.525     2.234    2000   74     90      72   2.80    65.79   32.96    0.18
      1.07
  98th %tile Delta-DV     0.303     2.537     2.234    2000   69     90      72   2.80    42.73   54.13    1.27
      1.86
  90th %tile Delta-DV     0.093     2.327     2.234    2000   56     90      72   2.80    64.31   33.68    0.60
      1.41

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.862     4.138     2.275    2000   47     99      81   2.90    61.39   37.26    0.43
      0.92
  98th %tile Delta-DV     0.486     2.653     2.167    2000  216     97      79   2.40    71.10   25.73    1.32
      1.85
  90th %tile Delta-DV     0.192     2.359     2.167    2000  215     99      81   2.40    63.48   25.76    4.16
      6.60

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

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CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 1) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                  SEQ    ND        % of Modeled Extinction by
                                                                      Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -------------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        2.620     4.854     2.234    2000   72     53    107   2.80    53.94   44.12    0.65
      1.29
  98th %tile Delta-DV     0.860     3.094     2.234    2000   75     56    110   2.80    59.84   38.69    0.21
      1.25
  90th %tile Delta-DV     0.217     2.344     2.127    2000  101     46     46   2.30    51.80   45.04    0.82
      2.35

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.302     4.535     2.234    2000   74     67     56   2.80    66.71   32.11    0.15
      1.03
  98th %tile Delta-DV     0.959     3.235     2.276    2000  316     85    114   3.00    55.14   43.39    0.56
      0.90
  90th %tile Delta-DV     0.235     2.468     2.234    2000   48     82     71   2.80    67.16   32.15    0.11
      0.57

  Number of days with Delta-Deciview > 0.50:    16
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        2.432     4.666     2.234    2000   74     90     72   2.80    65.88   32.95    0.17
      1.00
  98th %tile Delta-DV     0.596     2.830     2.234    2000   69     90     72   2.80    42.86   54.21    1.19
      1.74
  90th %tile Delta-DV     0.186     2.420     2.234    2000   56     90     72   2.80    64.41   33.71    0.56
      1.32

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        3.470     5.745     2.275    2000   47     99     81   2.90    61.59   37.14    0.41
      0.86
  98th %tile Delta-DV     0.954     3.121     2.167    2000  216     97     79   2.40    71.27   25.77    1.23
      1.73
  90th %tile Delta-DV     0.376     2.543     2.167    2000  215     99     81   2.40    64.11   25.79    3.89
      6.20

  Number of days with Delta-Deciview > 0.50:    28
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

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CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 2) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        1.352     3.585     2.234    2000   72    53    107   2.80    48.95   49.31    0.60
      1.14
  98th %tile Delta-DV     0.494     2.728     2.234    2000   75    56    110   2.80    52.28   46.33    0.21
      1.18
  90th %tile Delta-DV     0.125     2.274     2.149    2000  184    48    102   2.40    76.35   21.47    0.73
      1.44

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.227     3.460     2.234    2000   74    67     56   2.80    59.58   39.28    0.14
      0.99
  98th %tile Delta-DV     0.446     2.679     2.234    2000   36    82     71   2.80    40.08   57.92    0.55
      1.45
  90th %tile Delta-DV     0.124     2.294     2.170    2000  164    82     71   2.50    68.75   28.23    0.90
      2.11

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.268     3.502     2.234    2000   74    90     72   2.80    58.36   40.51    0.16
      0.97
  98th %tile Delta-DV     0.314     2.548     2.234    2000   54    90     72   2.80    60.03   38.06    0.63
      1.29
  90th %tile Delta-DV     0.088     2.343     2.255    2000   31    90     72   2.90    42.25   55.39    0.74
      1.62

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.824     4.100     2.275    2000   47    99     81   2.90    53.87   44.94    0.39
      0.80
  98th %tile Delta-DV     0.499     2.645     2.145    2000  136    99     81   2.30    45.57   51.66    1.01
      1.76
  90th %tile Delta-DV     0.215     2.447     2.232    2000  208    91     73   2.70    76.27   21.34    0.49
      1.90

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

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CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 2) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND        % of Modeled Extinction by
                                                                        Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         ----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        2.558     4.792     2.234    2000   72    53    107   2.80    48.86   49.51    0.56
      1.07
  98th %tile Delta-DV     0.970     3.203     2.234    2000   75    56    110   2.80    52.37   46.34    0.19
      1.10
  90th %tile Delta-DV     0.251     2.378     2.127    2000  101    46     46   2.30    45.21   52.12    0.68
      1.98

  Number of days with Delta-Deciview > 0.50:    18
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.326     4.560     2.234    2000   74    67     56   2.80    59.64   39.30    0.13
      0.93
  98th %tile Delta-DV     0.909     3.143     2.234    2000   54    82     71   2.80    51.97   46.47    0.55
      1.01
  90th %tile Delta-DV     0.245     2.415     2.170    2000  164    82     71   2.50    69.06   28.11    0.84
      1.98

  Number of days with Delta-Deciview > 0.50:    18
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        2.419     4.652     2.234    2000   74    90     72   2.80    58.46   40.49    0.15
      0.90
  98th %tile Delta-DV     0.627     2.733     2.106    2000  265    90     72   2.20    66.05   31.84    0.64
      1.46
  90th %tile Delta-DV     0.175     2.302     2.127    2000  109    90     72   2.30    18.62   74.81    2.79
      3.77

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        3.354     5.630     2.275    2000   47    99     81   2.90    54.03   44.86    0.36
      0.75
  98th %tile Delta-DV     0.983     3.128     2.145    2000  136    99     81   2.30    45.55   51.85    0.95
      1.65
  90th %tile Delta-DV     0.426     2.571     2.145    2000  247    91     73   2.30    62.84   35.39    0.35
      1.42

  Number of days with Delta-Deciview > 0.50:    29
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CCALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 3) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND         % of Modeled Extinction by
                                                                        Species
                         DELTA-DV  DV(Total)  DV(BKG)   YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -------------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        1.275     3.509     2.234    2000   72    53    107   2.80    52.09   46.06    0.64
      1.21
  98th %tile Delta-DV     0.467     2.701     2.234    2000   75    56    110   2.80    55.37   43.16    0.22
      1.25
  90th %tile Delta-DV     0.119     2.247     2.127    2000  101    46     46   2.30    48.00   48.98    0.78
      2.25

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.172     3.405     2.234    2000   74    67     56   2.80    62.56   36.25    0.15
      1.04
  98th %tile Delta-DV     0.416     2.649     2.234    2000   36    82     71   2.80    43.05   54.80    0.59
      1.56
  90th %tile Delta-DV     0.118     2.245     2.127    2000  110    63     52   2.30    14.70   70.78    6.10
      8.42

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.210     3.443     2.234    2000   74    90     72   2.80    61.37   37.45    0.17
      1.02
  98th %tile Delta-DV     0.300     2.533     2.234    2000   54    90     72   2.80    62.99   35.00    0.66
      1.35
  90th %tile Delta-DV     0.082     2.188     2.106    2000  214    90     72   2.20    93.83    1.40    1.72
      3.05

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.733     4.009     2.275    2000   47    99     81   2.90    56.97   41.78    0.41
      0.85
  98th %tile Delta-DV     0.469     2.614     2.145    2000  136    99     81   2.30    48.60   48.45    1.07
      1.87
  90th %tile Delta-DV     0.207     2.440     2.232    2000  204    96     78   2.70    51.65   45.89    0.87
      1.58

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 3) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        2.421     4.654     2.234    2000   72    53    107    2.80    52.01   46.26    0.60
      1.14
  98th %tile Delta-DV     0.918     3.152     2.234    2000   75    56    110    2.80    55.45   43.18    0.20
      1.17
  90th %tile Delta-DV     0.235     2.363     2.127    2000  101    46     46    2.30    48.18   48.98    0.73
      2.11

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.227     4.461     2.234    2000   74    67     56    2.80    62.61   36.27    0.14
      0.97
  98th %tile Delta-DV     0.860     3.094     2.234    2000   54    82     71    2.80    55.04   43.30    0.58
      1.07
  90th %tile Delta-DV     0.236     2.406     2.170    2000  164    82     71    2.50    71.56   25.51    0.87
      2.05

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        2.313     4.547     2.234    2000   74    90     72    2.80    61.46   37.43    0.15
      0.95
  98th %tile Delta-DV     0.605     2.711     2.106    2000  265    90     72    2.20    68.57   29.25    0.66
      1.52
  90th %tile Delta-DV     0.163     2.397     2.234    2000   56    90     72    2.80    60.77   37.41    0.55
      1.26

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        3.199     5.475     2.275    2000   47    99     81    2.90    57.11   41.71    0.38
      0.79
  98th %tile Delta-DV     0.924     3.070     2.145    2000  136    99     81    2.30    48.59   48.65    1.01
      1.76
  90th %tile Delta-DV     0.409     2.641     2.232    2000  204    96     78    2.70    51.88   45.82    0.82
      1.49

  Number of days with Delta-Deciview > 0.50:    26
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 4) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        1.113     3.346     2.234    2000   72    53    107   2.80    60.20   37.66    0.74
      1.40
  98th %tile Delta-DV     0.410     2.644     2.234    2000   75    56    110   2.80    63.24   35.08    0.25
      1.43
  90th %tile Delta-DV     0.106     2.276     2.170    2000  161    53    107   2.50    88.70    6.94    0.95
      3.41

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.055     3.288     2.234    2000   74    67     56   2.80    69.91   28.75    0.17
      1.16
  98th %tile Delta-DV     0.352     2.585     2.234    2000   36    82     71   2.80    51.03   46.42    0.70
      1.85
  90th %tile Delta-DV     0.105     2.233     2.127    2000  139    82     71   2.30    83.66   12.64    1.27
      2.43

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.085     3.319     2.234    2000   74    90     72   2.80    68.85   29.83    0.19
      1.14
  98th %tile Delta-DV     0.270     2.440     2.170    2000  164    90     72   2.50    91.76    4.11    1.41
      2.72
  90th %tile Delta-DV     0.072     2.306     2.234    2000   56    90     72   2.80    67.76   30.04    0.67
      1.52

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.539     3.814     2.275    2000   47    99     81   2.90    64.81   33.77    0.46
      0.96
  98th %tile Delta-DV     0.417     2.692     2.275    2000   72    97     79   2.90    63.51   35.10    0.49
      0.90
  90th %tile Delta-DV     0.180     2.412     2.232    2000  204    96     78   2.70    59.76   37.40    1.01
      1.83

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 4) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         ---------------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        2.125     4.359     2.234    2000   72    53    107   2.80    60.15   37.84    0.69
      1.31
  98th %tile Delta-DV     0.808     3.042     2.234    2000   75    56    110   2.80    63.34   35.10    0.23
      1.33
  90th %tile Delta-DV     0.210     2.380     2.170    2000  161    53    107   2.50    89.16    6.76    0.88
      3.21

  Number of days with Delta-Deciview > 0.50:    14
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.015     4.248     2.234    2000   74    67     56   2.80    69.97   28.78    0.16
      1.09
  98th %tile Delta-DV     0.732     2.965     2.234    2000   36    82     71   2.80    51.18   46.39    0.67
      1.76
  90th %tile Delta-DV     0.209     2.337     2.127    2000  139    82     71   2.30    83.94   12.59    1.19
      2.27

  Number of days with Delta-Deciview > 0.50:    14
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        2.087     4.320     2.234    2000   74    90     72   2.80    68.94   29.82    0.17
      1.07
  98th %tile Delta-DV     0.552     2.786     2.234    2000   54    90     72   2.80    70.54   27.37    0.69
      1.41
  90th %tile Delta-DV     0.146     2.380     2.234    2000   56    90     72   2.80    67.97   29.99    0.62
      1.41

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        2.864     5.139     2.275    2000   47    99     81   2.90    64.94   33.72    0.43
      0.90
  98th %tile Delta-DV     0.832     3.108     2.275    2000   72    97     79   2.90    63.65   35.05    0.45
      0.84
  90th %tile Delta-DV     0.358     2.633     2.275    2000   70    93     75   2.90    48.91   48.48    0.85
      1.75

  Number of days with Delta-Deciview > 0.50:    26
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 5) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                      SEQ    ND        % of Modeled Extinction by
                                                                          Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -------------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        0.867     3.101     2.234    2000   72    53    107   2.80    78.22   19.00    0.96
      1.82
  98th %tile Delta-DV     0.338     2.571     2.234    2000   44     3      3   2.80    67.59   28.69    1.02
      2.70
  90th %tile Delta-DV     0.081     2.209     2.127    2000  100    51    105   2.30    72.40   21.66    2.06
      3.88

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.929     3.035     2.106    2000  247    58     47   2.20    92.96    2.16    1.57
      3.30
  98th %tile Delta-DV     0.255     2.488     2.234    2000   36    82     71   2.80    70.77   25.70    0.97
      2.56
  90th %tile Delta-DV     0.097     2.225     2.127    2000  139    82     71   2.30    90.54    5.45    1.38
      2.63

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.897     3.130     2.234    2000   74    90     72   2.80    84.12   14.26    0.23
      1.40
  98th %tile Delta-DV     0.224     2.458     2.234    2000   54    90     72   2.80    84.64   12.66    0.89
      1.82
  90th %tile Delta-DV     0.067     2.216     2.149    2000  199    90     72   2.40    90.17    3.40    2.17
      4.26

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.242     3.517     2.275    2000   47    99     81   2.90    81.56   16.65    0.58
      1.21
  98th %tile Delta-DV     0.371     2.646     2.275    2000   54    91     73   2.90    81.49   16.23    0.86
      1.42
  90th %tile Delta-DV     0.139     2.371     2.232    2000  186    91     73   2.70    86.12    6.86    3.09
      3.93

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 5) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                  SEQ    ND         % of Modeled Extinction by
                                                                      Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         ------------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        1.672     3.906     2.234    2000   72    54    108   2.80    78.35   19.05    0.89
      1.71
  98th %tile Delta-DV     0.665     2.899     2.234    2000   44     3      3   2.80    67.81   28.72    0.95
      2.52
  90th %tile Delta-DV     0.161     2.288     2.127    2000  100    51    105   2.30    72.77   21.66    1.93
      3.64

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.768     3.874     2.106    2000  247    58     47   2.20    93.47    1.95    1.48
      3.10
  98th %tile Delta-DV     0.533     2.767     2.234    2000   36    82     71   2.80    70.96   25.68    0.93
      2.44
  90th %tile Delta-DV     0.194     2.321     2.127    2000  139    82     71   2.30    90.82    5.43    1.29
      2.46

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.739     3.973     2.234    2000   74    90     72   2.80    84.23   14.26    0.21
      1.30
  98th %tile Delta-DV     0.461     2.695     2.234    2000   54    90     72   2.80    84.86   12.62    0.83
      1.70
  90th %tile Delta-DV     0.133     2.282     2.149    2000  199    90     72   2.40    90.61    3.37    2.03
      3.99

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        2.340     4.615     2.275    2000   47    99     81   2.90    81.69   16.63    0.55
      1.13
  98th %tile Delta-DV     0.720     2.995     2.275    2000   37    97     79   2.90    69.90   26.17    1.33
      2.59
  90th %tile Delta-DV     0.277     2.423     2.145    2000  131    91     73   2.30    72.47   22.14    2.41
      2.98

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 6) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        0.787     3.020     2.234    2000   72    54    108   2.80    86.64   10.29    1.06
      2.01
  98th %tile Delta-DV     0.296     2.530     2.234    2000   75    56    110   2.80    88.13    9.53    0.35
      2.00
  90th %tile Delta-DV     0.073     2.200     2.127    2000  113    55    109   2.30    92.72    1.54    1.29
      4.46

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.919     3.025     2.106    2000  247    58     47   2.20    93.98    1.09    1.59
      3.34
  98th %tile Delta-DV     0.229     2.335     2.106    2000  239    82     71   2.20    93.17    3.42    1.09
      2.31
  90th %tile Delta-DV     0.095     2.222     2.127    2000  139    82     71   2.30    93.09    2.79    1.42
      2.70

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.835     3.068     2.234    2000   74    90     72   2.80    90.67    7.58    0.24
      1.51
  98th %tile Delta-DV     0.220     2.475     2.255    2000   11    90     72   2.90    80.94   14.95    1.25
      2.85
  90th %tile Delta-DV     0.057     2.185     2.127    2000  106    90     72   2.30    60.69   26.13    5.68
      7.49

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.143     3.418     2.275    2000   47    99     81   2.90    89.07    8.97    0.64
      1.32
  98th %tile Delta-DV     0.341     2.616     2.275    2000   54    91     73   2.90    88.73    8.79    0.94
      1.54
  90th %tile Delta-DV     0.128     2.274     2.145    2000  131    91     73   2.30    81.48   12.11    2.87
      3.54

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 6) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                       SEQ    ND        % of Modeled Extinction by
                                                                           Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         ------------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        1.522     3.755     2.234    2000   72     54    108   2.80    86.76   10.36    0.99
      1.89
  98th %tile Delta-DV     0.587     2.820     2.234    2000   75     56    110   2.80    88.29    9.54    0.32
      1.86
  90th %tile Delta-DV     0.147     2.380     2.234    2000   48     46     46   2.80    92.18    6.98    0.16
      0.68

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.753     3.859     2.106    2000  247     58     47   2.20    94.39    0.99    1.49
      3.13
  98th %tile Delta-DV     0.466     2.700     2.234    2000   36     82     71   2.80    81.42   14.72    1.06
      2.79
  90th %tile Delta-DV     0.188     2.316     2.127    2000  139     82     71   2.30    93.36    2.78    1.32
      2.53

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.623     3.857     2.234    2000   74     90     72   2.80    90.79    7.58    0.23
      1.40
  98th %tile Delta-DV     0.439     2.545     2.106    2000  247     90     72   2.20    95.28    0.67    1.58
      2.47
  90th %tile Delta-DV     0.113     2.241     2.127    2000  106     90     72   2.30    61.01   26.51    5.38
      7.10

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        2.163     4.438     2.275    2000   47     99     81   2.90    89.20    8.96    0.60
      1.24
  98th %tile Delta-DV     0.681     2.848     2.167    2000  216     97     79   2.40    90.95    5.30    1.56
      2.18
  90th %tile Delta-DV     0.248     2.481     2.232    2000  204     93     75   2.70    86.22    9.98    1.35
      2.46

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 7) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                      SEQ    ND        % of Modeled Extinction by
                                                                          Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         ------------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        0.917     3.151     2.234    2000   72     45     45   2.80    28.92   67.87    1.08
      2.13
  98th %tile Delta-DV     0.270     2.504     2.234    2000   75     56    110   2.80    34.07   63.36    0.38
      2.19
  90th %tile Delta-DV     0.072     2.221     2.149    2000  187     46     46   2.40    80.70   14.30    1.67
      3.33

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.708     2.941     2.234    2000   74     67     56   2.80    40.95   56.81    0.29
      1.94
  98th %tile Delta-DV     0.316     2.549     2.234    2000   54     82     71   2.80    33.72   63.27    1.05
      1.97
  90th %tile Delta-DV     0.061     2.231     2.170    2000  164     82     71   2.50    51.38   42.08    1.95
      4.59

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.758     2.992     2.234    2000   74     90     72   2.80    40.06   57.75    0.31
      1.88
  98th %tile Delta-DV     0.178     2.327     2.149    2000  184     90     72   2.40    78.93   12.37    3.25
      5.45
  90th %tile Delta-DV     0.049     2.176     2.127    2000   97     90     72   2.30    20.64   75.63    0.94
      2.79

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.158     3.434     2.275    2000   47     99     81   2.90    35.59   62.16    0.72
      1.53
  98th %tile Delta-DV     0.292     2.437     2.145    2000  136     99     81   2.30    27.47   67.55    1.83
      3.14
  90th %tile Delta-DV     0.115     2.326     2.211    2000  171     97     79   2.60    30.54   60.38    3.34
      5.74

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 7) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND         % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         ------------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        1.776     4.009     2.234    2000   72     45     45    2.80    28.88   68.12    1.01
      1.99
  98th %tile Delta-DV     0.533     2.767     2.234    2000   75     56    110    2.80    34.13   63.47    0.35
      2.05
  90th %tile Delta-DV     0.144     2.292     2.149    2000  187     46     46    2.40    80.96   14.36    1.56
      3.12

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.366     3.599     2.234    2000   74     67     56    2.80    41.03   56.88    0.27
      1.82
  98th %tile Delta-DV     0.617     2.850     2.234    2000   54     82     71    2.80    33.92   63.25    0.98
      1.85
  90th %tile Delta-DV     0.122     2.292     2.170    2000  164     82     71    2.50    51.52   42.37    1.82
      4.29

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.460     3.693     2.234    2000   74     90     72    2.80    40.14   57.81    0.29
      1.76
  98th %tile Delta-DV     0.356     2.589     2.234    2000   40     90     72    2.80    24.92   72.66    0.61
      1.80
  90th %tile Delta-DV     0.097     2.331     2.234    2000   41     90     72    2.80    17.04   78.24    1.56
      3.16

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        2.222     4.497     2.275    2000   47     99     81    2.90    35.70   62.19    0.68
      1.43
  98th %tile Delta-DV     0.575     2.720     2.145    2000  136     99     81    2.30    27.60   67.75    1.71
      2.94
  90th %tile Delta-DV     0.231     2.441     2.211    2000  171     97     79    2.60    30.65   60.81    3.15
      5.40

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 8) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND        % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        0.940     3.173     2.234    2000   72     53    107   2.80    25.00   72.44    0.89
      1.67
  98th %tile Delta-DV     0.328     2.562     2.234    2000   75     56    110   2.80    27.59   70.30    0.31
      1.80
  90th %tile Delta-DV     0.081     2.208     2.127    2000  110     48    102   2.30    12.91   77.78    3.89
      5.41

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.768     3.002     2.234    2000   74     67     56   2.80    33.88   64.26    0.23
      1.62
  98th %tile Delta-DV     0.326     2.580     2.255    2000   11     63     52   2.90    17.96   77.90    1.60
      2.55
  90th %tile Delta-DV     0.072     2.221     2.149    2000  187     82     71   2.40    81.48   12.31    1.75
      4.47

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.805     3.038     2.234    2000   74     90     72   2.80    32.76   65.42    0.25
      1.56
  98th %tile Delta-DV     0.186     2.292     2.106    2000  265     90     72   2.20    39.37   56.77    1.17
      2.69
  90th %tile Delta-DV     0.053     2.287     2.234    2000   56     90     72   2.80    32.16   64.85    0.92
      2.08

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.221     3.496     2.275    2000   47     99     81   2.90    28.87   69.31    0.59
      1.23
  98th %tile Delta-DV     0.336     2.612     2.275    2000   44     94     76   2.90    17.39   78.94    1.26
      2.41
  90th %tile Delta-DV     0.134     2.301     2.167    2000  229     93     75   2.40    13.17   67.57    8.01
      11.25

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 8) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        1.812     4.046     2.234    2000   72    53    107   2.80    24.93   72.67    0.83
      1.57
  98th %tile Delta-DV     0.649     2.883     2.234    2000   75    56    110   2.80    27.66   70.38    0.29
      1.67
  90th %tile Delta-DV     0.161     2.289     2.127    2000  110    48    102   2.30    13.01   78.25    3.66
      5.09

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.486     3.719     2.234    2000   74    67     56   2.80    33.91   64.36    0.22
      1.52
  98th %tile Delta-DV     0.638     2.892     2.255    2000   11    63     52   2.90    18.07   78.05    1.50
      2.39
  90th %tile Delta-DV     0.143     2.292     2.149    2000  187    82     71   2.40    82.05   12.12    1.64
      4.19

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.566     3.799     2.234    2000   74    90     72   2.80    32.83   65.48    0.24
      1.46
  98th %tile Delta-DV     0.370     2.604     2.234    2000   40    90     72   2.80    19.71   78.45    0.45
      1.39
  90th %tile Delta-DV     0.107     2.341     2.234    2000   56    90     72   2.80    32.33   64.89    0.85
      1.93

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        2.300     4.576     2.275    2000   47    99     81   2.90    28.94   69.35    0.56
      1.16
  98th %tile Delta-DV     0.667     2.942     2.275    2000   72    97     79   2.90    27.86   70.52    0.57
      1.05
  90th %tile Delta-DV     0.266     2.433     2.167    2000  229    93     75   2.40    13.59   68.13    7.59
      10.70

  Number of days with Delta-Deciview > 0.50:    16
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 9) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         ------------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        0.860     3.094     2.234    2000   72    53    107   2.80    27.43   69.76    0.97
      1.84
  98th %tile Delta-DV     0.301     2.535     2.234    2000   75    56    110   2.80    30.14   67.56    0.34
      1.96
  90th %tile Delta-DV     0.076     2.225     2.149    2000  187    46     46   2.40    78.07   17.13    1.61
      3.19

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.710     2.944     2.234    2000   74    67     56   2.80    36.74   61.25    0.25
      1.76
  98th %tile Delta-DV     0.296     2.551     2.255    2000   11    63     52   2.90    19.77   75.67    1.76
      2.80
  90th %tile Delta-DV     0.066     2.300     2.234    2000   70    83    112   2.80    22.75   74.87    0.60
      1.78

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.743     2.977     2.234    2000   74    90     72   2.80    35.58   62.45    0.28
      1.70
  98th %tile Delta-DV     0.174     2.280     2.106    2000  265    90     72   2.20    42.17   53.70    1.25
      2.88
  90th %tile Delta-DV     0.049     2.283     2.234    2000   56    90     72   2.80    34.81   61.94    0.99
      2.25

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.124     3.399     2.275    2000   47    99     81   2.90    31.51   66.50    0.65
      1.34
  98th %tile Delta-DV     0.306     2.581     2.275    2000   44    94     76   2.90    19.18   76.78    1.39
      2.65
  90th %tile Delta-DV     0.124     2.292     2.167    2000  215    99     81   2.40    34.74   48.85    6.36
      10.04

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 9) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND        % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        1.664     3.897     2.234    2000   72     53    107    2.80    27.36    70.01     0.91
      1.72
  98th %tile Delta-DV     0.596     2.829     2.234    2000   75     56    110    2.80    30.21    67.65     0.32
      1.83
  90th %tile Delta-DV     0.151     2.300     2.149    2000  187     46     46    2.40    78.41    17.09     1.51
      2.99

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.378     3.611     2.234    2000   74     67     56    2.80    36.77    61.35     0.24
      1.64
  98th %tile Delta-DV     0.581     2.836     2.255    2000   11     63     52    2.90    19.89    75.83     1.65
      2.63
  90th %tile Delta-DV     0.132     2.366     2.234    2000   70     83    112    2.80    22.79    74.99     0.56
      1.66

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.450     3.684     2.234    2000   74     90     72    2.80    35.65    62.51     0.26
      1.59
  98th %tile Delta-DV     0.343     2.449     2.106    2000  265     90     72    2.20    42.43    53.69     1.18
      2.71
  90th %tile Delta-DV     0.099     2.332     2.234    2000   56     90     72    2.80    35.00    61.99     0.92
      2.09

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        2.127     4.403     2.275    2000   47     99     81    2.90    31.59    66.54     0.61
      1.26
  98th %tile Delta-DV     0.612     2.887     2.275    2000   72     97     79    2.90    30.44    67.79     0.62
      1.15
  90th %tile Delta-DV     0.245     2.412     2.167    2000  229     93     75    2.40    14.76    65.37     8.24
      11.62

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 10) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND          % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        0.691     2.924     2.234    2000   72     53    107  2.80    34.47   62.00    1.22
      2.31
  98th %tile Delta-DV     0.243     2.349     2.106    2000  238     53    107  2.20    69.95   12.40    6.69
      10.96
  90th %tile Delta-DV     0.062     2.337     2.276    2000  336     47    101  3.00    23.90   70.07    2.59
      3.43

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.588     2.821     2.234    2000   74     67     56  2.80    44.68   52.87    0.31
      2.14
  98th %tile Delta-DV     0.233     2.488     2.255    2000   11     63     52  2.90    25.17   69.03    2.24
      3.57
  90th %tile Delta-DV     0.055     2.161     2.106    2000  238     85    114  2.20    72.69   15.18    4.21
      7.93

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.613     2.846     2.234    2000   74     90     72  2.80    43.44   54.15    0.34
      2.07
  98th %tile Delta-DV     0.147     2.381     2.234    2000   54     90     72  2.80    44.95   50.91    1.36
      2.78
  90th %tile Delta-DV     0.044     2.171     2.127    2000   97     90     72  2.30    23.16   72.67    1.06
      3.11

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        0.917     3.193     2.275    2000   47     99     81  2.90    39.03   58.51    0.80
      1.67
  98th %tile Delta-DV     0.246     2.522     2.275    2000   72     97     79  2.90    37.70   59.93    0.83
      1.53
  90th %tile Delta-DV     0.106     2.446     2.340    2000  350     91     73  3.20    27.28   66.69    1.73
      4.30

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 10) for Year 2000 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by
                                                                       Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %
                             _PMF
                         -----------------------------------------------------------------------------------------
                             ---

TRNP SOUTH UNIT

  Largest Delta-DV        1.345     3.578     2.234    2000   72    53    107   2.80    34.42   62.28    1.14
      2.16
  98th %tile Delta-DV     0.482     2.716     2.234    2000   75    56    110   2.80    37.53   59.81    0.39
      2.27
  90th %tile Delta-DV     0.127     2.403     2.276    2000  336    47    101   3.00    24.03   70.35    2.42
      3.20

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.146     3.380     2.234    2000   74    67     56   2.80    44.73   52.98    0.29
      2.00
  98th %tile Delta-DV     0.459     2.714     2.255    2000   11    63     52   2.90    25.32   69.23    2.10
      3.35
  90th %tile Delta-DV     0.109     2.279     2.170    2000  164    82     71   2.50    54.24   39.38    1.91
      4.48

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.203     3.436     2.234    2000   74    90     72   2.80    43.53   54.22    0.31
      1.94
  98th %tile Delta-DV     0.292     2.398     2.106    2000  265    90     72   2.20    49.95   45.47    1.39
      3.19
  90th %tile Delta-DV     0.087     2.215     2.127    2000   97    90     72   2.30    23.21   72.88    0.99
      2.92

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.751     4.026     2.275    2000   47    99     81   2.90    39.12   58.56    0.75
      1.56
  98th %tile Delta-DV     0.495     2.770     2.275    2000   72    97     79   2.90    37.84   59.95    0.78
      1.43
  90th %tile Delta-DV     0.210     2.377     2.167    2000  215    99     81   2.40    40.95   40.87    7.06
      11.12

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 0, Pre-BART) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.917     5.151     2.234    2001   64    52    106   2.80    77.08   22.59    0.11    0.22
  98th %tile Delta-DV     1.209     3.315     2.106    2001  257    48    102   2.20    81.37   17.38    0.44    0.81
  90th %tile Delta-DV     0.251     2.378     2.127    2001  131    53    107   2.30    69.04   30.09    0.22    0.65

  Number of days with Delta-Deciview > 0.50:    21
  Number of days with Delta-Deciview > 1.00:    11
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        3.801     6.034     2.234    2001   64    82     71   2.80    76.74   22.86    0.14    0.26
  98th %tile Delta-DV     1.154     3.281     2.127    2001  100    82     71   2.30    78.23   21.40    0.07    0.30
  90th %tile Delta-DV     0.372     2.606     2.234    2001   62    82     71   2.80    81.35   18.32    0.08    0.25

  Number of days with Delta-Deciview > 0.50:    27
  Number of days with Delta-Deciview > 1.00:    14
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        2.924     5.157     2.234    2001   64    90     72   2.80    77.73   21.95    0.11    0.22
  98th %tile Delta-DV     1.056     3.183     2.127    2001   92    90     72   2.30    58.08   40.84    0.36    0.72
  90th %tile Delta-DV     0.192     2.320     2.127    2001  109    90     72   2.30    62.94   35.94    0.28    0.85

  Number of days with Delta-Deciview > 0.50:    16
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        4.640     6.916     2.275    2001   64    91     73   2.90    70.40   29.04    0.15    0.41
  98th %tile Delta-DV     2.362     4.507     2.145    2001  259    97     79   2.30    85.36   13.84    0.25    0.55
  90th %tile Delta-DV     0.522     2.861     2.340    2001  316    93     75   3.20    60.23   38.90    0.36    0.50

  Number of days with Delta-Deciview > 0.50:    40
  Number of days with Delta-Deciview > 1.00:    23
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 0, Pre-BART) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station- BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        5.001     7.235     2.234    2001   64    52    106   2.80    75.58   24.10    0.10    0.22
  98th %tile Delta-DV     2.181     4.287     2.106    2001  257    48    102   2.20    80.18   18.59    0.43    0.80
  90th %tile Delta-DV     0.466     2.572     2.106    2001  254    45     45   2.20    94.17    3.91    0.58    1.34

  Number of days with Delta-Deciview > 0.50:    34
  Number of days with Delta-Deciview > 1.00:    21
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        6.322     8.555     2.234    2001   64    82     71   2.80    75.32   24.29    0.13    0.26
  98th %tile Delta-DV     2.094     4.221     2.127    2001  100    82     71   2.30    76.82   22.82    0.07    0.29
  90th %tile Delta-DV     0.694     2.928     2.234    2001   62    82     71   2.80    80.07   19.61    0.08    0.24

  Number of days with Delta-Deciview > 0.50:    46
  Number of days with Delta-Deciview > 1.00:    25
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP ELKHORN RANCH

  Largest Delta-DV        5.006     7.240     2.234    2001   64    90     72   2.80    76.29   23.40    0.11    0.21
  98th %tile Delta-DV     1.949     4.076     2.127    2001   92    90     72   2.30    56.05   42.91    0.35    0.69
  90th %tile Delta-DV     0.365     2.493     2.127    2001  109    90     72   2.30    61.06   37.85    0.27    0.82

  Number of days with Delta-Deciview > 0.50:    27
  Number of days with Delta-Deciview > 1.00:    16
  Max number of consecutive days with Delta-Deciview > 0.50:     3


LOSTWOOD NWA

  Largest Delta-DV        6.517     8.793     2.275    2001   64    97     79   2.90    82.16   17.18    0.17    0.48
  98th %tile Delta-DV     4.038     6.313     2.275    2001   63    91     73   2.90    82.39   17.32    0.08    0.21
  90th %tile Delta-DV     0.984     3.151     2.167    2001  232    91     73   2.40    88.98    9.56    0.29    1.17

  Number of days with Delta-Deciview > 0.50:    56
  Number of days with Delta-Deciview > 1.00:    35
  Max number of consecutive days with Delta-Deciview > 0.50:     6
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 1) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.282     3.516     2.234    2001   64    52    106  2.80    59.93   39.24    0.27    0.56
  98th %tile Delta-DV     0.509     2.763     2.255    2001   12    48    102  2.90    55.05   43.77    0.45    0.73
  90th %tile Delta-DV     0.116     2.244     2.127    2001  148    48    102  2.30    37.78   57.07    2.30    2.85

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.696     3.930     2.234    2001   64    82     71  2.80    59.56   39.44    0.34    0.66
  98th %tile Delta-DV     0.547     2.675     2.127    2001  109    83    112  2.30    38.76   54.96    2.38    3.90
  90th %tile Delta-DV     0.142     2.375     2.234    2001   62    82     71  2.80    66.26   32.87    0.22    0.66

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.276     3.509     2.234    2001   64    90     72  2.80    60.78   38.40    0.27    0.55
  98th %tile Delta-DV     0.505     2.739     2.234    2001   84    90     72  2.80    44.24   53.76    0.69    1.32
  90th %tile Delta-DV     0.076     2.182     2.106    2001  224    90     72  2.20    92.65    2.64    1.92    2.79

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.796     5.136     2.340    2001  326    99     81  3.20    56.42   41.65    0.74    1.19
  98th %tile Delta-DV     0.936     3.082     2.145    2001  259    97     79  2.30    70.71   27.12    0.69    1.48
  90th %tile Delta-DV     0.227     2.394     2.167    2001  275    93     75  2.40    50.16   44.42    1.81    3.61

  Number of days with Delta-Deciview > 0.50:    21
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 1) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station- BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.418     4.652     2.234    2001   64    52    106   2.80    59.97   39.26    0.25    0.52
  98th %tile Delta-DV     0.986     3.241     2.255    2001   12    48    102   2.90    55.06   43.83    0.42    0.68
  90th %tile Delta-DV     0.230     2.357     2.127    2001  148    48    102   2.30    38.00   57.16    2.16    2.68

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        3.144     5.378     2.234    2001   64    82     71   2.80    59.62   39.45    0.32    0.61
  98th %tile Delta-DV     1.069     3.196     2.127    2001  109    83    112   2.30    38.99   55.07    2.26    3.69
  90th %tile Delta-DV     0.282     2.516     2.234    2001   62    82     71   2.80    66.27   32.91    0.21    0.61

  Number of days with Delta-Deciview > 0.50:    25
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        2.406     4.640     2.234    2001   64    90     72   2.80    60.83   38.40    0.25    0.51
  98th %tile Delta-DV     0.984     3.218     2.234    2001   84    90     72   2.80    44.35   53.78    0.64    1.23
  90th %tile Delta-DV     0.151     2.257     2.106    2001  224    90     72   2.20    92.95    2.64    1.79    2.61

  Number of days with Delta-Deciview > 0.50:    14
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        4.932     7.272     2.340    2001  326    99     81   3.20    59.30   38.81    0.73    1.16
  98th %tile Delta-DV     1.778     3.924     2.145    2001  259    97     79   2.30    71.32   26.64    0.65    1.39
  90th %tile Delta-DV     0.448     2.723     2.275    2001   55    97     79   2.90    30.29   67.67    0.87    1.17

  Number of days with Delta-Deciview > 0.50:    34
  Number of days with Delta-Deciview > 1.00:    20
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 2) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC  %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.225     3.459     2.234    2001   64    52   106   2.80    62.92   36.22    0.28    0.58
  98th %tile Delta-DV     0.482     2.737     2.255    2001   12    48   102   2.90    58.12   40.63    0.48    0.77
  90th %tile Delta-DV     0.108     2.235     2.127    2001  148    48   102   2.30    40.61   53.85    2.47    3.06

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.620     3.854     2.234    2001   64    82    71   2.80    62.60   36.34    0.36    0.69
  98th %tile Delta-DV     0.512     2.639     2.127    2001  109    83   112   2.30    41.52   51.76    2.54    4.18
  90th %tile Delta-DV     0.136     2.369     2.234    2001   62    82    71   2.80    69.12   29.97    0.23    0.69

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.220     3.454     2.234    2001   64    90    72   2.80    63.75   35.39    0.29    0.58
  98th %tile Delta-DV     0.473     2.706     2.234    2001   84    90    72   2.80    47.32   50.54    0.73    1.41
  90th %tile Delta-DV     0.076     2.182     2.106    2001  224    90    72   2.20    92.94    2.34    1.92    2.80

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.677     5.017     2.340    2001  326    99    81   3.20    59.30   38.68    0.78    1.25
  98th %tile Delta-DV     0.907     3.053     2.145    2001  259    97    79   2.30    73.08   24.68    0.71    1.53
  90th %tile Delta-DV     0.212     2.358     2.145    2001  107    97    79   2.30    32.59   64.27    1.07    2.08

  Number of days with Delta-Deciview > 0.50:    18
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 2) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        2.316     4.549     2.234    2001    64   52    106   2.80    62.96   36.24    0.26    0.55
  98th %tile Delta-DV     0.936     3.191     2.255    2001    12   48    102   2.90    58.13   40.70    0.45    0.72
  90th %tile Delta-DV     0.214     2.341     2.127    2001   148   48    102   2.30    40.84   53.96    2.32    2.88

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        3.012     5.246     2.234    2001    64   82     71   2.80    62.66   36.36    0.34    0.65
  98th %tile Delta-DV     1.002     3.129     2.127    2001   109   83    112   2.30    41.75   51.89    2.42    3.95
  90th %tile Delta-DV     0.270     2.504     2.234    2001    62   82     71   2.80    69.14   30.01    0.21    0.64

  Number of days with Delta-Deciview > 0.50:    24
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        2.306     4.540     2.234    2001    64   90     72   2.80    63.79   35.40    0.27    0.54
  98th %tile Delta-DV     0.923     3.157     2.234    2001    84   90     72   2.80    47.43   50.56    0.69    1.32
  90th %tile Delta-DV     0.151     2.257     2.106    2001   224   90     72   2.20    93.25    2.33    1.80    2.62

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        4.773     7.112     2.340    2001   326   99     81   3.20    61.81   36.22    0.76    1.21
  98th %tile Delta-DV     1.726     3.872     2.145    2001   259   97     79   2.30    73.65   24.24    0.67    1.44
  90th %tile Delta-DV     0.419     2.564     2.145    2001   107   97     79   2.30    32.73   64.33    1.00    1.94

  Number of days with Delta-Deciview > 0.50:    33
  Number of days with Delta-Deciview > 1.00:    17
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 3) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.104     3.337     2.234    2001   64    52    106   2.80    70.29   28.74    0.31    0.65
  98th %tile Delta-DV     0.437     2.543     2.106    2001  257    48    102   2.20    73.41   22.87    1.31    2.41
  90th %tile Delta-DV     0.096     2.329     2.234    2001   55    46     46   2.80    59.18   39.59    0.28    0.95

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.459     3.692     2.234    2001   64    82     71   2.80    70.10   28.72    0.40    0.77
  98th %tile Delta-DV     0.436     2.564     2.127    2001  109    83    112   2.30    48.87   43.22    3.00    4.92
  90th %tile Delta-DV     0.127     2.297     2.170    2001  179    58     47   2.50    86.91   11.36    0.48    1.26

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.102     3.335     2.234    2001   64    90     72   2.80    71.03   28.01    0.32    0.64
  98th %tile Delta-DV     0.405     2.638     2.234    2001   84    90     72   2.80    55.44   42.04    0.86    1.65
  90th %tile Delta-DV     0.069     2.344     2.276    2001  310    90     72   3.00    50.62   43.88    1.02    4.47

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.418     4.757     2.340    2001  326    99     81   3.20    66.55   31.18    0.87    1.40
  98th %tile Delta-DV     0.846     2.991     2.145    2001  259    97     79   2.30    78.65   18.93    0.77    1.65
  90th %tile Delta-DV     0.190     2.357     2.167    2001  275    93     75   2.40    60.18   33.32    2.17    4.33

  Number of days with Delta-Deciview > 0.50:    15
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 3) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.097     4.330     2.234    2001   64    52    106   2.80    70.34   28.76    0.29    0.61
  98th %tile Delta-DV     0.854     2.960     2.106    2001  257    48    102   2.20    73.60   22.92    1.23    2.25
  90th %tile Delta-DV     0.194     2.428     2.234    2001   55    46     46   2.80    59.19   39.66    0.26    0.89

  Number of days with Delta-Deciview > 0.50:    18
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.730     4.964     2.234    2001   64    82     71   2.80    70.16   28.74    0.38    0.72
  98th %tile Delta-DV     0.858     2.985     2.127    2001  109    83    112   2.30    49.12   43.39    2.84    4.65
  90th %tile Delta-DV     0.253     2.529     2.276    2001  315    82     71   3.00    52.92   44.71    0.91    1.46

  Number of days with Delta-Deciview > 0.50:    20
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        2.093     4.326     2.234    2001   64    90     72   2.80    71.09   28.02    0.30    0.60
  98th %tile Delta-DV     0.793     3.027     2.234    2001   84    90     72   2.80    55.57   42.08    0.80    1.55
  90th %tile Delta-DV     0.137     2.413     2.276    2001  310    90     72   3.00    50.98   43.86    0.96    4.20

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        4.404     6.744     2.340    2001  326    99     81   3.20    68.33   29.49    0.84    1.34
  98th %tile Delta-DV     1.616     3.761     2.145    2001  259    97     79   2.30    79.13   18.60    0.72    1.55
  90th %tile Delta-DV     0.373     2.540     2.167    2001  275    93     75   2.40    60.66   33.19    2.06    4.09

  Number of days with Delta-Deciview > 0.50:    31
  Number of days with Delta-Deciview > 1.00:    15
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 4) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.920     3.153     2.234    2001   64    52    106   2.80    85.14   13.69    0.38    0.79
  98th %tile Delta-DV     0.373     2.479     2.106    2001  261    48    102   2.20    88.75    8.83    0.76    1.66
  90th %tile Delta-DV     0.075     2.351     2.276    2001  330    53    107   3.00    32.34   46.21    9.04   12.41

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.217     3.450     2.234    2001   64    82     71   2.80    85.10   13.47    0.49    0.94
  98th %tile Delta-DV     0.353     2.501     2.149    2001  198    86    115   2.40    95.65    1.12    0.95    2.28
  90th %tile Delta-DV     0.106     2.340     2.234    2001   62    82     71   2.80    88.65   10.18    0.29    0.88

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        0.923     3.156     2.234    2001   64    90     72   2.80    85.59   13.26    0.38    0.77
  98th %tile Delta-DV     0.319     2.446     2.127    2001  112    90     72   2.30    72.34   22.91    2.12    2.63
  90th %tile Delta-DV     0.058     2.164     2.106    2001  255    90     72   2.20    84.03    6.89    2.74    6.34

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        2.008     4.347     2.340    2001  326    99     81   3.20    81.86   15.34    1.07    1.72
  98th %tile Delta-DV     0.752     2.898     2.145    2001  259    97     79   2.30    88.81    8.46    0.87    1.86
  90th %tile Delta-DV     0.158     2.303     2.145    2001  100    97     79   2.30    88.36   10.59    0.27    0.78

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 4) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC   %_PMF
                         ----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.761     3.995     2.234    2001   64    52    106   2.80    85.20   13.70    0.36    0.74
  98th %tile Delta-DV     0.730     2.836     2.106    2001  261    48    102   2.20    89.11    8.63    0.71    1.55
  90th %tile Delta-DV     0.150     2.425     2.276    2001  330    53    107   3.00    32.84   46.92    8.51   11.74

  Number of days with Delta-Deciview > 0.50:    16
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.300     4.534     2.234    2001   64    82     71   2.80    85.18   13.49    0.46    0.88
  98th %tile Delta-DV     0.693     2.842     2.149    2001  198    86    115   2.40    95.92    1.06    0.89    2.13
  90th %tile Delta-DV     0.212     2.445     2.234    2001   62    82     71   2.80    88.71   10.20    0.27    0.82

  Number of days with Delta-Deciview > 0.50:    16
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        1.766     4.000     2.234    2001   64    90     72   2.80    85.66   13.26    0.36    0.72
  98th %tile Delta-DV     0.625     2.731     2.106    2001  260    90     72   2.20    93.12    4.17    0.97    1.74
  90th %tile Delta-DV     0.114     2.220     2.106    2001  255    90     72   2.20    84.61    6.86    2.58    5.96

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.766     6.106     2.340    2001  326    99     81   3.20    82.67   14.70    1.01    1.62
  98th %tile Delta-DV     1.447     3.593     2.145    2001  259    97     79   2.30    89.13    8.31    0.81    1.74
  90th %tile Delta-DV     0.314     2.459     2.145    2001  100    97     79   2.30    88.43   10.59    0.26    0.73

  Number of days with Delta-Deciview > 0.50:    28
  Number of days with Delta-Deciview > 1.00:    13
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 5) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                       SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.859     3.092     2.234    2001   64    52    106   2.80    91.45    7.29    0.41    0.85
  98th %tile Delta-DV     0.356     2.462     2.106    2001  261    48    102   2.20    92.88    4.59    0.80    1.73
  90th %tile Delta-DV     0.070     2.176     2.106    2001  255    51    105   2.20    88.34    2.50    3.03    6.13

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.138     3.371     2.234    2001   64    82     71   2.80    91.37    7.10    0.53    1.01
  98th %tile Delta-DV     0.333     2.461     2.127    2001  112    85    114   2.30    78.65   14.85    2.97    3.53
  90th %tile Delta-DV     0.101     2.377     2.276    2001  332    83    112   3.00    69.10   24.81    2.39    3.70

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        0.864     3.097     2.234    2001   64    90     72   2.80    91.72    7.04    0.41    0.83
  98th %tile Delta-DV     0.283     2.410     2.127    2001  112    90     72   2.30    81.71   12.93    2.40    2.97
  90th %tile Delta-DV     0.056     2.162     2.106    2001  255    90     72   2.20    87.06    3.52    2.84    6.57

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.867     4.207     2.340    2001  326    99     81   3.20    88.67    8.30    1.16    1.87
  98th %tile Delta-DV     0.670     2.946     2.275    2001   63    91     73   2.90    94.45    4.46    0.28    0.81
  90th %tile Delta-DV     0.149     2.295     2.145    2001  100    97     79   2.30    93.39    5.50    0.29    0.82

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 5) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.649     3.883     2.234    2001   64    52   106   2.80    91.53    7.30    0.38    0.79
  98th %tile Delta-DV     0.700     2.806     2.106    2001  261    48   102   2.20    93.15    4.48    0.74    1.62
  90th %tile Delta-DV     0.139     2.245     2.106    2001  255    51   105   2.20    88.92    2.48    2.85    5.75

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.158     4.391     2.234    2001   64    82    71   2.80    91.46    7.10    0.49    0.94
  98th %tile Delta-DV     0.656     2.784     2.127    2001  112    85   114   2.30    79.04   14.87    2.78    3.31
  90th %tile Delta-DV     0.202     2.477     2.276    2001  332    83   112   3.00    69.39   24.91    2.23    3.47

  Number of days with Delta-Deciview > 0.50:    15
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        1.658     3.891     2.234    2001   64    90    72   2.80    91.80    7.04    0.38    0.77
  98th %tile Delta-DV     0.557     2.684     2.127    2001  112    90    72   2.30    82.05   12.92    2.24    2.78
  90th %tile Delta-DV     0.110     2.216     2.106    2001  255    90    72   2.20    87.65    3.51    2.67    6.17

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.534     5.874     2.340    2001  326    99    81   3.20    89.19    7.97    1.09    1.75
  98th %tile Delta-DV     1.298     3.574     2.275    2001   63    91    73   2.90    94.52    4.47    0.26    0.75
  90th %tile Delta-DV     0.297     2.443     2.145    2001  100    97    79   2.30    93.46    5.50    0.27    0.77

  Number of days with Delta-Deciview > 0.50:    25
  Number of days with Delta-Deciview > 1.00:    12
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 6) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.800     3.034     2.234    2001   64    52    106   2.80    34.22   64.43    0.44    0.91
  98th %tile Delta-DV     0.340     2.574     2.234    2001   84    52    106   2.80    21.90   75.37    0.98    1.75
  90th %tile Delta-DV     0.062     2.211     2.149    2001  190    52    106   2.40    83.61    4.81    4.92    6.66

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.071     3.305     2.234    2001   64    82     71   2.80    33.87   64.49    0.56    1.08
  98th %tile Delta-DV     0.412     2.539     2.127    2001  109    83    112   2.30    17.98   73.64    3.17    5.21
  90th %tile Delta-DV     0.079     2.228     2.149    2001  195    82     71   2.40    73.96   23.01    0.79    2.24

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        0.790     3.023     2.234    2001   64    90     72   2.80    35.02   63.62    0.45    0.91
  98th %tile Delta-DV     0.309     2.415     2.106    2001  261    90     72   2.20    52.12   43.64    1.31    2.94
  90th %tile Delta-DV     0.039     2.188     2.149    2001  190    90     72   2.40    86.01    3.12    4.25    6.62

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.872     4.211     2.340    2001  326    99     81   3.20    30.73   66.25    1.16    1.86
  98th %tile Delta-DV     0.563     2.709     2.145    2001  261    97     79   2.30    34.40   59.13    2.86    3.62
  90th %tile Delta-DV     0.154     2.299     2.145    2001  266    91     73   2.30    19.30   74.98    1.43    4.29

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 6) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.541     3.774     2.234    2001   64    52    106   2.80    34.25   64.49    0.41    0.85
  98th %tile Delta-DV     0.668     2.901     2.234    2001   84    52    106   2.80    21.96   75.49    0.91    1.64
  90th %tile Delta-DV     0.123     2.272     2.149    2001  190    52    106   2.40    84.27    4.84    4.62    6.27

  Number of days with Delta-Deciview > 0.50:    15
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.037     4.270     2.234    2001   64    82     71   2.80    33.91   64.56    0.52    1.01
  98th %tile Delta-DV     0.811     2.938     2.127    2001  109    83    112   2.30    18.06   74.01    3.01    4.92
  90th %tile Delta-DV     0.156     2.305     2.149    2001  195    82     71   2.40    74.14   23.02    0.74    2.10

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.520     3.754     2.234    2001   64    90     72   2.80    35.05   63.67    0.42    0.85
  98th %tile Delta-DV     0.602     2.708     2.106    2001  261    90     72   2.20    52.89   43.09    1.24    2.78
  90th %tile Delta-DV     0.077     2.226     2.149    2001  190    90     72   2.40    86.65    3.13    3.99    6.23

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.489     5.828     2.340    2001  326    99     81   3.20    31.47   65.64    1.11    1.77
  98th %tile Delta-DV     1.086     3.362     2.275    2001   43    91     73   2.90    32.16   65.65    0.84    1.36
  90th %tile Delta-DV     0.303     2.470     2.167    2001  275    93     75   2.40    26.09   66.30    2.54    5.06

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:    11
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 7) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.740     2.974     2.234    2001   64    52    106   2.80    37.11   61.42    0.48    0.99
  98th %tile Delta-DV     0.310     2.543     2.234    2001   84    52    106   2.80    24.08   72.92    1.07    1.93
  90th %tile Delta-DV     0.062     2.211     2.149    2001  190    52    106   2.40    84.11    4.24    4.95    6.70

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.990     3.224     2.234    2001   64    82     71   2.80    36.79   61.43    0.61    1.17
  98th %tile Delta-DV     0.376     2.503     2.127    2001  109    83    112   2.30    19.74   71.06    3.48    5.72
  90th %tile Delta-DV     0.075     2.308     2.234    2001   62    82     71   2.80    43.76   54.57    0.42    1.25

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.731     2.964     2.234    2001   64    90     72   2.80    37.94   60.58    0.49    0.98
  98th %tile Delta-DV     0.294     2.400     2.106    2001  261    90     72   2.20    54.98   40.54    1.38    3.10
  90th %tile Delta-DV     0.038     2.272     2.234    2001   55    90     72   2.80    25.42   72.95    0.40    1.22

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.738     4.078     2.340    2001  326    99     81   3.20    33.31   63.41    1.26    2.02
  98th %tile Delta-DV     0.526     2.671     2.145    2001  261    99     81   2.30    38.19   54.71    3.12    3.97
  90th %tile Delta-DV     0.140     2.286     2.145    2001  266    91     73   2.30    21.22   72.49    1.58    4.72

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 7) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.429     3.662     2.234    2001   64    52    106   2.80    37.14   61.49    0.45    0.93
  98th %tile Delta-DV     0.609     2.843     2.234    2001   84    52    106   2.80    24.14   73.05    1.00    1.80
  90th %tile Delta-DV     0.123     2.271     2.149    2001  190    52    106   2.40    84.78    4.26    4.65    6.31

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.889     4.123     2.234    2001   64    82     71   2.80    36.84   61.50    0.57    1.09
  98th %tile Delta-DV     0.741     2.869     2.127    2001  109    83    112   2.30    19.82   71.47    3.30    5.40
  90th %tile Delta-DV     0.149     2.383     2.234    2001   62    82     71   2.80    43.79   54.66    0.39    1.16

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.411     3.644     2.234    2001   64    90     72   2.80    37.98   60.64    0.46    0.92
  98th %tile Delta-DV     0.573     2.679     2.106    2001  261    90     72   2.20    55.72   40.05    1.30    2.93
  90th %tile Delta-DV     0.076     2.182     2.106    2001  230    90     72   2.20    54.59   29.71    7.02    8.68

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.266     5.606     2.340    2001  326    99     81   3.20    34.01   62.87    1.20    1.92
  98th %tile Delta-DV     1.012     3.157     2.145    2001  261    97     79   2.30    37.61   55.75    2.93    3.70
  90th %tile Delta-DV     0.276     2.421     2.145    2001  266    91     73   2.30    21.45   72.61    1.49    4.45

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 8) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.613     2.846     2.234    2001   64    52    106   2.80    45.14   53.08    0.58    1.20
  98th %tile Delta-DV     0.248     2.354     2.106    2001  260    46     46   2.20    62.78   31.30    2.16    3.76
  90th %tile Delta-DV     0.054     2.182     2.127    2001  131    53    107   2.30    35.39   60.47    1.03    3.11

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.818     3.052     2.234    2001   64    82     71   2.80    44.91   52.92    0.74    1.43
  98th %tile Delta-DV     0.299     2.427     2.127    2001  109    83    112   2.30    24.87   63.53    4.39    7.21
  90th %tile Delta-DV     0.069     2.175     2.106    2001  230    82     71   2.20    74.40   10.30    5.97    9.33

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.606     2.840     2.234    2001   64    90     72   2.80    46.02   52.19    0.59    1.19
  98th %tile Delta-DV     0.259     2.365     2.106    2001  258    90     72   2.20    41.54   50.05    3.79    4.62
  90th %tile Delta-DV     0.032     2.138     2.106    2001  255    90     72   2.20    52.18   31.61    4.90   11.32

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.448     3.787     2.340    2001  326    99     81   3.20    40.59   55.42    1.53    2.46
  98th %tile Delta-DV     0.446     2.592     2.145    2001  261    99     81   2.30    45.17   46.44    3.70    4.70
  90th %tile Delta-DV     0.111     2.256     2.145    2001  266    91     73   2.30    26.88   65.15    2.00    5.97

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 8) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.189     3.423     2.234    2001   64    52    106   2.80    45.19   53.15    0.54    1.13
  98th %tile Delta-DV     0.484     2.718     2.234    2001   84    52    106   2.80    30.57   65.87    1.27    2.29
  90th %tile Delta-DV     0.108     2.236     2.127    2001  131    53    107   2.30    35.47   60.65    0.97    2.91

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.573     3.806     2.234    2001   64    82     71   2.80    44.98   53.00    0.69    1.33
  98th %tile Delta-DV     0.592     2.720     2.127    2001  109    83    112   2.30    24.99   64.04    4.16    6.81
  90th %tile Delta-DV     0.136     2.242     2.106    2001  230    82     71   2.20    75.22   10.36    5.63    8.80

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.177     3.410     2.234    2001   64    90     72   2.80    46.08   52.25    0.56    1.12
  98th %tile Delta-DV     0.509     2.615     2.106    2001  261    90     72   2.20    62.89   32.34    1.47    3.30
  90th %tile Delta-DV     0.064     2.191     2.127    2001  144    90     72   2.30    35.75   56.84    2.51    4.90

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.767     5.107     2.340    2001  326    99     81   3.20    41.22   55.01    1.45    2.32
  98th %tile Delta-DV     0.862     3.007     2.145    2001  261    97     79   2.30    44.49   47.67    3.47    4.38
  90th %tile Delta-DV     0.219     2.364     2.145    2001  266    91     73   2.30    27.14   65.34    1.88    5.63

  Number of days with Delta-Deciview > 0.50:    18
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 9) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.419     2.653     2.234     2001   64    52    106   2.80    66.57   30.79    0.86    1.78
  98th %tile Delta-DV     0.170     2.276     2.106     2001  257    48    102   2.20    66.47   23.84    3.42    6.28
  90th %tile Delta-DV     0.037     2.165     2.127     2001  148    48    102   2.30    41.02   42.92    7.17    8.90

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP NORTH UNIT

  Largest Delta-DV        0.560     2.793     2.234     2001   64    82     71   2.80    66.50   30.29    1.10    2.11
  98th %tile Delta-DV     0.184     2.312     2.127     2001  109    83    112   2.30    40.65   40.40    7.18   11.78
  90th %tile Delta-DV     0.048     2.324     2.276     2001  315    82     71   3.00    47.74   45.73    2.50    4.03

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.418     2.652     2.234     2001   64    90     72   2.80    67.37   30.01    0.87    1.75
  98th %tile Delta-DV     0.157     2.391     2.234     2001   84    90     72   2.80    50.35   43.09    2.25    4.32
  90th %tile Delta-DV     0.027     2.176     2.149     2001  201    90     72   2.40    85.15   11.16    0.88    2.81

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


LOSTWOOD NWA

  Largest Delta-DV        0.989     3.329     2.340     2001  326    99     81   3.20    60.84   33.18    2.29    3.69
  98th %tile Delta-DV     0.324     2.470     2.145     2001  259    97     79   2.30    73.24   20.29    2.05    4.41
  90th %tile Delta-DV     0.073     2.305     2.232     2001  197    91     73   2.70    79.11   12.09    3.92    4.89

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 9) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4    %_NO3    %_PMC    %_PMF
                         ------------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV         0.821     3.054     2.234    2001   64    52    106   2.80    66.69    30.85     0.80     1.66
  98th %tile Delta-DV      0.335     2.441     2.106    2001  257    48    102   2.20    66.91    23.99     3.20     5.89
  90th %tile Delta-DV      0.074     2.201     2.127    2001  148    48    102   2.30    41.43    43.38     6.77     8.41

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV         1.088     3.322     2.234    2001   64    82     71   2.80    66.64    30.35     1.03     1.98
  98th %tile Delta-DV      0.365     2.493     2.127    2001  109    83    112   2.30    41.00    41.00     6.83    11.17
  90th %tile Delta-DV      0.098     2.374     2.276    2001  315    82     71   3.00    47.83    46.01     2.37     3.79

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV         0.818     3.052     2.234    2001   64    90     72   2.80    67.49    30.06     0.81     1.63
  98th %tile Delta-DV      0.311     2.544     2.234    2001   84    90     72   2.80    50.58    43.27     2.11     4.05
  90th %tile Delta-DV      0.053     2.202     2.149    2001  201    90     72   2.40    85.39    11.17     0.82     2.63

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV         1.939     4.279     2.340    2001  326    99     81   3.20    61.39    32.99     2.16     3.46
  98th %tile Delta-DV      0.635     2.780     2.145    2001  259    97     79   2.30    73.67    20.27     1.93     4.14
  90th %tile Delta-DV      0.145     2.377     2.232    2001  197    91     73   2.70    79.40    12.29     3.69     4.62

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 10) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.355     2.589     2.234    2001   64    52    106   2.80    78.81   18.08    1.01    2.10
  98th %tile Delta-DV     0.149     2.276     2.127    2001  112    51    105   2.30    60.73   27.79    4.96    6.53
  90th %tile Delta-DV     0.031     2.137     2.106    2001  254    46     46   2.20    81.62    2.61    4.76   11.01

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP NORTH UNIT

  Largest Delta-DV        0.475     2.709     2.234    2001   64    82     71   2.80    78.64   17.56    1.30    2.50
  98th %tile Delta-DV     0.147     2.274     2.127    2001   98    84    113   2.30    49.30   32.63    7.41   10.66
  90th %tile Delta-DV     0.044     2.277     2.234    2001   85    84    113   2.80    49.31   37.83    4.62    8.25

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP ELKHORN RANCH

  Largest Delta-DV        0.356     2.589     2.234    2001   64    90     72   2.80    79.39   17.52    1.02    2.06
  98th %tile Delta-DV     0.123     2.250     2.127    2001   92    90     72   2.30    59.34   30.16    3.51    6.99
  90th %tile Delta-DV     0.022     2.298     2.276    2001  310    90     72   3.00    55.14   27.65    3.20   14.01

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


LOSTWOOD NWA

  Largest Delta-DV        0.831     3.171     2.340    2001  326    99     81   3.20    72.98   19.85    2.75    4.42
  98th %tile Delta-DV     0.292     2.437     2.145    2001  259    97     79   2.30    81.57   11.23    2.29    4.91
  90th %tile Delta-DV     0.065     2.232     2.167    2001  275    93     75   2.40    61.71   19.12    6.39   12.78

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 10) for Year 2001 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         -------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.698     2.931     2.234    2001   64    52    106   2.80    78.97   18.12    0.95    1.97
  98th %tile Delta-DV     0.294     2.421     2.127    2001  112    51    105   2.30    61.23   27.97    4.66    6.14
  90th %tile Delta-DV     0.062     2.168     2.106    2001  254    45     45   2.20    82.59    2.64    4.43   10.34

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.927     3.161     2.234    2001   64    82     71   2.80    78.83   17.61    1.22    2.34
  98th %tile Delta-DV     0.290     2.417     2.127    2001  109    83    112   2.30    51.83   25.42    8.64   14.12
  90th %tile Delta-DV     0.087     2.321     2.234    2001   85    84    113   2.80    49.74   38.15    4.35    7.76

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        0.698     2.932     2.234    2001   64    90     72   2.80    79.56   17.56    0.96    1.93
  98th %tile Delta-DV     0.242     2.369     2.127    2001   92    90     72   2.30    59.76   30.38    3.29    6.57
  90th %tile Delta-DV     0.044     2.320     2.276    2001  310    90     72   3.00    55.79   27.96    3.02   13.23

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.644     3.984     2.340    2001  326    99     81   3.20    73.53   19.74    2.59    4.15
  98th %tile Delta-DV     0.572     2.717     2.145    2001  259    97     79   2.30    82.02   11.22    2.15    4.61
  90th %tile Delta-DV     0.128     2.295     2.167    2001  275    93     75   2.40    62.46   19.32    6.09   12.13

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 0, Pre-BART) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        4.503     6.737     2.234    2002   78    46     46   2.80    71.11   28.40    0.09    0.39
  98th %tile Delta-DV     2.559     4.814     2.255    2002   26    47    101   2.90    64.72   34.53    0.28    0.47
  90th %tile Delta-DV     0.540     2.646     2.106    2002  270    53    107   2.20    58.28   40.09    0.61    1.01

  Number of days with Delta-Deciview > 0.50:    38
  Number of days with Delta-Deciview > 1.00:    23
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        6.532     8.766     2.234    2002   73    89    118   2.80    66.26   32.91    0.33    0.50
  98th %tile Delta-DV     2.113     4.347     2.234    2002   39    67     56   2.80    84.58   14.15    0.33    0.95
  90th %tile Delta-DV     0.385     2.512     2.127    2002  152    85    114   2.30    92.22    6.34    0.38    1.06

  Number of days with Delta-Deciview > 0.50:    30
  Number of days with Delta-Deciview > 1.00:    17
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP ELKHORN RANCH

  Largest Delta-DV        5.501     7.734     2.234    2002   73    90     72   2.80    69.47   29.82    0.26    0.45
  98th %tile Delta-DV     1.703     3.978     2.276    2002  336    90     72   3.00    61.77   37.21    0.46    0.57
  90th %tile Delta-DV     0.310     2.416     2.106    2002  255    90     72   2.20    88.37    7.70    1.41    2.52

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:    13
  Max number of consecutive days with Delta-Deciview > 0.50:     3


LOSTWOOD NWA

  Largest Delta-DV        3.827     6.102     2.275    2002   74    97     79   2.90    72.61   26.86    0.17    0.36
  98th %tile Delta-DV     1.814     4.154     2.340    2002  312    99     81   3.20    68.02   30.72    0.27    0.99
  90th %tile Delta-DV     0.385     2.531     2.145    2002  247    97     79   2.30    96.31    1.89    0.59    1.21

  Number of days with Delta-Deciview > 0.50:    32
  Number of days with Delta-Deciview > 1.00:    16
  Max number of consecutive days with Delta-Deciview > 0.50:     4
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 0, Pre-BART) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        6.675     8.908     2.234    2002   78    46     46   2.80    79.57   19.89    0.10    0.44
  98th %tile Delta-DV     4.475     6.730     2.255    2002   26    47    101   2.90    63.14   36.13    0.27    0.46
  90th %tile Delta-DV     0.971     3.077     2.106    2002  270    53    107   2.20    58.87   39.49    0.62    1.02

  Number of days with Delta-Deciview > 0.50:    50
  Number of days with Delta-Deciview > 1.00:    36
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP NORTH UNIT

  Largest Delta-DV       10.081    12.314     2.234    2002   73    89    118   2.80    65.93   33.24    0.33    0.49
  98th %tile Delta-DV     3.557     5.664     2.106    2002  250    82     71   2.20    89.34    9.05    0.68    0.93
  90th %tile Delta-DV     0.706     2.834     2.127    2002  152    85    114   2.30    92.23    6.33    0.38    1.06

  Number of days with Delta-Deciview > 0.50:    45
  Number of days with Delta-Deciview > 1.00:    27
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP ELKHORN RANCH

  Largest Delta-DV        8.644    10.878     2.234    2002   73    90     72   2.80    69.59   29.70    0.26    0.45
  98th %tile Delta-DV     3.039     5.315     2.276    2002  336    90     72   3.00    59.83   39.18    0.44    0.55
  90th %tile Delta-DV     0.581     2.708     2.127    2002   95    90     72   2.30    56.20   42.67    0.31    0.82

  Number of days with Delta-Deciview > 0.50:    42
  Number of days with Delta-Deciview > 1.00:    21
  Max number of consecutive days with Delta-Deciview > 0.50:     4


LOSTWOOD NWA

  Largest Delta-DV        6.332     8.608     2.275    2002   74    97     79   2.90    71.70   27.78    0.17    0.35
  98th %tile Delta-DV     3.190     5.487     2.297    2002   29    97     79   3.00    67.24   32.23    0.19    0.34
  90th %tile Delta-DV     0.707     2.852     2.145    2002  247    97     79   2.30    96.30    1.90    0.59    1.21

  Number of days with Delta-Deciview > 0.50:    45
  Number of days with Delta-Deciview > 1.00:    29
  Max number of consecutive days with Delta-Deciview > 0.50:     4
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 1) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.337     4.570     2.234    2002   78    46     46   2.80    51.48   47.33    0.24    0.95
  98th %tile Delta-DV     1.181     3.287     2.106    2002  233    53    107   2.20    67.36   30.47    0.77    1.39
  90th %tile Delta-DV     0.219     2.346     2.127    2002  100     6      6   2.30    54.02   43.86    0.56    1.56

  Number of days with Delta-Deciview > 0.50:    22
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        3.509     5.742     2.234    2002   73    89    118   2.80    46.16   51.95    0.75    1.14
  98th %tile Delta-DV     0.987     3.220     2.234    2002   50    58     47   2.80    38.33   59.46    0.68    1.53
  90th %tile Delta-DV     0.158     2.307     2.149    2002  189    58     47   2.40    91.54    3.96    1.57    2.93

  Number of days with Delta-Deciview > 0.50:    15
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        2.763     4.996     2.234    2002   73    90     72   2.80    49.87   48.47    0.59    1.06
  98th %tile Delta-DV     0.789     3.022     2.234    2002   78    90     72   2.80    51.41   47.45    0.22    0.92
  90th %tile Delta-DV     0.136     2.242     2.106    2002  271    90     72   2.20    49.55   45.09    2.45    2.91

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.775     4.050     2.275    2002   74    97     79   2.90    53.97   44.76    0.39    0.87
  98th %tile Delta-DV     0.832     3.129     2.297    2002   29    97     79   3.00    49.67   49.02    0.47    0.84
  90th %tile Delta-DV     0.178     2.453     2.275    2002   69    99     81   2.90    35.74   62.57    0.39    1.30

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 1) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        4.230     6.464     2.234     2002   78     46     46   2.80    51.61   47.27    0.23    0.89
  98th %tile Delta-DV     2.218     4.324     2.106     2002  233     53    107   2.20    68.06   29.90    0.73    1.31
  90th %tile Delta-DV     0.433     2.560     2.127     2002  100      6      6   2.30    54.10   43.91    0.53    1.46

  Number of days with Delta-Deciview > 0.50:    32
  Number of days with Delta-Deciview > 1.00:    22
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        6.089     8.323     2.234     2002   73     89    118   2.80    46.36   51.87    0.70    1.07
  98th %tile Delta-DV     1.880     4.114     2.234     2002   50     58     47   2.80    38.43   59.50    0.63    1.43
  90th %tile Delta-DV     0.313     2.462     2.149     2002  189     58     47   2.40    91.83    3.96    1.47    2.74

  Number of days with Delta-Deciview > 0.50:    26
  Number of days with Delta-Deciview > 1.00:    15
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP ELKHORN RANCH

  Largest Delta-DV        4.916     7.149     2.234     2002   73     90     72   2.80    50.05   48.40    0.55    1.00
  98th %tile Delta-DV     1.524     3.757     2.234     2002   78     90     72   2.80    51.44   47.49    0.21    0.86
  90th %tile Delta-DV     0.269     2.375     2.106     2002  271     90     72   2.20    50.10   44.85    2.31    2.74

  Number of days with Delta-Deciview > 0.50:    18
  Number of days with Delta-Deciview > 1.00:    12
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.284     5.559     2.275     2002   74     97     79   2.90    54.07   44.75    0.37    0.82
  98th %tile Delta-DV     1.601     3.897     2.297     2002   29     97     79   3.00    49.72   49.05    0.44    0.79
  90th %tile Delta-DV     0.350     2.626     2.275     2002   69     99     81   2.90    35.79   62.64    0.36    1.21

  Number of days with Delta-Deciview > 0.50:    26
  Number of days with Delta-Deciview > 1.00:    13
  Max number of consecutive days with Delta-Deciview > 0.50:     4
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 2) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                     SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.217     4.451     2.234    2002   78    46     46   2.80    54.60   44.14    0.26    1.01
  98th %tile Delta-DV     1.140     3.246     2.106    2002  233    53    107   2.20    69.96   27.79    0.80    1.44
  90th %tile Delta-DV     0.207     2.335     2.127    2002  100     6      6   2.30    57.03   40.72    0.59    1.65

  Number of days with Delta-Deciview > 0.50:    20
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        3.321     5.554     2.234    2002   73    89    118   2.80    49.26   48.72    0.80    1.22
  98th %tile Delta-DV     0.918     3.151     2.234    2002   50    58     47   2.80    41.35   56.27    0.73    1.65
  90th %tile Delta-DV     0.151     2.278     2.127    2002  138    82     71   2.30    34.32   60.77    1.96    2.94

  Number of days with Delta-Deciview > 0.50:    15
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        2.620     4.854     2.234    2002   73    90     72   2.80    52.98   45.26    0.63    1.13
  98th %tile Delta-DV     0.746     2.979     2.234    2002   78    90     72   2.80    54.51   44.28    0.23    0.98
  90th %tile Delta-DV     0.129     2.235     2.106    2002  271    90     72   2.20    52.30   42.04    2.59    3.07

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.686     3.961     2.275    2002   74    97     79   2.90    57.08   41.58    0.42    0.92
  98th %tile Delta-DV     0.783     3.080     2.297    2002   29    97     79   3.00    52.90   45.71    0.50    0.90
  90th %tile Delta-DV     0.165     2.440     2.275    2002   69    99     81   2.90    38.63   59.54    0.42    1.40

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 2) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV         4.033     6.266     2.234    2002   78    46     46   2.80    54.71   44.10    0.24    0.94
  98th %tile Delta-DV      2.145     4.251     2.106    2002  233    53    107   2.20    70.61   27.27    0.76    1.36
  90th %tile Delta-DV      0.410     2.538     2.127    2002  100     6      6   2.30    57.12   40.78    0.56    1.54

  Number of days with Delta-Deciview > 0.50:    32
  Number of days with Delta-Deciview > 1.00:    20
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV         5.800     8.033     2.234    2002   73    89    118   2.80    49.45   48.66    0.75    1.14
  98th %tile Delta-DV      1.755     3.988     2.234    2002   50    58     47   2.80    41.45   56.32    0.68    1.55
  90th %tile Delta-DV      0.298     2.532     2.234    2002   78    67     56   2.80    51.48   47.35    0.28    0.90

  Number of days with Delta-Deciview > 0.50:    26
  Number of days with Delta-Deciview > 1.00:    15
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP ELKHORN RANCH

  Largest Delta-DV         4.686     6.920     2.234    2002   73    90     72   2.80    53.15   45.20    0.59    1.06
  98th %tile Delta-DV      1.443     3.677     2.234    2002   78    90     72   2.80    54.54   44.33    0.22    0.91
  90th %tile Delta-DV      0.256     2.362     2.106    2002  271    90     72   2.20    52.84   41.84    2.44    2.89

  Number of days with Delta-Deciview > 0.50:    18
  Number of days with Delta-Deciview > 1.00:    11
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV         3.130     5.406     2.275    2002   74    97     79   2.90    57.18   41.57    0.39    0.86
  98th %tile Delta-DV      1.510     3.807     2.297    2002   29    97     79   3.00    52.95   45.74    0.47    0.84
  90th %tile Delta-DV      0.325     2.600     2.275    2002   69    99     81   2.90    38.69   59.61    0.39    1.31

  Number of days with Delta-Deciview > 0.50:    25
  Number of days with Delta-Deciview > 1.00:    13
  Max number of consecutive days with Delta-Deciview > 0.50:     4
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 3) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.960     4.194     2.234    2002   78    46     46   2.80    62.58   35.97    0.29    1.15
  98th %tile Delta-DV     1.052     3.158     2.106    2002  233    53    107   2.20    76.13   21.42    0.87    1.57
  90th %tile Delta-DV     0.186     2.419     2.234    2002   51    48    102   2.80    80.77   18.31    0.25    0.66

  Number of days with Delta-Deciview > 0.50:    20
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.913     5.146     2.234    2002   73    89    118   2.80    57.39   40.27    0.93    1.42
  98th %tile Delta-DV     0.813     2.919     2.106    2002  250    82     71   2.20    67.27   28.75    1.67    2.31
  90th %tile Delta-DV     0.131     2.386     2.255    2002   30    82     71   2.90    69.78   29.39    0.17    0.66

  Number of days with Delta-Deciview > 0.50:    14
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        2.313     4.547     2.234    2002   73    90     72   2.80    60.98   36.99    0.72    1.30
  98th %tile Delta-DV     0.654     2.887     2.234    2002   78    90     72   2.80    62.46   36.16    0.27    1.12
  90th %tile Delta-DV     0.118     2.246     2.127    2002   95    90     72   2.30    47.77   49.06    0.89    2.28

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.496     3.771     2.275    2002   74    97     79   2.90    64.95   33.53    0.47    1.05
  98th %tile Delta-DV     0.680     2.977     2.297    2002   29    97     79   3.00    61.21   37.18    0.58    1.04
  90th %tile Delta-DV     0.141     2.352     2.211    2002  172    97     79   2.60    80.33   10.28    3.11    6.28

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 3) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                      SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        3.602     5.835     2.234    2002   78    46     46   2.80    62.68   35.97    0.28    1.08
  98th %tile Delta-DV     1.991     4.097     2.106    2002  233    53    107   2.20    76.69   21.02    0.82    1.48
  90th %tile Delta-DV     0.371     2.604     2.234    2002   51    48    102   2.80    80.83   18.31    0.23    0.62

  Number of days with Delta-Deciview > 0.50:    30
  Number of days with Delta-Deciview > 1.00:    20
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        5.159     7.393     2.234    2002   73    89    118   2.80    57.57   40.23    0.87    1.33
  98th %tile Delta-DV     1.536     3.642     2.106    2002  250    82     71   2.20    67.80   28.47    1.56    2.17
  90th %tile Delta-DV     0.260     2.515     2.255    2002   30    82     71   2.90    69.83   29.39    0.16    0.61

  Number of days with Delta-Deciview > 0.50:    24
  Number of days with Delta-Deciview > 1.00:    14
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP ELKHORN RANCH

  Largest Delta-DV        4.185     6.418     2.234    2002   73    90     72   2.80    61.15   36.96    0.68    1.22
  98th %tile Delta-DV     1.271     3.504     2.234    2002   78    90     72   2.80    62.50   36.20    0.25    1.04
  90th %tile Delta-DV     0.234     2.362     2.127    2002   95    90     72   2.30    48.03   49.00    0.83    2.14

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:    10
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.799     5.075     2.275    2002   74    97     79   2.90    65.05   33.53    0.44    0.98
  98th %tile Delta-DV     1.318     3.615     2.297    2002   29    97     79   3.00    61.27   37.22    0.54    0.97
  90th %tile Delta-DV     0.279     2.489     2.211    2002  172    97     79   2.60    80.87   10.30    2.92    5.90

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:    11
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 4) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.564     3.798     2.234    2002   78    46    46   2.80    80.04   18.11    0.38    1.47
  98th %tile Delta-DV     0.799     3.032     2.234    2002   64    57   111   2.80    72.68   23.87    0.96    2.49
  90th %tile Delta-DV     0.160     2.394     2.234    2002   49    53   107   2.80    62.71   31.41    1.92    3.96

  Number of days with Delta-Deciview > 0.50:   13
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        2.273     4.506     2.234    2002   73    89   118   2.80    76.03   20.86    1.23    1.88
  98th %tile Delta-DV     0.677     2.783     2.106    2002  250    82    71   2.20    81.34   13.85    2.02    2.79
  90th %tile Delta-DV     0.121     2.248     2.127    2002  152    85   114   2.30    91.91    3.47    1.21    3.42

  Number of days with Delta-Deciview > 0.50:   11
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.837     4.071     2.234    2002   73    90    72   2.80    78.69   18.70    0.93    1.68
  98th %tile Delta-DV     0.515     2.748     2.234    2002   78    90    72   2.80    79.92   18.31    0.34    1.43
  90th %tile Delta-DV     0.090     2.196     2.106    2002  271    90    72   2.20    74.63   17.30    3.69    4.38

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.208     3.483     2.275    2002   74    97    79   2.90    81.64   16.44    0.60    1.32
  98th %tile Delta-DV     0.569     2.908     2.340    2002  312    99    81   3.20    73.42   21.30    1.15    4.13
  90th %tile Delta-DV     0.114     2.346     2.232    2002  195    99    81   2.70    65.19   25.04    4.01    5.75

  Number of days with Delta-Deciview > 0.50:   10
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 4) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.920     5.154     2.234    2002   78    46     46   2.80    80.14   18.13    0.35    1.38
  98th %tile Delta-DV     1.537     3.771     2.234    2002   64    57    111   2.80    72.87   23.91    0.89    2.32
  90th %tile Delta-DV     0.316     2.549     2.234    2002   49    53    107   2.80    63.01   31.48    1.80    3.71

  Number of days with Delta-Deciview > 0.50:    25
  Number of days with Delta-Deciview > 1.00:    13
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        4.120     6.354     2.234    2002   73    89    118   2.80    76.24   20.86    1.15    1.75
  98th %tile Delta-DV     1.290     3.396     2.106    2002  250    82     71   2.20    81.76   13.73    1.89    2.62
  90th %tile Delta-DV     0.239     2.367     2.127    2002  152    85    114   2.30    92.28    3.39    1.13    3.20

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:    10
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.386     5.619     2.234    2002   73    90     72   2.80    78.86   18.70    0.87    1.57
  98th %tile Delta-DV     1.006     3.240     2.234    2002   78    90     72   2.80    79.99   18.35    0.32    1.34
  90th %tile Delta-DV     0.180     2.286     2.106    2002  271    90     72   2.20    75.15   17.27    3.46    4.12

  Number of days with Delta-Deciview > 0.50:    14
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.287     4.563     2.275    2002   74    97     79   2.90    81.76   16.45    0.56    1.23
  98th %tile Delta-DV     1.105     3.445     2.340    2002  312    99     81   3.20    73.62   21.43    1.07    3.88
  90th %tile Delta-DV     0.224     2.456     2.232    2002  195    99     81   2.70    65.69   25.10    3.78    5.43

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:    10
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 5) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND          % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)   YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.431     3.665     2.234     2002   78    46     46   2.80    88.09    9.88    0.41    1.62
  98th %tile Delta-DV     0.706     2.940     2.234     2002   64    57    111   2.80    82.60   13.49    1.09    2.82
  90th %tile Delta-DV     0.140     2.373     2.234     2002   83    48    102   2.80    70.99   21.36    2.83    4.82

  Number of days with Delta-Deciview > 0.50:     11
  Number of days with Delta-Deciview > 1.00:      3
  Max number of consecutive days with Delta-Deciview > 0.50:      1


TRNP NORTH UNIT

  Largest Delta-DV        2.056     4.289     2.234     2002   73    89    118   2.80    85.02   11.50    1.38    2.10
  98th %tile Delta-DV     0.632     2.738     2.106     2002  250    82     71   2.20    87.41    7.42    2.17    3.00
  90th %tile Delta-DV     0.119     2.246     2.127     2002  152    85    114   2.30    93.60    1.70    1.23    3.48

  Number of days with Delta-Deciview > 0.50:      8
  Number of days with Delta-Deciview > 1.00:      2
  Max number of consecutive days with Delta-Deciview > 0.50:      2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.677     3.911     2.234     2002   73    90     72   2.80    86.92   10.20    1.03    1.85
  98th %tile Delta-DV     0.468     2.702     2.234     2002   78    90     72   2.80    88.02   10.03    0.38    1.57
  90th %tile Delta-DV     0.084     2.317     2.234     2002   75    90     72   2.80    94.58    4.37    0.17    0.89

  Number of days with Delta-Deciview > 0.50:      7
  Number of days with Delta-Deciview > 1.00:      1
  Max number of consecutive days with Delta-Deciview > 0.50:      2


LOSTWOOD NWA

  Largest Delta-DV        1.112     3.388     2.275     2002   74    97     79   2.90    89.07    8.83    0.65    1.44
  98th %tile Delta-DV     0.510     2.849     2.340     2002  312    99     81   3.20    82.16   11.93    1.29    4.62
  90th %tile Delta-DV     0.106     2.402     2.297     2002   31    97     79   3.00    93.23    5.95    0.16    0.66

  Number of days with Delta-Deciview > 0.50:      8
  Number of days with Delta-Deciview > 1.00:      2
  Max number of consecutive days with Delta-Deciview > 0.50:      1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 5) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        2.686     4.919     2.234    2002   78    46     46   2.80    88.20    9.89    0.39    1.52
  98th %tile Delta-DV     1.364     3.598     2.234    2002   64    57    111   2.80    82.83   13.51    1.02    2.64
  90th %tile Delta-DV     0.281     2.514     2.234    2002   83    48    102   2.80    71.36   21.49    2.63    4.52

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:    10
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        3.757     5.990     2.234    2002   73    89    118   2.80    85.25   11.50    1.29    1.96
  98th %tile Delta-DV     1.206     3.312     2.106    2002  250    82     71   2.20    87.80    7.36    2.03    2.81
  90th %tile Delta-DV     0.235     2.362     2.127    2002  152    85    114   2.30    93.93    1.66    1.15    3.26

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.110     5.344     2.234    2002   73    90     72   2.80    87.10   10.20    0.96    1.73
  98th %tile Delta-DV     0.917     3.151     2.234    2002   78    90     72   2.80    88.13   10.05    0.35    1.47
  90th %tile Delta-DV     0.167     2.401     2.234    2002   75    90     72   2.80    94.63    4.39    0.15    0.83

  Number of days with Delta-Deciview > 0.50:    14
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.115     4.391     2.275    2002   74    97     79   2.90    89.21    8.84    0.61    1.35
  98th %tile Delta-DV     0.992     3.332     2.340    2002  312    99     81   3.20    82.44   12.01    1.20    4.35
  90th %tile Delta-DV     0.207     2.352     2.145    2002  259    99     81   2.30    87.99    0.33    2.83    8.86

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 6) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                    SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.613     3.846     2.234    2002    78    46     46   2.80    26.94   71.27    0.36    1.43
  98th %tile Delta-DV     0.695     2.928     2.234    2002    50    48    102   2.80    21.01   76.17    0.78    2.04
  90th %tile Delta-DV     0.140     2.267     2.127    2002    95    46     46   2.30    14.22   82.69    0.98    2.12

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:      2


TRNP NORTH UNIT

  Largest Delta-DV        2.578     4.811     2.234    2002    73    89    118   2.80    22.95   74.35    1.07    1.63
  98th %tile Delta-DV     0.727     2.961     2.234    2002    39    58     47   2.80    29.46   66.42    1.01    3.10
  90th %tile Delta-DV     0.095     2.349     2.255    2002    30    82     71   2.90    33.78   65.06    0.24    0.92

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:      2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.947     4.180     2.234    2002    73    90     72   2.80    25.68   71.87    0.87    1.58
  98th %tile Delta-DV     0.531     2.765     2.234    2002    78    90     72   2.80    26.89   71.40    0.33    1.38
  90th %tile Delta-DV     0.088     2.216     2.127    2002   296    90     72   2.30    14.08   82.49    1.43    2.00

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:      2


LOSTWOOD NWA

  Largest Delta-DV        1.186     3.461     2.275    2002    74    94     76   2.90    28.92   69.13    0.61    1.34
  98th %tile Delta-DV     0.561     2.706     2.145    2002   110    91     73   2.30    31.68   65.54    1.03    1.75
  90th %tile Delta-DV     0.096     2.393     2.297    2002    13    97     79   3.00    17.53   81.49    0.39    0.60

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:      2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 6) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        3.004     5.238     2.234    2002   78    46     46   2.80    26.97   71.35    0.34    1.33
  98th %tile Delta-DV     1.344     3.578     2.234    2002   50    48    102   2.80    21.06   76.30    0.73    1.91
  90th %tile Delta-DV     0.278     2.512     2.234    2002   91    45     45   2.80    26.14   72.32    0.20    1.34

  Number of days with Delta-Deciview > 0.50:    29
  Number of days with Delta-Deciview > 1.00:    12
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        4.616     6.850     2.234    2002   73    89    118   2.80    23.04   74.43    1.00    1.53
  98th %tile Delta-DV     1.382     3.616     2.234    2002   66    83    112   2.80    17.82   78.26    1.15    2.77
  90th %tile Delta-DV     0.188     2.442     2.255    2002   30    82     71   2.90    33.82   65.11    0.22    0.86

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:    12
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.569     5.803     2.234    2002   73    90     72   2.80    25.77   71.94    0.82    1.47
  98th %tile Delta-DV     1.033     3.139     2.106    2002  250    90     72   2.20    47.14   46.00    2.56    4.31
  90th %tile Delta-DV     0.176     2.303     2.127    2002  296    90     72   2.30    14.12   82.68    1.34    1.87

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.247     4.523     2.275    2002   74    94     76   2.90    28.97   69.20    0.57    1.26
  98th %tile Delta-DV     1.088     3.233     2.145    2002  110    91     73   2.30    31.79   65.60    0.96    1.64
  90th %tile Delta-DV     0.193     2.468     2.275    2002   91    93     75   2.90    11.06   83.75    2.04    3.16

  Number of days with Delta-Deciview > 0.50:    21
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 7) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC  %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.484     3.717     2.234    2002   78    46     46   2.80    29.47   68.57    0.40    1.56
  98th %tile Delta-DV     0.640     2.746     2.106    2002  233    45     45   2.20    44.01   51.85    1.48    2.66
  90th %tile Delta-DV     0.129     2.299     2.170    2002  155    46     46   2.50    42.37   56.75    0.15    0.74

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.371     4.605     2.234    2002   73    89    118   2.80    25.22   71.81    1.18    1.79
  98th %tile Delta-DV     0.675     2.909     2.234    2002   39    58     47   2.80    31.82   63.73    1.09    3.35
  90th %tile Delta-DV     0.087     2.342     2.255    2002   30    82     71   2.90    36.62   62.13    0.26    0.99

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.792     4.025     2.234    2002   73    90     72   2.80    28.13   69.19    0.96    1.73
  98th %tile Delta-DV     0.487     2.721     2.234    2002   78    90     72   2.80    29.40   68.72    0.36    1.51
  90th %tile Delta-DV     0.085     2.191     2.106    2002  271    90     72   2.20    27.48   63.97    3.91    4.64

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.091     3.367     2.275    2002   74    94     76   2.90    31.57   66.29    0.67    1.47
  98th %tile Delta-DV     0.520     2.817     2.297    2002   29    97     79   3.00    28.07   69.80    0.76    1.37
  90th %tile Delta-DV     0.088     2.299     2.211    2002  178    97     79   2.60    82.99    9.58    3.04    4.39

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 7) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC  %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.484     3.717     2.234    2002   78    46     46   2.80    29.47   68.57    0.40    1.56
  98th %tile Delta-DV     0.640     2.746     2.106    2002  233    45     45   2.20    44.01   51.85    1.48    2.66
  90th %tile Delta-DV     0.129     2.299     2.170    2002  155    46     46   2.50    42.37   56.75    0.15    0.74

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.371     4.605     2.234    2002   73    89    118   2.80    25.22   71.81    1.18    1.79
  98th %tile Delta-DV     0.675     2.909     2.234    2002   39    58     47   2.80    31.82   63.73    1.09    3.35
  90th %tile Delta-DV     0.087     2.342     2.255    2002   30    82     71   2.90    36.62   62.13    0.26    0.99

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.792     4.025     2.234    2002   73    90     72   2.80    28.13   69.19    0.96    1.73
  98th %tile Delta-DV     0.487     2.721     2.234    2002   78    90     72   2.80    29.40   68.72    0.36    1.51
  90th %tile Delta-DV     0.085     2.191     2.106    2002  271    90     72   2.20    27.48   63.97    3.91    4.64

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.091     3.367     2.275    2002   74    94     76   2.90    31.57   66.29    0.67    1.47
  98th %tile Delta-DV     0.520     2.817     2.297    2002   29    97     79   3.00    28.07   69.80    0.76    1.37
  90th %tile Delta-DV     0.088     2.299     2.211    2002  178    97     79   2.60    82.99    9.58    3.04    4.39

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 8) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                  SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.207     3.440     2.234    2002   78    46     46   2.80    36.75   60.80    0.50    1.95
  98th %tile Delta-DV     0.546     2.653     2.106    2002  233    53    107   2.20    52.29   42.88    1.73    3.10
  90th %tile Delta-DV     0.106     2.339     2.234    2002   79    53    107   2.80    31.11   66.09    0.42    2.38

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.921     4.154     2.234    2002   73    89    118   2.80    31.87   64.38    1.49    2.26
  98th %tile Delta-DV     0.529     2.763     2.234    2002   50    58     47   2.80    25.43   70.35    1.29    2.92
  90th %tile Delta-DV     0.069     2.239     2.170    2002  178    85    114   2.50    71.22   22.05    2.60    4.13

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.457     3.691     2.234    2002   73    90     72   2.80    35.19   61.46    1.20    2.16
  98th %tile Delta-DV     0.393     2.626     2.234    2002   78    90     72   2.80    36.64   61.02    0.45    1.89
  90th %tile Delta-DV     0.073     2.243     2.170    2002  178    90     72   2.50    68.13   25.80    2.26    3.81

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        0.890     3.165     2.275    2002   74    97     79   2.90    39.17   58.18    0.82    1.82
  98th %tile Delta-DV     0.414     2.711     2.297    2002   29    97     79   3.00    35.42   61.90    0.96    1.73
  90th %tile Delta-DV     0.080     2.312     2.232    2002  192    91     73   2.70    79.16    9.32    4.66    6.86

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 8) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.286     4.519     2.234    2002   78    46     46   2.80    36.80   60.91    0.47    1.82
  98th %tile Delta-DV     1.057     3.163     2.106    2002  233    53    107   2.20    52.71   42.75    1.62    2.92
  90th %tile Delta-DV     0.210     2.443     2.234    2002   79    53    107   2.80    31.17   66.21    0.39    2.22

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        3.524     5.758     2.234    2002   73    89    118   2.80    31.99   64.50    1.39    2.12
  98th %tile Delta-DV     1.029     3.262     2.234    2002   50    58     47   2.80    25.52   70.54    1.21    2.74
  90th %tile Delta-DV     0.137     2.307     2.170    2002  178    85    114   2.50    71.58   22.10    2.44    3.87

  Number of days with Delta-Deciview > 0.50:    16
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        2.724     4.957     2.234    2002   73    90     72   2.80    35.30   61.56    1.12    2.02
  98th %tile Delta-DV     0.772     3.006     2.234    2002   78    90     72   2.80    36.67   61.14    0.42    1.76
  90th %tile Delta-DV     0.145     2.315     2.170    2002  178    90     72   2.50    68.47   25.85    2.12    3.57

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.707     3.983     2.275    2002   74    97     79   2.90    39.25   58.28    0.77    1.70
  98th %tile Delta-DV     0.812     3.109     2.297    2002   29    97     79   3.00    35.47   62.02    0.90    1.62
  90th %tile Delta-DV     0.158     2.390     2.232    2002  192    91     73   2.70    79.81    9.35    4.38    6.46

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 9) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.779     3.012     2.234    2002   78    46     46   2.80    58.22   37.91    0.79    3.08
  98th %tile Delta-DV     0.406     2.512     2.106    2002  233    53    107   2.20    70.84   22.62    2.34    4.20
  90th %tile Delta-DV     0.070     2.197     2.127    2002  100     6      6   2.30    59.27   34.04    1.77    4.92

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.211     3.444     2.234    2002   73    89    118   2.80    52.43   41.40    2.45    3.72
  98th %tile Delta-DV     0.325     2.431     2.106    2002  250    82     71   2.20    60.14   29.65    4.28    5.94
  90th %tile Delta-DV     0.049     2.283     2.234    2002   78    67     56   2.80    54.85   41.30    0.90    2.95

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        0.937     3.170     2.234    2002   73    90     72   2.80    56.19   38.45    1.91    3.45
  98th %tile Delta-DV     0.250     2.483     2.234    2002   78    90     72   2.80    58.04   38.26    0.71    2.99
  90th %tile Delta-DV     0.047     2.280     2.234    2002   66    90     72   2.80    49.08   45.59    0.81    4.53

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        0.583     2.858     2.275    2002   74    97     79   2.90    60.72   35.18    1.28    2.82
  98th %tile Delta-DV     0.261     2.429     2.167    2002  301    91     73   2.40    47.62   45.46    2.15    4.77
  90th %tile Delta-DV     0.059     2.269     2.211    2002  172    97     79   2.60    67.50    9.80    7.51   15.18

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 9) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC  %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.502     3.735     2.234    2002   78    46     46   2.80    58.34   38.03    0.74    2.89
  98th %tile Delta-DV     0.792     2.898     2.106    2002  233    53    107   2.20    71.29   22.57    2.19    3.95
  90th %tile Delta-DV     0.139     2.267     2.127    2002  100     6      6   2.30    59.55   34.18    1.66    4.61

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.284     4.518     2.234    2002   73    89    118   2.80    52.67   41.55    2.29    3.49
  98th %tile Delta-DV     0.627     2.733     2.106    2002  250    82     71   2.20    60.62   29.77    4.02    5.58
  90th %tile Delta-DV     0.098     2.332     2.234    2002   78    67     56   2.80    54.94   41.45    0.85    2.76

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.789     4.023     2.234    2002   73    90     72   2.80    56.40   38.58    1.79    3.23
  98th %tile Delta-DV     0.494     2.728     2.234    2002   78    90     72   2.80    58.15   38.38    0.67    2.80
  90th %tile Delta-DV     0.093     2.220     2.127    2002   95    90     72   2.30    42.39   50.06    2.12    5.43

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.134     3.409     2.275    2002   74    97     79   2.90    60.89   35.28    1.19    2.64
  98th %tile Delta-DV     0.513     2.681     2.167    2002  301    91     73   2.40    47.85   45.66    2.02    4.47
  90th %tile Delta-DV     0.115     2.326     2.211    2002  172    97     79   2.60    68.53    9.97    7.12   14.38

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (Scenario 10) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.634     2.868     2.234    2002   78    46     46   2.80    71.98   23.23    0.97    3.81
  98th %tile Delta-DV     0.332     2.565     2.234    2002   64    57    111   2.80    62.27   29.25    2.36    6.12
  90th %tile Delta-DV     0.062     2.168     2.106    2002  240    49    103   2.20    92.95    3.28    1.33    2.44

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.968     3.202     2.234    2002   73    89    118   2.80    66.36   25.84    3.10    4.71
  98th %tile Delta-DV     0.277     2.383     2.106    2002  250    82     71   2.20    70.63   17.36    5.03    6.98
  90th %tile Delta-DV     0.047     2.174     2.127    2002  152    85    114   2.30    83.50    4.43    3.15    8.93

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        0.761     2.995     2.234    2002   73    90     72   2.80    69.77   23.57    2.38    4.28
  98th %tile Delta-DV     0.202     2.436     2.234    2002   78    90     72   2.80    71.87   23.55    0.88    3.70
  90th %tile Delta-DV     0.038     2.187     2.149    2002  198    90     72   2.40    83.93    3.54    5.44    7.10

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        0.481     2.757     2.275    2002   74    97     79   2.90    73.92   21.09    1.55    3.44
  98th %tile Delta-DV     0.226     2.458     2.232    2002  200    93     75   2.70    85.94    7.47    2.42    4.17
  90th %tile Delta-DV     0.049     2.195     2.145    2002  247    97     79   2.30    83.85    1.24    4.93    9.98

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (Scenario 10) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.230     3.464     2.234    2002   78   46     46   2.80    72.19   23.32    0.92    3.57
  98th %tile Delta-DV     0.651     2.884     2.234    2002   64   57    111   2.80    62.64   29.41    2.21    5.74
  90th %tile Delta-DV     0.123     2.229     2.106    2002  240   49    103   2.20    93.17    3.31    1.24    2.28

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.845     4.078     2.234    2002   73   89    118   2.80    66.72   25.96    2.90    4.42
  98th %tile Delta-DV     0.536     2.642     2.106    2002  250   82     71   2.20    71.25   17.46    4.72    6.57
  90th %tile Delta-DV     0.092     2.219     2.127    2002  152   85    114   2.30    84.21    4.44    2.95    8.41

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.464     3.697     2.234    2002   73   90     72   2.80    70.09   23.67    2.23    4.01
  98th %tile Delta-DV     0.401     2.634     2.234    2002   78   90     72   2.80    72.06   23.64    0.83    3.46
  90th %tile Delta-DV     0.075     2.223     2.149    2002  198   90     72   2.40    84.54    3.67    5.11    6.68

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        0.940     3.215     2.275    2002   74   97     79   2.90    74.16   21.17    1.45    3.22
  98th %tile Delta-DV     0.444     2.676     2.232    2002  200   93     75   2.70    86.34    7.48    2.27    3.91
  90th %tile Delta-DV     0.096     2.263     2.167    2002  220   97     79   2.40    61.77   26.00    5.30    6.93

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (PM Scenario 0, All Pollutants Pre-BART) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        4.503     6.737     2.234    2002   78    46     46   2.80    71.11   28.40    0.09    0.39
  98th %tile Delta-DV     2.559     4.814     2.255    2002   26    47    101   2.90    64.72   34.53    0.28    0.47
  90th %tile Delta-DV     0.540     2.646     2.106    2002  270    53    107   2.20    58.28   40.09    0.61    1.01

  Number of days with Delta-Deciview > 0.50:    38
  Number of days with Delta-Deciview > 1.00:    23
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        6.532     8.766     2.234    2002   73    89    118   2.80    66.26   32.91    0.33    0.50
  98th %tile Delta-DV     2.113     4.347     2.234    2002   39    67     56   2.80    84.58   14.15    0.33    0.95
  90th %tile Delta-DV     0.385     2.512     2.127    2002  152    85    114   2.30    92.22    6.34    0.38    1.06

  Number of days with Delta-Deciview > 0.50:    30
  Number of days with Delta-Deciview > 1.00:    17
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP ELKHORN RANCH

  Largest Delta-DV        5.501     7.734     2.234    2002   73    90     72   2.80    69.47   29.82    0.26    0.45
  98th %tile Delta-DV     1.703     3.978     2.276    2002  336    90     72   3.00    61.77   37.21    0.46    0.57
  90th %tile Delta-DV     0.310     2.416     2.106    2002  255    90     72   2.20    88.37    7.70    1.41    2.52

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:    13
  Max number of consecutive days with Delta-Deciview > 0.50:     3


LOSTWOOD NWA

  Largest Delta-DV        3.827     6.102     2.275    2002   74    97     79   2.90    72.61   26.86    0.17    0.36
  98th %tile Delta-DV     1.814     4.154     2.340    2002  312    99     81   3.20    68.02   30.72    0.27    0.99
  90th %tile Delta-DV     0.385     2.531     2.145    2002  247    97     79   2.30    96.31    1.89    0.59    1.21

  Number of days with Delta-Deciview > 0.50:    32
  Number of days with Delta-Deciview > 1.00:    16
  Max number of consecutive days with Delta-Deciview > 0.50:     4
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (PM Scenario 1, PM at Pre-BART, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                          SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.474     3.708     2.234    2002   78    46     46   2.80    40.09   58.18    0.33    1.40
  98th %tile Delta-DV     0.749     2.855     2.106    2002  233    53    107   2.20    55.64   40.89    1.25    2.23
  90th %tile Delta-DV     0.135     2.263     2.127    2002  100    54    108   2.30    38.72   57.36    1.17    2.75

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.436     4.670     2.234    2002   73    89    118   2.80    34.70   62.54    1.10    1.65
  98th %tile Delta-DV     0.695     2.928     2.234    2002   50    58     47   2.80    27.85   69.05    0.95    2.15
  90th %tile Delta-DV     0.092     2.240     2.149    2002  198    84    113   2.40    84.80    5.35    3.51    6.34

  Number of days with Delta-Deciview > 0.50:    14
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.916     4.150     2.234    2002   73    90     72   2.80    38.06   59.46    0.90    1.58
  98th %tile Delta-DV     0.586     2.862     2.276    2002  336    90     72   3.00    30.14   66.71    1.41    1.75
  90th %tile Delta-DV     0.090     2.196     2.106    2002  271    90     72   2.20    37.58   54.52    3.62    4.29

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.188     3.463     2.275    2002   74    97     79   2.90    42.04   56.02    0.62    1.32
  98th %tile Delta-DV     0.536     2.833     2.297    2002   29    97     79   3.00    38.20   59.88    0.68    1.24
  90th %tile Delta-DV     0.099     2.331     2.232    2002  185    97     79   2.70    21.43   68.70    3.48    6.38

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (PM Scenario 2, PM at Permit Limit, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.507     3.741     2.234    2002   78    46     46   2.80    39.14   56.79    0.77    3.31
  98th %tile Delta-DV     0.784     2.890     2.106    2002  233    53    107   2.20    53.03   38.97    2.86    5.13
  90th %tile Delta-DV     0.143     2.270     2.127    2002  100    54    108   2.30    36.69   54.35    2.66    6.30

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.520     4.753     2.234    2002   73    89    118   2.80    33.40   60.20    2.57    3.83
  98th %tile Delta-DV     0.731     2.837     2.106    2002  250    82     71   2.20    42.38   45.91    4.96    6.76
  90th %tile Delta-DV     0.096     2.351     2.255    2002   30    82     71   2.90    46.56   50.82    0.55    2.07

  Number of days with Delta-Deciview > 0.50:    14
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.977     4.211     2.234    2002   73    90     72   2.80    36.77   57.45    2.10    3.68
  98th %tile Delta-DV     0.611     2.887     2.276    2002  336    90     72   3.00    28.85   63.86    3.25    4.04
  90th %tile Delta-DV     0.099     2.205     2.106    2002  271    90     72   2.20    33.80   49.03    7.86    9.32

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.218     3.494     2.275    2002   74    97     79   2.90    40.91   54.52    1.46    3.10
  98th %tile Delta-DV     0.578     2.745     2.167    2002  241    91     73   2.40    74.87   10.20    4.86   10.07
  90th %tile Delta-DV     0.112     2.345     2.232    2002  185    97     79   2.70    18.81   60.30    7.38   13.52

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (PM Scenario 3, PM at Average Actual, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.468     3.701     2.234    2002   78    46     46   2.80    40.28   58.46    0.24    1.02
  98th %tile Delta-DV     0.742     2.848     2.106    2002  233    53    107   2.20    56.18   41.28    0.91    1.63
  90th %tile Delta-DV     0.134     2.368     2.234    2002   91    45     45   2.80    38.80   59.98    0.17    1.04

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.420     4.653     2.234    2002   73    89    118   2.80    34.97   63.02    0.81    1.20
  98th %tile Delta-DV     0.689     2.922     2.234    2002   50    58     47   2.80    28.09   69.65    0.69    1.57
  90th %tile Delta-DV     0.089     2.323     2.234    2002   78    67     56   2.80    37.73   61.04    0.27    0.96

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.904     4.138     2.234    2002   73    90     72   2.80    38.32   59.87    0.66    1.15
  98th %tile Delta-DV     0.581     2.857     2.276    2002  336    90     72   3.00    30.40   67.30    1.03    1.28
  90th %tile Delta-DV     0.088     2.194     2.106    2002  271    90     72   2.20    38.41   55.73    2.68    3.18

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.182     3.457     2.275    2002   74    97     79   2.90    42.26   56.32    0.45    0.96
  98th %tile Delta-DV     0.533     2.830     2.297    2002   29    97     79   3.00    38.40   60.20    0.50    0.90
  90th %tile Delta-DV     0.097     2.437     2.340    2002  336    91     73   3.20    16.51   81.04    0.43    2.02

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 (PM Scenario 4, PM at Best Controls, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                     SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.459     3.692     2.234    2002   78    46     46   2.80    40.54   58.83    0.12    0.51
  98th %tile Delta-DV     0.733     2.839     2.106    2002  233    53    107   2.20    56.90   41.81    0.46    0.83
  90th %tile Delta-DV     0.133     2.367     2.234    2002   91    45     45   2.80    39.04   60.35    0.09    0.52

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.398     4.632     2.234    2002   73    89    118   2.80    35.33   63.66    0.41    0.61
  98th %tile Delta-DV     0.681     2.915     2.234    2002   50    58     47   2.80    28.41   70.45    0.35    0.79
  90th %tile Delta-DV     0.086     2.192     2.106    2002  249    63     52   2.20    31.60   61.47    2.76    4.17

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.889     4.122     2.234    2002   73    90     72   2.80    38.67   60.42    0.33    0.58
  98th %tile Delta-DV     0.570     2.676     2.106    2002  250    90     72   2.20    62.68   35.00    0.86    1.46
  90th %tile Delta-DV     0.085     2.191     2.106    2002  271    90     72   2.20    39.57   57.41    1.38    1.64

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.173     3.449     2.275    2002   74    97     79   2.90    42.56   56.73    0.23    0.48
  98th %tile Delta-DV     0.529     2.826     2.297    2002   29    97     79   3.00    38.67   60.62    0.25    0.45
  90th %tile Delta-DV     0.096     2.436     2.340    2002  336    91     73   3.20    16.71   82.05    0.22    1.02

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (PM Scenario 0, All Pollutants Pre-BART) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                         SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        6.675     8.908     2.234    2002   78    46     46   2.80    79.57   19.89    0.10    0.44
  98th %tile Delta-DV     4.475     6.730     2.255    2002   26    47    101   2.90    63.14   36.13    0.27    0.46
  90th %tile Delta-DV     0.971     3.077     2.106    2002  270    53    107   2.20    58.87   39.49    0.62    1.02

  Number of days with Delta-Deciview > 0.50:    50
  Number of days with Delta-Deciview > 1.00:    36
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP NORTH UNIT

  Largest Delta-DV       10.081    12.314     2.234    2002   73    89    118   2.80    65.93   33.24    0.33    0.49
  98th %tile Delta-DV     3.557     5.664     2.106    2002  250    82     71   2.20    89.34    9.05    0.68    0.93
  90th %tile Delta-DV     0.706     2.834     2.127    2002  152    85    114   2.30    92.23    6.33    0.38    1.06

  Number of days with Delta-Deciview > 0.50:    45
  Number of days with Delta-Deciview > 1.00:    27
  Max number of consecutive days with Delta-Deciview > 0.50:     4


TRNP ELKHORN RANCH

  Largest Delta-DV        8.644    10.878     2.234    2002   73    90     72   2.80    69.59   29.70    0.26    0.45
  98th %tile Delta-DV     3.039     5.315     2.276    2002  336    90     72   3.00    59.83   39.18    0.44    0.55
  90th %tile Delta-DV     0.581     2.708     2.127    2002   95    90     72   2.30    56.20   42.67    0.31    0.82

  Number of days with Delta-Deciview > 0.50:    42
  Number of days with Delta-Deciview > 1.00:    21
  Max number of consecutive days with Delta-Deciview > 0.50:     4


LOSTWOOD NWA

  Largest Delta-DV        6.332     8.608     2.275    2002   74    97     79   2.90    71.70   27.78    0.17    0.35
  98th %tile Delta-DV     3.190     5.487     2.297    2002   29    97     79   3.00    67.24   32.23    0.19    0.34
  90th %tile Delta-DV     0.707     2.852     2.145    2002  247    97     79   2.30    96.30    1.90    0.59    1.21

  Number of days with Delta-Deciview > 0.50:    45
  Number of days with Delta-Deciview > 1.00:    29
  Max number of consecutive days with Delta-Deciview > 0.50:     4
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (PM Scenario 1, PM at Pre-BART, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                        SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.755     4.988     2.234    2002   78    46     46   2.80    40.16   58.22    0.30    1.31
  98th %tile Delta-DV     1.434     3.540     2.106    2002  233    53    107   2.20    56.13   40.60    1.17    2.10
  90th %tile Delta-DV     0.270     2.504     2.234    2002   91    45     45   2.80    38.68   59.77    0.22    1.33

  Number of days with Delta-Deciview > 0.50:    27
  Number of days with Delta-Deciview > 1.00:    12
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        4.417     6.651     2.234    2002   73    89    118   2.80    34.80   62.63    1.03    1.54
  98th %tile Delta-DV     1.338     3.572     2.234    2002   39    82     71   2.80    39.20   57.27    0.97    2.56
  90th %tile Delta-DV     0.181     2.329     2.149    2002  198    84    113   2.40    85.40    5.33    3.30    5.96

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:    13
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.529     5.763     2.234    2002   73    90     72   2.80    38.17   59.52    0.84    1.48
  98th %tile Delta-DV     1.129     3.235     2.106    2002  250    90     72   2.20    61.71   32.39    2.19    3.72
  90th %tile Delta-DV     0.181     2.287     2.106    2002  240    90     72   2.20    87.34   10.33    0.82    1.51

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.258     4.533     2.275    2002   74    97     79   2.90    42.10   56.09    0.58    1.23
  98th %tile Delta-DV     1.050     3.347     2.297    2002   29    97     79   3.00    38.22   59.98    0.64    1.16
  90th %tile Delta-DV     0.197     2.429     2.232    2002  185    97     79   2.70    21.71   69.10    3.22    5.96

  Number of days with Delta-Deciview > 0.50:    22
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (PM Scenario 2, PM at Permit Limit, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                       SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.816     5.050     2.234    2002   78    46     46   2.80    39.16   56.77    0.77    3.31
  98th %tile Delta-DV     1.503     3.609     2.106    2002  233    53    107   2.20    53.36   38.60    2.88    5.16
  90th %tile Delta-DV     0.282     2.410     2.127    2002  100    54    108   2.30    36.58   54.35    2.72    6.35

  Number of days with Delta-Deciview > 0.50:    28
  Number of days with Delta-Deciview > 1.00:    12
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        4.563     6.796     2.234    2002   73    89    118   2.80    33.43   60.17    2.56    3.84
  98th %tile Delta-DV     1.402     3.508     2.106    2002  250    82     71   2.20    42.63   45.57    5.00    6.81
  90th %tile Delta-DV     0.195     2.450     2.255    2002   30    82     71   2.90    46.60   50.78    0.55    2.07

  Number of days with Delta-Deciview > 0.50:    20
  Number of days with Delta-Deciview > 1.00:    14
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.638     5.871     2.234    2002   73    90     72   2.80    36.81   57.41    2.09    3.68
  98th %tile Delta-DV     1.181     3.456     2.276    2002  336    90     72   3.00    28.72   64.01    3.20    4.06
  90th %tile Delta-DV     0.198     2.304     2.106    2002  271    90     72   2.20    33.92   48.83    7.89    9.35

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.316     4.591     2.275    2002   74    97     79   2.90    40.92   54.52    1.45    3.10
  98th %tile Delta-DV     1.125     3.292     2.167    2002  241    91     73   2.40    75.02   10.13    4.83   10.02
  90th %tile Delta-DV     0.226     2.458     2.232    2002  185    97     79   2.70    18.95   60.32    7.26   13.47

  Number of days with Delta-Deciview > 0.50:    22
  Number of days with Delta-Deciview > 1.00:    10
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (PM Scenario 3, PM at Average Actual, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.746     4.980     2.234     2002   78    46     46   2.80    40.31   58.44    0.24    1.02
  98th %tile Delta-DV     1.425     3.531     2.106     2002  233    53    107   2.20    56.54   40.90    0.92    1.64
  90th %tile Delta-DV     0.269     2.503     2.234     2002   91    45     45   2.80    38.82   59.98    0.17    1.04

  Number of days with Delta-Deciview > 0.50:    27
  Number of days with Delta-Deciview > 1.00:    12
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        4.397     6.630     2.234     2002   73    89    118   2.80    35.00   62.99    0.81    1.21
  98th %tile Delta-DV     1.328     3.562     2.234     2002   39    82     71   2.80    39.51   57.73    0.76    2.00
  90th %tile Delta-DV     0.179     2.413     2.234     2002   78    67     56   2.80    37.71   61.06    0.27    0.96

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:    11
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.514     5.747     2.234     2002   73    90     72   2.80    38.36   59.83    0.65    1.15
  98th %tile Delta-DV     1.115     3.221     2.106     2002  250    90     72   2.20    62.54   32.82    1.72    2.92
  90th %tile Delta-DV     0.180     2.286     2.106     2002  240    90     72   2.20    87.79   10.39    0.64    1.18

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.250     4.525     2.275     2002   74    97     79   2.90    42.27   56.32    0.45    0.96
  98th %tile Delta-DV     1.046     3.342     2.297     2002   29    97     79   3.00    38.38   60.22    0.50    0.90
  90th %tile Delta-DV     0.194     2.533     2.340     2002  336    91     73   3.20    16.50   81.07    0.40    2.03

  Number of days with Delta-Deciview > 0.50:    22
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     3
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CALBART - Summary of Visibility Results for 24-hr Delta-Deciview
Coal Creek Station Unit 1 & Unit 2 (PM Scenario 4, PM at Best Controls, SO2 and NOx at Presumptive) for Year 2002 Meteorological Data
Title lines from CALPUFF (POSTUTIL) output file:
Coal Creek Station - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)


                                                                  SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.736     4.970     2.234    2002   78    46     46   2.80    40.47   58.90    0.12    0.51
  98th %tile Delta-DV     1.448     3.554     2.106    2002  233    53    107   2.20    55.55   43.20    0.45    0.81
  90th %tile Delta-DV     0.268     2.438     2.170    2002  178    53    107   2.50    63.03   35.55    0.50    0.92

  Number of days with Delta-Deciview > 0.50:    25
  Number of days with Delta-Deciview > 1.00:    12
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        4.380     6.613     2.234    2002   73    89    118   2.80    35.17   63.82    0.40    0.61
  98th %tile Delta-DV     1.333     3.567     2.234    2002   50    58     47   2.80    28.15   70.71    0.35    0.79
  90th %tile Delta-DV     0.179     2.328     2.149    2002  198    84    113   2.40    86.02   10.36    1.29    2.33

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:    10
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.505     5.739     2.234    2002   73    90     72   2.80    38.48   60.62    0.33    0.58
  98th %tile Delta-DV     1.118     3.224     2.106    2002  250    90     72   2.20    62.37   35.32    0.86    1.46
  90th %tile Delta-DV     0.185     2.313     2.127    2002  125    90     72   2.30    30.17   68.80    0.05    0.98

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.234     4.510     2.275    2002   74    97     79   2.90    42.58   56.70    0.23    0.48
  98th %tile Delta-DV     1.048     3.345     2.297    2002   29    97     79   3.00    38.27   61.03    0.25    0.45
  90th %tile Delta-DV     0.192     2.532     2.340    2002  336    91     73   3.20    16.64   82.14    0.20    1.02

  Number of days with Delta-Deciview > 0.50:    20
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     2
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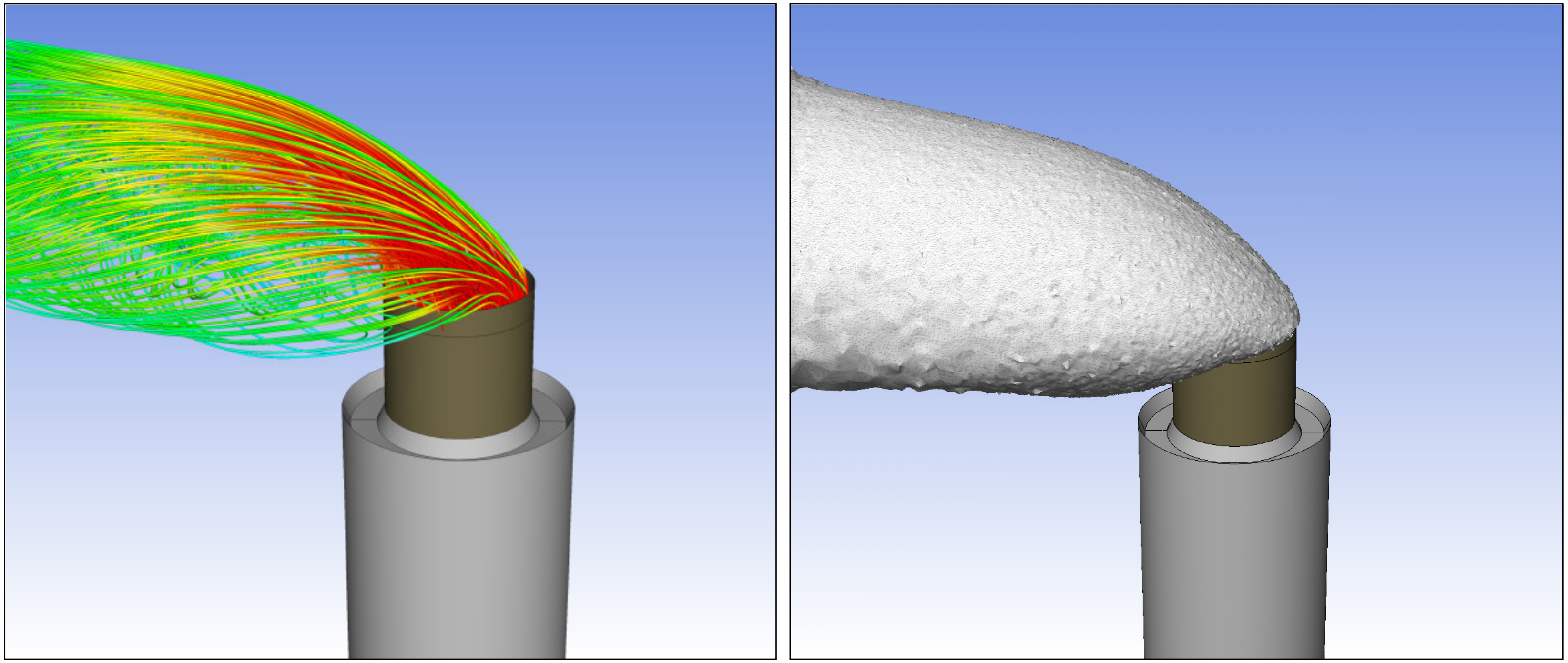
Appendix E

Wet Stack Study

Computational Fluid Dynamics Model of a Wet Stack in North Dakota

590 MW Unit at Full Load



Summary of Results

- The CFD model predicts a bifurcated plume for all cases.

- Predicted plume downwash:
  - 13 Feet Below Top of Liner Extension for 38 MPH wind speed at –7 degree F
  - 16.5 Feet Below Top of Liner Extension for 63 MPH wind speed at –17 degree F

- A 20 foot liner extension is sufficient to prevent stack gas from contacting shell under the worst case met condition.

- The model predicts the potential for ice formation along outer band of plume downwash on liner extension.

- The stack design philosophy is to manage, but not prevent, ice formation.

- Ice formation is managed through the use of an inverted rain cap on the stack shell.

- The model predicts increased vortex shedding in the wake behind the stack for the 63 MPH wind case. This creates additional undulations in the predicted plume shape for the 63 MPH case relative to the 38 MPH case.

CFD Cases

Case 1:
- Wind Speed = 38 MPH at Stack Height
- Ambient Air Temperature = - 7 deg. F

Case 2:
- Wind Speed = 63 MPH at Stack Height
- Ambient Air Temperature = - 17 deg. F

Modeled Flue Gas Conditions (All Cases)

- 1,947,000 acfm at 138 deg. F
- 590 MW at Full Load
- Corresponds to 55 ft/sec gas velocity inside stack
- Effect of buoyancy is included in CFD model

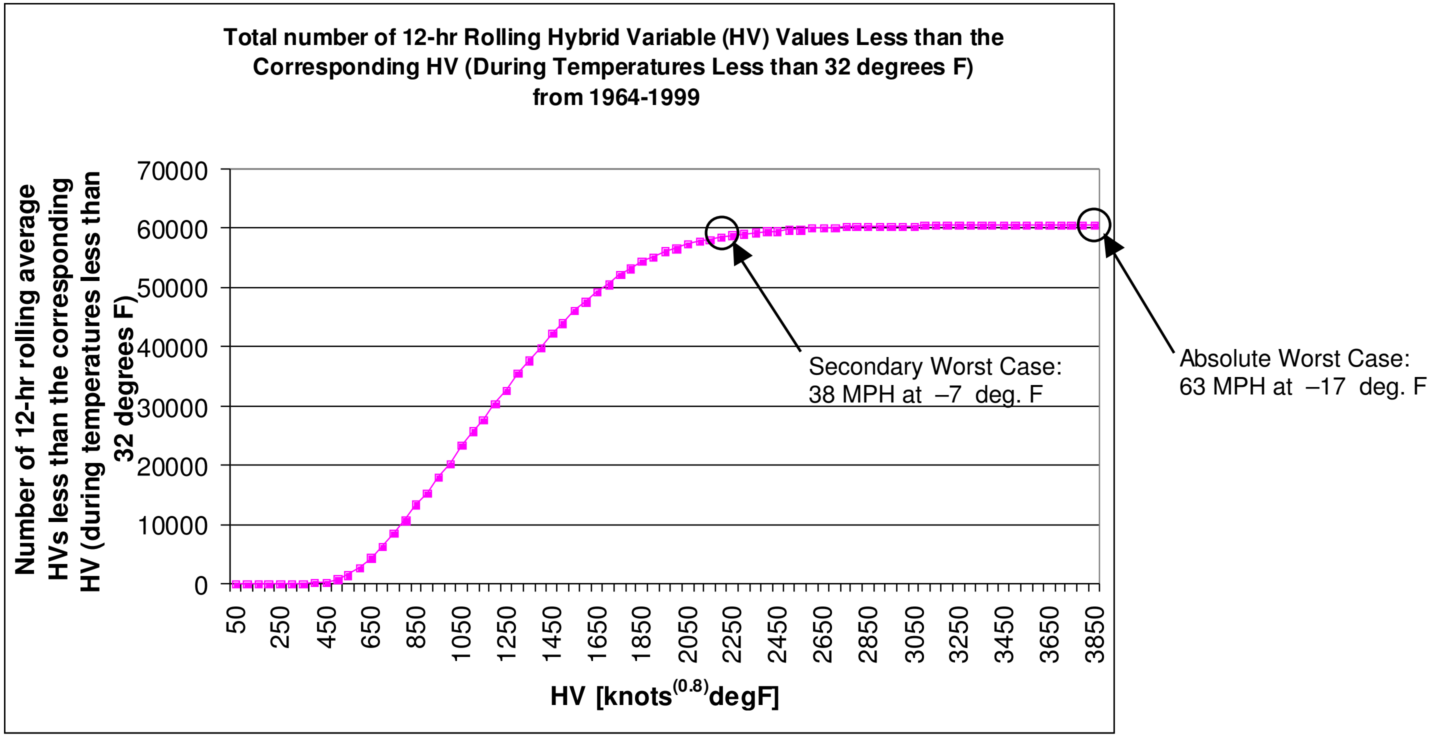
Modeling Assumptions (All Cases)

- Plane of symmetry at stack centerline for geometry and boundary conditions
- Liner extension is assumed to be perfectly insulated

Determination of Worst Case Met Conditions

- Based worst case met condition on wind speed and temperature
  - Reviewed 35 years of Minot met data: 1964 through 1999
  - Computed wind speed at stack height based on wind speed at ground level
  - Heat transfer proportional to [(Wind Speed)$^{0.8}$] * [138 - Temperature] = Hybrid Variable, HV
  - Prepared an occurrence distribution plot of 12 hour rolling average of HV for 35 year period

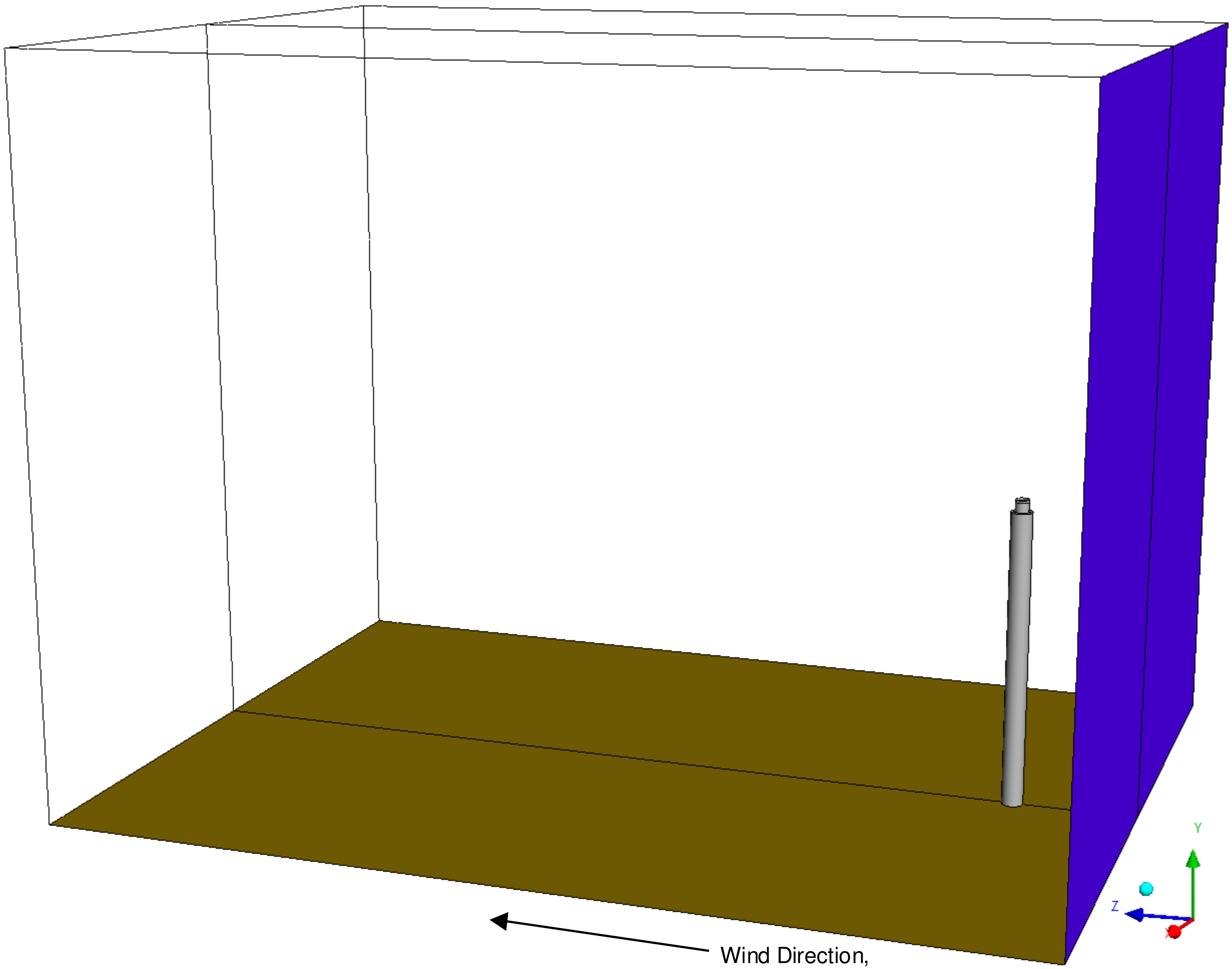
- Identified two met conditions based on 12 hour rolling average Hybrid Variable
  - Absolute worst case for entire 35 year period: Wind Speed at stack height = 63 MPH, Temperature = -17 F
  - Secondary worst case representing 99 % of 35 year period: Wind Speed at stack height = 38 MPH, Temperature = -7 F



Secondary Worst Case:
38 MPH at –7 deg. F

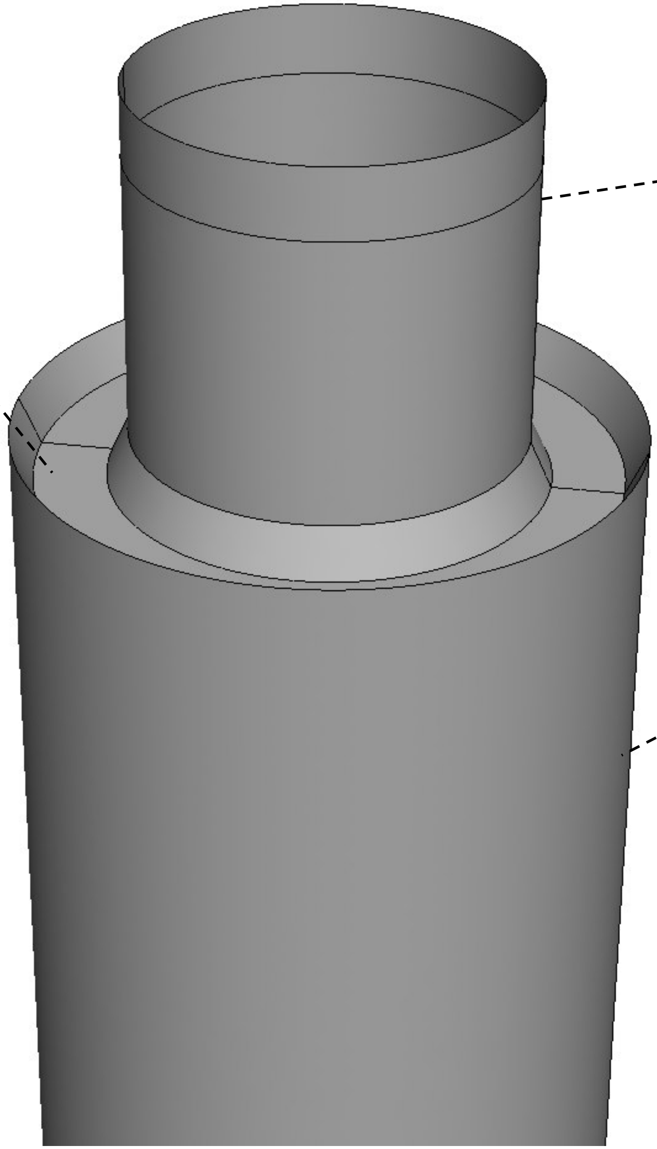
Absolute Worst Case:
63 MPH at –17 deg. F

CFD Model Geometry



Wind Direction,
All Cases

CFD Model Geometry: Top of Stack



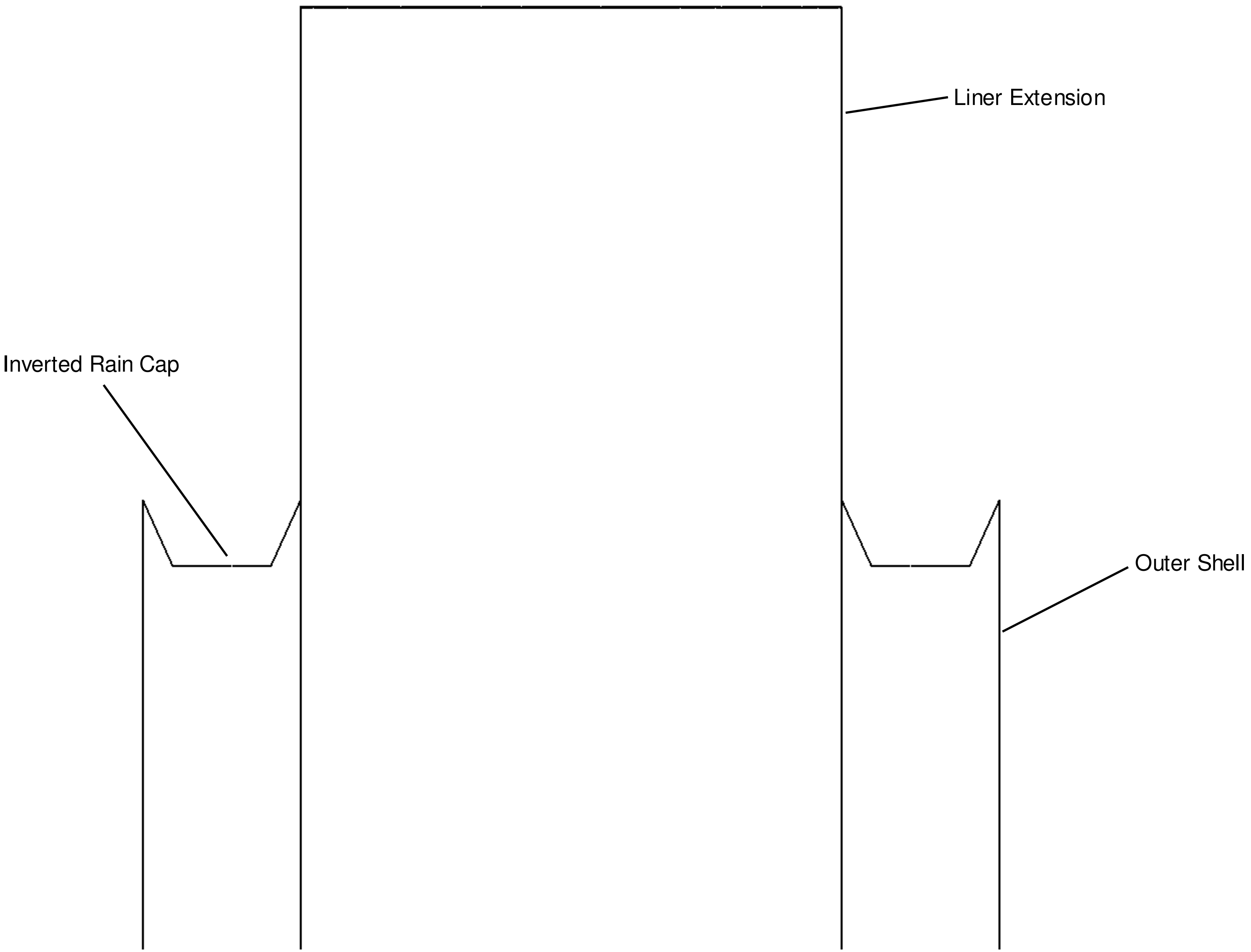
Inverted Rain Cap :
- 40” Deep
- 5’ Wide
- 1’-6” Wide Sloped Sides

Liner Extension:
- ID = 27’-5”
- Average Stack Gas Velocity = 55 ft/sec
- Extension Height = 25 Feet

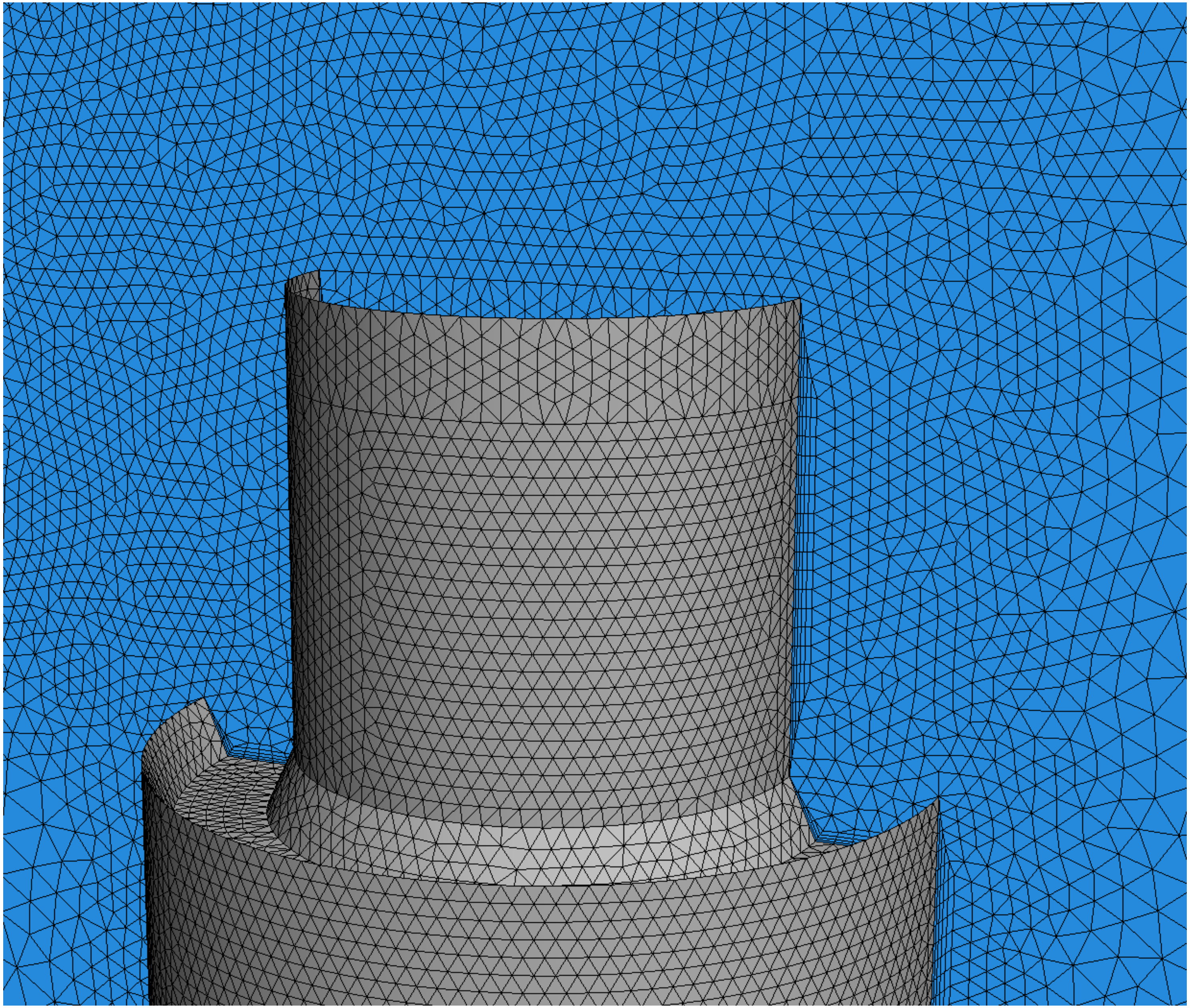
Outer Shell :
- OD = 43’-5”
- Top of Shell 600’ Above Ground Level

CFD Model Geometry: Top of Stack

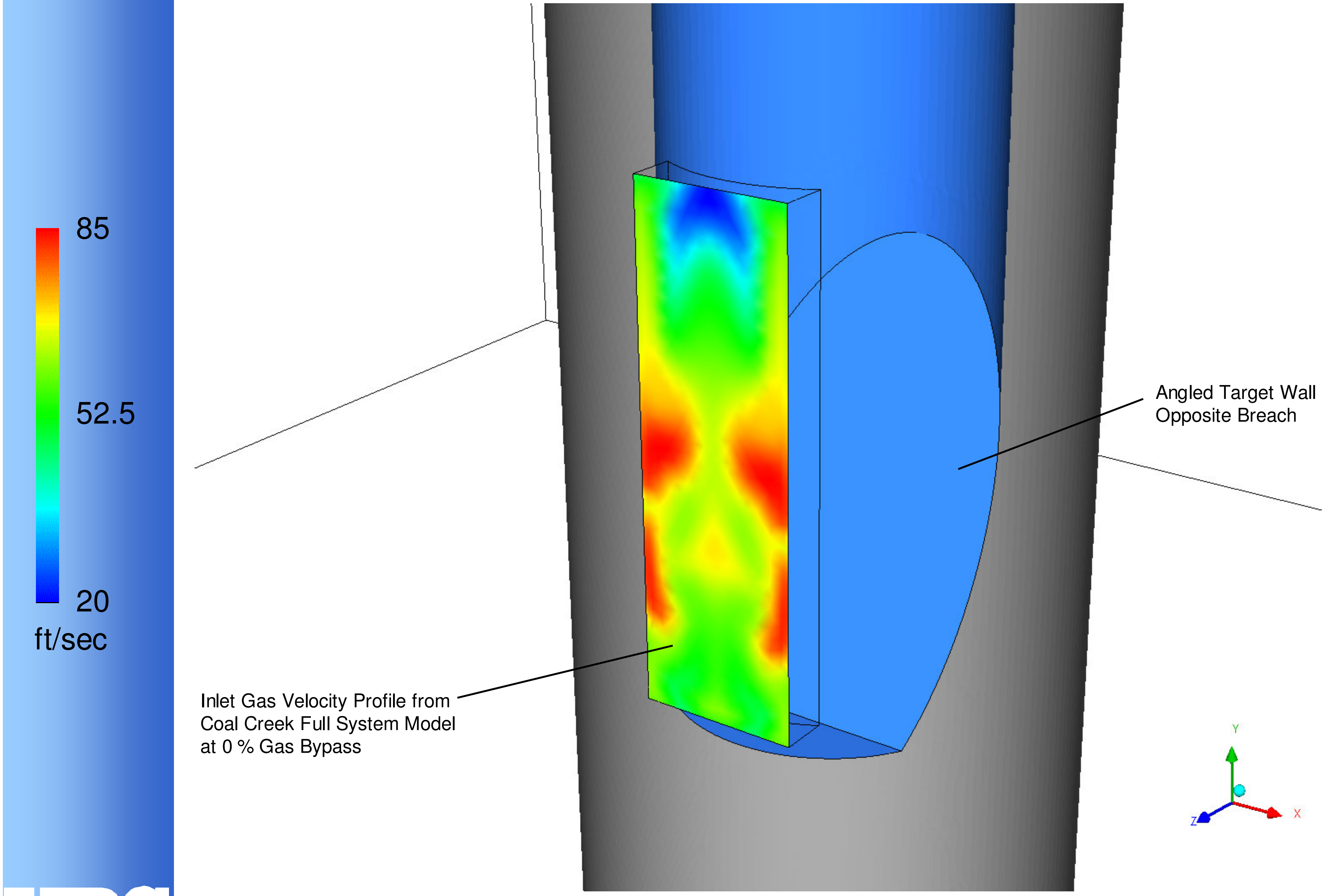
Elevation View



Computational Mesh at Stack Exit – All Cases



CFD Model Geometry: Breach and Liner Floor Details

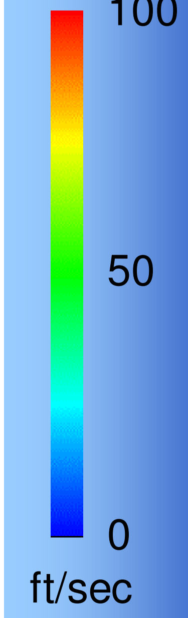


Angled Target Wall Opposite Breach

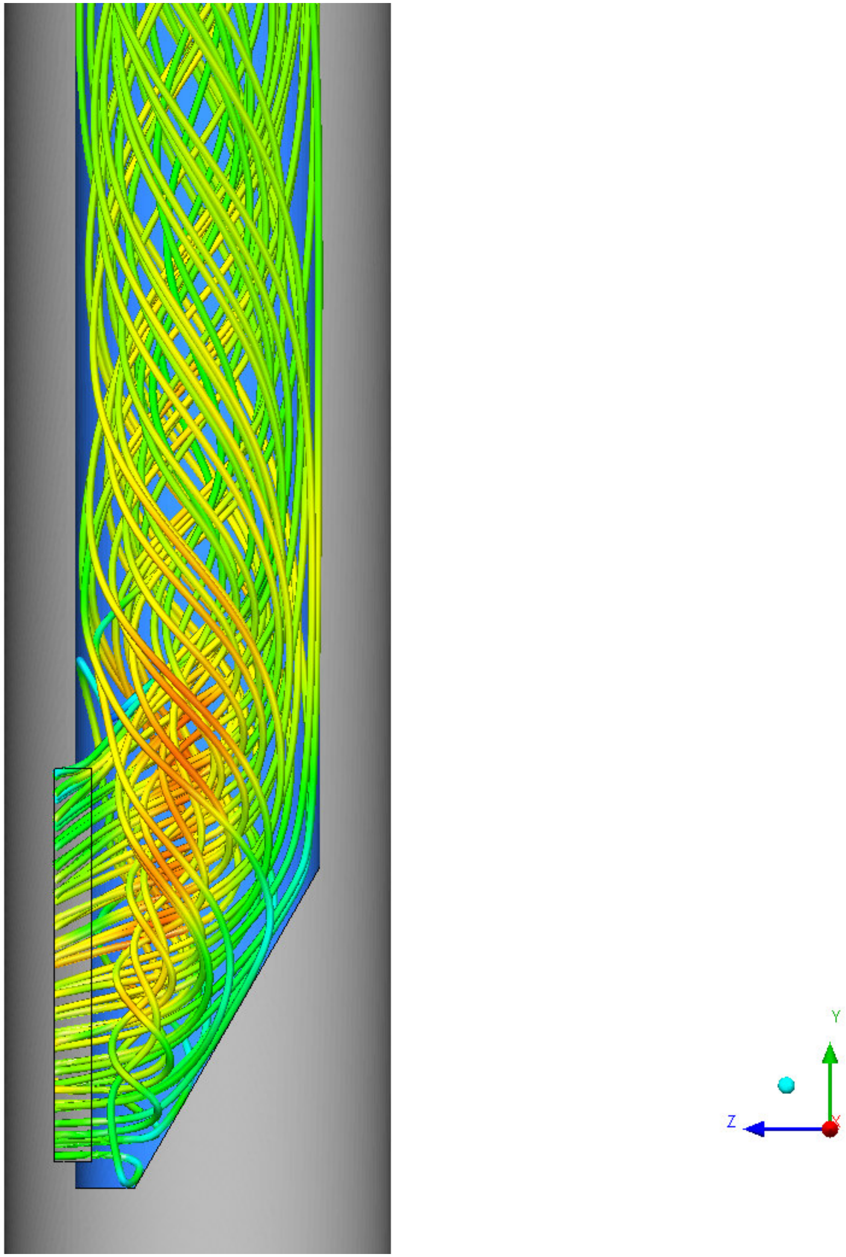
Inlet Gas Velocity Profile from Coal Creek Full System Model at 0 % Gas Bypass

Gas Streamlines Inside Stack Colored by Gas Velocity Magnitude

Showing Gas Swirl Pattern at Stack Beach, Liner Floor

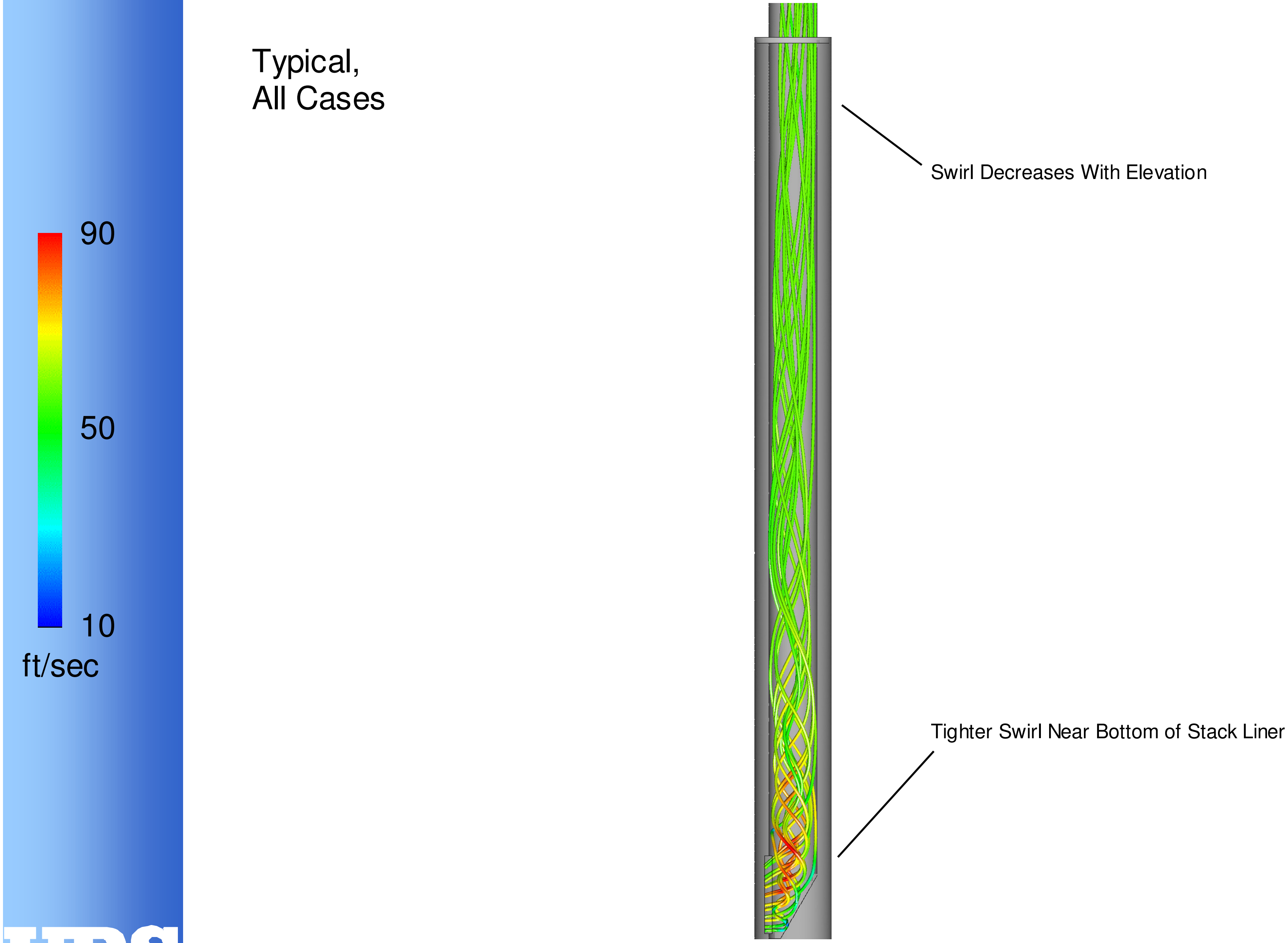


Typical,
All Cases



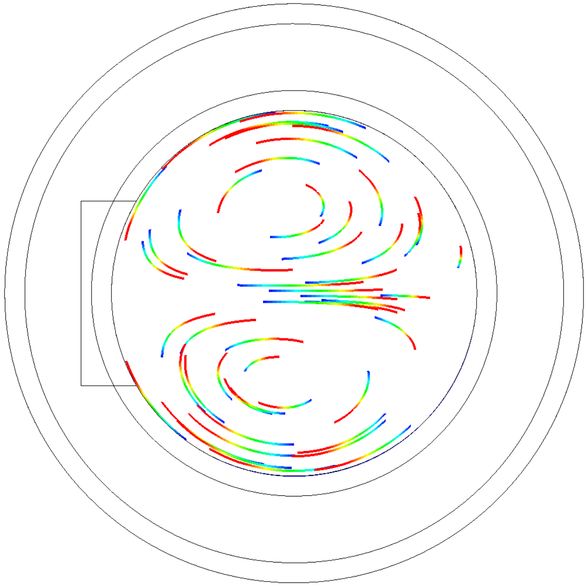
Gas Streamlines Inside Stack

Typical,
All Cases

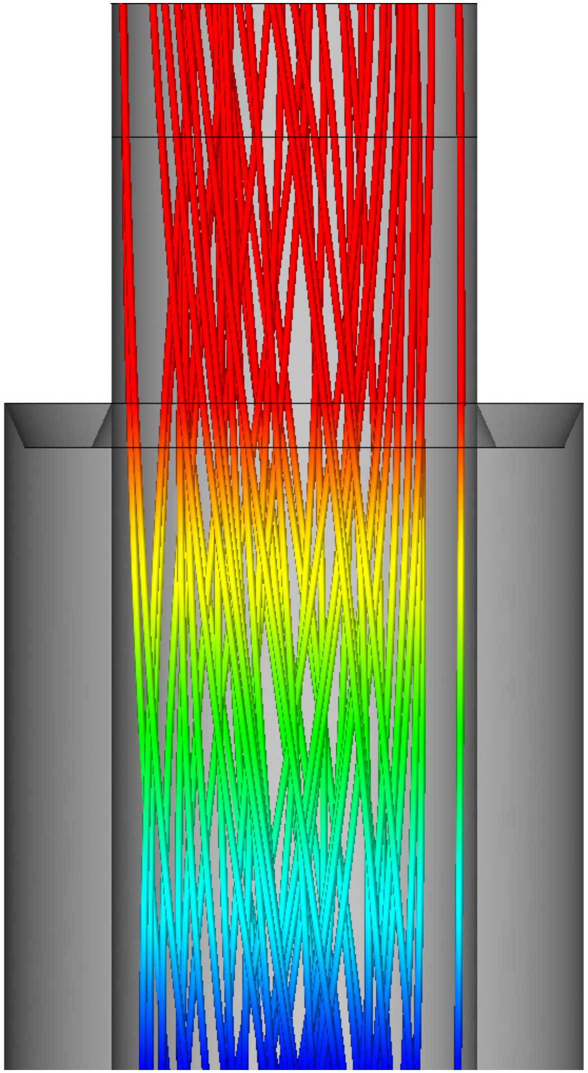


Streamlines Inside Stack: Top 75 Feet of Stack

Typical, All Cases



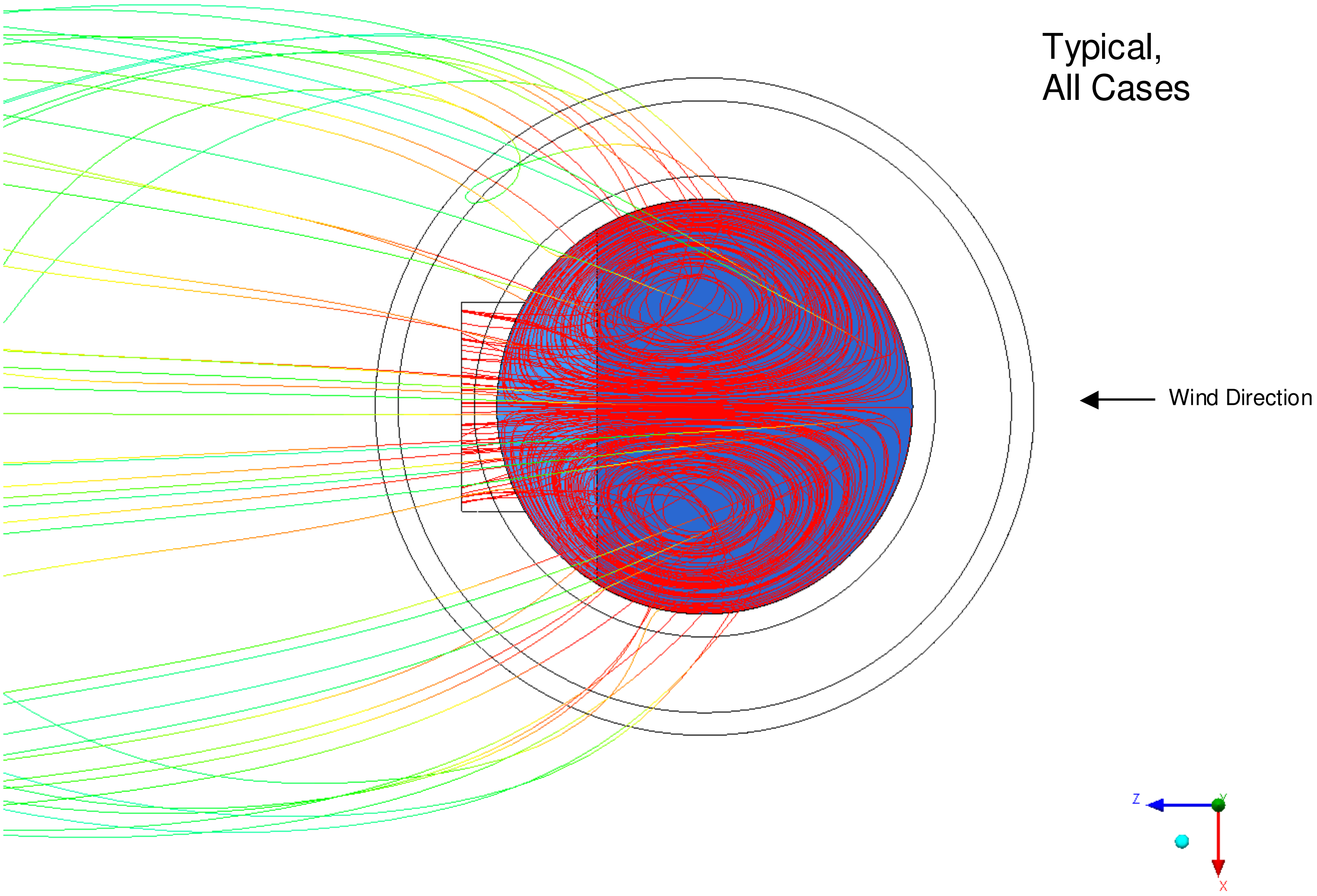
Plan



Side Elevation

Streamlines Along Entire Length of Stack

Plan View

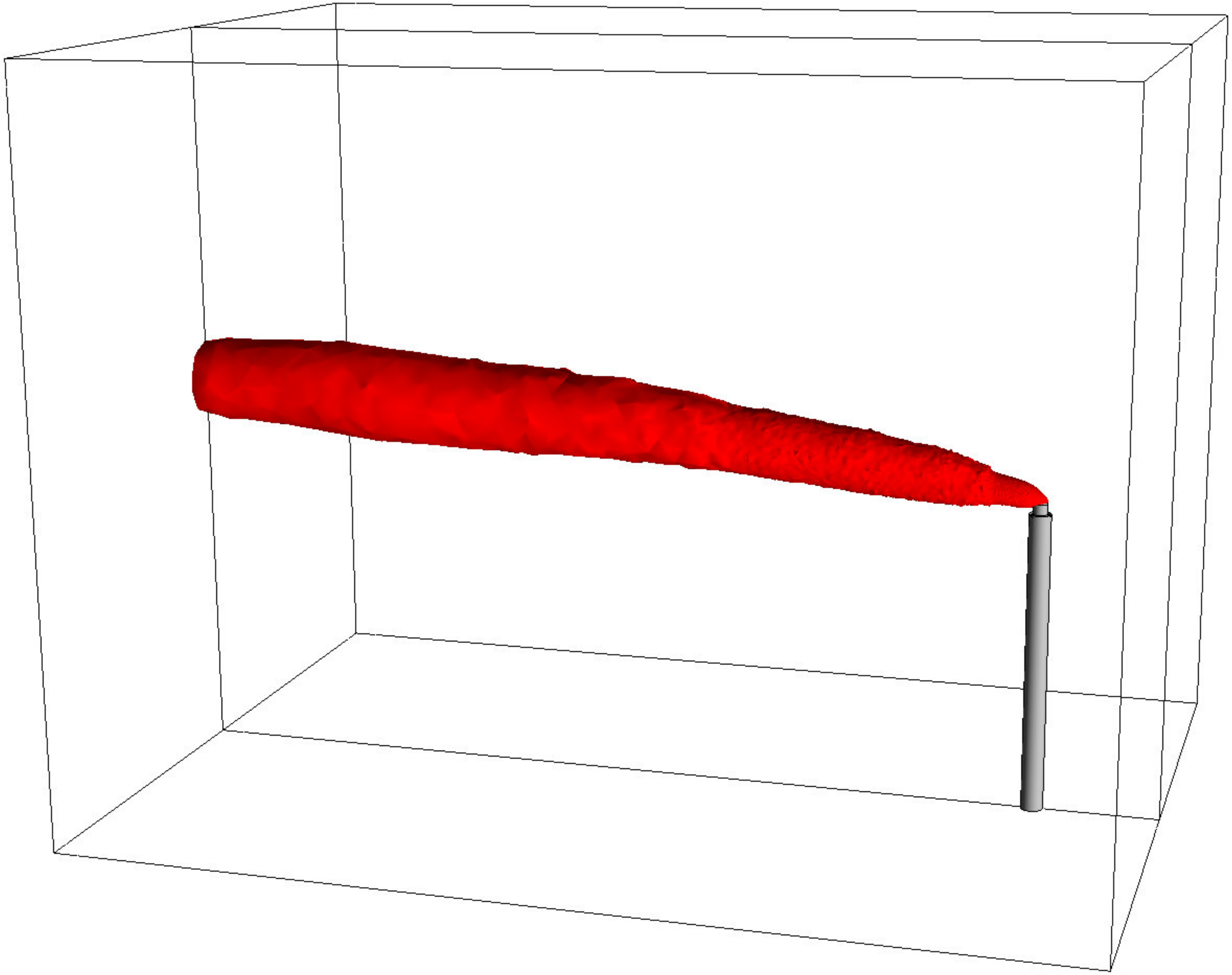


Case 1:

- Wind Speed = 38 MPH at Stack Height
- Ambient Air Temperature = -7 Degrees F

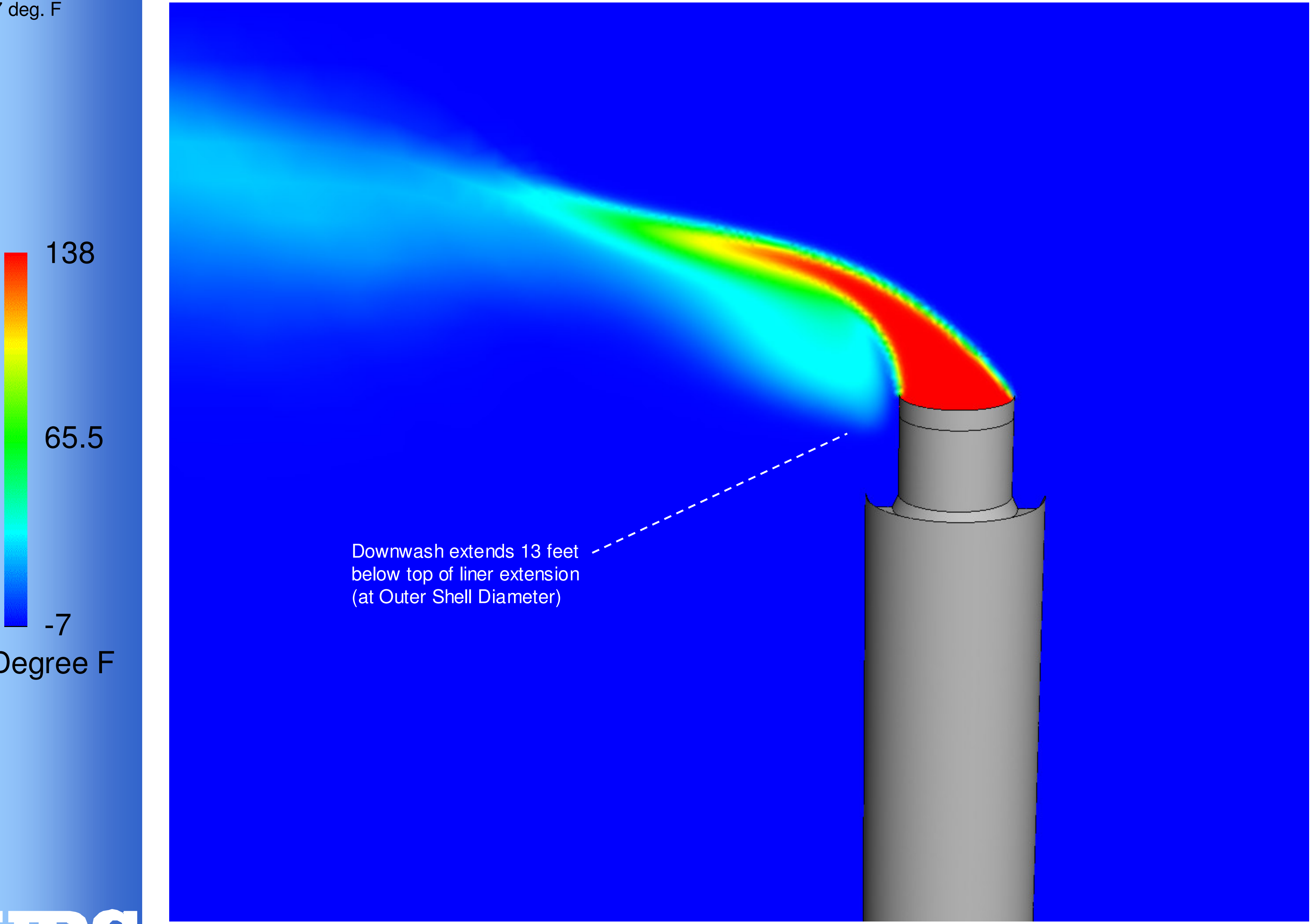
Case 1:
38 MPH
-7 deg. F

Surface Contour of Constant Temperature = - 6 Degrees F



Case 1:
38 MPH
-7 deg. F

Temperature at Stack Midplane

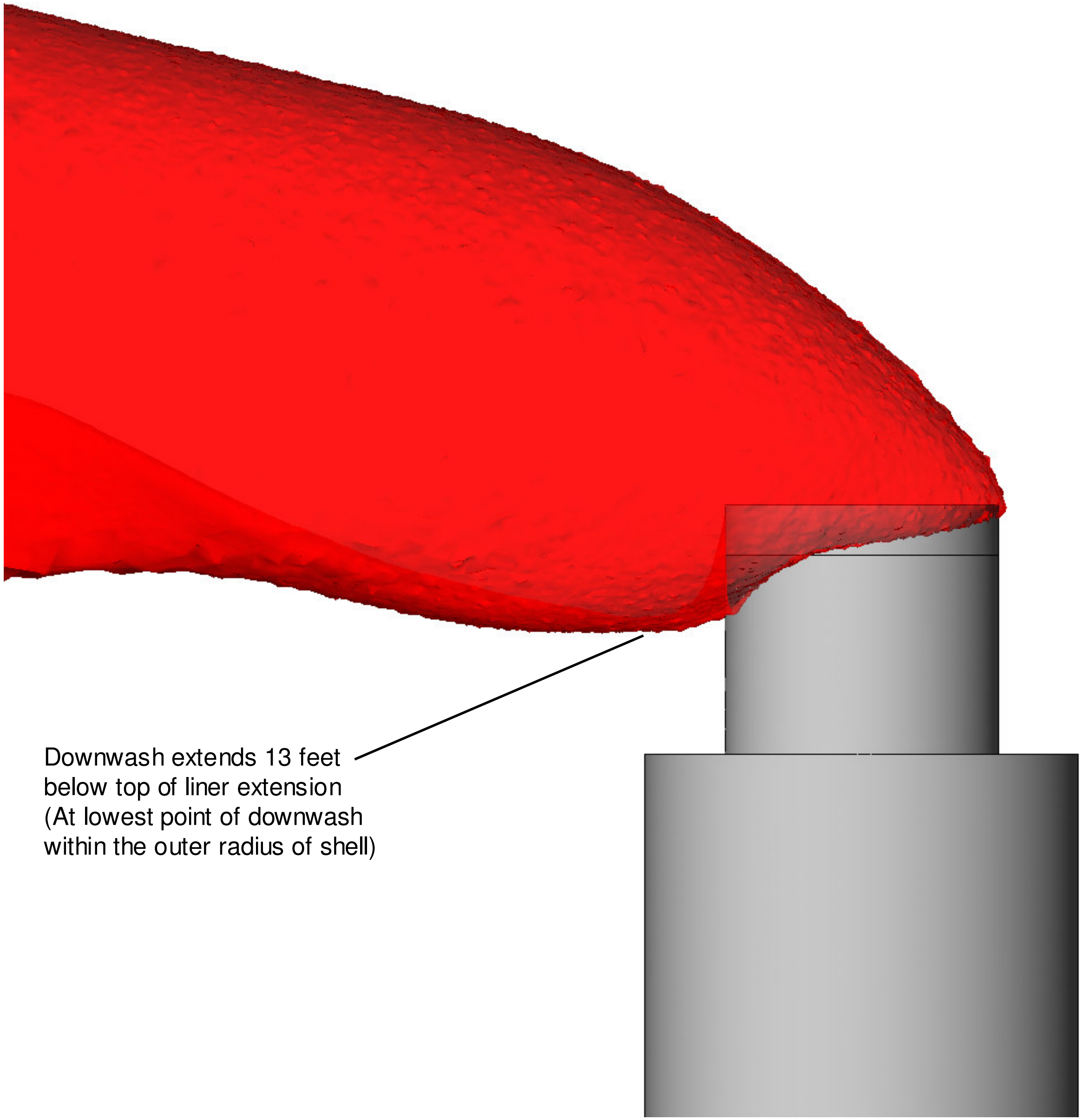


Downwash extends 13 feet below top of liner extension (at Outer Shell Diameter)

Case 1:
38 MPH
-7 deg. F

Surface Contour of Constant Temperature = - 6 Degrees F

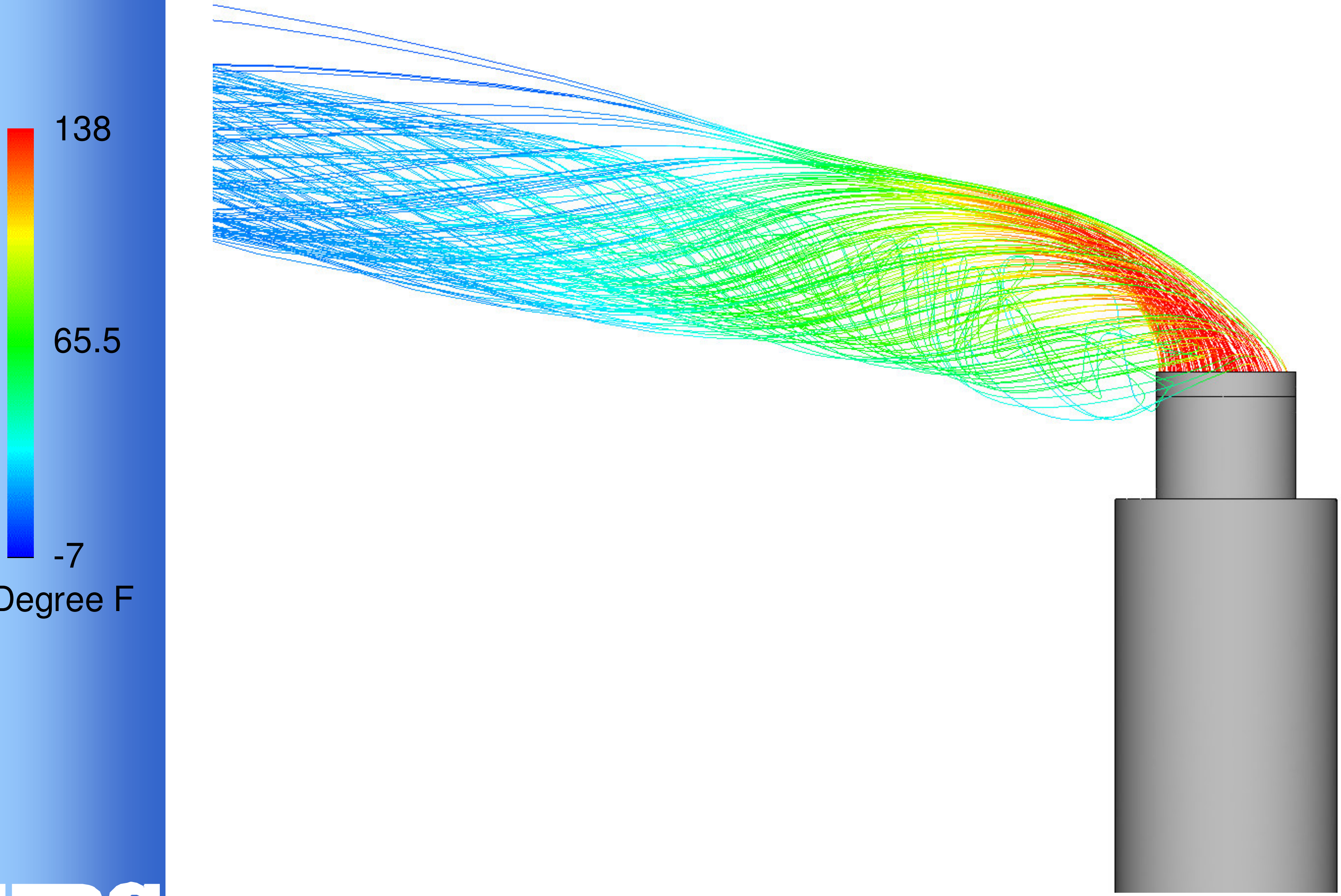
Surface is Semi-Transparent to Show Liner Extension



Downwash extends 13 feet below top of liner extension (At lowest point of downwash within the outer radius of shell)

Case 1:
38 MPH
-7 deg. F

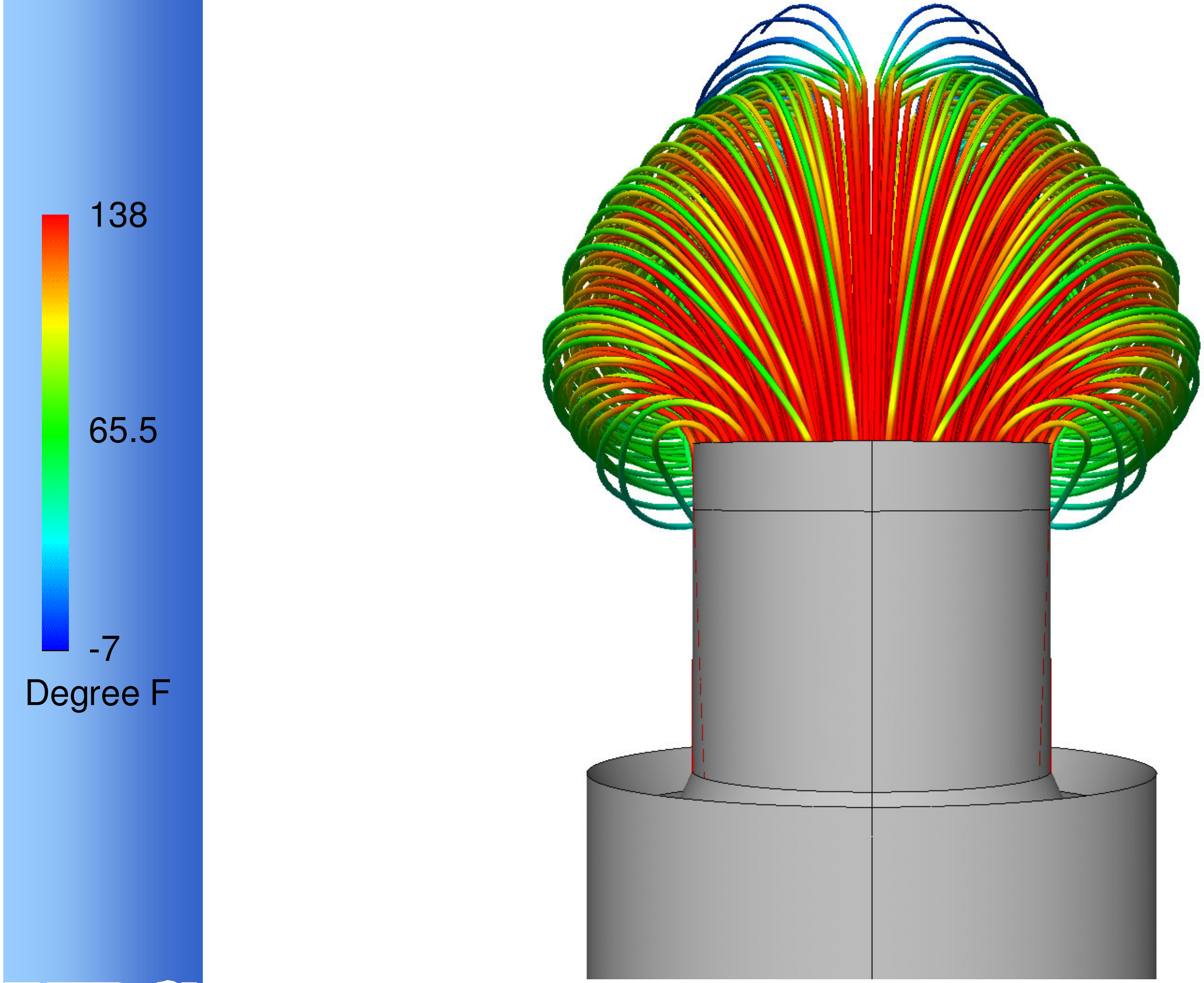
Streamlines Colored by Temperature



Case 1:
38 MPH
-7 deg. F

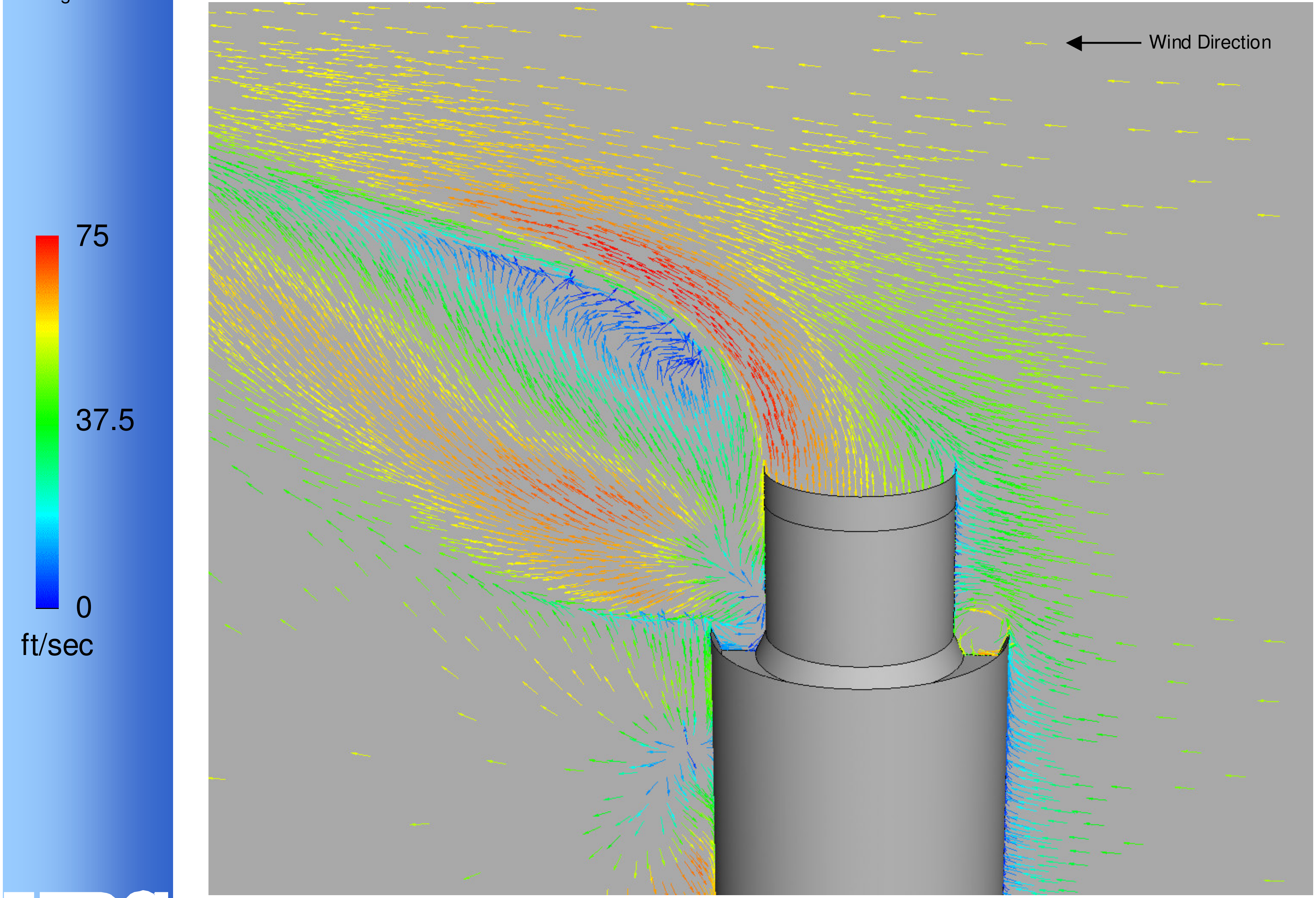
Streamlines Colored by Temperature

End Elevation View – Looking Downwind



Case 1:
38 MPH
-7 deg. F

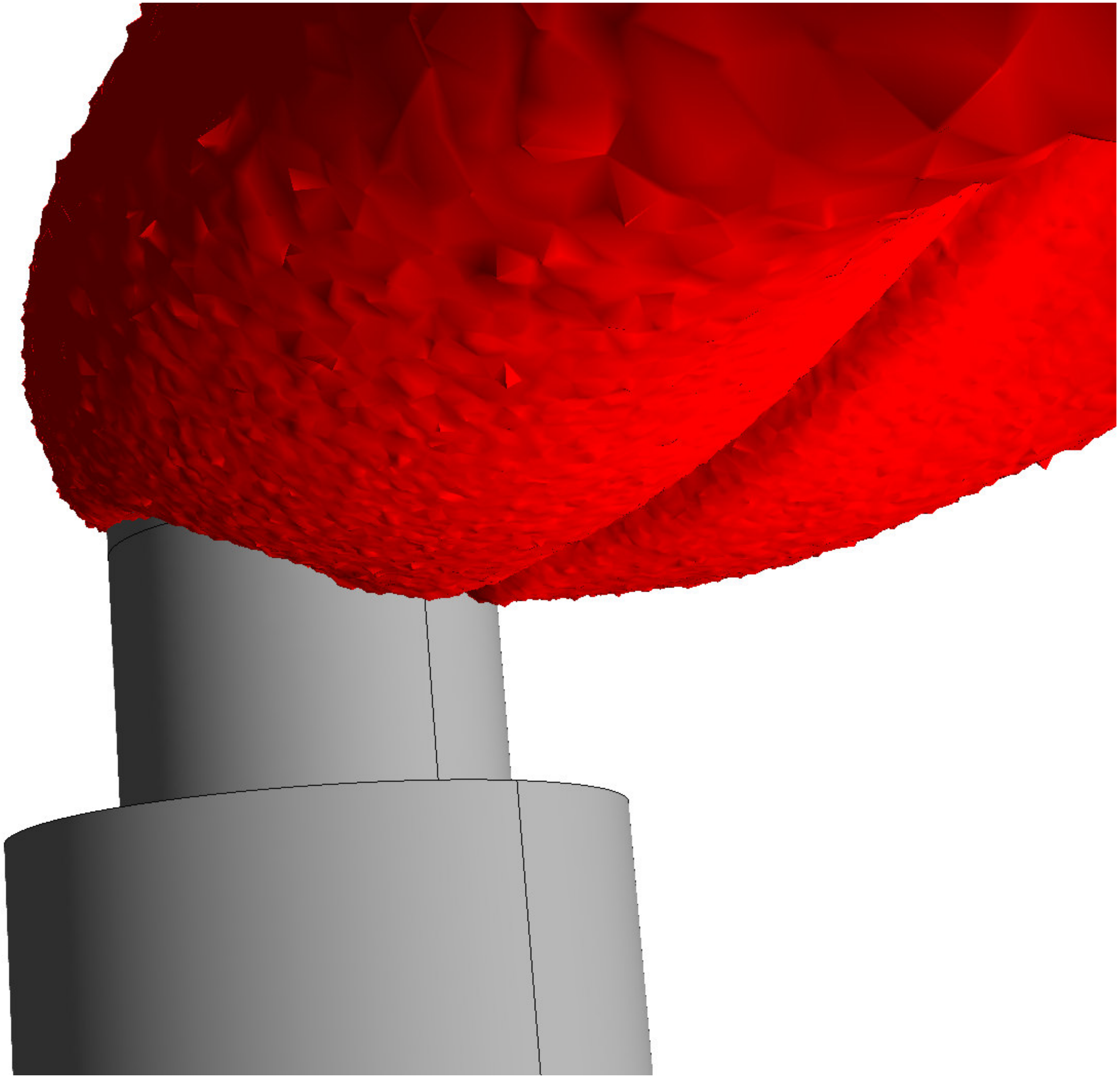
Velocity Vectors at Stack Midplane



Case 1:
38 MPH
-7 deg. F

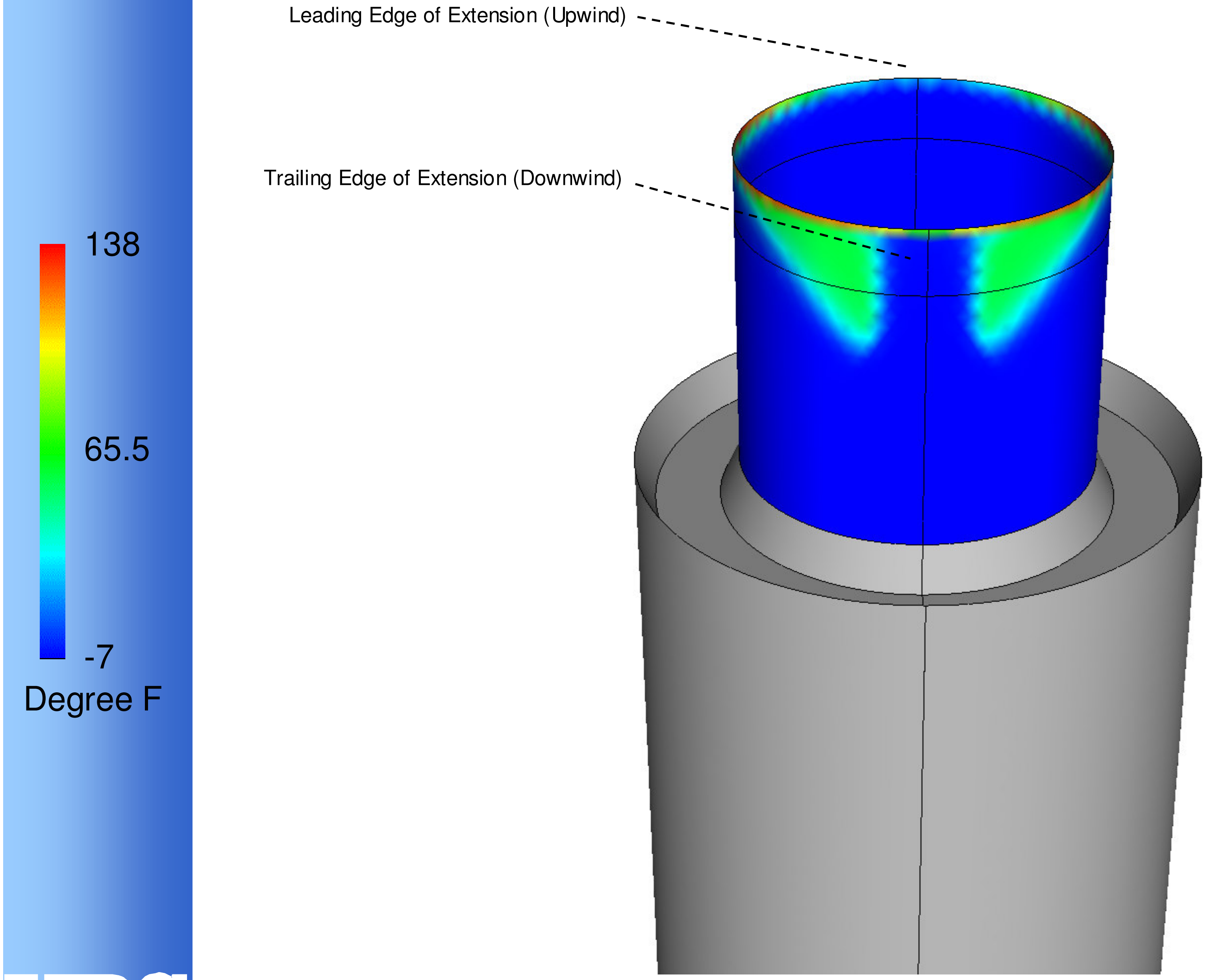
Surface Contour of Constant Temperature = - 6 Degrees F

Showing Bifurcated Plume



Case 1:
38 MPH
-7 deg. F

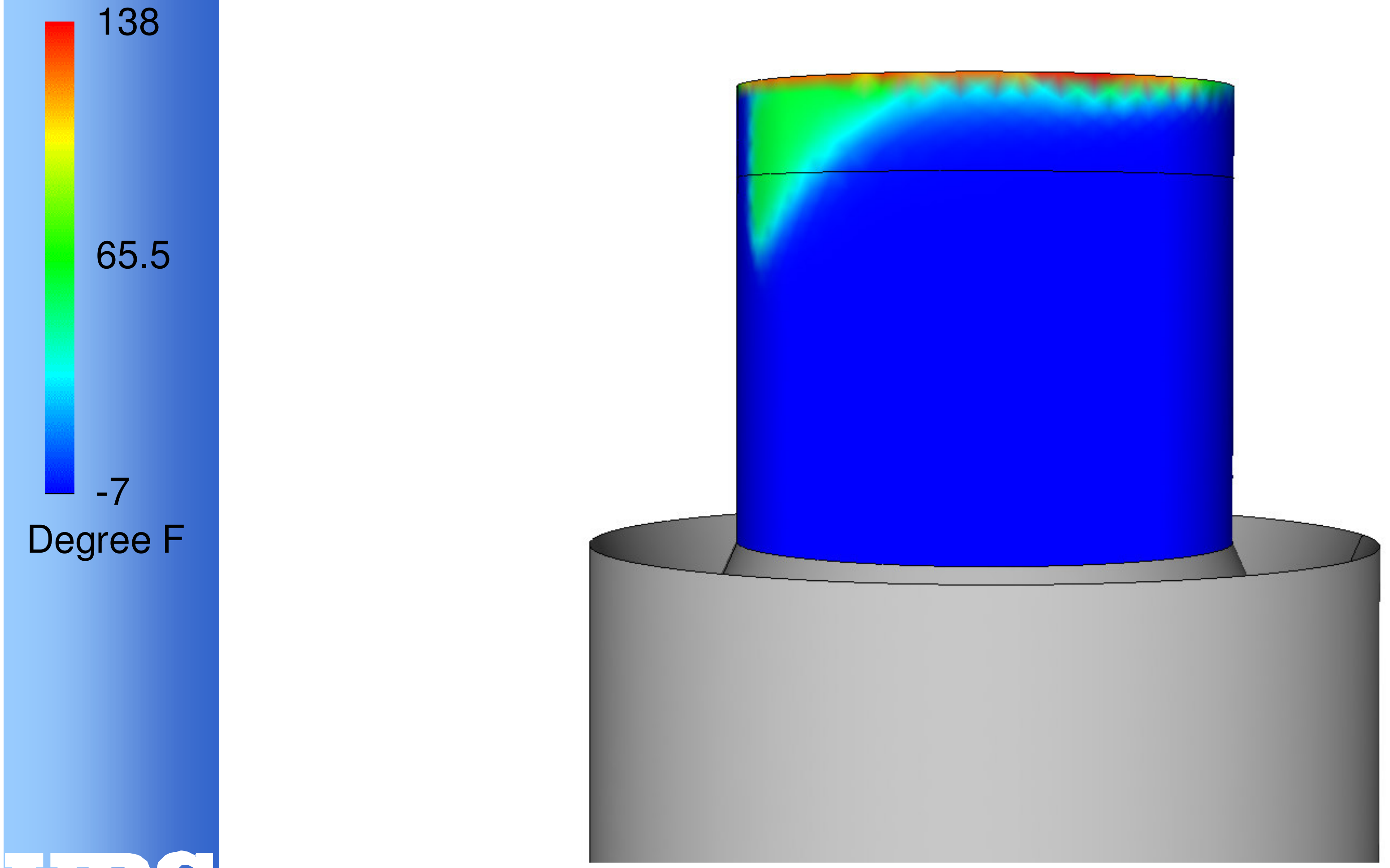
Temperature Adjacent to Liner Extension



Case 1:
38 MPH
-7 deg. F

Temperature Adjacent to Liner Extension

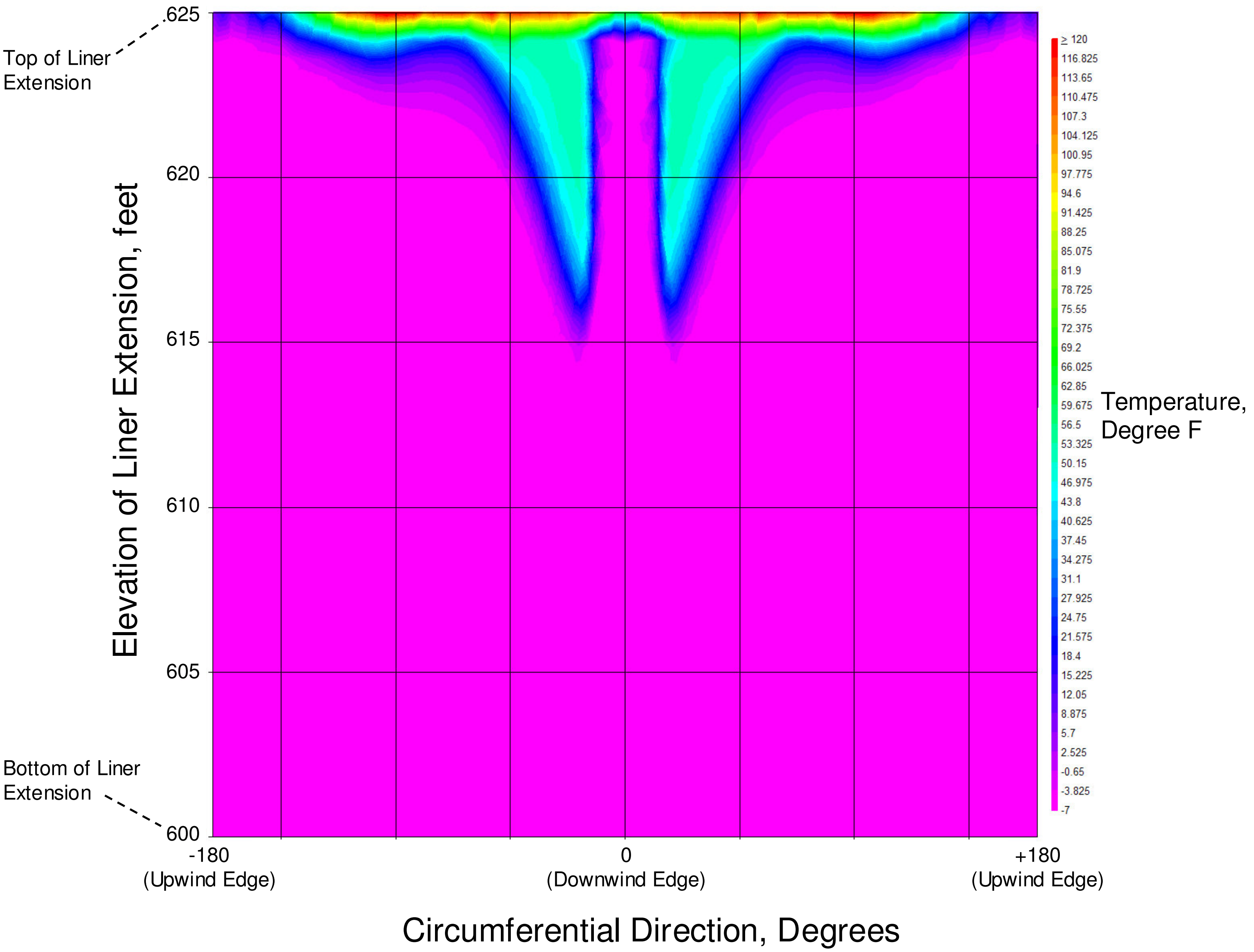
Side Elevation Perspective View



Case 1:
38 MPH
-7 deg. F

Temperature Adjacent to Liner Extension

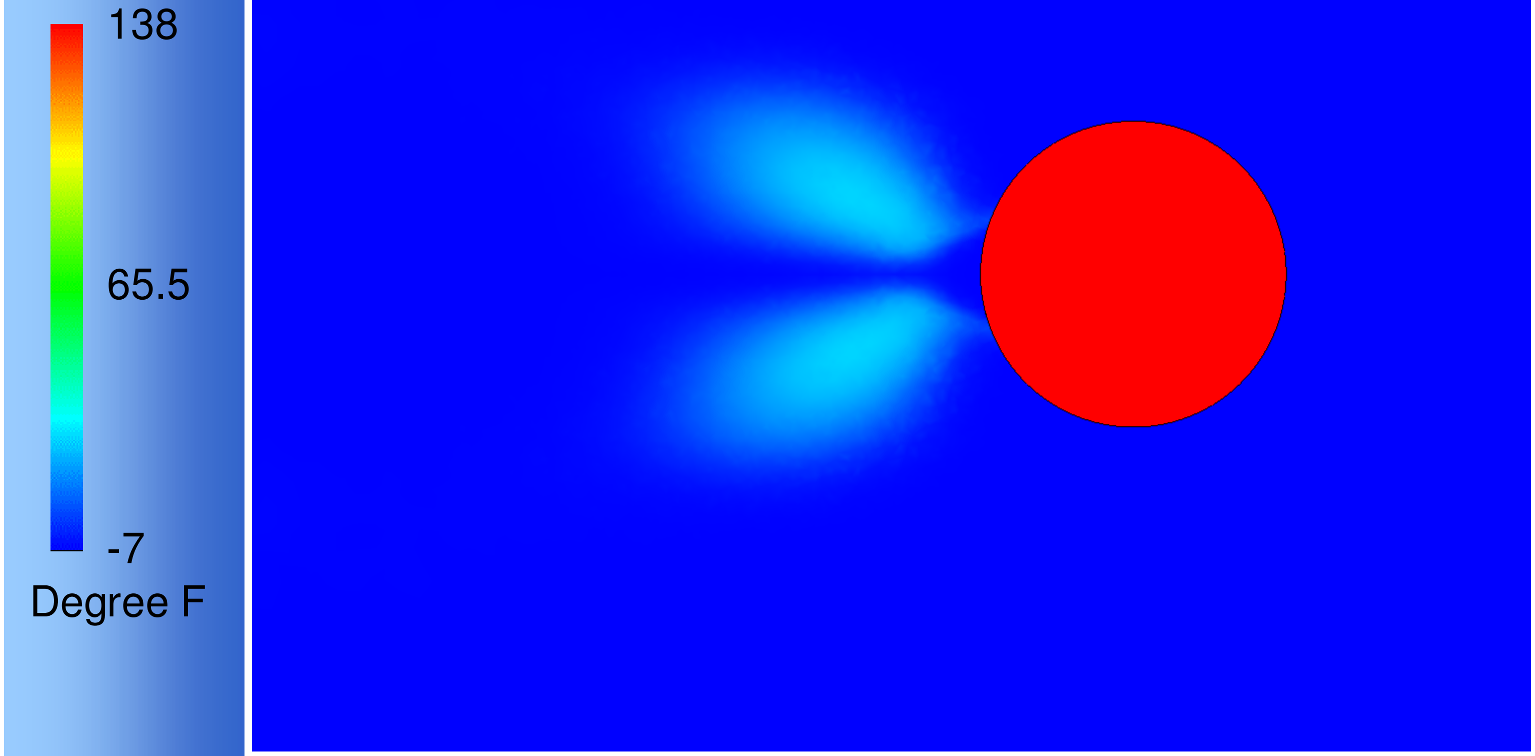
Plotted in Cylindrical Coordinates



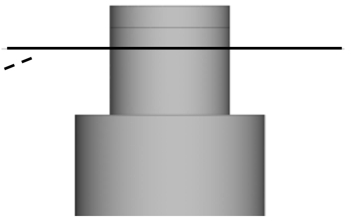
Case 1:
38 MPH
-7 deg. F

Temperature, 10 Feet Below Top of Liner Extension

Plan View



← Wind Direction

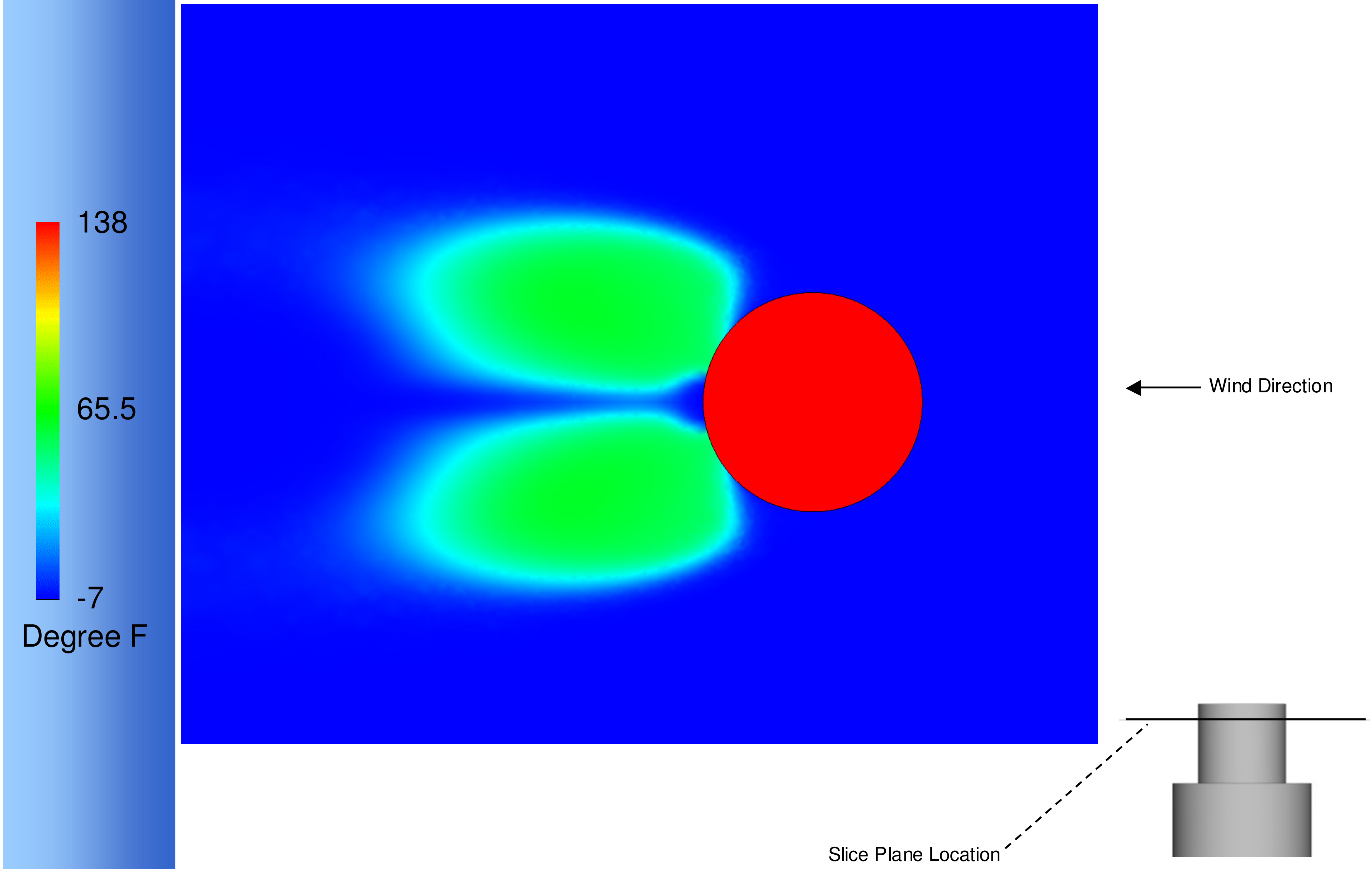


Slice Plane Location

Case 1:
38 MPH
-7 deg. F

Temperature, 5 Feet Below Top of Liner Extension

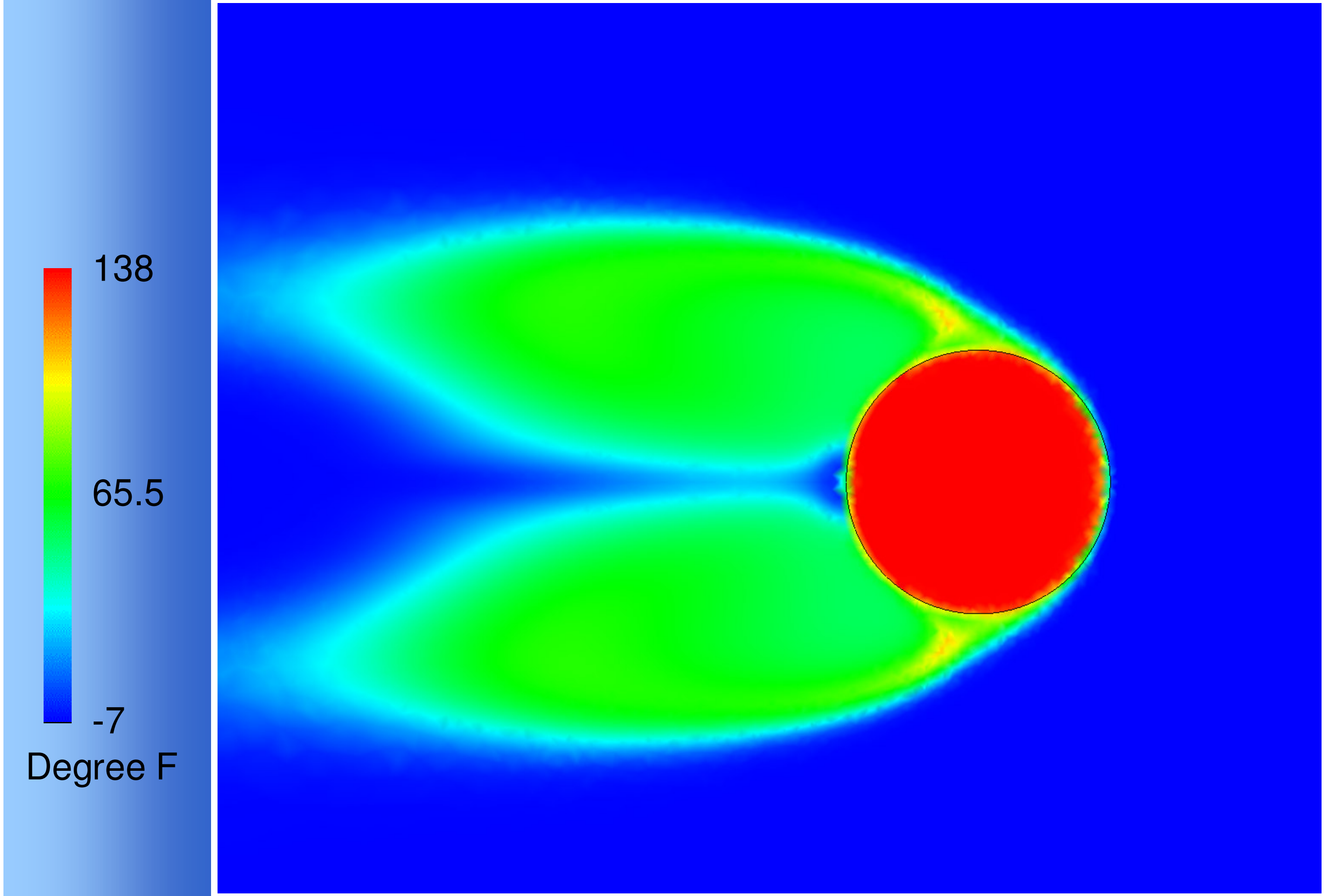
Plan View



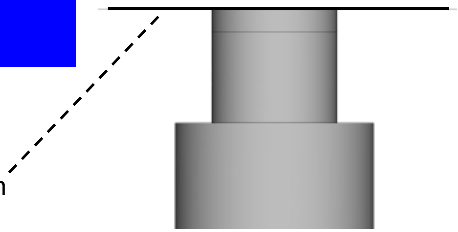
Case 1:
38 MPH
-7 deg. F

Temperature, at Top of Liner Extension

Plan View



Wind Direction

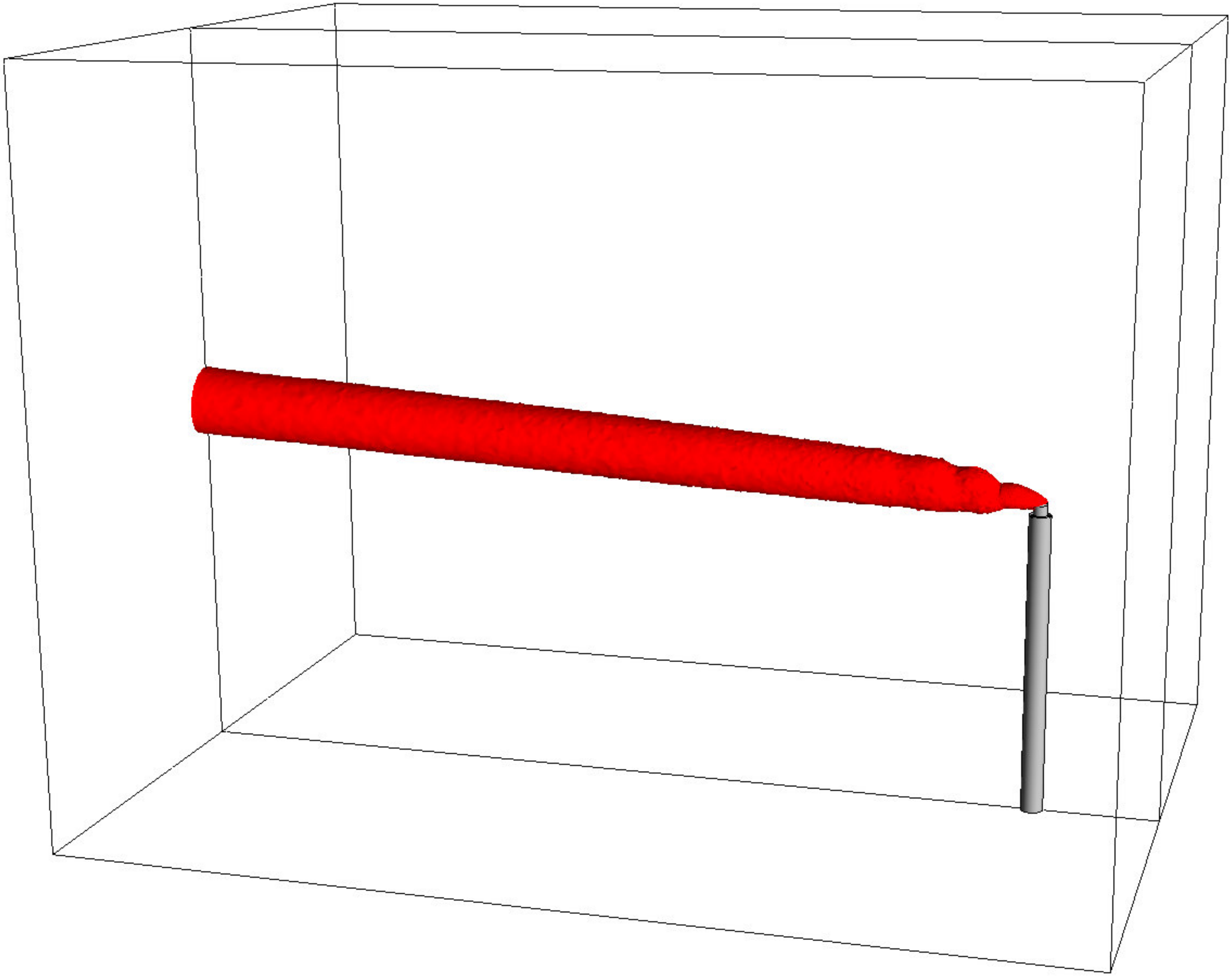


Case 2:

- Wind Speed = 63 MPH at Stack Height
- Ambient Air Temperature = -17 Degrees F

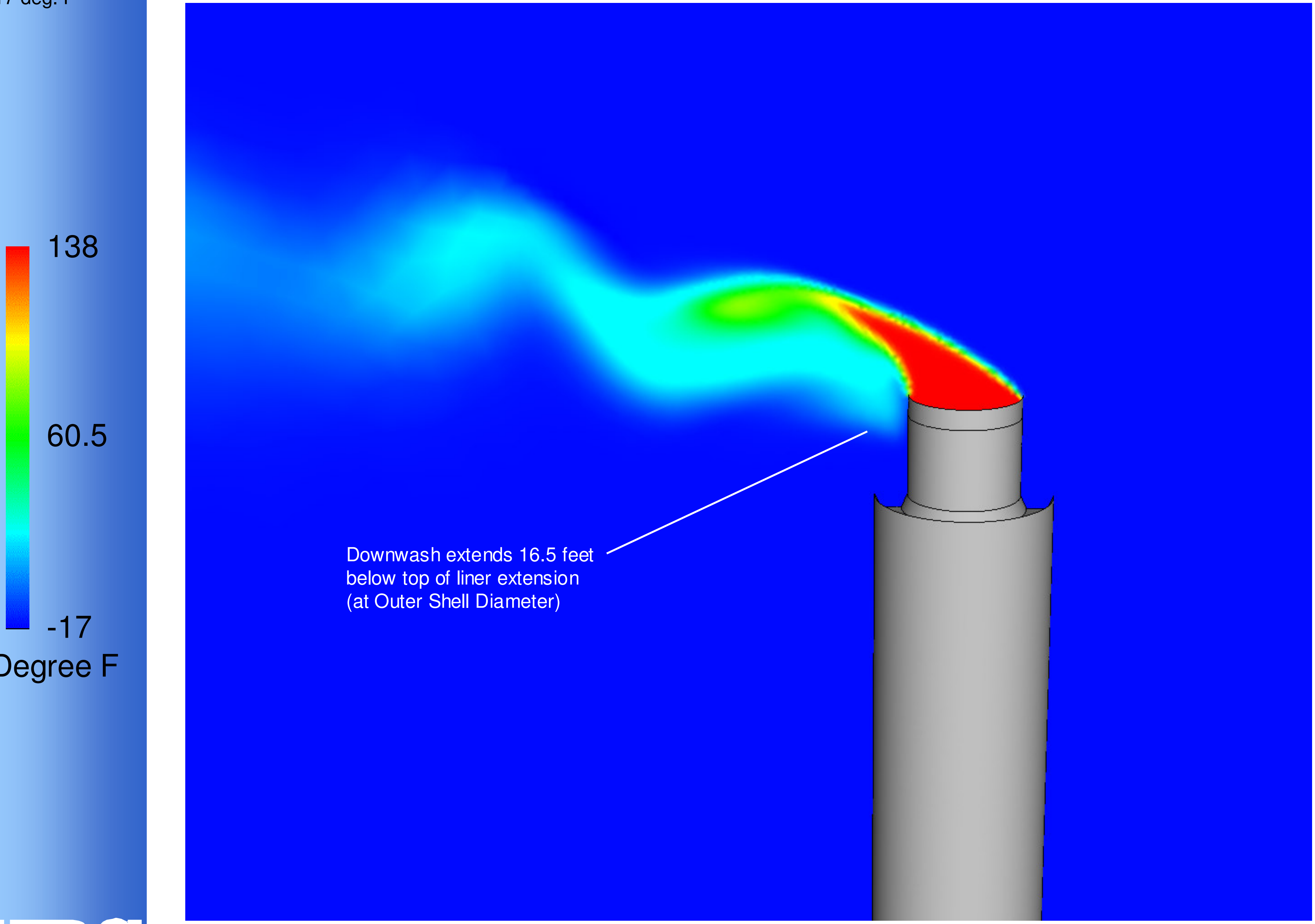
Case 2:
63 MPH
-17 deg. F

Surface Contour of Constant Temperature = - 16 Degrees F



Case 2:
63 MPH
-17 deg. F

Temperature at Stack Midplane

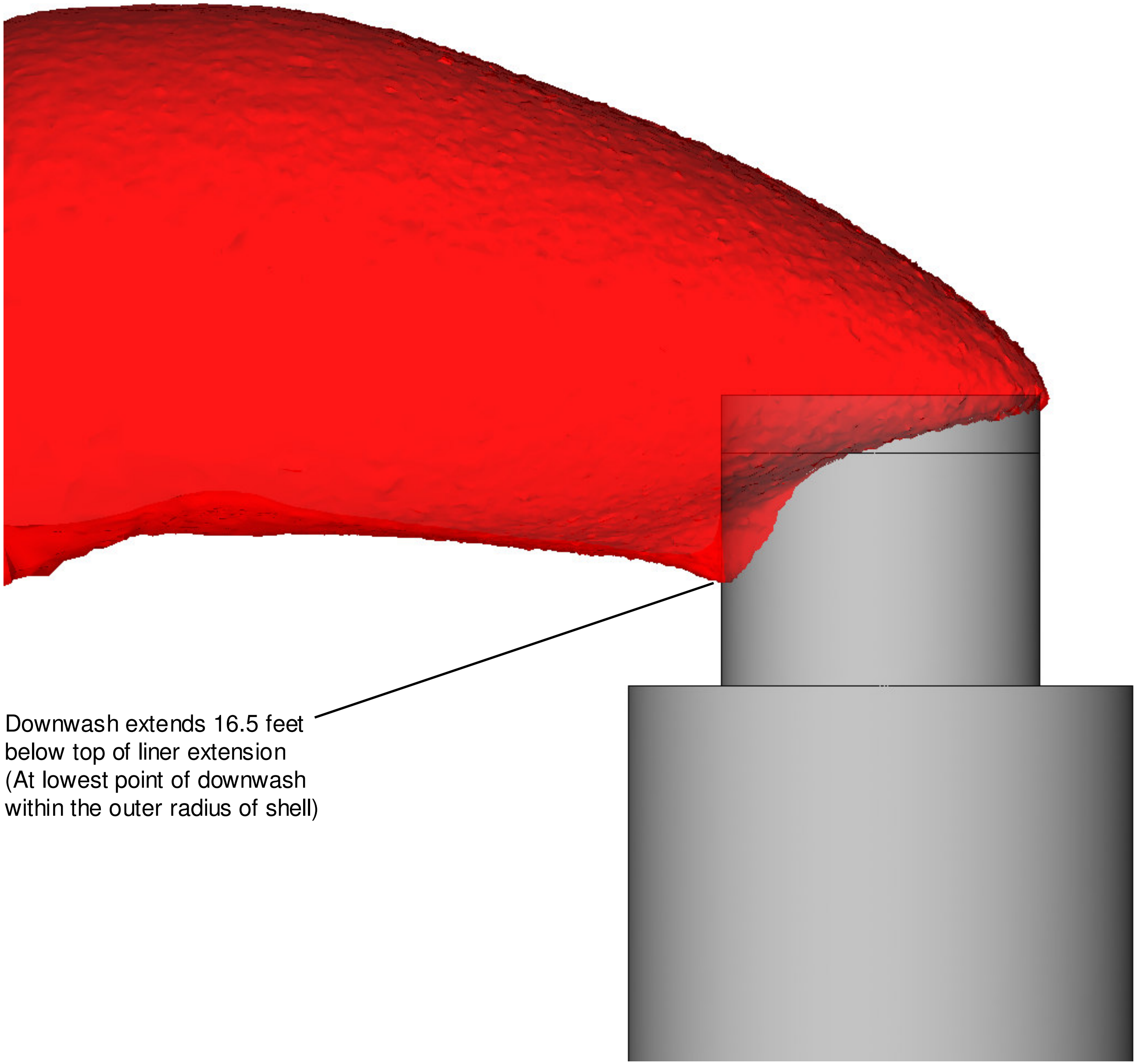


Downwash extends 16.5 feet below top of liner extension (at Outer Shell Diameter)

Case 2:
63 MPH
-17 deg. F

Surface Contour of Constant Temperature = - 16 Degrees F

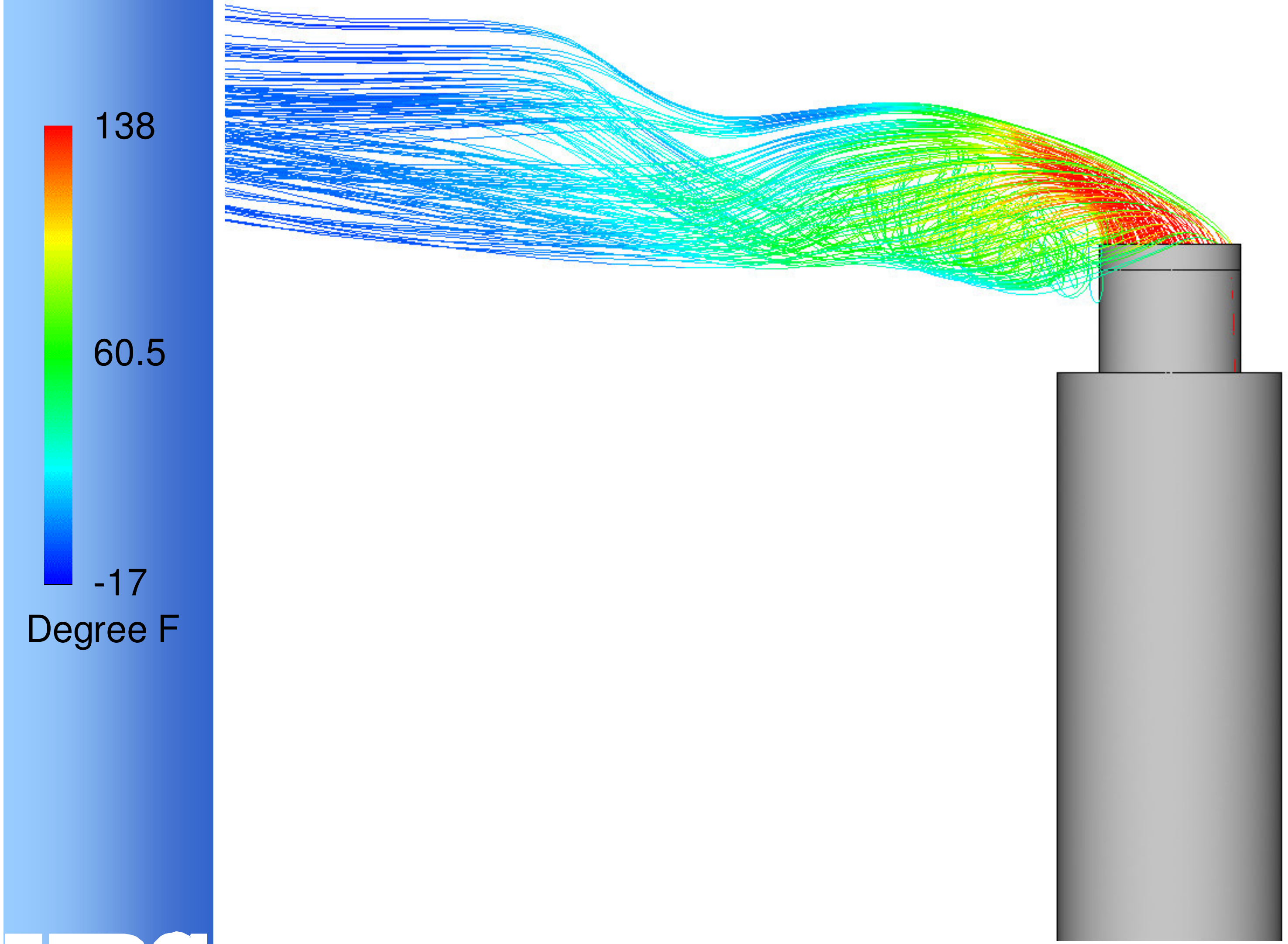
Surface is Semi-Transparent to Show Liner Extension



Downwash extends 16.5 feet below top of liner extension (At lowest point of downwash within the outer radius of shell)

Case 2:
63 MPH
-17 deg. F

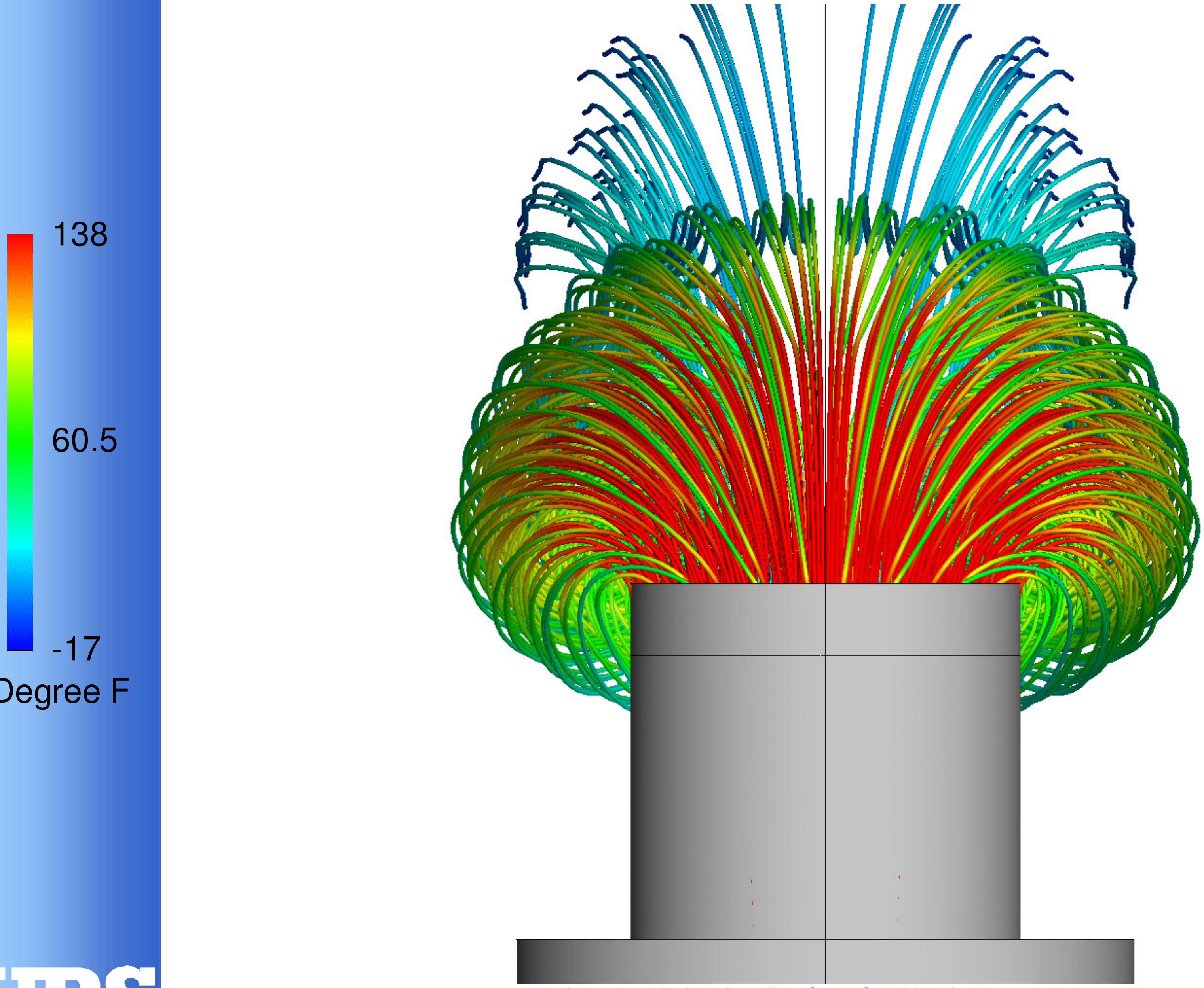
Streamlines Colored by Temperature



Case 2:
63 MPH
-17 deg. F

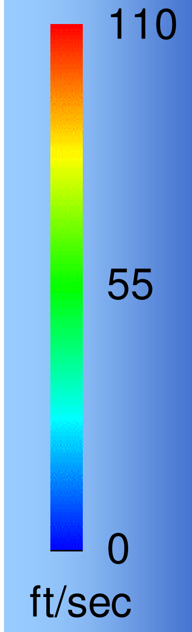
Streamlines Colored by Temperature

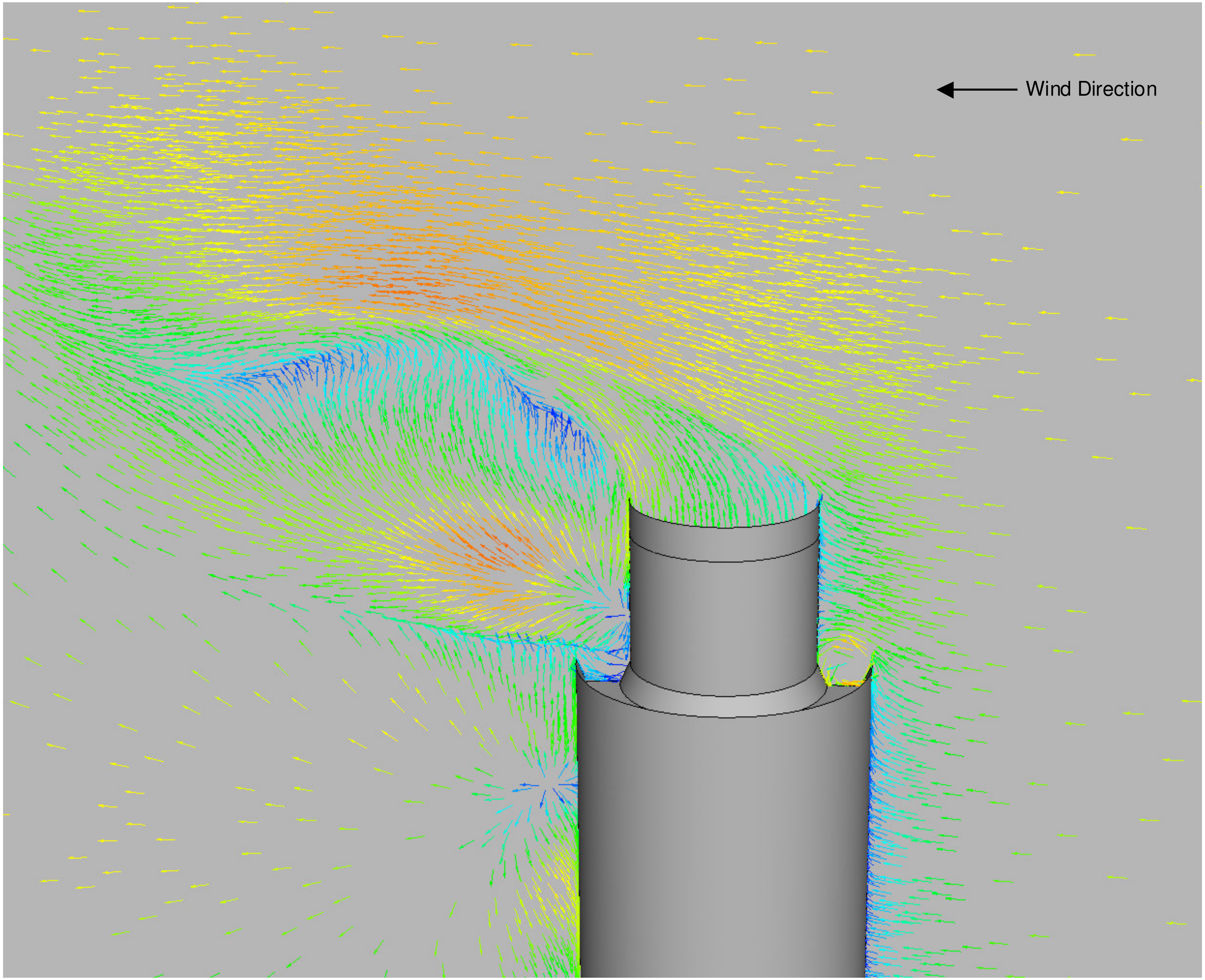
End Elevation View – Looking Downwind



Case 2:
63 MPH
-17 deg. F

Velocity Vectors at Stack Midplane

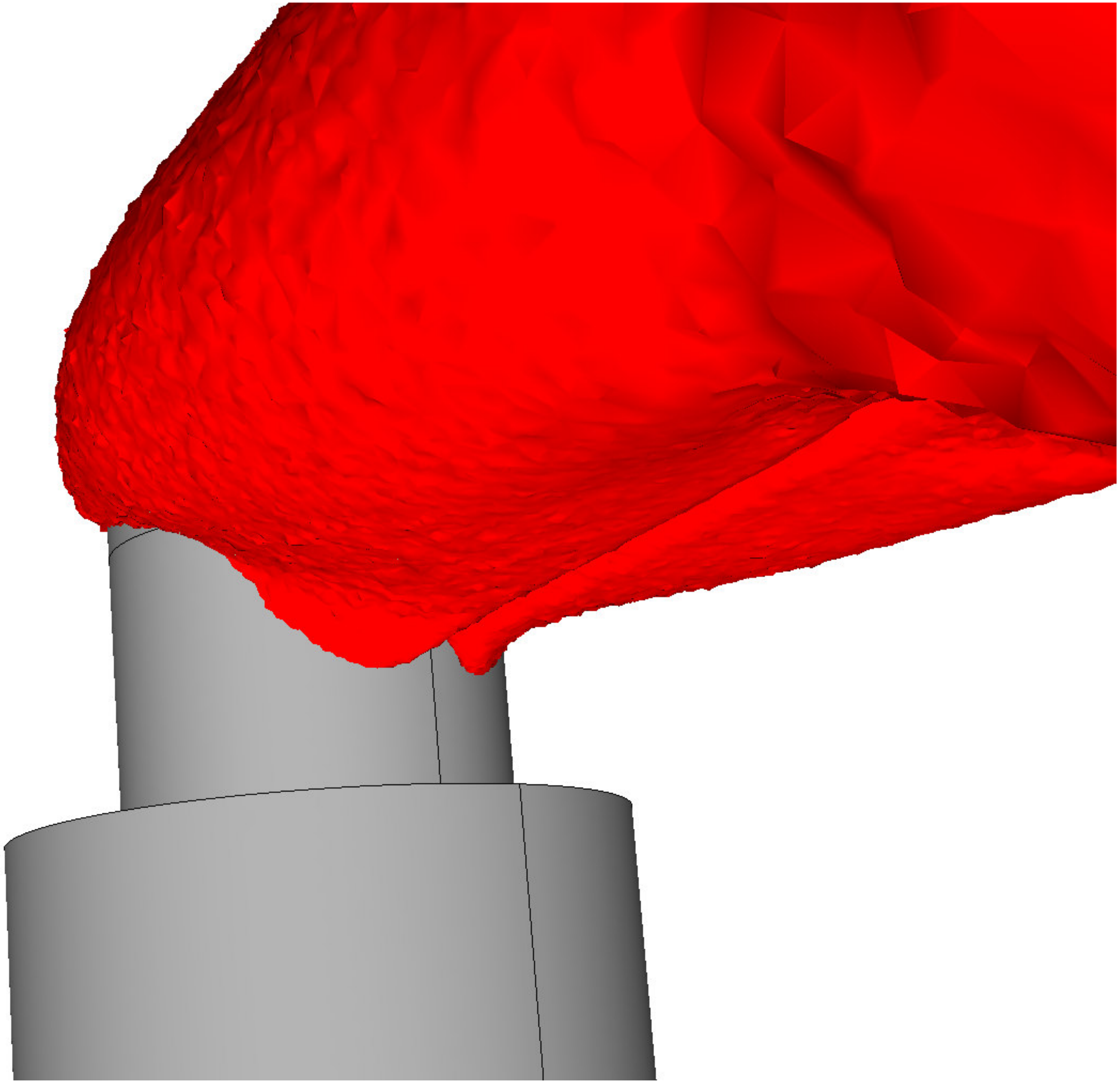




Case 2:
63 MPH
-17 deg. F

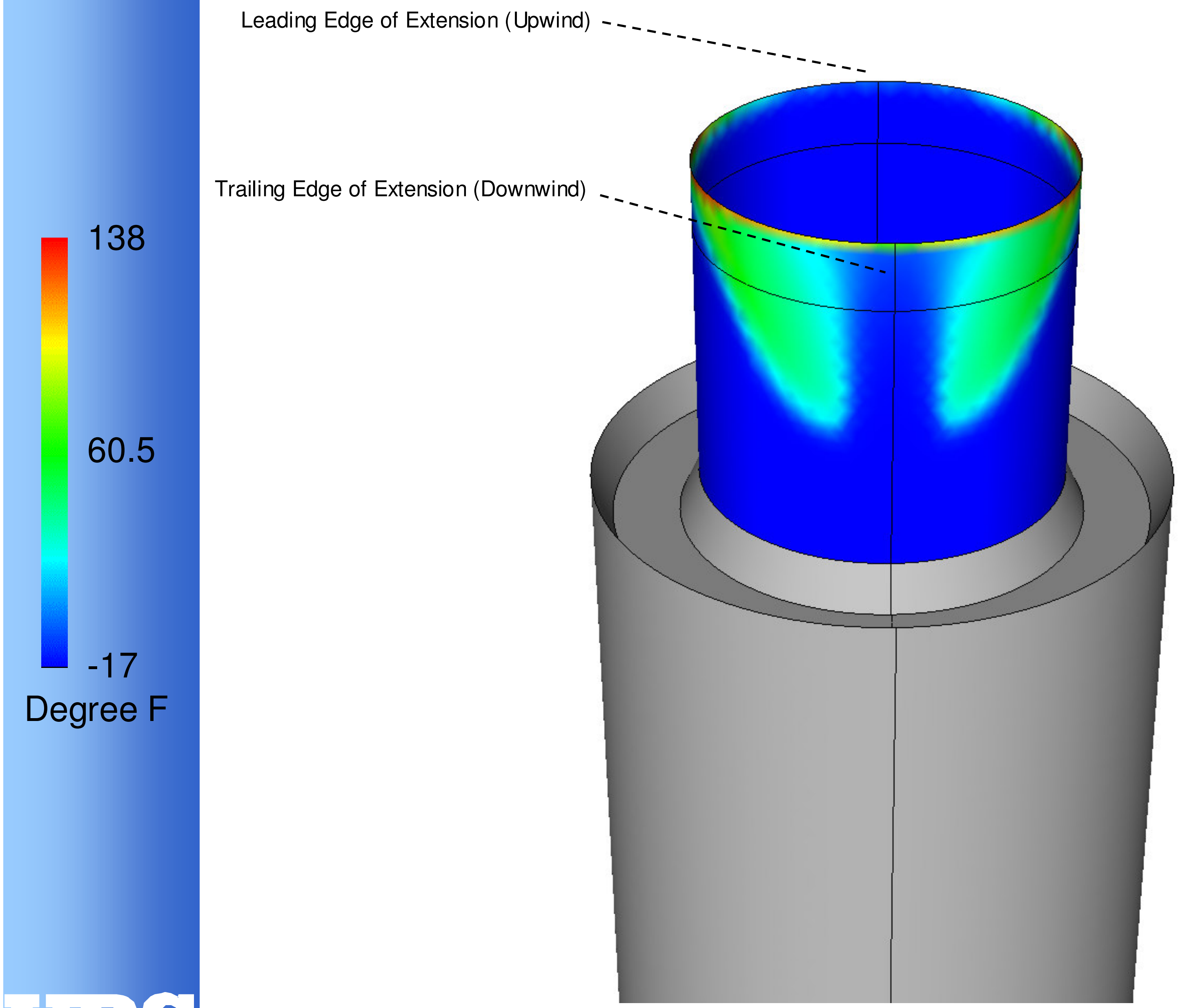
Surface Contour of Constant Temperature = - 16 Degrees F

Showing Bifurcated Plume



Case 2:
63 MPH
-17 deg. F

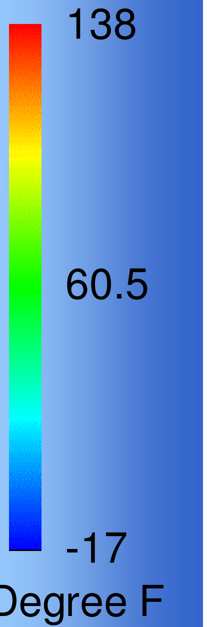
Temperature Adjacent to Liner Extension

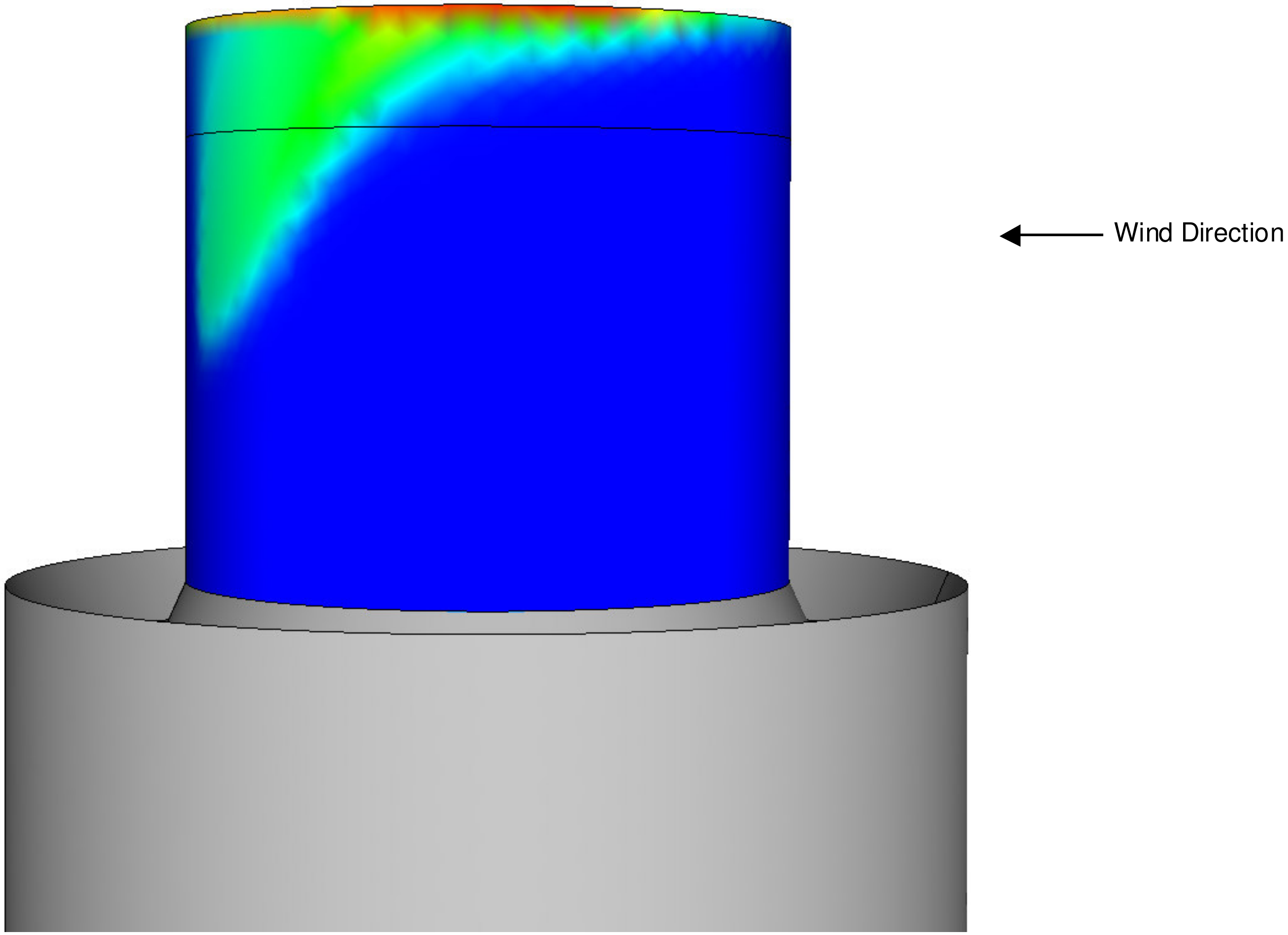


Case 2:
63 MPH
-17 deg. F

Temperature Adjacent to Liner Extension

Side Elevation Perspective View

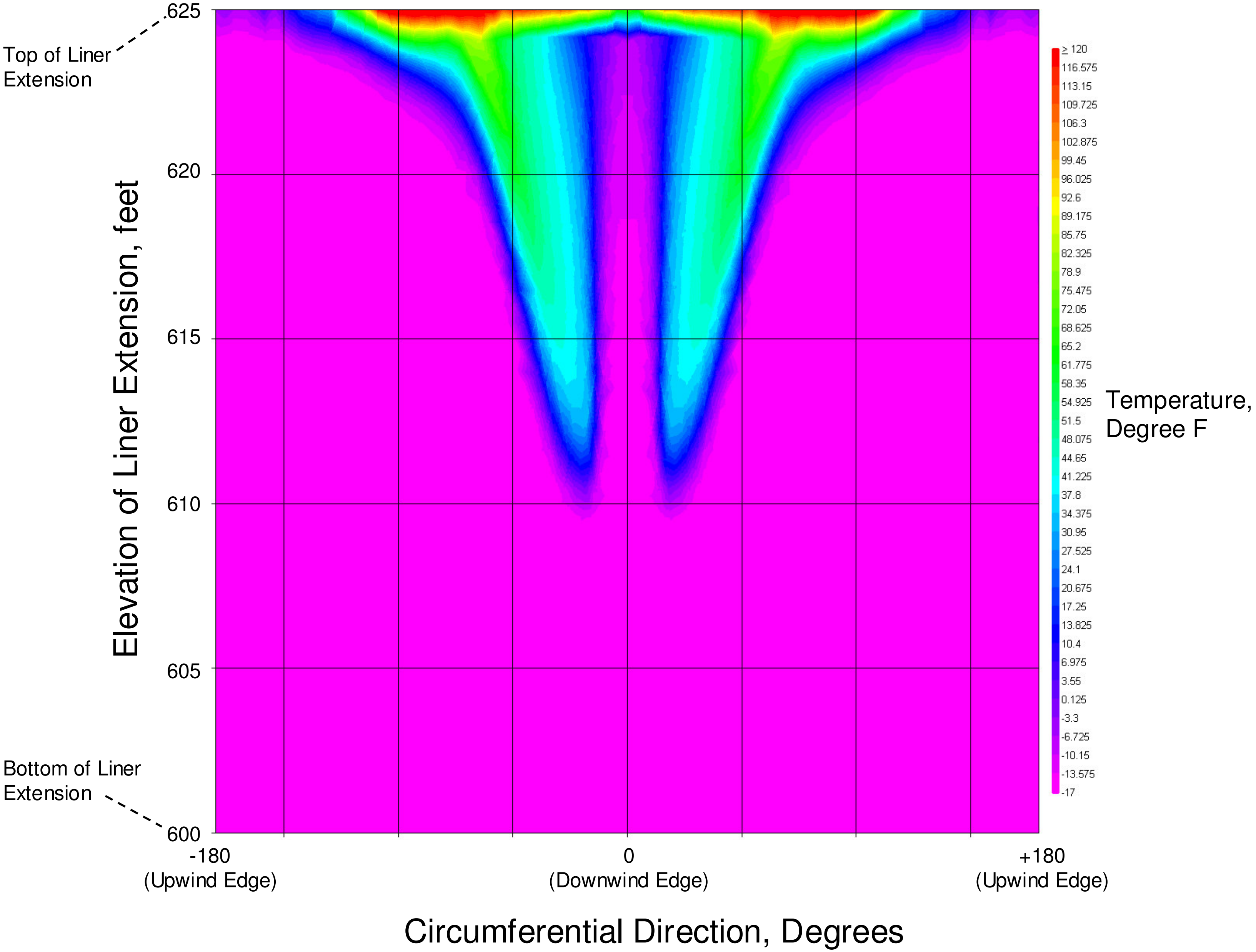




Case 2:
63 MPH
-17 deg. F

Temperature Adjacent to Liner Extension

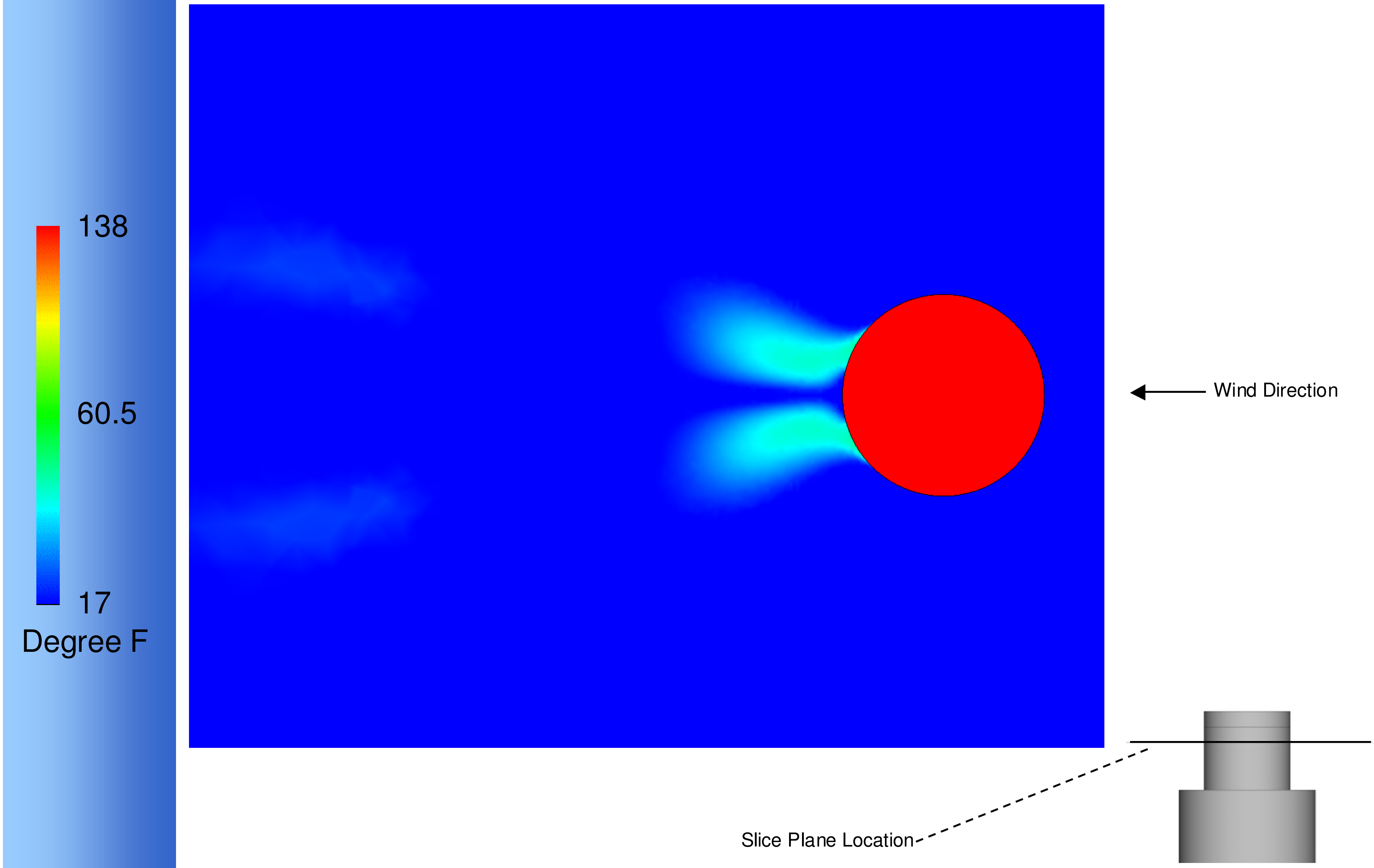
Plotted in Cylindrical Coordinates



Case 2:
63 MPH
-17 deg. F

Temperature, 10 Feet Below Top of Liner Extension

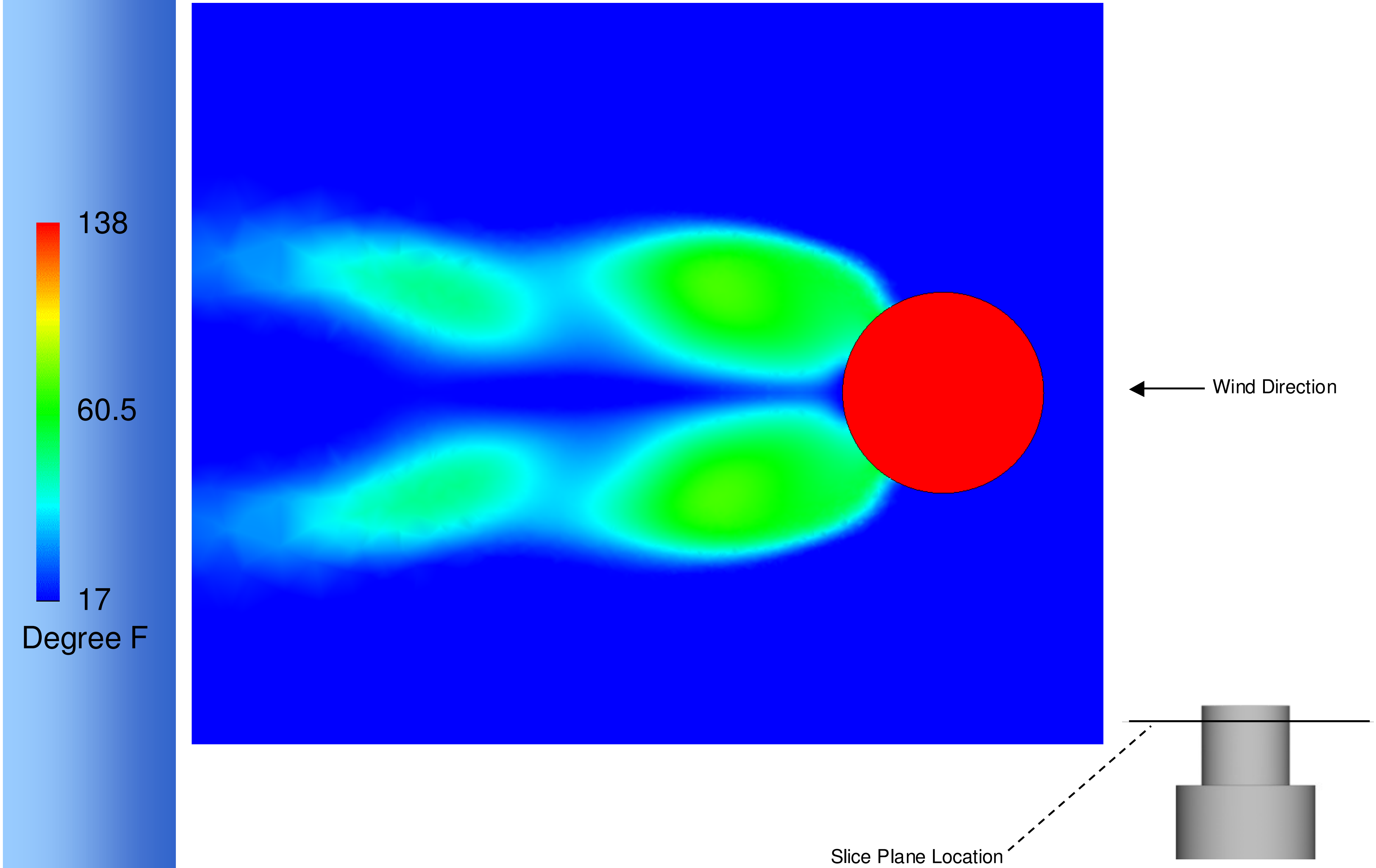
Plan View



Case 2:
63 MPH
-17 deg. F

Temperature, 5 Feet Below Top of Liner Extension

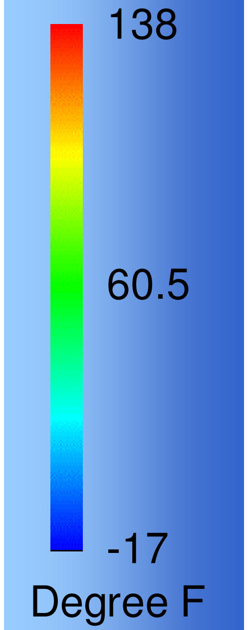
Plan View

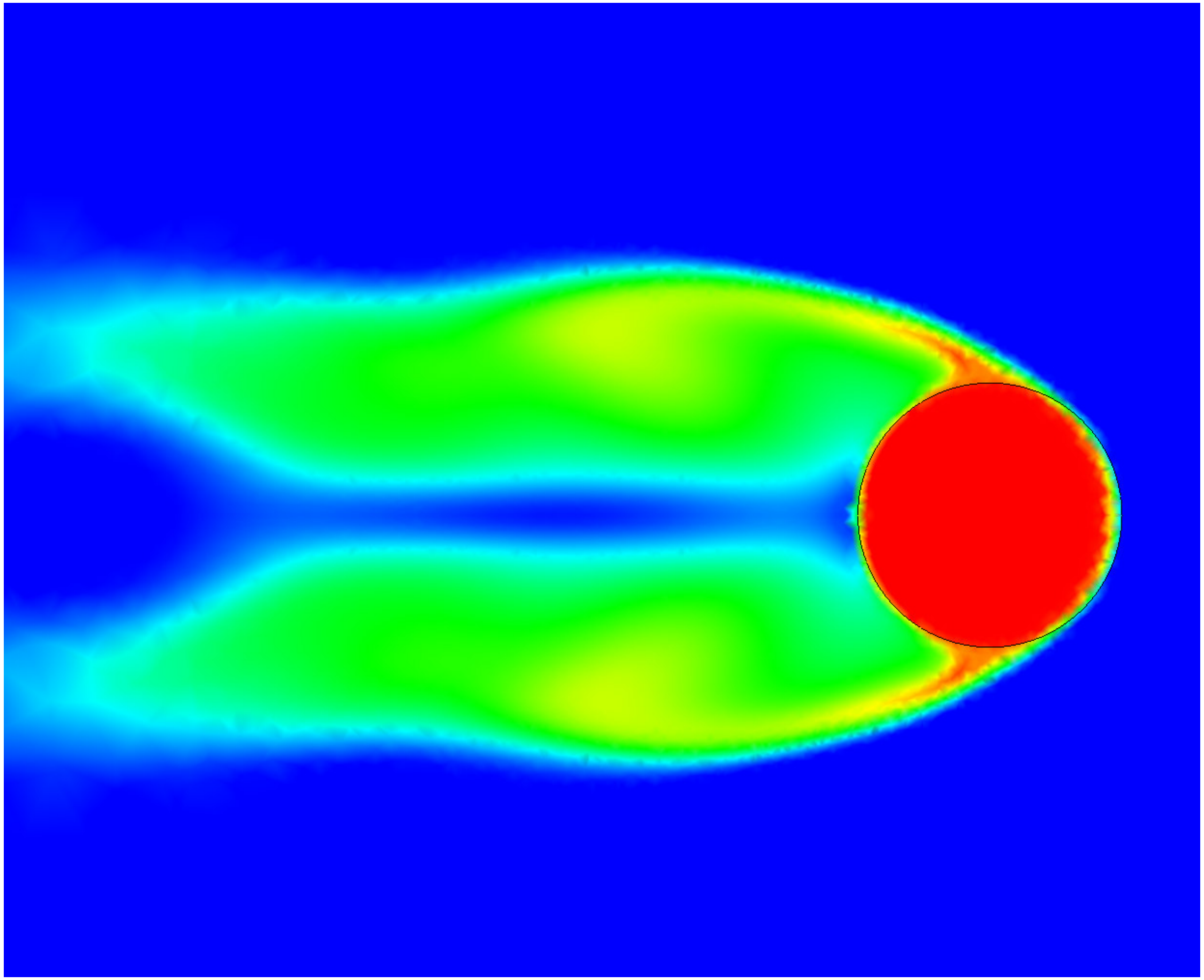


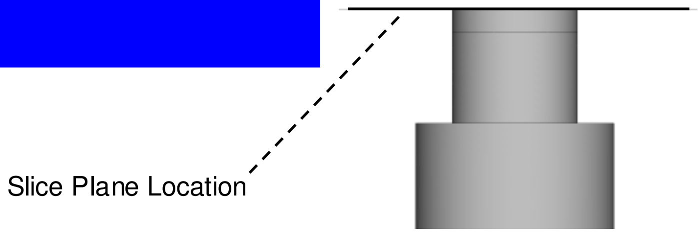
Case 2:
63 MPH
-17 deg. F

Temperature, at Top of Liner Extension

Plan View



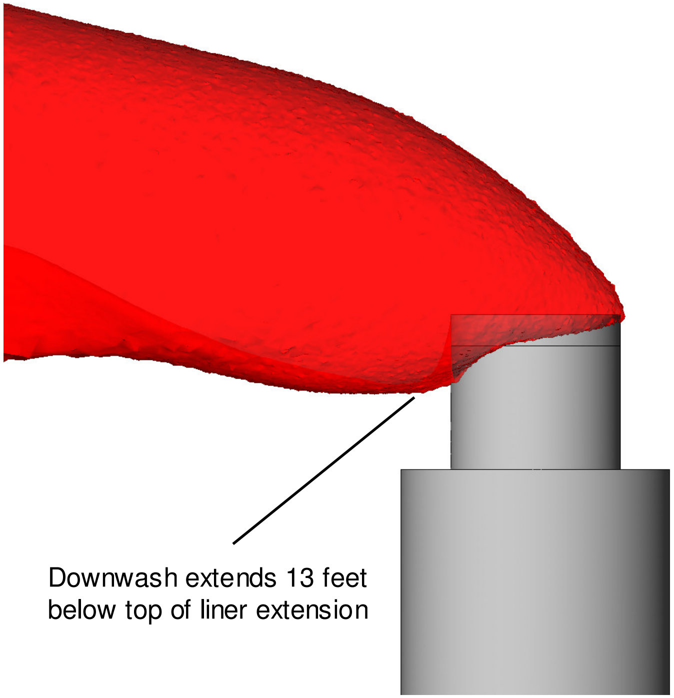




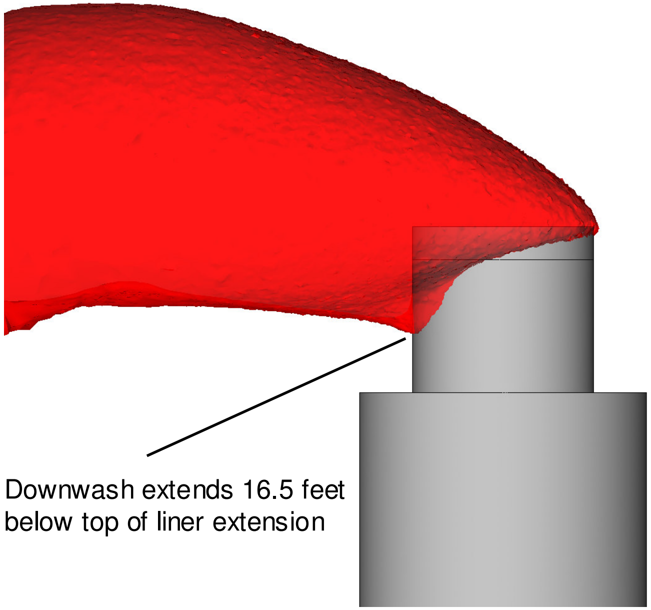
Side by Side Comparison of Both Cases

Surface Contour of Constant Temperature

Surface is Semi-Transparent to Show Liner Extension

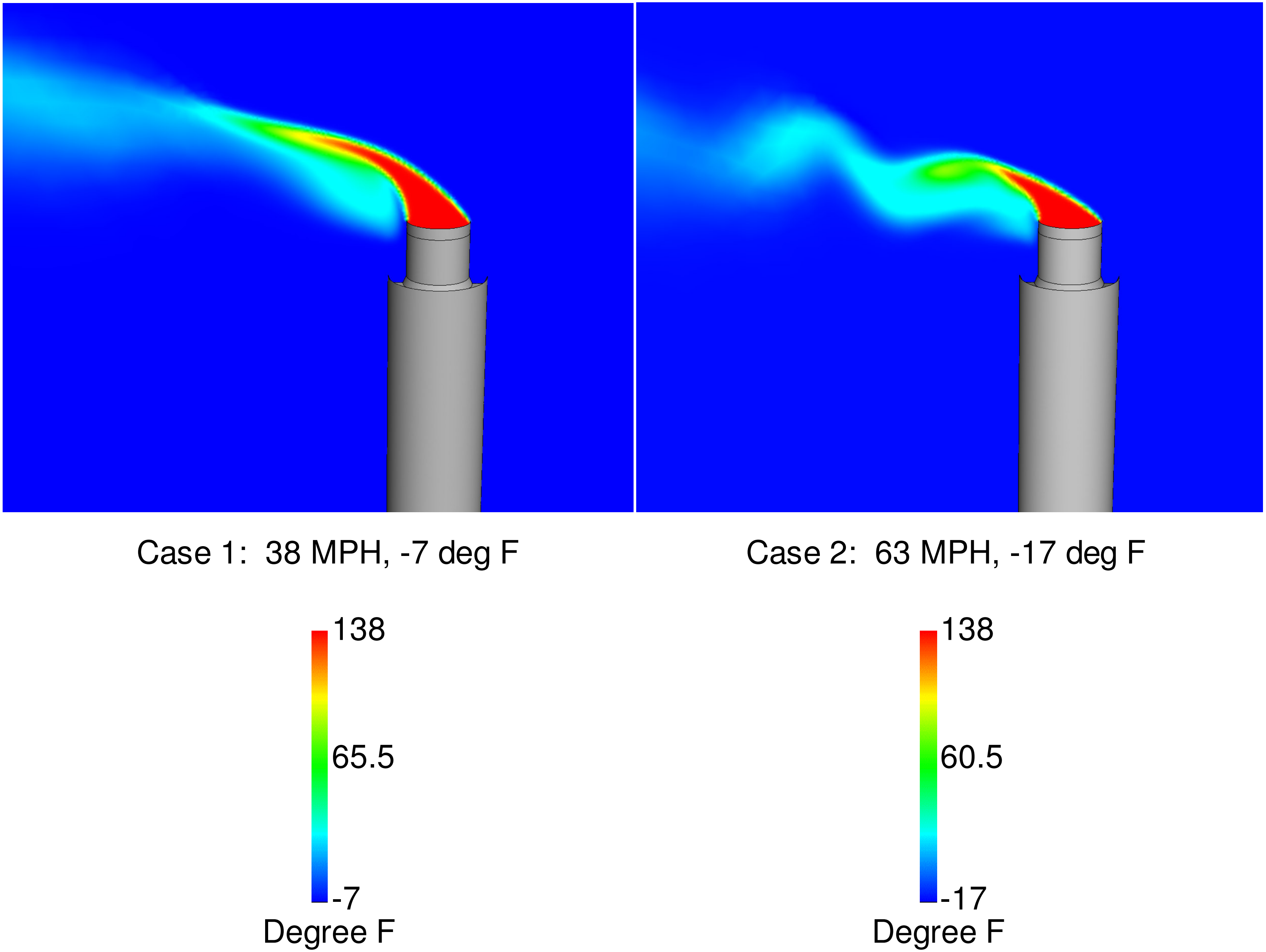

Downwash extends 13 feet
below top of liner extension

Case 1: 38 MPH, -7 deg F


Downwash extends 16.5 feet
below top of liner extension

Case 2: 63 MPH, -17 deg F

Temperature at Stack Midplane

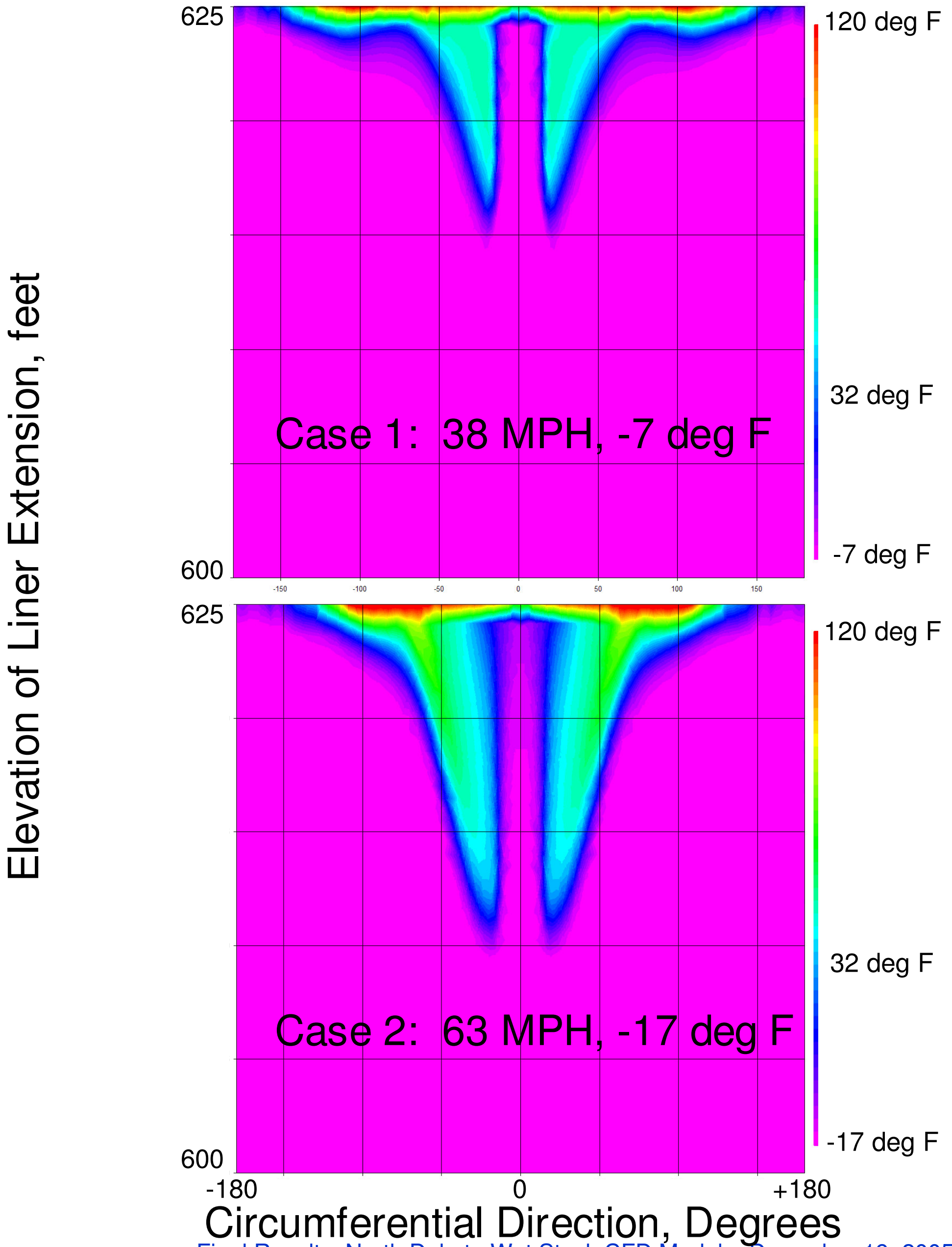


Case 1: 38 MPH, -7 deg F

Case 2: 63 MPH, -17 deg F

Temperature Adjacent to Liner Extension

Plotted in Cylindrical Coordinates



Appendix F

Foster Wheeler SOFA/LNB Analysis

FOSTER WHEELER NORTH AMERICA CORPORATION
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TLN3 SYSTEM ASSESSMENT AND RECOMENDATIONS FOR LOWER NOx OPERATION

GREAT RIVER ENERGY
UNDERWOOD, NORTH DAKOTA
COAL CREEK UNIT 1

FWNAC Contract No. 65-117436
September 9, 2005

Prepared By: Brad Moulton & John Grusha

NOTICE

Summary:

Foster Wheeler was on site at Great River Energy (GRE) Coal Creek Station August 16-18, 2005 for the purpose evaluating the current TLN3 system performance, for future NOx reduction potential. This consisted of conducting a series of tests that would both identify the effectiveness of various NOx reduction adjustments and subsystems, determine any barriers, and gather data that would help predict and quantify the benefits of specific modifications for additional NOx reduction. Several recommendations are summarized and offered to Great River Energy's for review and consideration.

The primary evaluation tests consisted of the following:

1. Static pressure measurements at the SOFA elevations were taken at varying conditions to determine SOFA flows and the effect on NOx levels.
2. Main windbox/furnace DP was increased to evaluate forcing more air to the SOFA windboxes.

The effect of operating oxygen levels and main burner tilts was not examined however there is potential here.

Separated Overfire Air flow measurements:

Separated overfire air (SOFA or SSAS 13 and 14) static pressure measurements were taken at each corner (both elevations). These readings were used to evaluate current overfire air flow rates versus the initial design and what it takes to increase the flow. Furnace draft measurements were taken at the observation doors near each SOFA corner, to determine the DP across the nozzle tips. Knowing the DP, nozzle tip flow area and k factors, velocity and flow can be determined. The measured overfire air flows are summarized in the following table:

		Corner Flows, lb/hr									
Date/Time	Test	1	2	3	4	5	6	7	8	Total	% Total Air
8/16; 0840	Baseline	109,015	104,905	109,427	112,929	114,412	90,225	114,431	107,919	863,263	17.51
8/16; 1055	SOFA 100%	121,118	108,569	113,245	118,113	114,827	81,526	106,691	121,718	885,808	17.97
8/16; 1306	Wbx 4.5 in	119,979	111,838	121,802	119,880	122,122	95,314	108,675	124,987	924,598	18.75
8/16; 1340	SOFA +25	115,588	110,638	114,176	107,221	114,230	95,461	101,727	118,294	877,334	17.79
8/16; 1430	SOFA horiz.	123,864	115,283	115,938	123,260	116,428	91,897	110,396	123,245	920,312	18.67
8/17; 0749	Base	107,206	103,250	96,452	110,546	115,660	83,842	Bad Data	Bad Data	N/A	N/A
8/17; 0935	SOFA 100%	114,196	105,169	107,891	107,341	108,195	107,836	102,862	121,673	875,161	17.75
8/17; 1110	Wbx 5.0 in	121,789	121,152	120,420	120,075	124,056	104,050	117,717	132,611	961,871	19.51
8/17; 1425	SOFA +25	115,461	104,534	111,151	108,207	109,267	101,874	111,560	112,574	115,461	17.74
8/18; 1322	Check	118,298	111,454	118,373	114,654	109,662	95,774	112,698	121,549	902,461	18.30

Table 1 –Separated Overfire Air Flow Rates for Individual Corners Under Various Conditions

The original overfire air system was designed for 20% at 5.0 in w.c. Some variances exist between corners but overall the current measured flow rates match initial predicted values closely. The first test consisted of raising the windbox/furnace DP from 4.0 to 4.5 in w.c. This increased the SSAS/ SOFA flow from 17.5 to 18.75% (table 1). Further SOFA flow increase was seen at 5.0 in w.c, however at this condition, the main windbox dampers were at their low limit of

10% open. (This is a plant- imposed limit for nozzle tip cooling considerations.) Further closure would have diverted more secondary air to the overfire air.

The next series of test consisted of evaluating SOFA tilt angle versus NOx. The lowest NOx emissions were at a SOFA tilt angle of +12 degrees. Further increasing SOFA tilts to +25 caused an increase in NOx. This was not expected and is suspected to be due to the apparent flow resistance being created by the "up-tilt" of the nozzle tips. Measured flow rates show a slight decrease in overfire air flow.

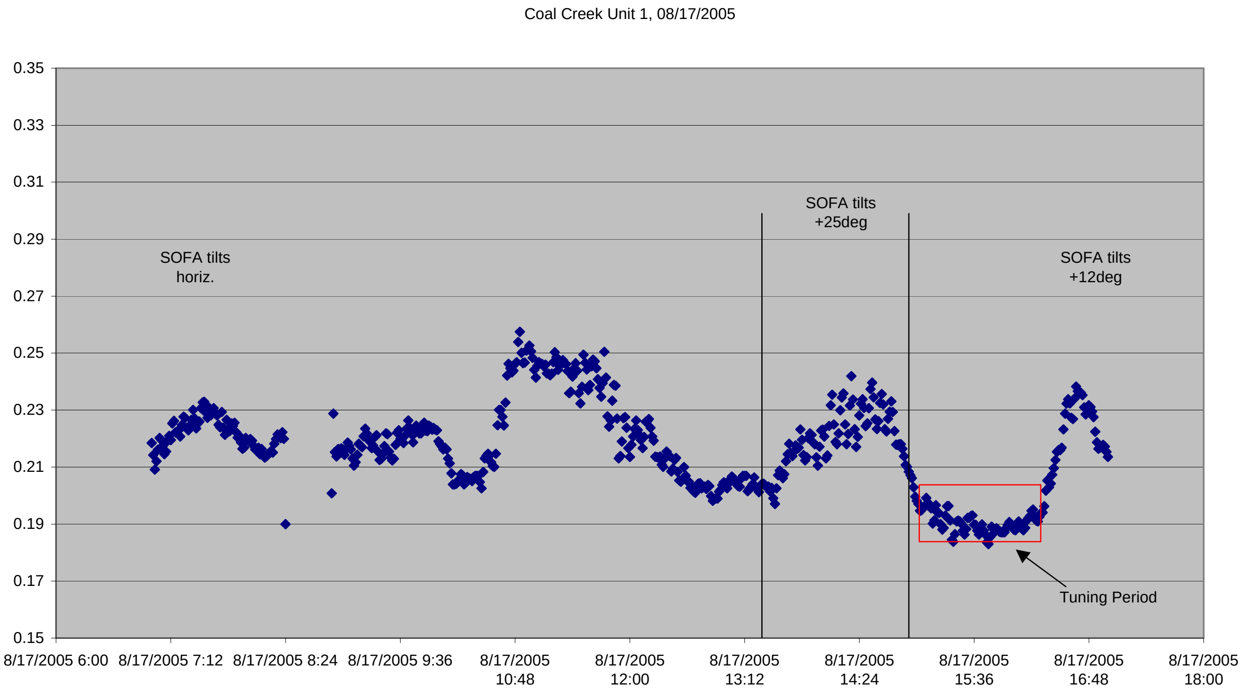

Figure 1: NOx versus Various Operating Conditions

NOx testing/tuning conducted on the last day of the visit (August 18, 2005) showed that opening up the close-coupled overfire air (CCOFA or SAS 11 and 12 compartments) reduced NOx emissions by approximately 0.02 lbs/MBtu.

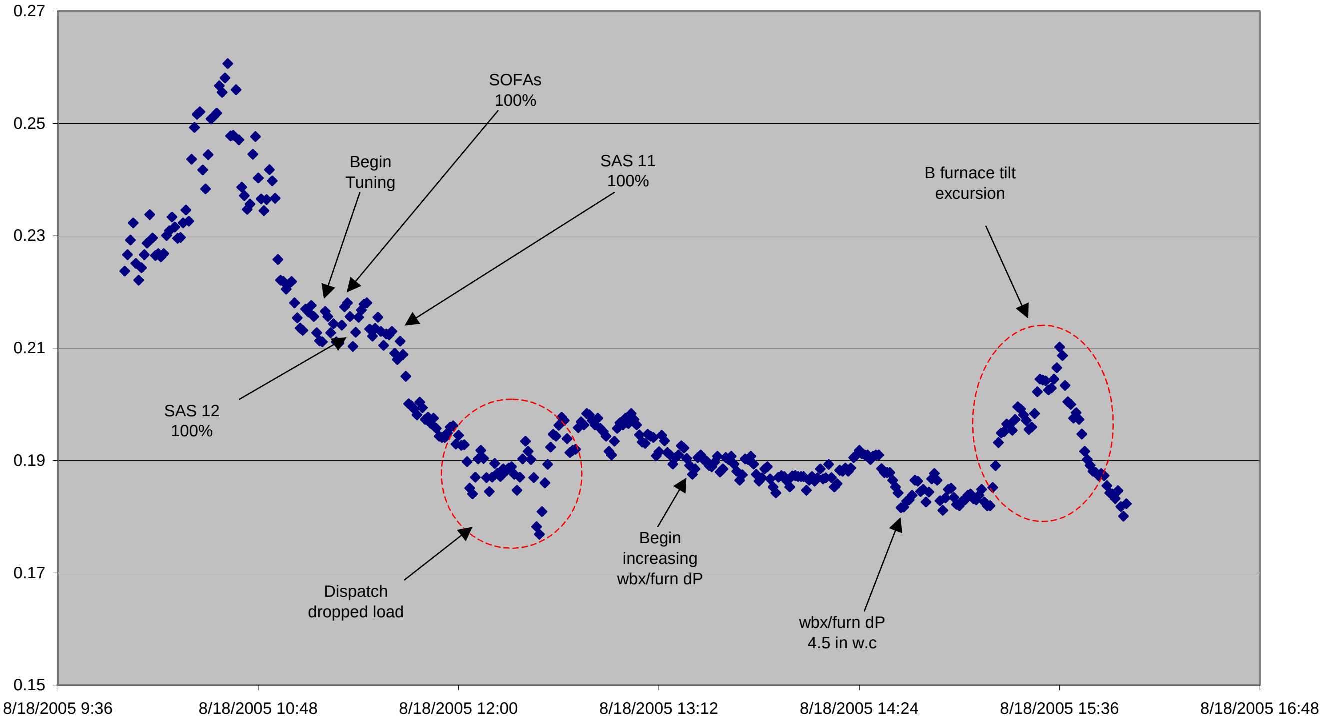

Figure 2. - NOx versus Various Operating Conditions – August 18th

Consistent sub 0.19 lb/MBtu NOx values were achieved with the SOFA and CCOFA compartments at 100% open. As figure 3 shows, only a load disruption and subsequent ramp up caused NOx values above 0.19 lb/MBtu for the better part of the entire afternoon. At these emission levels, main windbox tilts had a pronounced affect on NOx.

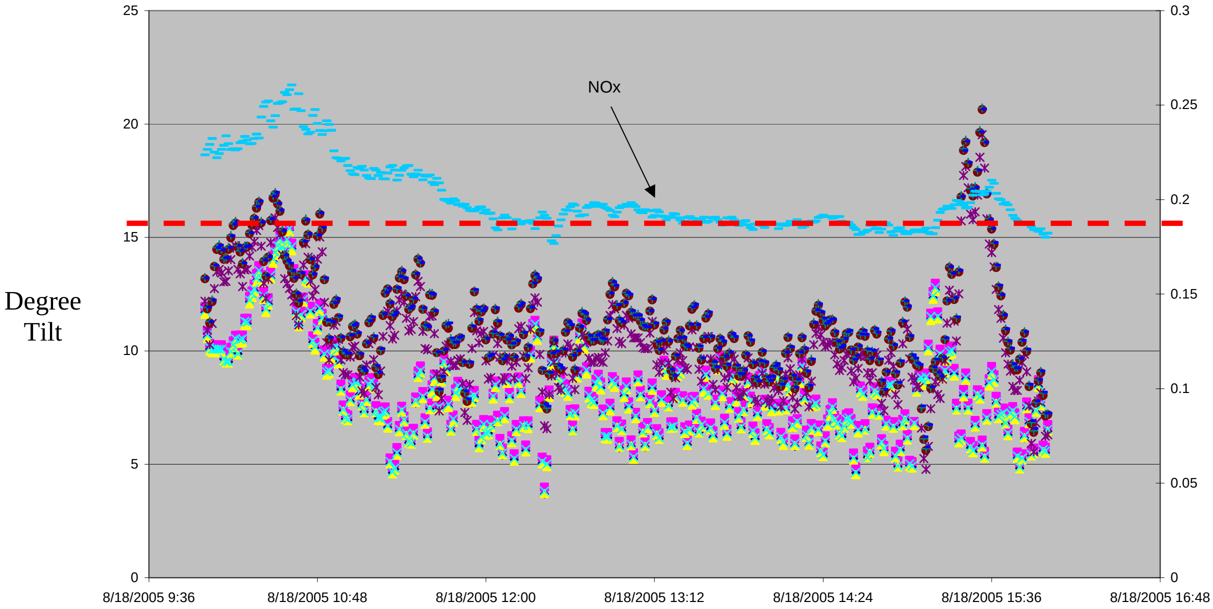

Figure 3. – NOx versus Main Windbox Tilts Over an Extended Period

The above graph shows the NOx and tilts as a function of time. As more overfired air was introduced into the furnace to lower NOx (by opening up the SAS 11 and 12), the main burner tilts were lowered while still controlling steam temperatures. It is clearly evident that fluctuations in NOx coincide with tilt perturbations. The rather drastic increase in NOx around 15:36 was caused by the raising of the A furnace tilts followed by the more marked increase in the B furnace tilts (above 20 degrees).

Recommendations

Based on this evaluation we offer three options that could be applied depending on Great River Energy's short and long-term goals

A. Current Operation:

Based on these evaluation tests, unit #1 should be able to operate at MCR closer to 0.19 lb /MBtu NOx level, with no modification but a few operational changes. This is approximately a 15% reduction from current levels

1. SOFA tilts should be set at + 12 degrees
2. The CCOFA curves (SAS 11 and 12) should be modified so they are 100% open at full load. Specifically they should be optimized to go 100% open at 90 % load, which will match the tested load condition during the time of the Foster Wheeler visit.
3. Further reduction in NOx may be realized by making modifications to the existing steam temperature control logic. Currently, the tilts modulate a fair

amount, which causes fluctuations in NOx of approximately ±0.01 lb/MBtu (over the range observed). (It should be noted that main windbox tilts were not optimized for NOx during this visit.)

4. Lower NOx should be realized with main windbox tilts lower, however some parametric testing would be needed to assess how steam temperatures are affected. Some changes to sootblowing cycles may be warranted to allow lower tilt operation.
5. Operation with a pulverizer out of service would also significantly aid toward maintaining higher overfire air levels. Besides lower NOx emissions it would provide improved DP control and more open auxiliary air dampers.

B. Modifications for 0.17 lbs NOx/MBtu:

Reducing NOx levels closer into the 0.17 levels would require diverting more secondary air to both the CCOFA and SOFA levels. We believe this NOx level could be still be achieved with the current SOFA windboxes and some additional modifications in the main windboxes.

Specifically our model shows that the following changes would be required.

New reduced flow area horizontally adjustable boundary air nozzle tips and new oil nozzle tips would be required. These are required to maintain nozzle tip velocities and nozzle tip cooling being lost due to diverting more secondary air to the SOFA, but also to maintain windbox to furnace DP and damper control. Besides staying cooler, they would also be less prone to slagging for a longer service life. This would be designed to our latest double shroud design standards.

Larger venturi over the coal and auxiliary air dampers would also be required in the main windboxes. These would reduce damper leakage and allow the auxiliary dampers to be at a more open position then current dampers for the same DP. Currently, increased staging is limited by the 10% limit on main windbox auxiliary dampers and the flow restrictions of the existing SOFA nozzle tips.

The following equipment (per unit) would need to be installed:

Item	Quantity	Description
1	Thirty two (32)	Reduced flow area, double shroud front removable section boundary air nozzle tips with full tilt and yaw capability. Matl: 309 SS
2	Twenty four (24)	Reduced flow area, tilting oil nozzle tips. Matl: 309 SS
3	One Hundred Twenty (120)	Venturi damper plates, one for each fuel air and boundary air compartment to further reduce the damper/area tip ratio. Matl. Carbon Steel
4	One lot	Revised SAMA drawings

5	Two Hundred (200) hours	Startup and optimization support for Reevaluating the damper curves regarding impact on the combustion process, furnace slagging, etc. Examination of boiler operational parameters including windbox-furnace DP, boiler O2, fuel/air staging and main burner tilt control.

For budgeting purposes, we estimate approximately $500,000 for the above scope on a D&S basis and approximately another $500,000 for installation.

C. Modifications for 0.15 lbs NOx/MBtu:

From the recent testing and our modeling, long term, NOx levels in the 0.15 lb/MBtu range will not be achieved without substantially increasing separated overfire air flow. At the current 20% SOFA air staging, the lower furnace is bright and free of “sparklers”. An additional 10 % staging could be appreciated with minimal boiler performance issues.

To achieve this objective, Foster Wheeler would recommend installing an additional level of SOFA windboxes and associated tube panels, ducts, hanger, etc. The challenge is to get the added SOFA flow, taking into account the high primary air flow percentage with all mills in service. For this we would be looking a duct arrangement that “scoops” secondary air from the secondary air ductwork rather than rely on windbox backpressure through venturi and nozzle tips. We would need to study the take-offs for this and CFD model the design to confirm the expected results.

The objective with this proposed modification is to divert the existing CCOFA air to the new SOFA windboxes. Separated overfired air is nearly twice as effective in reducing NOx as compared to close-coupled overfire air (CCOFA). Because of this fact, the existing CCOFA nozzles would be downsized and venturis added to the CCOFA dampers to achieve this objective.

Specifically, the following equipment (per unit) would need to be installed:

Item	**Quantity**	**Description**
1	Eight (8)	Separated SOFA windboxes sized for approximately 10% of total combustion air, with tilting and yawable double shroud nozzle tips and static pressure taps for air flow measurement, etc. Windbox material: Carbon Steel; Nozzle tip material: 309SS.
2	One (1) lot	Complete secondary air duct system for the SOFA system including ducts, hangers expansion joints, flow diverting vanes or scoops, and associated support steel.
3	Sixteen (16)	Reduced flow area, double shroud CCOFA nozzle tips. Matl: 309 SS

4	Sixteen (16)	Venturi damper plates, one for each CCOFA compartment to optimize the damper/area tip ratio. Matl. Carbon Steel
5	One session (1)	CFD modeling of secondary and OFA ducting to optimize duct design
6	Eight (8)	Waterwall tube panels to incorporate SOFA.
7	Five Hundred (500) hours	Startup and optimization support for Reevaluating the damper curves regarding impact on the combustion process, furnace slagging, etc. Examination of boiler operational parameters including windbox-furnace DP, boiler O2, fuel/air staging and main burner tilt control.

For budgeting purposes, we estimate approximately $1,000,000 for the above scope on a D&S basis and approximately another $1,000,000 for installation.

Conclusions:

Lower NOx operation in the range of 0.19 lb/MBtu should be achievable with the current equipment. Only a few operational changes are needed to realize these emission levels. The tilting SOFA nozzle tips have been optimized to produce the lowest NOx possible at +12 degrees with the current equipment.

For NOx emissions, in the range of 0.17 lb/MBtu, it will require additional equipment and operational modifications. Specifically this would include smaller main windbox boundary and oil nozzle tips along with damper venturis. These modifications will allow Coal Creek to "push" more SOFA air, maximizing the modifications within the current constraints of the primary air, existing SOFA ducts and windboxes.

For NOx emissions in the range of 0.15 lb/MBtu, about 10% additional overfire air would be required to reliably achieve these levels. This will require additional separated overfire air by installing an additional level. The objective would be to have the capability of introducing 30% of the total combustion air as separated overfire air.

We hope this information is helpful and are available to discuss this assessment and or other considerations with Great River Energy. Foster Wheeler has thoroughly enjoyed working with the Coal Creek Station and personnel and looks forward to future projects and discussions.

Appendix G

SCR catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals

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SCR catalyst performance in flue gases derived from subbituminous and lignite coals

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Abstract

Lignite and subbituminous coals from the United States of America have characteristics that impact the performance of catalysts used in selective catalytic reduction (SCR) for nitrogen oxide removal and mercury oxidation. Typically, these coals contain ash-forming components that consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. The alkali and alkaline-earth elements are partitioned between reactions with minerals and reactions to form alkali and alkaline-earth-rich oxides during combustion. The particles resulting from the reaction with minerals produce low-melting-point phases that cause a wide range of fireside deposition problems. The alkali and alkaline-earth-rich oxides consist mainly of very small particles (<5 μm) that are carried into the backpasses of the combustion system and react with flue gas to form sulfates, and possibly carbonates. These particles cause low-temperature deposition, blinding, and plugging problems in SCR systems. These coals also contain the very low levels of chlorine that are necessary for mercury oxidation. Slipstream testing was conducted at two selected subbituminous-fired power plants and one lignite-fired power plant to determine the impacts of ash on SCR plugging, blinding, and mercury oxidation. The results indicated a high potential for

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blinding and plugging due to the formation of sulfate-bonded deposits and no evidence for mercury oxidation.

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Keywords: Coal; Selective catalytic reduction (SCR); Blinding; NO_x; Mercury; Oxidation

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1. Introduction

Selective catalytic reduction (SCR) for NO_x control and mercury oxidation was investigated using a slipstream reactor at power plants firing subbituminous and lignite coals to determine the potential for ash plugging, catalyst blinding, and mercury oxidation. SCR units lower NO_x emissions by reducing NO_x to N_2 and H_2O. Ammonia (NH_3) is the most common reducing agent used for the SCR of NO_x. The SCR process involves the use of a metal oxide catalyst such as titanium dioxide-supported vanadium pentoxide catalyst (V_2O_5). These units are operated at about 340–370 °C (650–700 °F). Subbituminous and lignitic coals are known for their ability to produce alkali and alkaline-earth sulfate-bonded deposits at low temperature (<1000 °C) in utility boilers. The mechanisms of the formation of low-temperature sulfates have been extensively examined and modeled by the Energy and Environmental Research Center (EERC) in work termed Project Sodium and Project Calcium in the early 1990s [1,2]. Deposit buildup of this type blinds or masks the catalyst, diminishing its reactivity for converting NO_x to N_2 and water and potentially creating increased ammonia slip [3]. Elemental mercury oxidation has been observed in laboratory-, pilot-, and full-scale testing using SCR catalysts [4–6]. In these studies, the metal oxides, V_2O_5 and TiO_2, have been shown to promote the conversion of elemental mercury to oxidized and/or particulate-bound mercury. Full-scale tests in Europe [7] and the United States [8] have indicated that the V_2O_5 and TiO_2 catalyst may promote the formation of oxidized mercury. The ability to oxidize mercury is largely dependent on the composition of the coal [8].

Lignite and subbituminous coals produce ash that plug and blind catalysts [9–12]. The problems currently being experienced on SCR catalysts include the formation of sulfate- and phosphate-based blinding materials on the surface of catalysts and the carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing them on top of the SCR catalysts [3]. The most significant problem that limits the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates, phosphates, and possibly carbonates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency [3,11–14]. The degree of the ash-related impacts on SCR catalyst performance depends upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design [11–15].

Cichanowicz and Broske [13] conducted tests on a South African and a German Ruhr Valley coal and found that the German Ruhr Valley coal significantly increased the pressure drop across the catalyst because of the accumulation of ash. They found that the German coal produced a highly adhesive ash consisting of alkali (K and Na) sulfates. In addition, they reported that the alkali elements are in a water-soluble form and highly

Table 1
Description of power plants tested

	Baldwin	Columbia	Coyote
Unit #	1	2	1
Utility	Dynegy	Alliant	Otter Tail
Boiler type	Cyclone	T-Fired	Cyclone
Fuel type	Antelope—subbituminous	Caballo—subbituminous	Beulah—Zap lignite
Load	Base	Base	Base
Location	Baldwin, IL	Portage, WI	Beulah, ND
MW	600	520	425

mobile and will migrate throughout the catalyst material, reducing active sites. The water-soluble form is typical of organically associated alkali elements in coals. The German Ruhr Valley coal has about 9.5% ash and 0.9% S on an as-received basis, and the ash consists mainly of Si (38.9%), Al (23.2%), Fe (11.6%), and Ca (9.7%), with lower levels of K (1.85%) and Na (0.85%) [13]. Cichanowicz and Muzio [14] summarized the experience in Japan and Germany and indicated that the alkali elements (K and Na) reduced the acidity of the catalyst sites for total alkali content (K+Na+Ca+Mg) of 8–15% of the ash in European power plants. Licata et al. also found that alkaline-earth elements such as calcium react with SO_3 on the catalyst, resulting in plugging of pores and a decrease in the ability of NH_3 to bond to catalyst sites. The levels of calcium in the coals that caused blinding ranged from 3% to 5% of the ash. Studies conducted on the impact of alkali elements associated with biomass found that, when biomass is fired, poisoning and blinding of SCR catalysts occurred [16,17].

The slipstream reactors were installed at three power plants. Two of the plants were cyclone fired: one with lignite and one with subbituminous coal. The third plant was a pulverized-coal, tangentially fired unit with subbituminous coal. The slipstream reactors were designed to expose SCR catalysts to flue gas and particulate matter under conditions that simulate gas velocities, temperatures, and ammonia injection of a full-scale plant. The control system maintains catalyst temperature, pulse air to remove accumulated deposits, constant gas flow across the catalyst, and records pressure drops and temperatures. The reactor was operated in an automated mode and can be controlled via modem connection. Testing at each power plant was conducted over a 6-month period. The reactor was inspected and cleaned at 2-month intervals, and a catalyst section was removed for analysis. The

Table 2
Key selection criteria

Field test 1—Columbia Station
Tangentially fired boiler to show differences in ash partitioning as compared to cyclone-fired systems. High-potential-blinding coal in Caballo, which can be burned nearly 100% for the entire test.
Field test 2—Baldwin Station
Plant is cyclone fired. Units are already equipped to do slipstream testing. Plant currently fires a blend of Antelope and tires; plant is willing to fire 100% Antelope. High potential blinding coal in Antelope.
Field test 3—Coyote Station
Cyclone-fired with lignite. High potential blinding with high alkali and alkaline-earth elements. Coal can have very high sodium contents and is known to cause significant low-temperature deposition.

Table 3
Ultimate analysis results (dry basis)

	Antelope	Caballo	Beulah
Ash content	7.28	6.59	11.62
Total sulfur	0.33	0.51	1.49
Carbon	69.97	67.88	61.50
Hydrogen	4.77	4.83	3.96
Nitrogen	1.05	1.24	1.08
Oxygen (by difference)	16.61	18.96	20.35

catalysts and associated ash deposits were analyzed to determine the characteristics of the ash on the surface and in the pores. In addition, the mercury speciation in the flue gas upstream and downstream of the catalyst was conducted at 2-month intervals during the testing at the lignite-fired plant. The ability of the SCR catalyst materials to catalyze gaseous elemental mercury (Hg^0[g]) to a more soluble and chemically reactive $Hg^{2+}X(g)$ forms was evaluated, along with the potential increase in particle-associated mercury, Hg(p). Increasing the oxidized and particulate fractions of mercury has the potential to increase the capture efficiency of mercury by conventional control devices such as wet flue gas desulfurization (FGD) scrubbers and electrostatic precipitators (ESPs).

This paper summarizes pressure drop, formation of deposits that blind the surface of the catalyst, and the ability of SCR catalysts to oxidize mercury.

2. Experimental

2.1. Overview of test program and fuel characteristics

A portable SCR slipstream reactor system was designed and constructed to conduct full-scale evaluation of the SCR catalyst ash plugging and blinding and mercury oxidation. A particle-laden flue gas slipstream was isokinetically extracted from the flue gas duct ahead of the air heater at full-scale utilities using an induced-draft fan. Two systems were constructed

Table 4
Ash composition (wt.% equivalent oxide)

Oxide	Antelope	Caballo	Beulah
SiO_2	24.82	26.70	16.50
Al_2O_3	13.55	16.60	13.30
TiO_2	1.39	1.10	0.80
Fe_2O_3	7.52	5.10	16.60
CaO	26.68	25.10	19.50
MgO	7.14	8.00	7.40
K_2O	0.17	0.30	0.20
Na_2O	1.47	1.00	5.20
P_2O_5	0.90	1.70	0.00
SO_3	16.33	14.40	19.80

so that data may be collected simultaneously from two full-scale sites. Testing was conducted at three boilers, including tests on a cyclone boiler firing Powder River Basin (PRB) coal, a lignite-fired cyclone boiler, and a pulverized coal boiler burning PRB. SCR catalysts were exposed to flue gases and combustion-derived fly ash particles for 6-month time periods to study the blinding effect of fly ash and ash deposits on catalyst performance.

The electric utility units selected for testing are shown in **Table 1**. The plants where the SCR slipstream system was installed included Alliant Energy's Columbia Station, Dynegy's Baldwin Station, and Otter Tail Power Company's Coyote Station. **Table 1** describes the plants, and **Table 2** summarizes the characteristics and selection criteria.

The units tested were selected based on the fuels fired, boiler type, and availability of the unit for sampling. The average composition of the coals fired during the testing is

Table 5
CCSEM analysis results for Beulah, Antelope, and Caballo (values are wt.% on a mineral basis)

	Caballo	Antelope	Beulah
Total mineral wt.% on a coal basis	2.8	3.2	8.4
Quartz	40.4	31.5	11.0
Iron oxide	0.0	2.4	4.4
Periclase	0.0	0.0	0.0
Rutile	2.4	0.3	0.0
Alumina	0.0	0.0	1.1
Calcite	0.0	0.4	0.1
Dolomite	0.0	0.5	0.0
Ankerite	0.0	0.0	0.2
Kaolinite	23.7	17.1	4.9
Montmorillonite	0.4	6.5	6.6
K Al-silicate	0.0	1.6	7.2
Fe Al-silicate	0.0	0.8	9.0
Ca Al-silicate	0.1	1.0	2.6
Na Al-silicate	0.0	0.0	0.1
Aluminosilicate	0.7	3.3	3.2
Mixed Al-silicate	0.0	1.0	5.5
Fe silicate	0.0	0.0	0.0
Ca silicate	0.0	0.4	0.0
Ca aluminate	0.0	0.0	0.0
Pyrite	16.2	0.0	0.8
Pyrrhotite	0.0	4.8	18.4
Oxidized pyrrhotite	0.0	0.5	0.5
Gypsum	0.4	0.0	0.5
Barite	0.8	0.5	3.0
Apatite	0.0	0.2	0.0
Ca Al-P	8.5	13.5	0.1
KCl	0.0	0.0	0.0
Gypsum/barite	0.0	0.1	0.0
Gypsum/Al-silicate	0.1	0.9	4.0
Si-rich	0.3	3.7	4.9
Ca-rich	0.0	0.0	0.0
Ca–Si-rich	0.0	0.1	0.0
Unclassified	3.2	8.7	11.9
Total	100.0	100.0	100.0

listed in **Tables 3 and 4**. The subbituminous coals were typically low ash, nominally 4.5% to 5.5% with very high levels of calcium in the ash. In comparison, the lignite contains higher levels of ash and lower calcium but higher levels of sodium. The alkali and alkaline-earth elements are primarily associated with the organic matrix of the coal as salts of carboxylic acid groups [18]. The portion of the ash-forming components that are associated with the organic matrix of the coal for subbituminous coal ranges from 30% to 60% [18]; for the lignite coal, the portion is about 20% to 40%. The remaining ash-forming components consist of mineral grains. For these coals, the percent organically associated is 29% for the Antelope, 36% for Caballo, and 19% for Beulah. The minerals present in the coals determined by computer-controlled scanning electron microscopy (CCSEM) analyses are listed in **Table 5**. The primary minerals present in the subbituminous coals include quartz and various clay minerals with some pyrite and a mineral that is rich in Ca, Al, and P. This mineral has been identified in some coals as crandalite. The primary minerals found in the Beulah coal include clay minerals (kaolinite), pyrite, and quartz.

2.2. SCR slipstream system

The SCR slipstream system consists of two primary components: the control room and the SCR reactor. The reactor section consists of a catalyst section, an ammonia injection system, and sampling ports for NO_x at the inlet and exit of the catalyst section. The control

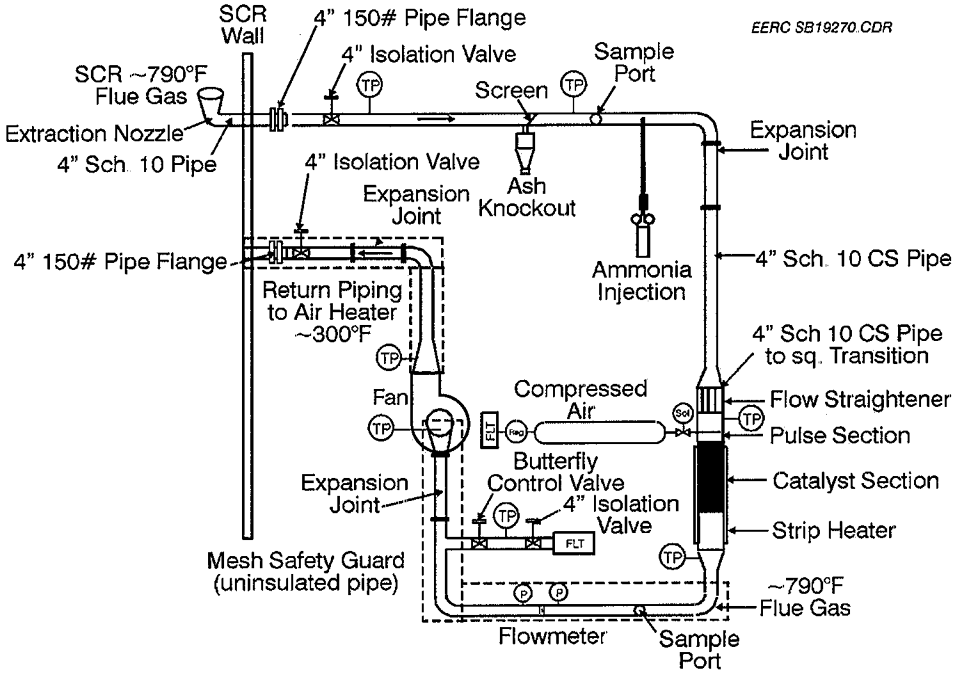


Fig. 1. Schematic diagram of SCR slipstream system.

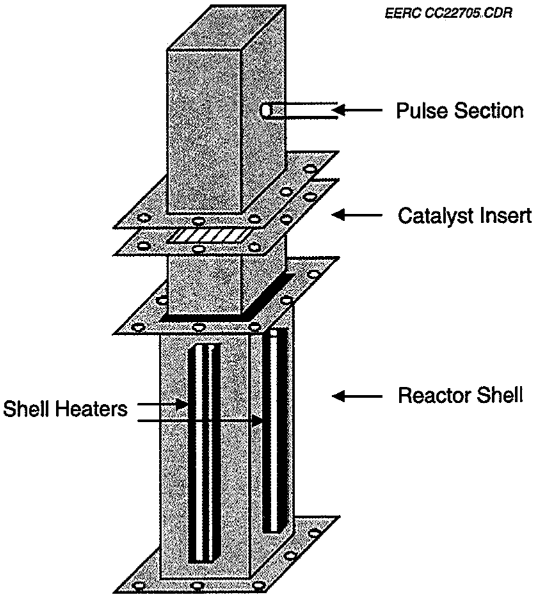


Fig. 2. Diagram of reactor section SCR slipstream system.

room houses a computer system that logs data and controls the gas flow rates, temperatures, pressure drop across the catalyst, and sootblowing cycles. The computer was programmed to maintain constant temperature of the catalyst, gas flow rates, sootblowing cycles, and ammonia injection. The computer is equipped with a modem that

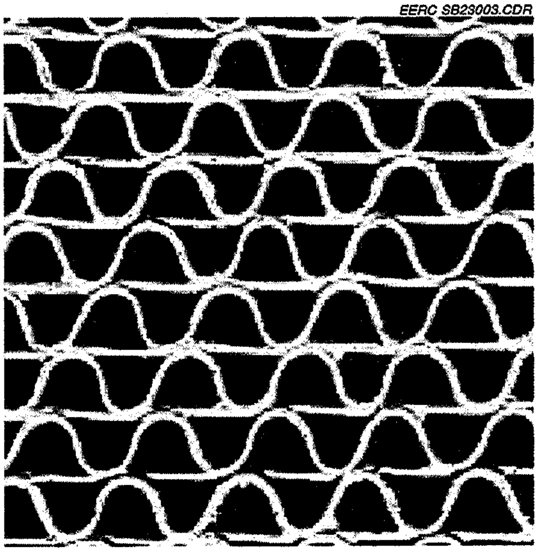


Fig. 3. Haldor Topsoe SCR catalyst showing the gas flow passages.

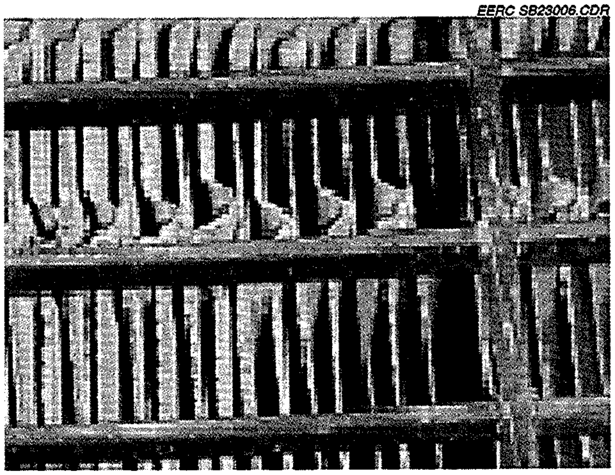


Fig. 4. Babcock Hitachi SCR catalyst showing the gas flow passages.

allowed for downloading of data and modification of the operation of the reactor from a remote computer located at the EERC.

A schematic diagram of the SCR slipstream system is shown in Fig. 1. Flue gas is isokinetically extracted from the convective pass of the boiler upstream of the air heater. The temperature is typically about 790 °F. The flue gases pass through a 4-in. pipe equipped with sampling, thermocouple, and pressure ports. Ammonia is injected into the piping upstream of the reactor section. The reactor consists of a steel housing that is approximately 8.5 in. square and 8 ft long. The reactor section illustrated in Fig. 2 has three components, including a flow straightener, a pulse section or sootblower, and a catalyst test section. A metal honeycomb is used as a flow straightener upstream of the catalyst section and is about 6 in. long. A purge section was installed ahead of the catalyst test section to remove accumulated dust and deposits. The catalyst test section is located downstream of the purge section. The entire catalyst section is insulated and equipped with strip heaters for temperature control. The catalyst test section is 3.28 ft (1 m) in length and houses three catalyst sections. Thermocouple and pressure taps are located in the purge sections for measurements before and after each section.

The induced-draft fan is used to extract approximately 400 acfm (200 scfm) of flue gas from the convective pass of the utility boiler to achieve an approach velocity of 5.2 m/s

Table 6
Selected operating conditions of the SCR catalysts

Plant name	Average SCR inlet temperature (°F)	Average SCR outlet temperature (°F)	Air pulse frequency	Flue gas flow rate (acfm)
Baldwin	645	549	Once per day and on demand	393
Columbia	672	662	Once per day and on demand	385
Coyote	675	667	Once per day and on demand	385

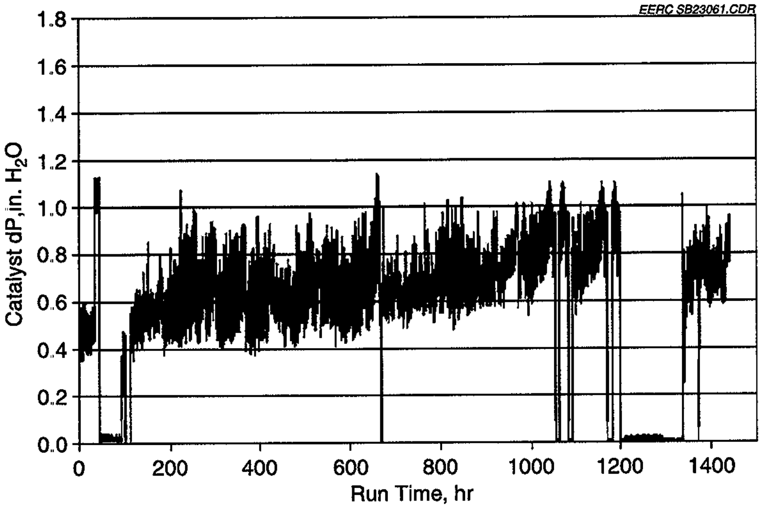


Fig. 5. Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.

(17.0 ft/s). The total gas flow through the reactor represents a thermal load of approximately 300 kW.

The range of operating conditions for the reactor is listed below:

- Gas temperature: ~700–800 °F
- Gas flow rate: 400–500 acfm
- Approach velocity range: 5.0–5.5 m/s
- Ammonia injection rate: 0.5:1 with NO_x level
- Tempering air for fan: ~50–200 scfm

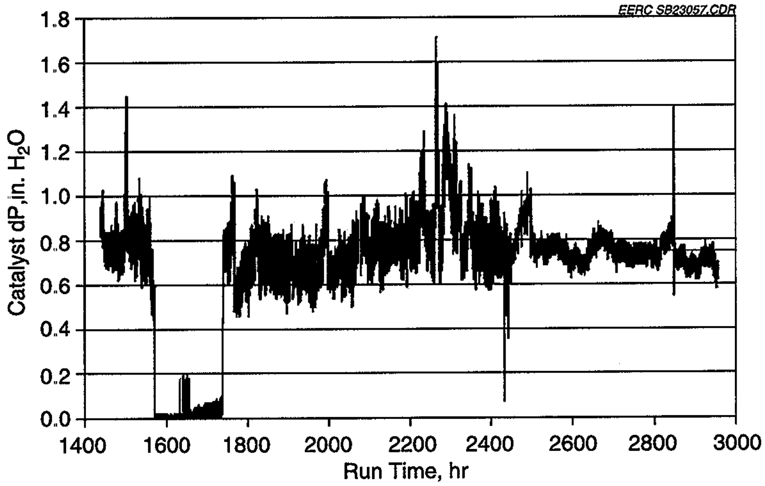


Fig. 6. Catalyst pressure drop at Baldwin Station at 2 to 4 months of operation.

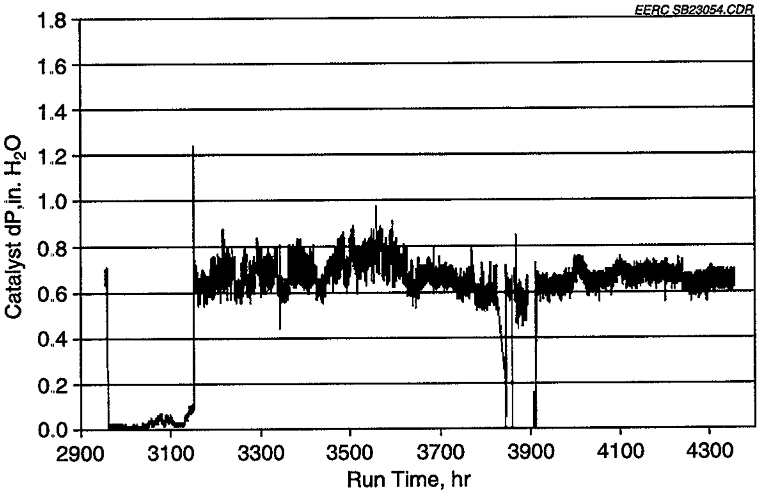


Fig. 7. Catalyst pressure drop at Baldwin Station at 4 to 6 months of operation.

- Catalyst dP: 0.5–1.0 in. water column
- Fan sized for up to 30 in. water column.

2.2.1. SCR catalyst

The catalyst installed at the Baldwin and Coyote Stations was the Haldor Topsoe catalyst. Topsoe's DNX-series of catalysts comprises SCR DENOX catalysts tailored to suit a comprehensive range of process requirements. DNX-series catalysts are based on a corrugated, fiber-reinforced titanium dioxide (TiO_2) carrier impregnated with the active components vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels. The unique catalyst design provides a highly porous structure with a large surface area and an ensuing

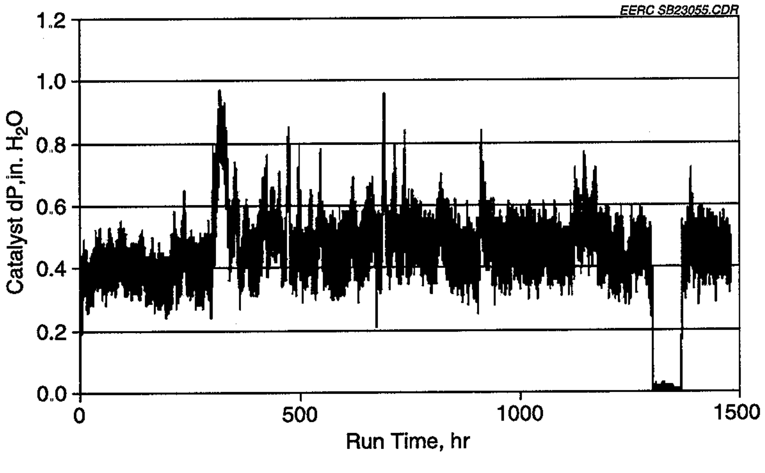


Fig. 8. Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.

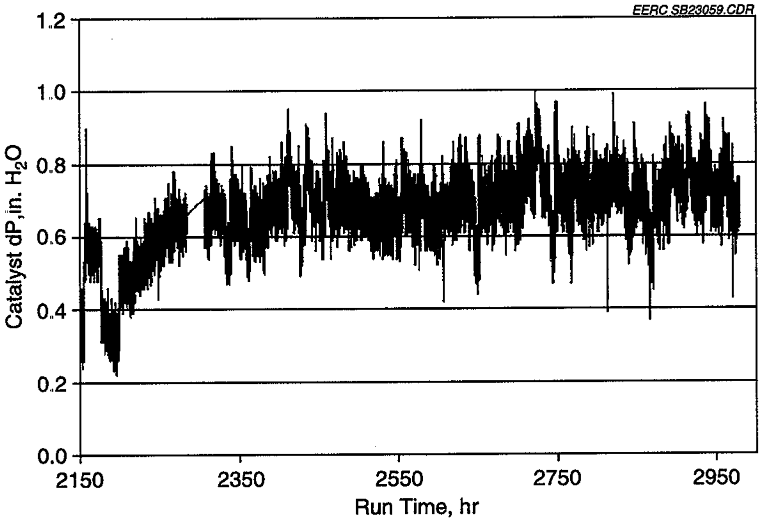


Fig. 9. Catalyst pressure drop at Columbia Station at 2 to 4 months of operation.

large number of active sites. Fig. 3 is an image of the Haldor Topsoe SCR catalyst. The pitch of the catalyst was approximately 6 mm.

The catalyst installed at the Columbia Station was a Babcock Hitachi plate-type catalyst. This catalyst is a TiO_2-based plate catalyst, developed and manufactured by Hitachi. Fig. 4 shows the design of the catalyst. The pitch of the catalyst was approximately 10 mm.

2.2.2. System performance measurement

Upon installation at each utility boiler unit, flue gas temperature, composition, and velocity measurements were obtained using portable equipment. Shakedown testing of the

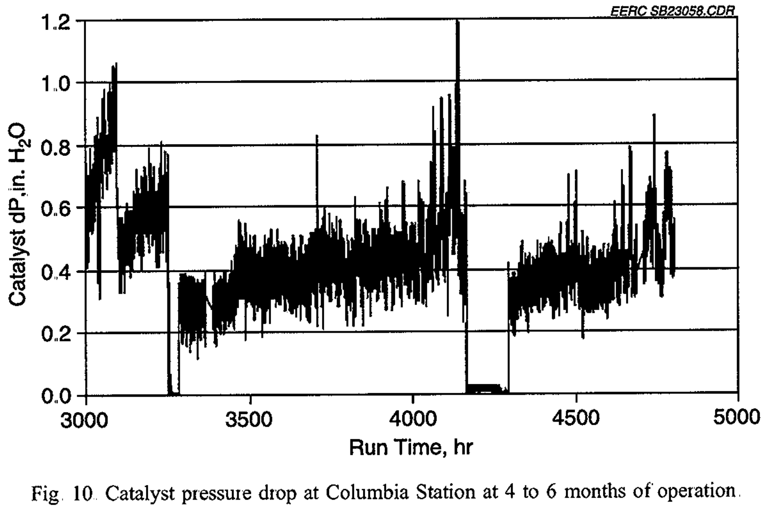


Fig. 10. Catalyst pressure drop at Columbia Station at 4 to 6 months of operation.

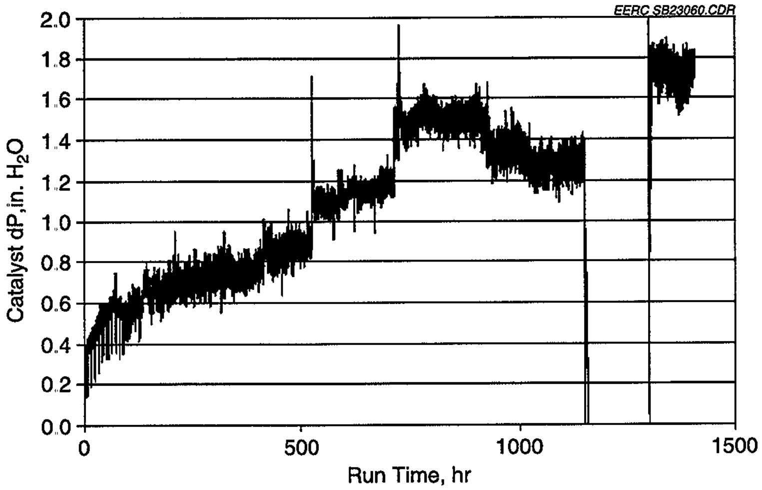


Fig. 11. Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.

unit was conducted to ensure that all components were operating properly and that data were being logged and could be retrieved. After installation and shakedown were completed, the reactor was operated in a computer-controlled, automated mode and monitored on a daily basis to ensure proper operation and data quality. During operation of the SCR slipstream system, catalyst temperature, sootblowing frequency, and pressure drop across the catalyst were monitored and logged. Samples of the exposed SCR catalyst and associated deposits were obtained after exposure to flue gas and particulate for 2, 4, and 6 months. The samples of the catalyst were analyzed to determine the components that were bonding and filling pores, resulting in decreased reactivity.

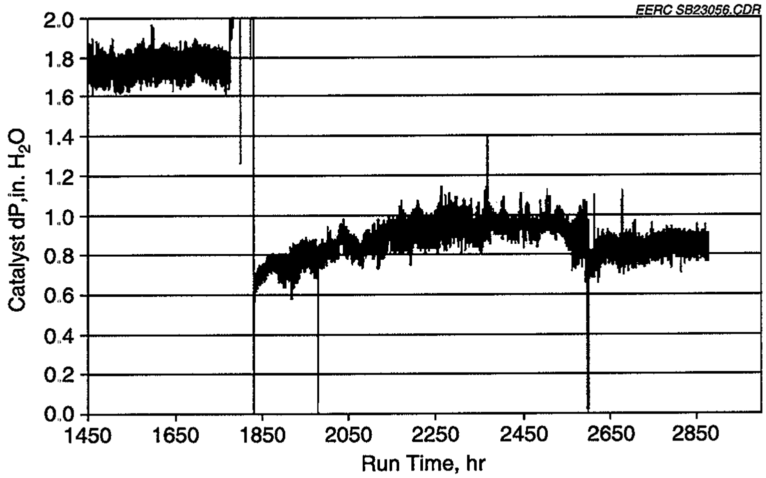


Fig. 12. Catalyst pressure drop at Coyote Station 2 to 4 months of operation.

The characteristics of ash that accumulated on the catalyst were examined using SEM–X-ray microanalysis and X-ray diffraction (XRD) [18]. Correlations between the physical and chemical characteristics of any ash deposits on the SCR test section and entrained-ash sample collected at the chamber inlet and the coal inorganic composition will be made to

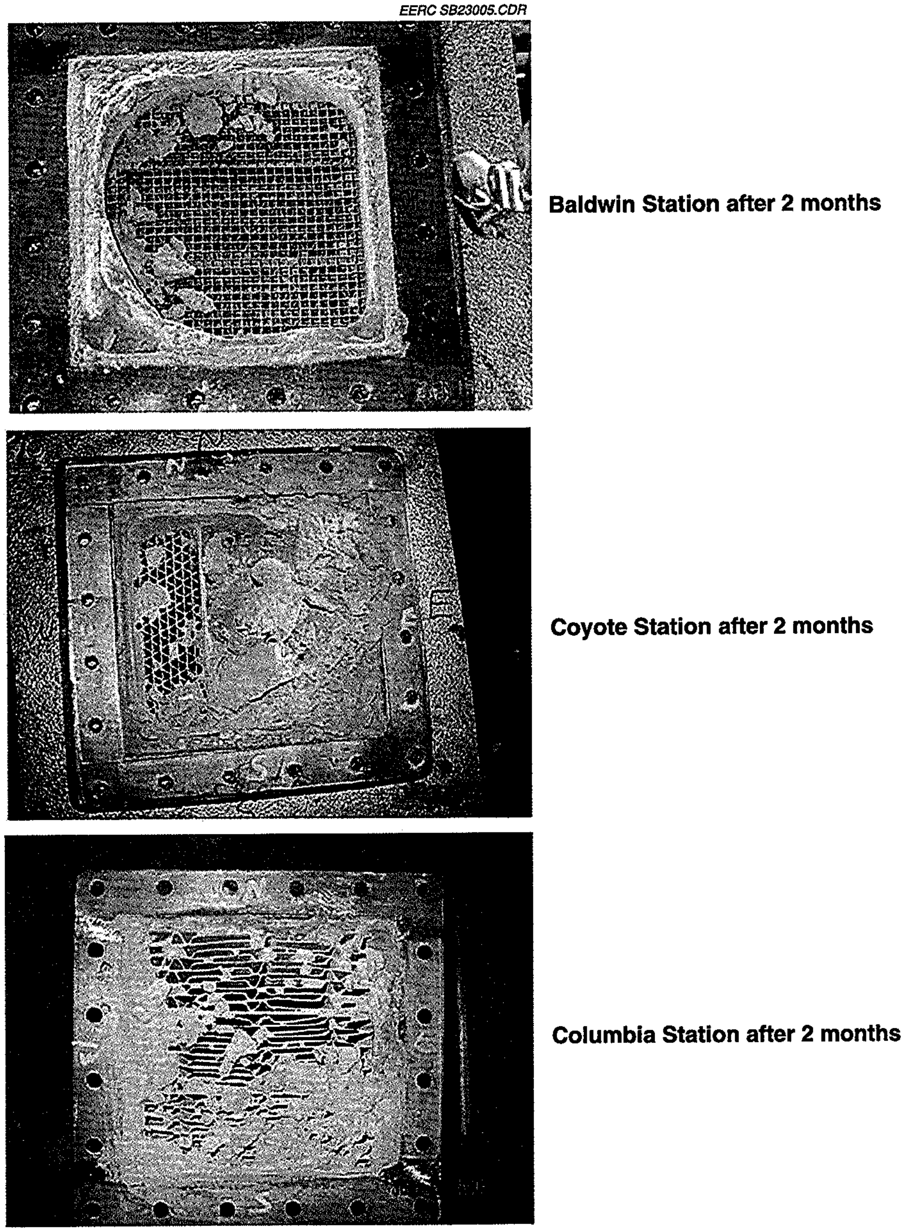


Fig. 13. Pictures of catalyst inlet after about 2 months of testing at each plant.

discern mechanisms of SCR blinding. Entrained ash was collected at Columbia Station only and characterized to composition and size.

2.3. Analysis of flue gas constituents across the catalyst—Ontario Hydro method for mercury speciation

At the Coyote Station, the Ontario Hydro (OH) mercury speciation sampling train was used to determine mercury forms across the SCR test section. The OH extractive mercury speciation sampling technique was used to measure potential mercury conversion across the SCR system over a period of several hours after fresh installation of the SCR test chamber and again just prior to removal of SCR catalyst sections.

The procedure used to conduct the mercury speciation sampling was American Society for Testing and Materials (ASTM) Method 06784-02 entitled "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" [19].

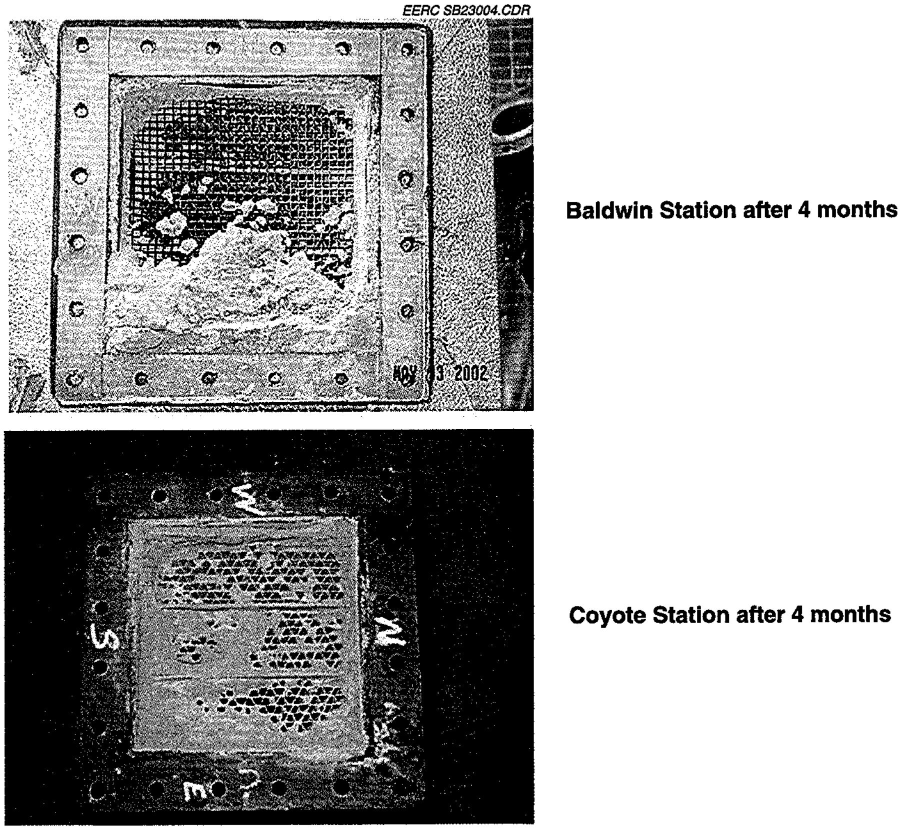


Fig. 14. Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.

The OH method follows standard EPA methods for isokinetic flue gas sampling (EPA Methods 1–3 and EPA Method 5/17). A sample is withdrawn from the flue gas stream isokinetically through the filtration system, which is followed by a series of impingers in

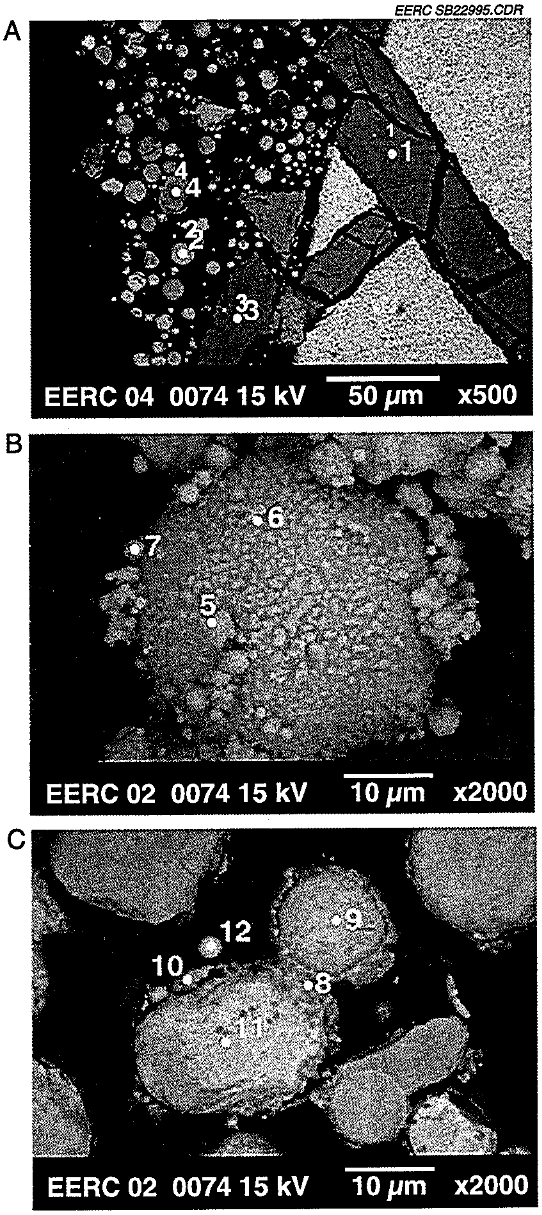


Fig. 15. SEM images of ash collected on catalyst surface at the Baldwin Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) high-magnification image of coated ash particle, and (C) high-magnification image of polished cross section showing coatings on particles.

an ice bath. Particulate-bound mercury is collected on the filter; Hg^{2+} is collected in impingers containing 1 N potassium chloride solution; and elemental mercury is collected in one impinger containing a 5% nitric acid and 10% peroxide solution and in three impingers containing a solution of 10% sulfuric acid and 4% potassium permanganate. An impinger containing silica gel collects any remaining moisture. The filter media is quartz fiber filters. The filter holder is glass or Teflon-coated. An approximate 2-h sampling time was used, with a target sample volume of 1 standard cubic meter.

3. Results and discussion

3.1. Pressure drop

3.1.1. Testing at the Baldwin Station

The reactor was installed at the Baldwin Station and operated for a 6-month time period on the Haldor Topsoe catalyst. The information obtained from testing included pressure drop, sootblowing cycles, and reactor temperatures. Table 6 summarizes the operating conditions of the reactors during the testing periods at all plants. Figs. 5–7 show the pressure drop across the catalyst test periods from 0 to 2 months, 2 to 4 months, and 4 to 6 months, respectively. During the first 2 months of operation, the pressure shown in Fig. 6 was about 0.5 in. of water; at the end of 2 months, the pressure drop was about 0.8 in. of water, indicating plugging had occurred. The air was pulsed a minimum of every 8 h in an attempt to maintain cleanliness. The reactor was monitored on a daily basis, and adjustments in pulsing cycles were made in order to minimize deposit accumulation. However, for the first 2 months, the pressure drop steadily increased. There are several periods where the unit was taken off-line; during those times, the temperature of the catalyst was maintained. At 2-month intervals, a section of catalyst was removed and replaced with a new one.

Table 7
Chemical composition of selected points and areas in Fig. 15

Element (wt.%)												
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
Na_2O	0.2	0.0	0.2	2.3	2.5	3.0	3.6	0.7	0.6	1.6	0.4	0.9
MgO	0.0	6.3	0.0	3.1	3.0	1.3	1.6	2.5	4.5	3.0	3.6	3.5
Al_2O_3	3.6	17.9	6.9	29.6	8.4	5.5	4.4	5.4	22.7	12.2	21.2	14.2
SiO_2	92.1	5.9	86.5	39.9	3.4	53.2	15.7	3.4	16.1	1.0	8.1	2.3
P_2O_5	0.1	0.4	0.0	0.0	1.8	0.0	1.5	0.3	0.5	2.3	0.0	4.6
SO_3	3.3	0.4	5.2	0.1	51.8	18.1	52.4	53.0	0.0	46.4	0.0	19.7
K_2O	0.0	0.0	0.0	0.6	0.4	0.5	0.7	0.2	0.0	0.1	0.0	0.0
CaO	0.0	49.4	0.1	18.6	16.4	14.6	13.0	28.8	41.5	27.1	51.1	39.2
TiO_2	0.7	4.5	0.4	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe_2O_3	0.0	14.6	0.7	3.6	12.3	3.8	7.1	5.7	14.2	6.5	15.6	15.6
BaO	0.0	0.6	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	100	100	100	100	100	100	100	100	100	100	100	100

For Months 2 through 4, the pressure drop was highly variable initially but was about 0.8 in. of water. From Months 4 through 6, the pressure drop was maintained between 0.6 and 0.8 in. of water. This is due to the installation of a fresh catalyst section and leaving two thirds of the catalysts in place that partially plugged. The gas velocity in the single section of new, clean catalyst was high because of channeling, and the result of the high gas flow was less deposition and accumulation. Gas velocity has a significant impact on the potential for deposits to form. However, at high gas velocity, low NO_x conversion is likely.

3.1.2. Testing at Columbia

The reactor was installed at the Columbia Station and operated for a 6-month period of time for the Babcock Hitachi catalyst. The information obtained from the testing included pressure drop information, sootblowing cycles, and reactor temperature. Table 6 shows the reactor temperature, air-pulsing cycles, and airflow rates. Figs. 8–10 show the test periods from 0 to 2 months, 2 to 4 months, and 4 to 6 months, respectively. The pressure drop across the SCR upon installation was about 0.4 in. of water and increased to an average of

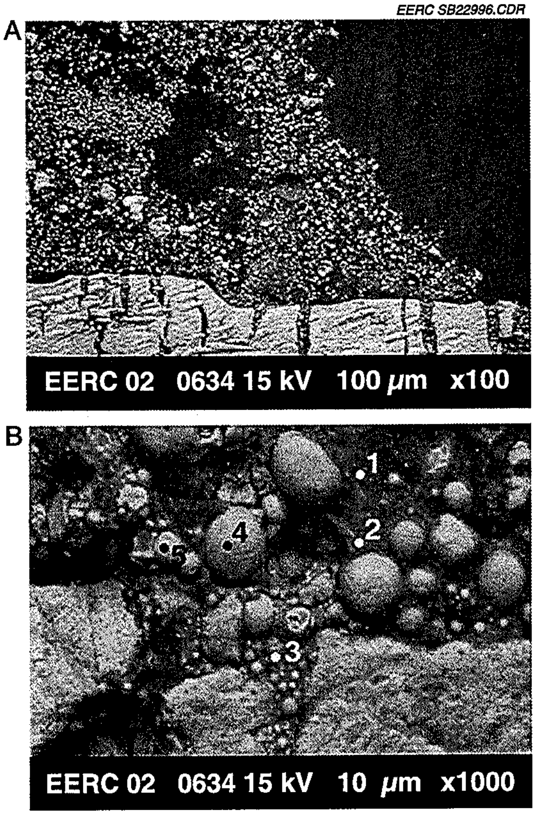


Fig. 16. SEM images of ash collected on catalyst surface at the Baldwin Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, and (B) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

about 0.5 in. of water, but ranged from less than 0.4 to greater than 0.8 in. of water. **Fig. 9** shows the pressure drop for Months 2 to 4. The pressure drop increased from about 0.5 to 0.7 in. of water because of accumulation of ash. **Fig. 10** shows a rapid increase in pressure drop across the catalyst at about 3000 h of operation, and aggressive pulsing brought it down to 0.4 in. of water until the catalyst section was changed out at about 3200 h. After cleaning the reactor and replacing one catalyst section, the pressure drop was about 0.3 but increased to over 0.6 in. of water up to about 4100 h. There was an outage at the plant, and aggressive pulsing of the reactor was conducted; the pressure drop was brought back down to 0.3 but rapidly increased to over 0.5 in. of water within 500 h.

3.1.3. Testing at Coyote

The same reactor that was installed at the Baldwin Station was moved and installed at the Coyote Station. In addition, the same Haldor Topsoe catalyst was used in the reactor. The cleaning cycles, temperatures, and gas flow rates are listed in **Table 6**. The reactor was operated for a 6-month period of time. **Figs. 11 and 12** show the test periods from 0 to 2 months and 2 to 4 months. As this paper is being prepared, the reactor is still operating on-site. The pressure drop across the catalyst upon installation was about 0.4 in. of water. After only 750 h, the pressure drop was 1.5 in. of water, indicating significant plugging. Very aggressive air pulsing was conducted, with little success in removing the deposits. The pressure drop for the catalyst was over two times greater than the pressure drop observed for the Baldwin Station utilizing the same reactor and same catalyst. At about 1700 h, the reactor was cleaned, and a section of catalyst was removed for characterization. The pressure drop after cleaning was about 0.8 to 1.0 in. of water. The pressure drop did not increase as rapidly because of the higher velocities through the clean section of the catalyst.

3.1.4. Visual observations of deposit characteristics

The tops of the catalysts were photographed during inspection and sampling of the catalyst sections. **Fig. 13** shows the ash materials that accumulated on the catalyst inlet after 2 months of operation. The most significant accumulation was noted for the Coyote

Table 8
Chemical composition of selected points and areas in Fig. 16

Element (wt.%)					
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5
Na_2O	1.7	2.3	0.0	0.3	1.0
MgO	5.9	3.0	1.2	1.8	3.8
Al_2O_3	3.7	2.5	3.3	5.7	6.3
SiO_2	9.7	31.5	13.3	70.0	18.5
P_2O_5	3.1	2.7	0.8	0.0	2.6
SO_3	48.1	31.0	35.8	0.0	32.1
K_2O	0.5	0.7	0.0	1.5	0.0
CaO	22.0	8.8	38.0	13.9	14.7
TiO_2	1.8	10.8	4.1	1.6	15.1
Fe_2O_3	2.1	6.6	3.4	4.2	5.9
BaO	1.4	0.0	0.0	0.9	0.0
Total	100	100	100	100	100

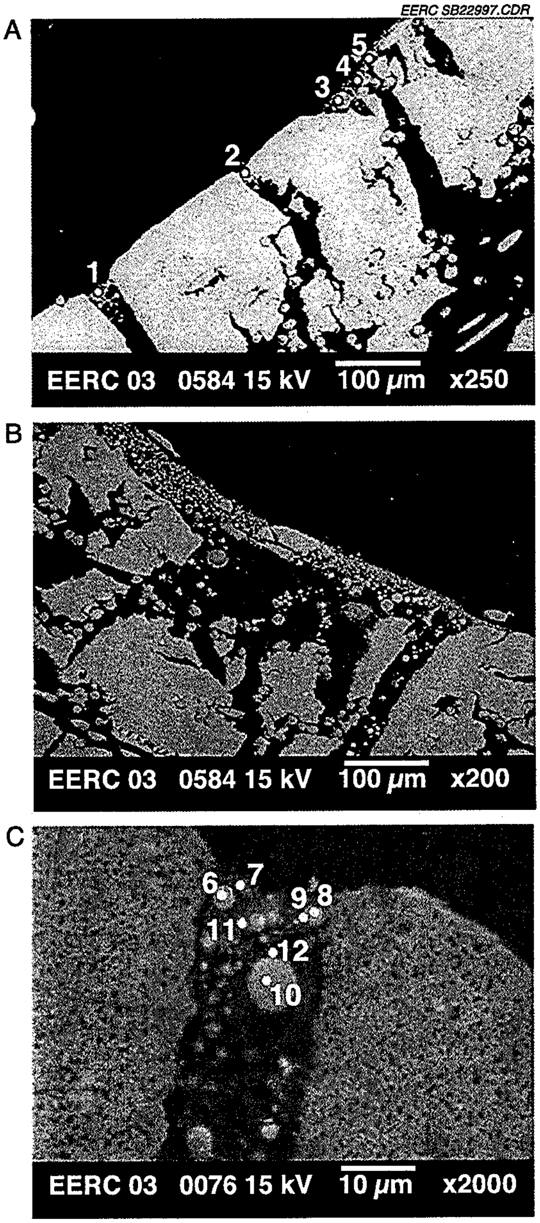


Fig. 17. SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure. (A and B) Low-magnification images of ash deposit on catalyst surface and (C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

Station, followed by Columbia and Baldwin. The Coyote Station had some larger pieces of ash deposit material on the surface as well as plugging of the catalyst passages. The Baldwin Station showed some obvious deposition along the walls of the reactor and some accumulation on the inlet sections. The Columbia Station showed more significant accumulation and plugging than the Baldwin Station.

After 4 months, the tops of the catalysts were photographed during inspection and sampling of the catalyst sections, as shown in Fig. 14. The most significant accumulation was noted for the Coyote Station and some accumulation for the Baldwin Station.

3.2. Deposit characteristics

The characteristics of the ash materials that collected on the catalyst surfaces and pores were characterized by SEM and X-ray microanalysis and, in selected cases, XRD was used to determine the crystalline phases present. The catalysts were sampled after 2, 4, and 6 months. The sections were sampled, and approximately 2.5-cm squares were mounted for SEM analysis on double-stick tape and in epoxy resin. The double-stick tape samples allowed for characterization of the external morphology of the particles and catalyst surface. The samples mounted in resin were cross-sectioned and polished, which allowed for more detailed and quantitative analysis of the bonding materials and materials that accumulated in the pores of the catalyst.

3.2.1. Plugging deposit characteristics

3.2.1.1. Baldwin Station deposits. Samples of catalyst were removed from the Baldwin Station after exposure to flue gases and particulate after 2, 4, and 6 months. Fig. 15 shows the characteristics of the ash deposit material on the SCR catalyst after 2 months of exposure. This is a polished cross section of a deposit on the surface of the catalyst. Fig. 15A shows particles on the surface of the catalyst that range in size from <1 to 15 μm. The larger particles range from oxides of solely silicon and iron to complex mixtures rich in

Table 9
Chemical composition of selected points and areas in Fig. 17

Element (wt.%)												
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
Na_2O	0.6	1.0	2.1	0.3	0.5	2.7	1.7	0.4	0.5	2.2	1.3	1.7
MgO	4.3	2.5	6.3	0.7	1.6	7.6	4.5	6.4	5.9	5.0	3.4	6.4
Al_2O_3	14.8	16.0	15.6	15.5	14.7	0.9	5.0	2.4	3.0	19.2	10.8	3.8
SiO_2	3.3	7.8	18.8	57.7	7.7	47.3	8.4	18.4	18.5	31.0	17.9	16.7
P_2O_5	2.3	2.1	0.5	0.6	1.8	0.0	1.8	0.9	1.0	0.0	1.7	1.2
SO_3	30.7	20.4	17.7	0.0	29.0	0.8	37.9	1.7	5.3	0.0	22.5	13.9
K_2O	0.7	0.0	1.0	0.4	0.9	0.9	0.4	0.0	0.0	0.9	0.8	0.0
CaO	28.8	28.7	28.1	22.5	34.9	28.4	31.4	52.6	49.0	28.9	30.6	45.4
TiO_2	2.0	7.2	2.2	0.3	1.3	1.1	1.9	6.9	7.4	2.4	2.0	1.1
Fe_2O_3	11.4	12.9	6.2	0.0	7.6	7.9	7.1	5.7	6.0	6.3	6.1	6.5
BaO	1.1	1.4	1.4	2.0	0.0	2.5	0.0	4.6	3.5	4.2	2.9	3.3
Total	100	100	100	100	100	100	100	100	100	100	100	100

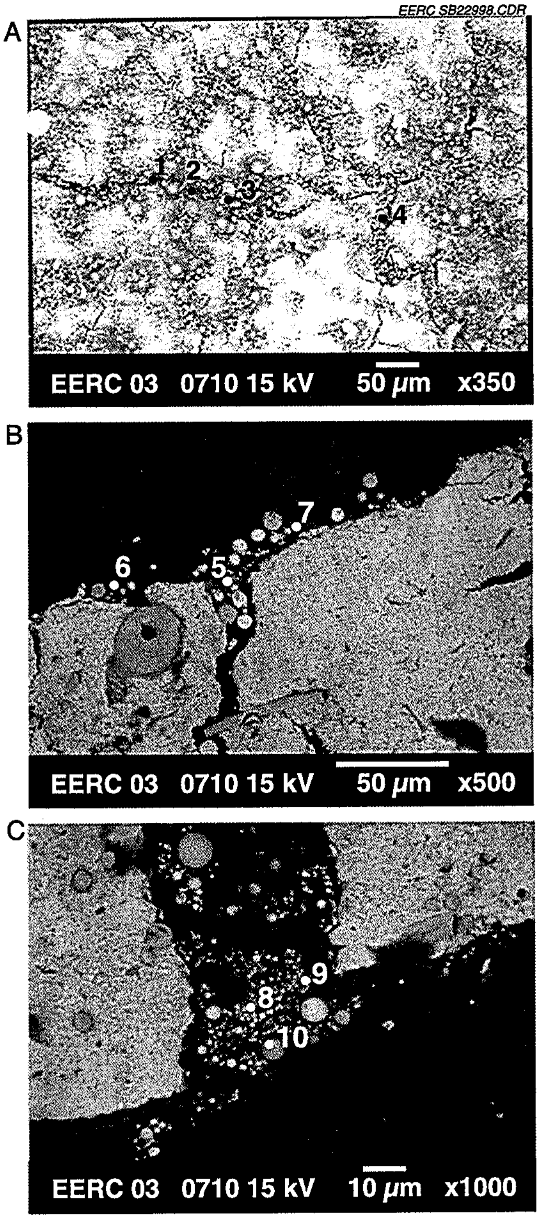


Fig. 18. SEM images of ash collected on catalyst surface at the Columbia Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

aluminum and calcium; aluminum, silicon, and calcium; aluminum, calcium, and iron; and sodium, calcium, aluminum, and silicon. Chemical analysis of selected particles is summarized in Table 7. The samples of ash mounted on double-stick tape allow for the characterization of the external surfaces of the particles. The surface of a typical particle that is accumulating on the surface of the catalyst is shown in **Fig. 15B**. The blebs on the surface are composed of calcium and sulfur, with some iron and minor amounts of sodium and potassium. **Fig. 15C** shows a cross section of the deposited particles showing calcium- and aluminum-rich particles bonded together with a calcium- and sulfur-rich phase. This phase is in the form of calcium sulfate based on XRD analysis conducted on the deposited ash samples.

The 4-month sample from the Baldwin Station showed more extensive sulfation of the alkaline-earth elements present in the deposits. **Fig. 16** shows the images of a polished cross section of an ash deposit on the surface of the catalyst. The deposit formed both on the surface of the catalyst and within the catalyst pores as shown in **Fig. 16A**. **Fig. 16B** shows a higher magnification view of the deposit on the catalyst surface. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical composition of selected points shown in **Table 8** shows high levels of calcium and sulfur. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample.

The 6-month sample from the Baldwin Station showed extensive sulfation of the alkaline-earth elements present in the deposits. **Fig. 17A and B** shows regions of the catalyst where all the pores were blocked and a minimal amount of deposit on the surface of the catalyst. **Fig. 17C** shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical compositions of selected points that indicate the presence of high levels of calcium and sulfur are listed in **Table 9**. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample. In addition, there are some regions of high levels of calcium, aluminum, and sulfur present. The calcium aluminum materials are likely derived from the calcium aluminum phosphate minerals found in the coal fired at this plant.

Table 10
Chemical composition of selected points and areas in Fig. 18

Element (wt.%)										
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10
Na_2O	0.0	0.9	1.3	0.1	0.3	0.0	0.6	1.0	0.5	1.8
MgO	0.7	1.5	3.2	3.9	0.9	0.0	1.5	2.9	1.4	0.7
Al_2O_3	12.2	17.6	20.9	12.2	5.9	5.5	12.4	13.6	9.0	20.7
SiO_2	10.8	4.1	23.3	7.3	6.3	9.4	6.1	15.4	7.9	61.8
P_2O_5	0.9	0.1	0.0	1.4	2.6	1.2	0.6	1.7	3.1	0.2
SO_3	15.2	17.6	16.8	17.1	32.3	33.3	22.0	19.5	30.7	0.0
K_2O	0.2	0.0	0.5	0.0	0.1	0.0	0.0	0.1	0.2	2.5
CaO	14.1	43.1	25.0	42.0	34.9	44.1	48.5	34.1	38.3	4.4
TiO_2	44.8	2.8	1.1	10.5	5.2	0.5	4.4	2.4	2.6	2.2
Fe_2O_3	1.1	12.3	3.9	5.5	11.5	3.1	2.3	6.0	6.3	4.4
BaO	0.0	0.0	4.2	0.0	0.0	2.8	1.6	3.3	0.0	1.3
Total	100	100	100	100	100	100	100	100	100	100

3.2.1.2. Columbia Station deposits. The 2-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst, as shown in Fig. 18. Fig. 18A shows the external morphology of the catalyst surface showing

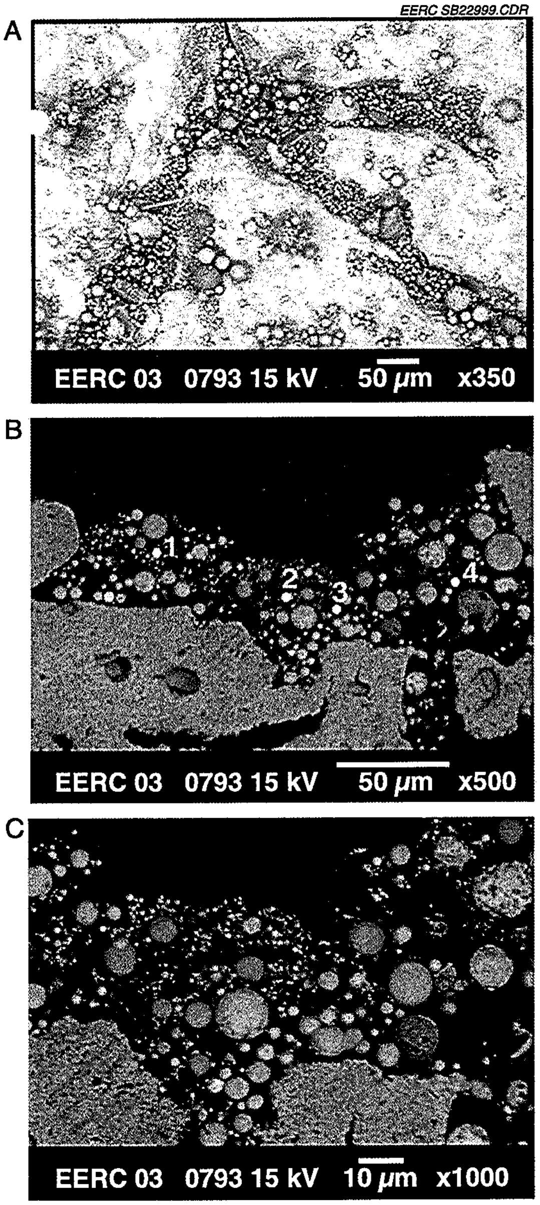


Fig. 19. SEM images of ash collected on catalyst surface at the Columbia Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in **Table 10**. The 2-month sample shows significant evidence of sulfation after only 2 months of exposure. It appears to be more significant than that observed for the Baldwin 2-month sample. **Fig. 18B** and C shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate.

The 4-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst, as shown in **Fig. 19**. **Fig. 19A** shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in **Table 11**. It appears to be more significant than that observed for the Baldwin 2-month sample. **Fig. 19B** and C shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate.

The 6-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst as shown in **Fig. 20**. **Fig. 20A** shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in **Table 12**. **Fig. 20B** and C shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The 6-month samples show the most extensive degree of sulfation of the Columbia Station samples.

3.2.1.3. Coyote Station deposits. The 2-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst as shown in **Fig. 21**. **Fig. 21A** shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in **Table 13**.

Table 11
Chemical composition of selected points and areas in Fig. 19

Element (wt.%)				
Oxide	Point 1	Point 2	Point 3	Point 4
Na_2O	0.5	0.0	0.6	0.3
MgO	3.3	1.9	3.2	2.4
Al_2O_3	13.1	10.2	13.0	6.3
SiO_2	12.4	8.4	8.4	3.6
P_2O_5	1.3	0.5	2.1	0.6
SO_3	27.7	29.9	32.2	47.4
K_2O	0.2	0.6	0.1	0.8
CaO	32.1	38.1	28.9	33.2
TiO_2	1.0	2.7	1.3	0.0
Fe_2O_3	6.3	6.3	7.6	2.6
BaO	2.0	1.4	2.5	2.6
Total	100	100	100	100

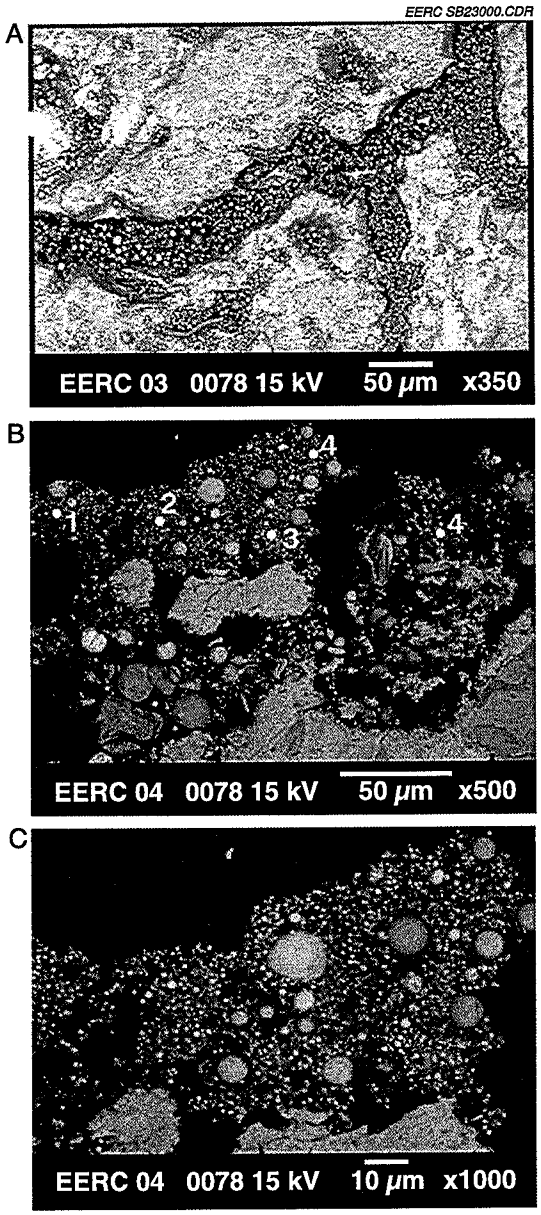


Fig. 20. SEM images of ash collected on catalyst surface at the Columbia Station after 6 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

The 2-month sample shows significant evidence of sulfation after only 2 months of exposure and was much more pronounced than the 2-month samples for the Baldwin and Columbia Stations that are fired on PRB coals. Fig. 21B and C shows a higher

Table 12
Chemical composition of selected points and areas in Fig. 20

Element (wt.%)				
Oxide	Point 1	Point 2	Point 3	Point 4
Na_2O	0.1	0.0	0.3	0.6
MgO	1.8	0.7	1.7	2.2
Al_2O_3	10.9	9.6	6.2	11.3
SiO_2	13.1	11.3	12.4	19.5
P_2O_5	3.9	4.8	0.2	2.1
SO_3	27.6	34.0	35.5	30.0
K_2O	0.5	0.3	0.1	1.2
CaO	33.0	25.9	39.8	25.8
TiO_2	0.8	2.5	1.6	3.3
Fe_2O_3	6.1	9.7	1.9	2.9
BaO	2.1	1.2	0.0	1.1
Total	100.00	100.00	100.00	100.00

magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The presence of sodium enhances the bonding and sulfation of the particles to form a strongly bonded matrix.

The 4-month sample from the Coyote Station showed particles adhering to the surface and completely filling and masking the pores in the catalyst as shown in **Fig. 22**. **Fig. 22A** shows the external morphology of the catalyst surface showing the masking of the catalyst surface. Chemical compositions of selected points are shown in **Table 14**. The 4-month sample shows more sulfation than the 2 months of exposure samples. **Fig. 22B and C** shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of sodium-, calcium-, and sulfur-rich material, likely in the form of calcium sulfate. The presence of sodium and potassium enhances the bonding and sulfation of the particles to form a strongly bonded matrix. Significant sodium was found in the deposits, as shown in **Table 14**.

3.2.2. Deposit formation mechanisms

The mechanism for the formation of deposits that blind SCR catalysts involves the transport of very small particles rich in alkali and alkaline-earth elements, the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. The formation of SO_3 from SO_2 is catalyzed by the SCR; this, in turn, increases the reaction rate of SO_3 to form sulfates. In some cases, the alkali and alkaline-earth elements will also react with CO_2 to form carbonates. XRD analysis shown in **Fig. 23** identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements including sodium, magnesium, calcium, and potassium, in addition to mineral phases. The primary minerals present in these coals include quartz, clay minerals, carbonates, sulfates, sulfides, and phosphorus-containing minerals [18].

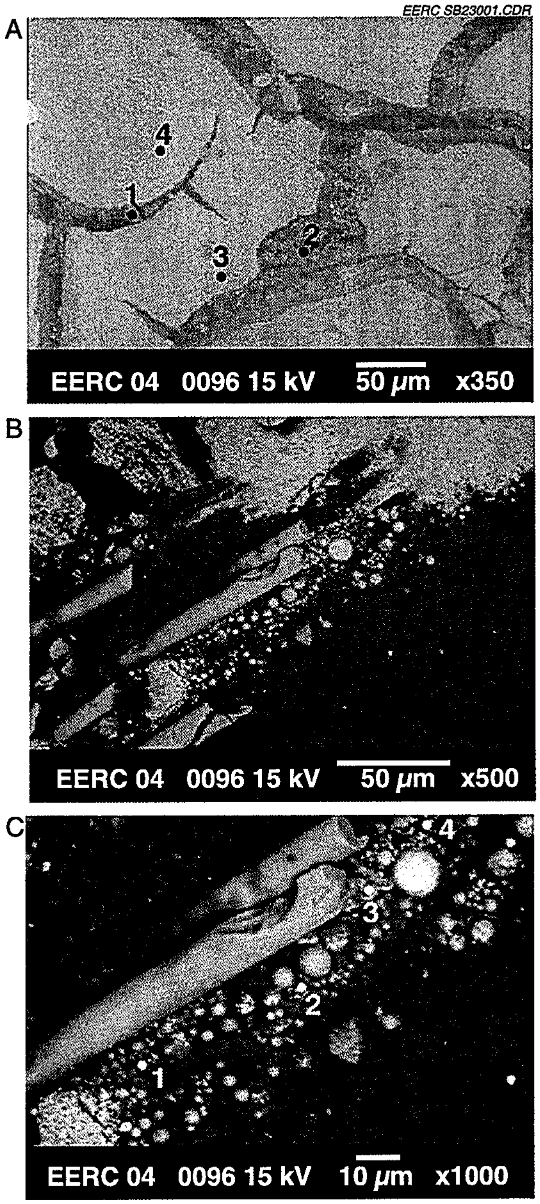


Fig. 21. SEM images of ash collected on catalyst surface at the Coyote Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component, their association in the coal, and combustion system design and operating conditions. There has been

Table 13
Chemical composition of selected points and areas in **Fig. 21**

Oxide	Point 1	Point 2	Point 3	Point 4
Na_2O	0.9	0.7	1.2	1.0
MgO	5.0	1.6	5.6	1.7
Al_2O_3	12.3	5.8	11.9	5.5
SiO_2	24.6	3.1	21.1	2.6
P_2O_5	0.7	0.0	0.5	0.0
SO_3	23.5	44.0	17.4	31.8
K_2O	0.5	0.3	0.8	0.4
CaO	14.9	36.4	19.6	46.9
TiO_2	7.2	1.9	8.0	2.1
Fe_2O_3	9.2	5.5	11.8	6.9
BaO	1.3	0.7	2.1	1.1
Total	100	100	100	100

significant research conducted on ash formation mechanisms and relationships to impacts on power plant performance [18–34]. Typically, during combustion the inorganic components associated with western subbituminous and lignite coal are distributed into various size fractions of ash, as shown in Fig. 24. The results shown in Fig. 24 were obtained from isokinetic sampling and aerodynamically size-fractionating ash particles from a full-scale pulverized-coal-fired boiler firing subbituminous coal and analyzing each size fraction. The results show that the smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. These ash particles are largely derived from the organically associated cations in the coal. The larger size fraction has higher levels of aluminum and silicon derived from the mineral fraction of the ash-forming component of the coal. Entrained ash was extracted from the Columbia Station at the point of the inlet to the SCR reactor and was aerodynamically classified and analyzed. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst, as shown in Fig. 25. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-μm size fraction. The deposited material shows significantly more sulfation than the entrained-ash size fraction, indicating that the sulfation process occurs after the particles are deposited in the catalyst.

The mechanism of SCR catalyst blinding when firing lignite or subbituminous coals is shown in Fig. 26 [35]. The requirements for the formation of deposits that blind SCR catalyst include firing a coal that produces significant levels of <5-μm-sized particles. The particles are transported into the pores of the catalyst and subsequently reacted with SO_3 to form sulfates. The sulfate forms a matrix that bonds other ash particles. The SCR catalyzes the formation of SO_3 and thereby increases the rate of sulfation [9,15]. The sulfation of CaO increases the molar volume, resulting in the filling of the pore. For coals that have high sodium contents, formation of low-melting-point phases such as pyrosulfates are possible [36]. Pyrosulfate materials can melt at temperatures as low as 535 °F in coal-fired power systems.

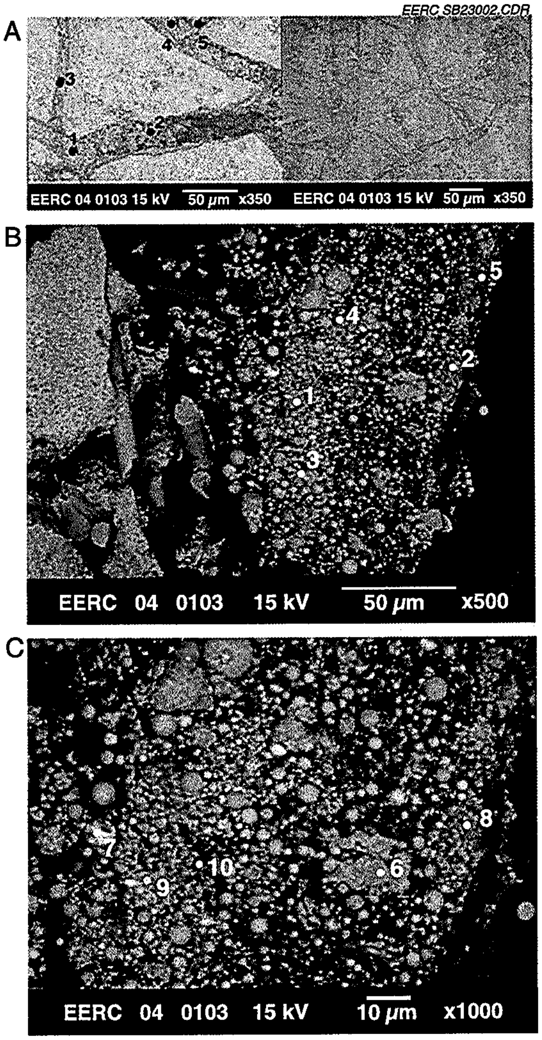


Fig. 22. SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

3.3. Flue gas measurements

3.3.1. Mercury transformations

The ability of mercury to be oxidized across the SCR catalyst was investigated at the Coyote Station. The Coyote Station is fired on North Dakota lignite, and the flue gases are dominated by elemental mercury. Measurement of mercury speciation was conducted using the OH method at the inlet and the outlet of the SCR catalyst. The measurements were made upon installation of the catalyst and after 2 and 4 months of operation. The

Table 14
Chemical composition of selected points and areas in Fig. 22

Element (wt.%)										
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10
Na_2O	6.7	1.9	7.1	6.2	3.1	9.5	2.6	10.4	8.9	4.4
MgO	1.1	1.7	1.1	2.6	3.2	1.2	1.9	1.3	3.0	3.7
Al_2O_3	2.6	8.8	4.0	4.8	10.5	2.6	8.6	4.2	4.9	10.6
SiO_2	7.0	21.1	11.3	5.6	32.2	6.3	18.2	10.5	5.0	28.9
P_2O_5	0.2	2.4	0.0	0.2	0.9	0.1	1.9	0.0	0.1	0.7
SO_3	54.7	38.5	56.4	57.5	30.4	41.8	28.4	44.9	44.5	23.4
K_2O	2.0	2.8	0.7	2.8	2.4	3.2	4.3	1.2	4.4	3.8
CaO	18.0	3.4	15.8	9.3	2.3	24.5	4.4	22.5	12.8	3.1
TiO_2	0.6	0.8	1.1	1.3	1.5	0.6	0.8	1.3	1.5	1.8
Fe_2O_3	5.8	5.1	2.1	6.5	9.8	7.7	6.6	2.9	8.9	13.2
BaO	1.4	13.5	0.5	3.4	3.6	2.4	22.3	0.9	5.9	6.3
Total	100	100	100	100	100	100	100	100	100	100

results of the mercury speciation measurement at the inlet and outlet of the SCR catalyst conducted upon installation are shown in Fig. 27. The inlet and outlet measurements were repeated three times and are shown in Fig. 27. The level of elemental mercury at the inlet was approximately 76% to 92%, with the remaining in the oxidized form ranging from 8% to 24%. Very little was in the form of particulate mercury at the inlet. Measurement of mercury speciation was conducted with the ammonia on and off. The results with the ammonia off showed an increase in the oxidized mercury to 43% of the total mercury occurring across the SCR catalyst. However, when the ammonia was introduced into the

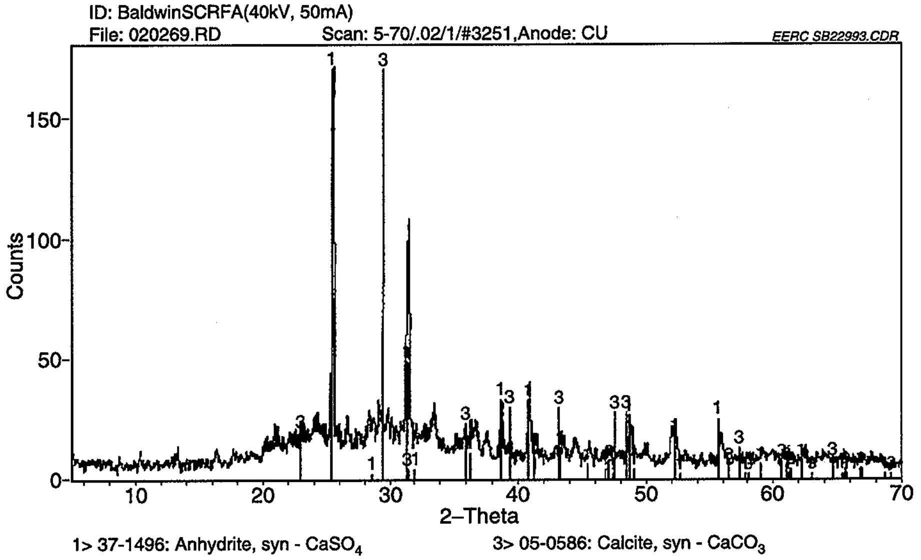
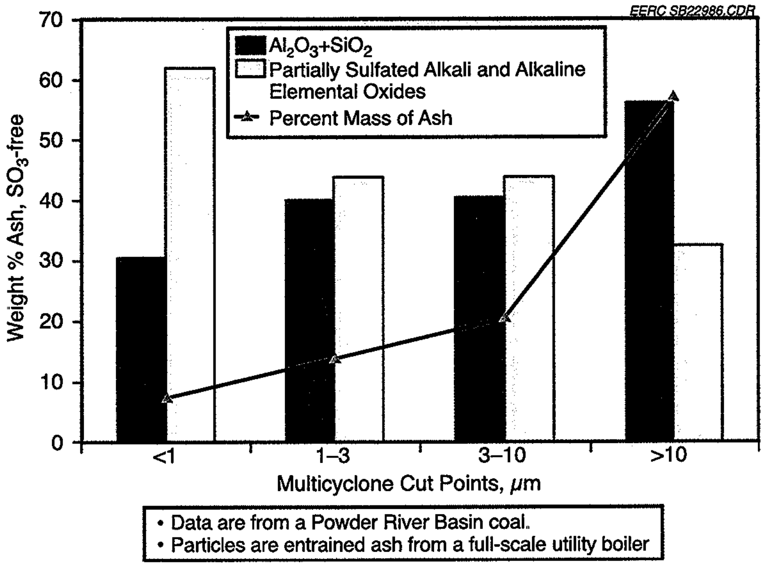


Fig. 23. X-ray diffraction of ash collected on SCR catalyst (1—$CaSO_4$, 2—$Ca_3Mg(SiO_4)_2$, and 3—$CaCO_3$).



- Data are from a Powder River Basin coal.
- Particles are entrained ash from a full-scale utility boiler

Fig. 24. Simplified illustration of ash partitioning in combustion systems [18].

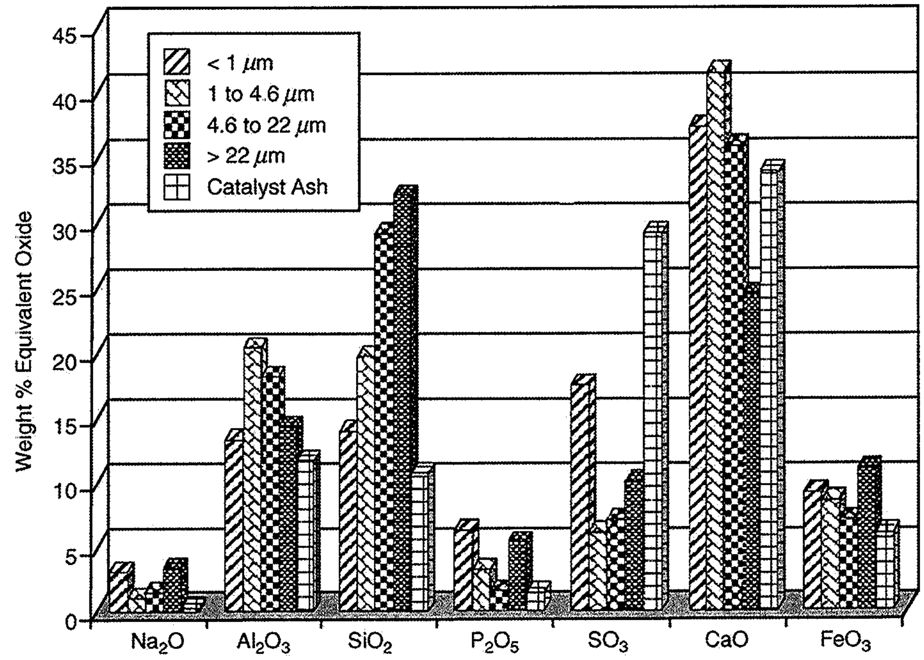


Fig. 25. Comparison of entrained ash and deposited ash on catalyst for Columbia Station.

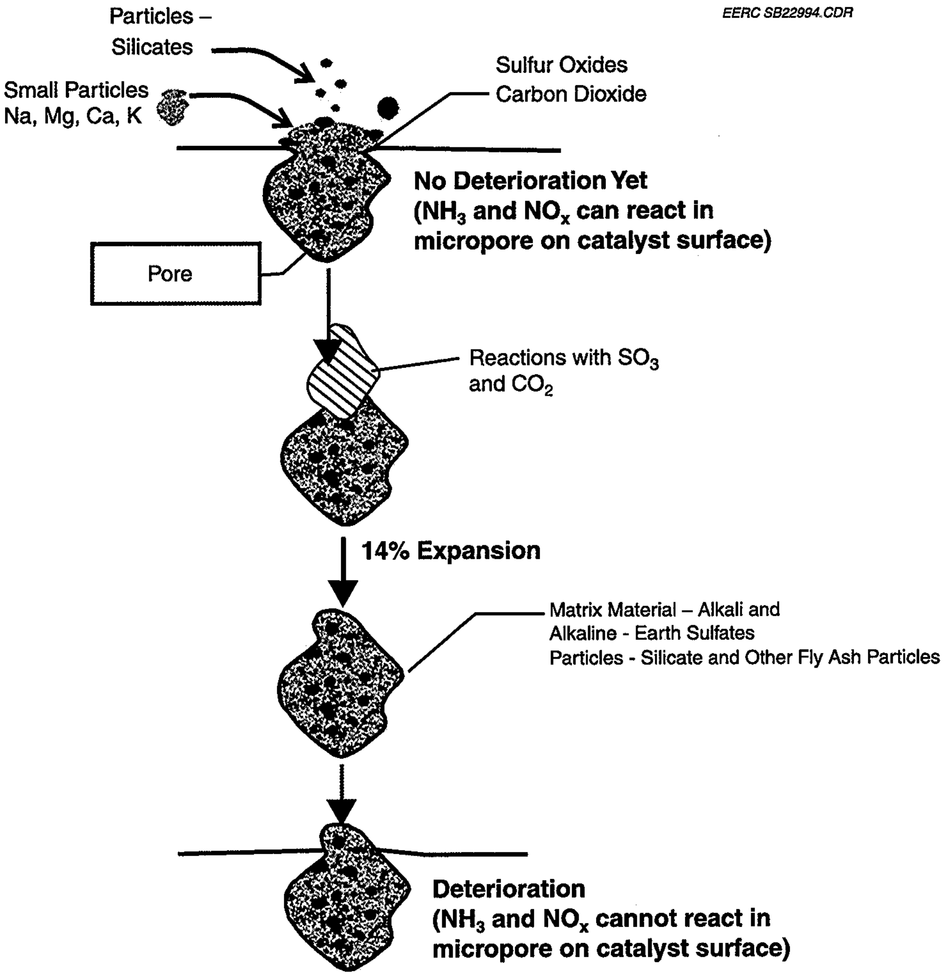


Fig. 26. Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard et al. [35]).

SCR catalyst, the amount of mercury oxidation decreased from 43% to 19%. There was an increase in the particulate mercury from 1.0% to 7.2%.

The mercury oxidation after the SCR catalyst was exposed to flue gas and particulate for 2 months is shown in Fig. 28. The level of oxidized mercury at the inlet ranges from 7.5% to 11.1% of the total mercury. The level of oxidized mercury at the outlet ranged from 7.6% to 14% of the total mercury. The level of particulate mercury increased from a negligible level to 3% of the total mercury at the outlet.

The results of mercury oxidation across the SCR catalyst after 4 months of exposure to flue gases and particulate are shown in Fig. 29. The results show a higher level of oxidized mercury at the inlet as compared to testing conducted at installation and after 2 months. The level of oxidized mercury at the inlet ranges from 32% to 38% of the total,

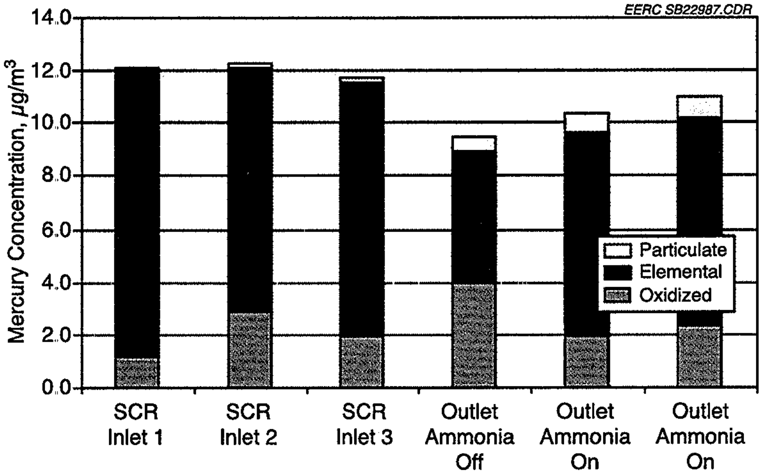


Fig. 27. Mercury speciation measurement at the inlet and outlet of the SCR catalyst upon installation of the catalyst.

with about 5% of the total in the particulate form. The outlet levels of oxidized mercury decrease after passing through the catalyst to about 20% of the total. The level of particulate mercury remained about the same across the catalyst.

4. Conclusions

A slipstream reactor is designed to expose SCR catalyst to coal combustion-derived flue gases and particulate. The system is computer-controlled and operates in an automated

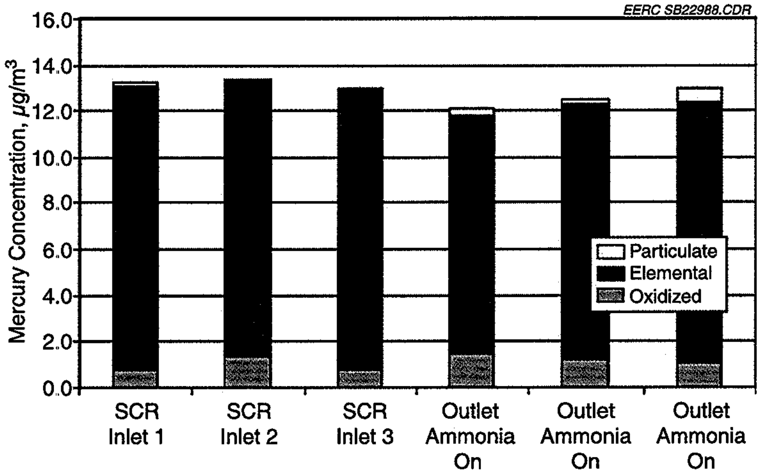


Fig. 28. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gases and particulate for 4 months.

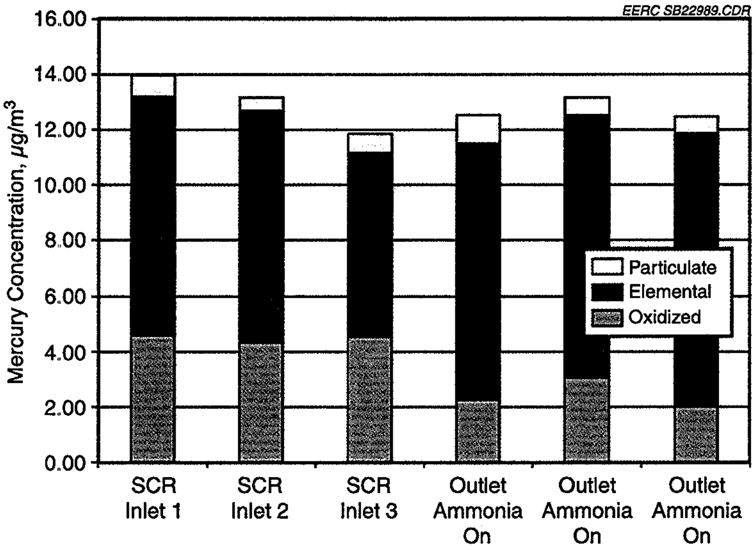


Fig. 29. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gases and particulate for 2 months.

mode. The system can be operated and monitored remotely through a modem connection. SCR catalyst testing was conducted at two subbituminous-fired plants and one lignite-fired plant. The boiler configurations for the subbituminous-fired plants included a cyclone- and a tangentially fired boiler. The boiler configuration for the lignite plant was a cyclone-fired system.

The pressure drop across the catalyst was found to be the most significant for the lignite-fired plant as compared to the subbituminous-fired plants. Both coals had significant accumulations of ash on the catalyst, on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation.

The deposits on the surfaces and within the pores of the catalyst consisted of mainly alkali and alkaline-earth element-rich phases that have been sulfated. The mechanism for the formation of the sulfate materials involves the formation of very small particles rich in alkali and alkaline-earth elements, transport of the particles to the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. XRD analysis identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements, including sodium, magnesium, calcium, and potassium in addition to mineral phases. During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component and their association in the coal and combustion system design and operating conditions. The results of this testing found that the smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-μm size fraction.

The ability of mercury to be oxidized across the SCR catalyst was investigated at the Coyote Station. The Coyote Station is fired on North Dakota lignite, and the flue gases are dominated by elemental mercury. Measurement of mercury speciation was conducted using the OH method at the inlet and the outlet of the SCR catalyst. These results show limited oxidation of mercury across the SCR catalyst when firing lignite coals. The reasons for the lack of mercury oxidation include the following: no or low chlorine present in the coal and flue gas to catalytically enhance the oxidation of Hg^0, high levels of alkali and alkaline-earth elements acting as sorbents for any chlorine present in the flue gas, and low levels of acid gases present in the flue gas.

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Appendix H

EPRI SO_2 Control Support Documentation

Status and Performance of Best Available Control Technologies

Technical Report

Status and Performance of Best Available Control Technologies

1008114

Interim Report, March 2005

EPRI Project Manager
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REPORT SUMMARY

This study is intended to provide a better understanding of the best available control technology (BACT) as required today in permits issued for new coal-fired power plants and to document the actual emissions performance of the emission control technologies on new units. The study focused on controls technologies, data reporting, initial test results, and permitting trends.

Background

EPRI has been working with its members to develop a plan that links near-term, tactically-focused work to the ultimate vision of "The Roadmap for the Electricity Sector." A key element of the plan is the development of Near Zero Emissions (NZE) plants that preserve the coal option. Qualitatively, NZE are defined as emissions virtually equivalent to those from gas-fired power plants except for CO_2.

This investigation is intended to provide a better understanding of best available control technology (BACT) proposed today for emission control as well as the performance of the most recently installed equipment on coal-fired power plants. Due to the time lag between permitting of a new coal-fired power plant and initial operation and emissions performance testing, it was necessary to consider units that have been permitted but not yet started up.

Objectives

- To compare the most recent permitted emissions levels to the actual emissions achieved by the newest plants in the generating fleet
- To provide direction for technology development for near zero emission plants by examining the control capabilities of the most recently installed technologies.

Approach

The project team examined the most recent permits that have been issued. It was necessary to examine permits issued as far back as 1997 in order to find plants that had sufficient operating data to examine with respect to initial operation. The focus of this report is on pulverized coal (PC) boilers and circulating fluidized bed (CFB) boilers in Rankine cycle plants. Integrated gasification combined cycle (IGCC) plants have very different needs because they use species capture devices before the addition of combustion air for both process reasons and because of emission constraints.

Results

Various technologies have been installed for SO_2 and NO_X; however, the fabric filter/baghouse is the overwhelming choice for particulate control. SO_2 control technologies were evenly divided between wet and dry technologies. For NO_X control the CFB units were dominated by selective noncatalytic reduction (SNCR), while the majority of PC units are equipped with low NO_x burners (LNBs) and selective catalytic reduction (SCR). Permitting trends for most emissions suggest an increasing tightening of control, and the initial operating experience shows that most of these units were able to achieve the permit limit. There is increasing interest in fine particulates, though little guidance on measurement methods.

EPRI Perspective

This report provides a distillation of available information on emissions control technologies for coal-fired generating stations. It provides a ready source of information on not only permit limits but also the ability to achieve these limits on start-up. Its summary of trends in permit limitation and rundown of recently installed technologies provide some insights into which technologies are appropriate for consideration when examining the development of NZE power stations.

Keywords

Emissions Control Technologies
SO_2 Control
NO_X Control
BACT

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1

INTRODUCTION

EPRI has been working with its members to develop a Plan that links the near-term, tactically-focused work to the ultimate vision of "The Roadmap for the Electricity Sector". A key element of the plan is the development of Near Zero Emissions (NZE) plants that preserve the coal option. Qualitatively, NZE is defined as being virtually equivalent to emissions from gas-fired power plants, with the exception of CO_2.

The focus is on pulverized coal (PC) boilers and circulating fluidized bed (CFB) boilers in Rankine cycle plants, as integrated gasification combined cycle (IGCC) plants have very different needs because they use species capture devices for both process reasons (before the addition of combustion air) and emission constraints. However, some of the findings and technologies for PC- and CFB-based plants could apply to the final pollution control systems in the stream of devices in IGCC plants. This investigation is intended to provide a better understanding of best available control technology (BACT) proposed today as well as the performance of the most recently installed equipment on coal-fired power plants. Due to the time lag between permitting of a new coal-fired power plant and initial operation and emissions performance testing, it is necessary to consider units which have been permitted but not yet started up.

2

RECENTLY PERMITTED U.S. COAL-FIRED ELECTRIC UTILITY UNITS

The list of units to include in the study was obtained from two sources:

- The RACT/BACT/LAER Clearinghouse (RBLC) database www.epa.gov/ttn/catc
- The National Coal-Fired Utility Projects Spreadsheet http://www.epa.gov/ttn/catc/dir1/natlcoal.xls

For purposes of this study, "recent" permits will be those issued during the calendar year 1997 or thereafter. Advanced queries were run on the RBLC database to find all facilities permitted in 1997 or after and having a Standard Industrial Classification (SIC) code of 4911 "Electric Services". Additionally, the RBLC listed "process" was examined to eliminate any units that were not coal-fired boilers. Added to this basic list were any additional units from the National Coal-Fired Utility Projects Spreadsheet. From this list, all citations for anything other than new coal-fired boilers were eliminated (e.g. modifications to existing boilers were eliminated). Lastly, all units which did not have an issued permit as of February 2005 were eliminated.

To determine the operational status of each unit, the state agency was contacted.

Included Units

Forty-four units at 31 facilities have been identified as meeting the requirements of this study (25 PC units, 19 CFB units). Twelve units are operational and eight of those have been stack tested. Table 2-1 lists the units included in this study. Table 2-2 summarizes each facility and Appendix A describes each facility in detail. Plants that were excluded from the study are listed in Appendix B.

Controls

PC and CFB boilers employ the types of emission control for the various pollutants that are effective for the boiler configuration and operating conditions. Emission controls can be integral to the combustion process or add-on equipment that is installed downstream of the combustion zone. The types of emission control employed for BACT at recently permitted utility boilers are described below. The specific control equipment utilized for each pollutant at each boiler unit identified in Table 2-1 is listed in Tables 2-3 through 2-6.

SO_2

The primary types of SO_2 control for the units in this study are circulating fluidized bed (CFB) combustion, wet flue gas desulfurization, and semi-dry flue gas desulfurization. Flue gas desulfurization (FGD) refers to the treatment of flue gas to remove the SO_2 which has formed during the combustion of fossil fuels. These controls are described in this section, including the prevalence of each type.

In the CFB combustion process, limestone is added to the boiler furnace, resulting in the removal of SO_2 during the combustion process. A grid supports a bed of coal and limestone in the firebox of the CFB boiler. Combustion air is forced upward through the grid, suspending the coal and limestone bed in a fluid-like motion. The sulfur in the coal is oxidized to SO_2 and consequently combines with calcined limestone to form calcium sulfate ($CaSO_4$). The flyash containing the calcium sulfate is collected in the downstream baghouse.

In the wet FGD process, a slurry of finely ground limestone ($CaCO_3$) in water is recirculated through an absorber tower and placed in turbulent contact with the flue gas. The contact between the flue gas and the slurry cools and saturates the gas stream as SO_2 and other acid gasses are absorbed into the slurry droplets. Calcium sulfate (gypsum) and calcium sulfite are formed in the chemical reaction that occurs in the slurry, which is typically dewatered and removed as a solid waste by-product.

Table 2-1
Recently Permitted Coal-Fired Power Plants Included in the Study

Facility	# of Units	Boiler Type	State	Operational Status			
				Permit Issued	Under Construction	Operational	Tested
AES Puerto Rico (Units 1 and 2)	2	CFB	PR	X	Finished	X	X
Corn Belt Energy	1	PC	IL	X	X		
Council Bluffs (Mid America)	1	PC	IA	X	X		
Elm Road Generating Station (WE-Energies) (2 Units)	2	PC	WI	X	X		
Energy Services of Manitowoc	1	CFB	WI	X	X		
EnviroPower IL – Benton (Unit 1 and 2)	2	CFB	IL	X	X		
Hawthorn 5 (KCP&L)	1	PC	MO	X	Finished	X	X
Holcomb Unit #2 (Sand Sage Power, LLC)	1	PC	KS	X			
Indeck-Elwood LLC (Units 1 and 2)	2	CFB	IL	X	X		
Intermountain Power Unit #3	1	PC	UT	X	X		
JEA Northside (1 and 2)	2	CFB	FL	X	Finished	X	X
Kentucky Mountain Power, LLC (EnviroPower), Units 1 and 2	2	CFB	KY	X	X		
Longview Power (GenPower)	1	PC	WV	X			
Plum Point Power Station	1	PC	AR	X	X		
Prairie State (2 units)	2	PC	IL	X			
Red Hills (Choctaw Generation Limited Partnership) Units 1 and 2	2	CFB	MS	X	Finished	X	RATA data only
Rocky Mountain Power (Hardin Generator Project)	1	PC	MT	X			
Roundup (Bull Mountain) (2 units)	2	PC	MT	X			
Santee Cooper/Cross Units 3 and 4	2	PC	SC	X	X		
Sevier Power (Nevco Energy)	1	CFB	UT	X	X		
Seward Reliant Units 1 and 2	2	CFB	PA	X	Finished	X	
Southern Illinois Coop (Marion Generating Station)	1	CFB	IL	X	Finished	X	X
Spurlock (E. KY Power Coop)	1	CFB	KY	X	X		
Thoroughbred (2 units)	2	PC	KY	X			
Toledo Edison Co. Bayshore Plant	1	CFB	OH	X	Finished	X	X
Tucson – Springerville Units 3 and 4	2	PC	AZ	X	X		
Two Elk	1	PC	WY	X			
Whelan Energy Center Unit 2- Hastings	1	PC	NE	X	X		
Wisconsin Public Service - Weston 4	1	PC	WI	X	X		
WYGEN I (Black Hills)	1	PC	WY	X	Finished	X	X
WYGEN II (Black Hills)	1	PC	WY	X			

Table 2-2
Summary of Facilities

Circulating Fluid Bed Plants	**NO_x**	**PM_{10}**	**SO_2**
AES Puerto Rico (2 units)	SNCR	ESP	DFGD, CFB
Energy Services of Manitowoc	SNCR	FF/BH	CFB
EnviroPower IL - Benton (2 units)	SNCR	FF/BH	DFGD, CFB
Indeck-Elwood LLC (2 units)	SNCR	FF/BH	DFGD, CFB
JEA Northside #1 & #2 (2 units)	SNCR	FF/BH	DFGD, CFB
Kentucky Mountain Power, LLC (EnviroPower) (2 units)	SNCR	FF/BH	DFGD, CFB
Red Hills (Choctaw Generation Limited Partnership) (2 units)	CFB	FF/BH	CFB
Sevier Power (Nevco Energy)	SNCR	FF/BH	DFGD, CFB
Seward Reliant (2 units)	SNCR	FF/BH	DFGD, CFB
Southern Illinois Coop (Marion Generating Station)	SNCR	FF/BH	CFB
Spurlock (E. KY Power Coop)	SNCR	FF/BH	DFGD, CFB
Toledo Edison Co. Bayshore Plant	CFB	FF/BH	CFB
Pulverized Coal Plants	**NO_x**	**PM_{10}**	**SO_2**
Corn Belt Energy	SCR, LNB	ESP	WFGD
Council Bluffs (Mid America)	SCR, LNB	FF/BH	DFGD
Elm Road Generating Station (WE-Energies) (2 units)	SCR, LNB	FF/BH	WFGD
Hawthorn 5 (KCP&L)	SCR	FF/BH	DFGD
Holcomb Unit #2 (Sand Sage Power, LLC)	SCR, LNB	FF/BH	DFGD
Intermountain Power Unit #3	SCR, LNB	FF/BH	WFGD
Longview Power (GenPower)	SCR, LNB	FF/BH	WFGD
Plum Point Power Station	SCR, LNB	FF/BH	DFGD
Prairie State (2 units)	SCR, LNB	ESP	WFGD
Rocky Mountain Power (Hardin Generator Project)	SCR	multiclone	WFGD
Roundup (Bull Mountain) (2 units)	SCR, LNB	FF/BH	DFGD
Santee Cooper/Cross #3 & #4 (2 units)	SCR, LNB	ESP	WFGD
Thoroughbred (2 units)	SCR, LNB	ESP, WESP	WFGD
Tucson - Springerville (2 units)	SCR, LNB	FF/BH	DFGD
Two Elk	SCR, LNB	FF/BH	DFGD
Whelan Energy Center Unit 2- Hastings	SCR	FF/BH	DFGD
Wisconsin Public Service - Weston 4	SCR, LNB	FF/BH	DFGD
WYGEN I (Black Hills)	LNB	FF/BH	DFGD
WYGEN II (Black Hills)	SCR, LNB	FF/BH	DFGD

Table 2-3
SO_2 Controls

CFB	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
	Energy Services of Manitowoc	0.30 (non-BACT)	6, 6A or 6C	30 day rolling	
	Red Hills (Choctaw Generation Limited Partnership) (2 units)	0.25		30 day rolling	
	Southern Illinois Coop (Marion Generating Station)	0.6 (non-BACT)	Method 6 or 19	30 day rolling	
	Toledo Edison Co. - Bayshore Plant	0.6 (non-BACT)		30 day rolling	
CFB-DFGD	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	AES Puerto Rico (2 units)	0.042		30 day	
	EnviroPower IL - Benton (2 units)	0.25	6 or 19	30 day rolling	92% control, if emissions are 0.20 lb/MMBtu or greater. 90% control
	Indeck-Elwood LLC (2 units)	0.10 - 0.15	19	30 day rolling	Illinois coal, washed: 3.51 percent sulfur by weight and 9,965 Btu/lb HHV, uncontrolled SO_2 rate: 7.0 lb/MMBtu, washed coal uncontrolled SO_2 rate: 4.7 lb/MMBtu
	JEA Northside #1 & #2 (2 units)	0.15 (non-BACT)		30 day rolling	
	Kentucky Mountain Power, LLC	0.13	401 KAR 50:015	30 day rolling	
	(EnviroPower) (2 units)				
	Sevier Power (Nevco Energy)	0.022	6, 6A, 6B, 6C	30 day rolling	1.0 lb SO_2 /MMBtu
	Seward Reliant (2 units)	0.6 (non-BACT)		30 day rolling	
	Spurlock (E. KY Power Coop)	0.2		30 day rolling	

PC DFGD-	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Council Bluffs (Mid America)	0.1	6C	30 day rolling	0.625 lb SO_2 /MMBtu
	Hawthorn 5 (KCP&L)	0.12		30 day rolling	1.60 lb SO_2 /MMBtu max at scrubber inlet, 92.5% control
	Holcomb Unit #2 (Sand Sage Power, LLC)	0.12	40 CFR 60.48a	30 day rolling	0.60% on an average annual basis
	Plum Point Power Station	0.16	Method 6C	30 day - NSPS, 3 hour rolling	
	Roundup (Bull Mountain) (2 units)	0.12		30 day average, 24 hour rolling	•1.00% sulfur in coal,9232 Btu/lb, uncontrolled: 2.17 S lb/MMBtu, 94.5% control while burning 1.0% sulfur coal. 90% for 30 day rolling
	Tucson - Springerville (2 units)	0.6 (non-BACT)		30 day rolling	
	Two Elk	0.132	6C	30 day rolling	70% minimum removal efficiency (30 day rolling)
	Whelan Energy Center Unit 2- Hastings	0.12	19	30 day rolling	
	Wisconsin Public Service - Weston 4	0.1	6, 6A or 6C	30 day rolling	1.23 lb S/MMBtu 30 day average
	WYGEN I (Black Hills)	0.17	6	30 day rolling average	
	WYGEN II (Black Hills)	0.10	6C	30 day rolling	70% minimum removal efficiency (30 day rolling)
PC - WFGD	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Corn Belt Energy	0.10 - 0.15	Method 6 or 19	30 day rolling average	3.25%, 6.2 lb S/MMBtu uncontrolled
	Elm Road Generating Station (WE-	0.15	Method 6, 6A or 6C	30 day rolling average	
	Energies) (2 units)				
	Intermountain Power Unit #3	0.09	Method 6, 6A, 6B, 6C	30 day rolling average	
	Longview Power (GenPower)	0.08	30 day rolling average		

	Prairie State (2 units)	0.182	30 day rolling	4% sulfur in raw coal	
	Rocky Mountain Power (Hardin Generator	0.14	30 day rolling average		
	Project)				
	Santee Cooper/Cross #3 & #4 (2 units)	0.6	Method 6 or 6C	30 day rolling average	70% removal efficiency (30-day rolling avg.)
	Thoroughbred (2 units)	0.167		30 day rolling average	

* Secondary averaging period

CFB - circulating fluidized bed boiler

DFGD - semi-dry flue gas desulfurization (either fluidized bed dry scrubber or spray dryer absorber)

PC - pulverized coal boiler

WFGD - wet flue gas desulfurization

Table 2-4
NO$_x$ Controls

CFB	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Red Hills (Choctaw Generation Limited Partnership) (2 units)	0.2 (non-BACT)		30 day rolling	
	Toledo Edison Co. - Bayshore Plant	0.2 (non-BACT)		30 day rolling	
SNCR	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	AES Puerto Rico (2 units)	0.19		30 day	Calculated lb/MMBtu = 2058 tpy x 2000 lb/ton x yr/8760 hr x hr/2461.35 MMBtu
	Energy Services of Manitowoc	0.155 (non-BACT)	7	30 day rolling	In the first month of operation, the average monthly NOx emissions may not exceed the limit of 0.155 pound per million Btu the limit of 0.155 pound per million Btu heat input. After the second month, the average NOx emissions shall be determined to be the total NOx emissions for the last two mo
	EnviroPower IL - Benton (2 units)	0.125 - 0.07	7, 7E or 19	30 day rolling	Evaluation to 0.07 lb/MMBtu
	Indeck-Elwood LLC (2 units)	0.10 (optimization study to 0.08)	19	30 day rolling	
	JEA Northside #1 & #2 (2 units)	0.09	30 day rolling		
	Kentucky Mountain Power, LLC (EnviroPower) (2 units)	0.07	401 KAR 50:015	30 day rolling	The NOX emission limit of 0.07 lbs/MMBTU is waived for the specific SNCR optimization study activity
	Sevier Power (Nevco Energy)	0.1	7, 7A, 7B, 7C, 7D, 7E	30 day rolling	NOx limit listed as 24 hr rolling average, but calculates out to the same limit as a 30 day average (Calculated lb/MMBtu =1066.6 tpy x 2000 lb/ton x yr/8760 hr x hr/2532 MMBtu)
	Seward Reliant (2 units)	0.15		30 day rolling	
	Southern Illinois Coop (Marion Generating Station)	0.2 (non-BACT)	7, 7E or 19	30 day rolling	
	Spurlock (E. KY Power Coop)	0.07		30 day rolling	SNCR optimization study

PC - LNB	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	WYGEN I (Black Hills)	0.17 (non-Bact)	40 CFR 60.48a	30 day rolling average	Calculated from limit of 1.6 lb/MWhr (168 lb/hr / 1,014 MMBtu/hr)
PC - SCR	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Hawthorn 5 (KCP&L)	0.08		30 day rolling	evaluation period: NOx limited to 0.12 lbs/MMBtu on a 30-day rolling
	Rocky Mountain Power (Hardin Generator Project)	0.09		30 day rolling	
	Whelan Energy Center Unit 2- Hastings	0.08		30 day rolling	During the first 18 months following initial startup (demonstration period), the Unit 2 Boiler shall not emit NOx exceeding 0.12 lb/MMBtu on a 30-day rolling average instead of 0.08 lb/MMBtu as listed in Table 4
PC –SCR, LNB	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Corn Belt Energy	0.10	7, 7E, or 19	30 day rolling	2 year demonstration period; determine if lower NOx limit (as low as 0.07) may be reliably achieved, 0.12 demonstration / 0.10 or lower at conclusion of demonstration period
	Council Bluffs (Mid America)	0.07	7E	30 day rolling	
	Elm Road Generating Station (WE-Energies) (2 units)	0.07	7	30 day rolling	
	Holcomb Unit #2 (Sand Sage Power, LLC)	0.08	40 CFR 60.48a	30 day rolling	During the first 18 months following initial startup, the unit shall not emit or cause to be emitted any NOx emissions exceeding average, excluding periods of startup, shutdown, and malfunction, in lieu of the 0.08 lb/MMB
	Intermountain Power Unit #3	0.07	7, 7A, 7B, 7C, 7D, 7E	30 day rolling	
	Longview Power (GenPower)	0.08		30 day rolling	NOx limit listed as 24 hr rolling, assumed the same for 30 day rolling
	Plum Point Power Station	0.09	7E	30 day - NSPS, 24 hour rolling	
	Prairie State (2 units)	0.07		30 day rolling	
	Roundup (Bull Mountain) (2 units)	0.07		30 day average, 24 hour rolling	

	Santee Cooper/Cross #3 & #4 (2 units)	0.185	7 or 7E	30 day rolling	
	Thoroughbred (2 units)	0.08		30 day rolling	
	Tucson - Springerville (2 units)	0.15 (non- BACT)	7E	30 day rolling	Calc from NSPS value - Calculated lb/MMBtu = 1.6 lb/MW-hr * 400 MW =640 lb/hr / 4,200 MMBtu/hr = 0.15 lb/MMBtu
	Two Elk	0.09		30 day rolling	
	Wisconsin Public Service - Weston 4	0.07	Method 7, 7E	30 day rolling	
	WYGEN II (Black Hills)	0.07	40 CFR 60.48a	30 day rolling	

* Secondary averaging period

CFB - circulating fluidized bed boiler

LNB - low NOx burner

OFA - over-fire air

PC - pulverized coal boiler

SCR - selective catalytic reduction

SNCR - selective non-catalytic reduction

Table 2-5
PM_{10} Controls

CFB - ESP	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
	AES Puerto Rico (2 units)	0.03 (f/c)	201, 201A, 202		

CFB FF/BH	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
	Energy Services of Manitowoc	0.03 (f/c) (non-BACT)	5, 202		
	EnviroPower IL - Benton (2 units)	0.015 (f)	5, or 201, or 201A or 19		
	Indeck-Elwood LLC (2 units)	0.015 (f/c)	5, 201 or 201A, 202	3 hour block	
	JEA Northside #1 & #2 (2 units)	0.011 (f)	201 or 201A	3 hour	
	Kentucky Mountain Power, LLC (EnviroPower) (2 units)	0.015	401 KAR 50:015	3 hour	
	Red Hills (Choctaw Generation Limited Partnership) (2 units)	0.015 (f)	5		
	Sevier Power (Nevco Energy)	0.0154 (f/c)	201, 201A, 202	24 hour rolling	
	Seward Reliant (2 units)	0.01			
	Southern Illinois Coop (Marion Generating Station)	0.011 (f) (non-BACT)	5,or 201, or 201A, or 19		
	Spurlock (E. KY Power Coop)	0.015 (f)	5	3 hour rolling	
	Toledo Edison Co. - Bayshore Plant	0.025 (non-BACT)			

PC - ESP	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Corn Belt Energy	0.02 (f)	5, or 201, or 201A, with 19; 202	3 hour block	
	Prairie State (2 units)	0.035	202 (adapted to prevent bias)	3 hr block	
	Santee Cooper/Cross #3 & #4 (2 units)	0.018 (f/c)	201, 202		

PC – ESP, WESP	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Thoroughbred (2 units)	0.018 (f/c)	5, 9, 201 or 201A, 202	3 hour rolling	

PC – FF/BH	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Council Bluffs (Mid America)	0.025 (f/c)	201A, 202	3 hour rolling	
	Elm Road Generating Station (WE-Energies) (2 units)	0.018 (f/c)	5, 202	3 hour rolling	
	Hawthorn 5 (KCP&L)	0.018 (f/c)	201A, 202		
	Holcomb Unit #2 (Sand Sage Power, LLC)	0.018 (f/c)	40 CFR 60.48a		
	Intermountain Power Unit #3	0.012 (f)	201, 201A, 202	3 hour rolling	
	Longview Power (GenPower)	0.018 (f/c)	201 or 201A , 202	6 hour rolling	
	Plum Point Power Station	0.018 (f/c)	201A, 202		
	Roundup (Bull Mountain) (2 units)	0.015	optimization to 0.012		
	Tucson - Springerville (2 units)	0.055 (f/c)	5, 9, 201 or 201A, and 202	3 hour rolling	
	Two Elk	0.018 (f)			
	Whelan Energy Center Unit 2- Hastings	0.018		3 hour	
	Wisconsin Public Service - Weston 4	0.018 (f/c)	5 or 5B plus 202 or (201A and 202) or CTM039	3 hour rolling	
	WYGEN I (Black Hills)	0.02 (f)	Method 5		

	WYGEN II (Black Hills)	0.012 (f)	40 CFR 60.48a		

Multiclone	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Rocky Mountain Power (Hardin Generator Project)	0.015			

BH - Bag house
CFB - Circulating fluidized bed boiler
ESP - Electrostatic precipitator
(f) - Filterable
(f/c) - Filterable and Condensable
FF - Fabric Filter
PC - Pulverized coal boiler
WESP - Wet electrostatic precipitator

Table 2-6
VOC and CO Controls

All units are controlled by good combustion practices

CO	Plant Name	Limit lb/MBtu	Test Method	Averaging Time	Notes
CFB	EnviroPower IL - Benton (2 units)	0.27	10	30 day rolling	
	Kentucky Mountain Power, LLC (EnviroPower) (2 units)	0.27		30 day rolling	
	Red Hills (Choctaw Generation Limited Partnership) (2 units)	0.2			
	Sevier Power (Nevco Energy)	0.115	10	1 hour	
	Seward Reliant (2 units)	0.15			
	Southern Illinois Coop (Marion Generating Station)	0.15	10	3 hour rolling	
	Spurlock (E. KY Power Coop)	0.15		30 day rolling	
	Toledo Edison Co. - Bayshore Plant	0.13			
	JEA Northside #1 & #2 (2 units)	0.127		24 hour rolling	350 lb/hr / 2,764 MMBtu/hr = 0.127 lb/MMBtu
	Energy Services of Manitowoc	0.15	10	24 hour rolling	BACT
	Indeck-Elwood LLC (2 units)	0.11	10	24 hour rolling	Emission testing shall be conducted for purposes of certification of the continuous emission monitors required by Condition1.9. Thereafter, the NOx, SO2 and CO emission data from certified monitors may be provided in lieu of conducting emissions tests.
	AES Puerto Rico (2 units)	0.1	10	8 hour basis	Emissions of CO shall not exceed 0.10 lb/MMBTU on an eight-hour average basis, 94 ppmdv corrected to 7% oxygen, or 246.1 lb/hour, whichever is more stringent.
CO	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
PC	Prairie State (2 units)	0.12		24 hr block	
	Corn Belt Energy	0.2	10	30 day rolling	
	Council Bluffs (Mid America)	0.154	10	24 hour rolling	

	Hawthorn 5 (KCP&L)	0.16	10		
	Holcomb Unit #2 (Sand Sage Power, LLC)	0.15			
	Intermountain Power Unit #3	0.15	10	30 day rolling	
	Longview Power (GenPower)	0.11	10B	3 hour rolling	
	Plum Point Power Station	0.16	10		
	Rocky Mountain Power (Hardin Generator Project)	0.15			
	Santee Cooper/Cross #3 & #4 (2 units)	0.16	10		
	Thoroughbred (2 units)	0.1		30 day rolling	
	Tucson - Springerville (2 units)	0.15		30 day rolling	
	Two Elk	0.135	10		
	Whelan Energy Center Unit 2- Hastings	0.15	10	3 hour rolling	
	WYGEN I (Black Hills)	0.15	10		
	WYGEN II (Black Hills)	0.15	10		
	Roundup (Bull Mountain) (2 units)	0.15			Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the CO emissions from the two main boilers does not exceed 4,910.4 tons during any rolling 12-month
	Elm Road Generating Station (WE-Energies) (2 units)	0.12	10	24 hour rolling	
	Wisconsin Public Service - Weston 4	0.15	10, 10B	1 day	

VOC CFB	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Energy Services of Manitowoc	0.013	25A and/or 18		
	Kentucky Mountain Power, LLC (EnviroPower) (2 units)	0.0072			
	Red Hills (Choctaw Generation Limited Partnership) (2 Units)	0.0058			
	Seward Reliant (2 units)	0.005			
	Spurlock (E. KY Power Coop)	0.0036	25A	30 day rolling	

	JEA Northside #1 & #2 (2 units)	0.005	18, 25, or 25A	3 hour rolling	14 lb/hr / 2,764 MMBtu/hr = 0.005 lb/MMBtu
	AES Puerto Rico (2 units)	0.0047	25A and 18		Emissions of VOCs shall not exceed based on the average of three 1-hour stack performance tests 7.70 ppmdv corrected to 7% oxygen, 0.0047 lb/MMBTU, or 11.6 lb/hour, whichever is more stringent.
	Southern Illinois Coop (Marion Generating Station)	0.01 (non-BACT)	18, 25, or 25A		Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for any such compounds is included in the test plan approved by the Illinois EPA.
	EnviroPower IL - Benton (2 units)	0.007	Method 18, 25, or 25A		Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for any such compounds is included in the test plan approved by the Illinois EPA.
	Indeck-Elwood LLC (2 units)	0.004	18 or 25A	3 hour rolling	Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for any such compounds is included in the test plan approved by the Illinois EPA.

VOC PC	**Plant Name**	**Limit lb/MBtu**	**Test Method**	**Averaging Time**	**Notes**
	Prairie State (2 units)	0.004	3 hr block		
	Corn Belt Energy	0.0065	Method 18 or 25A		
	Council Bluffs (Mid America)	0.0036	Method 25A		
	Elm Road Generating Station (WE-Energies) (2 units)	0.0035	25A and/or 18	24 hour rolling	
	Hawthorn 5 (KCP&L)	0.0036	25		
	Holcomb Unit #2 (Sand Sage Power, LLC)	0.0035			
	Intermountain Power Unit #3	0.0027	25 or 25A		
	Longview Power (GenPower)	0.004	18	3 hour rolling	
	Plum Point Power Station	0.02	25A and/or 18		
	Rocky Mountain Power (Hardin Generator Project)	0.0034			
	Santee Cooper/Cross #3 & #4 (2 units)	0.0024	18, 25 or 25A		

	Thoroughbred (2 units)	0.0072	18 or 25	30 day rolling	
	Two Elk	0.0135	18 and 25		
	Whelan Energy Center Unit 2- Hastings	0.004	25		
	Wisconsin Public Service - Weston 4	0.0036	25A and/or 18	1 day	
	WYGEN I (Black Hills)	0.015	18		
	WYGEN II (Black Hills)	0.01	18 and 25		
	Tucson - Springerville (2 units)	0.06 lb/ton	18 or 25	3 hour rolling	coal
	Roundup (Bull Mountain) (2 units)	0.003			Roundup Power shall limit the hours of operation, the capacity, the emission rate, and/or the fuel consumption of the two main boilers such that the sum of the VOC emissions from the two main boilers does not exceed 98.2 tons during any rolling 12-month t

CFB - circulating fluidized boiler

PC - pulverized coal boiler

In the semi-dry FGD process, boiler flue gas is taken from a point downstream of the air heater and introduced into a reactor vessel into which hydrated lime (calcium hydroxide, $Ca(OH)_2$) and water are added. The calcium hydroxide reacts with SO_2 that has been absorbed into the water to form calcium sulfite and calcium sulfate. The heat from the flue gas causes the water to evaporate, cooling the gas and drying the reaction products. The amount of water added to the process is carefully controlled so that the flue gas temperature is maintained safely above the saturation, or dew point, temperature. The reaction product leaves the reactor as fine particles entrained in the flue gas and is collected in the particulate control equipment (usually a baghouse) located downstream of the FGD equipment.

There are two main variants of the semi-dry FGD process: lime spray drying and fluidized bed (or circulating) dry scrubbing. They are differentiated by the type of reactor vessel used and the method in which water and lime are introduced into the reactor. In the lime spray drying process, quicklime (CaO) is slaked with water to form a slurry of calcium hydroxide. The lime slurry is mixed with additional water and sprayed into the reactor as finely atomized droplets. The turbulent mixing of the flue gas and the droplets of slurry promote rapid absorption of SO_2 into the water of the slurry droplets. The flue gas is cooled and humidified as the water evaporates from the droplets, leaving a dry powdered reaction product entrained in the flue gas along with any fly ash that entered the reactor. The entrained particles are collected in an electrostatic precipitator (ESP) or baghouse downstream. To enhance the lime utilization, a portion of the collected product is typically recycled back to the process. It is slurried with water and sprayed into the reactor along with the fresh lime slurry.

In the fluidized bed (or circulating) dry scrubbing process, the flue gas is introduced into the bottom of a reactor vessel at high velocity. The movement of the gas through the reactor suspends particles of fly ash and reaction products from the process that are introduced into the reactor, creating a fluidized bed. Dry, powdered, hydrated lime and/or ash product from the downstream particulate collection device is introduced into the bed within the reactor vessel. Water is sprayed into the reactor near the bottom of the bed under high pressure or mixed with the reagent/ash product before it is added to the reaction vessel. In the moist layer at the surface of the lime particles, calcium hydroxide reacts with the absorbed SO_2 to form calcium sulfite and calcium sulfate. The evaporation of water cools and humidifies the flue gas and maintains the bed in a slightly moist, powdery condition. The continuous motion of the bed prevents solids deposition, and promotes regeneration of the particle surfaces, exposing the lime to additional reaction with SO_2. Particles that are entrained in the flue gas leaving the top of the reactor are collected in an ESP or baghouse downstream. A large portion of the collected particles is recycled to the reactor, sustaining the bed and improving lime utilization.

Five of the 19 recently permitted CFB units identified in this study did not add additional SO_2 controls. The remaining fourteen units employed some variant of semi-dry FGD technology in combination with the SO_2 removal capability of the limestone injection to the CFB boiler.

Thirteen of the 25 recently permitted PC units used semi-dry FGD as their SO_2 control. Wet FGD was used at twelve PC units.

NO_x

The primary types of NO_x control for the units in this study are CFB combustion, selective non-catalytic reduction (SNCR), over-fire air (OFA), low NO_x burners (LNB), and selective catalytic reduction (SCR). These controls are described in this section, including the prevalence of each type.

The CFB combustion process has an inherently low level of NO_x emissions due to the combustion temperature. Combustion in a CFB boiler occurs at relatively low combustion temperatures ranging from 1,500 to 1,800 °F. Because thermal NO_x formation occurs at temperatures greater than 2,000 °F, the lower combustion zone temperatures in a CFB boiler significantly reduces NO_x production.

SNCR is an add-on control technology commonly applied to CFB boilers that utilizes ammonia or urea injection into the flue gas near the furnace exit or in the convective passes. Due to the high temperatures in these zones a catalyst is not needed for NO_x to react with ammonia to form nitrogen gas and water.

Overfire air technology reduces NO_x emissions within the normal combustion zone of the furnace without any chemical additives or alternate fuel. An OFA system reduces the formation of NO_x by inhibiting the immediate availability of oxygen to the fuel. OFA also reduces thermal NO_x by spreading the combustion over a larger volume in the boiler and lowering the combustion temperature in the lower part of the furnace.

An SCR system uses ammonia injected into the flue gas upstream of a catalyst placed downstream of the economizer exit to reduce NO_x to molecular nitrogen and water. The process is termed "selective" because the ammonia preferentially reacts with the NO_x rather than with the oxygen in the flue gas. A catalyst is used to achieve NO_x reduction by chemical reaction with ammonia to form elemental nitrogen and water at appropriate flue gas temperatures. Ammonia for use in an SCR system can come in one of two forms, anhydrous ammonia or aqueous ammonia. Another option is to use a dry urea storage system that generates ammonia on site as needed.

Three of the recently permitted CFB units did not use add on controls for NO_x, while 16 units used SNCR controls.

The controls for PC units were divided up into two groups: SCR, and LNB/ SCR. Three units used SCR, and 24 units used LNB and SCR controls.

PM_{10}

The principal types of PM_{10} control for the units in this study are electrostatic precipitator (ESP), fabric filter/baghouse (FF/BH), and multi clones. These controls are described in this section, including the prevalence of each type.

An electrostatic precipitator (ESP) removes solid or liquid particulate matter from a gas stream by imparting an electrical charge on the individual particle and collecting the charged particle to an oppositely charged surface. Most ESPs used in coal-fired boiler applications are dry, but some high-sulfur coal-fired units are now being permitted with a wet ESP (WESP) located in the saturated flue gas environment down stream of the wet FGD system. The purpose of the WESP is to collect sulfuric acid mist, which is a major component of the condensable fraction of the total particulate emissions. WESPs are not used as the primary particulate control device and either an ESP of a baghouse would be provided upstream of the wet FGD system to remove a majority of the fly ash.

Baghouses collect particulate matter on the surfaces of filter bags. Most of the particles are captured by impaction and sieving on already collected particles, which are present as a dust layer on the bags (dust cake). There are two major types of baghouses: reverse-air and pulse jet. In reverse air baghouse setups, the particulate-laden gas stream enters from the bottom and passes into the inside of the bag. Filtered gas passes through the dust cake on the inside of the bag and is exhausted. In order to clean this type of baghouse, some of the filtered gas is passed in a reverse direction (outside to inside the bag) to remove some of the dust cake. In pulse jet baghouses, the flue gas is passed through the outside of the bags thereby producing the dust cake on the exterior of the bags. These bags are cleaned by injecting a short pulse of compressed air, which removes some of the dust cake.

The multiclone is a mechanical collector sometimes used as a precollector upstream of an ESP, FF, or wet scrubber. These devices can be specified to reduce particle loadings and consequently reduce capital and/or operating costs for downstream equipment.

The primary particulate control technology identified in permits for the 19 recently permitted CFB boilers is a fabric filter (baghouse). Seventeen units used this control. Two CFB units were permitted for an ESP for particulate control.

Fabric filters were also the primary particulate control technology among recently permitted PC boilers, with 17 of the 25 units using this control method. Seven PC units used ESP as the primary particulate controls. ESPs are generally used for high-sulfur coal applications. A multi clone was identified in the permit as the particulate control technology to be used for one unit. Six PC units have been permitted with a WESP for control of the sulfuric acid aerosol downstream of a wet FGD system. Four of these units will use dry ESPs as the primary control upstream of the wet FGD. Two will use a fabric filter.

CO and VOC

VOC and CO emissions at all CFB and PC units are controlled by good combustion practices.

3

EMISSION LIMITS ACHIEVED IN PRACTICE

In order to determine the emissions levels that have been achieved in practice, data was gathered from the Acid Rain data submitted to the EPA.

The data gathered was not sufficient to determine if the pollution control equipment is being operated at its maximum performance level or at a lower level to provide a margin of safety. There are numerous factors that go into such an operating methodology, including the cost (energy, reagents, and maintenance) as well as allowances and compliance averaging periods. Although it seems logical that a "more powerful design" would achieve additional removal at the sacrifice of cost and operational reliability, no concrete data was found to support such a conclusion.

Electronic Data Reporting

The Clean Air Markets division of EPA maintains data from power plants as it is collected from the quarterly electronic data reports (EDRs) submitted by each facility. This database was queried to find the monthly emissions for the units included in this study (http://cfpub.epa.gov/gdm/). Data was pulled for reporting years 2001 through 2003 and is presented in Figures 3-1 through 3-8. The lb/MBtu values for NO_x were provided directly in the retrieved data. The lb/MBtu values for SO_2 were calculated from the retrieved tons SO_2/month and MBtu/month values.

NO_x and SO_2 emission limits that were not given as a 30-day average were converted to a 30-day average using the tpy limits and heat input of the unit. Where a conversion was made, it was noted in the general notes on Tables 2-3 through 2-6 for that facility and pollutant. No Acid Rain data was available for AES Puerto Rico.

Please note that the Acid Rain data is from monthly blocks of data not 30-day rolling averages. This may explain some of the instances where the Acid Rain data shows values higher than the limits.

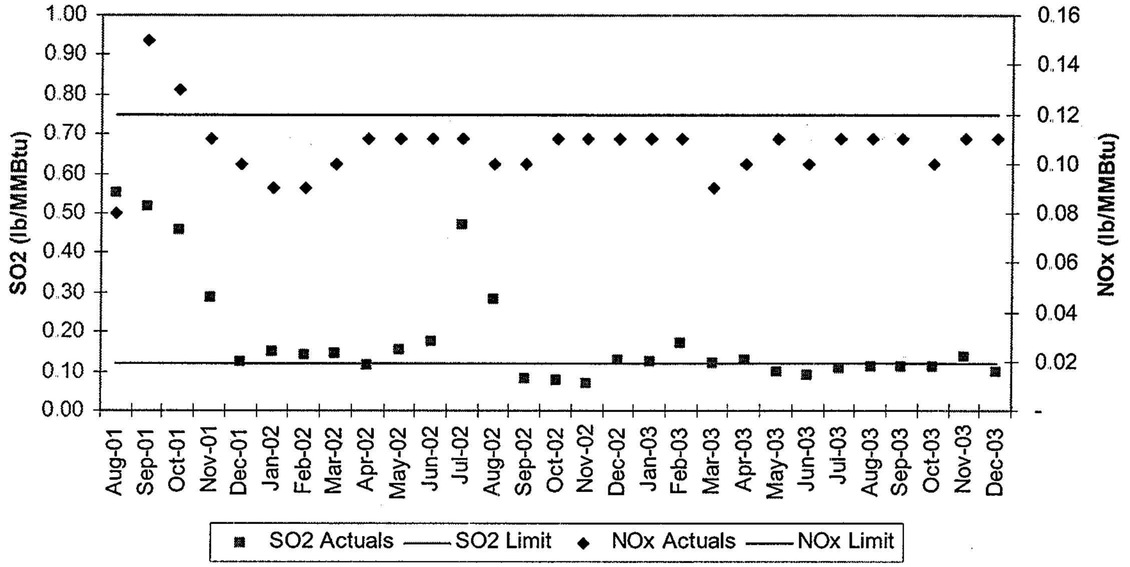


Figure 3-1
Hawthorn 5 Acid Rain Data

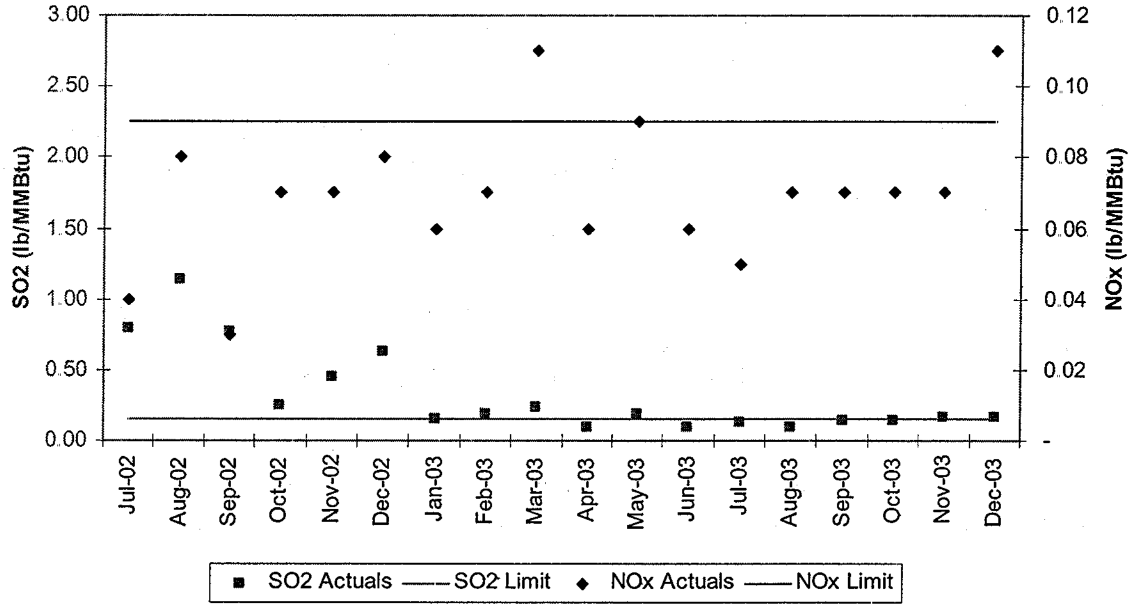


Figure 3-2
JEA Northside Unit 1A Acid Rain Data

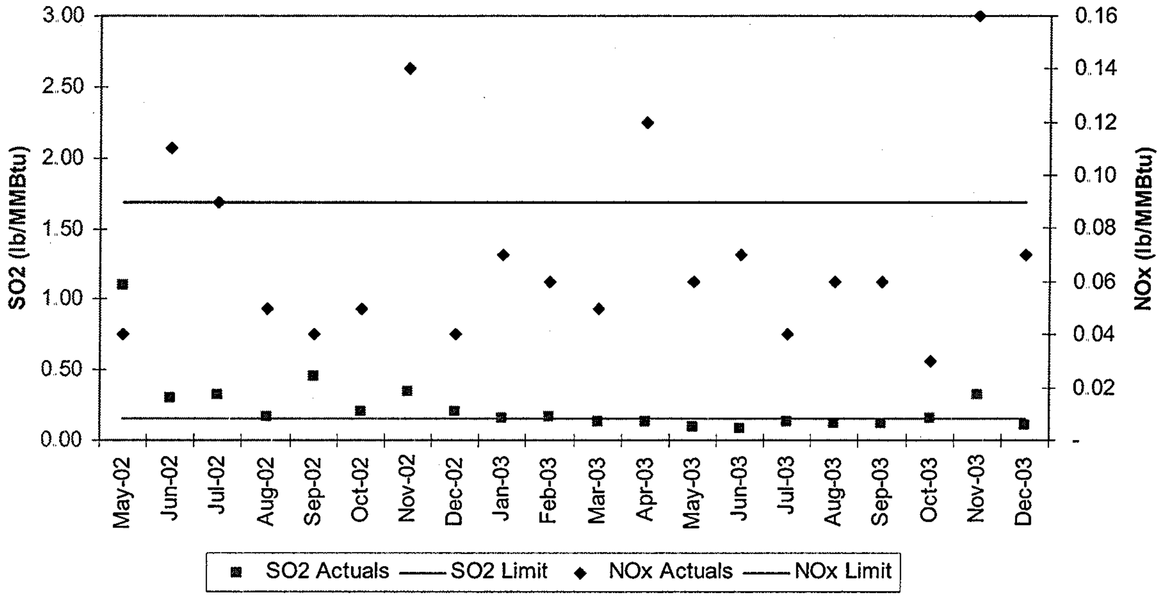


Figure 3-3
JEA Northside Unit 2A Acid Rain Data

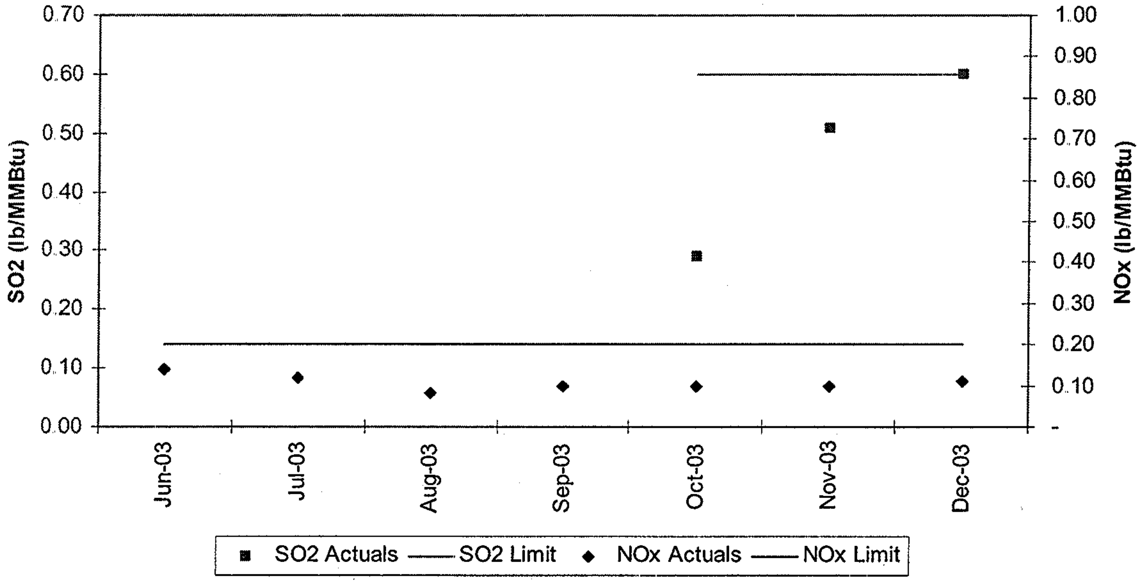


Figure 3-4
Southern Illinois Acid Rain Data

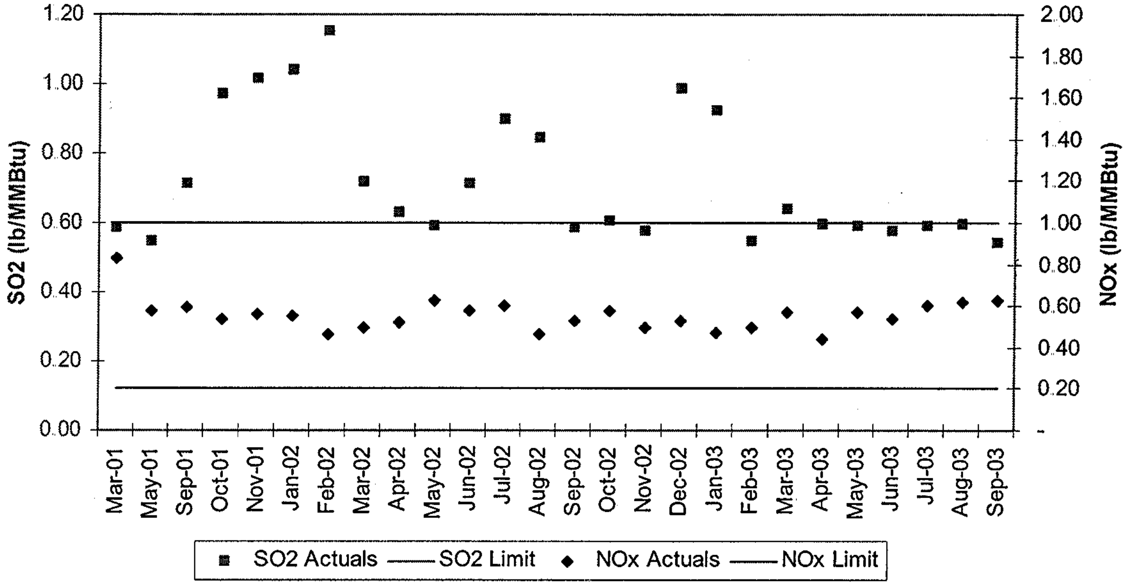


Figure 3-5
Toledo Edison – Bayshore Acid Rain Data

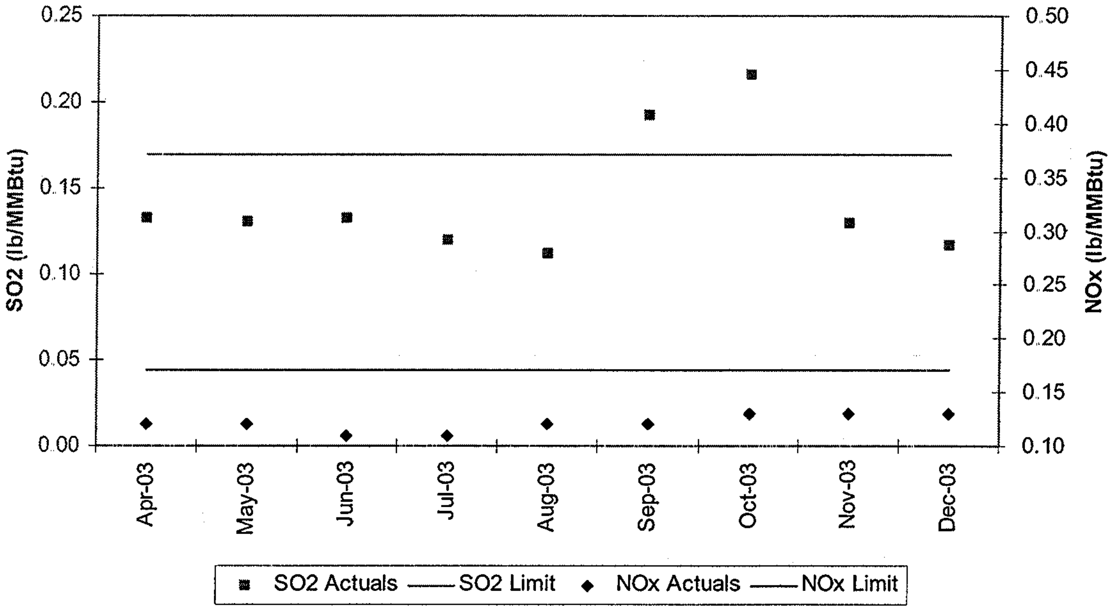


Figure 3-6
Wygen I Acid Rain Data

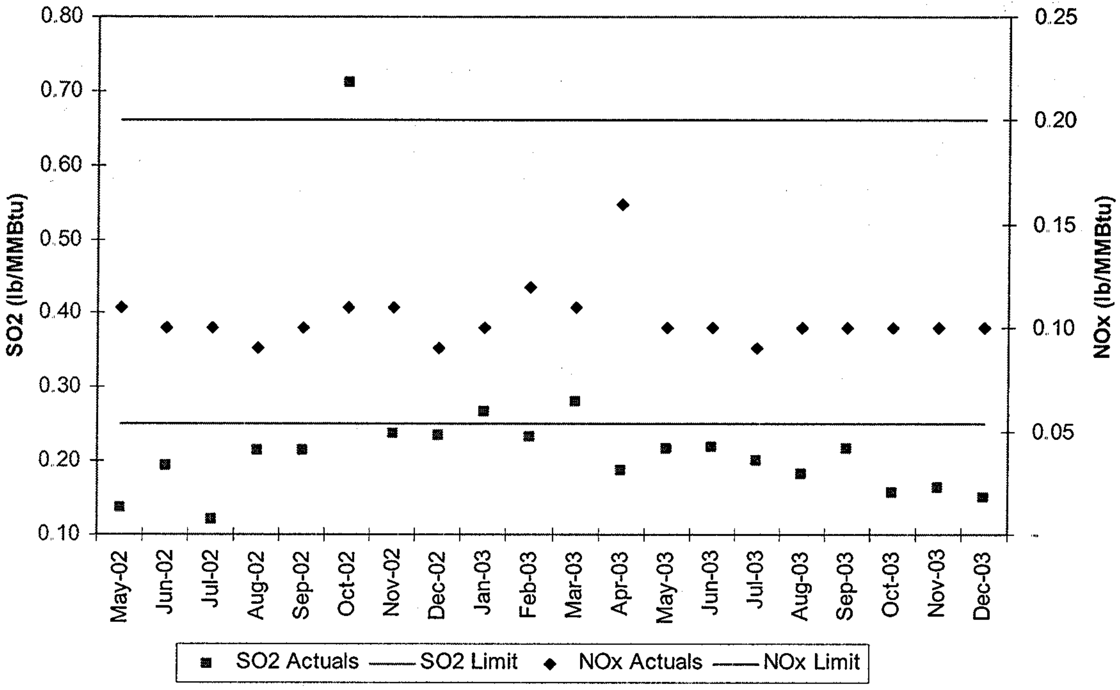


Figure 3-7
Red Hills Unit 1 Acid Rain Data

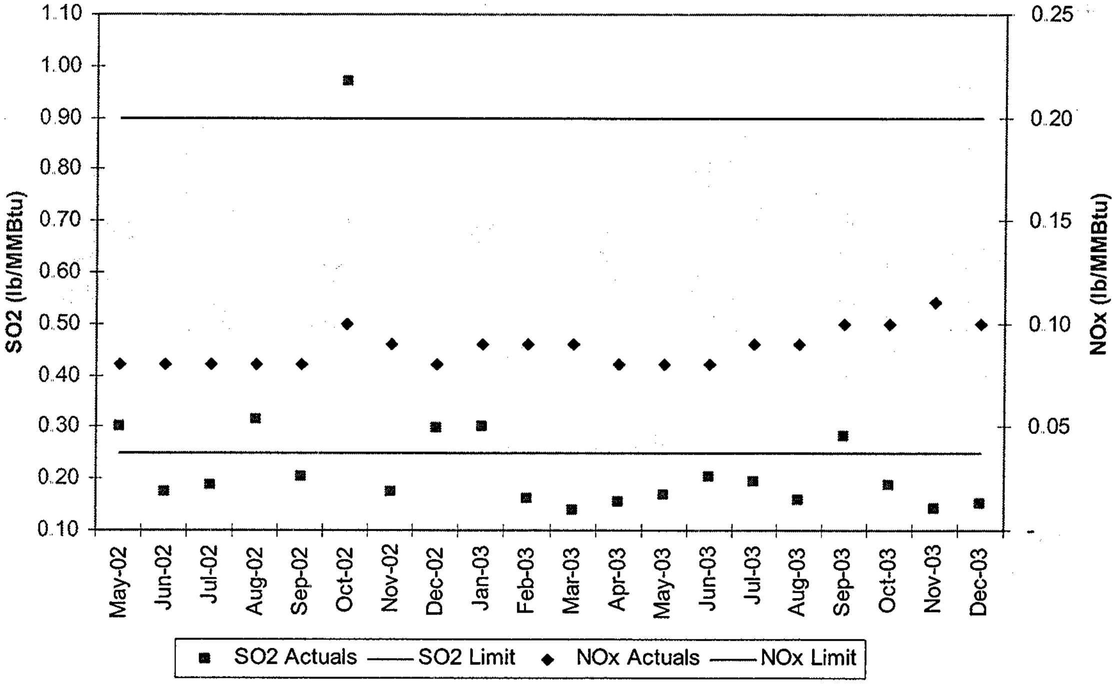


Figure 3-8
Red Hills Unit 2 Acid Rain Data

Initial Test Results

Initial test data was available for eight units, as shown in Table 7. The data was obtained through the state agency or the facility and is for a 3-run average (not a 30-day rolling average). See Figures 3-9 through 3-12. Exceedances are shown for AES Puerto Rico on PM_{10} and TSP; however, results of a repeat stack test were not available from the agency. The limit for AES Puerto Rico was subsequently increased.

Table 3-1
Initial Test Data

Facility	PM/TSP	PM_{10}	CO	VOC
AES Puerto Rico Units 1 and 2	X	X	X	X
Hawthorn	X	X	X	X
JEA Northside Units 1 and 2	X	X	X	X
Southern Illinois	X	X	X	X
Toledo Edison Bayshore		X	X	
Wygen 1	X		X	X

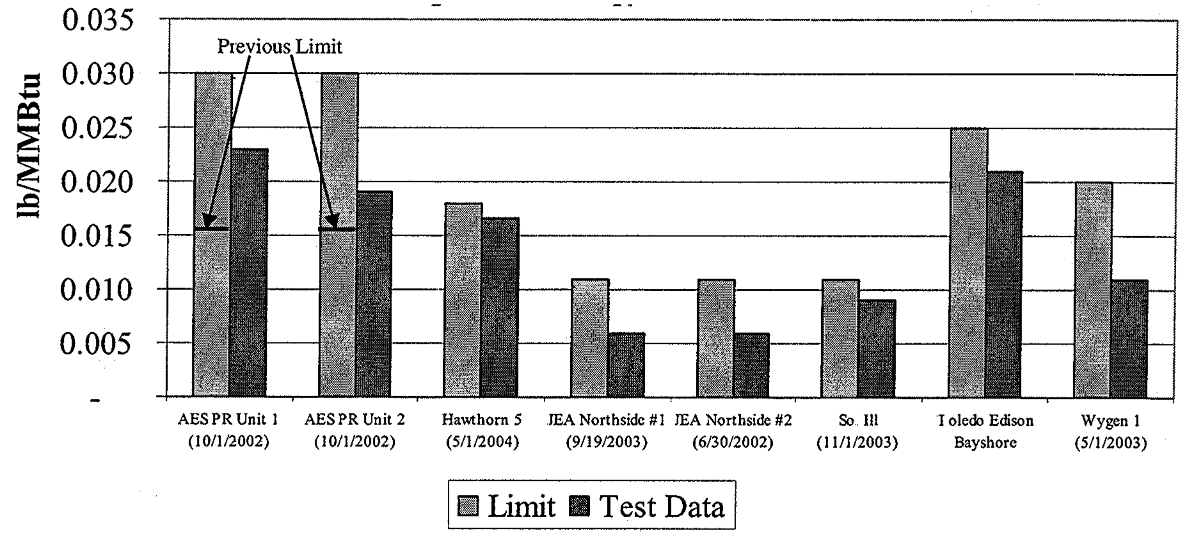


Figure 3-9
PM_{10} Test Data

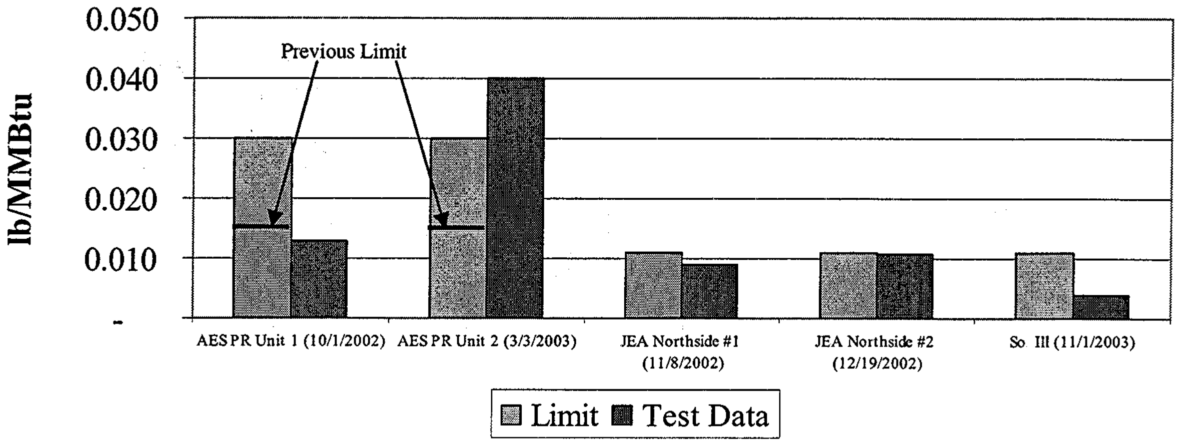


Figure 3-10
TSP Test Data

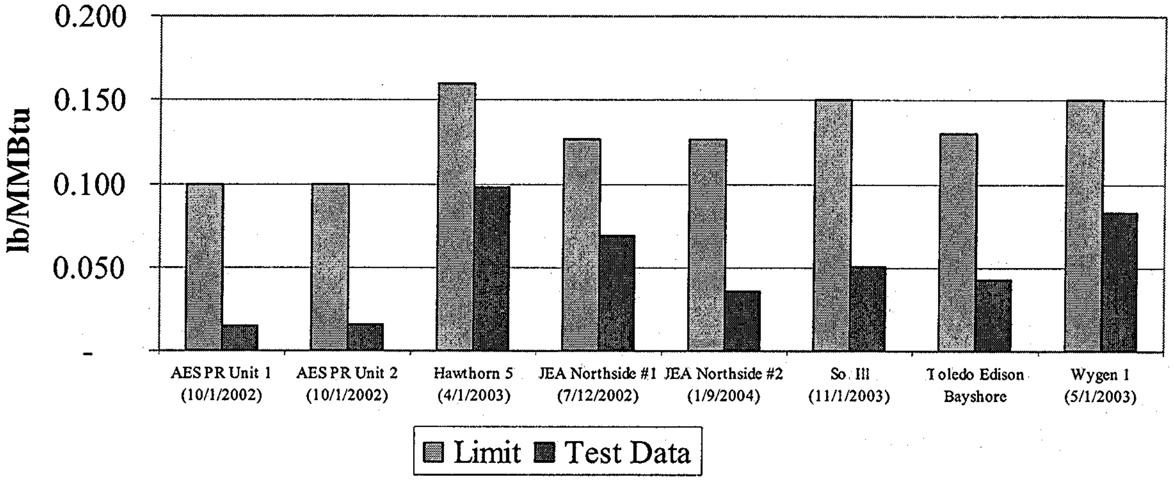


Figure 3-11
CO Test Data

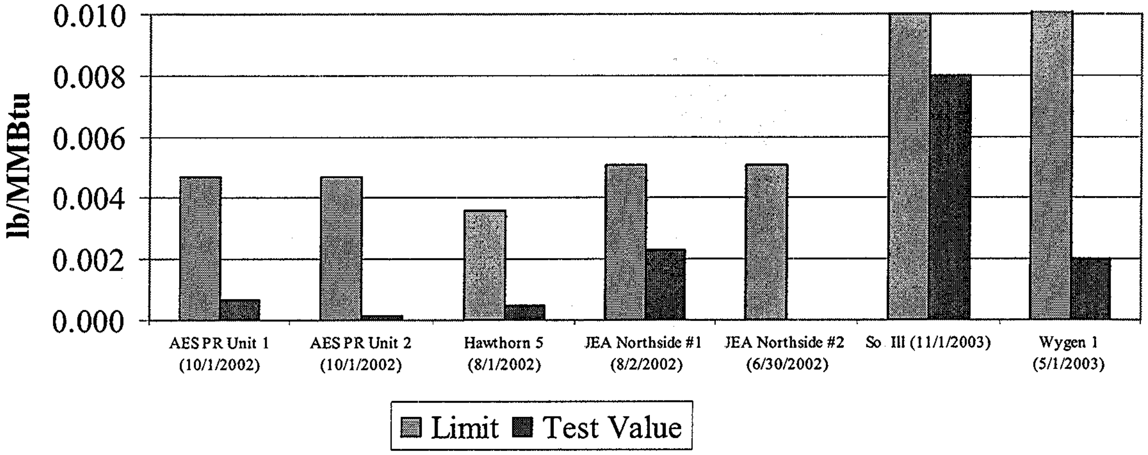


Figure 3-12
VOC Test Data

Permitting Trends

Permitting trends for SO_2, NO_X, and PM_{10} are shown in Figures 3-13, 3-15, and 3-17. These figures were generated to show trends and differences between the permitted emission limits established for units that are operating versus those that are not yet operating. Figures 3-14, 3-16, and 3-18 show trends and differences between permitted emission limits for PC boilers and CFB boilers.

The data in Figures 3-13 through 3-19 is based on permitted emission limits that are based on a Best Available Control Technology (BACT) analysis (i.e. control equipment capabilities). It does not include emission limits that were established from non-BACT criteria, such as the emission limits in NSPS, Subpart Da. For example, pollutants for some of the units replacing existing units did not exceed emission significance thresholds in the netting analysis. Consequently, these pollutants were able to net out of PSD review for those pollutants and be based a less stringent requirement such as NSPS, Subpart Da.

In regards to SO_2, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units. Figures 3-13 and 3-14 show that the emission limits for operating and not yet operating units are in the same range with most of the emission limits being in the center of the range. CFB boilers have the largest range of limits ranging from 0.022 to 0.25 lb/MMBtu. The emission limits for PC boilers are concentrated around the 0.10 to 0.15 lb/MMBtu range. Both figures show downward trends in the SO_2 emission rates meaning that SO_2 emission limits are becoming more stringent.

In regards to NO_X, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units. Figures 3-15 and 3-16 generally show that NO_x emission limits for PC units were slightly lower than for CFB boilers (i.e. about 0.08 lb/MMBtu for PC boiler, and about 0.10 lb/MMBtu for CFB boiler). The figures also show a slight downward trend in the NO_x emission limits for both CFB and PC units.

In regards to PM_{10}, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units. See Figures 3-17, 3-18, and 3-19.

There is an increasing emphasis on speciation between filterable and condensable particulate matter and the appropriate limits for each. Specifying limits as to filterable only or both filterable and condensable is more common in recent years. In fact, the limit for AES Puerto Rico was changed from 0.015 lb/MMBtu to 0.03 lb/MMBtu in order to account for the condensable fraction of the particulate emissions.

Figures 3-18 and 3-19 show emission limits for "filterable" and "filterable and condensable" PM_{10} emissions. There are no distinct trends in the emissions data. With the exception of a couple outliers, the emissions limits for both types of PM_{10} are in the 0.015 to 0.02 lb/MMBtu range.

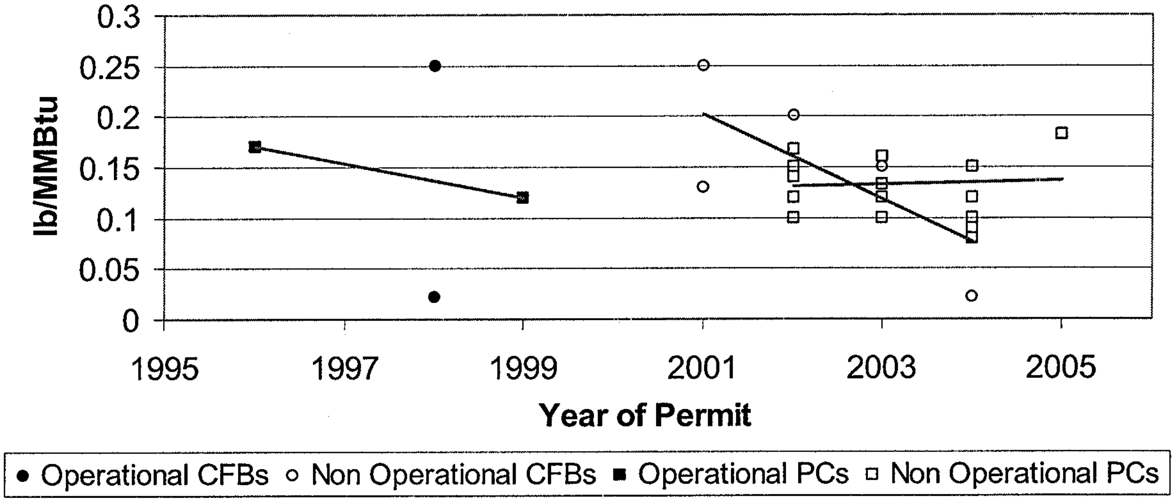


Figure 3-13
SO_2 30 Day Rolling Limits and Operational Status

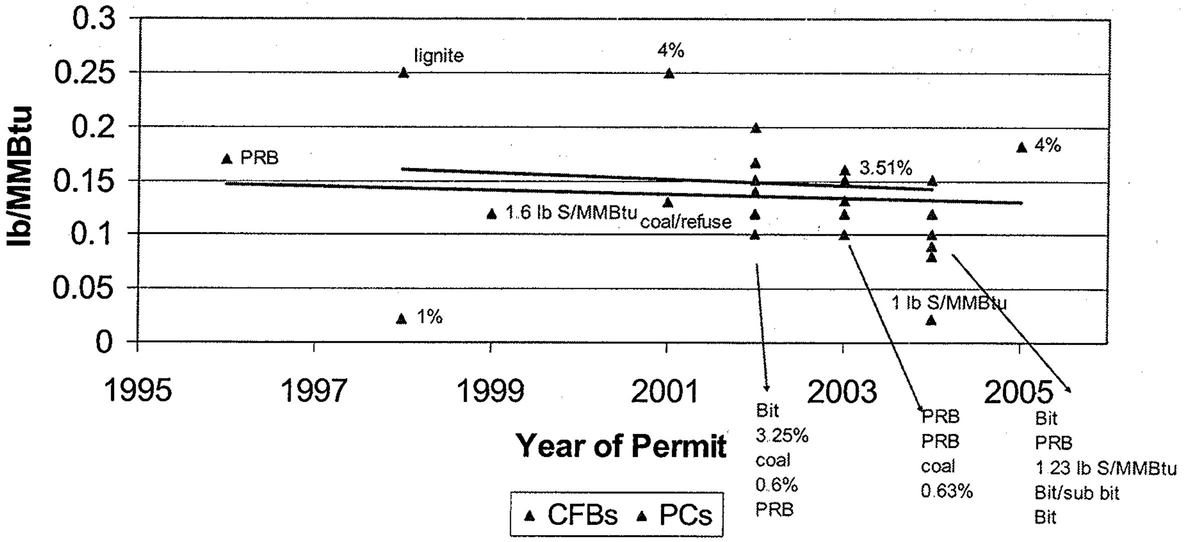


Figure 3-14
SO_2 Permitting Trends

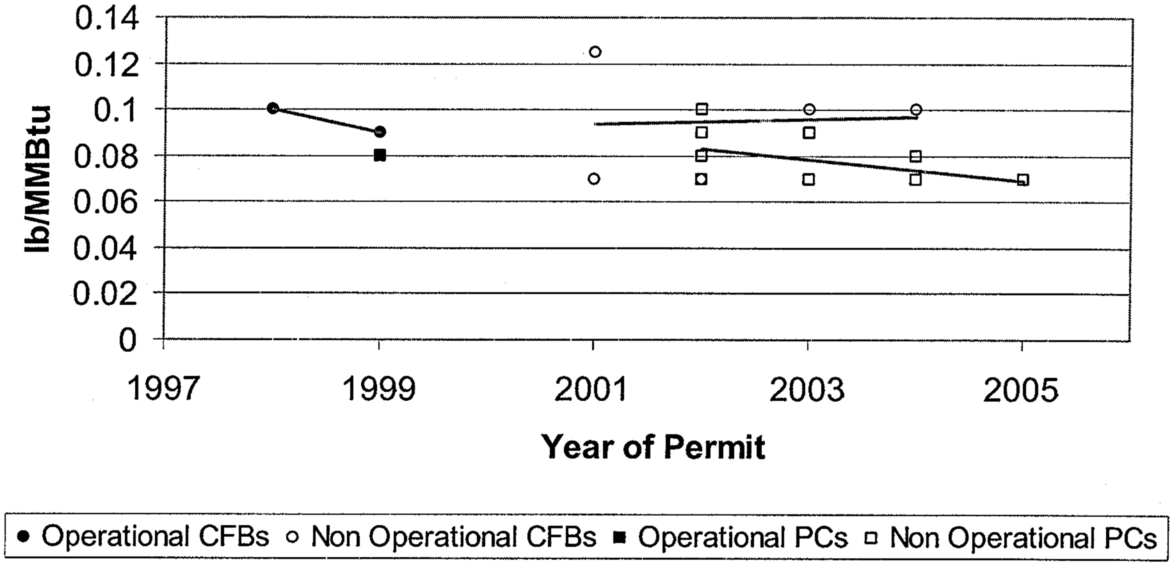


Figure 3-15
NO_x 30-Day Rolling Limits and Operational Status

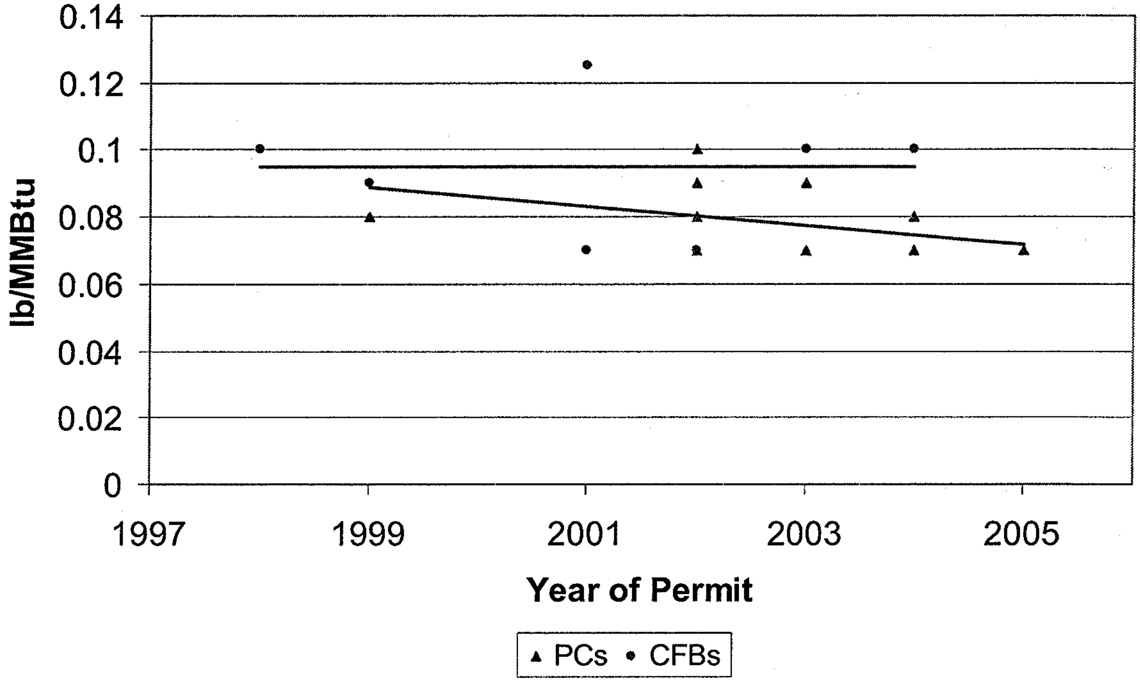


Figure 3-16
NO_x Permitting Trends

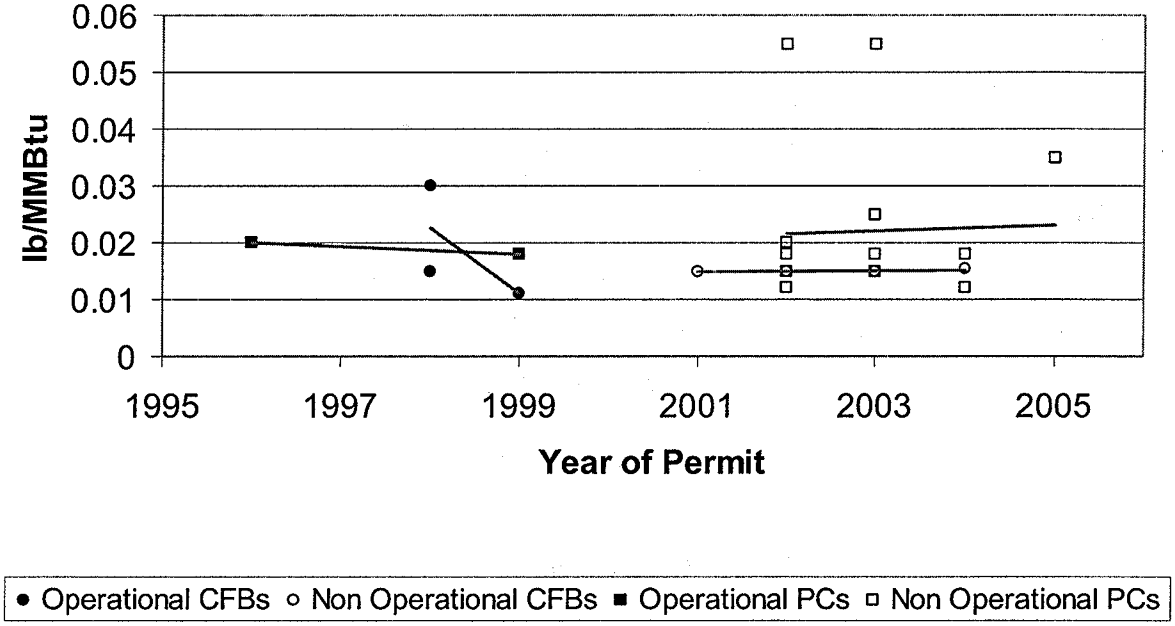
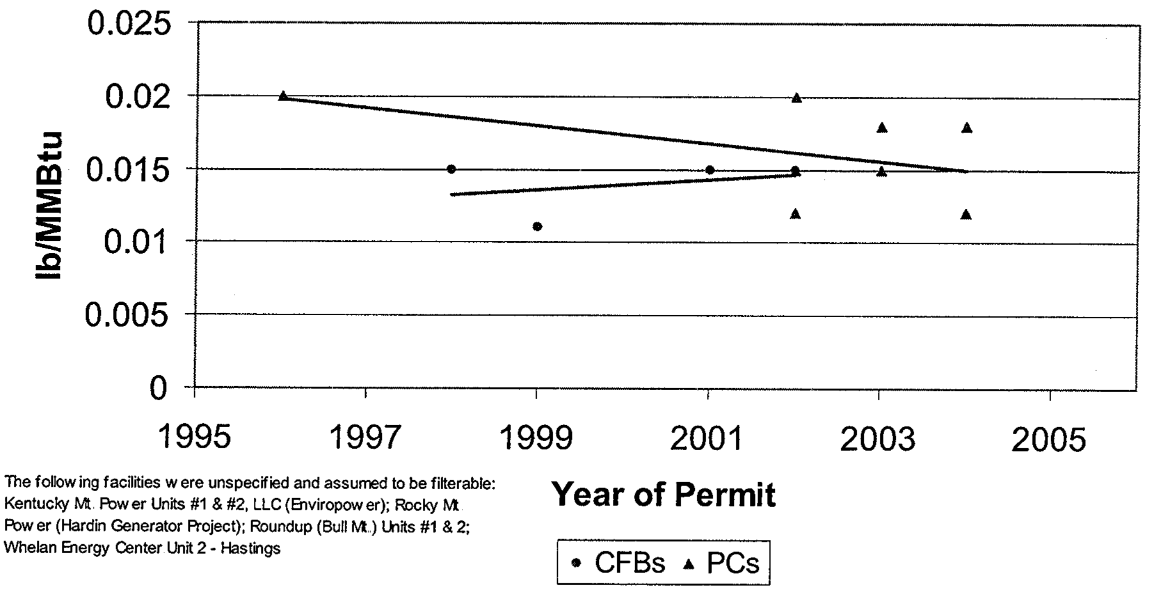


Figure 3-17
PM_{10} Permitting Trends



The following facilities were unspecified and assumed to be filterable: Kentucky Mt. Power Units #1 & #2, LLC (Enviropower); Rocky Mt Power (Hardin Generator Project); Roundup (Bull Mt.) Units #1 & 2; Whelan Energy Center Unit 2 - Hastings

Figure 3-18
PM_{10} Permitting Trends – Filterable

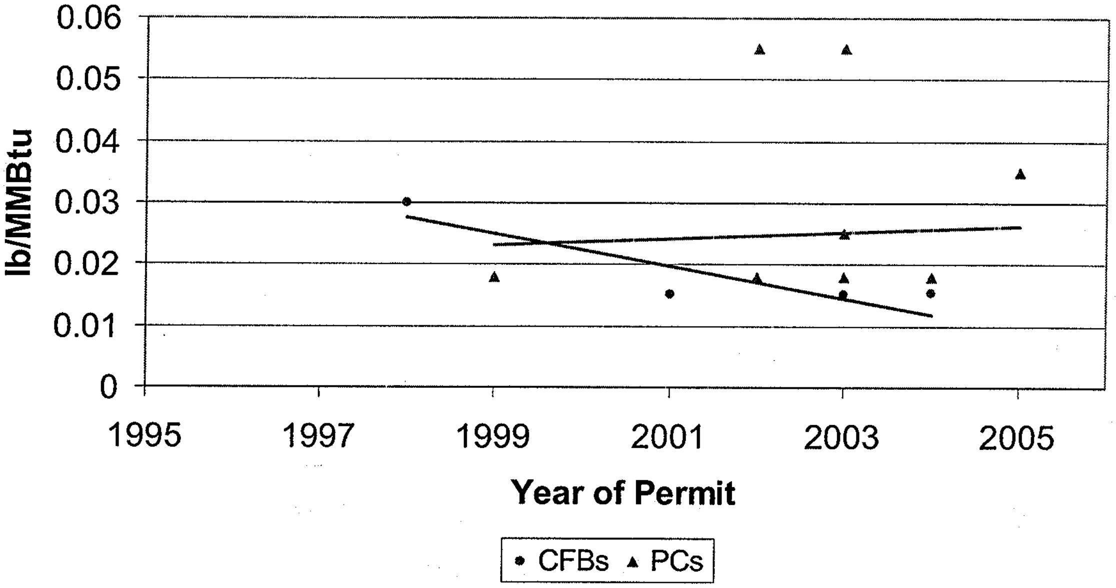


Figure 3-19
PM_{10} Permitting Trends – Filterable and Condensable

4
SUMMARY AND CONCLUSIONS

This investigation is intended to provide a better understanding of the best available control technology (BACT) being required today in permits issued for new coal-fired power plants and to document the actual emissions performance of the air pollution control technologies installed on new units that have recently begun operation. The study focused on four areas: emission controls used, electronic data reporting, initial test results, and permitting trends.

Controls

The types of emission control employed for BACT at recently permitted utility boilers were examined. Permitted SO_2, NO_x, PM_{10}, and CO and VOC controls were compiled from 44 units at 31 facilities. This included 25 PC units and 19 CFB units.

For CFB boilers, 26 percent of the facilities used no additional SO_2 controls. The other 74 percent used some variant of semi-dry FGD technology in combination with the SO_2 removal capability of the limestone injection to the CFB boiler. Semi-dry FGD and wet FGD were the two SO_2 control technologies used at PC facilities, with half of the units using each technology (13 semi-dry and 12 wet).

A majority of CFB units used SNCR to control NO_x emissions and three of the facilities did not use supplemental NO_x controls. Eighty-eight percent of the PC units used LNB and SCR controls, while 12 percent used SCR.

The primary particulate control technology identified in permits for CFB and PC boilers is a fabric filter (baghouse). Out of 44 total units, just seven PC units and two CFB units used ESPs for particulate control and one unit was permitted with a multiclone for particulate control.

VOC and CO emissions at all CFB and PC units are controlled by good combustion practices.

Electronic Data Reporting

Data from power plants as it is collected from the quarterly electronic data reports (EDRs) submitted by each facility was queried to find the monthly emissions for the units included in this study (http://cfpub.epa.gov/gdm/). Monthly data was downloaded for reporting years 2001 through 2003 for the eight operating new units that had data available. In general, the monthly average emissions of SO_2 and NO_x for each unit were consistently below the permit limits for the facilities with the exception of a few outliers.

Initial Test Results

Initial stack test data was available for eight units. The data was obtained through the state agency or the facility and is for a 3-run average (not a 30-day rolling average). All of the facilities met the permit limits for PM_{10}, TSP, CO and VOC, with the exception of the TSP test results dated 3/3/2003 for AES Puerto Rico. This limit was subsequently increased via a permit modification.

Permitting Trends

Permitting trends for SO_2, NO_X, and PM_{10} were generated to show trends and differences between the permitted emission limits established for units that are operating versus those that are not yet operating. Trends and differences between permitted emission limits for PC boilers and CFB boilers were also examined. Data based on permitted emission limits that are based on a Best Available Control Technology (BACT) analysis (i.e., control equipment capabilities) were used.

In regards to SO_2, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units. The emission limits for operating and not yet operating units are in the same range with most of the emission limits being in the center of the range. CFB boilers have the largest range of limits ranging from 0.022 to 0.25 lb/MBtu. The emission limits for PC boilers are concentrated around the 0.10 to 0.15 lb/MBtu range. The results displayed a downward trend in the SO_2 emission rates meaning that SO_2 emission limits are becoming more stringent.

In regards to NO_X, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units. The NO_x emission limits for PC units were slightly lower than for CFB boilers (i.e., about 0.08 lb/MBtu for PC boiler, and about 0.10 lb/MBtu for CFB boiler). The results indicated a slight downward trend in the NO_X emission limits for both CFB and PC units.

In regards to PM_{10}, no significant trends or differences between the permitted emission limits established for units that are operating versus those that are not yet operating were found for either CFB or PC units.

There is an increasing emphasis on speciation between filterable and condensable particulate matter and the appropriate limits for each. Specifying limits as to filterable only or both filterable and condensable is more common in recent years. In fact, the limit for AES Puerto Rico was changed from 0.015 lb/MBtu to 0.03 lb/MBtu in order to account for the condensable fraction of the particulate emissions.

There are no distinct trends in the emissions data for "filterable" and "filterable and condensable" PM_{10} emissions. With the exception of a couple outliers, the emissions limits for both types of PM_{10} are in the 0.015 to 0.02 lb/MBtu range.

A
FACILITY INFORMATION

CFB

AES Puerto Rico (2 units)

State: PR *EPA* 2 *Operational:* yes (& tested)
MW: 2 units at 227 MW each (Net) *MBtu/Hr:* 2461.35 MBtu/hr each - 2 units *Number Of Units:* 2
Permit Date: 9/18/1998 *Permit* AES-PRCP
Fuel: bituminous coal

AES-PRCP shall combust the following fuels: Low sulfur coal with a maximum sulfur content of 1.0% by weight.

Energy Services of Manitowoc

State: WI *EPA* 5 *Operational:* no
MW: 64 MW *MBtu/Hr:* 270 MBtu/hr *Number Of Units:* 1
Permit Date: 12/3/2003 *Permit* 02-RV-147
Fuel: coal, petroleum coke, and/or paper pellets
Facility Notes: SO_2, NOx, and PM10 are non-BACT; CO is BACT

EnviroPower IL - Benton (2 units)

State: IL *EPA* 5 *Operational:* no
MW: 2 units at 250 MW each (nominal net output) *MBtu/Hr:* 2,550 MBtu/hr each - 2 units *Number Of Units:* 2
Permit Date: 7/3/2001 *Permit* I.D. #: 055802AAG , Application #: 00080042
Fuel: coal tailings and coal

Coal mine tailings will be taken from the mine tailing piles at the former Old Ben 24 mine site as well as from other sites in southern Illinois.

Indeck-Elwood LLC (2 units)

State: IL *EPA* 5 *Operational:* no
MW: 2 units at 330 MW each (gross) *MBtu/Hr:* 2,900 MBtu/hour each - 2 units *Number Of Units:* 2
Permit Date: 10/10/2003 *Permit* ID #: 197035AAJ, Application #: 02030060
Fuel: coal, petroleum coke, coal tailings

The boilers would be fired on coal as their primary fuel and petroleum coke and coal tailings as supplemental fuels. (The boilers are designed to use coal mixed with up to 20 % petroleum coke and waste coal as their primary fuel.)

JEA Northside #1 & #2 (2 units)

State: FL ***EPA*** 4 ***Operational:*** yes (& tested)
MW: 2 units at 297.5 MW each ***MBtu/Hr:*** 2,764 MBtu/hr each - 2 units ***Number Of Units:*** 2
Permit Date: 7/14/1999 ***Permit*** PSD-FL-265
Fuel: coal, petroleum coke
Facility Notes: SO_2 based on NSPS: other pollutants based on BACT

Kentucky Mountain Power, LLC (EnviroPower) (2 units)

State: KY ***EPA*** 4 ***Operational:*** no
MW: ***MBtu/Hr:*** 2,550 MBTU/hour each - 2 units ***Number Of Units:*** 2
Permit Date: 5/4/2001 ***Permit*** V-00-045
Fuel: coal and coal refuse

Red Hills (Choctaw Generation Limited Partnership) (2 units)

State: MS ***EPA*** 4 ***Operational:*** yes (initial testing waived)
MW: ***MBtu/Hr:*** 2,475.6 MBTU/hr each - 2 units ***Number Of Units:*** 2
Permit Date: 8/25/1998 ***Permit*** 0400-00011
Fuel: lignite
Facility Notes: RBLC indicates NOx is non-BACT; the other pollutants are BACT

Sevier Power (Nevco Energy)

State: UT ***EPA*** 8 ***Operational:*** no
MW: 270 MW ***MBtu/Hr:*** 2532 MBtu/hr ***Number Of Units:*** 1
Permit Date: 10/12/2004 ***Permit*** DAQE-AN2529001-04
Fuel: bituminous coal

Seward Reliant (2 units)

State: PA ***EPA*** 3 ***Operational:*** yes (not tested)
MW: 521 MW (net nominal) ***MBtu/Hr:*** 2,532 MBtu/hr each (nominal), atmospheric CFB - 2 units ***Number Of Units:*** 2
Permit Date: 10/19/2001 ***Permit*** PA-32-040B
Fuel: coal refuse and/or run-of-mine (raw) coal, up to 35% maximum on an annual basis
Facility Notes: non-BACT for SO_2, NOx, PM10; BACT for CO, NSR for VOC

Southern Illinois Coop (Marion Generating Station)

State: IL ***EPA*** 5 ***Operational:*** yes (& tested)
MW: 120 MW ***MBtu/Hr:*** 1402 MBtu HHV/hr ***Number Of Units:*** 1
Permit Date: 6/15/2001 ***Permit*** 00070030- 199856aac
Fuel: coal refuse, coal, petroleum coke
Facility Notes: non-BACT for SO_2, NOx, PM10, and VOC; BACT for CO

Spurlock (E. KY Power Coop)

State: KY ***EPA*** 4 ***Operational:*** no
MW: 270 MW ***MBtu/Hr:*** 2,500 MBTU/hour ***Number Of Units:*** 1
Permit Date: 8/4/2002 ***Permit*** V-97-050 (Revision 1)
Fuel: coal

Toledo Edison Co. - Bayshore Plant

State: OH ***EPA*** 5 ***Operational:*** yes (& tested)
MW: ***MBtu/Hr:*** 1,736 MBtu/hr ***Number Of Units:*** 1
Permit Date: 10/21/1997 ***Permit*** 04-01056
Fuel: pet coke, coal CFB boiler fired primarily with petroleum coke (1736 MMBTU/hr rating) and use of coal (1764 MMBTU/hr rating) as a backup fuel
Facility Notes: non-BACT for SO_2, NOx, PM10, VOC; BACT for CO

PC

Corn Belt Energy

State: IL ***EPA*** 5 ***Operational:*** no
MW: 91 MW ***MBtu/Hr:*** 900 MBtu/hr ***Number Of Units:*** 1
Permit Date: 12/17/2002 ***Permit*** Application #: 1070028, I.D. #: 107806AAC
Fuel: bituminous coal and coal tailings 10450 btu/lb, , Elkhart Mine Road, Mine-Mouth Project, Elkhart, Logan County
Facility Notes: The project is being pursued by Corn Belt in conjunction with a clean coal combustion grant from the United States Department of Energy (USDOE). 365 day "shakedown" period when only nsps limits apply

Council Bluffs (Mid America)

State: IA ***EPA*** 7 ***Operational:*** no
MW: 790 net MW ***MBtu/Hr:*** 7,675 MBtu/hr ***Number Of Units:*** 1
Permit Date: 6/17/2003 ***Permit*** 03-A-425-P
Fuel: PRB

Elm Road Generating Station (WE-Energies) (2 units)

State: WI ***EPA*** 5 ***Operational:*** no
MW: 2 units at 615 MW each ***MBtu/Hr:*** 6180 MBtu/hr each - 2 units ***Number Of Units:*** 2
Permit Date: 1/14/2004 ***Permit*** 03-RV-166
Fuel: bituminous coal -washed Eastern United States Pittsburgh #8

Hawthorn 5 (KCP&L)

State: MO ***EPA*** 7 ***Operational:*** yes (& tested)
MW: 570 MW ***MBtu/Hr:*** 6,000 MBtu/hr ***Number Of Units:*** 1
Permit Date: 8/17/1999 ***Permit*** 888
Fuel: PRB 8350

Holcomb Unit #2 (Sand Sage Power, LLC)

State: KS ***EPA*** 7 ***Operational:*** no
MW: 660 MW ***MBtu/Hr:*** 6,501 MBtu/hr ***Number Of Units:*** 1
Permit Date: 10/8/2002 ***Permit*** Source ID #: 0550087
Fuel: PRB

Intermountain Power Unit #3

State: UT ***EPA*** 8 ***Operational:*** no
MW: nominal 950-gross MW (900-net MW) ***MBtu/Hr:*** 9,050 MBtu/hr ***Number Of Units:*** 1
Permit Date: 10/15/2004 ***Permit*** DAQE-AN0327010-04
Fuel: bituminous or blend of bituminous and up to 30% subbituminous

Longview Power (GenPower)

State: WV ***EPA*** 3 ***Operational:*** no
MW: 600 MW ***MBtu/Hr:*** 6,114 MBtu/hr ***Number Of Units:*** 1

Permit Date: 3/2/2004 ***Permit*** R14-0024
Fuel: bituminous coal 2.5% sulfur (nominal)

Plum Point Power Station
State: AR ***EPA*** 6 ***Operational:*** no
MW: 550-800 MW (nominal) ***MBtu/Hr:*** 8,897 MBtu/hr ***Number Of Units:*** 1
Permit Date: 8/20/2003 ***Permit*** 1995-AOP-R0
Fuel: PRB
Facility Notes: MMBtu/hr for the boiler was found in the predetermination document for Longview

Prairie State (2 units)
State: IL ***EPA*** 5 ***Operational:*** no
MW: 1500 MW ***MBtu/Hr:*** 7,450 MBtu/hr (each) ***Number Of Units:*** 2
Permit Date: 1/14/2005 ***Permit*** 189808AAB
Fuel: bituminous coal mine mouth; Illinois coal; 4% sulfur; 8,780 btu/lb

Rocky Mountain Power (Hardin Generator Project)
State: MT ***EPA*** 8 ***Operational:*** no
MW: 113 MW (nominal) ***MBtu/Hr:*** 1,304 MBtu/hr ***Number Of Units:*** 1
Permit Date: 6/11/2002 ***Permit*** 3185-00
Fuel: coal

coal owned by the Tribe of Crow Indians from the Absaloka Mine. The mine, which is owned by Westmoreland Resources, Inc., is located approximately 30 miles east of Hardin. Using the heat content of 8,700 Btu/lb of Absaloka Mine coal, as provided by Westmoreland Resources, Inc., the coal-firing rate will be approximately 75 ton/hr and 656,500 tpy.

Roundup (Bull Mountain) (2 units)
State: MT ***EPA*** 8 ***Operational:*** no
MW: 2 units at 390 MW each (nominal) ***MBtu/Hr:*** 4,013 MBtu/hr each (Max short term heat input to boiler); 2 units - 3,737 mmBtu/hr each (Max long term heat input to boiler) - 2 units ***Number Of Units:*** 2
Permit Date: 7/21/2003 ***Permit*** 3182-00
Fuel: coal

Coal for the main boilers will be supplied by the BMP Investments Incorporated coal mine that is located on the adjacent property immediately to the east of the power plant location. (Bull Mountain Mine)

Santee Cooper/Cross #3 & #4 (2 units)
State: SC ***EPA*** 4 ***Operational:*** no
MW: 2 units at 600 MW each ***MBtu/Hr:*** 5,400 MBTU/hr (normal pressure rating), 5,700 „BTU/hr (overpressure rating) each - 2 units ***Number Of Units:*** 2
Permit Date: 8/5/2004 ***Permit*** 0420-0030-CI-R1
Fuel: coal, synfuel and petcoke blended up to 30% by weight as fuel

coal, including synfuel, and petcoke blended up to 30% by weight as fuel. For this permit, the term "coal" and requirements pertaining to coal shall also include the following synthetic fuel-altered coal (synfuel): - coal with HES binder (petroleum emulsion - MSDS identification AMI-403) - coal with NALCO 9838 binder (water based vinyl polymer)- coal with Dow Latex DL 298NA (latex based emulsion in water) Boilers 03 and 04) The owner/operator shall maintain daily monitoring of the petcoke blend ratio. This blend shall not exceed 30% by weight blend petcoke. The petcoke blend ratio shall be calculated daily by measuring the weight of the petcoke burned as well as the weight of the entire coal/petcoke mixture. Records of daily petcoke blend ratios shall be submitted to the Manager of the Technical Management Section, Bureau of Air Quality along with the quarterly CEMS reports.

Facility Notes: NOx and SOx are non-BACT, the rest are BACT

Thoroughbred (2 units)

State: KY ***EPA*** 4 ***Operational:*** no, Permit under litigation
MW: 2 units at 750 MW each ***MBtu/Hr:*** 7,446 MBTU/hour each - 2 units ***Number Of Units:*** 2
Permit Date: 10/11/2002 ***Permit*** V-02-001 Revision 1
Fuel: bituminous coal

Tucson - Springerville (2 units)

State: AZ ***EPA*** 9 ***Operational:*** no
MW: 2 units at 400 net MW each ***MBtu/Hr:*** 4,200 MBtu/hr each - 2 units ***Number Of Units:*** 2
Permit Date: 4/29/2002 ***Permit*** 1001554
Fuel: PRB
Facility Notes: Netted for NOx and SO_2, non-BACT for SO_2 and NOx; BACT for PM10, CO and VOC

Two Elk

State: WY ***EPA*** 8 ***Operational:*** no
MW: 280 MW (nominal) ***MBtu/Hr:*** 2,960 MBtu/hr ***Number Of Units:*** 1
Permit Date: 5/29/2003 ***Permit*** CT-1352B
Fuel: PRB

Whelan Energy Center Unit 2- Hastings

State: NE ***EPA*** 7 ***Operational:*** no
MW: 220 MW ***MBtu/Hr:*** 2,211 MBtu/hr ***Number Of Units:*** 1
Permit Date: 3/30/2004 ***Permit*** 58048
Fuel: PRB has a minimum heat content of approximately 8,100 Btu/lb (from NDEQWhelanFactSheet58048f02doc.pdf)

Wisconsin Public Service - Weston 4

State: WI ***EPA*** 5 ***Operational:*** no
MW: 500 MW ***MBtu/Hr:*** 5,173 MBtu/hr ***Number Of Units:*** 1
Permit Date: 10/19/2004 ***Permit*** 03- RV- 248
Fuel: PRB

WYGEN I (Black Hills)

State: WY ***EPA*** 8 ***Operational:*** yes (& tested)
MW: 80 MW ***MBtu/Hr:*** 1,014 MBtu/hr ***Number Of Units:*** 1
Permit Date: 9/6/1996 (5/17/2004) ***Permit*** CT-1236
Fuel: PRB
Facility Notes: Modified Permit CT-1236A reflects the as-build WYGEN 1 facility and to revise the short term SO_2 limit for the PC boiler from a 2 hour block average to a 3 hour block average. The as-built modifications consist of the installation of a boiler baghouse instead of a precipitator, installation of a Spray Dryer Absorber instead of a Circulating Dry Scrubber, and modifications to the material handling dust collectors.

WYGEN II (Black Hills)

State: WY ***EPA*** 8 ***Operational:*** no
MW: 500 MW ***MBtu/Hr:*** 5,145.7 MBtu/hr ***Number Of Units:*** 1
Permit Date: 9/25/2002 ***Permit*** CT-3030
Fuel: PRB

B

PLANTS EXCLUDED FROM THE STUDY

Facility	State	Exclusion Reason
AES Beaver Valley Partners, Inc.	PA	Not a new boiler
AES Hawaii	HI	Not a new boiler
Baldwin Expansion (Dynegy)	IL	Application only
Calla (Estill county)	KY	Not permitted yet
Cash Creek	KY	Application only
Clover, VA	VA	Not a new boiler
Collins Power Plant (Midwest)	IL	Withdrawn
Colstrip Energy Limited Partnership	MT	Not a new boiler
Colstrip Energy Limited Partnership	MT	Not a new boiler
Cottonwood Energy Center	NM	Application only
Deseret Generation & Transmission Company - Bonanza	UT	Not a new boiler
Desert Rock Energy (Steag Power)	NM	Application only
Dominion Resources - Ashtabula County	OH	Application only
Edison Mission Energy	PA	Not a new boiler
Encoal Corporation-Encoal North Rochelle Facility	WY	Pennsylvania NOx budget affected facility.
Franklin Proj. - IL Energy	IL	Application only
Gascoyne Generating Station (Montana Dakota Utilities)	ND	Not permitted yet
Great Plains Weston Bend	MO	Application only
Independence	AR	Not a new boiler
J.K. Spruce II - San Antonio	TX	Application only
Limestone Electric Generating Station (Reliant)	TX	Not a new boiler
Mustang (Peabody) Energy, Mustang Generating Station	NM	Not permitted yet
NorthHampton	PA	Not a new boiler
OPPD - Nebraska City Unit 2	NE	Application only
Orion Power Midwest LP	PA	Not BACT (RACT)
Sandy Creek Energy - LS Power	TX	Application only

Facility	State	Exclusion Reason
SC Elec & Gas Cope, SC	SC	Not a new boiler
Southwest Unit #2 - City Utilities	MO	Application only
Stanton (Orlando), FL (OUC- Orlando utilities)	FL	Not a new boiler
TECO-Big Bend Station	FL	Not a new boiler
TES Filer City Station	MI	Not a new boiler
Thermal Ventures (Martinsville Thermal)	VA	Not a new boiler
Trimble County (LG&E)	KY	Application only
TS Power Plant (Newmount NV)	UT	Application only
UAE Mecklenburg	VA	Not a new boiler
Upshur Energy Center (Dom.)	WV	Withdrawn
W.A. Parish Electric Generating Station (PSD-TX-234)	TX	Not a new boiler
WA Parish Electric Generating Station (PSD-TX-33 M1)	TX	Not a new boiler
WA Parish Electric Generating Station (PSD-TX-901, PSD-TX-902 & -33M1)	TX	Not a new boiler

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Appendix I

URS SO_2 Control Evaluation

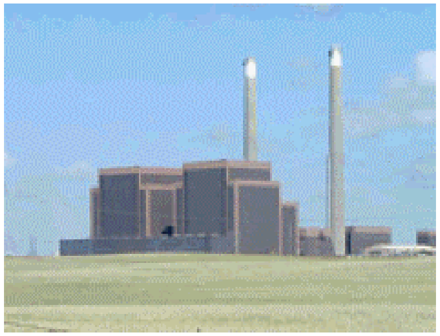
Reduction of SO_2 Emissions at Coal Creek

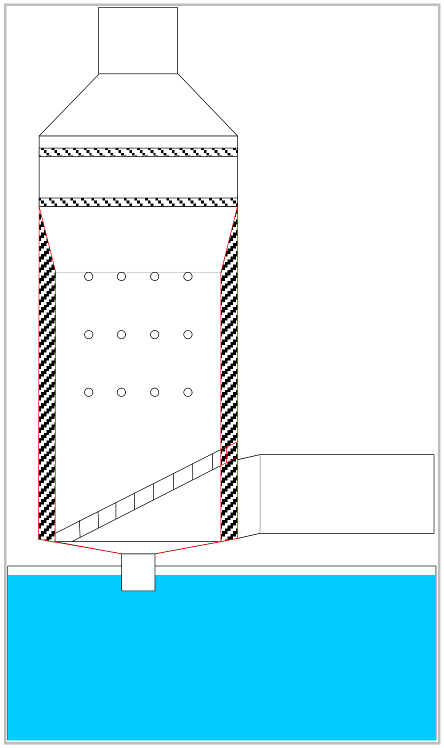
URS

GRE Coal Creek Units 1 & 2

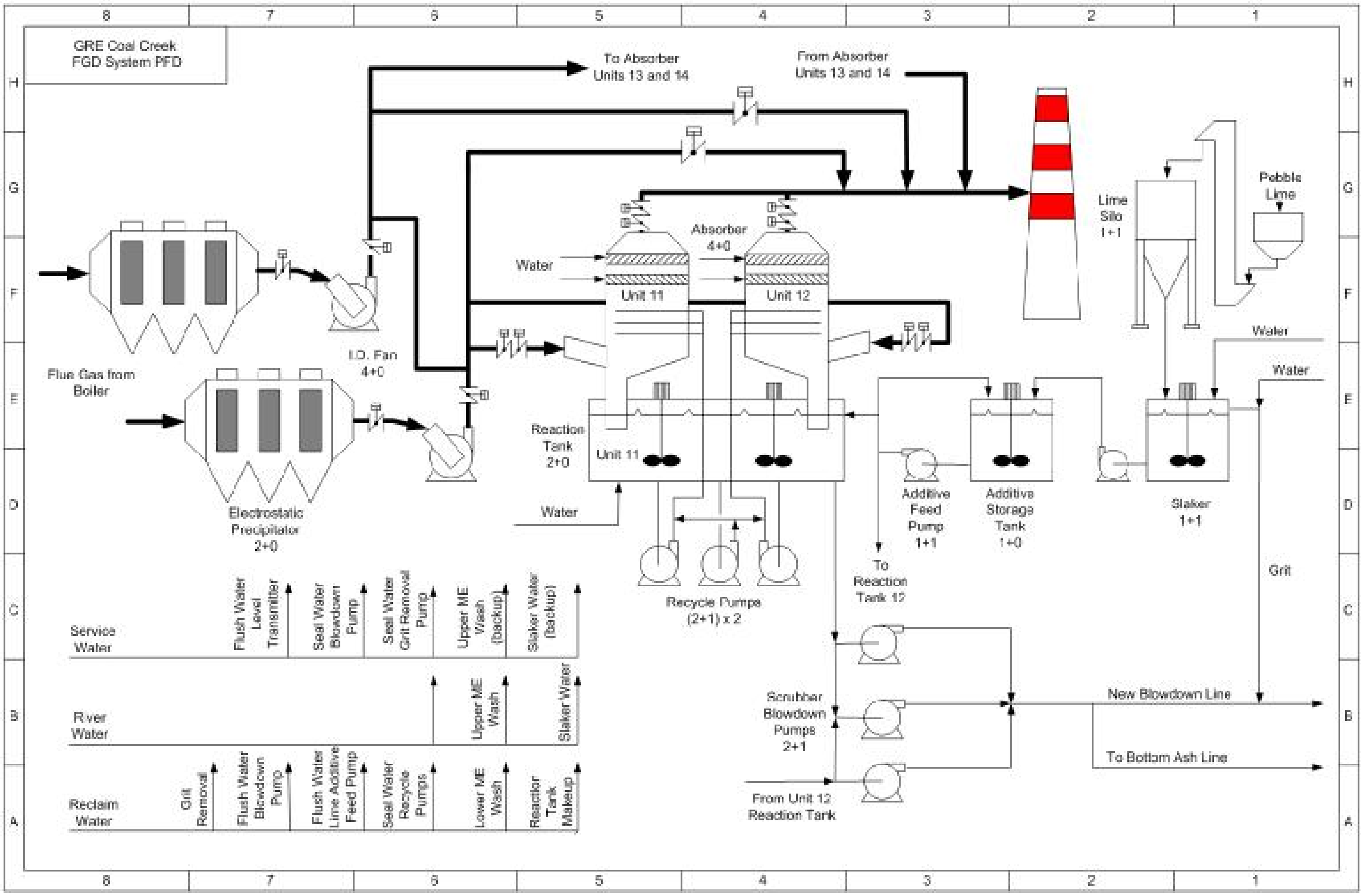
Review of Options to Reduce SO_2 Emissions

October 26, 2004





Process Flow Diagram



URS

Current Operating Conditions

- Operating data provided by GRE
  - Boiler
  - Fuel
  - Flue gas
- In most cases, the median value was used
  - Data from several months available
  - No significant trends detected in heat rate, flow or sulfur

Boiler & Fuel Characteristics	**Units**	**Current**
Unit Load	MW $_{gross}$	595
Plant Heat Rate	Btu/KWh)$_{gross}$	10,500
Heat Input	MM Btu/hr	6,248
Capacity Factor	percent	85
Coal HHV, Btu/lb	Btu/lb	6,200
Sulfur	percent	0.64
FGD Characteristics		
Absorber Removal	percent	95.0
Bypass	percent	27.0
Plant Removal	percent	69.4
Emissions	TPY	13,817
Allowances	TPY	23,111
Credits	TPY	9,294
Flue Gas Characteristics		
Excess Air, APH Leakage	percent	17.0
APH O_2 Concentration	percent	2.6
APH Flue Gas Flow Rate	scfm	1,485,334
APH SO_2 Concentration		795
ESP, Ductwork Leakage	percent	10.0
Stack O_2 Concentration		4.0
Stack Flue Gas Flow Rate	scfm	1,707,670
Stack SO_2 Concentration		262
Stack Temperature	deg F	191

Determination of Current Bypass

- Current bypass flow was determined using several different methods:
  - ü Historical Emissions
  - ü Stack Temperature

Method	Bypass	Accuracy	Comment
Historical Emissions	27.0	Poor	Annual average
Stack Temperature	28.0	Good	Heat losses hard to estimate
Mass Balance	27.0	Medium	Combo of all parameters
Median	27.0		

Mass Balance, 27% Bypass

	A	B	C	D	E	F	G	H
GAS COMPOSITION	Combustion Air	A APH Outlet	ESP/FF Outlet	FGD Bypass	FGD Inlet	Forced Oxidation Air	FGD Outlet	Stack
N_2	4,270,474	4,276,520	4,777,157	1,289,832	3,487,324	-	3,487,324	4,777,157
O_2	1,309,154	190,200	343,674	92,792	250,882	-	250,474	343,266
CO_2	2,833	1,369,894	1,370,226	369,961	1,000,265	-	1,005,919	1,375,880
Ar	72,972	72,972	81,527	22,012	59,515	-	59,515	81,527
SO_2		11,763	11,763	3,176	8,587	-	429	3,605
HCl		104	104	28	76	-	-	28
HF		5	5	1	4	-	-	1
H_2O	73,521	708,521	716,219	193,379	522,840	-	726,136	919,515
FLY ASH	-	84,644	423	114	309	-	108	222
GAS LB/HR TOTAL	5,728,954	6,629,979	7,300,674	1,971,182	5,329,492	-	5,529,797	7,500,979
TOTAL LB/HR	5,728,954	6,714,622	7,301,098	1,971,296	5,329,801	-	5,529,905	7,501,202
MOLE WT. GAS WET	29.33	28.68	28.69	28.69	28.69		28.06	28.22
MOLE WT. GAS DRY	28.96	30.87	30.67	30.67	30.67		30.65	30.65
TEMPERATURE, deg F	85.0	372.0	340.0	340.0	340.0		138.0	191.1
HUMIDITY, lb/lb	0.013	0.120	0.109	0.109	0.109		0.151	0.140
DRAFT, in.H2O	26.0	-20.6	-10.0	4.0	4.0		2.0	1.0
FLOW RATE, acfm	1,217,479	2,465,374	2,540,009	662,430	1,791,014		1,427,014	2,100,586
FLOW RATE, scfm	1,254,890	1,485,334	1,635,195	441,503	1,193,693		1,266,167	1,707,670
SO_2, ppm actual	-	795	722	722	722		34	212
SO_2, ppm dry	-	958	856	856	856		43	262
SO_2, lbs/MM Btu	-	1.88	1.88	0.51	1.37	-	0.07	0.58
SO_2, tpy		43,794	43,794	11,824	31,969		1,598	13,423
PARTICULATE, grains/acf	0.000	4.006	0.019	0.020	0.020		0.009	0.012
PARTICULATE mg/Nm3	0.0	16,353	74.3	74	74		25	37
PARTICULATE lbs/MM Btu	-	13.55	0.07	0.02	0.05	-	0.02	0.04
PARTICULATE, tpy	-	315,128	1,576	425	1,150		403	828
OXYGEN, percent	20.9	2.6	4.2	4.2	4.2		4.0	4.04
CO_2, percent	0.0	13.5	12.2	12.2	12.2		11.6	11.76

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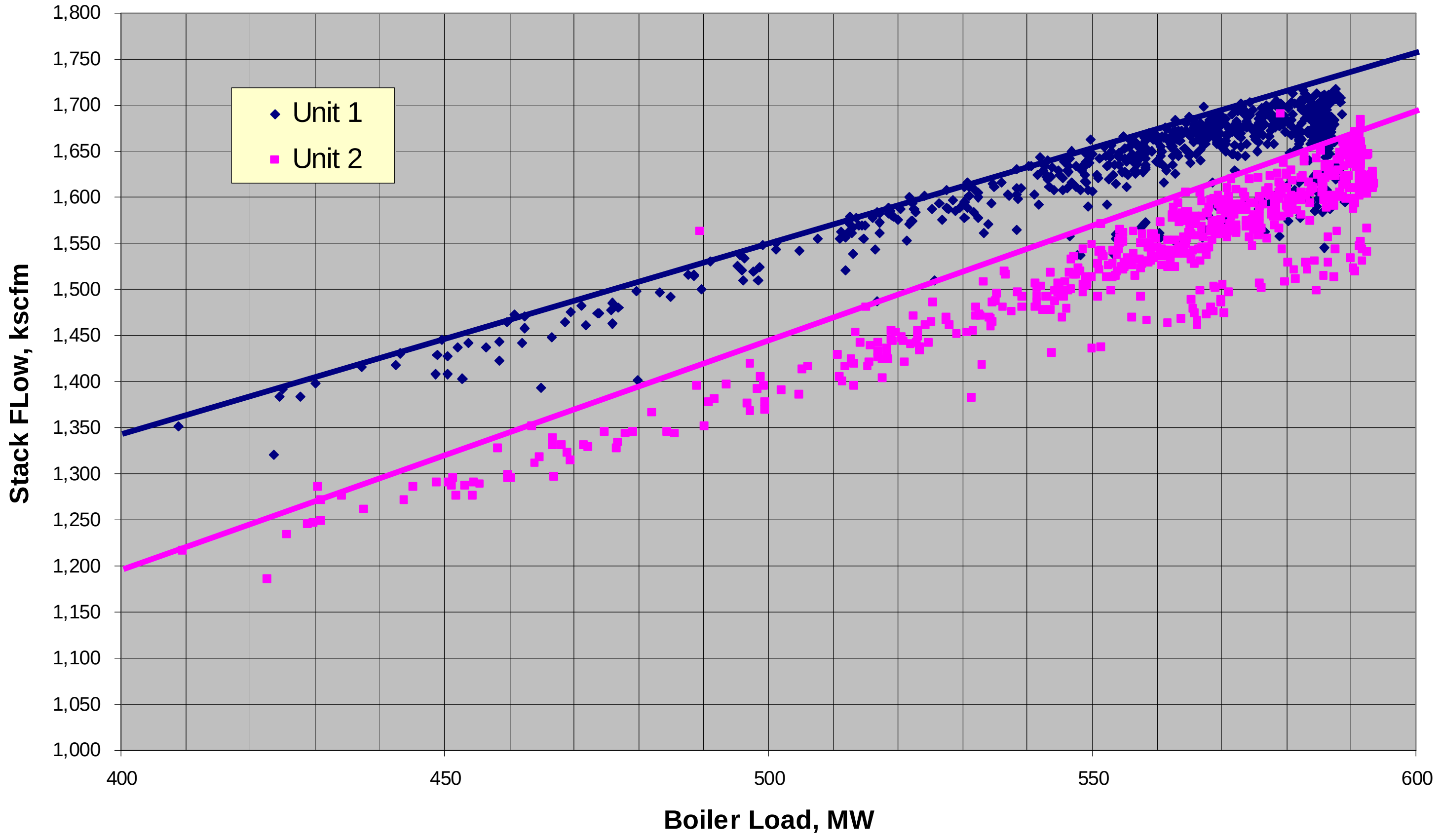
Flue Gas Flow Rate



1,750 kscfm used as maximum flow

Mass Balance, 0% Bypass

GAS COMPOSITION	A Combustion Air	B A APH Outlet	C ESP/FF Outlet	D FGD Bypass	E FGD Inlet	F Forced Oxidation Air	G FGD Outlet	H Stack
N_2	4,270,474	4,276,520	4,777,157	-	4,777,157	-	4,777,157	4,777,157
O_2	1,309,154	190,200	343,674	-	343,674	-	343,116	343,116
CO_2	2,833	1,369,894	1,370,226	-	1,370,226	-	1,377,971	1,377,971
Ar	72,972	72,972	81,527	-	81,527	-	81,527	81,527
SO_2		11,763	11,763	-	11,763	-	588	588
HCl		104	104	-	104	-	-	-
HF		5	5	-	5	-	-	-
H_2O	73,521	708,521	716,219	-	716,219	-	994,706	994,706
FLY ASH	-	84,644	423	-	423	-	148	148
GAS LB/HR TOTAL	5,728,954	6,629,979	7,300,674	-	7,300,674	-	7,575,065	7,575,065
TOTAL LB/HR	5,728,954	6,714,622	7,301,098	-	7,301,098	-	7,575,213	7,575,213
MOLE WT. GAS WET	29.33	28.68	28.69	0.00	28.69		28.06	28.06
MOLE WT. GAS DRY	28.96	30.87	30.67	#DIV/0!	30.67		30.65	30.65
TEMPERATURE, deg F	85.0	372.0	340.0	340.0	340.0		138.0	138.0
HUMIDITY, lb/lb	0.013	0.120	0.109	0.000	0.109		0.151	0.151
DRAFT, in.H2O	26.0	-20.6	-10.0	4.0	4.0		2.0	1.0
FLOW RATE, acfm	1,217,479	2,465,374	2,540,009	0	2,453,444		1,954,814	1,959,608
FLOW RATE, scfm	1,254,890	1,485,334	1,635,195	#DIV/0!	1,635,195		1,734,475	1,734,475
SO_2, ppm actual	-	795	722	-	722		34	34
SO_2, ppm dry	-	958	856	-	856		43	43
SO_2, lbs/MM Btu	-	1.88	1.88	-	1.88	-	0.09	0.09
SO_2, tpy		43,794	43,794	0	43,794		2,190	2,190
PARTICULATE, grains/acf	0.000	4.006	0.019	0.000	0.020		0.009	0.009
PARTICULATE mg/Nm3	0.0	16,353	74.3	0	74		25	25
PARTICULATE lbs/MM Btu	-	13.55	0.07	-	0.07	-	0.02	0.02
PARTICULATE, tpy	-	315,128	1,576	0	1,576		551	551
OXYGEN, percent	20.9	2.6	4.2	0.0	4.2		4.0	3.97
CO_2, percent	0.0	13.5	12.2	#DIV/0!	12.2		11.6	11.60

Gas Velocities

- Design Flow
  - Absorber Inlet Duct
    - Potential increase in erosion
    - Elevated pressure drop
    - Flue gas maldistribution
  - Absorber Mist Eliminator
    - High liquid loading
    - Scaling
    - Carryover
- Low Flow
  - No issues

Area	Units	Design Flow Flue Gas Bypass		
		0.00	10.00	27.00
Inlet Plenum	fps	75.61	68.05	55.2
Bypass Duct	fps	0.00	15.80	57.6
Absorber Inlet Duct	fps	67.4	60.7	48.5
Absorber Inlet	fps	67.4	60.7	48.5
Absorber	fps	19.2	17.3	13.8
Mist Eliminator	fps	~~16.0~~	~~14.4~~	~~11.5~~
Absorber Outlet Duct	fps	67.2	60.5	48.4
Stack Breach	fps	48.3	49.6	51.9
Stack Bottom	fps	53.7	55.1	57.7
Stack Top	fps	85.9	88.2	92.3

Area	Units	Low Flow Flue Gas Bypass		
		0.00	10.00	27.00
Inlet Plenum	fps	62.8	56.5	45.8
Bypass Duct	fps	0.0	13.1	47.8
Absorber Inlet Duct	fps	56.0	50.4	40.3
Absorber Inlet	fps	56.0	50.4	40.3
Absorber	fps	15.9	14.3	11.5
Mist Eliminator	fps	~~13.3~~	~~12.0~~	~~9.6~~
Absorber Outlet Duct	fps	55.8	50.2	40.2
Stack Breach	fps	40.1	41.2	43.1
Stack Bottom	fps	44.6	45.7	47.9
Stack Top	fps	71.3	73.2	76.6

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Available Options - Design

- Design, 10% Bypass
  1. Gas Velocity at 17 fps
  2. New mist eliminator
  3. Liquid Distribution Rings
  4. Duct and stack condensation traps
  5. Fan upgrade
     1. 2.4” increase in pressure drop
     2. Tip the fan
     3. New motor?
  6. Evaluate if DBA system is required to control scaling
     1. If scaling continues to be a problem – not expected

- Design, 0% Bypass
  1. Expand current towers or install a fifth module
     1. Reduce velocity from 18.9 fps to 15.4 modified
     2. Reduce pressure drop increase from 4.3” to 1.4”
  2. New mist eliminator
  3. Liquid Distribution Rings
  4. Fan upgrade
     1. 1.4” increase in pressure drop
     2. Within the capability of the existing fan?
  5. Duct and stack condensation traps
  6. **Stack upgrade or new stack**
  7. Evaluate if DBA system is required to control scaling
     1. If scaling continues to be a problem – not expected

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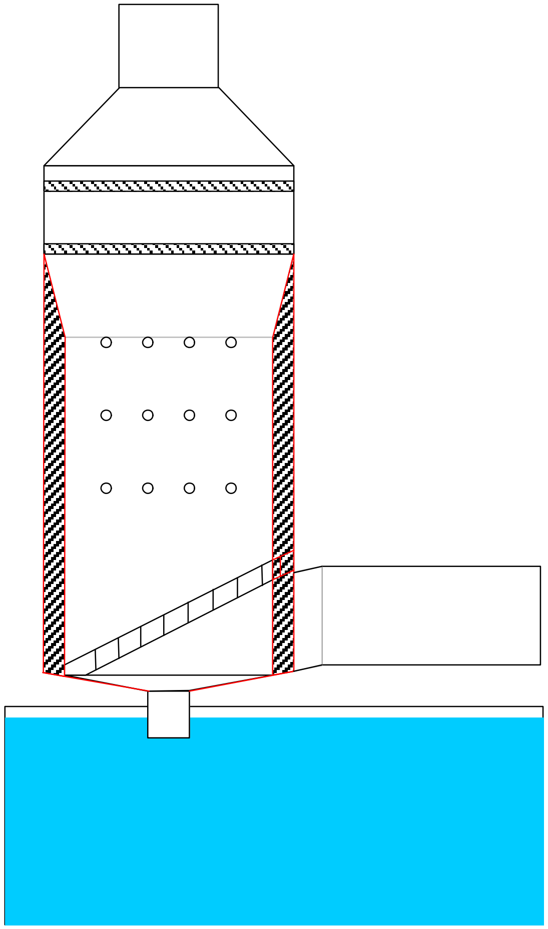
Expand Current Absorber Modules

- Concept
  - Upgrade to straight sides
  - Pros
    - Complete utilization of ME area
    - 20 percent reduction in gas velocity
    - No changes in:
      - Foundation
      - Building
      - Electrical
      - Process etc
      - Equipment (pumps etc)
  - Cons
    - Module outages required
      - Can be completed over several regular scheduled outages
    - Substantial field work



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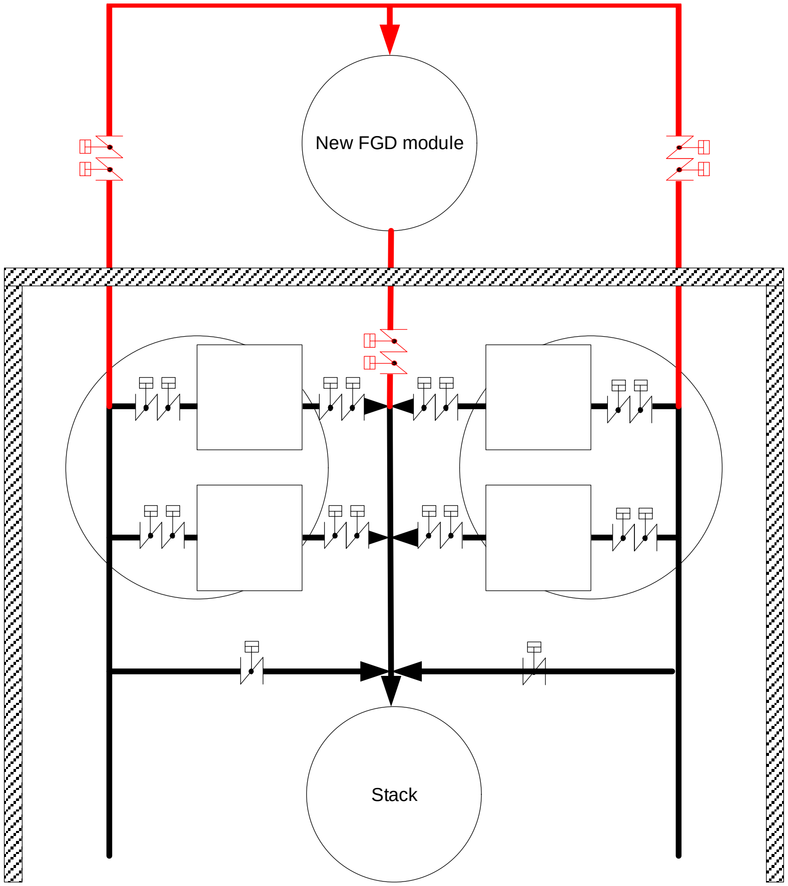
New Fifth Absorber Module

- Concept
  - Install a fifth absorber module
  - Pros
    - 20 percent reduction in gas velocity
    - Limited impact on operation
  - Cons
    - Considerable plant impact
      - Building expansion
      - Foundation
      - Electrical
      - Process (pumps, piping)
      - Ductwork
      - Dampers
      - Flow balancing



Lime Slaker Capacity

- Lime Consumption
  - Current: 4.7 tph
  - 10% bypass
    - 4.7 tph
    - One slaker required
  - 0% bypass:
    - 6.4 tph
    - Two slakers required
- Byproduct Blowdown
  - Current 234 gpm
  - Future 288 to 320 gpm
  - Sufficient capacity for all conditions

Bypass percent	Lime Consumption tph	Blowdown Rate gpm
0	6.4	325
10	5.8	292
20	5.2	260
27	4.7	237
30	4.5	227
6+4 tph slaker capacity		
2 x 300 gpm blowdown pump capacity		

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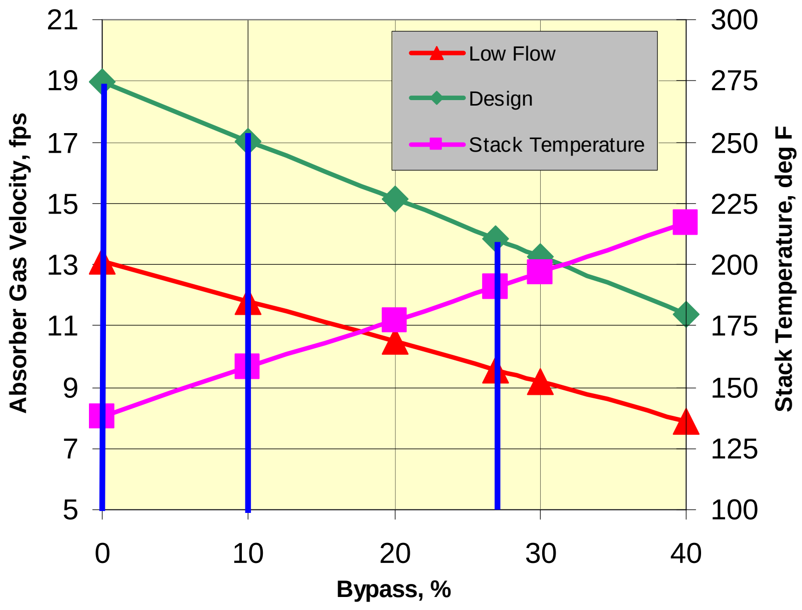
Mist Eliminator and Stack

- Maximum gas velocity in the Spray Zone and ME

Bypass %	Design fps	Low Flow fps
0	18.9	15.9
10	17.0	14.3
20	15.2	12.8
27	13.8	11.6

- Issues from higher gas velocity
  - Higher liquid loading potentially leading to carryover
  - Increased alkalinity on the ME vanes potentially leading to scaling
  - Potentially higher wall sneakage leading to lower SO_2 removal
  - Reduced L/G leading to lower SO_2 removal



- Stack temperature
  - 158 ^{o}F at 10 percent bypass
    - May not be sufficient during winter
  - 138 ^{o}F at 0 percent bypass
    - Wet stack or reheat?

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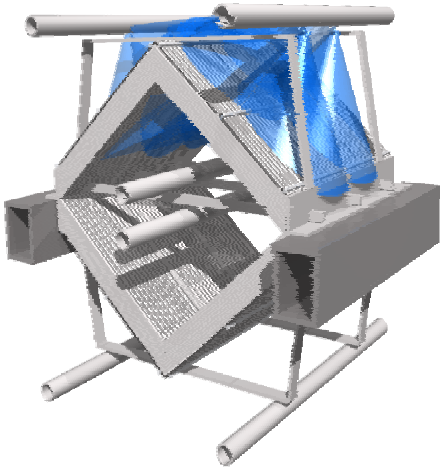
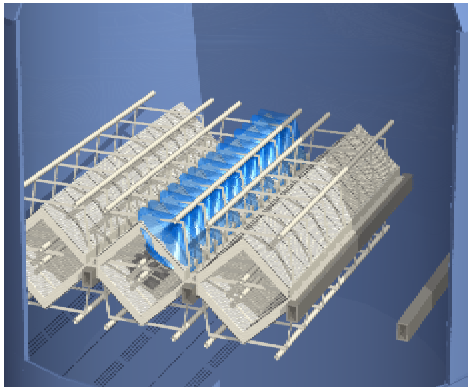
Achieve Required ME Performance

- New High Velocity Mist Eliminator
  - Munters DV 210 Plus
    - Single layer, diamond shape ME
    - Increased disengagement zone
    - Ideal for rectangular tower designs
    - High velocity, up to 25 fps continuous flow
    - Can handle flue gas mal-distribution up to 29 fps
  - Change wash water to 50/50 mixture of ash/service water





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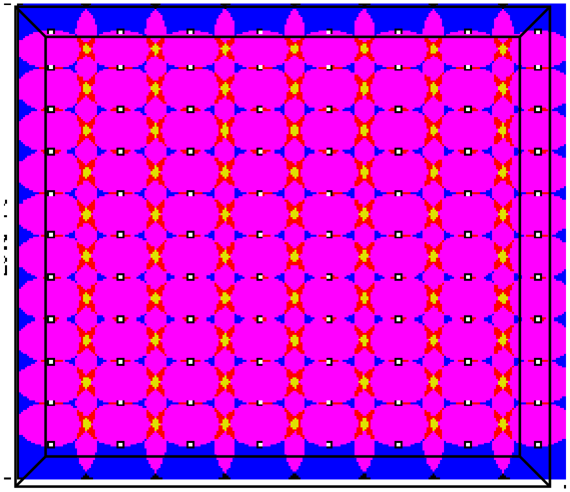
ME Wash System Guidelines

- Wash intensity – 1.5 gpm/ft2
- Wash pressure - >40 psi
- Spray nozzle – 90 degree, full cone
- Wash coverage – 200% overlap
- Distance from tip of wash nozzle to ME surface – 18” to 36”
- Wash duration – 90 to 120 seconds
- Wash frequency – 1st stage and front side of 2nd stage every 2 to 3 hours
- Backside of 2nd stage every 4 to 8 hours
- Wash water - < 50% saturated

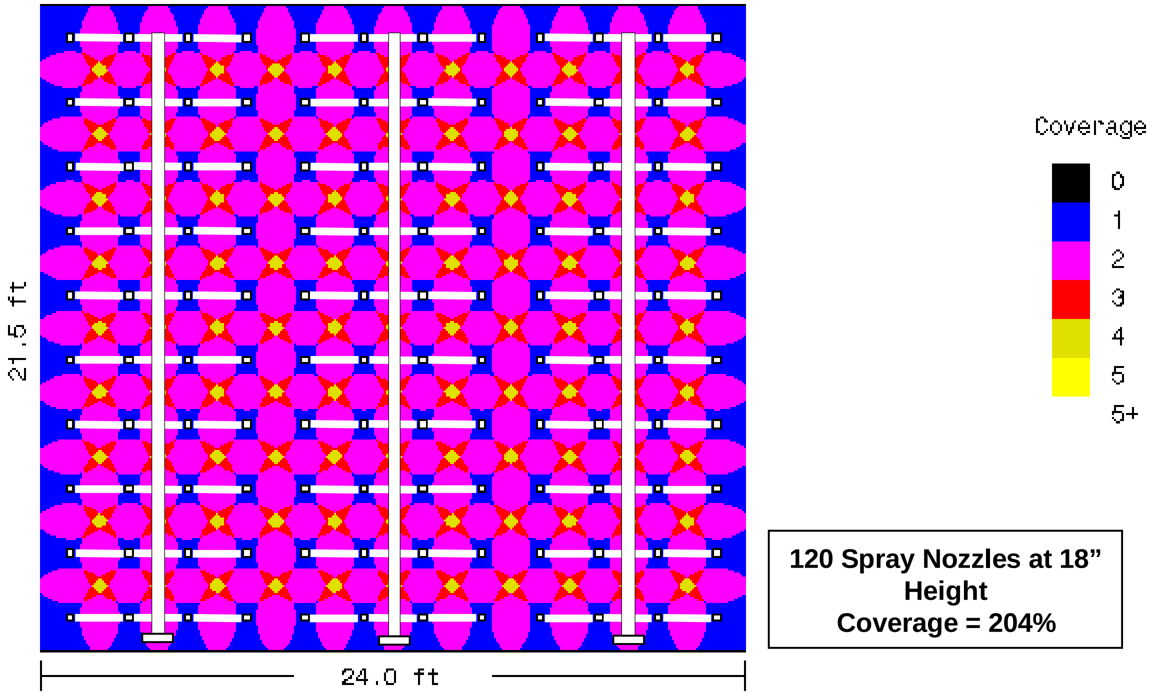
Eliminate Wall Sneakage

- Liquid Distribution Rings
  - improve gas distribution
  - eliminate wall sneakage
  - increase SO_2 removal



Conditions		Design		Low Flow	
		Absorber	Station	Absorber	Station
As is	0	89.9	89.9	90.1	90.1
	10	90.9	81.8	92.3	83.1
	27	93.7	68.4	96.0	70.1
with LDR	0	94.0	94.0	94.1	94.1
	10	94.6	84.6	95.4	85.4
	27	96.2	69.2	97.6	70.6

Proposed Nozzle Layout

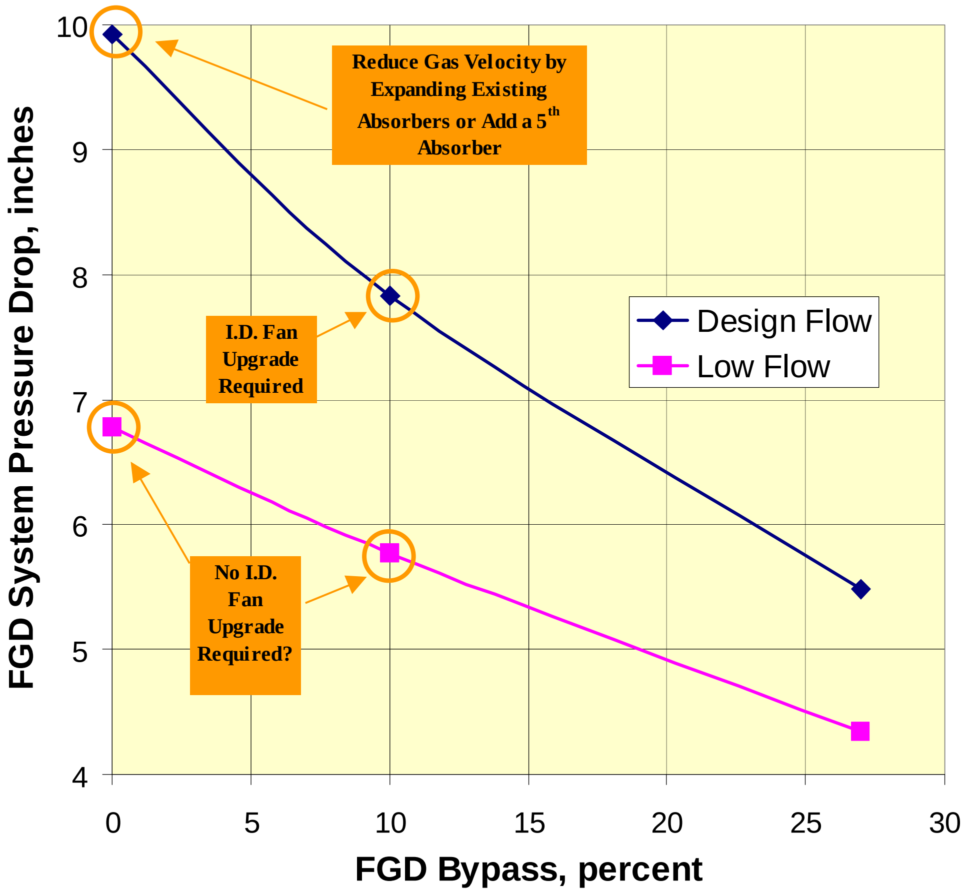


120 Spray Nozzles at 18" Height Coverage = 204%

Figure 3: Proposed Nozzle Layout and Wash Coverage for Intermediate Wash Levels

Fan Capacity – Pressure Drop

- No Absorber Mods Implemented
  - Design
    - 5.5” at 27% bypass
    - 7.8” at 10% bypass
    - 9.9” at 0% bypass
  - Low Flow
    - 4.2” at 27% bypass
    - 5.7” at 10% bypass
    - 6.8” at 0% bypass
- Fan upgrade required and/or
- Reduction in gas velocity



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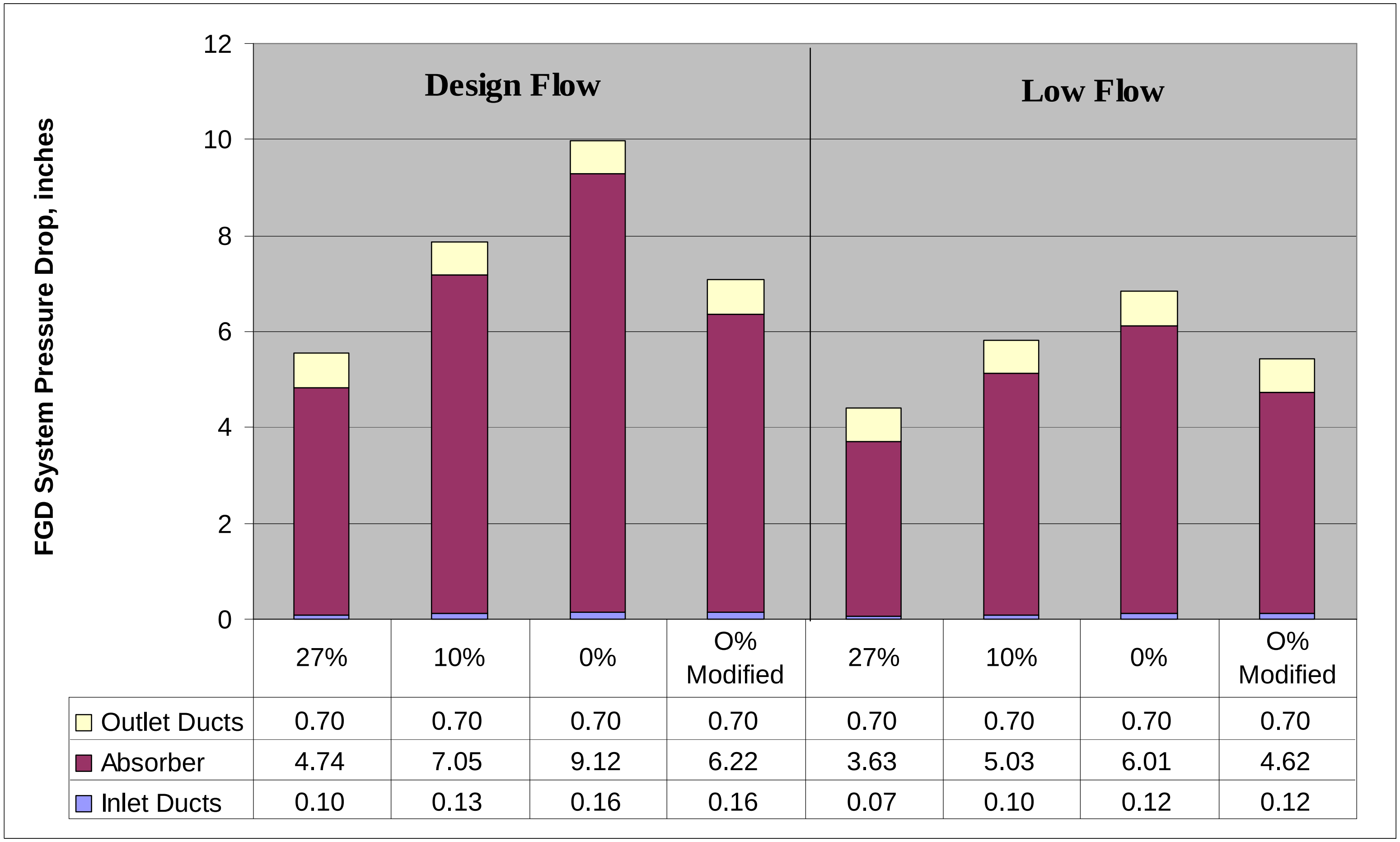
Pressure Drop Prediction



	Design Flow				Low Flow			
	27%	10%	0%	O% Modified	27%	10%	0%	O% Modified
🟨 Outlet Ducts	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
🟪 Absorber	4.74	7.05	9.12	6.22	3.63	5.03	6.01	4.62
🟦 Inlet Ducts	0.10	0.13	0.16	0.16	0.07	0.10	0.12	0.12

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Remaining Issues – Path Forward

- Is partial bypass permissible
    - Costly stack modifications or a new stack can possibly be avoided
- Does zero bypass require a dry stack or is a wet stack feasible
    - Can the existing stack be upgraded to accommodate new conditions
- Can the existing fans be upgraded to provide the required head
    - Is the fan motor capacity sufficient
- Study gas distribution inside absorber modules and associated duct work using CFD to reduce overall pressure drop
- Select upgrade option/options, validate design assumptions and fine tune cost estimates

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Summary

- Stack uses other than condensation traps excluded from study
- If permissible, partial bypass (10%) is clearly the low cost option
- Reducing flue gas flow is very cost effective option
- If zero bypass is required, expanding the current absorber modules is the low cost and least intrusive approach
- URS has the experience and know-how to provide the required absorber modifications

Appendix J

Revised Foster Wheeler Proposal

Added February 2007

FOSTER WHEELER NORTH AMERICA CORPORATION
Perryville Corporate Park
Clinton, NJ 08809-4000, USA

TANGENTIAL LOW NOx COMBUSTION SYSTEM EMISSIONS PERFORMANCE UPGRADE

GREAT RIVER ENERGY

COAL CREEK
UNITS 2

Proposal No. 65-120220-00 rev01

October 6th, 2006

PROPIETARY AND CONFIDENTIAL INFORMATION

This proposal and the information, design and material contained and/or illustrated herein (hereinafter "proprietary and confidential" material), are the property of FOSTER WHEELER NORTH AMERICA CORPORATION, (FWNAC) and is submitted, lent and furnished to you in the strict confidence with the expressed understanding that you shall not use said proprietary material for any purpose other than for the evaluation of this proposal or reproduce, copy, lend, dispose of, or disclose said proprietary material to anyone outside receipt organization. By receiving said proprietary material you agree not to use the same in any way injurious to the interest of FOSTER WHEELER NORTH AMERICA CORPORATION, and agree to return to same upon request.

The Foster Wheeler North America Corporation Services Management Commitment

Foster Wheeler is committed to being the vendor of choice for our utility and industrial clients by continually supplying products and services that meet their need for improved profitability. We will accomplish this through open communication and measurable performance objectives and by being fiercely focused on cost.

Foster Wheeler is uniquely qualified to support the mission of Great River Energy with over a century of experience with design, fabrication, erection, commissioning, and rehabilitation of steam generating equipment. We have over 150,000 MW of installed equipment. Our mission is to provide our clients the best low NOx technology in the world. The experience we have gained through over 200 million hours of operation of our equipment and our sophisticated simulation models allow us to accurately predict how your unit will operate as a result of changes intended to increase performance, reliability, and operational flexibility, regardless of the OEM. As a subsidiary of Foster Wheeler Limited, we have the financial clout to stand behind our performance guarantees. We have the project managers, engineers, procurement and financial specialists and the manufacturing, erection, and commissioning capability to meet your needs regardless of complexity. Our list of repeat, satisfied customers is long and growing. We would like to continue our relationship with Great River Energy with this challenging project and look forward to the opportunity to work with you.

Sincerely,

Ed Dean

Executive Vice President, Services Division

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1. EXECUTIVE SUMMARY

Foster Wheeler North America Corporation is pleased to submit to Great River Energy our proposal for the engineering and material supply of a TLN3 System for Coal Creek Units 1 & 2. Foster Wheeler has enjoyed the successful relationship we have and look forward to serving Great River Energy in this and future projects. Foster Wheeler believes this proposal is a high value solution with many unique features and capabilities that will benefit the long-term emission performance, operation and maintenance of these units.

The original TLN3 system supplied by Foster Wheeler in the late 1990s was designed to reduce NOx below 0.35 lb/MBtu. After installation and optimization, even lower NOx levels were achieved. Great River Energy is planning to install a coal drying system to reduce the coal moisture from current levels of 35 – 38%. After this system is on-line, the primary air will be greatly reduced from current levels of over 50%. This primary air reduction will result in more secondary air available for staging as well as introduction into the main windboxes.

The new TLN3 System is based on increasing the size of the SOFA windboxes and ducts to allow more overfire air and thereby lower NOx levels. In addition, the main windbox damper venturi system will be modified to accommodate the increased amount of secondary air.

Primary Scope of Supply

Our base scope of supply includes all the necessary components to achieve the requested 0.17 lb/MBtu NOx levels.

a) The proposed TLN system(s) will be based on a single level of separated overfire air (SOFA) including all necessary waterwall tube panel openings and secondary air ducting. The new, larger SOFA windboxes will be located in the same location as the current windboxes. The SOFA ductwork is larger to allow more flow, but is less tortuous to provide less pressure drop.

b) Larger damper venturis will be provided to allow operators with enhanced air-staging capability. It also improves windbox-to-furnace and secondary air damper control over a greater unit load range.

c) Foster Wheeler patented Double Shroud “Boundary” auxiliary air nozzles will be provided to direct air in “multiple directions” versus just “concentrically”, to reshape the fireball for control of slagging, emissions, as well as oxygen and temperature profiles.

Other typical features of the Foster Wheeler TLN Systems

a.) Our separated overfire air systems are designed to <u>reduce installation time and costs</u> including minimal, or no buckstay modifications, minimal tube cuts, etc.

b.) All nozzle tips, windbox components and upgrades are <u>100% compatible</u> and interchangeable with existing windbox equipment.

c.) We provide a <u>full line</u> of tilt, damper and other related tangential firing equipment upgrades to compliment your TLN retrofit.

Our vision is to provide our clients with the best low NOx coal fired technologies in the world. We believe we have achieved this goal. As part of this goal we provide user-friendly, low NOx systems that not only meet your long-term emission and boiler performance objectives, but also minimize retrofit and long-term operating costs. We look forward to continuing our relationship with Great River Energy with this project.

2. INTRODUCTION TO FOSTER WHEELER NORTH AMERICA CORPORATION

In 1927, Foster Wheeler Corporation was formed when Wheeler Condenser and Engineering Company of Carteret, New Jersey merged with Power Specialty Company of Dansville, New York. Innovators in the field of superheaters and condensers, the two companies, operating as Foster Wheeler Corporation, went on to form other subsidiary companies to specialize in different facets of the steam generation and process plants industries.

Foster Wheeler Corporation grew and subdivided into Foster Wheeler Ltd., Foster Wheeler International Corporation, and Foster Wheeler Equipment, Process Plants and Fired Heater Divisions. In 1973, Foster Wheeler Energy Corporation (FWEC) was established by joining the FWC Equipment, Process Plants and Fired Heater Divisions.

In 1985, Foster Wheeler Energy Corporation transferred the assets of the Process Plants and Fired heater Division to form Foster Wheeler USA Corporation. Foster Wheeler Constructors, Inc. was formed in 1987 to provide construction services for both FWEC and FWUSA. In 2001, Foster Wheeler Corporation organized and adopted the name Foster Wheeler Ltd. Today, Foster Wheeler Ltd. is an internationally operating company addressing the needs of clients through two operating groups. They are the Engineering & Construction and Energy Equipment Groups.

Foster Wheeler Power Corporation (FWNAC) is the wholly owned subsidiary of Foster Wheeler Power Group, Inc. (FWPGI) in the United States of America. FWPGI provides products and services in steam generation and process plant markets throughout the world.

With the acquisitions of Zack Power and Industrial and Alhstrom Pyropower in 1995, Foster Wheeler Power Group Inc. now offers greater capabilities within our range of products and services. Operations have expanded and include engineering and construction services, manufacturing, research and development, aftermarket customer service and project management. Our equipment includes pulverized coal, oil and gas boilers (both utility and industrial), fluidized bed boilers (bubbling and circulating), condensers, feedwater heaters, tubular air heaters, wall, tangential and arch fired burners, pulverizers and other related equipment.

The scope of FWNAC Services includes, but is not limited to, engineered unit retrofits, increase in unit efficiency and availability, test and performance engineering, inspection services, engineering and life extension studies, alternative fuel firing, options and analysis, and replacement parts. This full-service operation ranges from conceptual analysis through manufacturing and construction for all boiler types, regardless of size, fuel or original design.

3. TECHNICAL DISCUSSION

3.1 Unit Description

Coal Creek Units 1 & 2 are 560 MWG, controlled circulation, radiant, reheat, balanced draft, and divided furnace, Combustion Engineering (CE) generating units. Each unit was originally designed for a maximum continuous rating (MCR) for superheat and reheat steam flow of 3,730,000 lbs/hr and 3,325,000 lbs/hr, respectively. Steam conditions at the superheater outlet are 1,005°F and 2620 psig. Reheat outlet temperature of 1,005°F is controlled by fuel nozzle tilt and superheat outlet temperature is controlled by two desuperheating spray valves (one for each furnace half).

The unit is designed to fire North Dakota Lignite from the nearby Falkirk mine, through eight (8) 1043 RP mills with hydraulics into eight elevations of tilting tangential fuel nozzles. Each of the 1043 RP pulverizers were designed to pulverize 136,8000 lbs/hr coal flow with a Hardgrove Grindability Index (HGI) of 35, while producing coal fineness output of 65% through 200 Mesh and 2% on 50 mesh screens. The moisture of the coal was specified for design as 36.6%, but typically varies between 35 and 42%. The design airflow through these 1043 RP mills was 255,000 lbs/hr.

In the early 1990’s, the 1043 RP mills were retrofitted with ABB-CE vane wheels to increase airflow. Currently, these mills operate at 350,000 lbs/hr airflow in order to keep the mill outlet temperatures above 145 °F. At mill outlet temperatures below 145 °F, these pulverizers have the tendency to load up and/or plug up.

In the late 1990’s, Foster Wheeler designed and supplied the current TLN3 low NOx system. It was designed to achieve NOx emission levels of 0.35 lb/MBtu. Further reduction with the Foster Wheeler TLN3 System was achieved after tuning and optimization. Currently, NOx emissions range between 0.18 – 0.30 lb/MBtu.

3.2 Technical Evaluation of Current Unit Operation

We believe that it is very important, when designing a low NOx firing system retrofit, that the designers understand the current unit operation including fuel effects, equipment limitations and client requirements. Each boiler windbox arrangement is simulated with our proprietary Windbox Simulation Program to assure proper flow distribution for staging and air jet penetration for optimal fuel air mixing. We also look at the boiler design and arrangements, fuel ranges and constituents, pulverizer air, coal and fineness, burner zone heat release rates, etc. We also compare each proposed design to other similar units that we have retrofit, further assuring successful post-retrofit performance.

Foster Wheeler was last on site to perform some unit optimization in August 2005. Some highlights of this evaluation are presented below. FWNAC believes that such on-site evaluations and discussions with operations personnel allow the designer to provide a low NOx system custom tailored for the unit.

- Overall, this unit currently operates at average NOx levels compared to units of similar vintage and size firing similar coals. NOx emissions at full load range from 0.18 to 0.30 lb/MBtu. The EPA website data shows the NOx averaging 0.22 to 0.24 lb/MBtu at full load. The higher NOx values are attributed (most likely) to a function of main windbox burner tilt location, excess air levels and manual, non-adjusted control of main windbox air dampers. During the August optimization, NOx levels were maintained at 0.18 lb/MBtu for extended periods.
- Main burner tilts operate above horizontal position between 5 to 12 degrees
- CO levels are not measured on these units.
- UBC is reportedly below 0.5%
- Mill fineness is reported as 65% though 200 mesh and 98% through 50 mesh.
- Windbox-to-furnace differential pressure averages 4.0 – 4.5 In. H_2O at 100% MCR.
- Superheat and reheat temperatures were 1000 °F and 1003 °F respectively.
- Boiler O_2 averaged 2.5% during optimization with side to side values measuring ±0.2% from average.
- All pulverizers were evenly loaded during the testing.

3.3 Foster Wheeler’s Tangential Low NOx (TLN) Systems

3.3.1 Design Philosophy

Foster Wheeler North America Corp’s (FWNAC) Tangential Low NOx (TLN) Combustion Systems provide industrial and utility boiler owners with an alternative solution to their NOx compliance needs. Our philosophy is to provide our clients with the highest value low NOx system.

- Our systems are designed to maximize NOx reduction efficiency while minimizing the impact on combustion performance or unit operation. Our combined wall and tangential-fired combustion expertise gives FWNAC a unique perspective no other combustion equipment supplier can claim. An extensive support team of experienced technical and project specialists backs our commitment.

- We focus on designing systems that minimize changes to the furnace and/or the boiler house. This reduces installation time and costs for the owner.

- We believe each TLN application should compliment the unit's operational capabilities as well as the range of current and future fuels.

- We believe that each TLN system should provide years of reliable service. All tangential-fired windbox components are manufactured in either our own facilities or per our specifications by high quality suppliers.

- A team of experienced and qualified tangential firing engineers, project managers, service engineers and suppliers, supports each project. Our goal is to make each of your TLN retrofits your most favorable project.

Our system technology is supported by a continuous commitment to improve performance and reliability. For example, our on-line, real-time, ECT coal flow distribution, velocity and particle size monitoring technology combined with our CADM system allows fuel and air to be more balanced for lower CO and higher combustion efficiency.

3.3.2 FWNAC’s TLN Systems

Foster Wheeler’s Tangential Low NOx (TLN) firing systems are based on the application of secondary air staging technology commonly referred to as “overfire air”. Both in-windbox and separated secondary air-staging arrangements are applied depending on current windbox configurations and the desired level of NOx reduction. Staging of secondary combustion air has been well documented throughout the international boiler industry to be the single most effective technique for reducing NOx emissions from tangentially fired boilers. By redirecting a portion of the combustion air above the upper fuel elevation, fuel nitrogen conversion and thermal NOx production is reduced. Control of this staging process through proper nozzle and damper design is critical in order to maximize combustion efficiency and component longevity. Depending on the unit configuration and required NOx reductions, Foster Wheeler can offer several high value options. These include the TLN1, TLN2 and TLN3 arrangements, which are shown below in **Figure 1.**

FWNAC’s **TLN1** arrangement is an “in-windbox” secondary air staging system. It consists of reconfiguring the tangential windbox fuel and air nozzle arrangement to provide the required air staging effect. The TLN1 arrangement requires lowering existing upper coal elevations in the windboxes to make provision for “in- windbox secondary air staging, or overfire Air. Depending on the specific windbox arrangement, these systems can provide up to approximately 250 ppm (corrected to 3% O_2) of NOx reduction.

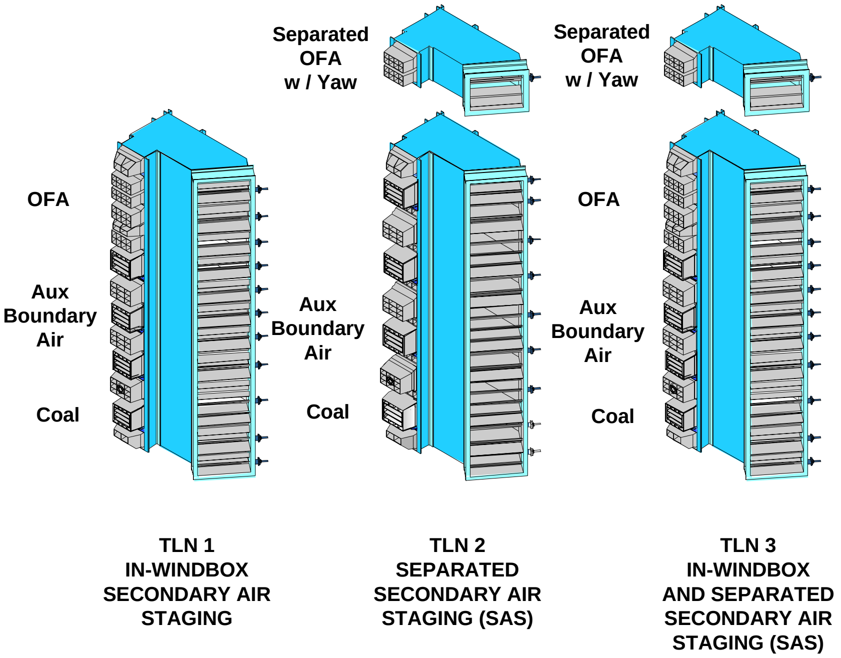


Figure 1 - FWNAC Tangential Low NOx (TLN) Configurations

Alternatively, for units that already have in-windbox/CCOFA compartments installed, the TLN1 installation would involve installing High Efficiency (HE) type CCOFA and top end air nozzle tips. These provide up to an additional 30% more flow area than the original tips. By utilizing the existing manual tilt capabilities in the CCOFA compartments, separation can be obtained between the CCOFA and the main combustion zone. In addition, the flow areas in the bottom end air, auxiliary air, and coal elevations would be optimized to bias air flow to the top end air / CCOFA elevations and nozzle tips would be re-sized to maintain design outlet velocities.

The TLN1-HE arrangement can also be upgraded to a TLN3 System in the future with minimal main windbox modifications

FWNAC also offers more aggressive NOx control arrangements using Separated Overfire Air (SOFA), including the TLN2 and the TLN3 systems. Increased separation between the upper most coal elevation and overfire Air level results in greater NOx reduction. Depending on the unit design and fuel, these arrangements are capable of NOx reductions exceeding 70%.

FWNAC's **TLN2** system consists of adding an additional level of overfire Air above the main firing zone to provide the required air staging effect. Because of increased spacing from the upper coal elevation, these arrangements generally provide higher NOx reduction efficiencies compared with in-windbox arrangements.

FWNAC's **TLN3** system consists of adding single level of separated overfire Air to units that already have an in-windbox OFA. This system is best suited for both post-NSPS or unit units previously retrofit with in-windbox overfire Air arrangements. Other applications of the TLN3 arrangements are units where interferences do not permit placement of an adequate single overfire Air windbox. According to our experience, the reduction efficiencies of the TLN3 systems are similar to TLN2 systems.

It should be noted that applying more levels of overfire air results in a limitation of furnace residence time for carbon particle burnout; therefore careful design consideration is required to minimize UBC losses.

3.4 Typical TLN Components and System Features

3.4.1 Separated Overfire Air Systems

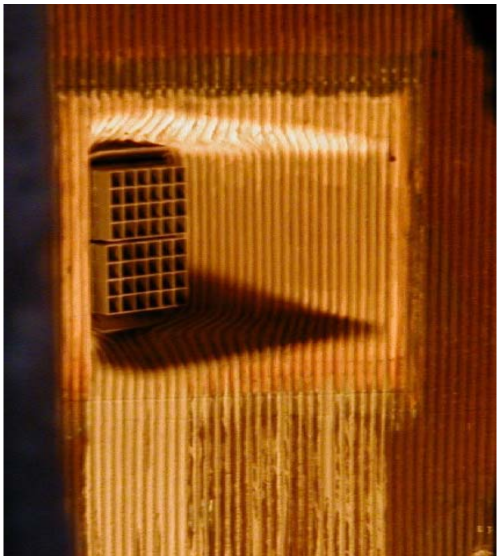
The advantages of the FWNAC Separated Overfire Air (SOFA) system over other suppliers are its compact, yet performance efficient, design. This reduces the physical changes within the boiler house, thereby reducing installation time and cost. See **Figure 2** below for typical SOFA windbox and nozzle assembly**.**

Figure 2 - TLN Separated Overfire Air Windbox with Horizontal Yaw and Vertical Tilt Control

Introduction of staged secondary air, as “overfire air” is the single most important NOx performance component in any tangential low NOx system retrofit. Whether it is located in the main windbox or separated, it should provide the highest NOx reduction efficiency. The FWNAC SOFA systems provide the following specific features:

1. Compact separated windbox design that minimizes installation costs associated with tube panels, buckstay or other boiler house modifications.
2. Optimum vertical and horizontal placement assures highest NOx reduction efficiency and maximizes fuel/air mixing during this critical stage in the combustion process.
3. SOFA placement considers minimizing tube cuts and welds.
4. Adjustment capability is provided for maximizing fuel/air mixing through horizontal yaw, velocity, tilt and flow control.
5. Separated staging windboxes are fitted with turning vanes. The associated connecting duct designs are laid out to minimize system resistance, reducing auxiliary power requirements.
6. A minimal number of nozzle tips and linkages are applied to improve reliability and reduce long-term maintenance.
7. No refractory SOFA ports, only proven adjustable stainless nozzle tips with directional control are used.
8. Pressure taps in each compartment provide air distribution information and are used in the optimization process.
9. All components are designed and fabricated for long-term reliability.
10. For more aggressive NOx control, Foster Wheeler offers ours ECT and CADM systems, which allow for real-time quantified coal pipe distribution, velocity and particle size as well as air distribution.
11. Pressure taps in each compartment provide air distribution information and are used in the optimization process.
12. All components are designed and fabricated for long-term reliability.
13. For more aggressive NOx control, Foster Wheeler offers ours ECT and CADM systems, which allow for real-time quantified coal pipe distribution, velocity and particle size as well as air distribution.

Foster Wheeler SOFA Windbox with two "double shroud" nozzle tips



Installed TLN SOFA System

Figure 3 - Foster Wheeler Separated Overfire Air Windbox

14. Pressure taps in each compartment provide air distribution information and are used in the optimization process.

15. All components are designed and fabricated for long-term reliability.

16. For more aggressive NOx control, Foster Wheeler offers ours ECT and CADM systems, which allow for real-time quantified coal pipe distribution, velocity and particle size as well as air distribution.

3.4.2 Coal Nozzle Tips and Nozzle Assemblies

All Foster Wheeler coal nozzle tips and coal nozzle assemblies are designed to match coal characteristics and pulverizer performance. This is key to preventing future pluggage or burn-back problems that reduce component life and inhibit unit long-term emission performance. All are designed to provide localized air staging, complimenting the overfire air based TLN system. Each Foster Wheeler coal nozzle assembly offers the following features:

1. All coal nozzle tips are designed to maintain high temperature structural integrity. This includes the mechanical design aspect as well as radiation protection for the internal sections. Foster Wheeler's new "Double Shroud" (DS) coal nozzle tips (US

Patent No. 6,260,491) are standard on most TLN retrofits. This design can offer even greater high temperature thermal resistance over conventional designs. See **Figure 4** below.

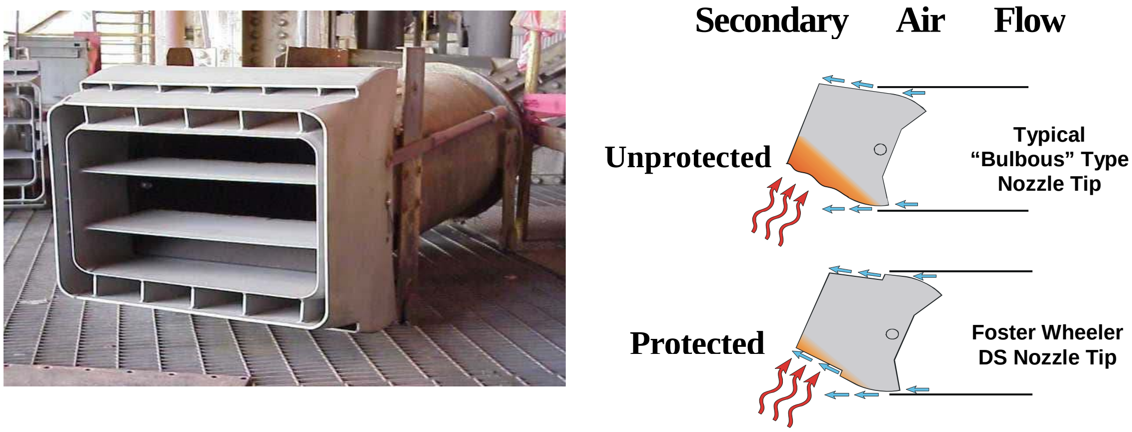


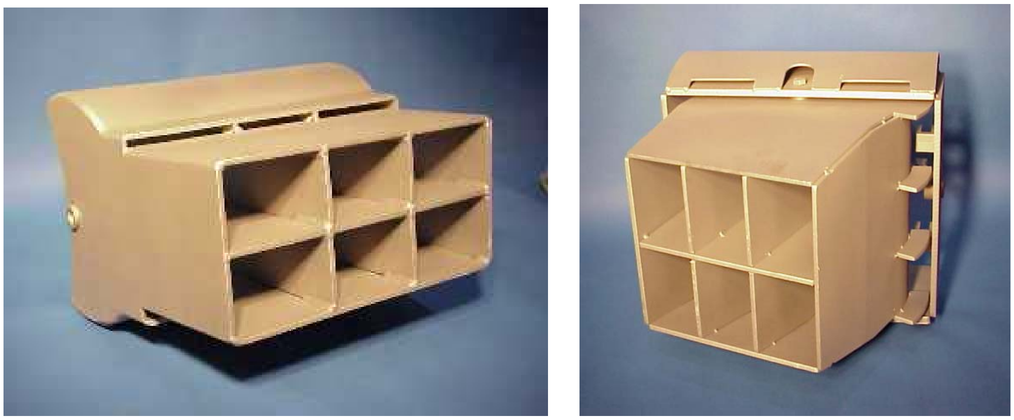
Figure 4 - Foster Wheeler’s Double Shroud Coal Nozzle Tip

2. The new DS style coal nozzle tips are available in either single piece or two-piece stainless steel construction. Most Foster Wheeler DS style coal nozzle tips are capable of being replaced from the furnace side without removing the stationary coal nozzle assembly. This feature also allows coal nozzle tip side clearance adjustment without having to remove the complete stationary coal nozzle assembly. This feature saves 80 to 100 man-hours per coal nozzle.
3. Contoured outer radiation shrouds provide laminar air flow around the tips for added cooling and directional control of the air.
4. All nozzle tips are designed to maintain structural integrity due to thermal stresses.
5. All Foster Wheeler coal nozzle tip assemblies are 100% compatible and interchangeable with all existing windbox tilt linkages and other windbox internals.
6. The leading edges of splitter plates are hard surfaced for increased erosion resistance.
7. *Optional* coal nozzle tips are also available without seal plates.
8. *Optional* coal nozzle and tip assemblies are available with added wear resistant hard-surfacing and or materials.

3.4.3 Auxiliary, Boundary and Overfire Air Nozzle Tips

Typical windbox changes, associated with a TLN retrofit, consist of replacing many of the nozzle tips and associated hardware. Replacing particular nozzle tips is required primarily for performance reasons and secondly for reducing long-term maintenance costs. Foremost, it allows the system designer to redistribute the air properly in order to achieve the desired staging for NOx reduction. Secondly, it maximizes the air velocity leaving the air nozzle to ensure the highest degree of fuel/air mixing in the main firing zone. Thirdly, is assures adequate nozzle tip film cooling is maintained. Consequently, service life of individual nozzle tips is noticeably increased through proper nozzle sizing. Significant maintenance cost reductions can be realized in these cases.

All FWNAC air nozzle tips are designed for high temperature structural integrity. Each is available either as a single or two-piece design fabricated from a 309 stainless steel for high temperature oxidation resistance. Other specific materials are available upon request. Where applicable, the new “Double Shroud” (US Patent No. 6,260,491) design is provided for all air nozzle tips. See **Figure 5**.



(a) Tilting *(b) Boundary Air*

Figure 5 - FWNAC’s Double Shroud Air Nozzle Tips

The configuration of each newly provided nozzle tip consists of a contoured inlet for more laminar flow under tilted conditions as compared to the current equipment. An optional two-piece design allows replacement from the furnace side should it ever become necessary.

Foster Wheeler’s “Boundary Air” nozzles direct secondary air tangent to two or more imaginary circles within the furnace. The air tips in each corner are set independently to direct air from a given corner at a significantly different angle from the air coming from another corner or other corners. These range from one corner being aimed directly at the center of the furnace for instance, to another directing air along the furnace waterwall, etc. This variable positioning allows further control of the fireball shape to provide more even flue gas conditions exiting the combustion zone. These tips are provided only when required to reduce furnace waterwall slagging and/or any localized corrosion. This is usually a one-time adjustment that is set during post-retrofit system optimization. See **Figure 6** following.

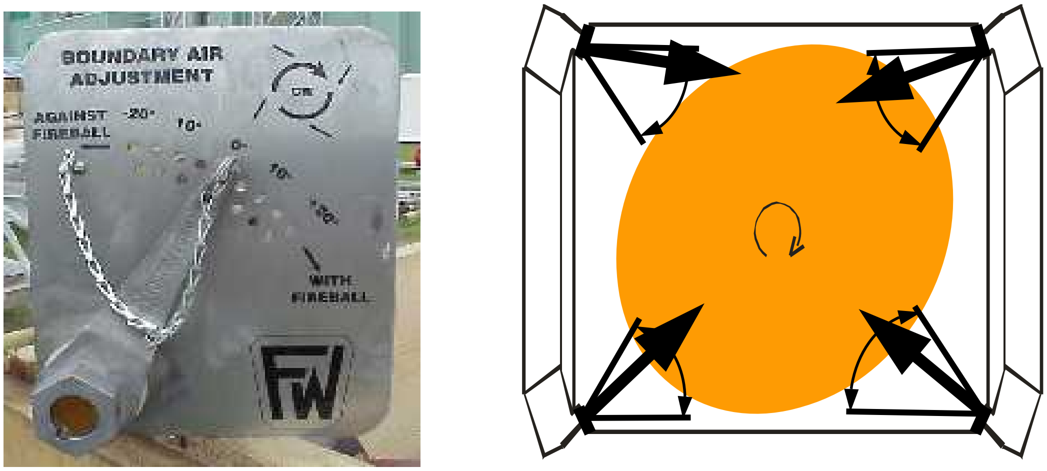


Figure 6 - Boundary Air Direction Control

The FWNAC SOFA nozzle tips include a similar feature that provides horizontal yaw adjustments. The nozzles from each individual SOFA windbox can be aimed, in unison, to direct the overfire air as required to maximize fuel/air-mixing momentum in this final phase of the combustion process. This adjustment is key for controlling exit CO emissions. This is a manual adjustment that usually requires only an initial adjustment during optimization. See **Figure 7** following.

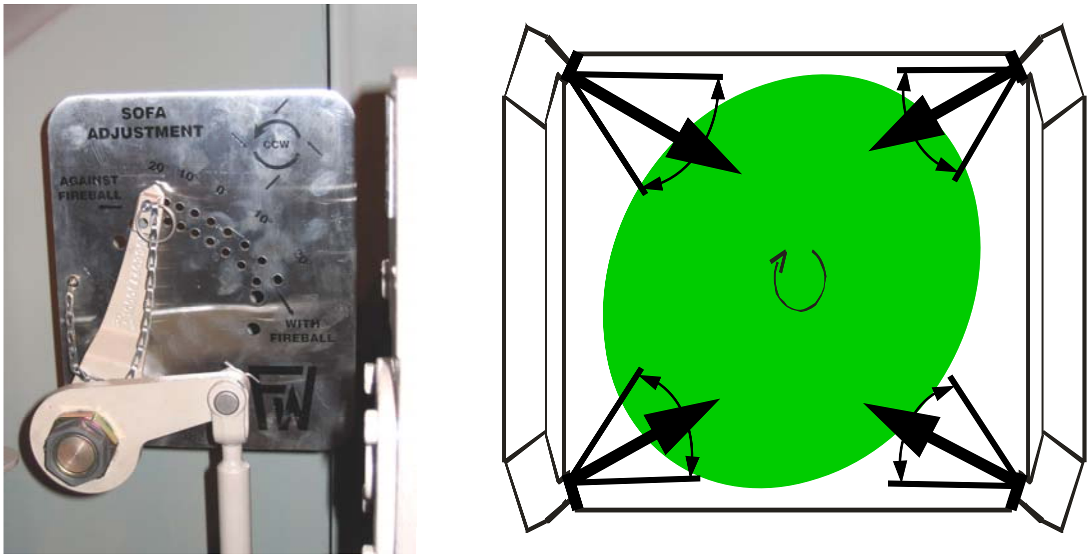


Figure 7 - SOFA Direction Control

3.4.4 Damper Venturi Inserts

FWNAC includes damper venturi inserts on most TLN retrofits. This upgrade, available for either existing or new damper systems, re-establishes windbox differential pressure control over the load range, lost due to the addition of overfire Air. It also insures that dampers operate in a controllable range. Another application is older tangential-fired units. These units tend to lose some windbox differential pressure control due to increasing furnace in leakage or other increased differential pressure requirements. Venturi damper inserts help re-establish this control.

The upgrade consists of installing venturi plates around existing damper blades or with new windbox dampers. It is an aerodynamic solution to increase the damper to nozzle tip flow ratio, providing improved air flow control and increased windbox to furnace differential control over a greater load range. A typical damper venturi installation is shown in **Figures 8 and 9.**

For information on the Optional Full Windbox Damper Upgrade, see “Design Update Bulletin No. 114.

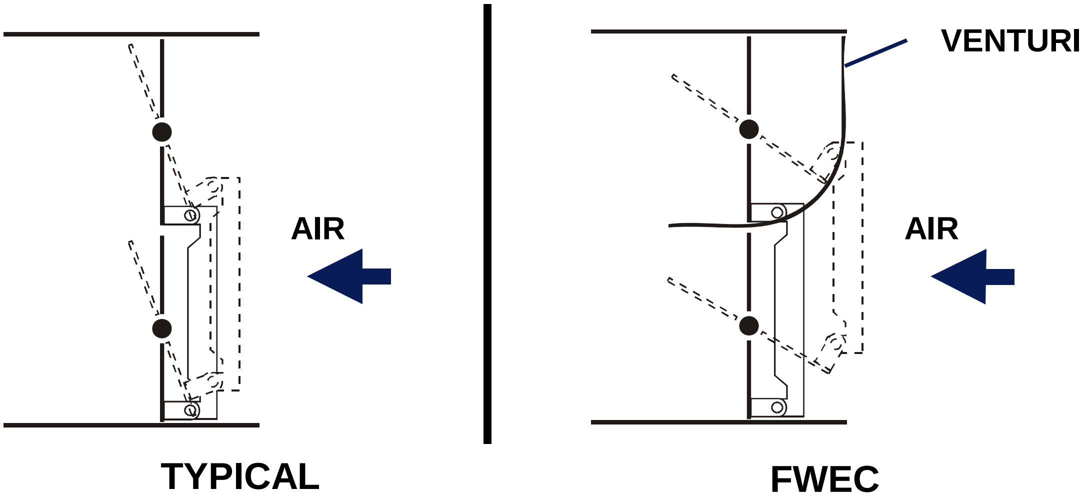


Figure 8 - FWNAC Damper Venturi Inserts

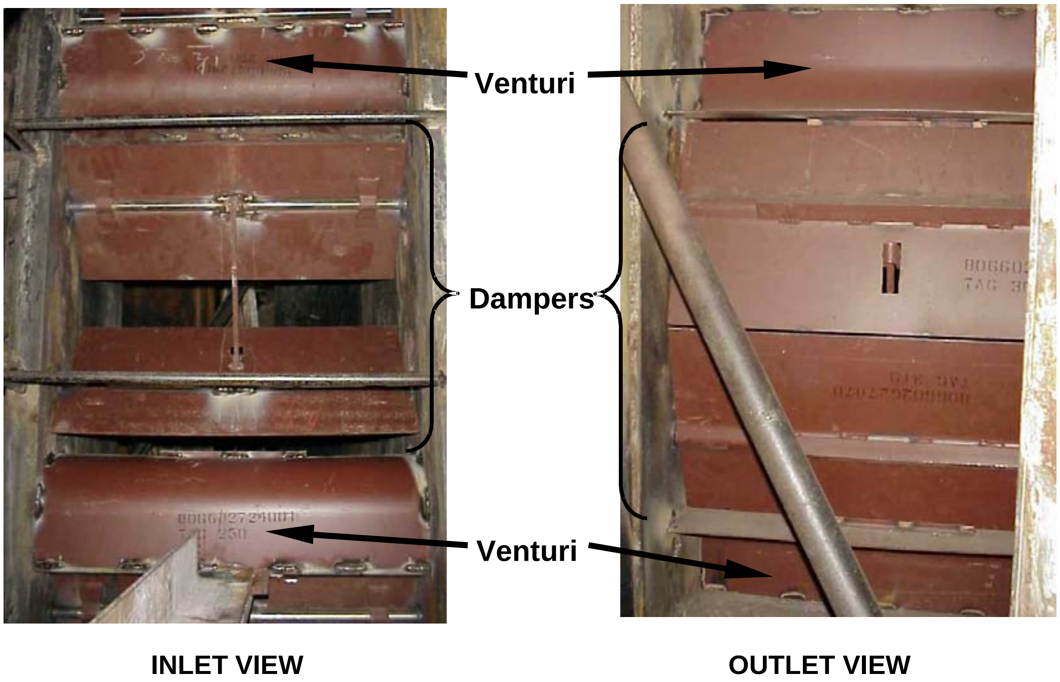
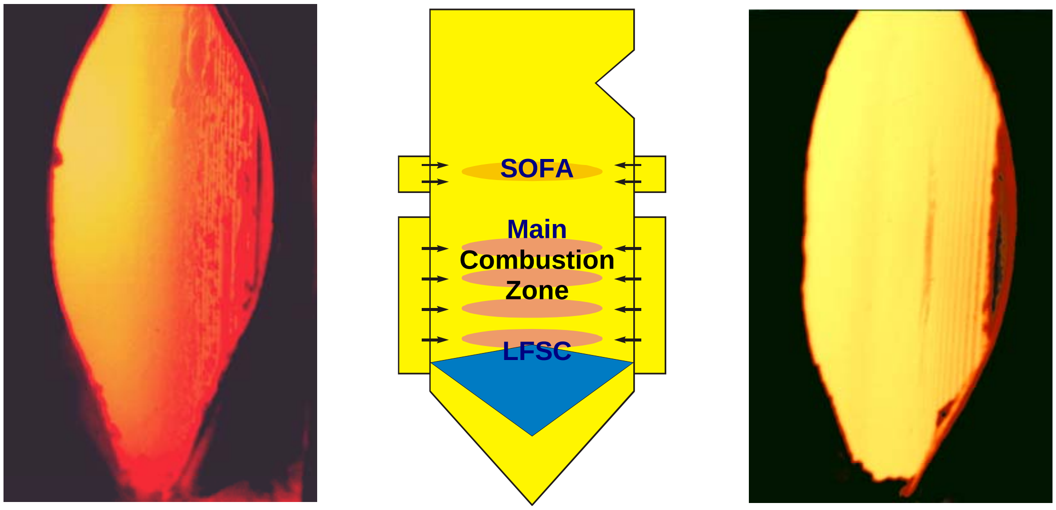


Figure 9 - Typical Damper Venturi Installation

3.4.5 Lower Furnace Stoichiometry Control (LFSC)

FWNAC's Lower Furnace Stoichiometry Control was developed to help control the lower furnace hopper conditions created during deep staged low NOx combustion. Specifically, this FWNAC unique feature was developed to manage the fuel rich, smoky conditions as well as slag buildup in the lower furnace. Dark lower furnace /hopper conditions are common on many tangential-fired units equipped with competitor's tangential low NOx systems. LFSC includes nozzle tips (sometimes) and linkage modifications (always) to independently direct a percentage of secondary combustion air into the furnace hopper. Besides reducing the dark lower furnace conditions, FWNAC's experience with the LFSC system has also seen NOx benefits. The lower furnace concept is depicted as **Figure 10**.



Original Firing Arrangement

TLN System With LFSC

Figure 10 - Comparison of Lower Furnace Conditions Without & With FWNAC's TLN System

3.4.6 Windbox Secondary Air Biasing

In order to efficiently achieve the lowest NOx levels from tangential-fired units, some degree of secondary air flow biasing, is usually recommended as part of every TLN retrofit. Depending on what air biasing capability exists presently, FWNAC may recommend some or all of the following biasing controls:

- Corner-to-corner auxiliary air biasing.
- Hot and cold corner fuel and auxiliary air biasing (8 corner units).
- Front-to-rear and/or side-to-side secondary air biasing.

- Elevation air biasing.
- Furnace-to-furnace air biasing.
- Individual compartment air flow control.

Many tangential-fired units have oblong “fireballs” due to the aspect ratios associated with this type of firing system. These conditions, especially under deeply-staged low NOx firing conditions, if left uncontrolled, could lead to high CO emissions, increased corner slag buildup, furnace oxygen imbalance, etc. Such limitations could become barriers to achieving the lowest possible NOx emissions. FWNAC’s experience with air biasing shows that by selective air biasing, these conditions can be lessened and a rounder fireball shape can be achieved.

3.4.7 On-Line Conduit Coal Flow Measurement System (ECT)

Older vintage NOx reduction systems were capable of achieving moderate reductions in NOx at best. With the current emphasis on ultra low NOx emissions, these levels of reduction are no longer sufficient. Knowing and controlling the fuel and air distribution in a modern ultra low NOx combustion system is now key to achieving reliable long-term air staged operation without excessive CO or UBC formation. This fact has become evident, as more units are required to achieve very low emission levels. Without balance, high CO levels, unburned carbon, unequal oxygen profiles and temperature splits, etc. limit the reduction potential of low NOx systems. As a result, Foster Wheeler recommends the Electric Charge Transfer (ECT) system to provide operators with on-line, real time indication of coal flow conduit mass distribution, velocity and/or coal particle size.

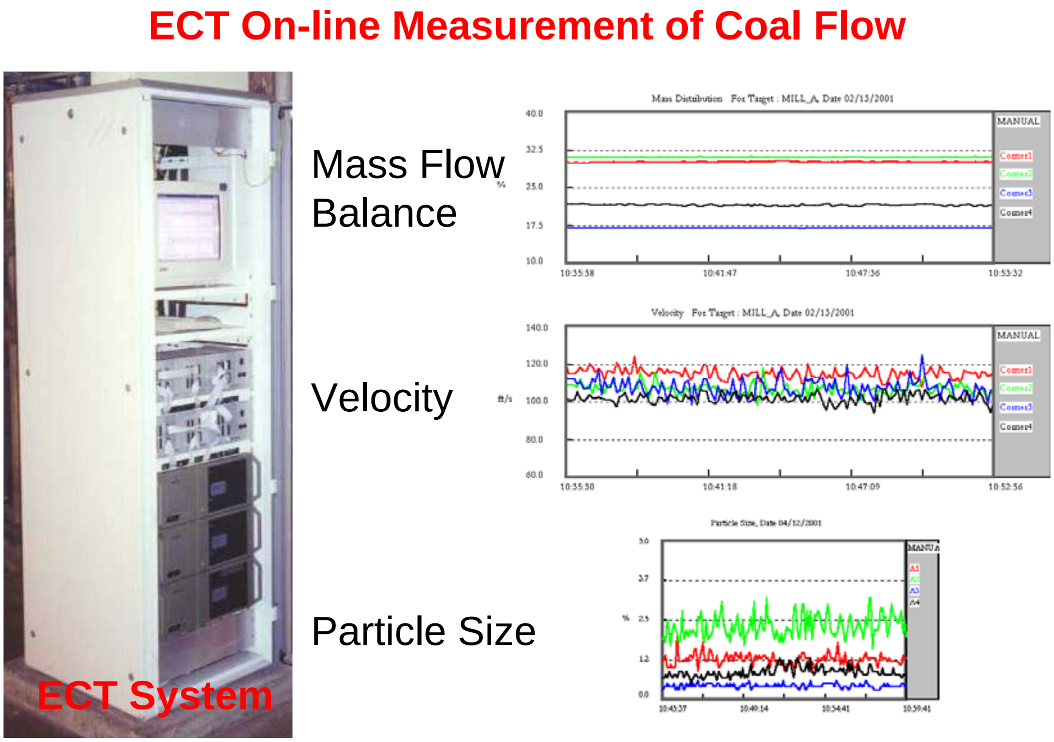


Figure 11 - ECT System and Features Measured

Due to aggressive CO requirements in typical specifications, Foster Wheeler commonly offers a system that monitors both the coal flow, velocity and/or particle size in each coal conduit as well as windbox air flow distribution in real time.

The ECT measurement, coupled with individual windbox compartment static air pressure measurements further enhances and accelerates the combustion optimization process. This type of information and control technology is well suited for application with Boiler Optimization Software. Additional information on the ECT System is presented in Attachments.

3.4.8 Compartment Air Distribution Monitoring (CADM) System

As mentioned previously, it is becoming more apparent in the low NOx power industry that in order to achieve ultra low NOx levels, air and coal flow distribution must be simultaneously monitored and controlled. This is analogous to the automobile industry changing from carburetors to fuel injection. Foster Wheeler is taking the lead in the industry with this Fuel Injection approach for pulverized coal-fired units.

Combined ECT/CADM are available as a fully automatic DCS controlled system. This is Foster Wheeler's Fuel Injection (FI) system. Coal flow through each coal nozzle is measured in real-time along with secondary air flow through each windbox compartment. Comparisons are made and the DCS is instructed to adjust secondary air balancing the air to match the coal floe distribution entering the furnace. Besides NOx and other gas profile benefits, results have shown extremely low CO levels under ultra low NOx operating conditions. **Figure 12** shows typical benefits data obtained from combined ECT/CADM System.

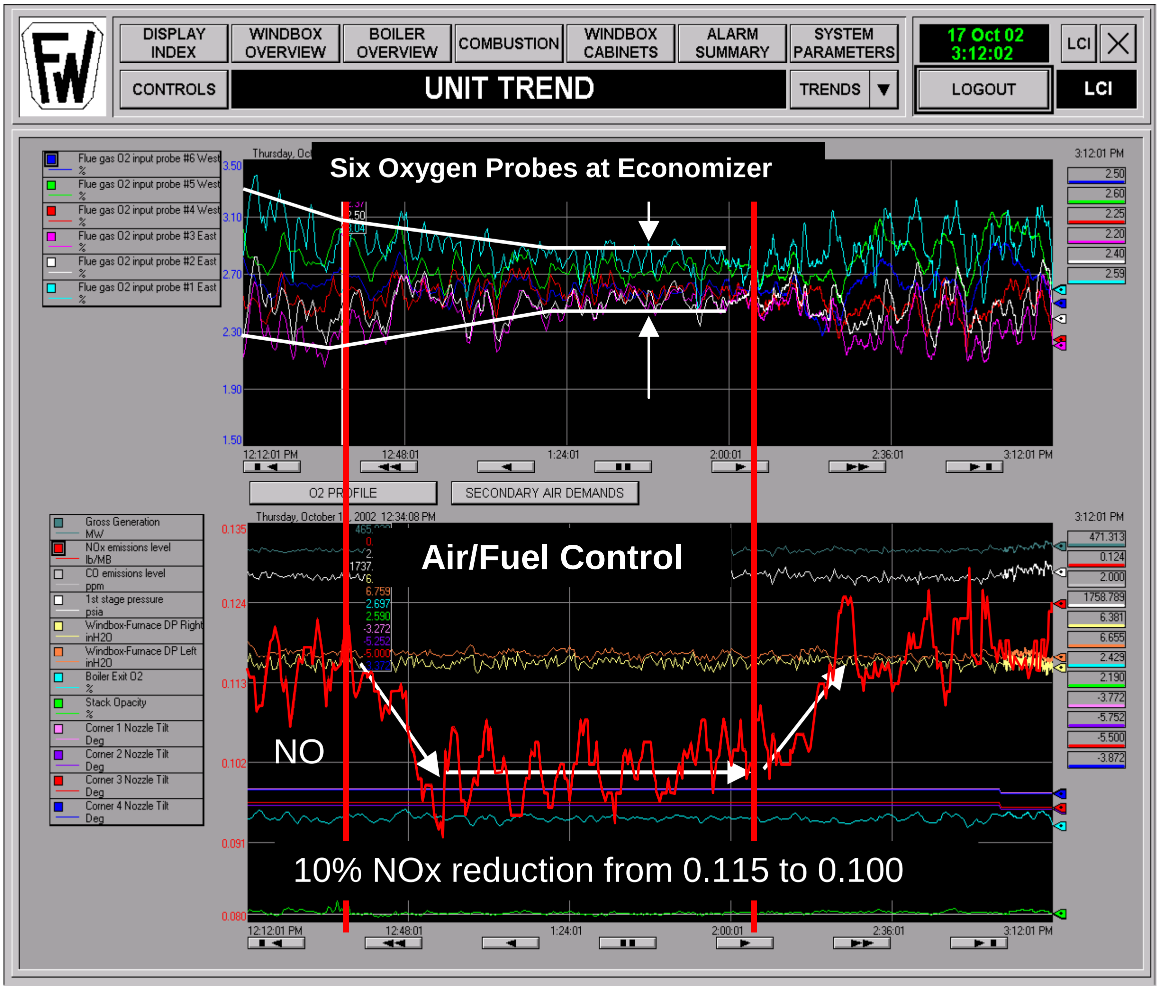


Figure 12 - NOx Reduction and O_2 Profile Improvement Results from 480 MW Unit Firing PRB Coal and Equipped with a TLN3 and both ECT and CADM operating under DCS Control

4. DESCRIPTION OF PROPOSED FWNAC TLN3 SYSTEM

4.1 Proposed TLN3 System for Coal Creek Units 1 & 2

Based on Great River Energy's requirements and FWNAC's evaluation of the current unit operation, FWNAC is proposing an "expanded" TLN3 System. Foster Wheeler's approach is to increase the amount of SOFA to each corner by installing larger SOFA windboxes and ducts, while staying between the existing buckstays, thereby reducing installation time and costs.

The descriptions of Foster Wheeler modifications are the same for both units. This will allow for design interchangeability.

The proposed FWNAC modifications to Coal Creek Units 1 & 2 are shown on FWNAC proposal drawings attached in the Appendices.

a) A SINGLE level of new separated SOFA windboxes will be provided as part of the FWNAC TLN3 system. This would consist of four (4) new, larger SOFA windboxes. To minimize physical changes to the boiler house, the new overfire air windboxes would be installed where the existing SOFA windboxes are. The new, larger SOFA windboxes are wider but maintain the same height so as to fit between the buckstays. The SOFA windboxes would be designed to supply an increased amount of combustion air as overfire air. Each new windbox will be provided along with new waterwall panels and the necessary larger, connecting ductwork, hangers, expansion joints and steel modifications to interface with the secondary air ducts. The new SOFA duct arrangement will eliminate the "S-shaped" bends to the inner corner windboxes, thereby providing less pressure drop. Each windbox will be fitted with nozzle tips, turning vanes, access doors, air control dampers and electric actuators and static pressure taps to provide total overfire air control. Manual "set and forget" horizontal yaw and vertical tilt capability would be provided in the SOFA to help control CO as well as back end gas temperature and oxygen profiles. The yaw linkage, manual tilt gearbox and damper drives will be accessible from the sides of each windbox.

b) On the rear waterwall, at the inside corners, there is an existing economizer valve that will need to be relocated. This is noted on the proposal drawing and will be detailed during the engineering and design phase. Currently, this relocation is anticipated as a simple matter of moving the valve down an elevation. (Note: there are several wall blowers one elevation above this valve).

c) Platform and structural steel modifications are not needed.

d) New Double Shroud "Boundary" auxiliary air nozzle tips for the (non-oil) 19 ¼" compartments. These nozzle tips are designed to provide the necessary velocity, air flow distribution and direction control to benefit NOx emissions, fireball shaping while maximizing combustion efficiency.

e) All CCOFA, coal and auxiliary air windbox compartments will be modified with FWNAC’s larger damper venturi plates to improve air flow distribution control over a larger load range.

5. PROPOSED SCOPE OF SUPPLY

The Scope of Supply for the Foster Wheeler TLN3 System is listed below. Due to the similarities between Coal Creek Units 1 & 2, components are interchangeable. Quantities listed are for one (1) unit only.

5.1 TLN3 Engineering Scope

Item	Quantity	Description
1	One (1) lot	Engineering and design analysis for new TLN3 System.
2	One (l) lot	Engineering arrangement drawings to incorporate TLN equipment and unit modifications, including Bill of Materials.
3	One (l) lot	SAMA control diagrams to describe the desired control SOFA dampers, (see Appendix for typical SAMA drawings).
4	One (l) set	Listing of all required I/O

5.2 TLN3 Equipment Scope

Item	Quantity	Description
1	Eight (8)	Separated SOFA windbox; 32” wide furnace channel by approx. 56” high, complete with an appropriate number of compartments, including turning vanes, yaw and tilt mechanisms and 48” wide opposed blade damper assemblies. Damper blades will be carbon steel with stainless steel damper shafts. Damper bearings will be stainless steel except for the outboard damper bearings that will be self-aligning graphite. Two (2) Hagan pneumatic drives, and all mounting brackets and hardware are provided with each SOFA windbox (16 total). Each compartment will be fitted with an individual static air pressure tap. A rear access door is also provided.
2	One (1) lot	Complete secondary air duct system for SOFA. Includes structural steel check for proposed hanger assemblies.

3	Four (4)	Waterwall tube panels to incorporate SOFA. Rifled/ribbed tubes of material similar to existing water wall.
4	Two (2)	Duct scoops to direct secondary air into the overfire air ducts.
5	Thirty-two (32)	“Boundary” air nozzles for each of the 19 ¼” auxiliary air (non-oil) compartments. Includes quadrants.
6	Sixty-four (64)	Air deflector plates (3” high) for installation in each of the 19 ¼” auxiliary air (non-oil) compartments. Replaces the current 2” high deflector plates. Material: 309 SS
7	One Hundred Twenty (120)	Flow controlling damper venturi plate sets for all coal and auxiliary air compartment dampers. Material: Corten.
8	Fourteen (14)	Fabric Expansion joints with welded flange joints.
9	One (1) lot	Hanger rod assemblies
10	One (1) lot	Spare pins and hardware for installation support as determined by FWNAC.
11	Ten (10)	Operating instruction manuals with parts lists.
12	One (1)	Three (3) day Operator Training Sessions and ten (10) Training Manuals (prior to startup).

5.3 Technical Field Support

1	Technical support of FWNAC service engineer time covering pre-outage, outage and post-outage time frame. Billed on a Per Diem rate presented in the Appendix.

5.4 Scope NOT Included

The following work will be performed or furnished and installed by others:

a) Installation.

b) Asbestos removal.

c) Instrumentation and control equipment or modifications, except as expressly specified by FWNAC. Great River Energy is required to incorporate FWNAC provided SAMA control logic into their DCS as part of the TLN retrofit.

d) Any new/additional neural network inputs.

e) Electrical wiring, cable trays/modifications and conduit.

f) Pneumatic and control system additions or modifications, including relocation of existing pneumatic piping.

g) Insulation and lagging. Insulation removed for fitting SOFA system or for other work proposed by FWNAC is not included.

h) Material for removal or relocating sootblower (other than the required pipe material), downcomers, economizer valves, refractory replacement, material to limit spray arc of sootblowers etc. Material for relocating cable trays, fire water, service air piping is not included.

i) Structural steel or modifications to the existing steel is by others except where specified by Foster Wheeler.

j) Temporary office space or trailer with telephone and electricity at the jobsite for use by FWNAC Service Engineer(s) should be provided by Great River Energy and is not included in FWNAC scope.

k) Repair or replacement of damaged components discovered during TLN outage.

l) Fuel, ash sampling and lab analysis is not included in FWNAC scope of supply.

m) If coal flow balancing is required during baseline testing and/or optimization, FWNAC scope does not include procuring and installing coal pipe sampling ports and any subsequent corrections.

n) Provision and installation of the necessary ports and sampling probes at the economizer outlet for system optimization is not included.

5.5 Terminal Points

The FWNAC terminal points for this scope will be as shown on the attached proposal drawings and are further identified by the material listed in Section 5 under “Scope of Supply”.

A) OFA System:

Ductwork termination points are at the connecting point to the existing air ducts and at the register. The ductwork includes expansion joints, hangers and support steel only as required to attach to existing steel. The termination point is the connection at the existing steel. The register includes the tube openings and seal boxes. Termination points are the tube ends of the panels.

B) Windbox Material:

Material to replace identified tilting nozzle tips is included. Termination points are at the windbox front channel and the windbox damper frame. Plate work and hardware as required to modify the windbox is included. Any additional material required to return the existing windbox shell or internal structural components to a structurally sound and dimensionally true condition is not included in FWNAC's scope.

C) Electrical and Controls:

All electrical, pneumatic and control interface points are the field device termination points of the identified field devices.

D) Control System:

Seller will provide SAMA drawings.

5.6 Post-Retrofit System Tuning/Optimization

The objective of this phase is to optimize the newly installed TLN system for the required emissions performance and unit operation. The unit's Continuous Emission Monitoring System (CEMS) will be used as the basis for assessing NOx. It will again be the client's responsibility to ensure the accuracy of the CEMS system through proper calibration and maintenance procedures. To evaluate and confirm long-term emission performance, FWNAC estimates approximately a one (1) to four (4) week period for optimization to establish and confirm long-term reliable operating set points.

To ensure a technically proper evaluation of the low NOx burner performance, it will be necessary to have steady state system operating conditions during evaluation of individual settings.

a) The unit's Continuous Emission Monitoring System (CEMS) will be used as the basis for assessing NOx. A multi-point gas sampling grid at the economizer outlet, which can be provided by FWNAC, to measure exit gas NOx, CO and O_2 on a per point basis can be utilized as well. This has been proven to reduce optimization time and costs. FWNAC will provide an Engineer to conduct the optimization program. Great River Energy should also provide an air-conditioned test facility for the test instrumentation during optimization. Supply utilities such as electric power and air at sampling locations are also required by client.

b) FWNAC will request that Great River Energy make preparations for supplying and firing a coal within the guarantee range.

c) If coal fineness is suspect, Great River Energy may be requested that coal fineness be taken on a mill basis.

d) Normal unit board data, furnace slag profiles and temperature measurements, etc. necessary for proper boiler performance evaluation, will be taken.

e) Great River Energy shall perform any required station instrumentation calibration, if necessary and assist if requested in making control room data available to FWNAC.

f) FWNAC will provide an optimization plan prior to commencement of the TLN3 system.

g) FWNAC will provide a Service Engineer for unit testing. The extension of field testing service time and/or schedules for reasons beyond the control of FWNAC, shall be considered extra work assignments and be billable at the standard FWNAC service rates (see Appendices for standard rates).

5.7 Post-Retrofit Performance Testing

a) Prior to guarantee testing, FWNAC will conduct preliminary "dry-runs" of guarantee testing.

b) Foster Wheeler will notify Great River Energy when the unit is ready to be tested. Individual testing will be conducted at MCR steam flow (3,730,000 lbs/hr) over a four (4) hour period. FWNAC will work with Great River Energy to establish the final post-retrofit test plan, following engineering submittal.

c) Guarantee testing will consist of a four (4) hour test period conducted under steady-state NORMAL OPERATING CONDITIONS as identified under guarantee requirements.

d) To ensure a technically proper evaluation of the TLN system performance it will be necessary to have a four (4) hour test period with normal, non-transient, boiler operation and consistent fuel supply with confirmation of fineness levels. Any periods of unit upsets or if unplanned transient conditions occur, additional time will be required.

e) Unit should be fuel seasoned for at least two (2) days of MCR operation. Great River Energy is requested to provide coal fineness from each mill.

f) FWNAC site representative may request changes in the sootblowing procedures as required for fuel changes and / or performance requirements.

Post-Retrofit Performance Testing will be conducted under FWNAC guidance. FWNAC will assign an engineer to participate in witnessing the test program. If the allotted Service time has been exceeded, additional service time above those listed in the Scope of Supply will be considered as extra work assignments.

FWNAC will accept post-retrofit testing using the plant CEMS equipment and standard fly ash sampling methods with the following provision.

Note: For optimization FWNAC may elect to install probes into existing economizer outlet gas duct taps. The probes will be provided by Great River Energy. It is assumed this unit is already equipped with economizer outlet taps that are in good shape.

5.8 FWNAC Outage Support

FWNAC can furnish one qualified service representative to assist in installation and commissioning activities for erection coverage. It is estimated that this individual would be required for four weeks of the scheduled outage. Pricing is based up an eight hour day for six days a week for four weeks. If activities extend beyond the anticipated time or allotted hours, service engineer’s time will be billed on a per diem basis at the agreed upon rates.

6. PREDICTED PERFORMANCE

The Tangential Low NOx Operating System offered in this proposal is designed for current operating conditions. The system is designed with enough flexibility for 7/8 mills in service (pre-drying system) and for 6/8 mills in service (post-drying system) to achieve 3,730,000 lbs/hr of main steam flow. Fuel analyses provided by Great River Energy were utilized in the design.

Note: The following projections are not to be construed as guarantees.

6.1 NOx Emissions

Foster Wheeler predicts the following NOx emissions at the customer defined MCR load point for the TLN3 proposed within this document:

- The TLN3 system is designed with the potential to produce 0.15 lb/MBtu NOx emissions at full load MCR.

Figure 13 shows the current NOx performance been achieved on the Coal Creek boilers (2^{nd} quarter 2006 EPA data) and the predicted NOx levels that will be achieved post-retrofit on these boilers.

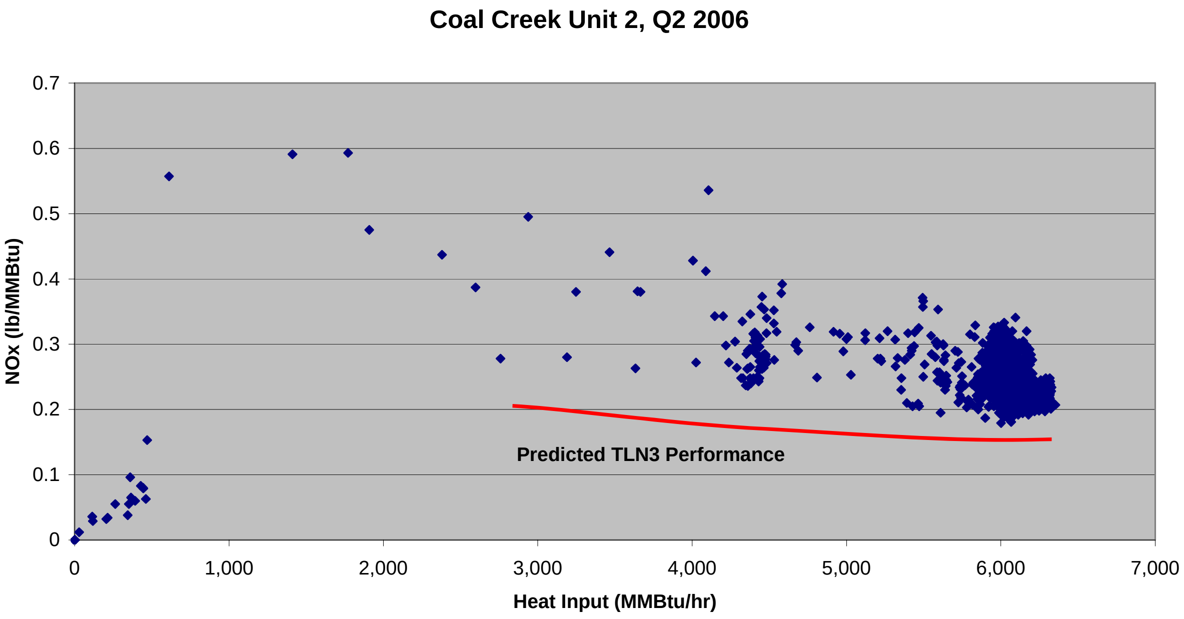


Figure 13 - Predicted NOx Performance on Coal Creek Boilers

Notes

1.) All full load predictions are based on ideal boiler operating conditions and 7/8 mills in service (pre-drying system) or 6/8 mills in service (post-drying system). They are also based on the assumption that burner tilts are no higher than the horizontal position.

Low load NOx performance is very unit specific. Since the reduction of heat input into the furnace inhibits the NOx formation, NOx emissions should decrease with reduced loads unless excess air increases. However, the actual amount of reduction also depends on other boiler operating parameters such boiler excess O_2 and actual levels of boiler in-leakage. In addition, nozzle tilts are often brought above horizontal to maintain steam temperature at lower loads, thereby decreasing furnace residence time. Therefore, the appropriate SOFA flows at various points in the load range will be determined during post-retrofit tuning to maintain Low NOx operation.

Current data gathered from the EPA website for Coal Creek No. 2 indicates that as unit load is decreased, NOx emissions is reduced.

See **Figure 13** for low load NOx predictions.

Note:

NOx emissions are not directly affected by variances in mill fineness levels. Values lower than 65% through 200 mesh will most likely result in higher percentages on the 50 mesh and this will indirectly cause NOx emissions to increase by virtue of reducing staging to control UBC levels. Fineness on it’s own has no direct impact on NOx formation.

6.2 Unburned Carbon (UBC) in Flyash

As with the NOx emissions, Foster Wheeler's predictions for the Coal Creek boilers are based on past experience with these types of fuel and unburned carbon levels.

Foster Wheeler predicts that the UBC levels for the proposed TLN3 system will be as follows:

- Less than 0.5% when firing the design coal at MCR.

Improved fineness levels and coal/air distribution can help reduce the UBC in fly ash levels. Current predictions are based on a minimum fineness of 65% through 200 mesh and 1.5% on the 50 mesh.

Fuel related impacts on unburned carbon are much higher than on NOx. Therefore, any future changes in actual fuel characteristics might necessitate revision of the above predictions.

UBC does not significantly increase when firing lignite fuels under staged conditions, again due to its relatively high reactivity. However, as with all other performance parameters, the unburned carbon is negatively impacted by up-tilt on the burners. High tilt positions on tangential-fired units result in poor fuel/air interaction leading to higher UBC and CO. Thus, it will be important to maintain the tilts at or below horizontal to ensure high levels of burnout.

6.3 Steam Temperature Performance

Foster Wheeler predicts that steam temperatures will remain near current levels following the TLN3 retrofit. Our experience with at Coal Creek and with tangential-fired units firing similar fuels to that being fired on the Coal Creek boilers is that a more balanced or uniform temperature profile will result following the TLN3 retrofit. After the first Foster Wheeler TLN retrofits, the Coal Creek units experienced cleaner waterwalls in the firing zone. Foster Wheeler predicts no change in steam temperatures from current values.

6.4 Effects of Excess Air (Boiler O_2 levels)

Excess air is an important parameter that affects NOx, steam temperatures, boiler efficiency, etc. Maintaining proper boiler O_2 levels is key to low NOx combustion. Too much O_2 at the burner can create high NOx as well as contribute to lower boiler efficiencies due to stack losses. However, too little O_2 can lead to unacceptable UBC and CO values as well as lowered steam temperatures. FWNAC evaluates each of these parameters to determine the optimum post-retrofit excess air level. The TLN3 will be designed to operate at or near current O_2 levels. However, the effects of excess air levels will be investigated during the optimization/tuning phase.

6.5 Effects of Nozzle Tilt Angle

In order to maintain steam temperatures, main burner nozzle tilt angle is typically modulated. Through the tilt range, various combustion effects are reflected through fluctuating NOx, CO, and UBC levels. A downward tilt angle will provide increased residence time for greater carbon burnout, hence lower UBC levels. Increased residence time also helps NOx emissions. CO effects are typically unit and fuel specific. It is predicted that the burner tilt positions at MCR conditions will remain unchanged (or possibly lower with more SOFA flow) following the TLN3 retrofit.

6.6 Effects of Coal

Coal properties play a very important role in operation of any low NOx combustion system. For both NOx and UBC, fuel reactivity plays the key role. FC/VM, HHV(daf), as well as fuel nitrogen loading are the primary parameters. Ash constituents also are important as they effect the furnace thermal environment that affects NOx and UBC.

7. PERFORMANCE GUARANTEES

7.1 Performance Guarantees

The following Performance Guarantees contained in sections 7.2 through 7.5 are the **exclusive performance guarantees** offered by FWNAC relating to the equipment supplied by FWNAC. Any graphs, stated performance values, predictions or discussions in other sections of the proposal shall not be construed as performance guarantees.

- The guarantee will be considered met, if the average of the guarantee value, over the test period meets the guarantee values offered below by FWNAC.

- All performance conditions, test methods, and referenced fuels/ranges of fuels as defined in Section 7.2 of this proposal are considered a prerequisite for the guarantees. All sampling must ensure that a representative average of the flue gas emissions and fly ash sample is taken.

7.1.1 NOx Guarantee

- **NOx will average less than or equal to 0.170 lb NOx/MBtu** at 100% MCR (3,730,000 lbs/hr steam)

7.2 Performance Condition Requirements

To ensure a technically proper evaluation of the low NOx system performance, it is necessary to have normal, non-transient unit operating conditions. The following requirements are the basis for the post-retrofit performance period (cold/hot commissioning, optimization and performance guarantee test):

a) Unit Operation - Operation of the unit should be in accordance with the manufacturer's instructions and the direction of Foster Wheeler’s site representative. Adjustable parameters include O_2, mill sequencing, mill biasing, windbox-to-furnace differential pressure, damper and yaw settings, load ramping rates, sootblowing and others. Boiler and steam cycle equipment must be operated in a manner similar to baseline conditions including normal design temperatures, flow, pressures, etc. tests. Boiler should be seasoned to the fuels being fired. Any modifications to boiler heat transfer equipment (i.e., SH, economizer, air preheaters) or changes in system operation (such as feedwater heaters out of service) prior to the retrofit outage will require alterations of guarantees.

NOTE: All emission and steam temperatures guarantees are subject to maintaining the same baseline main steam flow and pressure, reheat flow and pressure, feedwater temperature and cold reheat inlet temperature following retrofit. This will assure a fair evaluation basis for both Great River Energy and Foster Wheeler to evaluate the TLN3 system performance.

b) The NOx guarantees are based on the post-retrofit coal being within the shaded qualifying region shown on **Figures 14** and within the ranges from **Table 1.** Should the coal fall outside that region the appropriate NOx emission corrections shall apply.

c) For the performance guarantee test, coal fineness levels on a per mill basis will be no coarser than 1.5% on Mesh 50, 88% passing Mesh 100, and 65% passing Mesh 200.

d) All pulverizers are to be operated in accordance with the manufacturer's instruction and the Buyer is responsible for ensuring that coal pipe riffle elements and orifices are in good condition prior to optimization. Primary air flow must be in accordance with the associated pulverizer airflow curves. Foster Wheeler has designed the system to accommodate the current 350 klb/hr primary air flow and the expected future (post-drying system) 255 klb/hr primary air flow. Coal flow imbalance between coal conduits should not exceed the normal industry standard of ± 20% from average on an elevation basis. It is assumed that the pulverizers are operating in accordance with the OEM's air flow and temperature criteria. Primary air flow between coal conduits should be within the normal industry standard of ± 10% from average on an elevation basis.

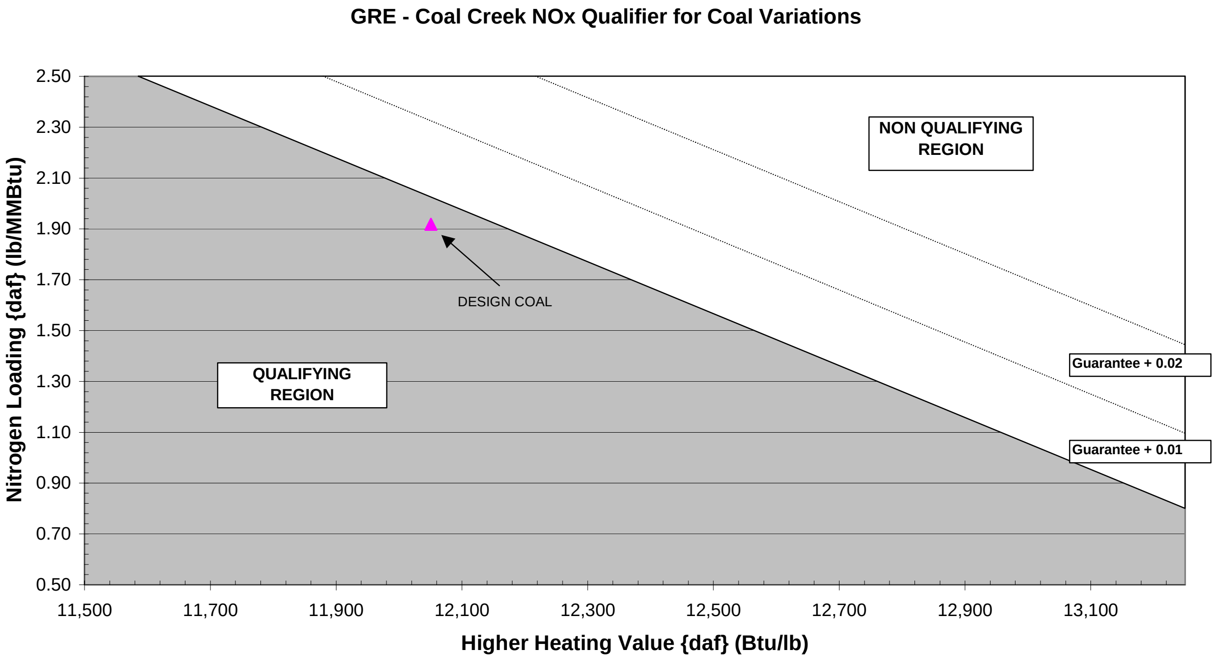


Figure 14 - NOx Fuel Qualifier Curve for HHV (daf) and Nitrogen Loading (daf)

e) A qualified Foster Wheeler Technical Services representative will recommend the final O_2 operating level during the start-up and optimization of the low NOx firing system. The actual level of excess oxygen will be adjusted to simultaneously optimize NOx, CO, and UBC. The low NOx firing system will be designed for a target average excess oxygen level of 2.5 %.

f) All performance guarantee testing shall be conducted under standard plant operating conditions at steady-state loads of 3,730,000 lbs/hr (100% MCR) steam flow with no feedwater heaters out of service, no hindrances due to incapacitated FD or ID fans, flue gas cleaning equipment, coal feeders, pulverizers, ash handling system, sootblowers, wall blowers and burner controls.

g) It is assumed that all other existing related windbox structure, linkage, hardware and nozzle tips not supplied under this proposal are in good operating condition.

h) All guarantee parameters measured during the performance test will be an average over the four (4) hour test period.

i) The CEMS shall be used to determine the NOx emission levels during all performance tests. If the guarantee testing fails to demonstrate the guaranteed emissions, EPA methods 3A, 7E, and 10 and isokinetic testing shall be used at a grid in the economizer outlet to determine excess O_2, NOx and CO during a second performance guarantee test. This data is the determining data.

j) Economizer O_2 must be maintained within a ± 0.20% range from set-point.

Fuel - Coal characteristics play a major role in determining achievable emission as well as combustion efficiency. For both NOx and UBC, fuel reactivity plays the key role. FC/VM, HHV (daf), as well as fuel nitrogen loading are the primary parameters. Ash constituents also are important as they effect the furnace thermal environment that affects NOx and UBC. These are listed below. Foster Wheeler has taken all these parameters into consideration in offering our guarantees. Consequently, all guarantees are based on firing the following fuel consistent with fuel parameters identified below. Coals outside the qualification ranges in **Figure 14** and **Table 1** below do not qualify as fuels that meet the performance conditions. During optimization and testing, coal loaded in various bunkers must be kept consistent, i.e. same coal in same bunkers. Prior to commencing any testing, the boiler must be properly seasoned with the design fuel that will be burned during the test.

LOW NOX SYSTEM DESIGN COAL AND ALLOWABLE RANGE		
Fuel Parameter	**Design**	**Allowable Range**
Volatile Matter, as rec. (VM), %	25.2	See FC/VM
Fixed Carbon as rec., (FC), %	26.5	See FC/VM
FC/VM Ratio	1.05	Max: 1.2
Moisture, total %	36.3	38.0
Ash, as rec. %	11.9	8.0 – 14.0
HHV, as rec. Btu/lb	6,241	See Figure 14
Carbon, as rec. %	37.0	Max: 39.0
Hydrogen, as rec. %	6.5	-
Nitrogen, as rec. %.	0.6	Max: 0.7
Sulfur, as rec. %.	0.7	Max: 0.9
Oxygen, as rec. %	7.0	-
Fe2O3 in ash, as rec. %	6.7	Max: 8.5
Na2O in ash, as rec. %	2.2	Max: 5.0

Table 1.Design Coal

Furnace In-Leakage - The furnace in leakage shall be less than 8%. Should the furnace fail to meet the in-leakage requirement, emissions and combustion efficiencies will be affected and thus the related performance guarantees will have to be adjusted accordingly.

Slagging - Furnace slagging should be controlled in accordance with normal industry practice.

8. COMMERCIAL OFFERING

8.1 Project Schedule

The project schedule is very aggressive. Based upon current shop loadings and space availability, equipment delivery to support the March 15, 2007 outage start date can be achieved. FWNAC will monitor shop space during the engineering phase of the project and alert GRE to any changes to shop space availability. A preliminary schedule can be found in the Appendices.

8.2 Pricing & Payment Terms

8.2.1 Engineering and Material Supply:

FWNAC offers to perform the scope of work contained in Sections 5.1 and 5.2 FOB jobsite, exclusive of taxes, subject to availability of shop space:

One Million Six Hundred and Fifty Thousand Dollars
US $ 1,650,000

8.2.2 Outage Support

FWNAC offers to provide technical outage support in accordance with Section 5.3

Forty Thousand Dollars

US $40,000

8.2.3 Commissioning and Optimization

FWNAC offers to provide technical support for the Commissioning and Optimization of the equipment on a per diem rate of $1200 for each eight hour day Monday through Friday plus Travel and Living expenses. Travel and Living expense will be invoiced at cost. Additional hours per day, weekends and Holidays would be billed at a rate of $225/ hour. The estimated **budget** cost for two Service Engineers for approximately four weeks for sixty hours per week plus Travel and Living expenses is $96,000.

8.2.4 Terms and Conditions

FWNAC offers to perform the above scope of work in accordance with the attached Standard FWNAC Terms and Conditions of Sale Material Only.

If the equipment fails to achieve the Guaranteed NOx level in Section 7, FWNAC will perform additional tuning and optimization of the equipment with a maximum cost of $30,000. Performing the additional tuning and optimization and expenditure of this money shall be in full settlement of all liabilities of FWNAC for failure to meet the Performance Guarantee.

A written notification of award setting forth the basis of the award including the agreed upon Terms and Conditions is required by FWNAC prior to starting work. In the event Great River Energy would like work to proceed prior to agreement on Terms and Conditions, FWNAC would do so in accordance with and upon receipt of the executed “Authorization to Begin Work” form included with this proposal.

8.2.5 Validity of Proposal

The prices tendered with this proposal are subject to acceptance by Great River Energy within a period of thirty (30) days from the date hereof, except Foster Wheeler North America Corp. shall have the right to withdraw its proposal at any time before formal acceptance by Great River Energy and receipt of written approval by an officer of Foster Wheeler North America Corp.

The proposed schedule is contingent upon receipt of an acceptable purchase order and full release to proceed by an award date of October 16, 2006. It is also contingent upon availability of vendor shop space at the time of material/equipment procurement.

8.2.6 Progress Payment Terms

The payment to Foster Wheeler North America Corp. shall proceed by the following schedule:

5% of Contract Value upon Award/Release

10% of Contract Value upon Drawing Submittal

30% of Contract Value upon Purchase of Major Material and Equipment

45% of Contract Value upon Delivery of Material and Equipment

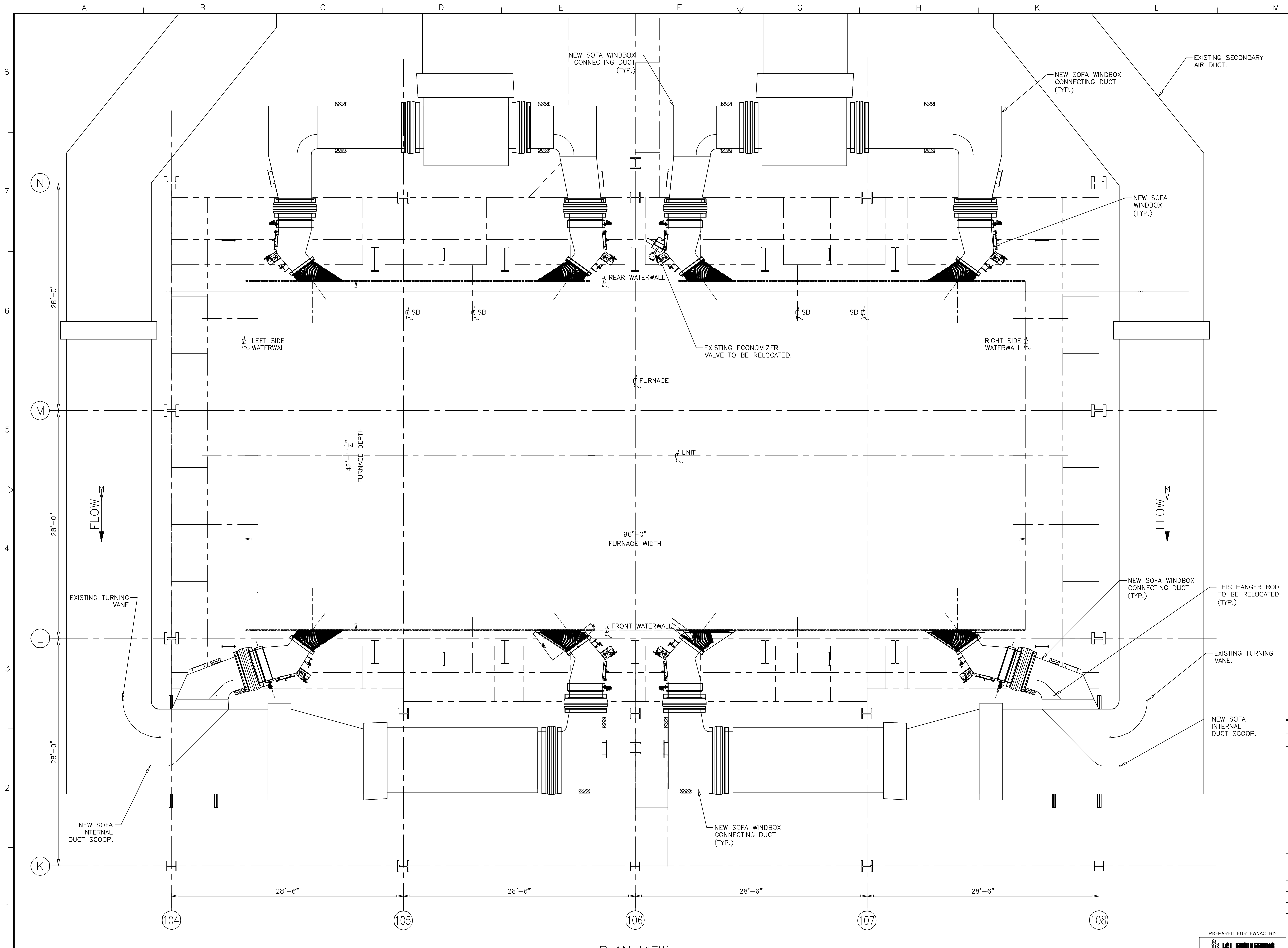
10% of Contract Value upon Successful Achievement of Performance Guarantee or Six Months after delivery whichever is sooner.

APPENDICES

A. Drawings

Drawing No.	Description
D-001	Proposed Tangential Low NOx SOFA System Arrangement
D-002	Proposed Tangential Low NOx SOFA Air System General Arrangement – Plan View
D-003	Proposed Tangential Low NOx SOFA Air System General Arrangement – Front & Side Views
D-004	Proposed Tangential Low NOx SOFA Air System General Arrangement – Isometric Views

B. Preliminary Schedule



PLAN VIEW

LEGEND OF SYMBOLS

℄ CENTRELINE

▨ INSULATION

⊞ DUCT ACCESS DOOR

} FABRIC (CLOTH) EXPANSION JOINT

⌶ DAMPER

REFERENCE DRAWINGS

1) GENERAL ARRG'T FRONT VIEW ____ D-003
2) GENERAL ARRG'T ISOMETRIC VIEWS ____ D-004

REV.	DATE	DR. INIT.	DESCRIPTION
A	09/13/06	R.D.	FIRST ISSUE

REVISIONS

PROPOSED TANGENTIAL LOW NOx
SOFA AIR SYSTEM
GENERAL ARRANGEMENT-PLAN VIEW

FOR: GREAT RIVER ENERGY
COAL CREEK UNIT NO.1
UNDERWOOD, ND.

FWNAC CONTRACT NUMBER:

DRAWING NUMBER	SCALE:	REVISION
D-002		A

DRAWN BY	R.D.	09/13/06	
CHECKED BY			
APPROVED BY			

PREPARED FOR FWNAC BY:
LCI ENGINEERING
Ottawa, Ont., Canada
LCI Contract no. 2006077

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CLINTON , N.J.

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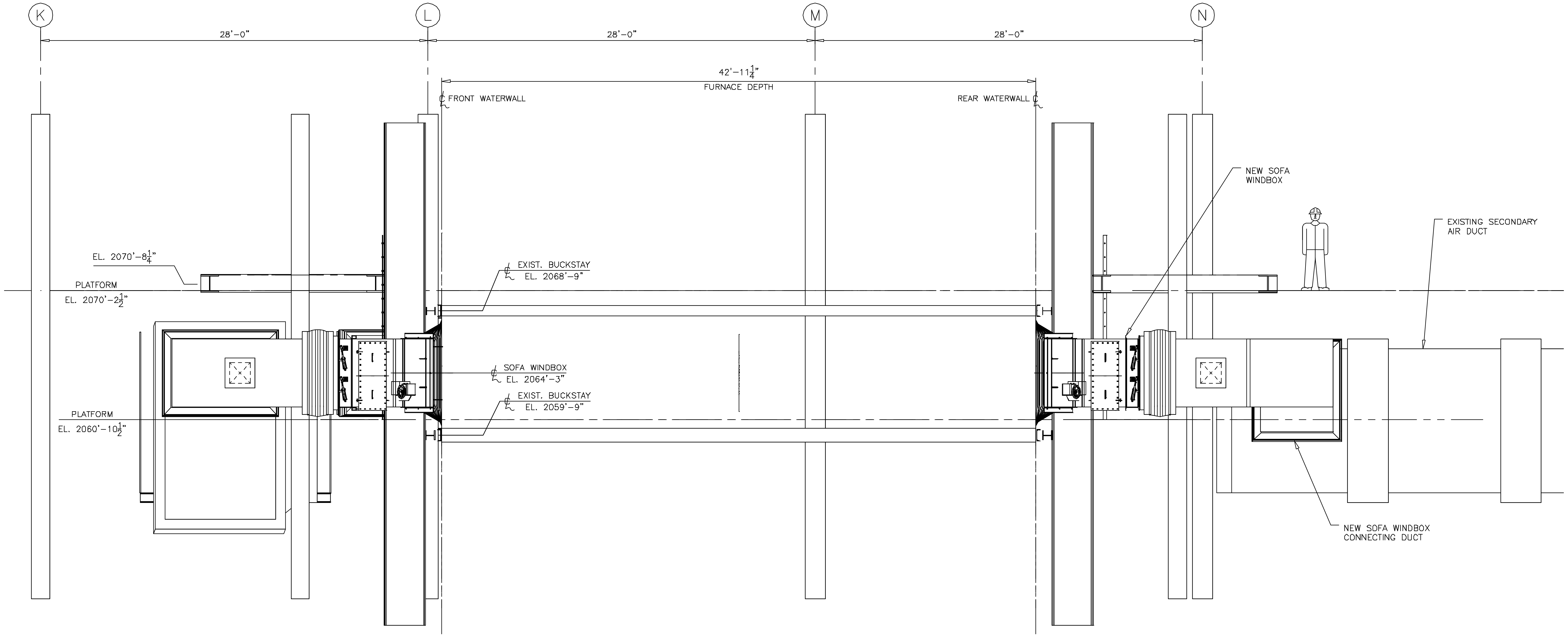
SECTIONAL FRONT ELEVATION



SECTIONAL SIDE ELEVATION

REFERENCE DRAWINGS

1) GENERAL ARRG'T PLAN VIEW ______ D-002
2) GENERAL ARRG'T ISOMETRIC VIEW ______ D-004

A	01/13/06	GF	FIRST ISSUE
REV.	DATE	DR. INIT.	DESCRIPTION

REVISIONS

PROPOSED TANGENTIAL LOW NOx
SOFA AIR SYSTEM
GENERAL ARRG'T– FRONT & SIDE VIEWS

FOR: GREAT RIVER ENERGY
COAL CREEK UNIT NO.1
UNDERWOOD, ND.

FWNAC CONTRACT NUMBER:

DRAWING NUMBER
SCALE:

D–003

REVISION
A

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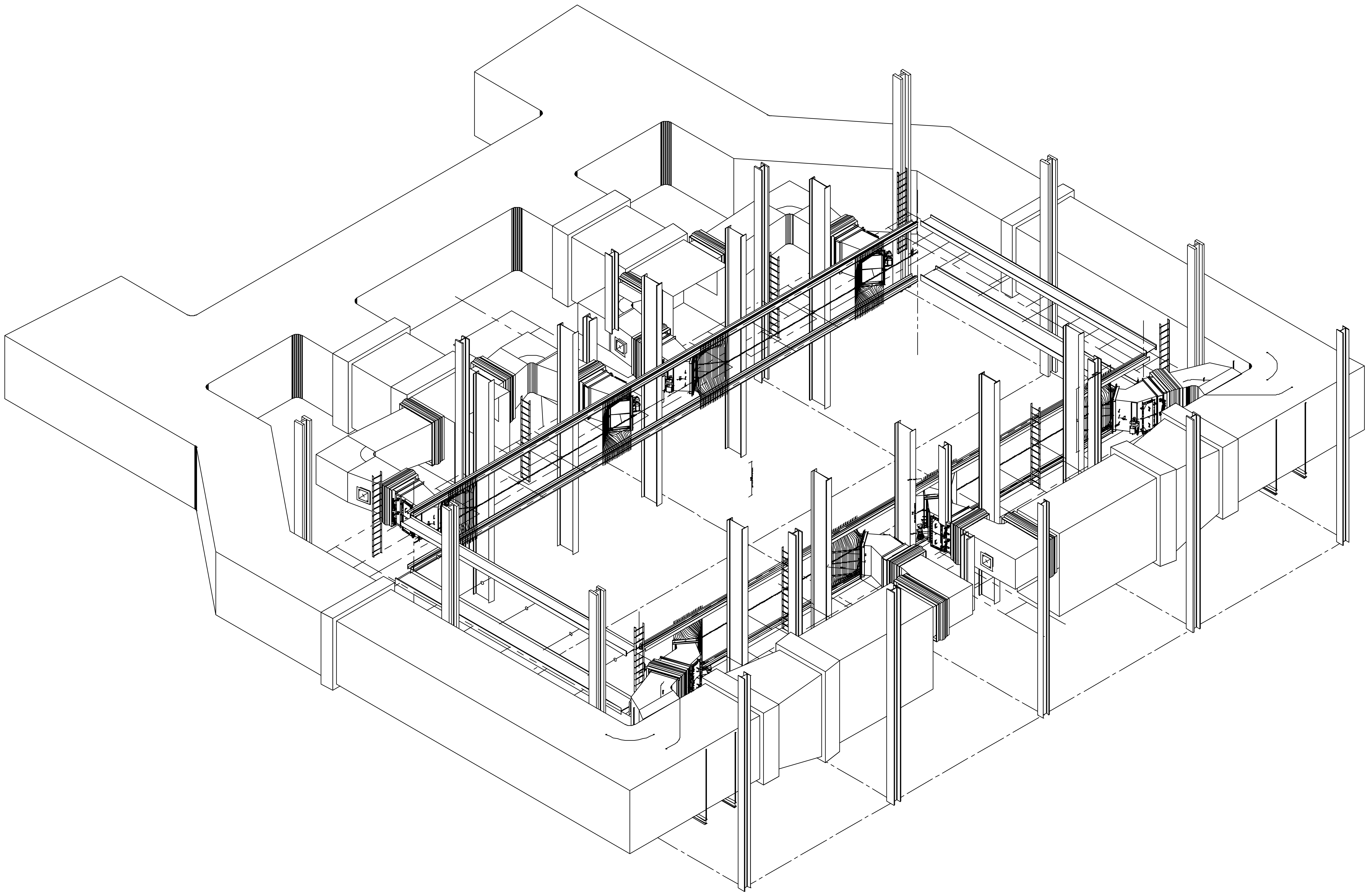

REFERENCE DRAWINGS

1) GENERAL ARRG'T PLAN VIEW	D-002
2) GENERAL ARRG'T FRONT & SIDE VIEWS	D-003

REV.	DATE	DR. INIT.	DESCRIPTION
A	01/13/06	GF	FIRST ISSUE

REVISIONS

PROPOSED TANGENTIAL LOW NOx
SOFA AIR SYSTEM
GENERAL ARRANGEMENT- ISOMETRIC VIEWS

FOR: GREAT RIVER ENERGY
COAL CREEK UNIT NO.1
UNDERWOOD, ND.

FWNAC CONTRACT NUMBER:

DRAWING NUMBER: D-004
SCALE:
REVISION: A

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AUTHORIZATION TO BEGIN WORK

Great River Energy hereby authorizes Foster Wheeler North America Corporation to perform the work described in its Proposal No. 65-120220-00 rev01 dated October 6, 2006 the rates and/or prices stated therein. Foster Wheeler North America Corporation is to commence the work in accordance with the Terms and Conditions of the proposal. It is understood that Great River Energy reserves the right to request changes in the Terms and Conditions and in the event that mutual agreement cannot be reached regarding the requested changes, we shall have the right to direct Foster Wheeler North America Corporation to stop work, in which case Foster Wheeler North America Corporation shall be paid for all materials as well as all work performed and Foster Wheeler North America Corporation shall have no further obligation to Great River Energy.

It is understood that a formal contract or purchase order will be prepared confirming this Authorization and or agreements regarding the work.

Great River Energy

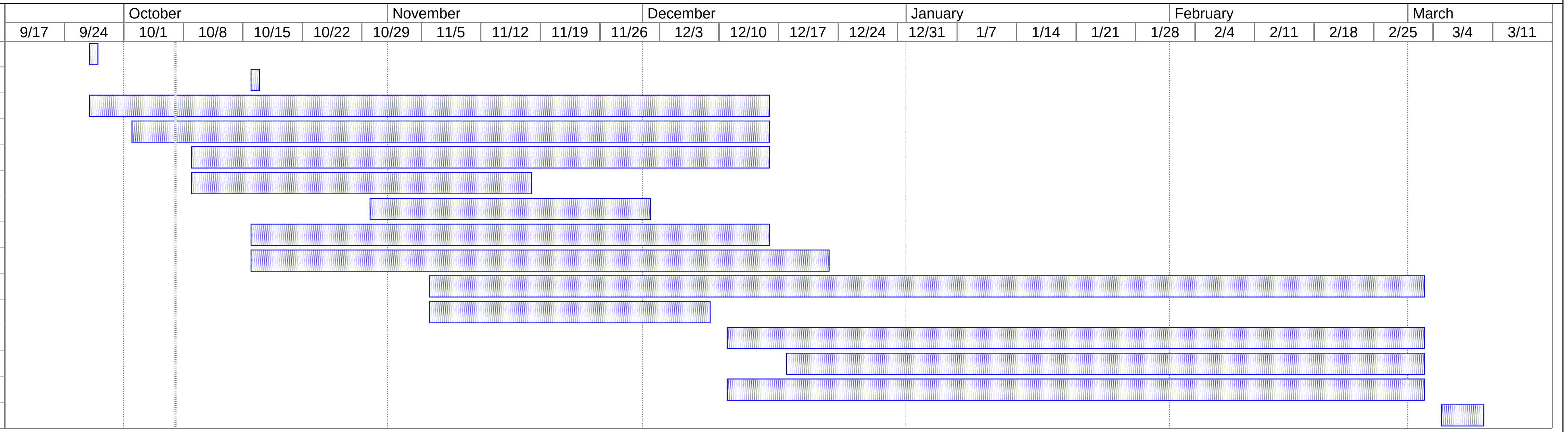
By:__________________________
Signature (Authorized Representative)

Printed or Typed Signature

Date:_________________________

GREAT RIVER ENERGY COAL CREEK TLN RETROFIT

ID	Task Name	Start	Finish
1	**ENGINEERING CONTRACT AWARD**	Wed 9/27/06	Wed 9/27/06
2	**MATERIAL CONTRACT AWARD**	Mon 10/16/06	Mon 10/16/06
3	**ENGINEERING**	Wed 9/27/06	Fri 12/15/06
4	GA Drawings	Mon 10/2/06	Fri 12/15/06
5	SOFA Duct Design	Mon 10/9/06	Fri 12/15/06
6	Pressure Part Design	Mon 10/9/06	Fri 11/17/06
7	Platform/Structural Design	Mon 10/30/06	Fri 12/1/06
8	SOFA Boxes, Tips	Mon 10/16/06	Fri 12/15/06
9	**MAT'L / EQUIP. PROCUREMENT**	Mon 10/16/06	Fri 12/22/06
10	**FABRICATION**	Mon 11/6/06	Fri 3/2/07
11	Tubing	Mon 11/6/06	Fri 12/8/06
12	SOFA Boxes Tips	Mon 12/11/06	Fri 3/2/07
13	SOFA Port Panels	Mon 12/18/06	Fri 3/2/07
14	Structural Steel & Ductwork	Mon 12/11/06	Fri 3/2/07
15	**SHIPMENT**	Mon 3/5/07	Fri 3/9/07



Project: GRE Coal Creek 2 TLN
Date: Sat 10/7/06

Task	▭	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	┈	Milestone	◆	Project Summary	▬	External Milestone	◆		

Appendix K

Coal Drying Study

Added February 2007

(Revised 2/6/07)

LIGNITE FUEL ENHANCEMENT

Final Technical Report: Phase 1

Reporting Period: July 9, 2004 to August 1st, 2006
DOE Award Number: DE-CF26-04NT41763
Date Report Issued: November 30, 2006

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DISCLAIMER

ACKNOWLEDGEMENT

The authors wish to acknowledge the contributions and support provided by various project managers: Dr. Sai Gollakota (DOE), Matt Coughlin (Barr), Dave Rian (Barr), John Wheeldon (EPRI), Tony Armor (EPRI), Dr. Ed Levy (Lehigh), Dr. Nedad Sarunac (Lehigh), and Mark Ness (GRE).

ABSTRACT

U.S. lignites have moisture contents ranging from 25 to 40 percent. This results in lower heating value, higher fuel flow rate, higher stack flue gas flow rate and stack loss, higher station service power, lower plant efficiency, and higher mill, coal pipe and burner maintenance requirements compared to that of the Eastern bituminous coals. Despite problems associated with their high-moisture content, lignite and sub-bituminous coals from the Western U.S. are attractive due to their low cost and emissions, and high reactivity.

A process that uses low-grade heat rejected from the steam condenser and waste heat from the flue gas leaving the boiler to evaporate a portion of the fuel moisture from the lignite feedstock in a fluidized bed dryer ("FBD") was developed in the U.S. by a team led by Great River Energy ("GRE"). The research is being conducted with Department of Energy ("DOE") funding under DOE Award Number: DE-CF26-04NT41763.

The objective of GRE's Lignite Fuel Enhancement project is to demonstrate a 5 to 15 percentage point reduction in lignite moisture content (about ¼ of the total moisture content) by using heat rejected from the power plant. This will significantly enhance the value of lignite as a fuel in electrical power generation power plants. Although current lignite power plants are designed to burn wet lignite, the reduction in moisture content will increase efficiency, reduce pollution, and improve plant economics.

The benefits of reduced-moisture-content lignite are being demonstrated at GRE's Coal Creek Station (CCS). A phased approach is used. In Phase 1 of the project, a full-scale prototype coal drying system, including a fluidized bed coal dryer, was designed, constructed, and integrated into Unit 2 at Coal Creek.

The prototype coal drying system at CCS has been in almost continuous, fully automatic operation since February 2006. Performance of the prototype dryer and the effect of partially dried coal on unit performance and emissions were determined from a series of paired performance tests that were conducted at carefully controlled test conditions. In addition, dryer performance during regular operation was determined.

According to the test results, at the baseline feed rate of 75 tons per hour, the prototype coal dryer easily meets the performance goals and specifications established for the project. The maximum continuous feed rate to the dryer is 101 t/hr. Further increases in feed rate are prevented by limitations on the coal conveying system throughput and dust collector fan power limits.

A commercial coal drying system, consisting of four fluidized bed dryers will be designed, built, installed, and tested at CCS during Phase 2 of the project. With four dryers in service it will be possible to reduce moisture content of the total coal feed to Unit 2 at Coal Creek to a target level of 29.5 percent. This will allow determination of boiler and unit efficiency improvements and emissions reductions, and evaluation of the effects of partially dried coal on unit operation and maintenance requirements.

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1. INTRODUCTION

U.S. low-rank coals have moisture contents ranging from 15 to 30 percent for sub-bituminous coals and from 25 to 40 percent for lignites. When high-moisture coals are burned in utility boilers, about seven percent of the fuel heat input is used to evaporate fuel moisture. The use of high-moisture coals results in higher fuel flow rate, higher stack flue gas flow rate, higher station service power, lower plant efficiency, and higher mill, coal pipe and burner maintenance requirements compared to that of the Eastern bituminous coals. Despite problems associated with their high-moisture content, lignite and sub-bituminous coals from the Western U.S. are attractive due to their low cost and emissions.

Countries with large resources of high-moisture low-quality coals are developing coal dewatering and drying processes. However, thermal processes developed thus far are complex and require high-grade heat to remove moisture from the coal. This significantly increases process cost, which represents a main barrier to industry acceptance of the new technology. A review of thermal drying technology is presented in [1].

A process that uses low-grade heat rejected from the steam condenser and waste heat from the flue gas leaving the boiler to evaporate a portion of fuel moisture from the lignite feedstock in a fluidized bed dryer (FBD) was developed in the U.S. by a team led by Great River Energy (GRE). The research was conducted with Department of Energy (DOE) funding under DOE Award Number: DE-CF26-04NT41763.

The objective of GRE's Lignite Fuel Enhancement project is to demonstrate a 5 to 15 percentage point reduction in lignite moisture content (about ¼ of the total moisture content) by incremental drying using heat rejected from the power plant. This will significantly enhance the value of lignite as a fuel in electrical power generation power plants. Although current lignite power plants are designed to burn wet lignite, the reduction in moisture content will increase efficiency, reduce pollution, and improve economics.

The benefits of reduced-moisture-content lignite are being demonstrated at GRE's Coal Creek Station. A phased approach is being used. In Phase 1, a full-scale prototype coal dryer was designed, constructed, and integrated into Unit 2 at Coal Creek. Dryer performance was tested at the baseline coal feed rate of 75 tons per hour. Field experience, dryer performance, and the effects of burning a lower moisture coal on unit performance, emissions, and operations are described in this report.

An additional four full-scale coal dryers will be designed, built, installed, and tested during Phase 2 of the project. With four dryers in service it will be possible to reduce the moisture of the total coal feed to Unit 2 at Coal Creek. This will allow determination of the efficiency improvement and emissions reduction for a unit operating on partially dried coal. Also, the effects of burning coal with reduced moisture content on unit operation will be evaluated.

A fluidized bed coal dryer ("FBD") was selected for this project due to its good heat and mass transfer characteristics which result in a much smaller dryer, compared to a fixed bed design. The FBD size, flow rate of fluidizing air and the power required to drive the fluidizing air fan are strongly influenced by the FBD operating conditions, such as coal size, bed depth, fluidizing air temperature, maximum allowed bed temperature, heat transferred to the fluidized bed by the in-bed heat exchanger, desired moisture level in the dried coal leaving the dryer, and amount of waste/rejected heat that could be used for drying. Higher dryer temperatures result in a smaller dryer size but require a more expensive heat exchanger system, working at higher temperature levels.

EXECUTIVE SUMMARY

A process which uses low-grade heat rejected from the steam condenser and waste heat from the flue gas leaving the boiler to evaporate a portion of fuel moisture from the lignite feedstock in a FBDwas developed in the U.S. by a team led by Great River Energy (GRE). The research was conducted with Department of Energy (DOE) funding under DOE Award Number: DE-CF26-04NT41763. The objective of GRE's Lignite Fuel Enhancement project is to demonstrate a 5 to 15 percentage point reduction in lignite moisture content by incremental drying using heat rejected from the power plant.

The benefits of reduced-moisture-content lignite are being demonstrated at GRE's Coal Creek Station (CCS). A phased approach is used. In Phase 1 of the project, a full-scale prototype coal drying system, including a fluidized bed coal dryer, was designed, constructed, and integrated into Unit 2 at Coal Creek.

The prototype coal drying system at CCS has been in almost continuous fully automatic operation since February 2006. Performance of the prototype dryer, and the effect of partially dried coal on unit performance and emissions, was determined in a series of paired performance tests that were conducted at carefully controlled test conditions. In addition, dryer performance during regular operation was determined as well.

According to the test results, the prototype coal dryer easily meets the performance goals and specifications established for the project, while operating at the baseline feed rate of 75 tons per hour. The maximum continuous feed rate to the dryer is 101 t/hr. Further increases in feed rate were prevented by limitations on the coal conveying system throughput and dust collector fan power limits. With a coal feed rate of 101 t/hr, a moisture reduction in the 7 to 9 percentage point range (20 to 26 percent on a relative basis) was achieved in the prototype coal dryer. The corresponding improvement in higher heating value (HHV) was in the 875 to 1,280 Btu/lb range, or 14 to 21 percent.

The plant performance parameters are summarized in Table E-1. For the total coal feed moisture reduction of 1.14 percent that was achieved with one coal dryer in service, boiler efficiency was improved by 0.37 percentage points. The improvement in net unit heat rate was 40 Btu/kWh, or 0.37 percent.

Table E-1

Effect of Partially Dried Coal on
Plant Performance Parameters Determined From Parametric Tests

Paired Performance Tests					
Parameter	**Units**	**Wet Coal**	**Partially Dried Coal**	**Absolute Change WRT Wet Coal**	**Relative Change WRT Wet Coal [%]**
Dried Coal	**% of total**	**0.00**	**14.12**	**14.1**	
Total Coal Flow Rate	klbs/hr	971	953	**-17.8**	**-1.8**
Total Coal Moisture	**%**	**37.06**	**35.92**	**-1.14**	**-3.1**
Coal HHV	**BTU/lb**	**6,299**	**6,402**	**103**	**1.64**
Gross Unit Load	MW	590	590	**0**	**0.0**
Throttle Steam Temperature	^{o}F	989	988	**-0.1**	**0.0**
Reheat Steam Temperature	^{o}F	1,002	1,002	**0.3**	**0.0**
SHT Desuperheating Spray Flow Rate	klbs/hr	45	51	**5.5**	**12.2**
Mill Power	kW	4,176	4,037	**-140**	**-3.3**
FD Fan Power with IGV	kW	2,049	2,056	**7**	**0.4**
ID Fan Power with ID	kW	11,782	11,613	**-169**	**-1.4**
PA Fan Power with IGV	kW	6,618	6,989	**371**	**5.6**
Total Fan and Mill Power	kW	24,624	24,694	**70**	**0.3**
Flue Gas Flow Rate at Scrubber Inlet	klbs/hr	7,140	7,101	**-39**	**-0.55**
Boiler Efficiency	**%**	**78.07**	**78.44**	**0.37**	**0.47**
Net Unit Heat Rate	**BTU/kWh**	**10,688**	**10,648**	**-40**	**-0.37**
FD Fan Power with VSD	kW	2,049	2,037	**-12**	**-0.6**
ID Fan Power with VSD	kW	11,782	11,430	**-351**	**-3.0**
PA Fan Power with VSD	kW	6,618	6,923	**305**	**4.6**
Total Fan and Mill Power with VSD	kW	24,624	24,427	**-197**	**-0.8**
Net Unit Heat Rate	**BTU/kWh**	**10,693**	**10,639**	**-54**	**-0.50**

With four driers in service, it would be possible to partially dry 100 percent of coal feed to the boiler. Performance predictions for a target moisture removal level of 8.5 percent are summarized in Table E-2. The results show that reducing the coal moisture content from 38.5 to 30 percent, would improve boiler efficiency by 1.70 percentage points. The improvement in net unit heat rate would be 219 Btu/KWh, or 2.05 percent.

Table E-2

Predicted Performance Improvement for Target Coal Moisture Removal of 8.5 Percent

Predicted Performance					
Parameter	**Units**	**Wet Coal**	**Partially Dried Coal**	**Change WRT Wet Coal**	**Percent Change WRT Wet Coal**
Dried Coal	% of total	0.00	100	100	
Total Coal Flow Rate	klbs/hr	971	837	-134	**-13.8**
Total Coal Moisture	%	37.06	28.56	-8.50	**-22.9**
Coal HHV	BTU/lb	6,299	7,150	851	**13.5**
Mill Power	kW	4,176	3,100	-1,076	**-25.8**
FD Fan Power with VSD	kW	2,049	1,928	-120	**-5.9**
ID Fan Power with VSD	kW	11,782	10,551	-1,231	**-10.5**
PA Fan Power with VSD	kW	6,618	8,305	1,687	**25.5**
Total Fan and Mill Power with VSD	kW	24,624	23,884	-740	**-3.0**
Flue Gas Flow Rate at Scrubber Inlet	klbs/hr	7,140	6,864	-276	**-3.9**
Boiler Efficiency	**%**	**78.07**	**79.77**	1.70	**2.18**
Net Unit Heat Rate	**BTU/kWh**	**10,688**	**10,469**	-219	**-2.05**

The effect of the prototype coal drying system on plant emissions is summarized in Table E-3. As the test results show, firing of partially dried coal has resulted in reduced NO_x, SO_x, CO_2, and mercury emissions.

Table E-3

Effect of Partially Dried Coal on Plant Emissions Determined From Parametric Tests

Paired Performance Tests		Segregated Stream Mixed with Product Stream				Segregated Stream not Mixed with Product Stream		
Parameter	**Units**	**Wet Coal**	**Partially Dried Coal**	**Absolute Change WRT Wet Coal**	**Percent Change WRT Wet Coal**	**Partially Dried Coal**	**Absolute Change WRT Wet Coal**	**Percent Change WRT Wet Coal**
NOx Emissions	lbs/hr	1,469	1,359	-111	**-7.5**			**-7.5**
CO_2 Emissions (due to HR Improvement)	klbs/hr	848	844.5	-3.2	**-0.37**			**-0.37**
SO_x Emissions (all 16 paired tests)	lbs/hr	3,670	3,641	-30	**-0.81**			**-1.8 to -2.5**
SO_x Emissions (first 12 paired tests)	lbs/hr	3,692	3,621	-71	**-1.93**			**-2.0 to -2.7**
Mercury Emissions					**-0.37**			**-2.2 to -3.9**

With the current design of the prototype coal drying system at CCS, the segregated and product streams are mixed. The segregated stream is mostly comprised of the non-fluidizable material discharged from the first dryer stage, and contains 3 to 3.5 times more sulfur and mercury compared to the product and feed streams. If the segregated stream were not mixed with the product stream, the mass flow rates of sulfur and mercury to the boiler would be reduced, resulting in lower emissions of these pollutants.

The predicted reduction in emissions for a target value of moisture reduction of 8.5 percent, is summarized in Table E-4 for the cases where the segregated stream and product streams are mixed, and for the case where the segregated stream is further processed and not mixed with the product stream. The results show the potential for significant reductions in SO_x and mercury emissions.

Table E-4

Predicted Emission Reduction for Target Coal Moisture Removal of 8.5 Percent

Predicted - Fanroom Coil in Service		**Segregation Stream Mixed with Product Stream**				**Segregation Stream not Mixed with Product Stream**		
Parameter	**Units**	**Wet Coal**	**Partially Dried Coal**	**Absolute Change WRT Wet Coal**	**Percent Change WRT Wet Coal**	**Partially Dried Coal**	**Absolute Change WRT Wet Coal**	**Percent Change WRT Wet Coal**
NOx Emissions					**> -7.5**			**> -7.5**
CO_2 Emissions (due to HR Improvement)					**-2.4**			**-2.4**
SO_x Emissions					**> -2**			**-12 to -17**
Mercury Emissions					**-15**			**-25 to -35**

The predicted reductions in SO_x and Hg emissions due to the sulfur and Hg removal from the feed stream in the first dryer stage are affected by the accuracy of the measured sulfur and Hg concentration levels in the feed, segregated, and product streams, and the segregated stream flow rate. The actual reductions in SO_x and Hg emissions will be determined when the commercial coal drying system at CCS is operating at 100 percent capacity.

A commercial coal drying system, consisting of four fluidized bed dryers will be designed, built, installed, and tested at CCS during Phase 2 of the project. With four dryers in service it will be possible to reduce the moisture content of the total coal feed to Unit 2 at Coal Creek to a target level of 29.5 percent. This will allow determination of the resulting efficiency improvement and emissions reduction and evaluation of the effects of partially dried coal on unit operation and maintenance requirements.

2. DESCRIPTION OF COAL CREEK STATION

Coal Creek Station (CCS) is a 1,200 MW lignite-fired power plant located in Underwood, North Dakota. The plant supplies electricity to 38 member cooperatives in

Minnesota. Two tangentially fired CE boilers supply steam to two single reheat GE G-2 turbines rated at 560 MW each. The units are designed for 1,005°F main steam and reheat steam temperature at a 2,520 psi throttle pressure. Three mechanical draft cooling towers are used to reject heat to environment. The boiler fires lignite coal from the nearby Falkirk mine. The coal that has a HHV of 6,200 Btu/lb and total moisture content of approximately 38 percent. An aerial photograph of Coal Creek Station is presented in Figure 1-1.

Figure 1-1: Aerial Photograph of Coal Creek Station

A schematic representation of heat flows for the CCS is given in Figure 1-2. For full unit load (gross power output of 576.7 MW (546 MW nameplate)) and fuel containing 40 percent moisture, the heat input with the fuel (Q_{fuel}) is approximately 5,670 MBtu/h. The boiler loss (Q_{loss}), including dry stack loss (Q_{stack}) and fuel moisture evaporation loss (Q_{evap}) is approximately 1,090 MBtu/h, or 19.2% of the fuel heat input. This gives a boiler efficiency of 80.78%. The dry stack loss is 436 MBtu/h, which represents 7.7 percent of the fuel heat input. The loss due to evaporation of fuel moisture is 370 MBtu/h (approximately 6.6 percent of fuel heat input). Thermal energy

(Q_T) transferred to the working fluid in the boiler is about 4,580 MBtu/h. The thermal efficiency of the steam turbine cycle is approximately 43 percent, which gives rejected heat of approximately 2,600 MBtu/h (46 percent of the fuel heat input). The gross unit efficiency is approximately 34.7 percent, with a gross unit heat rate of 9,825 Btu/kWh.

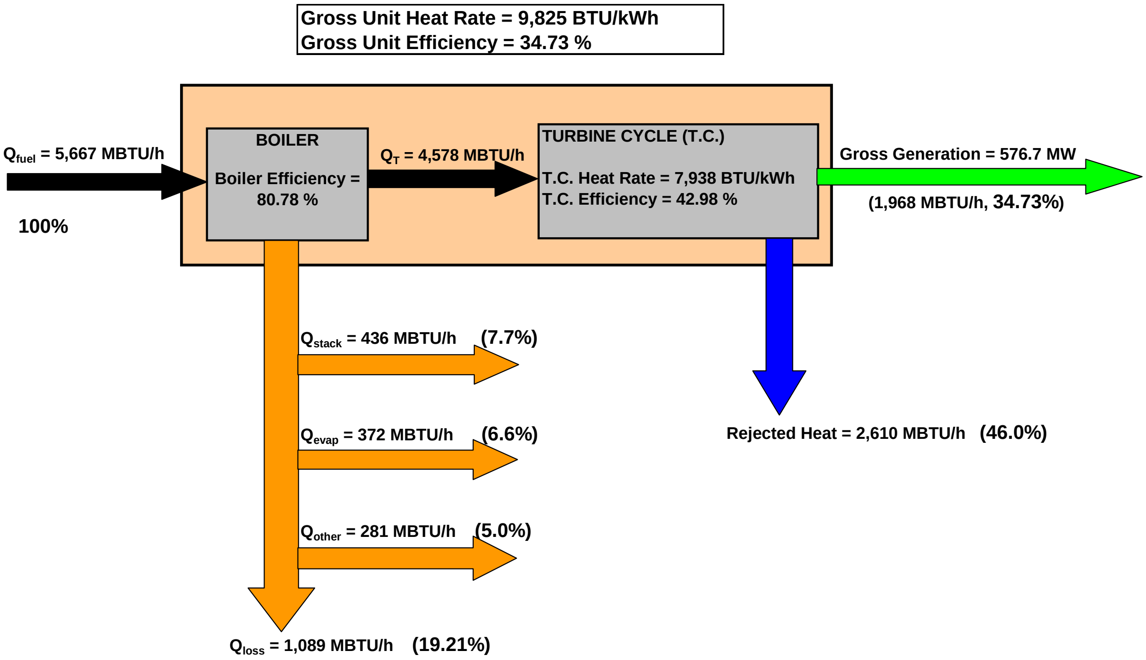

Figure 1-2: Coal Creek Unit Heat Flow Schematic – One Unit

2.1: Sources and Magnitudes of Waste Heat

Thermal energy in the flue gas leaving the plant represents waste heat. For one unit of the Coal Creek Station with a lignite feed containing 40 percent moisture, the waste heat in the flue gas is approximately 440 MBtu/hr. Engineering analyses show that using waste heat in flue gas to remove 5 percent of coal moisture would decrease the stack temperature by approximately 30°F.

Heat rejected in the main steam condenser represents another large source of waste heat. For one unit of the Coal Creek Station, heat rejection in the condenser is approximately 2,600 MBtu/hr (about 46 percent of the fuel heat input). The cooling water leaving the Coal Creek condenser has a temperature of approximately 120°F. This warm cooling water is then cooled in the cooling towers to approximately 90°F and is circulated back to the condenser. Engineering analyses show that, at full unit load, approximately 2 percent of the heat rejected in the condenser/cooling tower would be needed to decrease the coal moisture content by 5 percent. The cooling water circuit is constructed of pipes, which makes the access to this waste heat source relatively easy.

3. PREVIOUS WORK

During the 1990's the engineering staff at CCS began investigating alternative approaches to dealing with future emission regulations. Conventional approaches included changing fuels and/or adding environmental control equipment. This approach often results in lowering emissions at the expense of increases in unit heat rate and operating and maintenance costs. Higher heat rate results in higher required fuel heat input, higher CO_2 emissions, higher flow rate of flue gas leaving the boiler and lower plant capacity. Lower capacity is due to higher station service power requirements or limited equipment capacity. Also, increased flue gas flow rate requires a larger size of environmental control equipment, higher equipment cost and station service power.

A theoretical analysis was performed by the Lehigh University's Energy Research Center (ERC) in 1997-98 to estimate the magnitude of performance improvement that could be achieved by firing coal having lower moisture content [2]. The results showed that a decrease in fuel moisture would have a large positive effect on unit performance, Figure 1-3.

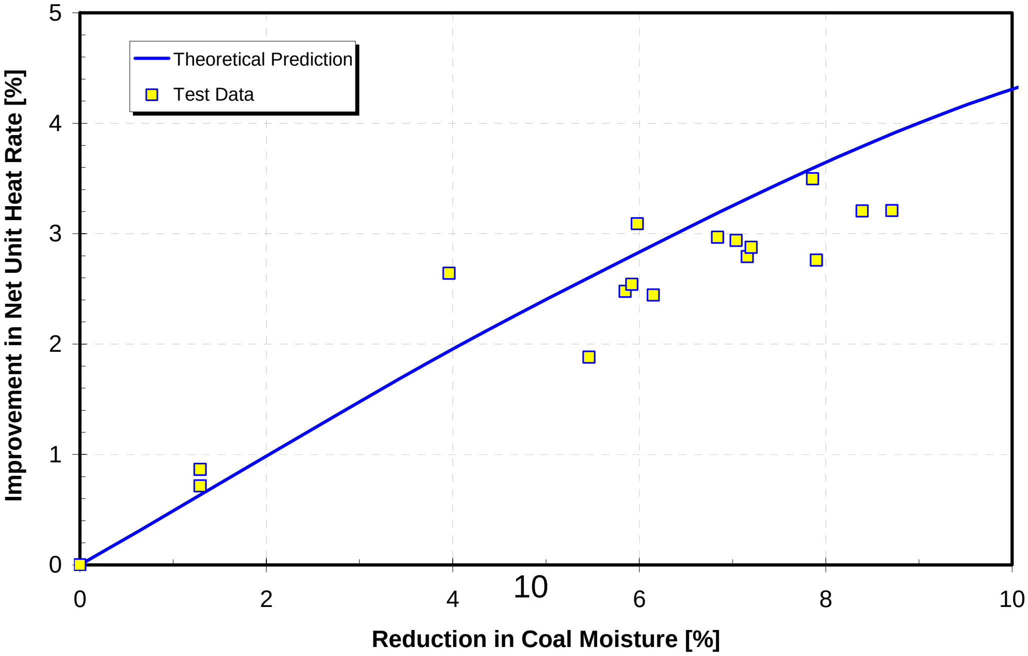

Figure 1-3: Effect of Fuel Moisture on Unit Performance

Based on these theoretical results, CCS personnel performed test burns with partially dried lignite in 2001 to confirm whether the boiler and coal handling system could handle the partially dried lignite. Except for dust in the transfer hoppers, no other fuel handling problems were encountered. Also, test results confirmed the theoretical performance improvement predictions [3].

After demonstrating the benefits of firing dried fuel, a technology for coal drying needed to be selected. Based on laboratory testing conducted at the ERC in 2002, a FBD was selected as the best technology due to its high heat and mass transfer coefficients and compact size.

GRE submitted an application to DOE in 2002 under the Clean Coal Power Initiative (CCPI) to develop a prototype fluidized bed coal dryer and develop and install a commercial coal drying system on one unit at CCS. GRE, ERC, EPRI, Barr Engineering and Falkirk Mining Company participated in the proposal development. The project was negotiated with DOE for funding under the CCPI in July 2004. Previous work and project activities are summarized in Table 1-1.

Table 1-1

Previous Work

Time Period	Activity
1997-1998	Preliminary studies and concept development.
1999	Lignite-drying tests using low-temperature fixed-bed dryer.
2000	CCS Boiler modeling. Laboratory lignite drying tests. Full-scale test burns using 20,000 tons of lignite dried using low-temperature air.
2001	Fixed bed dryer designed. Fluidized bed dryer selected for coal drying due to higher efficiency, smaller size, and lower cost. Application for funding under the PPI initiative was filed but turned down. Laboratory-scale FB drying tests at ERC.
2002	Application filed with DOE under the Clean Coal Power Initiative (CCPI)
2003	Application selected for negotiation with DOE. Pilot FBD built at CCS. Pilot FBD testing.
2004	Contract signed with DOE. Design of the prototype coal dryer and associate equipment.

2005	Construction of prototype coal dryer begins.
2006	Prototype dryer checkout and start-up. Prototype dryer performance testing. Unit performance testing. Maximum capacity testing. Data analysis and project report. August: Phase 1 milestone.

The project is divided into two phases. The first phase involved design, construction, installation and testing of a prototype coal drying system at CCS consisting of one FBD. The prototype coal drying system was designed in 2004. The construction began in 2004 and was finished in February 2006. The system checkout tests were conducted in February and March 2006. Performance testing was performed in March and April. Maximum capacity tests were performed in June 2006.

The second phase of the project involves installation of a commercial drying system at CCS capable of drying 500 tons/hr of wet lignite fuel.

3.1: Pilot Coal Dryer

Prior to DOE Project selection, and with funding from the North Dakota Industrial Commission (NDIC), GRE designed and constructed a 2 ton/hr pilot dryer at CCS in 2003 to provide operating experience and design scalability data for the DOE project. The pilot dryer is depicted in Figure 1-4. Field testing was conducted over a range of FBD operating conditions. A methodology for analyzing test data and determining FBD performance was developed [4].

The pilot coal dryer was operated for a 12-week period beginning in September 2003. The pilot dryer dried 150 tons of coal in 38 tests reducing the moisture content of the lignite by 24 to 60 percent, Figure 1-5. Moisture-free heating values for the feed and product streams indicated that no appreciable carbon oxidation took place during the drying process.

A buildup of the non-fluidizable material on the distributor plate, close to the coal feed point, was observed during testing. This was especially evident in the final days of testing when non-fluidizable material was cleaned out between tests, and its mass was measured. It was realized that accumulation of non-fluidizable material on a distributor plate could be used to segregate out ash, pyrites, and other impurities from the coal.

Analysis of collected samples confirmed that the non-fluidizable material on the bed bottom exhibited very high concentrations of ash, sulfur, and mercury. Depending on the feed material, it is likely that removal of this material from the feed stream would create a relatively minor energy loss, while causing a significant reduction in ash sulfur and mercury. It is possible that removal of the concentrated bed bottom material could result in SO_2 and mercury reductions of greater than 20 percent as was seen in several tests.

The pilot dryer field results were also compared to the predictions obtained by a FBD Simulation Code, developed under DOE Award Number DE-FC26-03NT41729 by ERC researchers [5] and [6]. Comparison between measured and predicted values is given in Table 1-2. A very good agreement between measurements and predictions was achieved.

Figure 1-4: Pilot Fluidized Bed Dryer at CCS

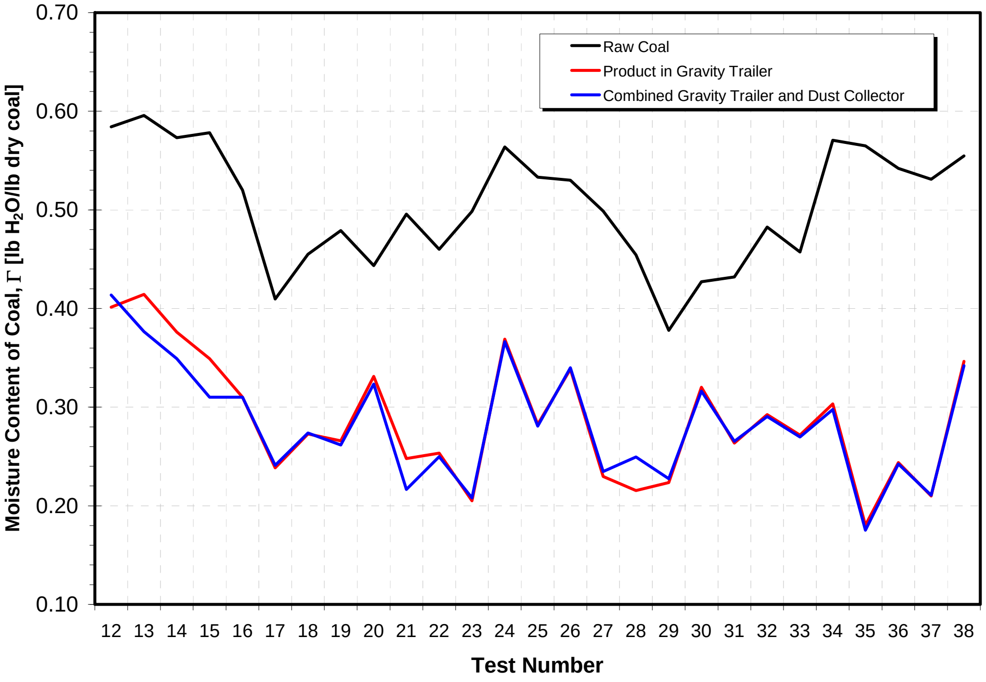

Figure 1-5: Pilot Test Results

Table 1-2

Comparison Between Pilot Test Results and FBD Simulation Code Predictions

Test Number	ΔΓ [lb/lb dry coal]		Outlet Air Temp. [°C]		RH of Outlet Air [%]	
	Measured	Predicted	Measured	Predicted	Measured	Predicted
4	0.175	0.151	25.5	26	72.5	69
20	0.134	0.217	33.5	36.7	86.9	70
23	0.300	0.335	36.9	37.8	66.7	67
30	0.107	0.150	30.2	33.3	86.1	72

The FBD simulation code was used to design a prototype coal dryer and, later on, the commercial coal dryers at CCS. The technical approach and results are described in [7] and [8].

PART 1: PROTOTYPE COAL DRYER AND ITS PERFORMANCE

4. COAL CREEK PROTOTYPE COAL DRYING SYSTEM

The prototype coal drying system employed at Coal Creek is based on using waste heat from the steam condenser and the hot flue gas to heat the fluidizing air used for coal drying. These two waste heat sources are also used to provide heat within the freeboard region of the FBD to provide an additional drying of the coal. The prototype coal drying system and FBD were designed by a design team assembled by GRE.

Coal feed for the dryer is supplied from existing coal bunker No. 28 (Figure 1-6). The wet coal (feed stream) is fed by a vibrating coal feeder (Figure 1-9) to a coal crusher and crushed and sieved to -1/4”. The crushed coal is screened by a vibrating screen (Figure 1-7) and conveyed to the dryer inlet hopper. Two rotary coal feeders (air locks) feed coal to the first stage of the FBD. The screen bypass flow (i.e., the larger particles separated out by the screen that were not therefore dried in the dryer) is mixed with a product stream leaving the dryer employing a bypass conveyer. Mixing of the two streams takes place downstream of the coal sampling location.

Figure 1-6: Coal Feeder

Figure 1-7: Vibrating Screen

The dried coal (product stream) leaving the dryer is stored in coal bunker No. 26, feeding coal mill 26. A coal conveyor and bucket elevator are used to transport dried coal to the No. 26 bunker. As product stream is transported from the dryer to the bunker, it cools down, and its temperature drops by approximately 10°F.

The coal-drying system was designed in modular fashion to allow incremental drying of the coal. Each coal-drying module will dry a portion of the total coal flow and will also include environmental controls (baghouse for dust control). With all four coal-drying modules in service it will be possible to dry 100% of the coal feed.

The commercial coal drying system design will provide redundancy whereby coal dryers will be able to supply dried product to any coal mill. This will provide backup in the event of the equipment problem. This redundancy will also extend from Unit 1 to Unit 2 and vice versa.

Also, in the commercial coal drying system, the segregated stream will not be combined with the product stream. This will have a significantly positive effect on SO_x and mercury emissions.

4.1: Fluidized Bed Coal Dryer

A fluidized bed dryer is a good choice for drying coal to be burned at the same site where it is dried. The coal dryer can be of single-stage or multiple-stage design, with the stages contained in one or more vessels. The multi-stage design allows maximum utilization of fluidized bed mixing, segregation and drying characteristics.

A two-stage fluidized bed dryer design, where the bed volume is divided into two parts, is employed at Coal Creek. The dryer was manufactured by Heyl & Patterson, Inc. and is comprised of two stages, packaged into a single vessel. The first stage occupies approximately 20 percent of the dryer volume.

In the first stage, the coal is preheated and partially dried (a portion of surface moisture is removed). Non-fluidizable particles segregate out, thereby forming the segregated stream. The first dryer stage accomplishes the following functions: separates the fluidizable and non-fluidizable material, pre-dries and preheats the coal, and provides uniform flow of coal to the second stage.

The fluidizable material flows over the weir to the second stage of the dryer, where the coal is heated and dried to a desired outlet moisture level. The product stream from the second stage is discharged over the discharge weir into the discharge hopper. From the discharge hopper, the product stream is fed to the product stream conveyor through three rotary coal feeders (air locks) (Figure 1-8). Although the second stage can also be used to further separate ash and other impurities from the coal, this option was not employed at CCS.

Figure 1-8: Dried Coal is Discharged through Three Rotating Coal Feeders

Fluidization and heating of coal and removal of coal moisture is accomplished within the fluidized bed by hot fluidization air. The air stream is cooled and humidified as it flows upwards through the coal bed. The quantity of moisture, which can be removed from the bed of fluidized coal, is limited by the drying capacity of the fluidization air stream. The drying capacity of the fluidization air stream can be increased by supplying additional heat to the bed by the in-bed heat exchanger. The in-bed heat exchanger not only increases drying capacity of the fluidizing air stream but it also reduces the quantity of drying air required to accomplish a desired degree of coal drying.

Five in-bed heat exchangers (bed coils), employing finned tubes, are used to supply additional heat to the coal: one in the first dryer stage, with the other four in the second stage. Different designs and materials were used for each bed coil tested in the prototype dryer. The best performing design will be used in the additional four dryers that will be built in Phase 2 of the project.

The prototype dryer design data are summarized in Table 1-3. As the data in Table 1-3 show, the heat transfer area for individual bed coils, depending on their design, varies from 1,144 to 1,982 ft^2. The average heat transfer coefficient for finned tubes of 18 Btu/hr-ft^2-°F was determined experimentally by GRE and Barr engineers.

Table 1-3

Prototype Dryer Design Data

Prototype Coal Dryer Parameter	Units	Prototype Value
Distributor Area	ft^2	**308**
First Stage Fluidizing Air Flow	klbs/hr	**55**
Second Stage Fluidizing Air Flow	klbs/hr	**250**
Expanded Bed Depth	"	**38 to 40**
In-Bed Heat Exchanger No. 1 HT Area	ft^2	**1,982**
In-Bed Heat Exchanger No. 2 HT Area	ft^2	**1,696**
In-Bed Heat Exchanger No. 3 HT Area	ft^2	**1,982**
In-Bed Heat Exchanger No. 4 HT Area	ft^2	**1,832**
In-Bed Heat Exchanger No. 5 HT Area	ft^2	**1,144**
Total In-Bed Heat Exchnager Area	**ft^2**	**8,636**
Total Exchanged Heat, In-Bed HXE	MBTU/hr	**16.53**
Average Heat Transfer Coefficient	BTU/hr-ft^2-^{o}F	**18.08**
Total Water Flow Through the In-Bed Heat Exchangers, Actual	gpm	**1,588**
Total Water Flow Through the In-Bed Heat Exchangers, Indicated	gpm	**1,363**

In order to achieve maximum drying, the drying air stream would need to leave the fluidized bed at saturation conditions (i.e., with 100 percent relative humidity). This is, however, undesirable since condensation would occur in the freeboard region of the dryer. To prevent this, the CCS prototype coal dryer was designed for an outlet air relative humidity less than 100 percent.

Alternatively, reheat surfaces in the freeboard region of the bed or duct skin heating can be used to increase the temperature and lower the relative humidity of the air leaving the dryer and prevent downstream condensation. This option was not implemented at CCS.

The particle control equipment, consisting of a dust collector (baghouse) and discharge fan, is used to remove elutriated fines from the moist air stream leaving the dryer. Collected particulate matter is mixed with the coal product stream, and clean particle-free moist air is discharged through a stack to the atmosphere, as presented in Figure 1-9.

Figure 1-9: Clean Moist Air Stream Leaving Dust Collector is Discharged into the Atmosphere

4.2: Instrumentation

The prototype coal drying system tested at CCS was instrumented to allow determination of dryer performance. Plant instrumentation was used to determine boiler efficiency and plant heat rate.

Measured variables include: coal feed rate, crusher power, inlet and outlet air lock (rotary feeder) loading, temperature of feed stream, temperature of coal in the No. 26 bunker, CO level at the dryer outlet and in the bunker, dust collector fan power, moisture in product stream, moisture in fluidizing air stream leaving the dryer and dust collector, temperature of fluidizing air stream at the dryer inlet, cold and hot PA temperatures, flow rate of fluidizing air into the first and second dryer stage, circulating water flow and inlet and outlet temperature, pressure of fluidizing air in the plenum, above the bed and other state points including dust collector inlet and outlet, and flow rate of the bypass and scrubbing air. An array of thermocouples is used to measure the coal and freeboard temperature in the dryer. Thermocouple arrangement in the dryer is presented in Figure 1-10. Process values, measured during dryer testing will be presented later.

It has to be noted that the on-line instrument for coal moisture measurement is not providing representative information since it measures surface moisture. A very poor correlation was found between coal moisture values measured by the on-line instrument and determined from the laboratory analysis of coal samples. Therefore, the on-line measurement of coal moisture content was not used in the data analysis.

The relative humidity of fluidizing air stream leaving the dust collector (baghouse) was usually in the 99 to 100 percent range. Its value was not affected by changes in dryer operating conditions. It is believed that this measurement, although correct, is not representative of the dryer outlet conditions. In addition, as elutriated coal particles are collected on a bag wall, they form a layer (cake) of wet coal. This layer is dried by the air flowing through the bags. Engineering analyses suggest that the air leaving the cake is saturated.

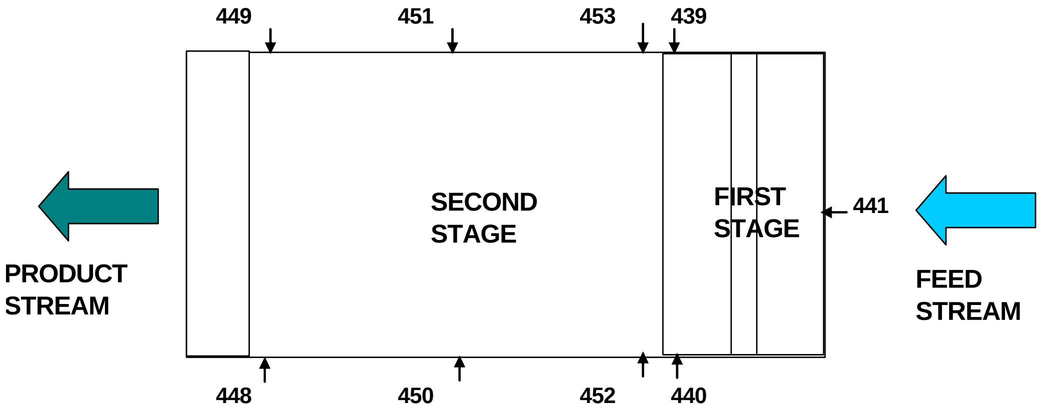

Figure 1-10a: Thermocouple Locations and Numbers in First and Second Stages of a Prototype Coal Dryer at CCS

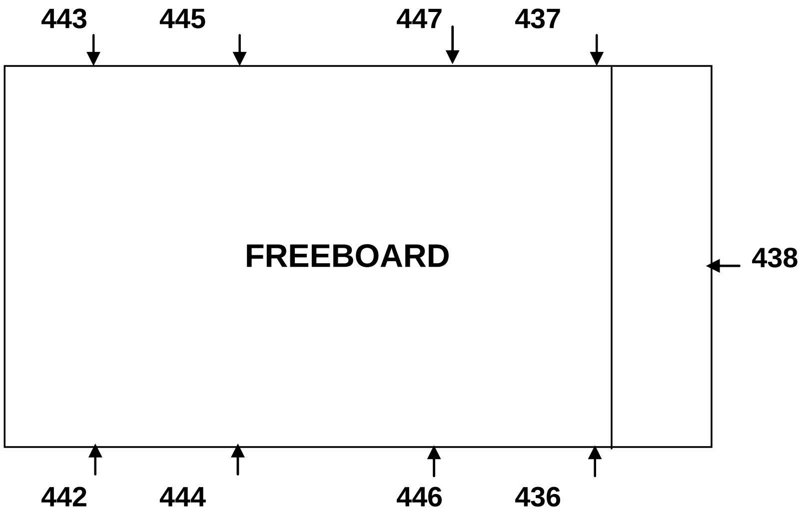

Figure 1-10b: Thermocouple Locations and Numbers in the Freeboard Region of a Prototype Coal Dryer at CCS

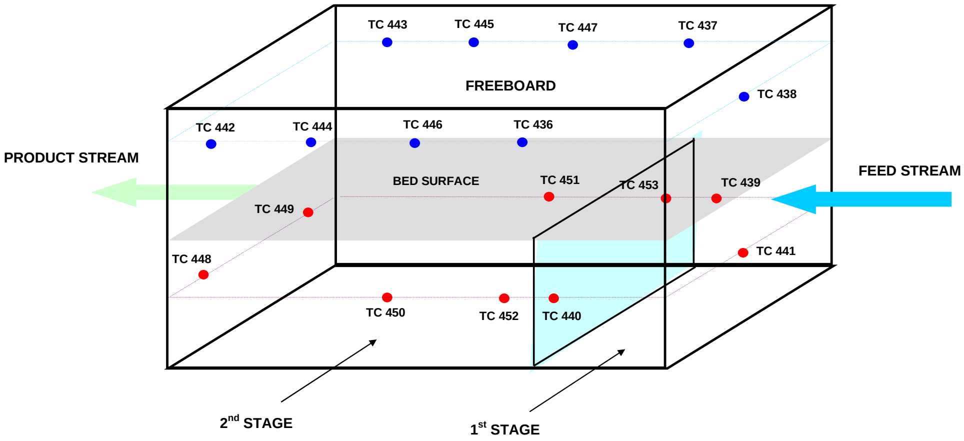

Figure 1-10c: Thermocouple Locations in First and Second Stagesand in a Freeboard Region of a Prototype Coal Dryer at CCS Isometric View

The second instrument for air moisture measurement, located at the dryer outlet, upstream of the dust collector was, unfortunately, not working properly. Therefore, no measured values of dryer outlet air moisture are available for analysis and comparison with theoretical predictions.

Two automatic coal samplers were used to collect samples of the feed and product streams. The feed coal sampler, located on the feed conveyer, is presented in Figure 1-11.

Figure 1-11: Automatic Coal Analyzer: Feed Conveyer

The automatic coal sampler for the product stream is located on the product conveyer after the product stream leaving the dryer is mixed with the segregated stream and elutriated coal particles collected by the dust collector. This introduces an uncertainty in product moisture and dryer performance. Manual coal samples were also taken from the segregated stream conveyer to determine composition of the segregated stream.

4.3: <u>Process Control</u>

Operation of the prototype coal drying system at CCS is completely automated, including the startup, shutdown, and emergency shut down procedures. Heat input to the dryer is controlled by adjusting the input flow rates of the waste heat sources to match the heat input required to accomplish the desired degree of drying.

Heat input to the dryer, Q_1, is defined as:

$$Q_1 = Q_{air} + Q_{Circulating\ water} \qquad \text{Eqn. 1-1}$$

where:

Q_{air}	Heat input with the air stream
$Q_{Circulating\ Water}$	Heat supplied to the in-bed heat exchanger

The required heat input to the dryer, Q_2, is defined as:

$$Q_2 = M_{coal}\ \Delta TM\ h_{fg} + \Delta Q_{Coal\ Sensitive} \qquad \text{Eqn. 1-2}$$

where:

M_{coal}	Coal feed flow rate
ΔTM	Required (desired) absolute reduction in total coal moisture content
h_{fg}	Latent heat of evaporation of coal moisture
$\Delta Q_{Coal\ Sensitive}$	Change in sensitive heat of coal

As long as $Q_1 < Q_2$, during the dryer startup or transient operation when coal feed rate to the dryer is increased, the control algorithm increases the hot air flow rate until the heat input supplied to the dryer matches the required heat input.

When the coal feed flow rate is reduced, or a lower reduction of coal moisture content is required, $Q_2 > Q_1$, the control algorithm reduces the flow rate of hot air flow until $Q_1 = Q_2$. This simple control algorithm works very well in practice.

5. DRYER PERFORMANCE

5.1: Factors Affecting Dryer Performance

Performance of a fluidized bed dryer is affected by many operating and design parameters. The most important include: flow rate and inlet moisture content of coal, flow rate, temperature and humidity of drying/fluidizing air, bed depth, coal residence time, and heat input by the in-bed heat exchanger. The latter is directly proportional to the heat transfer surface area and the average difference in temperature between the heat exchanger tube surface area and fluidized coal particles.

5.2: First and Second-Stage Dryer Performance

As discussed earlier, a two-stage dryer design offers several advantages, compared to a single-stage design. The most important advantage is segregation of coarse and non-fluidizable material which is collected at the bottom of the first stage and discharged from the dryer and scrubbing boxes. The fluidizable material flows over the weir separating the first and second dryer stages and enters the second stage. After passing through the second stage, dried coal is discharged into the outlet hopper over the discharge weir. The function of the discharge weir is to maintain the bed height.

The calculated variations of the bed temperature and coal moisture content along the length of the prototype dryer are presented in Figures 1-12 and 1-13 for a feed rate of 75 t/hr of wet Falkirk mine lignite, a fluidization air temperature at 170°F and an average bed coil temperature of 210°F are required. Calculations were performed with an inlet coal moisture content of 37.08 percent on a wet coal basis, corresponding to $\Gamma = 0.589$ lb moisture/lb dry coal.

The results presented in Figures 1-12 and 1-13 show that the main functions of the first and second dryer stages are very different. The incoming coal is preheated in the first dryer stage from the inlet temperature to a temperature corresponding to approximately 90 percent of the maximum coal temperature leaving the dryer. The reduction in coal moisture content in the first stage is small -- less than 10 percent of the total coal moisture is removed in the first stage. By contrast, the increase in bed temperature in the second dryer stage is very small -- only about 10 percent of the total temperature increase in coal dryer. However, the second dryer stage removes more than 90 percent of the total moisture removed from the feed stream.

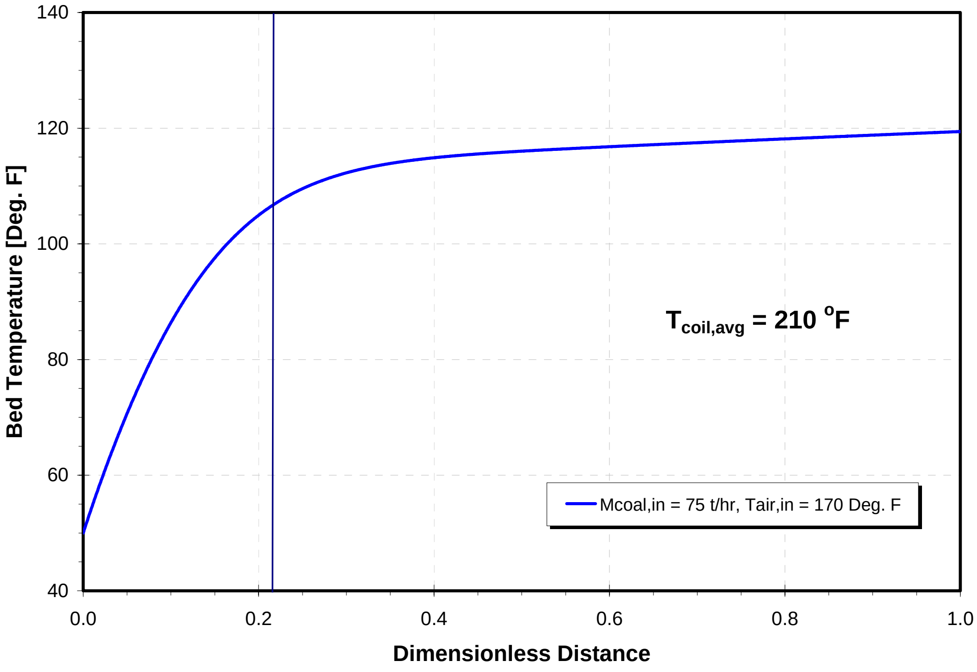

Figure 1-12: Variation of Bed Temperature Along the Dryer Length

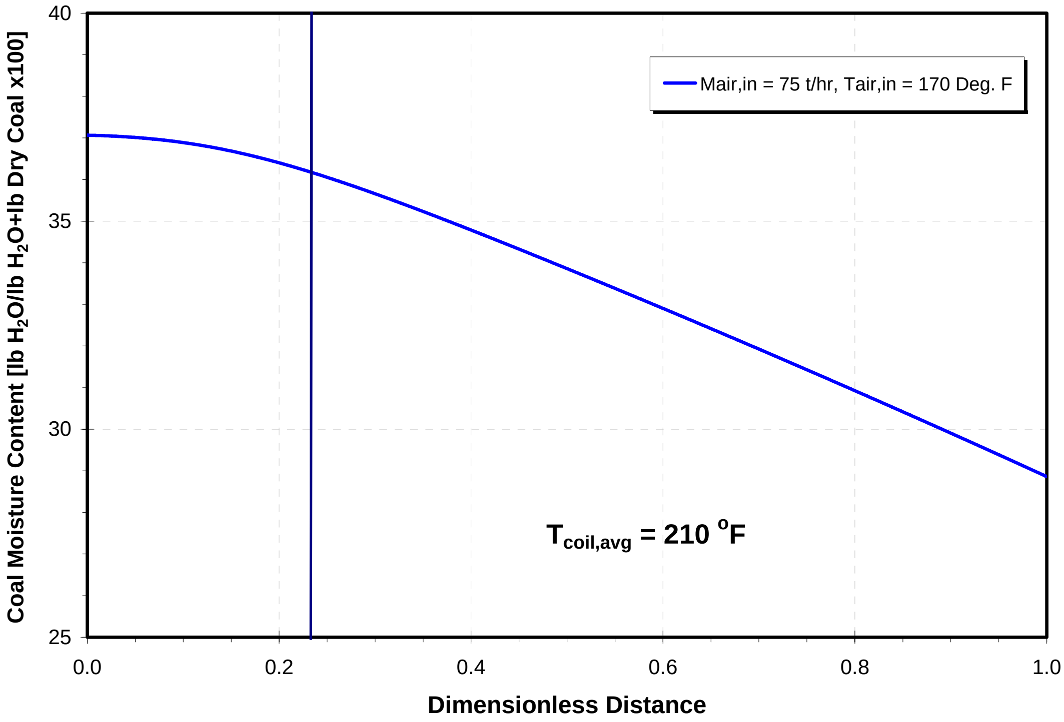

Figure 1-13: Variation of Coal Moisture Content Along the Dryer Length

6. TEST RESULTS

6.1: Operation Under Controlled Conditions

Performance tests were conducted under controlled conditions to determine dryer performance and the effect of firing dried coal on boiler efficiency and unit performance. As suggested by Dr. Moen, a paired-test approach was used where two consecutive performance tests were run per day: one with the prototype dryer in operation, the other with the prototype dryer off. The order of tests, i.e., dry and wet, or wet and dry, was determined randomly. Such an approach minimizes or eliminates the effects of bias errors, i.e., day-to-day differences/variations in plant operating conditions, and other uncontrollable variables.

Statistics was used to determine the number of required tests. The test uncertainty, i.e., random error vs. number of tests relationship presented in Figure 1-14, shows that the benefit of running more than 12 tests is very small. This is because test uncertainty is inversely related to the square root of the number of tests. The random error in Figure 1-14 was normalized with respect to the best estimate of standard deviation S. The absolute value of random error can be determined by multiplying values from Figure 1-14 by the numerical value of S.

Test uncertainty (random error) is defined as:

$$RE = \frac{tS}{\sqrt{N}} \qquad \text{Eqn. 1-3}$$

where:

RE	Random error (test uncertainty)
t	Student (W. Gosset) variable, where t = f(N, Confidence Level)
S	Best estimate of standard deviation σ

$$S = \sigma\sqrt{\frac{N}{N-1}} \qquad \text{Eqn. 1-4}$$

Standard deviation is calculated from the test data. Based on the statistical analysis, it was decided to conduct 16 paired performance tests.

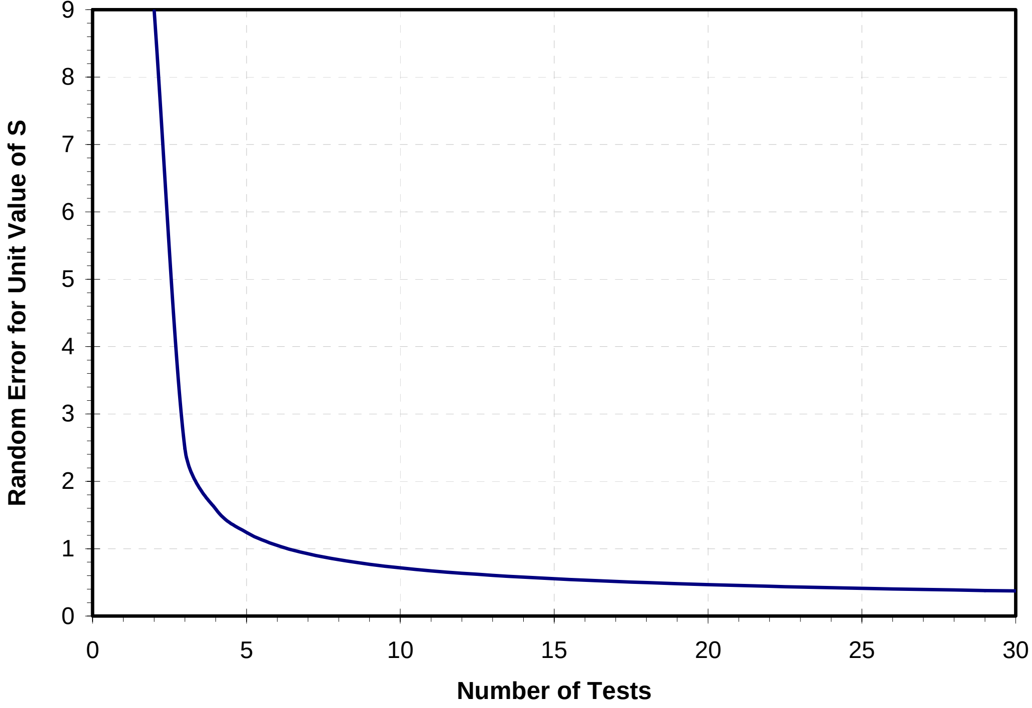

Figure 1-14: Normalized Random Error vs. Number of Tests Relationship

Statistics also provides information regarding the minimum detectable difference. The minimum detectable difference is the smallest statistically significant difference between two sets of measurements -- in this case between two sets of performance tests conducted with dried and wet coals. For sixteen performance tests, the minimum statistically significant difference in boiler efficiency that can be measured is in the 0.025 to 0.125 range, depending on the precision of the measurement. Assuming an S of 0.10 gives the minimum statistically significant difference in boiler efficiency of 0.096 (Figure 1-15). Since the theoretical difference in boiler efficiency, for the expected reduction in coal moisture content of feed coal is in the 0.35 percentage point range, the test results will be statistically significant.

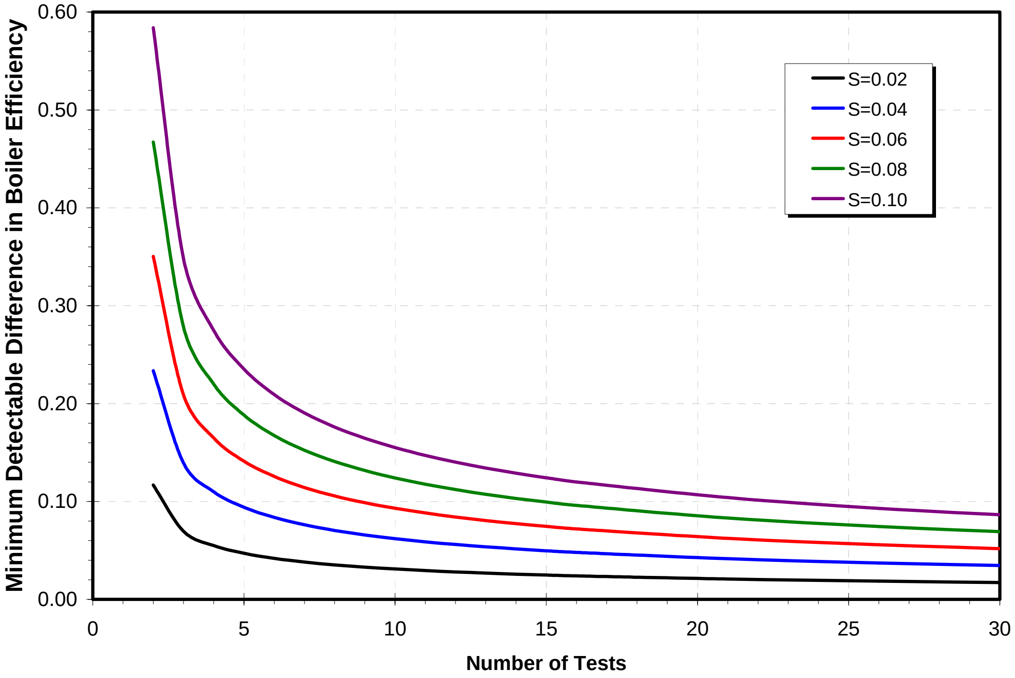

Figure 1-15: Minimum Statistically Significant Difference in Boiler Efficiency vs. Number of Performed Tests

Sixteen dryer performance tests were performed during time period from March 22nd to May 12th 2006, under controlled conditions with a baseline coal feed rate of 75 t/hr, fluidization air temperature in the 165 to 190°F range, and average bed coil temperature of 210°F. Under these operating conditions, in-bed heat input to the dryer was in the 15 to 16 MBtu/hr range.

A comparison of measured and predicted (simulated) dryer performance is presented in Figures 1-16 and 1-17. The total moisture content measured in the product stream is presented in Figure 1-16 as a function of fluidization air temperature. Dryer simulation results are represented by a solid line. As Figure 1-16 shows, there is a very good agreement between the measured and predicted product moisture contents. The results also show that the prototype dryer was operated with a relatively low fluidization air temperature. Increasing the fluidization temperature will have a positive effect on dryer performance.

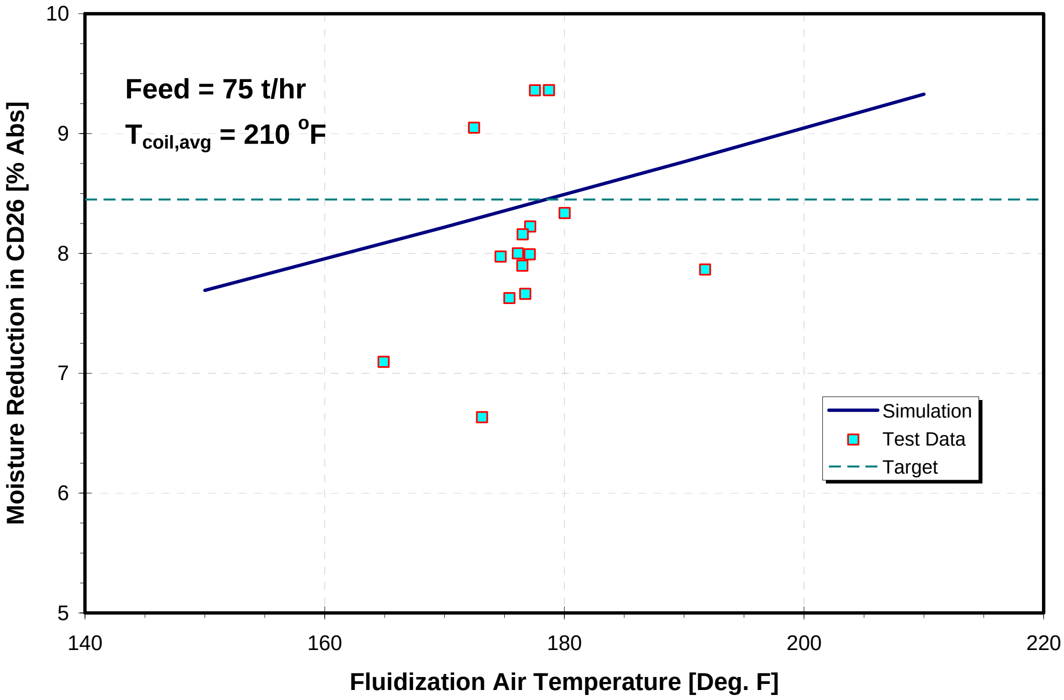

Figure 1-16: Measured and Predicted Dryer Performance: Total Moisture

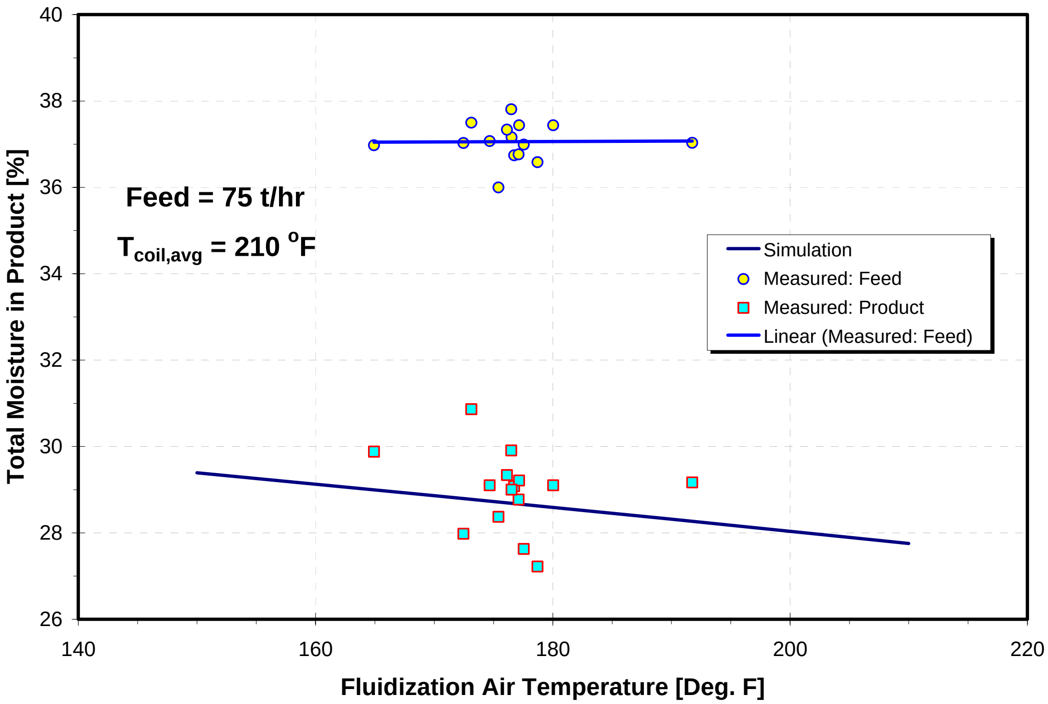

Figure 1-17: Measured and Predicted Dryer Performance: Moisture Reduction

Figure 1-17 compares the measured and predicted coal moisture reduction in the prototype dryer. Except for a few test points, there is very good agreement between the measurements and simulation. The target moisture removal level of 8.45 percent was easily reached by operating the prototype dryer with fluidization temperature at or above 180°F.

The total coal moisture (TM) and higher heating value (HHV) measured in the feed and product streams during the controlled dryer tests are summarized in Table 1-4 and presented in Figures 1-18 and 1-19. The Test 16 results show a much lower TM content and higher HHV value compared to the other tests and were, therefore, not included in the statistical analysis of data. The results show that average moisture reduction was 8.08 ± 0.42 percent. The HHV was on average improved by 727 ± 62 Btu/lb. The random error in Table 1-4 represents the 95 percent confidence interval. The variation in TM and HHV during the controlled tests is presented in Figures 1-41 and 1-19. The improvement in HHV and reduction in total coal moisture content are presented in Figure 1-20.

Table 1-4

Dryer Performance Tests: Coal Moisture and HHV

CD 26 Test Number	**TM [%]** Product	**TM [%]** Feed	**TM [% Abs]** Reduction	**Dry Coal Flow** % of Total	**HHV [BTU/lb]** Product	**HHV [BTU/lb]** Feed	**ΔHHV [BTU/lb]** Difference
1	27.98	37.03	9.05	14.28	6,871	6,203	668
2	29.08	36.74	7.66	14.28	6,746	6,148	598
3	29.21	37.44	8.22	13.79	7,069	6,392	677
4	28.77	36.76	7.99	13.91	7,037	6,292	745
5	30.87	37.50	6.63	13.32	7,028	6,172	857
6	27.22	36.58	9.36	13.84	7,212	6,214	997
7	29.10	37.44	8.34	14.28	7,162	6,392	770
8	27.63	36.99	9.36	14.29	6,947	6,337	610
9	29.88	36.98	7.09	14.26	7,033	6,489	544
10	29.10	37.07	7.97	14.14	7,109	6,361	748
11	28.37	36.00	7.63	14.29	7,084	6,270	814
12	29.00	37.16	8.16	14.29	7,035	6,340	695
13	29.34	37.34	8.00	14.29	7,060	6,285	775
14	29.17	37.03	7.86	14.29	6,854	6,176	679
15	29.91	37.81	7.90	14.29	7,145	6,415	730
16	21.19	37.47	16.28	13.90	7,499	6,440	1,059
Average	**28.98**	**37.06**	**8.08**	**14.12**	**7,026**	**6,299**	**727**
Std.Dev	0.92	0.44	0.75	0.29	125	102	112
St.Error	0.24	0.11	0.19	0.07	32	26	29
Random Error	**0.51**	**0.24**	**0.42**	**0.16**	**69**	**56**	**62**

Note: The data from Test 16 are considered outliers and are not included in the calculated average and standard deviation values.

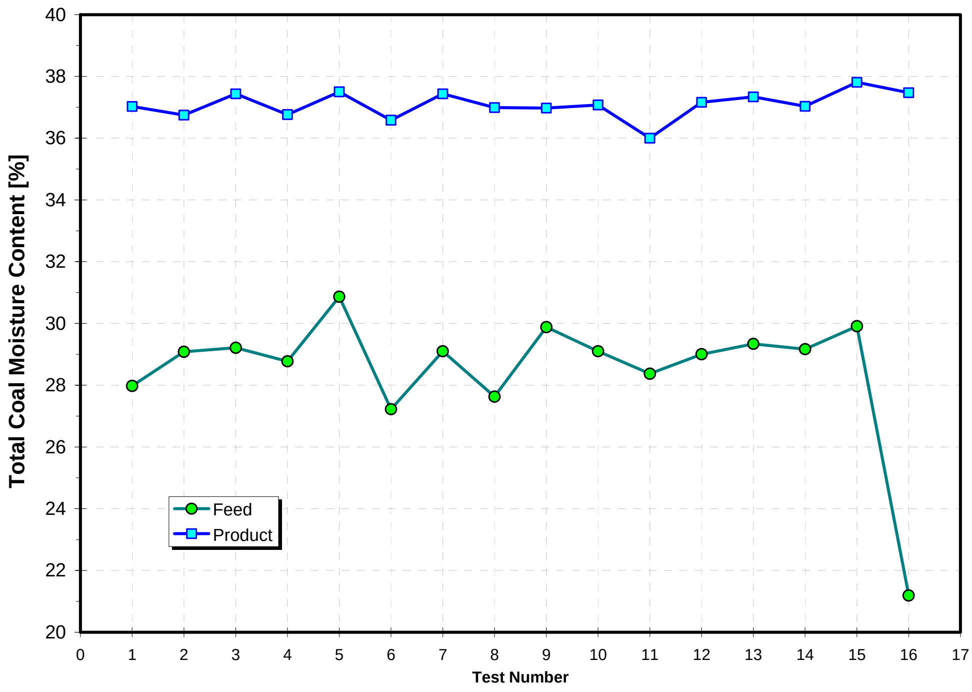

Figure 1-18: Total Coal Moisture Content in Feed and Product Streams Measured During Dryer Performance Tests

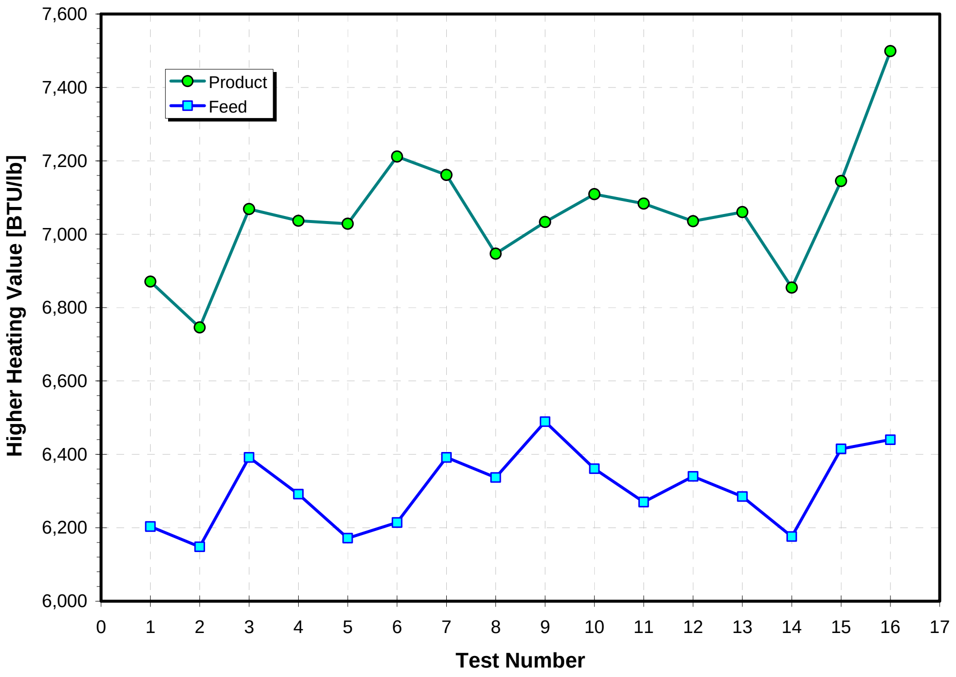

Figure 1-19: Higher Heating Value in Feed and Product Streams Measured During Dryer Performance Tests

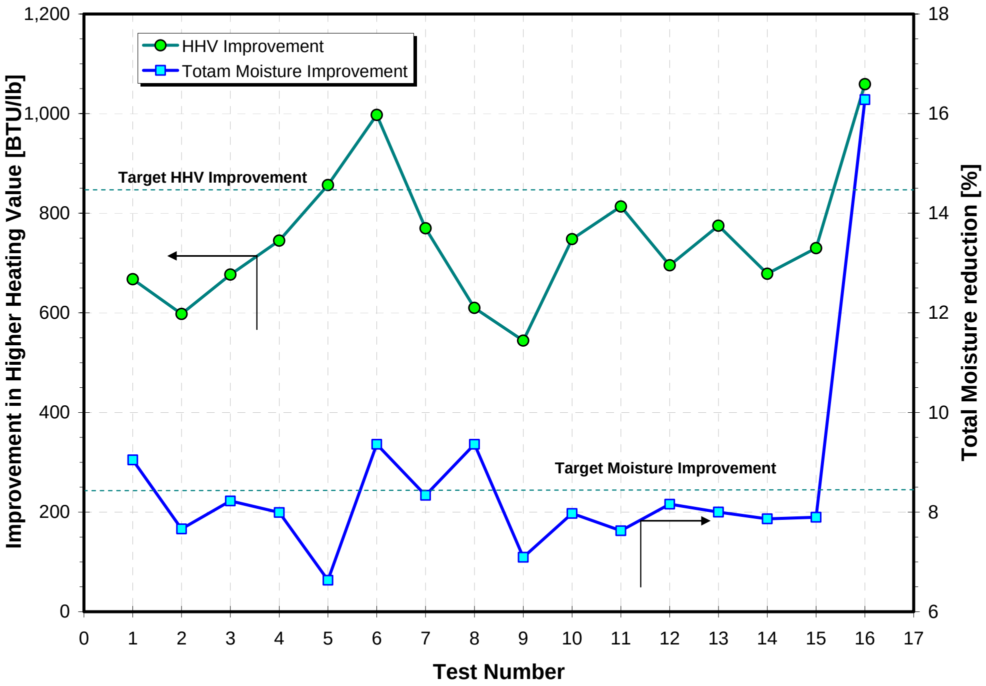

Figure 1-20: Improvement in HHV and Reduction in Total Moisture Measured in Dryer Performance Tests

6.2: Regular Dryer Operation

Coal quality data were collected during regular dryer operation for the time period from March to April, 2006. Results are presented in Table 1-5 and Figures 1-21 and 1-22.

Table 1-5

Regular Dryer Performance: Coal Moisture and HHV

Parameter	Feed TM %	Product TM %	Change TM % Abs	Change TM % Rel
Average Total Moisture, TM	**36.78**	**28.55**	**8.23**	**22.4**
Std. Deviation	**1.26**	**1.00**	**1.07**	
Std. Deviation of the Mean	**0.34**	**0.27**	**0.30**	

Parameter	Feed HHV [BTU/lb]	Product HHV [BTU/lb]	Change HHV [BTU/lb]	Change HHV [%]
Average HHV	**6,290**	**7,043**	**752**	**12.0**
Std. Deviation	**159**	**121**	**131**	
Std.Deviation of the Mean	**43**	**33**	**37**	

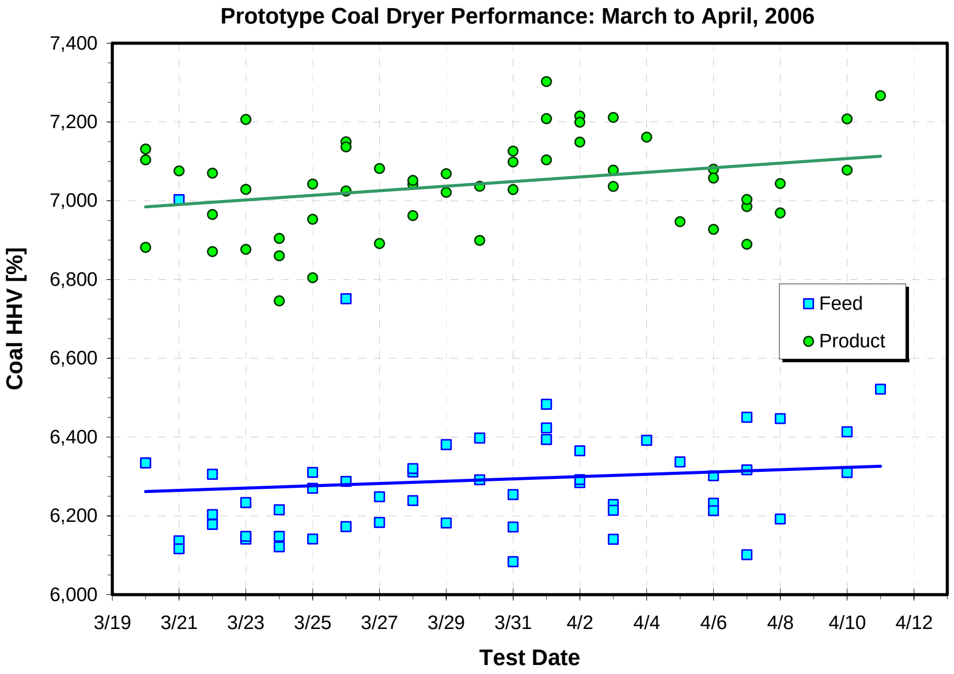

Figure 1-21: Coal Moisture in Feed and Product Streams Measured During Regular Dryer Operation

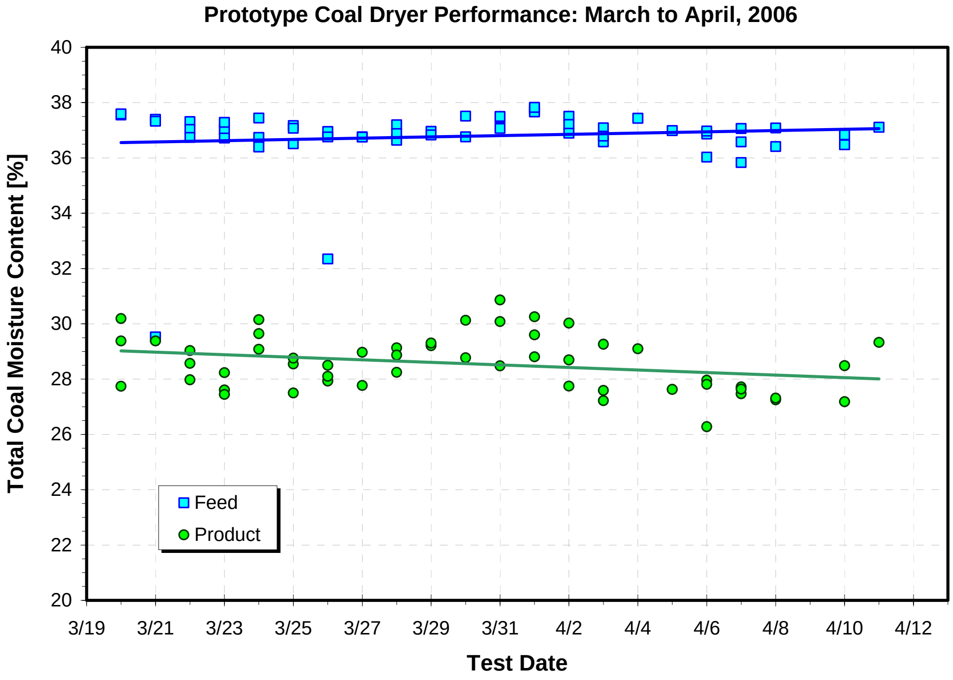

Figure 1-22: Higher Heating Value for Feed and Product Streams Measured During Regular Dryer Operation

The average moisture reduction, achieved during regular dryer operation, was 8.23 ± 0.6 percent. This is almost identical to the total moisture reduction achieved during the controlled performance tests. The improvement in HHV during regular dryer operation was 752 ± 74 Btu/lb. Within the accuracy of the data, this is the same improvement in HHV achieved during the controlled dryer performance tests. In conclusion, this means that dryer performance, measured during the controlled tests, is sustainable over the long-term [9].

6.3: Dryer Performance at Maximum Coal Feed Rate

6.3.1: Maximum Capacity Tests

The maximum design coal feed rate for the prototype dryer is 112.5 tons per hour. With four dryers in service, each operating at the maximum feed rate, it would be possible to dry the total full-load coal feed for Unit 2 at Coal Creek (450 t/hr).

Three maximum capacity tests (CT1, CT2, and CT3) were performed from June 21 to 23, 2006, wherein coal feed rate was increased from the baseline value of 75 t/hr first to 90 t/hr, and finally to the maximum value of 101 t/hr. The coal conveying system and dust collector fan power imposed a limit on the maximum coal feed rate, which fell short of the design value by 10 percent.

The maximum capacity test data are summarized in Tables 1-6 to 1-8. Operating conditions of the dryer, presented in Table 1-6, show that inlet temperatures of fluidizing air and circulating water were increased above the baseline values to accommodate higher coal feed to the dryer. With the maximum coal feed rate at 101 t/hr, fluidization air temperature was 40°F higher compared to baseline operation, while the circulating water temperature was 20°F higher. With the feed rate at 101 t/hr, the dried coal represented 21 percent of the total coal feed to the boiler.

Table 1-6

Maximum Capacity Tests: Dryer Operating Conditions

Test	**Date**	**Test Duration**	**Dryer Coal Feed**	**Total Coal Flow**	**Dried Coal**	**Fluidization Air Flow**	**Fluidization Temperature**	**Circulating Water Inlet Temperature**	**Circulating Water Outlet Temperature**	**In-Bed Heat Transfer**
		hours	t/hr	t/hr	% of Total	klbs/hr	°F	°F	°F	MBTU/hr
1	6/21/2006	4	**90**	494.0	**18.2**	301	188	219	200	15.1
2	6/22/2006	4	**90**	484.5	**18.6**	291	214	233	211	16.4
3	6/23/2006	2	**101**	480.5	**21.0**	288	220	236	214	16.9

Table 1-7

Maximum Capacity Tests: Coal Moisture Reduction

Test	**Coal Feed**	**Feed Moisture**	**Coal Dryer**			**Coal Feed to the Boiler**	
			Product Moisture	**Moisture Reduction**	**Moisture Reduction**	**Average Coal Moisture**	**Moisture Reduction**
	t/hr	**%**	**%**	**% Abs**	**% Rel**	**%**	**% Abs**
1	90	35.2	27.9	**7.3**	**20.7**	33.9	**1.3**
2	90	36.8	27.4	**9.4**	**25.5**	35.1	**1.7**
3	101	36.4	29.1	**7.3**	**20.1**	34.9	**1.5**

Table 1-8

Maximum Capacity Tests: Improvement in HHV

Test	**Coal Feed**	**Feed HHV**	**Coal Dryer**			**Coal Feed to the Boiler**		
			Product HHV	**HHV Increase**	**HHV Increase**	**Average Coal HHV**	**HHV Improvement**	**HHV Improvement**
	t/hr	**BTU/lb**	**BTU/lb**	**BTU/lb**	**%**	**BTU/lb**	**BTU/lb**	**%**
1	90	5,895	6,886	991	16.8	6,076	181	3.1
2	90	6,198	7,074	876	14.1	6,361	163	2.6
3	101	6,116	7,393	1,277	20.9	6,384	268	4.4

The reduction in coal moisture, achieved in the maximum capacity tests, is summarized in Table 1-7. The results show that the coal moisture reduction in the 7 to 9 percentage point range (20 to 26 percent relative) was achieved. The average coal moisture in the coal feed to the boiler (blend of dried and wet coal), was in the 1.3 to 1.7 percent range.

The coal HHV improved as moisture was removed from the coal in the prototype coal dryer (Table 1-8). The achieved HHV improvement was in the 875 to 1,280 Btu/lb range, or 14 to 21 percent. The improvement in the HHV of the boiler coal feed was in the 160 to 270 Btu/lb range, or from 2.6 to 4.4 percent.

Computer simulations were performed using operating conditions corresponding to the dryer capacity tests. Measured and predicted values are presented in Figures 1-23and 1-24. The comparison between measured and predicted moisture reduction values are presented in Figure 1-46.

An excellent agreement was achieved between measurements and predictions for capacity tests 1 and 3 (CT 1 and CT3). The measured value of moisture reduction for CT2 was approximately one percentage point higher compared to the predictions. This disagreement could be due to an error in coal analysis or a mislabeling of coal samples that were sent to the plant coal analysis laboratory.

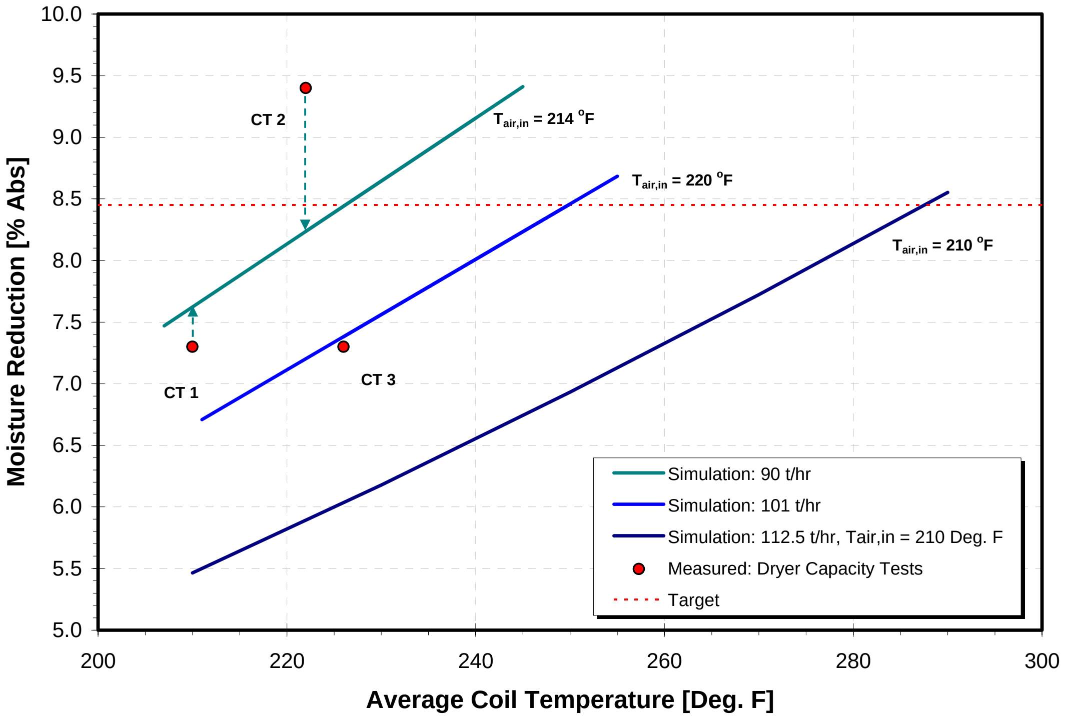

Figure 1-23: Maximum Capacity Tests - Measured vs. Predicted Values of Moisture Reduction

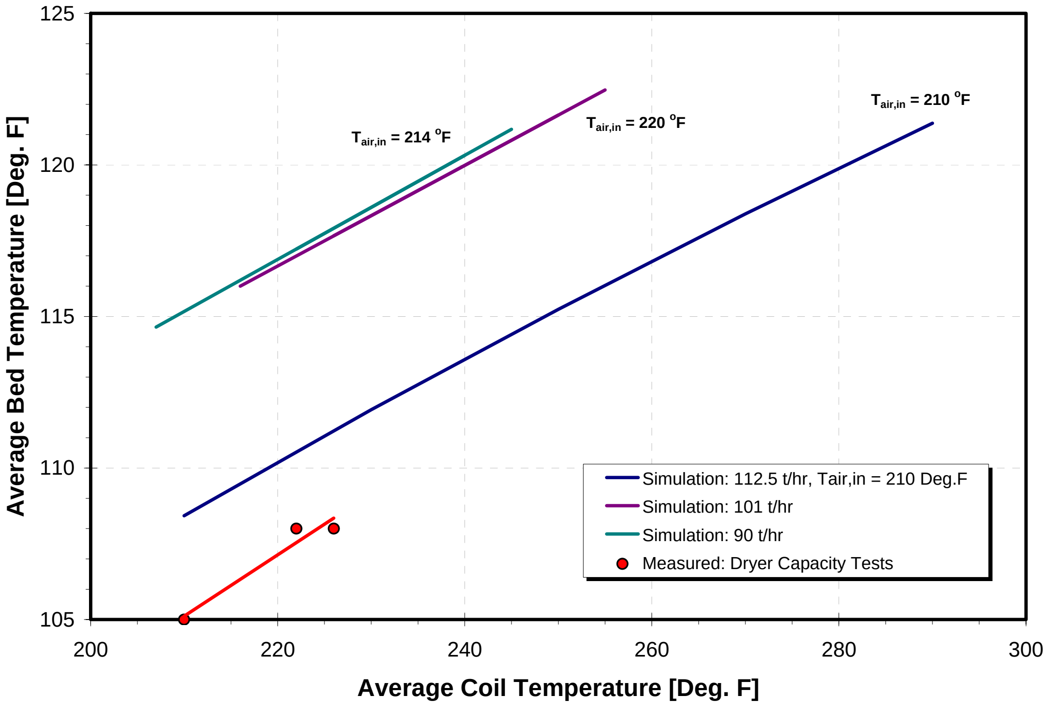

Figure 1-24: Maximum Capacity Tests - Measured vs. Predicted Values of Average Bed Temperature

The results also show that with a feed rate at 90 t/hr and an inlet air temperature at 214°F, the target moisture reduction can be achieved by increasing the average coil temperature to 227°F. With a feed rate at 101 t/hr and a fluidization air temperature at 220°F, the average coil temperature needs to be increased to 250°F. Predictions are also given for the maximum design coal feed at 112.5 t/hr and fluidizing air temperature at 210°F. It has to be noted that the average coil temperature is, for practical purposes, equal to the average of the circulating water inlet and outlet temperatures.

Predicted and measured values of the average bed temperature are presented in Figure 1-24. The results show that the predicted values followed the same trend as measurements, with measured values being, on average, 9°F lower. Considering locations of the in-bed thermocouples and uncertainties in bed temperature measurement, this represents a very good agreement.

6.4: First-Stage Segregation

The non-fluidizable material is removed from the dryer as the segregated stream by a patent pending system. Samples were taken from the segregated stream and analyzed to determine its composition. Results are presented in Tables 1-9 and 1-10 and in Figures 1-25 to 1-28 for baseline coal feed flow rate.

The total moisture, sulfur, and mercury content, and HHV of the feed, product, and segregated streams, determined from samples that were collected during the May-June time period, are summarized in Table 1-9. While the total moisture content of the product stream is significantly lower and its HHV higher compared to the feed stream, the moisture content and HHV of the segregated stream are similar to the feed stream. These experimental findings are in agreement with the dryer simulation results that show that only 10 percent of the total moisture removed in the dryer is removed in the first stage.

Table 1-10 presents the sulfur, mercury, and HHV of the segregated stream as percentages of the feed stream. The results show that approximately 30 percent of sulfur and mercury in the feed stream entering the dryer are removed in the first stage and discharged as the segregated stream. The segregated stream also contains approximately 10 percent of the inlet HHV. Additional processing of the segregated stream is needed to further concentrate sulfur and mercury and reduce the HHV content. Segregated stream processing will be incorporated into the commercial coal drying system.

The segregated stream samples were also collected during the maximum dryer capacity tests.

Table 1-9

Composition of Feed, Product and Segregated Streams (May-June, 2006)

	Feed Stream				**Product Stream**				**Segregation Stream**			
Test	**HHV**	**TM**	**Sulfur**	**Hg**	**HHV**	**TM**	**Sulfur**	**Hg**	**HHV**	**TM**	**Sulfur**	**Hg**
	BTU/lb	%	% AR	ppm AR	BTU/lb	%	% AR	ppm AR	BTU/lb	%	% AR	ppm AR
1	6,359	38.1	0.61	614	7,477	28.1	0.60	498	6,631	35.7	1.37	1,347
2	6,303	37.2	0.69	700	7,448	27.1	0.60	380	6,263	35.3	2.00	1,853
3	6,271	38.1	0.63	500	7,363	25.3	0.62	463	6,097	33.9	2.16	2,290
4	6,324	37.3	0.66	648	7,565	23.2	0.60	615	6,504	37.2	1.39	1,509
5	6,370	37.8	0.58	495	7,840	23.2	0.67	493	6,696	37.1	1.13	1,246
6	6,115	37.3	0.55	616	7,796	21.0	0.61	555	6,223	35.0	1.97	2,237
7	6,085	36.8	0.61	748	7,434	25.1	0.60	553	6,267	34.7	1.71	1,839
8	6,236	37.0	0.61	625	7,583	28.6	0.55	457	6,389	36.0	1.58	1,970
9	6,421	38.1	0.57	604	7,303	28.3	0.63	536	6,427	35.9	1.85	2,537
10	6,303	38.2	0.69	591	7,335	28.8	0.65	606	6,558	36.1	1.89	2,121

Table 1-10

Sulfur and Mercury Removed by the First Stage and HHV Content of the Segregated Stream

Segregated Stream			
Test	**S**	**Hg**	**HHV**
	% of Feed	% of Feed	% of Feed
1	22.5	21.9	10.4
2	29.3	26.5	9.9
3	34.5	45.8	9.7
4	21.2	23.3	10.3
5	19.4	25.2	10.5
6	36.0	36.3	10.2
7	28.2	24.6	10.3
8	25.7	31.5	10.2
9	32.5	42.0	10.0
10	27.4	35.9	10.4
Average	**27.7**	**31.3**	**10.2**

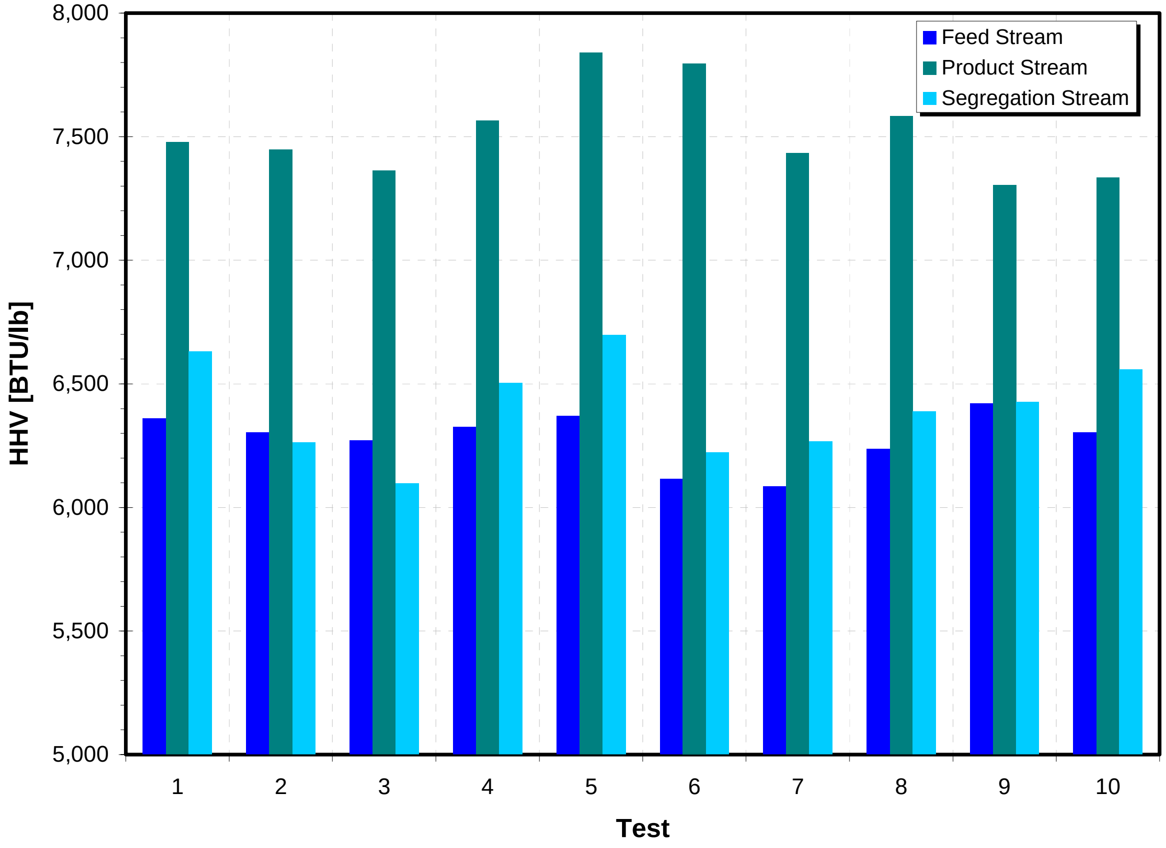

Figure 1-25: HHV of the Feed, Product and Segregated Streams

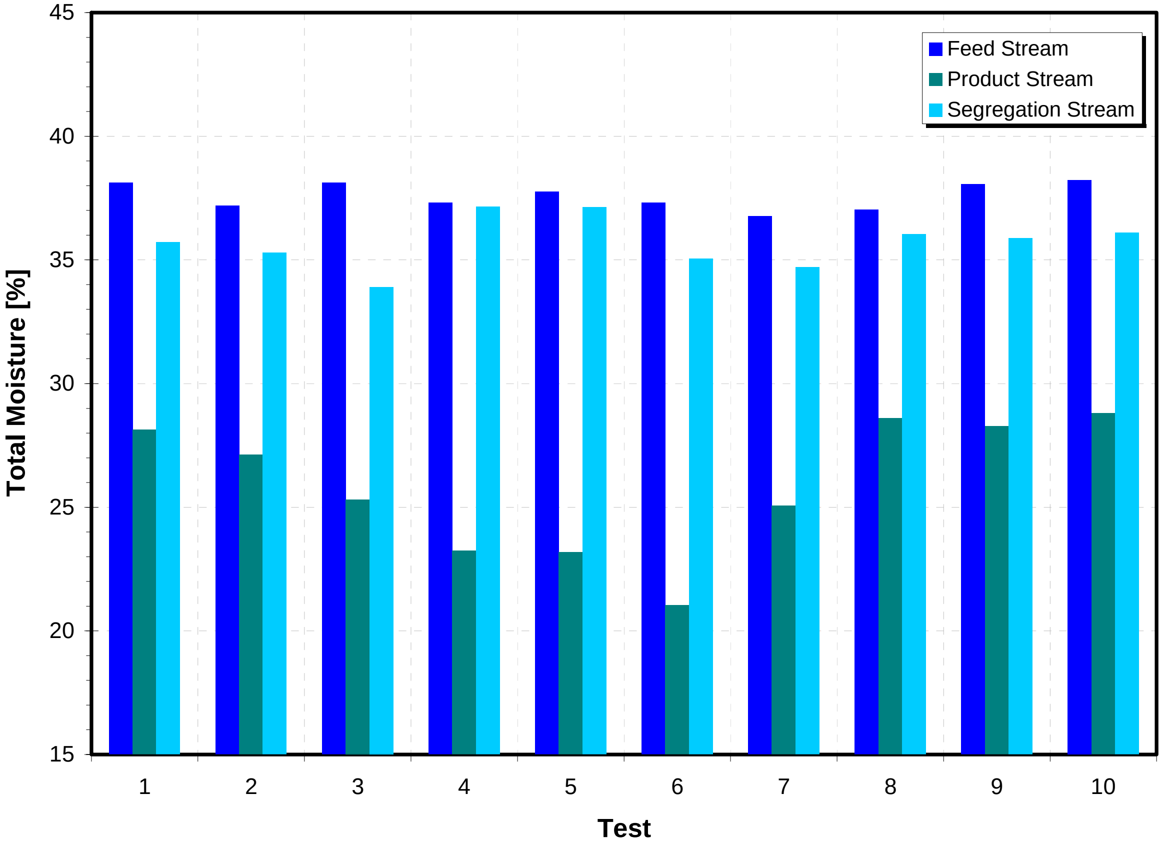

Figure 1-26: Total Moisture in the Feed, Product and Segregated Streams

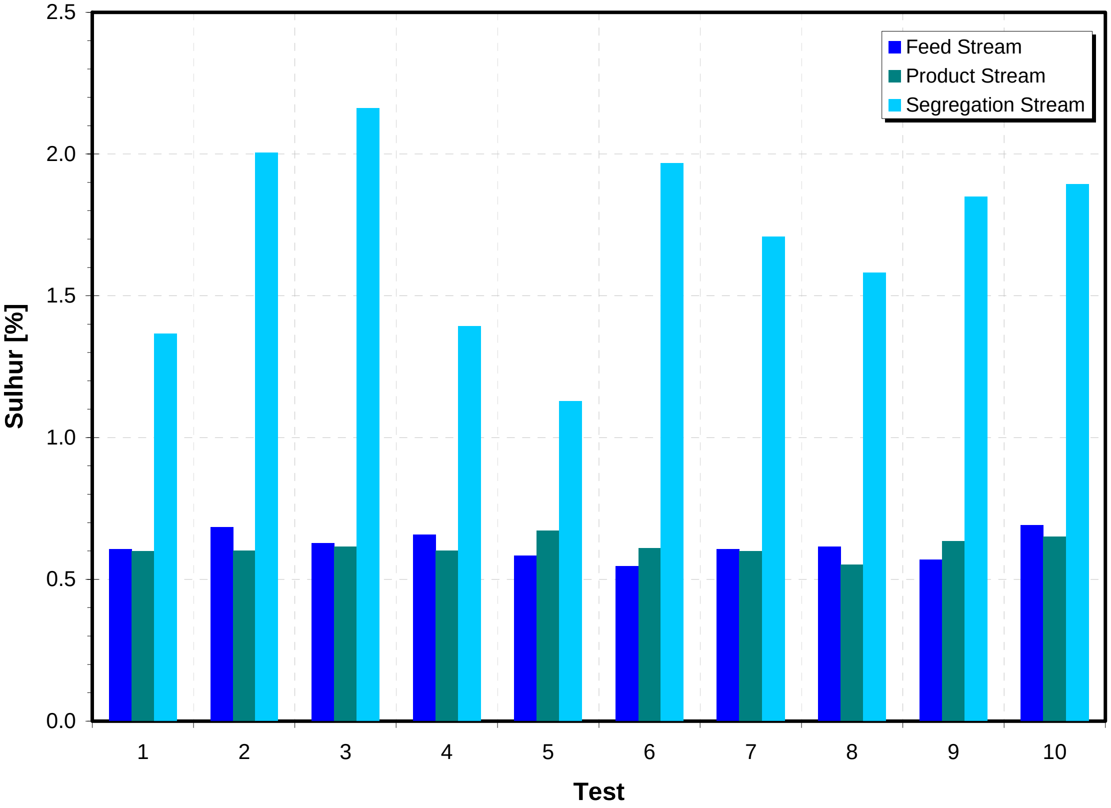

Figure 1-27: Sulfur in the Feed, Product, and Segregated Streams

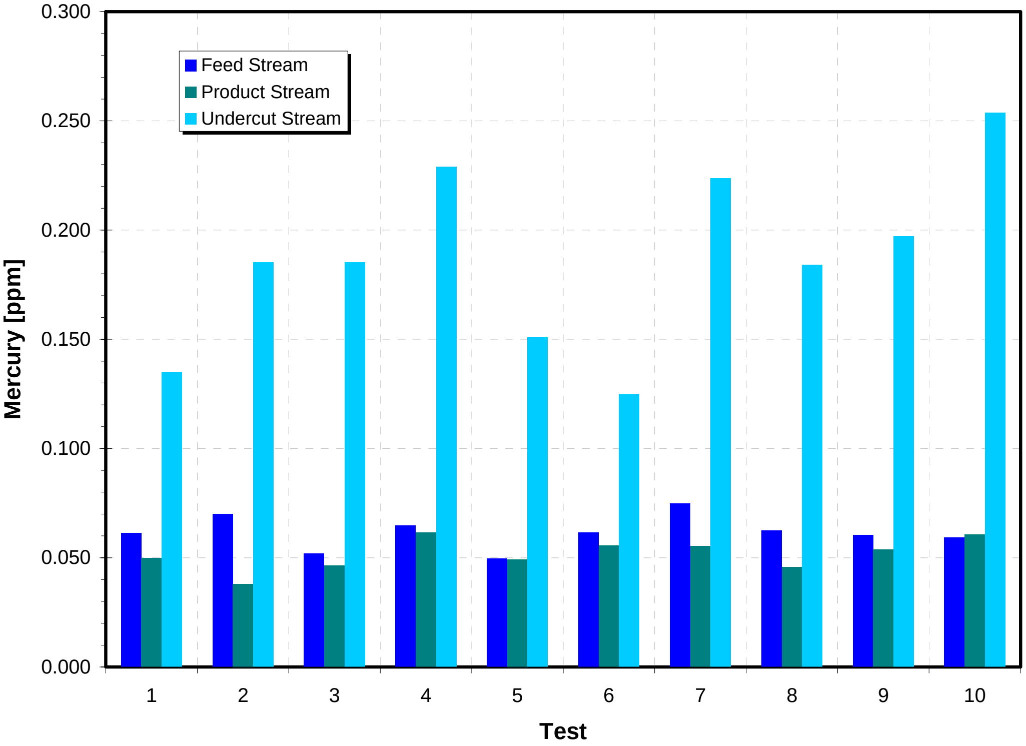

Figure 1-28: Mercury in the Feed, Product, and Segregated Streams

The S, Hg and HHV content of the segregated stream, expressed as percentage of feed, are summarized in Table 1-13 and Figure 1-29 as functions of feed rate. The results show that mercury content of the segregated stream increased as feed rate increased, while sulfur and HHV contents remained approximately constant.

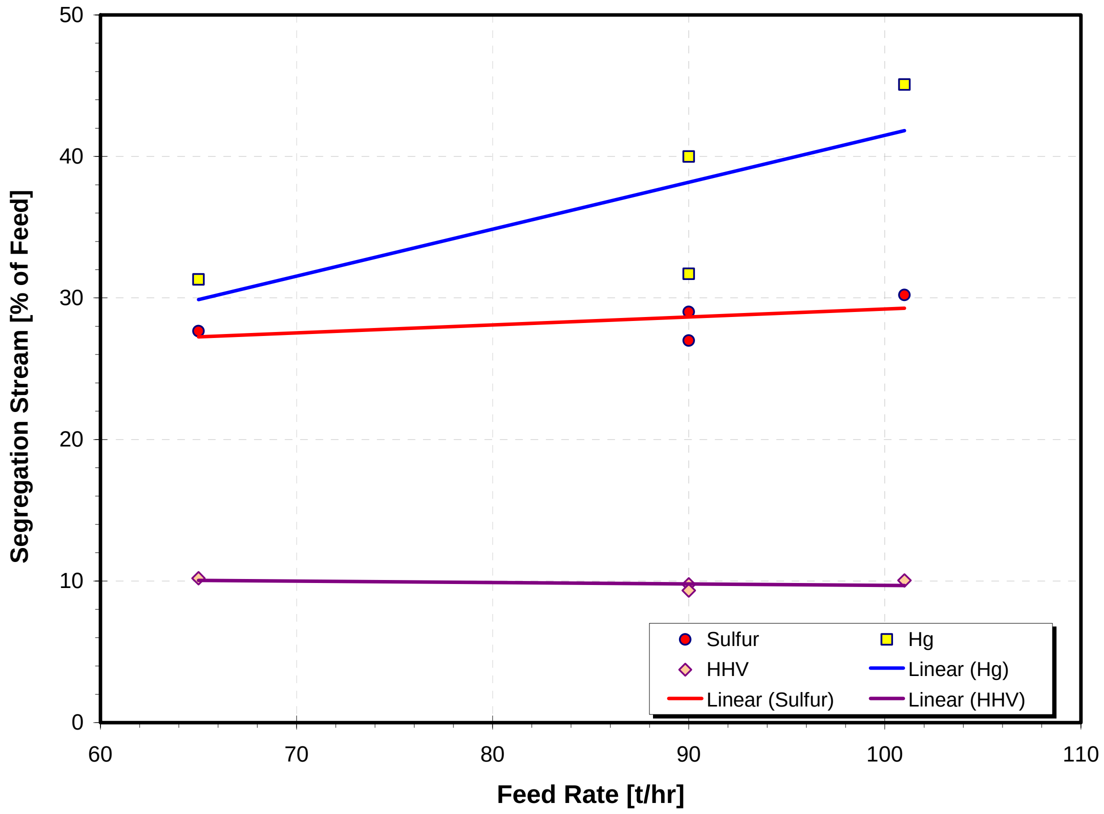

Figure 1-29: Sulfur, Mercury, and HHV Content of Segregated Stream vs. Feed Rate

PART 2: UNIT PERFORMANCE AND EMISSIONS

7. UNIT PERFORMANCE

As discussed in Section 6.1 (Operation Under Controlled Conditions), performance tests were conducted under carefully controlled conditions to determine the effect of firing dried coal on boiler efficiency and unit performance. A paired-test approach was used where two performance tests were run per day: one with the prototype dryer in operation, the other with the prototype dryer out of service. Such an approach minimizes or eliminates the effects of bias errors, i.e., day to day differences in plant operating conditions, variation in uncontrollable variables, and calibration drift of coal feeders.

Plant operating parameters such as main and reheat steam temperature, main steam and desuperheating spray flow rates, coal feeder flow rate, mill and fan power, flow rates of primary air to the mills, temperature of air and flue gas at a number of state points, and plant emissions were measured and recorded by the plant data acquisition system. Coal composition and HHV were determined from coal samples that were collected manually and by automatic coal samplers.

As predicted by theoretical calculations and confirmed in test burns, firing of partially dried coal in the boiler has a positive effect on boiler and unit efficiency, and stack emissions. The improvement in performance and reduction in emissions were determined for a series of 16 paired dryer tests.

In the current arrangement of a prototype coal drying system at CCS, the prototype coal dryer supplies dried coal to coal mill No. 26. With the prototype coal dryer in service and operating at a nominal coal feed of 75 t/hr, dried coal represents approximately 14 percent of the total coal flow rate supplied to the boiler (Figure 2-1).

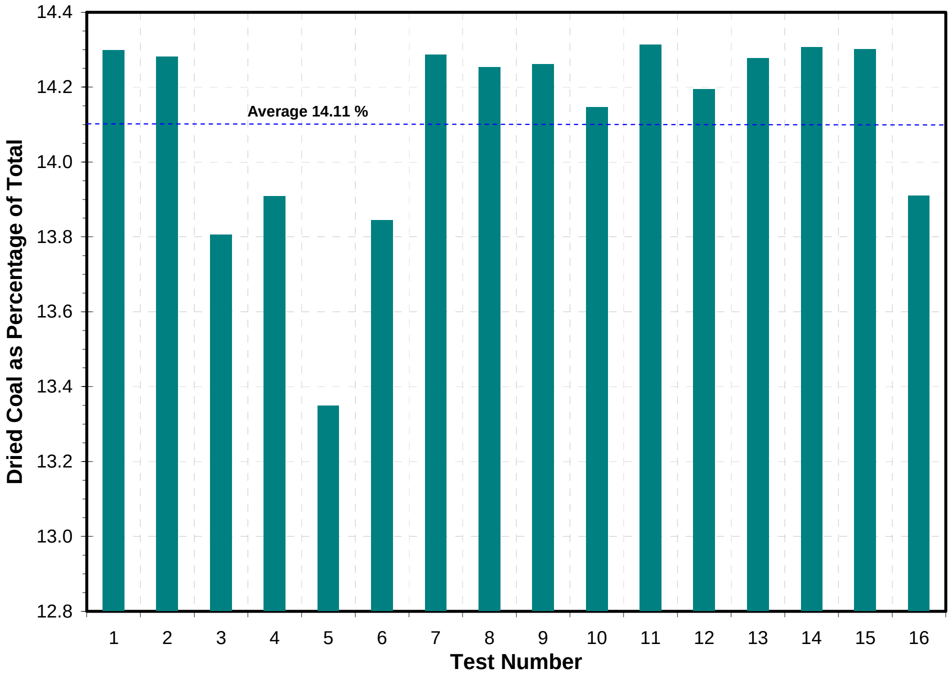

Figure 2-1: Dried Coal as Percentage of Total Coal Feed

Coal composition, HHV, and fuel heat input, determined for 16 pairs of coal dryer performance tests, are summarized in Table 2-1. With the prototype coal dryer (CD26) in service, the properties of the dried and wet coal streams were mass-averaged to determine properties of the coal blend fired in the boiler. The composition and HHV of the coal blend were determined from the following expression:

$$X_{\text{Mass-Average}} = X_{\text{Blend}} = X_{\text{Dry}}\ M_{\text{Dry}}/M_{\text{Total}} + X_{\text{Wet}}\ M_{\text{Wet}}/M_{\text{Total}} \qquad \text{Eqn. 2-1}$$

where:

X_{Blend} Composition or HHV of blended coal
X_{Dry} Composition or HHV of dried coal out of the CD26
X_{Wet} Composition or HHV of wet coal
M_{Dry} Flow rate of dried coal out of the CD26
M_{Wet} Flow rate of wet coal to the boiler
M_{Total} Total coal flow rate, where:

$$M_{\text{Total}} = M_{\text{Dry}} + M_{\text{Wet}} \qquad \text{Eqn. 2-2}$$

Table 2-1

Properties of Blended and Wet Coals

Description	**Units**	**Mass-Average Dry**	**Average Wet**	**% Change WRT Wet**	**Absolute Change WRT Wet**
C	% by weight	39.55	39.00	1.4	0.6
S	% by weight	0.68	0.66	1.6	0.0
H	% by weight	3.34	3.35	-0.1	0.0
N	% by weight	0.54	0.53	1.4	0.0
O	% by weight	8.55	8.26	3.5	0.3
Moisture	**% by weight**	**35.92**	**37.06**	**-3.1**	**-1.14**
Ash	% by weight	11.42	11.14	2.5	0.3
Total	**% by weight**	100.00	100.00		
HHV	**BTU/lb**	**6,402**	**6,299**	**1.63**	**103**
TOTAL FEEDER COAL FLOW RATE	**klbs/hr**	**953**	**971**	**-1.83**	
Total heat input	**MBTU/hr**	**6,102**	**6,117**	**-0.24**	
MAF-Basis HHV	**BTU/lb**	**12,157**	**12,160**	**-0.03**	**-4**

The results show that, with CD26 in service, the total moisture of the coal blend was reduced by 1.14 percentage points, or 3.1 percent on a relative basis, Figures 2-2 and 2-3. The improvement in HHV was 103 Btu/lb, or 1.63 percent, Figures 2-4 and 2-5. As expected, the coal HHV, expressed on a moisture-and-ash-free (MAF) basis, remained constant.

With the prototype coal dryer in service, the total coal flow rate, measured by the mill feeders, was reduced by 1.83 percent, Figures 2-6 and 2-7. The measured and theoretically predicted reductions in total coal flow rate are compared in Figure 2-8. The results show an excellent agreement between the calculated and measured values. For a target value of coal moisture reduction of 8.5 percent, the predicted decrease in coal flow rate is approximately 14 percent. This decrease is due to the higher HHV of the partially dried coal and improved boiler and unit performance.

The reduction in unit heat rate, due to the improvement in HHV and reduction in total coal flow rate, resulted in a 0.24 percent lower fuel heat input to the boiler, Table 2-2.

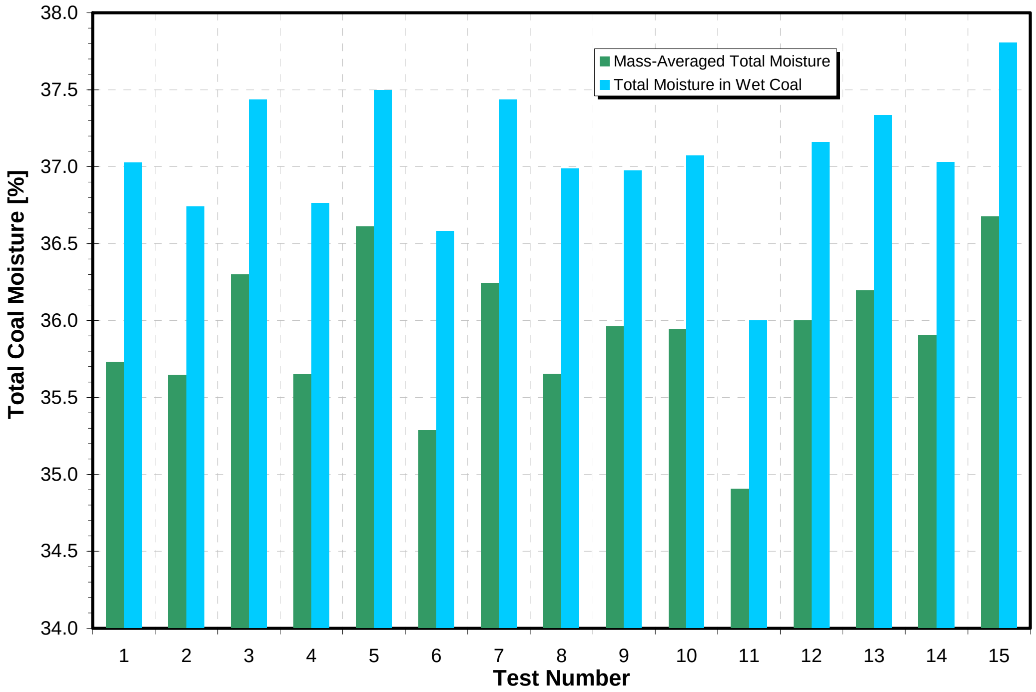

Figure 2-2: Total Coal Moisture in Wet and Partially Dried Coal

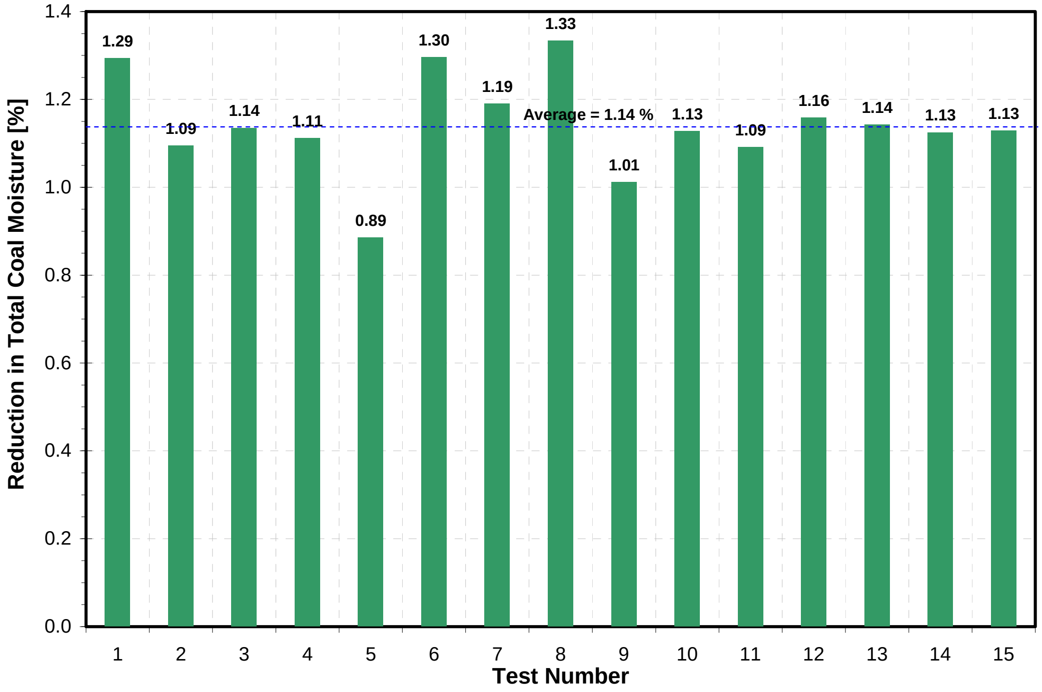

Figure 2-3: Reduction in Total Coal Moisture Content

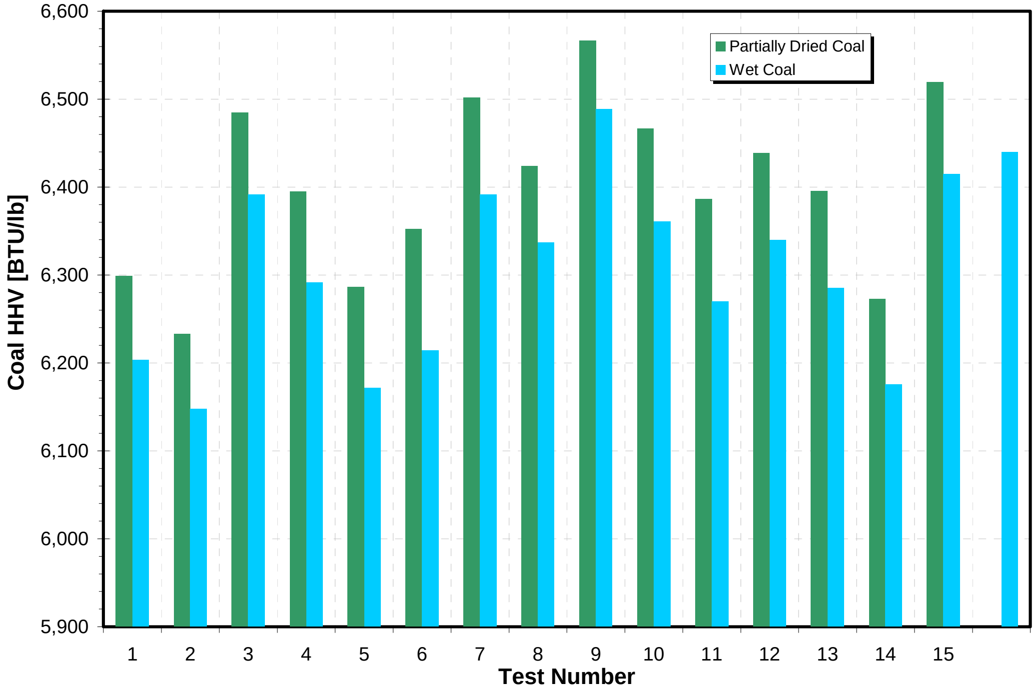

Figure 2-4: HHV of Wet and Partially Dried Coal

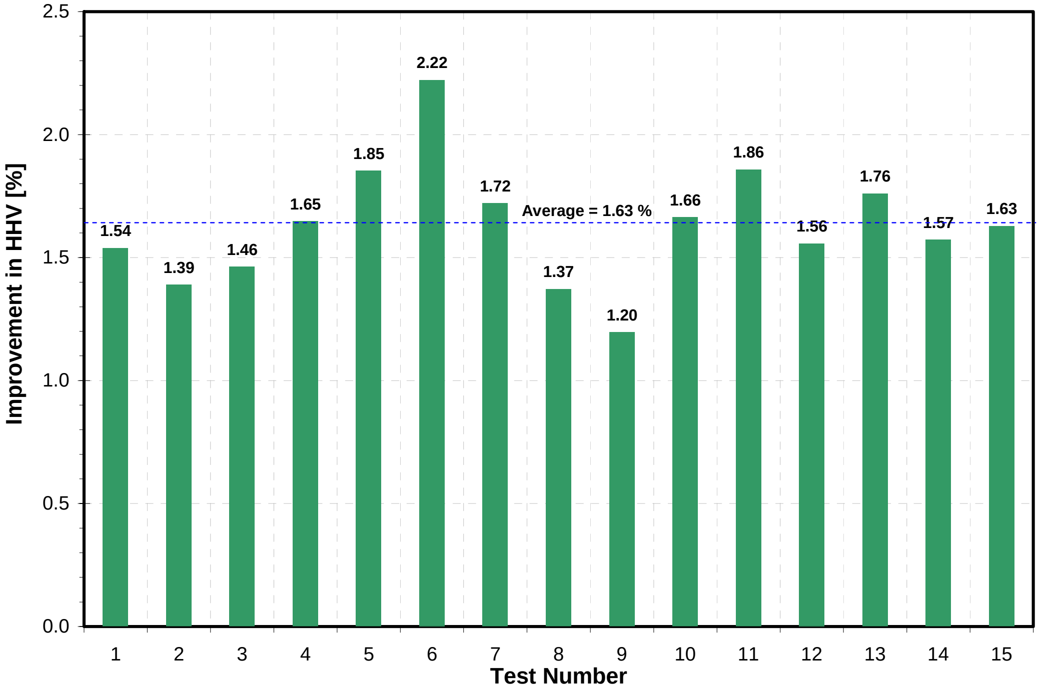

Figure 2-5: Improvement in Coal HHV

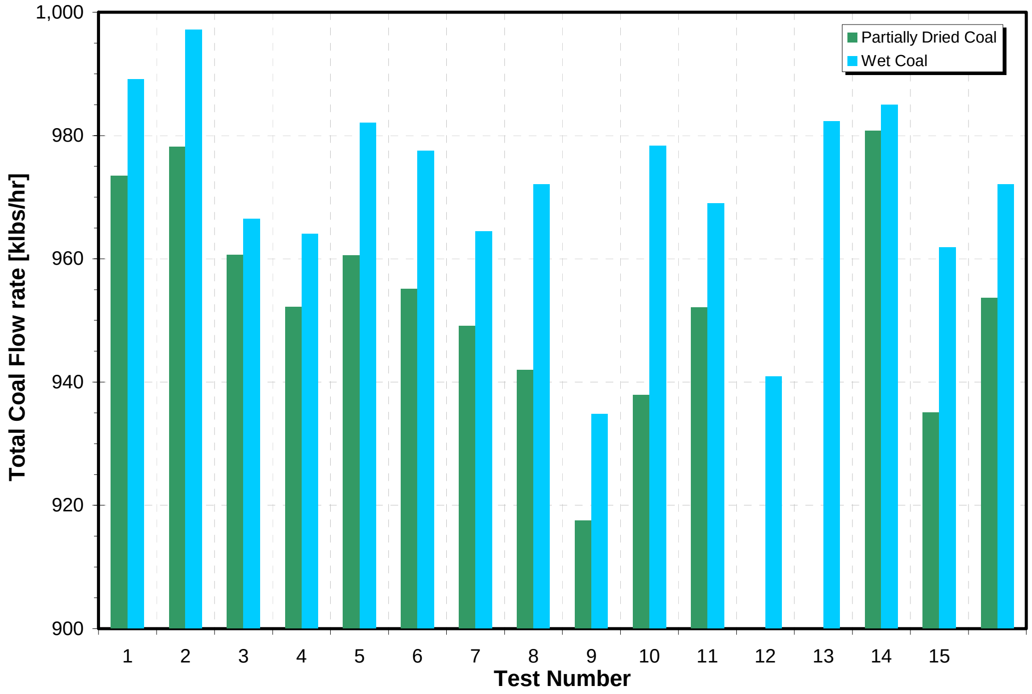

Figure 2-6: Total Coal Flow Rate Sent to the Mills of Partially Dried and Wet Coal

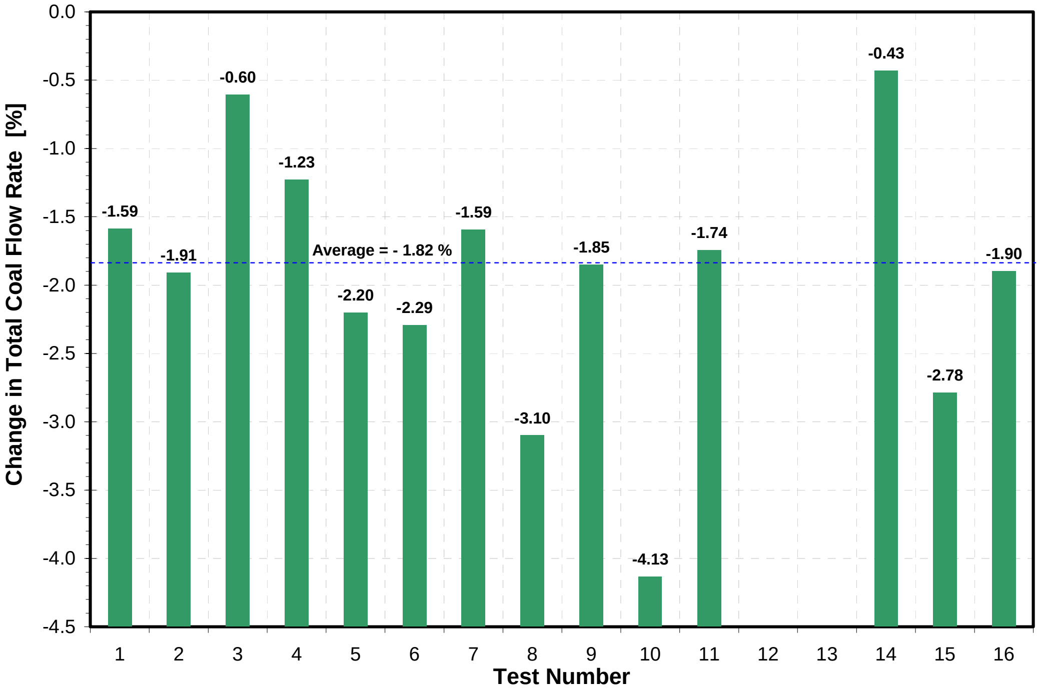

Figure 2-7: Reduction in Total Coal Flow Rate Sent to the Mills Due to Drying

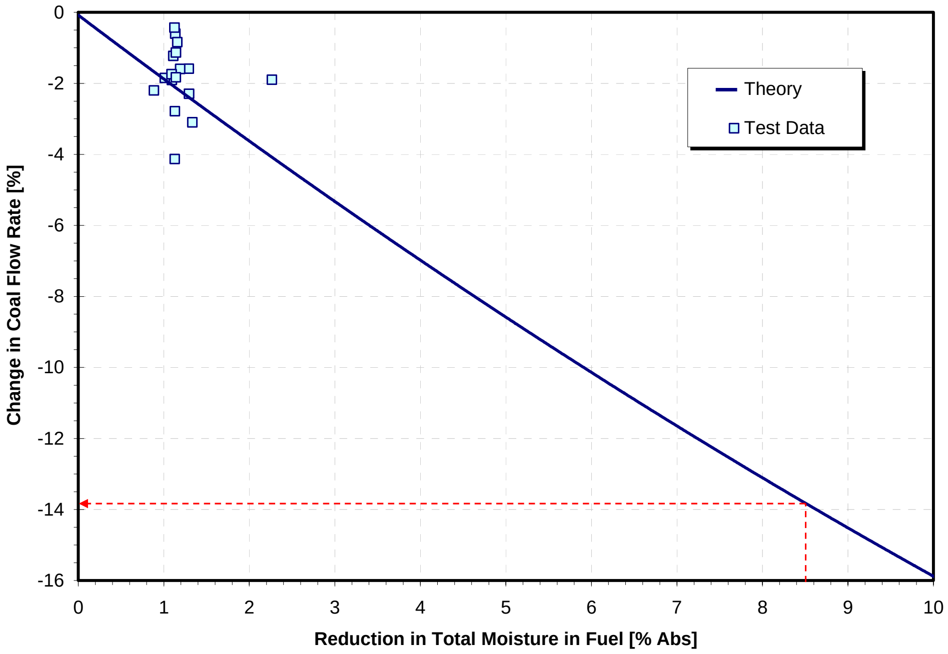

Figure 2-8: Comparison Between Measured and Predicted Reduction in Coal Flow Rate to the Mills vs. Reduction in Total Coal Moisture Content

7.1: Boiler and Plant Operating Parameters

The average process parameters, determined in a series of 16 paired tests with the prototype CD26 in and out of service, are summarized in Table 2-2.

The gross unit load, main (throttle) and reheat steam temperatures, and fanroom temperature (temperature of the PA and SA at the inlet to the PA and FD fans) were constant throughout the test. The boiler feedwater flow was 0.3 percent higher with partially dried coal, compared to the wet coal. The superheater ("SHT") desuperheating spray flow rate was approximately 10 percent lower compared to the operation with wet coal.

The average coal feed to the prototype dryer during the test was 73 t/hr. This corresponds to 14.12 percent of the total coal input to Unit 2 boiler, or 15.5 percent of fuel heat input to the boiler.

Table 2-2

Average Process Parameters Determined in a Series of 16 Paired Performance Tests

Description	Units	Mass-Average Dry	Average Wet	% Change WRT Wet	Absolute Change WRT Wet
Ambient Dry Bulb Temperature	Deg. F	47	51		**-4**
FAN ROOM TEMP	Deg. F	71	72		
CD26 CONVEYOR 263 SCALE RATE MI2924	**tons/hr**	**73**	**0**		
Gross Power Output	**MW**	**590**	**590**		**0**
Throttle Steam Temperature	Deg. F	988	989		**0**
Reheat Steam Temperature	Deg. F	1,002	1,002		**0**
Boiler Feewater Flow Rate	**klbs/hr**	**4,008**	**3,996**	**0.30**	
SHT Desuperheating Spray Flow Rate	klbs/hr	45	51		**-6**
Flue Gas Temperature at APH Inlet	Deg. F	828.5	828.7		**-0.2**
AVG AH 21 GAS OUT TEMP	Deg. F	353.4	361.6		**-8.3**
AVG AH 22 GAS OUT TEMP	Deg. F	368.4	377.2		**-8.8**
PULV 21 FEEDER FLOW RATE	klbs/hr	128	140		
PULV 22 FEEDER FLOW RATE	klbs/hr	137	140		
PULV 23 FEEDER FLOW RATE	klbs/hr	137	138		
PULV 24 FEEDER FLOW RATE	klbs/hr	127	139		
PULV 25 FEEDER FLOW RATE	klbs/hr	135	139		
PULV 26 FEEDER FLOW RATE	klbs/hr	135	**0**		
PULV 27 FEEDER FLOW RATE	klbs/hr	137	121		
PULV 28 FEEDER FLOW RATE	klbs/hr	137	138		
TOTAL FEEDER COAL FLOW RATE	**klbs/hr**	**953**	**971**	**-1.83**	
Dried Coal Flow Rate	klbs/hr	**135**	**0**		
Dried Coal as Percentage of Total	**%**	**14.12**	**0.00**		
Heat Input with Dry Coal	MBTU/hr	947	0		
Heat Input with Wet Coal	MBTU/hr	5,155	6,117		
Total heat input	**MBTU/hr**	**6,102**	**6,117**	**-0.24**	
Heat Iput with Dry Dry Coal as % of Total	**% of Total**	**15.50**	**0.0**		
PULV 21 FUEL-AIR TEMPERATURE	Deg. F	152	152		
PULV 22 FUEL-AIR TEMPERATURE	Deg. F	148	148		
PULV 23 FUEL-AIR TEMPERATURE	Deg. F	148	148		
PULV 24 FUEL-AIR TEMPERATURE	Deg. F	146	146		
PULV 25 FUEL-AIR TEMPERATURE	Deg. F	149	149		
PULV 26 FUEL-AIR TEMPERATURE	Deg. F	158	147		
PULV 27 FUEL-AIR TEMPERATURE	Deg. F	147	147		
PULV 28 FUEL-AIR TEMPERATURE	Deg. F	149	148		
AVG DRY COAL PULV TEMP (PULV 26)	Deg. F	158	147		**10**
AVG WET COAL PULV TEMPERATURE	Deg. F	149	148		**12**
PULV 21 KW	kW	593	605		
PULV 22 KW	kW	577	588		
PULV 23 KW	kW	530	543		
PULV 24 KW	kW	543	603		
PULV 25 KW	kW	586	603		
PULV 26 KW	kW	549	0		
PULV 27 KW	kW	612	625		
PULV 28 KW	kW	590	610		
TOTAL PULVERIZER POWER	**kW**	**4,037**	**4,176**	**-3.34**	**-140**
FD Fan Power	kW	2,056	2,049	**0.36**	**7**
PA Fan Power	kW	6,989	6,618	**5.61**	**371**
ID Fan Power	kW	11,613	11,782	**-1.43**	**-169**
Total mill and fan power	kW	24,694	24,624	**0.28**	**70**

7.2: Mill Operation and Performance

With drier coal, mill power is 3.34 percent (140 kW) lower compared to the operation with wet coal (Figure 2-9). This decrease in mill power is due to a decrease in coal flow rate, and also due to the mill power required to grind a given coal flow rate, which is reduced with drier coal. With drier coal, the specific mill work is reduced by approximately 4.2 percent (Figure 2-10). The comparison of the measured and theoretically predicted reductions in mill power, presented in Figure 2-11, shows an excellent agreement between the calculated and measured values.

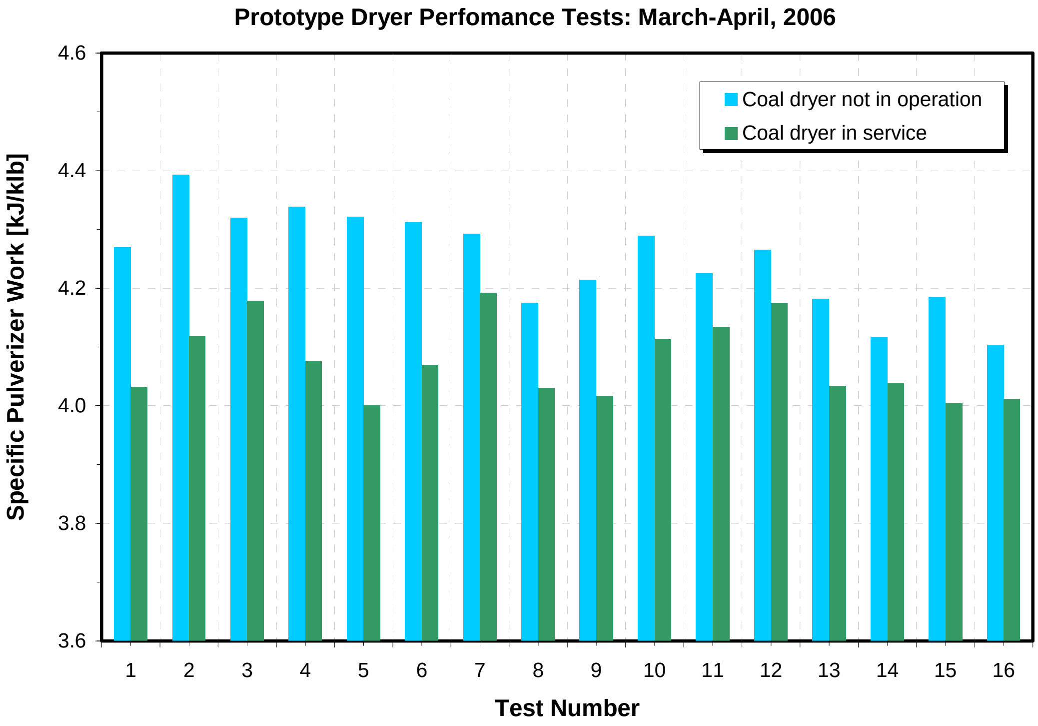

Figure 2-9: Total Mill (pulverizer) Power

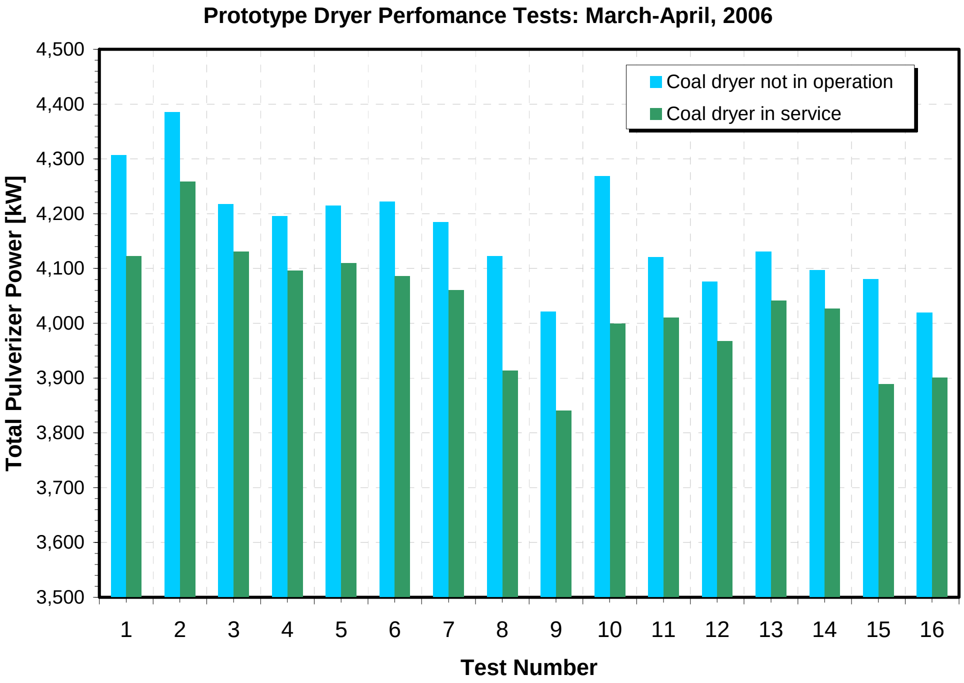

Figure 2-10: Specific Mill (pulverizer) Work

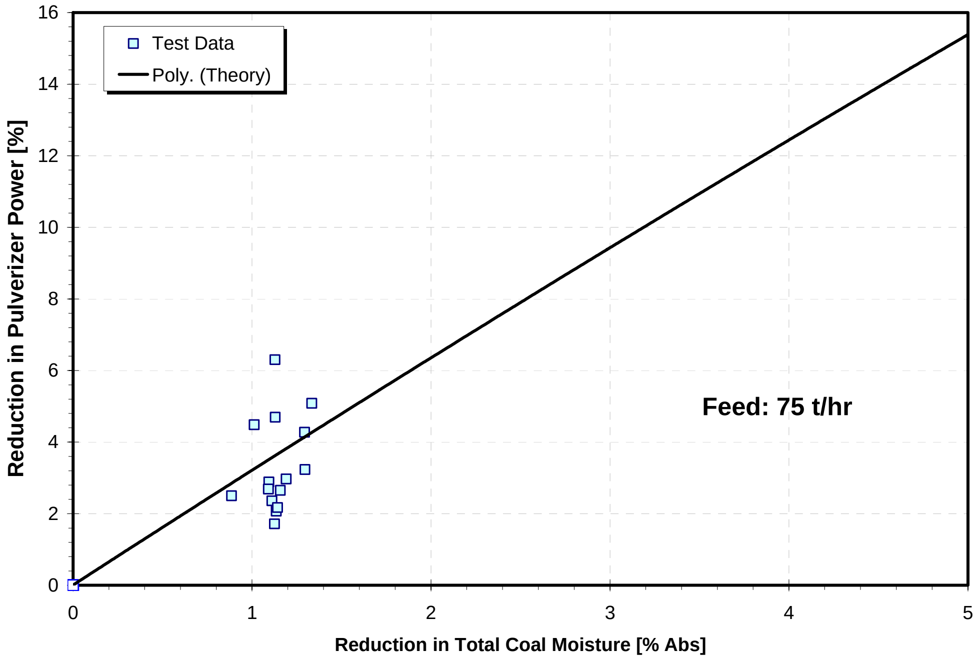

Figure 2-11: Comparison of Predicted and Measured Reduction in Mill Power

The temperature of the air-coal mixture leaving the No. 26 mill, processing partially dried coal, is 10°F higher compared to the mills processing wet coal (Figure 2-

12). This increase is due to the lower moisture content and higher temperature of partially dried coal entering the No. 26 mill.

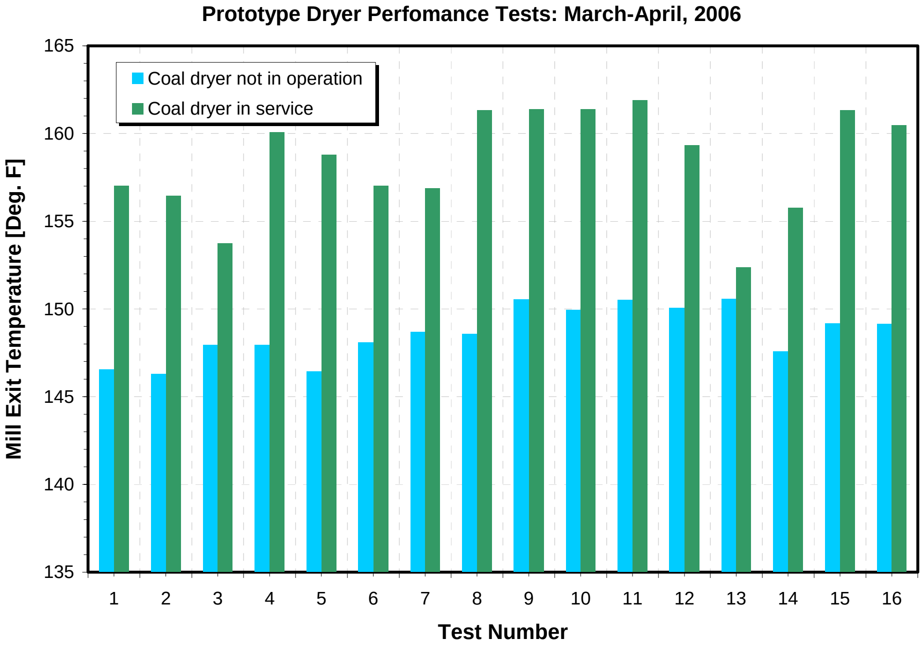

Figure 2-12: Mill Exit Temperature

Also, with CD26 in service, mill feeder No. 26 trips were eliminated. This is because the oversize material, typically responsible for feeder trips, was either screened out or discharged from the first dryer stage with the rest of the non-fluidizable material.

A coal crusher is used at Coal Creek to reduce coal top particle size to ¼-inch. The crusher power requirement for a baseline coal feed rate of 75 tons per hour is approximately 100 kW.

7.3: <u>Flue Gas Flow</u>

The flow rates of combustion air and flue gas decrease as coal moisture content is reduced. A decrease in combustion air flow rate is due to the improvement in boiler and unit performance, which result in a reduction in coal flow rate and heat input. The decrease in flue gas flow rate is due to the improvement in boiler and unit performance and decreased coal moisture content. A lower coal moisture results in lower water vapor content of flue gas. With blended coal fired during the paired tests, the flue gas moisture content was reduced from 15.5 to 15.1 percent on a volume basis. For a target value of total coal moisture removal of 8.5 percent, the flue gas moisture content will be reduced by more than 2.5 percentage points. As a result, the decrease in flue gas flow rate is larger than the decrease in combustion air flow rate.

The flue gas volumetric flow rates, measured by the plant CEM during the paired tests, are presented in Figure 2-13. A comparison between measured and predicted decrease in flue gas flow rate, presented in Figure 2-14, shows a very good agreement between the measured and predicted values.

For a target value of total moisture reduction of 8.5 percent, the predicted decrease in flue gas flow rate is approximately 3.9 percent. The average values of flue gas flow rate corresponding to the partially dried and wet coals are summarized in Table 2-3.

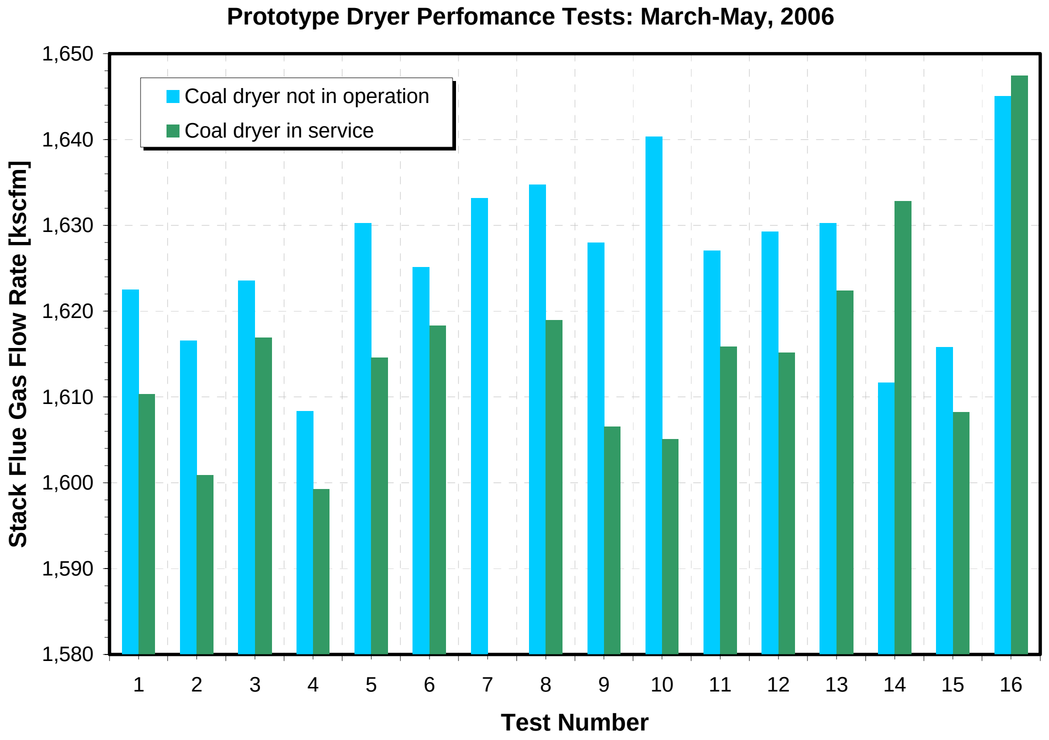

Figure 2-13: Flue Gas Flow Rate in Standard Volumetric Units

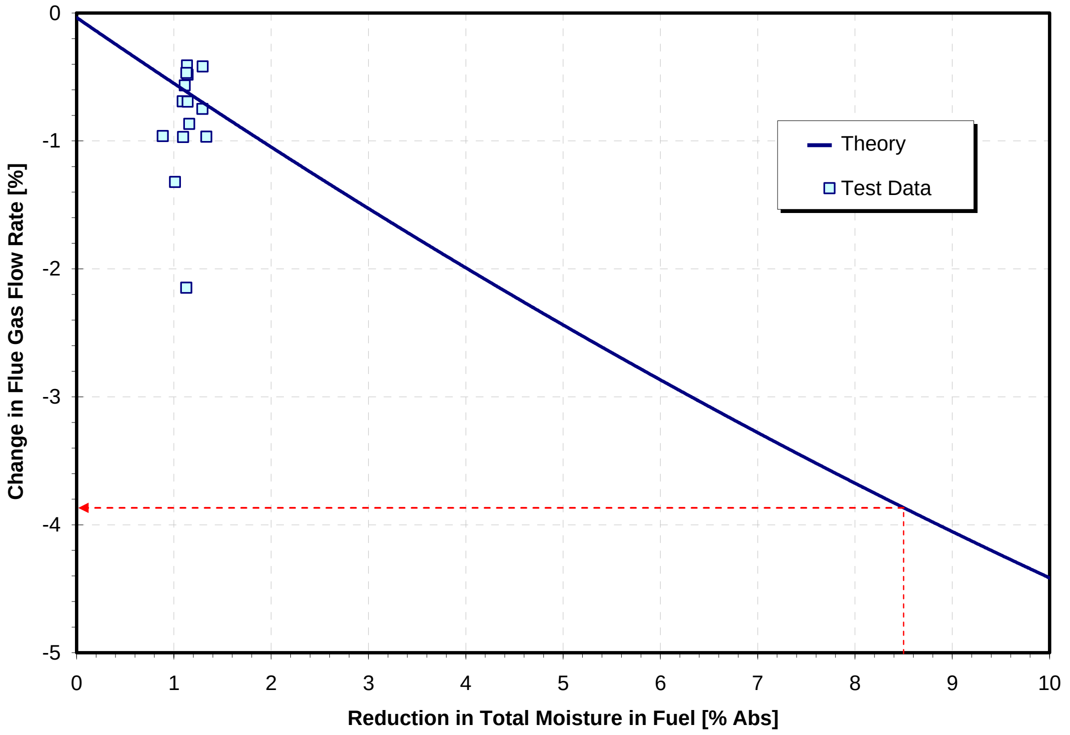

Figure 2-14: Comparison of Measured and Predicted Reduction in Flue Gas Flow Rate

Table 2-3

Flue Gas Flow Rate and Temperature, and Scrubber ΔP

Description	Units	Average Dry	Average Wet	% Change WRT Wet	Change WRT Wet
FLUE GAS FLOW RATE	kscfm	1,613	1,625	**-0.73**	
FLUE GAS TEMP	^{o}F	180	184		**-4.1**
Flue gas flow rate	kacfm	1,922	1,949	**-1.36**	
Flue gas flow rate	klbs/hr	7,101	7,140	**-0.55**	
U2 SCRUBBER DIFF PRESS	" wg	5.46	5.50	**-0.83**	**-0.05**

Table 2-3 also summarizes the values of the flue gas temperature at the stack inlet and the differential pressure, ΔP, across the wet scrubber. The flue gas flow rate, reported in standard volumetric units (kscfm), was converted to actual volumetric units (kacfm) and to mass units (klbs/hr) using the flue gas density values from Table 2-4. With a partially dried coal, the density of the flue gas is approximately 0.8 percent higher compared to the flue gas density corresponding to the wet coal.

Table 2-4

Flue Gas Density Calculation

Description	Units	Mass-Average Dry	Average Wet	% Change WRT Wet	Absolute Change WRT Wet
Flue gas molecular weight	kg/mole	28.754	28.702	**0.18**	
Actual flue gas temperature	Deg. C	82.16	84.41		**-2.25**
Actual flue gas temperature	K	355.31	357.56		**-2.25**
Gas constant	J/mole-K	289.14	289.67	**-0.18**	
Ambient pressure	N/m^2	101,300	101,300		
Flue gas density	kg/m^3	0.9860	0.9781		
Flue gas density	**lb/ft^3**	**0.06156**	**0.06106**	**0.82**	
Standard temperature	Deg.C	25	25		
Standard temperature	K	298.15	298.15		

The results from Table 2-3 show that with the partially dried coal, the volumetric flue gas flow rate, at actual conditions, decreased 1.36 percent compared to that with wet coal. The reduction in mass flow rate of flue gas is lower, 0.55 percent, due to the increase in flue gas density with partially dried coal. The measured reduction in flue gas flow rate is close to the theoretically calculated value of 0.65 percent.

With partially dried coal, the flue gas temperature at the stack inlet is lower compared to that with wet coal by approximately 4.3°F (2.25°C). This lower temperature decrease can be explained by the fact that with reduced flue gas flow rate with partially dried coal, a larger fraction of flue gas passes through the wet scrubber (where its temperature is decreased to a value close to the saturation temperature) while a smaller flue gas fraction bypasses the scrubber, compared to that with wet coal operation. The bypass and scrubbed streams mix downstream of the scrubber before entering the stack, resulting in inlet stack temperature being higher than saturation temperature. Measured values of flue gas temperature at the stack inlet are presented in Figure 2-15. The red bar indicates an erroneous temperature reading.

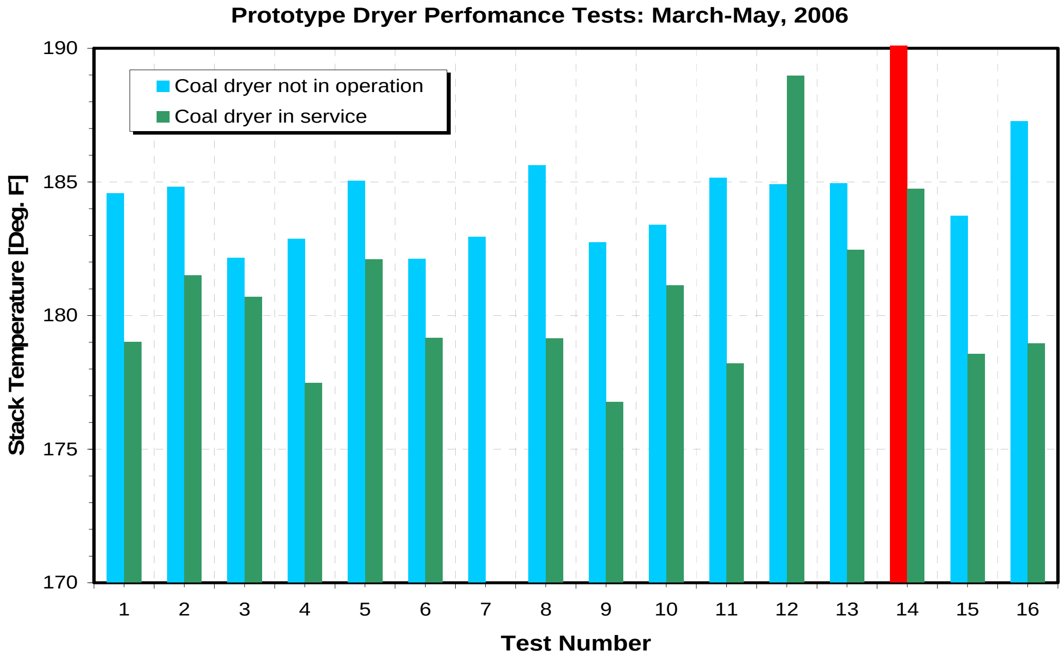

Figure 2-15: Flue Gas Temperature at Stack Inlet

The air flow through the forced draft (FD) and primary air (PA) fans at CCS is, at present, controlled with inlet guide vanes (IGV). Flow control through the induced draft (ID) fans at Coal Creek is accomplished by the inlet damper (ID). With the IGV and ID methods of flow control, a full reduction in fan power due to the reduced air and flue gas flow rates with partially dried coal is not possible. Variable speed fan drives (VSD) are needed to achieve the maximum reduction in fan power with partially dried coal.

With the presently used fan flow control methods at CCS, the FD fan power remained virtually constant (2,056 vs. 2,049 kW) for both the partially dried and wet coals. For the case of partially dried coal, the ID fan power was reduced 1.43 percent (169 kW).

7.4: Calculation of the Average Boiler Efficiency Improvement From Plant Data

By using the definition of boiler efficiency, η_B, shown below, the improvement in this parameter due to firing of partially dried coal can be determined directly from the measured plant data, using the input/output method without performing boiler efficiency calculations. Since the input/output approach suffers from large errors due to uncertainties (random errors) in coal flow rate and HHV measurement, this approach is not suitable for determining boiler efficiency improvement for individual performance tests. Instead, the input/output approach was used to calculate average efficiency improvement for all 16 performance tests, where individual test uncertainties averaged out reducing, therefore, the overall test uncertainty.

By definition:

$\eta_B = Q_T/Q_{Fuel}$ Eqn. 2-4

where:

Q_T	Boiler thermal duty (heat transferred to the steam turbine cycle)
Q_{Fuel}	Heat input with fuel, in this case coal:

$Q_{Fuel} = M_{Fuel}\ HHV$ Eqn. 2-5

where:

M_{Fuel}	Fuel (coal) flow rate
HHV	Fuel (coal) higher heating value

The relative improvement in boiler efficiency, $\Delta\eta_{/}\eta_{B,Wet}$, can then be determined as:

$\Delta\eta_{/}\eta_{B,Wet} = Q_{T,Dry}/Q_{T,Wet} \times Q_{Fuel,Wet}/Q_{Fuel,Dry} - 1$ Eqn. 2-6

Using results from Table 2-5 show, the improvement in boiler efficiency due to firing of partially dried coal, calculated by the input/output method is:

$\Delta\eta_{/}\eta_{B,Wet} = 0.00535 \pm 0.000315$

Expressed on a relative basis, the improvement in boiler efficiency $\Delta\eta_{/}\eta_{B,Wet}$ is equal to 0.535 ± 0.0315 percent.

Table 2-5

Boiler Efficiency Improvement Calculated From the Plant Data

Description	**Units**	**Mass-Average Dry**	**Average Wet**	**% Change WRT Wet**	**Absolute Change WRT Wet**
$Q_{T,dry}/Q_{T,wet}$	ratio			1.002962	
$Q_{fuel,wet}/Q_{fuel,dry}$	ratio			1.002388	
$\eta_{B,dry}/\eta_{B,wet}$	ratio			**1.005357**	

The uncertainty in $\Delta\eta/\eta_{B,Wet}$ was determined by assuming typical uncertainty value of ± 3 percent for coal flow rate measurement, ± 1 percent for laboratory determination of coal HHV, and baseline boiler efficiency of 80 percent.

The calculated values of boiler efficiency for the partially dried and wet coals are presented in Table 2-6 and Figure 2-16.

Table 2-6

Boiler Efficiency for Partially Dried and Wet Coal Calculated by Using the Mass and Energy Balance Approach and Paired Performance Test Data

Test	**Total Fuel Moisture, TM [%]**		**DTM**	**Boiler Efficiency [%]**		**Difference**
	Dry Mix	Wet	**% Abs**	Dry Mix	Wet	**% Abs**
1	35.73	37.03	**1.29**	78.54	78.06	**0.48**
2	35.69	36.74	**1.06**	78.37	78.00	**0.37**
3	36.29	37.44	**1.14**	78.41	78.01	**0.40**
4	35.70	36.76	**1.07**	78.51	78.41	**0.10**
5	36.58	37.50	**0.92**	77.93	77.41	**0.52**
6	35.25	36.58	**1.34**	78.88	78.46	**0.42**
7	36.25	37.44	**1.19**	78.66	78.23	**0.43**
8	35.65	36.99	**1.33**	78.91	78.74	**0.17**
9	35.97	36.98	**1.00**	78.43	78.14	**0.29**
10	35.93	37.07	**1.14**	77.87	77.07	**0.80**
11	34.92	36.00	**1.08**	78.36	77.93	**0.43**
12	35.99	37.16	**1.16**	78.79	78.60	**0.19**
13	36.19	37.34	**1.14**	78.05	77.59	**0.46**
14	35.91	37.03	**1.12**	78.64	78.56	**0.08**
15	36.71	37.81	**1.10**	78.25	77.90	**0.35**
16	**35.17**	**37.47**	**2.30**	**78.91**	**78.39**	**0.52**
Average	**35.92**	**37.06**	**1.14**	**78.44**	**78.07**	**0.37**
Std. Dev	0.49	0.43	0.31	0.33	0.45	0.18
Std. Error	0.14	0.13	0.09	0.10	0.13	0.05
Random Error	**0.30**	**0.27**	**0.19**	**0.20**	**0.28**	**0.11**

The results show that boiler efficiency achieved by firing partially dried coal is consistently higher compared to the boiler efficiency corresponding to firing wet coal. The average absolute boiler efficiency improvement, $\Delta\eta_B$, calculated from the boiler efficiency values from Table 2-5, excluding test point 16, is:

$$\Delta\eta_B = 0.37 \pm 0.11 \text{ percentage points}$$

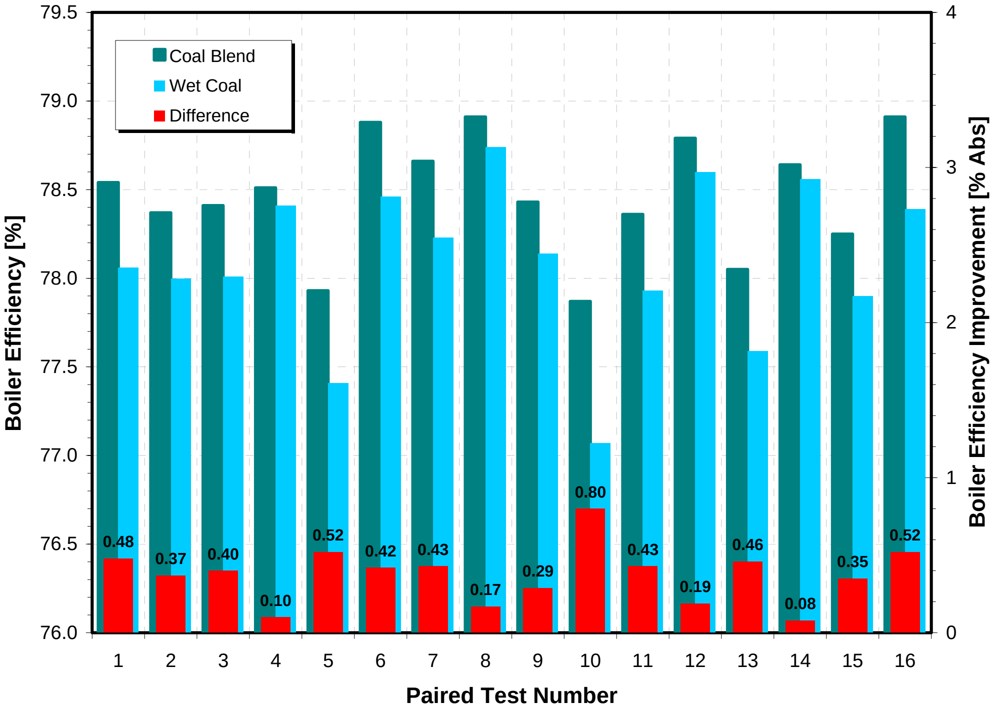

Figure 2-16: Boiler Efficiency for Partially Dried and Wet Coal

This corresponds to $\Delta\eta/\eta_{B,Wet}$ = 1.0047, or a **0.470** percent improvement on a relative basis. Considering the uncertainties in coal composition, HHV, and flow rate measurement, this value is close (within 14 percent) to the relative boiler efficiency improvement of **0.5357** percent calculated by the input/output approach.

Since the uncertainty interval of ± 0.11 percentage points is significantly smaller than the calculated boiler efficiency difference of 0.37 percentage points, the calculated improvement in boiler efficiency is statistically significant.

The comparison of theoretically predicted boiler efficiency improvement and boiler efficiency improvement determined from a series of 16 paired performance tests is presented in Figure 2-17. Theoretical predictions were obtained by applying the mass and energy balance and above-described calculation approach.

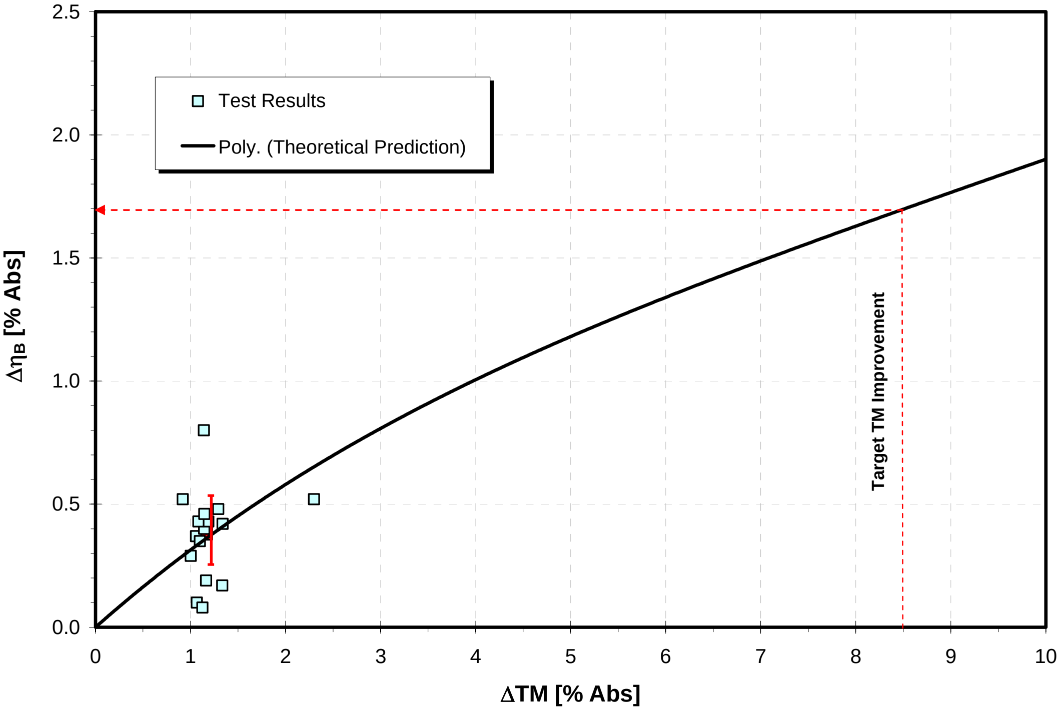

Figure 2-17: Comparison of Predicted and Test Values of Absolute Boiler Efficiency Improvement

The difference between the theoretical calculations and performance test results is that in the theoretical calculations, analytical models for APH thermal performance and fan and mill power were used to determine temperatures of flue gas, PA and SA leaving the APH, and FD, PA, ID and mill power. The coal flow rate was calculated by assuming constant boiler thermal duty, Q_T. When calculating boiler efficiency from the boiler performance test data, measured values of these parameters, obtained in a series of 16 paired performance tests were used.

With the exception of one outlier test point, the results in Figure 2-17 show excellent agreement between theoretical predictions and performance test results. For a target reduction in total coal moisture of 8.5 percent, the predicted improvement in boiler efficiency is 1.7 percent.

7.5: Net Unit Heat Rate

The net unit heat rate is calculated according to the following expression:

$$HR_{net} = HR_{cycle}/[\eta_B(1 - P_{ss}/P_g)] \qquad \text{Eqn. 2-16}$$

where:

HR_{cycle}	Turbine cycle heat rate (8,000 Btu/kWh for CCS)
η_B	Boiler efficiency
P_{ss}	Total measured station service power (mills, fans, crusher, etc.)
P_g	Gross unit power output

The values of net unit heat rate calculated from the paired performance test data for the partially dried and wet coal are presented in Table 2-7 and Figure 2-18.

Table 2-7

Net Unit Heat Rate for Partially Dried and Wet Coal Calculated by Using the Mass and Energy Balance Approach and Paired Performance Test Data

Test	**TM [%]**		**DTM**	**$HR_{net,mix}$**	**$HR_{net,wet\ coal}$**	**ΔHR_{net}**	**ΔHR_{net}**
	Dry Mix	Wet	**% Abs**	BTU/kWh	BTU/kWh	BTU/kWh	%
1	35.73	37.03	**1.29**	10,634	10,688	54	0.51
2	35.69	36.74	**1.06**	10,661	10,702	41	0.38
3	36.29	37.44	**1.14**	10,664	10,693	29	0.27
4	35.70	36.76	**1.07**	10,638	10,643	5	0.05
5	36.58	37.50	**0.92**	10,725	10,789	64	0.59
6	35.25	36.58	**1.34**	10,589	10,634	45	0.42
7	36.25	37.44	**1.19**	10,611	10,661	50	0.47
8	35.65	36.99	**1.33**	10,585	10,588	3	0.03
9	35.97	36.98	**1.00**	10,647	10,677	30	0.28
10	35.93	37.07	**1.14**	10,732	10,827	95	0.88
11	34.92	36.00	**1.08**	10,660	10,709	49	0.46
12	35.99	37.16	**1.16**	10,602	10,621	19	0.18
13	36.19	37.34	**1.14**	10,695	10,754	59	0.55
14	35.91	37.03	**1.12**	10,620	10,629	9	0.08
15	36.71	37.81	**1.10**	10,657	10,705	48	0.45
16	**35.17**	**37.47**	**2.30**	**10,578**	**10,634**	**56**	**0.53**
Average	**35.92**	**37.06**	**1.14**	**10,648**	**10,688**	**40**	**0.37**
Std. Dev	0.49	0.43	0.31	47	64	24	0.23
Std. Error	0.14	0.13	0.09	13	18	7	0.07
Random Error	**0.30**	**0.27**	**0.19**	**29**	**39**	**15**	**0.14**

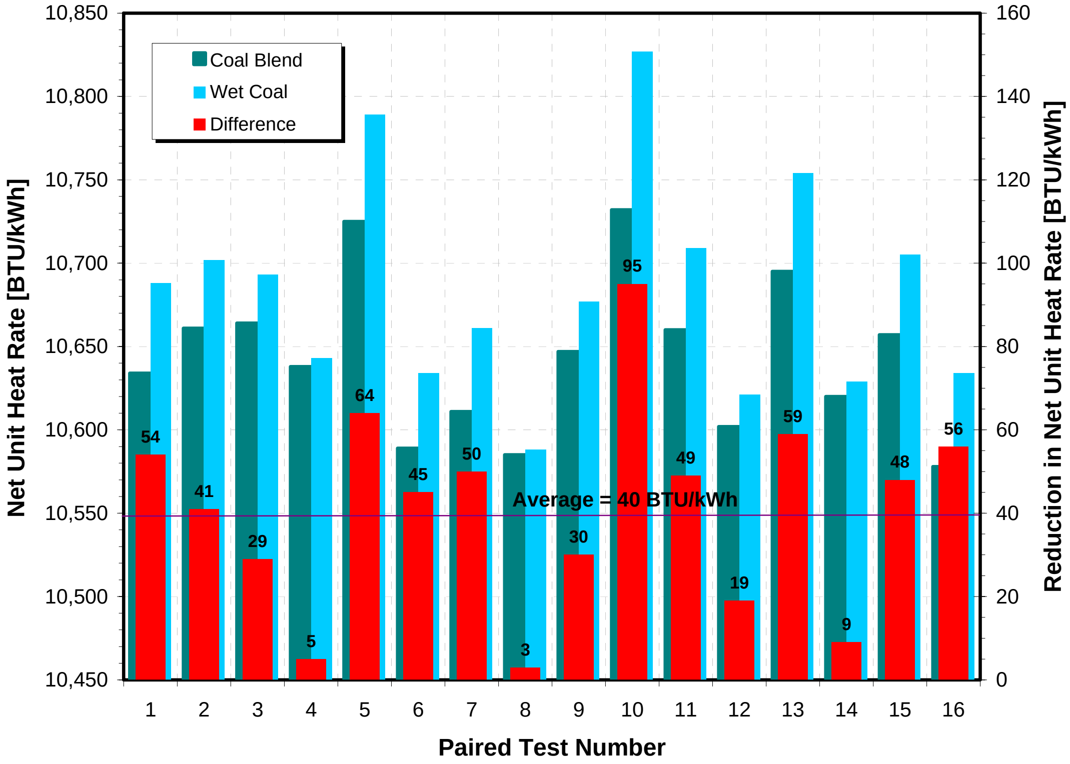

Figure 2-18: Net Unit Heat Rate for Partially Dried and Wet Coal

The results show that the net unit heat rate, HR_{net}, corresponding to the unit operation with partially dried coal is consistently lower compared to HR_{net} obtained with the wet coal. The average improvement in net unit heat rate due to lower fuel moisture, excluding Test 16, is:

$\Delta HR_{net} = 40 \pm 15$ Btu/kWh

On a relative scale this corresponds to a HR_{net} improvement of 0.37 percent. Since the uncertainty interval of ± 15 Btu/kWh is significantly smaller than the calculated heat rate difference of 40 Btu/kWh, the calculated improvement in HR_{net} is statistically significant.

If VSD were used for fan flow control, fan power requirement would be lower than with the presently used fan flow control methods (Table 2-7). With a partially dried coal and VSD drives, the FD fan power would be reduced 0.58 percent, while the ID fan power would be 2.98 percent (350 kW) lower compared to the wet coal and IGV/ID flow control. With VSD drive the PA fan power would be 66 kW lower than with the IGV flow control.

The final result would be a 0.80 percent (197 kW) reduction in total fan power and a 0.50 percent (54 Btu/kWh) total improvement in net unit heat rate (Table 2-8).

Table 2-8

Effect of VSD Fan Flow Control on Fan Power Requirements and Net Unit Heat Rate

Description	**Units**	**Mass-Average Dry**	**Average Wet**	**% Change WRT Wet**	**Absolute Change WRT Wet**	**Comments**
Pulverizer Power	kW	4,037	4,176	**-3.34**	**-140**	
FD Fan Power	kW	2,056	2,049	**0.36**	**7**	IGV
PA Fan Power	kW	6,989	6,618	**5.61**	**371**	IGV
ID Fan Power	kW	11,613	11,782	**-1.43**	**-169**	Inlet Damper
Total Mill and Fan Power	kW	**24,694**	**24,624**	**0.28**	**70**	
Boiler Efficiency	%	**78.44**	**78**	**0.47**	**0.37**	
Net Unit Heat Rate	BTU/kWh	**10,648**	**10,688**	**-0.37**	**-40**	
FD Fan Power	kW	2,037	2,049	**-0.58**	**-12**	VSD for dry coal
ID Fan Power	kW	11,430	11,782	**-2.98**	**-351**	VSD for dry coal
PA Fan Power	kW	6,923	6,618	**4.62**	**305**	VSD for dry coal
Total Mill and Fan Power	kW	**24,427**	**24,624**	**-0.80**	**-197**	VSD for dry coal
Net Unit Heat Rate	BTU/kWh	**10,639**	**10,693**	**-0.50**	**-54**	VSD for dry coal

8. <u>EMISSIONS</u>

The NO_x and SO_x emissions, flue gas flow rate, and flue gas CO_2 composition, measured by the plant CEM for 16 paired performance tests, are summarized in Table 2-9. As discussed earlier, firing partially dried coal results in lower flue gas flow rate. For the coal moisture reduction of 1.14 percent, achieved in the dryer performance tests, the reduction in flue gas mass flow rate is 0.55 percent.

Table 2-9

NO_x and SO_x Emissions, Stack Flow Rate,
and Flue Gas CO_2 Concentration Measured by the Plant CEM

Description	Units	Mass-Average Dry	Average Wet	% Change WRT Wet	Absolute Change WRT Wet
NOx Emissions	lbs/hr	1,359	1,469	**-7.52**	**-111**
SOx Emissions	lbs/hr	3,641	3,670	**-0.81**	**-30**
Flue Gas Flow Rate	kscfm	1,613	1,625	**-0.73**	**-12**
Flue Gas Flow Rate	klbs/hr	7,101	7,140	**-0.55**	**-39**
Flue Gas CO2	%	11.90	11.87	**0.27**	**0**

8.1: NO_x Emissions

The 7.5 percent average reduction in NO_x mass emissions, measured during the paired performance tests (Figure 2-19), is significantly higher than the percentage reduction in flue gas flow rate. This reduction in NO_x emissions cannot be explained by a lower flue gas flow rate. Instead it is attributed to a lower primary air flow rate to Mill No. 26, which was handling partially dried coal. From combustion optimization tests, performed by the ERC and GRE engineers at Coal Creek in 1997 [10], it is known that NO_x emissions at this plant are quite sensitive to the primary air flow. NO_x decreases as primary air flow is reduced.

The primary air flow rates to Mill 26 and to other mills handling wet coal are presented in Figure 2-20. With partially dried coal, the primary air flow rate to the No. 26 mill was, on average, reduced from 355 to 310 klbs/hr, a 12 percent reduction. Modifications to the coal mills will allow the primary air flow to be decreased even more to 255 klbs/hr. This is expected to result in a further decrease in NO_x emissions.

With the commercial coal drying system in service, i.e., with 100 percent dried coal delivered to the coal mills, and the reduced PA flows to the mills, the reduction in NO_x emissions is expected to exceed 10 percent.

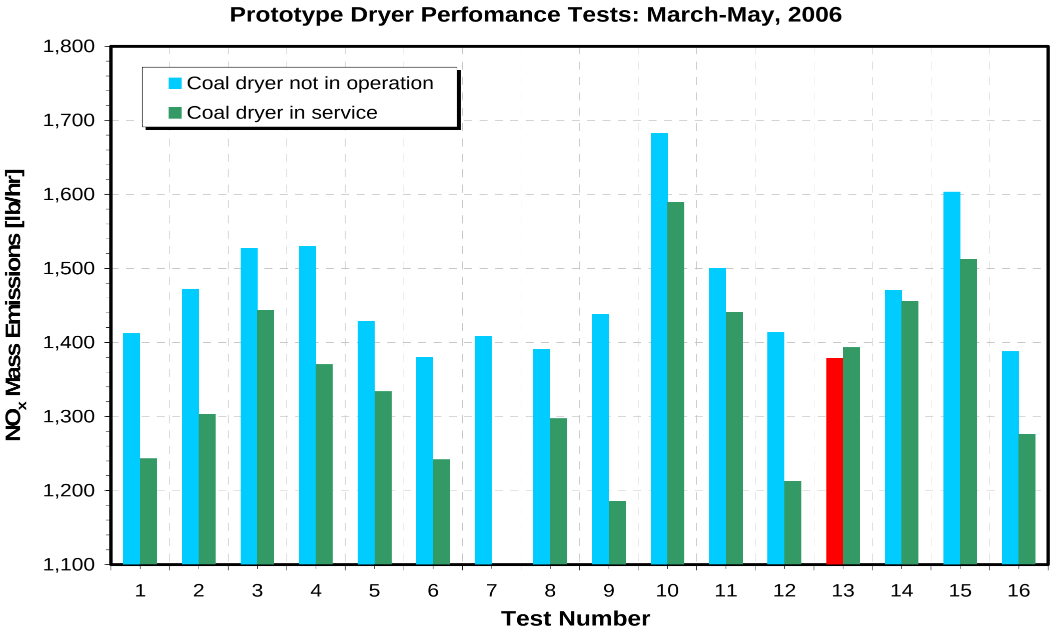

Figure 2-19: NO_x Emissions with Wet and Partially Dried Coal

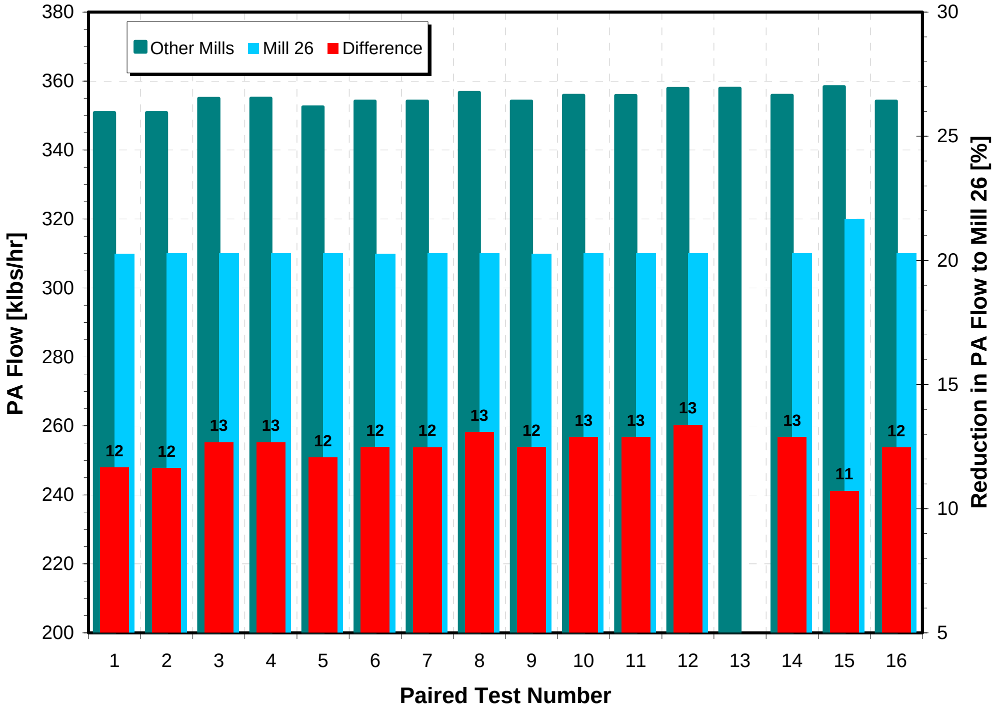

Figure 2-20: Primary Air Flow Rates to the Mills with Wet and Partially Dried Coal

8.2: SO_x Emissions

The measured reduction in SO_x emissions with partially dried coal, measured during the series of 16 paired parametric tests, is approximately 0.8 percent (Table 2-9 and Figure 2-21). The red bar represents a bad reading.

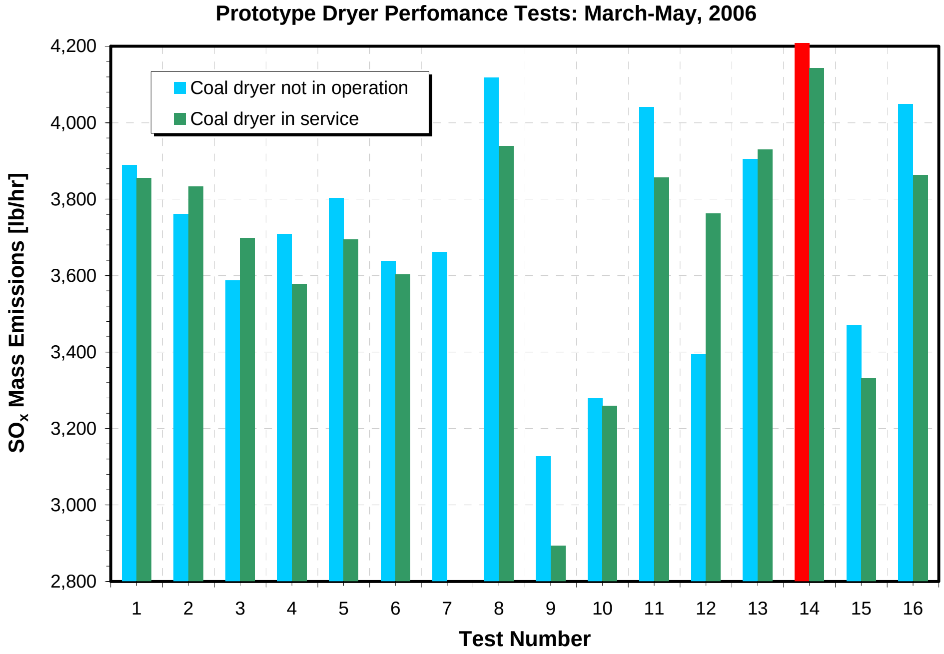

Figure 2-21: SO_x Emissions with Wet and Partially Dried Coal

A closer inspection of the recorded plant data and the results presented in Figure 2-21 points to problems with SO_x measurement that occurred during Tests 12 to 14, where measured SO_x emissions are higher with a partially dried coal compared to the wet coal. These inconsistencies are explained by a malfunctioning SO_x monitor that was providing unreliable SO_x readings for Tests 12 to 14. A comparison of the results for the first 11 paired tests and for all 16 paired tests shows a significant difference in SO_x reduction (1.9 percent for the first 11 tests vs. 0.8 percent for all 16 tests). It is, therefore, reasonable to assume that the actual reduction in SO_x emissions, achieved with partially dried coal, is in the 1.9 percent range.

The percentage reduction in SO_x emissions is larger than the percentage the reduction in flue gas mass flow rate. This is because with a lower flue gas flow rate, the flue gas bypass around the scrubber decreases (CCS is a partially scrubbed unit), resulting in a higher SO_x removal. With 100 percent partially dried coal fired in the boiler, the flue gas flow rate to the wet scrubber will be reduced by an estimated four percent. Combined with lower APH leakage, that would be achieved by using double-edge APH seals, the percentage of the scrubbed flue gas flow will further increase, approaching a zero scrubber bypass configuration. This will result in an additional reduction in SO_x emissions.

Due to a gravitational separation that is taking place in the first dryer stage, the sulfur concentration in the segregated stream is three times higher compared to the product and feed streams. This increase in sulfur content in the segregated stream can be explained by the fact that pyrites, having higher density than coal, are segregated out in the first dryer stage. For the present configuration of the prototype coal drying system at CCS, the segregated stream is returned to and mixed with the product stream from the coal dryer. Therefore, the benefit of sulfur removal in the first dryer stage, is not being realized, and the measured reduction in SO_x emissions is solely due to the lower flue gas and scrubber bypass flows.

The commercial coal drying system is designed to further process the segregated stream. After processing, the segregated stream will not be mixed with the product stream from the commercial dryers. With the segregated stream representing 5 to 10 percent of the dryer feed, the reduction in mass flow rate of sulfur to the boiler would be in the 7 to 12 percent range. By combining reductions due to the lower scrubber bypass and lower sulfur input to the boiler, the potential reduction in SO_x emissions that could be achieved with the commercial coal drying system at CCS operating at 100 percent capacity is expected to be in the 12 to 17 percent range.

Since the calculated reduction in SO_x emissions is very much affected by the accuracy of the measured S concentration levels in the feed, segregated, and product streams, and the segregated stream flow rate, the actual reduction in SO_x emissions will be determined from the plant CEM measurements with the commercial coal drying system at CCS operating at 100 percent capacity.

8.3: CO_2 Emissions

The reduction in CO_2 mass emissions is proportional to the improvement in unit performance (net unit heat rate). For the target moisture reduction of 8.5 percent, the expected reduction in CO_2 emissions is approximately 2.4 percent.

8.4: Mercury (Hg) Emissions

The reduction in Hg emissions, achieved during paired performance tests at CCS, is proportional to the improvement in unit performance, and is estimated to be in the 0.4 percent range.

The segregated stream from the first dryer stage contains approximately 3.5 to 4 times more Hg compared to the product and feed streams, (Figures 2-22 and 2-23). This increase in Hg content in the segregated stream can be explained by the fact that for the Falkirk lignite, a significant portion of mercury is bound to pyrites that are segregated out in the first dryer stage.

With the present configuration of the prototype coal drying system at CCS, the segregated stream is returned to the product stream from the coal dryer. Therefore, the benefit of Hg removal in the first dryer stage on Hg emissions is not realized.

As discussed in Section 8.2, the commercial coal drying system is designed to further process the segregated stream. After processing, the segregated stream will not be mixed with the product stream from the commercial dryers and will not be burned in the CCS boiler. With the segregated stream representing 5 to 10 percent of the dryer feed, the estimated reduction in mass flow rate of mercury to the boiler is in the 13 to 25 percent range (Figures 2-22 and 2-23).

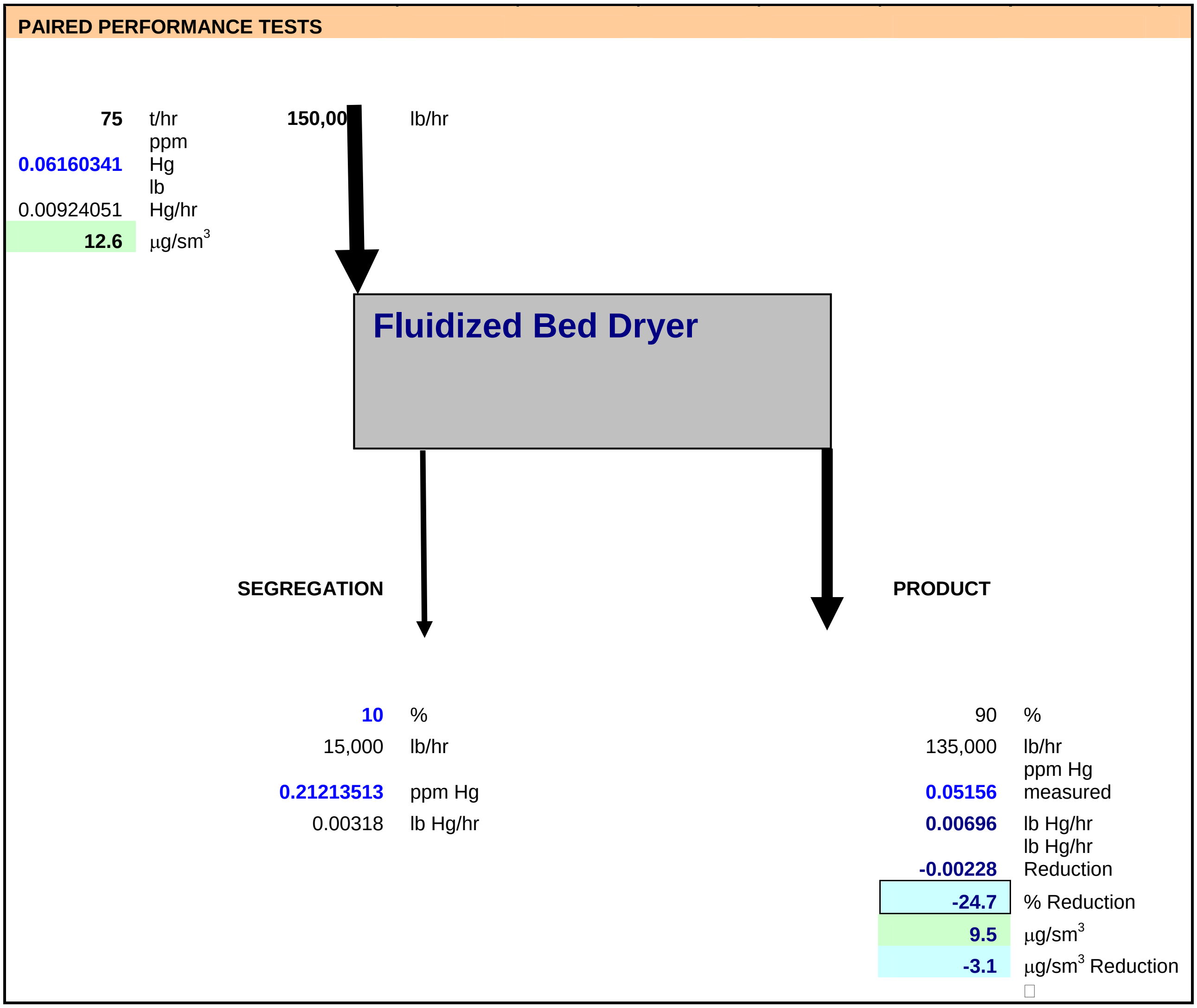

Figure 2-22: Mercury Mass Balance Around FBD – Paired Performance Tests

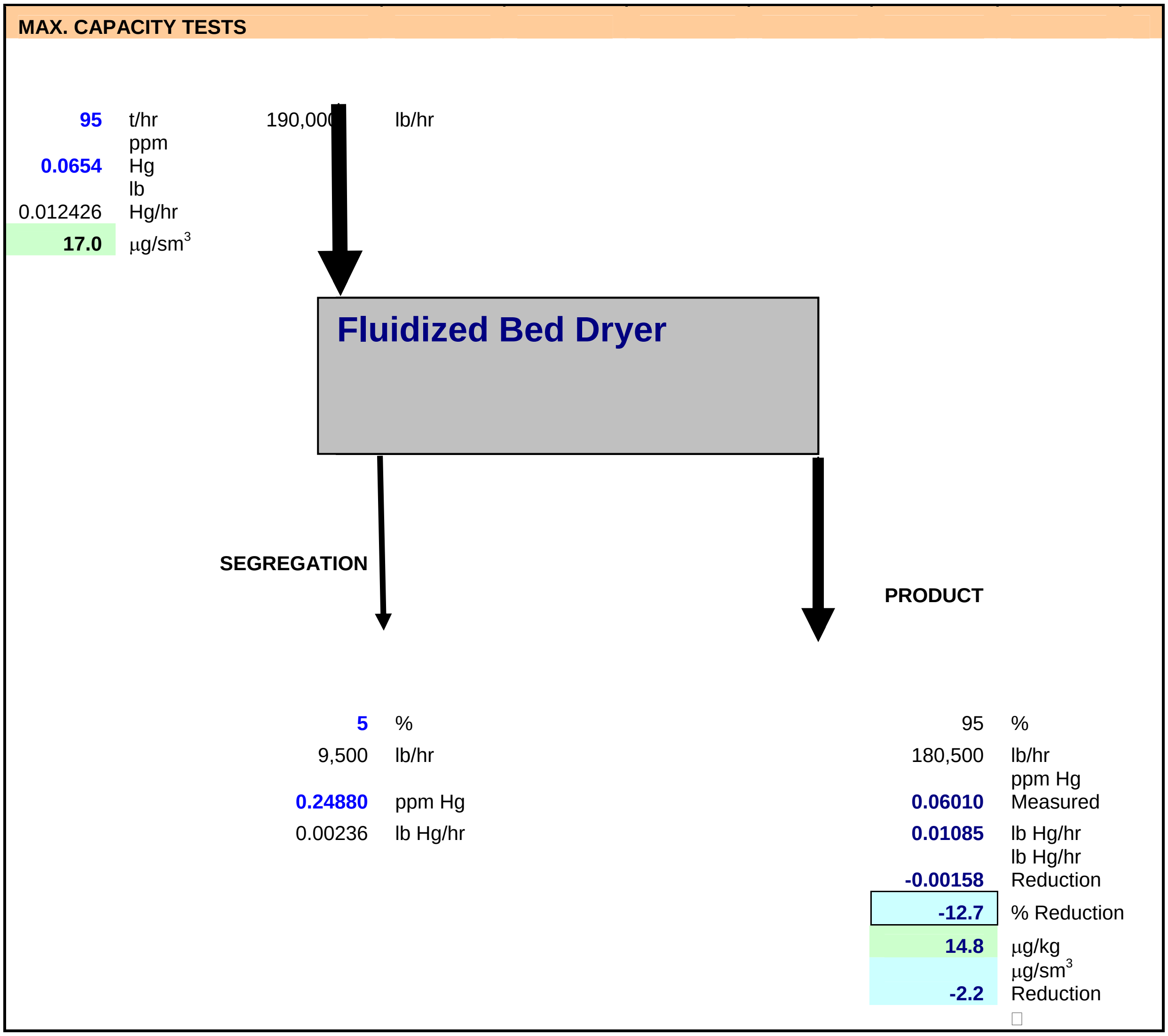

Figure 2-23: Mercury Mass Balance Around FBD – Maximum Capacity Tests

8.4.1: Effect of Flue Gas Moisture on Mercury Speciation

Mercury speciation is, among many other factors, affected by flue gas moisture content and residence time. With the target moisture removal of 8.5 percent, the flue gas moisture content is 2.5 percentage points lower compared to that with wet coal. According to the theoretical gas-phase results in Figure 2-24, this would result in approximately a 20 percent reduction in elemental mercury, Hg^o, in the flue gas [11].

Expressed differently, with a partially dried coal, approximately 20 percent more elemental mercury will be oxidized compared to the wet coal. The oxidized mercury, Hg^{+2}, is water soluble and can be removed in the wet scrubber.

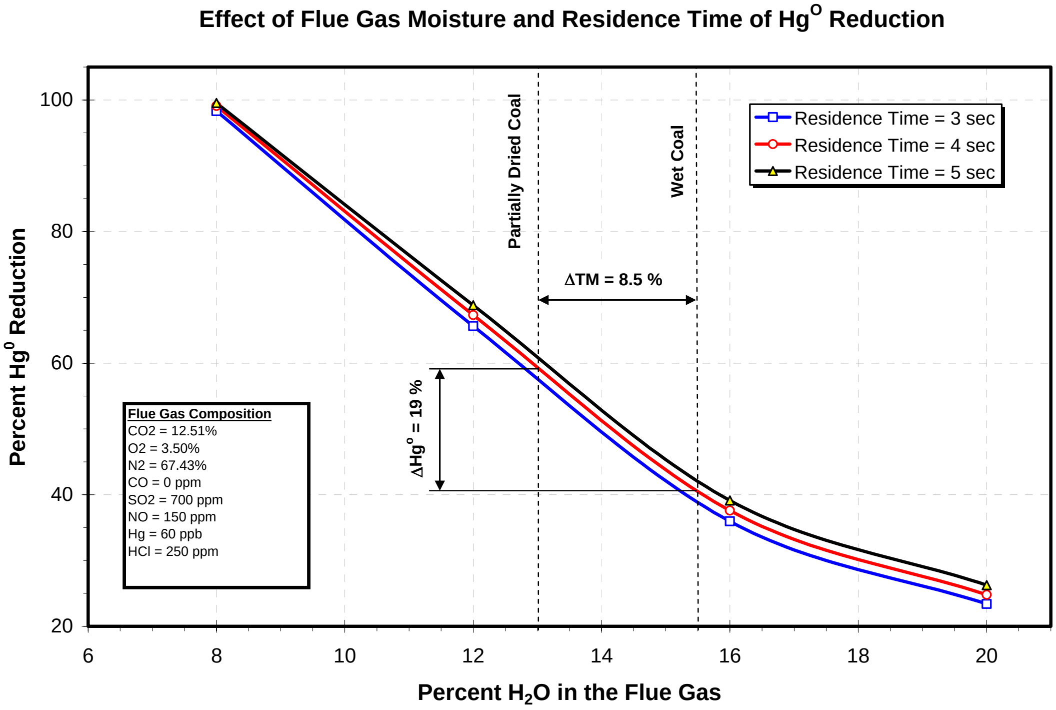

Figure 2-24: Effect of Flue Gas Moisture Content and Residence Time on Mercury Speciation (Theoretical results provided by Dr. Carlos Romero, ERC.)

Also, an increase in residence time has a positive effect on mercury oxidation. This effect is, however, small, of the order of one percent per one second increase in residence time. With a partially dried coal, the residence time will increase due to lower flow rates.

According to [12], the total vapor phase mercury concentration at CCS is in the 15 to 18 $\mu g/Nm^3$ range. This compares favorably to flue gas Hg concentrations calculated from the mercury content in coal and flue gas flow rate, Figures 2-22 and 2-23. Also, according to [12], approximately 65 percent (12 $\mu g/Nm^3$) of the vapor phase mercury at CCS is elemental mercury, Hg^o. Assuming a 20 percent relative reduction in elemental mercury due to lower flue gas moisture content and increased residence time, the reduction in Hg^o in flue gas stream would be 13 percent, or approximately 2.3 $\mu g/Nm^3$, assuming 98 percent Hg removal in the wet scrubber.

By combining a reduction in coal mercury content due to gravitational separation in a fluidized bed coal dryer (13 to 25 percent), and reduction in Hg^o due to the lower flue gas moisture content (13 percent), the total reduction in Hg emissions that could be achieved at CCS with the commercial coal drying system operating at 100 percent capacity, is predicted to be in the 25 to 35 percent range.

Similar to SO_x, reduction in Hg emissions that is achieved by gravitational separation in the coal dryer is very much affected by the accuracy of the measured Hg concentration levels in the feed, segregated, and product streams, and the segregated stream flow rate. The actual reduction in Hg emissions would be determined when the commercial coal drying system at CCS is operating at 100 percent capacity.

9. CONCLUSIONS

A prototype fluidized coal dryer, coal handling, particulate control, and dryer systems were designed, constructed and integrated into Unit 2 at Coal Creek as a Part of Phase 1 of the Lignite Fuel Enhancement project. The project objective was to demonstrate a 5 to 15 percentage point reduction in lignite moisture content by incremental drying using heat rejected from the power plant. Dryer performance was tested at the baseline (75 t/hr) and maximum (100 t/hr) coal feed rates.

The prototype coal drying system at CCS has been in almost continuous fully automatic operation since February 2006. A few minor problems that were easily corrected were encountered. The results obtained in a series of paired performance tests and from regular dryer operation confirm the theoretically predicted dryer performance and unit performance improvement. The achieved reduction in NO_x emissions is larger than expected.

The two-stage design of the dryer, with the first stage acting as a gravitational separator, worked as designed. The segregated stream, discharged from the first stage contained 3 to 3.5 times more sulfur and mercury compared to the product and feed streams. This first stage separation offers a potential for significant reduction in emissions. The segregated stream needs to be further processed to minimize the heat loss, which is proportional to the segregated stream flow rate, and remove additional amounts of sulfur, mercury, and other mineral matter from the dried coal. This will be accomplished in a commercial coal drying system.

In summary, the prototype coal drying system has met and exceeded expectations in terms of performance improvement, emissions reduction, operability, and positive effect on plant operation. It is, therefore, recommended to proceed with the commercial system design, construction, and implementation at CCS.

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LIST OF ACRONYMS AND ABBREVIATIONS

avg	Average
APH	Air preheater
CCPI	Clean Coal Power Initiative
CCS	Coal Creek Station
CD	Coal dryer
CD26	Coal dryer supplying dried coal to Mill Number 26
CO	Carbon monoxide
CO_2	Carbon dioxide
CT	Capacity test
CV	Control volume
DC	Dry coal, or dust control
DOE	Department of Energy
EPRI	Electric Power Research Institute
ERC	Energy Research Center
fg	Flue gas
FBD	Fluidized Bed Dryer
GRE	Great River Energy
h_{fg}	Latent heat of evaporation
Hg	Mercury
Hg^o	Elemental mercury
Hg^{+2}	Oxidized mercury
HHV	Higher heating value of fuel (coal)
HR_{cycle}	Turbine cycle heat rate (inverse of cycle efficiency)
HR_{net}	Net unit heat rate (inverse of unit efficiency)
HT	Heat transfer
HXE	Heat exchanger
ID	Inlet damper
IGV	Inlet guide vanes
M_{air}	Flow rate of air

M_{coal}	Coal flow rate
M_{Dry}	Flow rate of dried coal out of CD26
M_{Fuel}	Fuel flow rate
M_{Total}	Total coal flow rate (wet and dried) to the boiler
M_{Wet}	Flow rate of wet coal to the boiler
MAF	Moisture-and-ash-free
N	Number of independent tests (observations)
NDIC	North Dakota Industrial Commission
Nm^3	Normal cubic meter
NO_x	Nitrous oxide
P	Pressure or power
PA	Primary air
P_G, P_g	Gross unit power output
P_{PA}	PA fan power
P_{ss}	Station service power
Q_1	Heat input to the coal dryer
Q_2	Required heat input to the coal dryer
$Q_{Circulating\ water}$	Heat supplied to the in-bed heat exchanger
$Q_{Coal\ sensitive}$	Sensitive heat input with coal
Q_{air}	Heat input with air stream
Q_{evap}	Fuel moisture evaporation loss
Q_{fuel}, Q_{Fuel}	Heat input with fuel
Q_{loss}	Boiler heat loss
Q_{stack}	Dry gas stack loss
Q_T	Thermal energy transferred to the working fluid in the boiler
$Q_{T,Wet}$	Thermal energy transferred to the working fluid in the boiler – wet coal
$Q_{T,Dry}$	Thermal energy transferred to the working fluid in the boiler – dry coal
RE	Random error (test uncertainty)
S	Best estimate of standard deviation
SA	Secondary air
SO_2	Sulfur dioxide

SO_3	Sulfur trioxide
SO_x	SO_2 and SO_3
t	Student (W. Gosset) variable
T_{coil}	Surface temperature of the in-bed heat exchanger
$T_{coil,avg}$	Average surface temperature of the in-bed heat exchanger
$T_{FA,in}$	Temperature of fluidization air into the coal dryer
TM	Total coal moisture (moisture in coal and coal ash)
VSD	Variable speed drive
WC	Wet coal
X_{Blend}	Composition or HHV of blended coal
X_{Dry}	Composition or HHV of dried coal out of CD26
X_{Wet}	Composition or HHV of wet coal to the boiler
σ	Standard deviation
η_B	Boiler efficiency
Δ	Difference or change
ΔHR_{net}	Change in net unit heat rate
ΔP	Differential pressure or pressure loss
$\Delta\eta_B$	Change in boiler efficiency
$\Delta\eta_{B,TOT}$	Total change in boiler efficiency

Dendy, Lewis H.

From: Nelson, Debra GRE/MG [dnelson@grenergy.com]
Sent: Friday, August 08, 2008 3:19 PM
To: Dendy, Lewis H.
Cc: Roth, Mary Jo GRE/MG; Stockdill, Diane GRE/CCS
Subject: RE: Coal Creek BART proposal
Attachments: BART NH4 in Ash.doc

Lew,
Here is our response to Mr. Shepherds inquiries about ammonia in fly ash.

Thank you.

Deb Nelson
Environmental Services
Great River Energy
(763)445-5208
dnelson@grenergy.com

Response to question about ammonia in fly ash

Currently Coal Creek Station fly ash is highly desirable due to the physical and chemical characteristics which enable it to create high quality concrete. The ASTM standard states the purchaser shall specify any supplementary optional physical requirements. Due to the odoriferous nature of ammoniated ash it is a characteristic likely to be limited in purchase orders. Ash with high levels of ammonia is less desirable by concrete manufacturers due to the strong odor released from the ammoniated ash. Ammonia release from ash impacts ambient air quality and indoor air quality or presents a direct exposure hazard. Fly ash will emit ammonia as the ash is transferred, transported or mixed and concrete will emit ammonia – as the ammonia "off-gases" or volatilizes when the fly ash is transferred, transported, or mixed for concrete. Tests conducted under DOE funding suggest that the ammonia loss in concrete occurs in two phases: first a rapid initial release within 24 hrs.; then a slower linear release rate – which occurred throughout the 3 week test period. Based on the measurements and calculations it was determined that over 80% of the ammonia remained in the concrete at the conclusion of the test period. This leaves a potential for ammonia release during future rainfall events when the water volatilizes the ammonia. This could be very hazardous in occupied spaces. [See the exposure description below.] The study does not encourage the use of ammoniated ash, but recommends that ammonia concentration in fly ash be kept below 100 mg/kg for concrete used in enclosed spaces and below 200 mg/kg for concrete used in other applications.

Ammonia is considered a toxic air pollutant by the environmental and health regulatory agencies in North Dakota, Minnesota, and other surrounding states for which the ammoniated ash would be handled and processed. In North Dakota, the Department of Health's Air Toxics Policy establishes acute health risk standards. The ambient ammonia concentration thresholds are 0.49 mg/m^3 (0.66 ppm) on a 1-hour average and 0.35 mg/m^3 (0.47 ppm) on an 8-hour average. Any concentration above these levels would exceed the State's acceptable level of non-carcinogenic risk.

Ammonia is considered an upper respiratory irritant for inhalation health effects. The EPA's Integrated Risk Information System (IRIS) has a reference concentration (RfC) of 0.1 mg/m^3 (0.14 ppm) for acute exposure to ammonia, and the Occupational Safety and Health Administration (OSHA) has set an 8-hour exposure limit of 25 ppm and a 15-minute exposure limit of 35 ppm.

A majority of the Coal Creek Station market resides in the upper Midwest. Fly ash created during the off season for construction is either used in internal enclosed applications or is stored (e.g. pre-cast concrete blocks or panels). The storage and transfer of ammoniated ash in enclosed facilities could have the potential to produce high concentrations of ammonia in the occupied buildings. In an example from an Electric Power Research Institute paper, if the assumption is made that fly ash contains 100 ppm by weight of ammonia, then one ton of fly ash, evolving all of the ammonia present, can produce 90,000 cubic feet of air (at 68 F, 1 atm) that contains 50 ppmv of ammonia (the upper odor threshold). When given the option concrete manufacturers will purchase a non ammoniated ash over the ammoniated ash due to the odor produced when mixing and pouring the concrete.

In addition to the stated health risk criteria, ammonia is a highly odoriferous compound that is regulated by many localities and states, including in North Dakota (see NDCC 23-25-11). Of particular concern is the risk of odors that disperse to nearby locations off-site from Coal Creek Station. Blue Flint Ethanol is located next to Coal Creek Station, and their property is located 850 feet from the fly ash dome and related ash handling activities. Volatilized ammonia represents an odor and health concern at areas proximate to the plant and at endpoint locations where the ash/cement is used. These risks would need to be better understood and addressed before the ash, as modified, is beneficially used for high quality concrete rather than go to a landfill or other disposition.

Dendy, Lewis H.

From: Nelson, Debra GRE/MG [dnelson@grenergy.com]
Sent: Wednesday, September 17, 2008 2:22 PM
To: Dendy, Lewis H.
Cc: Roth, Mary Jo GRE/MG; Stockdill, Diane GRE/CCS
Subject: Additional Information on Ammonia in Fly Ash

Lew,

Great River Energy respectfully submits the following text in response to your request for additional information on the concentration of ammonia in fly ash during the August 21, 2008 conference call. A review of the papers and studies completed on ammoniated ash from two of the top electric power research organizations in the US (EPRI and UND-EERC) found that very little if any work has been completed to date with respect to lignite coal combustion and SCR or SNCR NO_X control equipment. GRE made direct requests of individuals in charge of research in this area. Several studies have been conducted but at least one was inconclusive for lignite fly ash. The SCR catalyst research included in the original Coal Creek Station BART analysis in Appendix G had conclusive information about SCR use with lignite coal combustion but only evaluated the performance of the SCR catalyst and mercury ionization. It did not include an analysis of the ammonia in the ash. One other study by EERC was evaluating the leaching of specific constituents in ammoniated fly ash but the results were not conclusive for ND lignite since the method used to ammoniate the fly ash was unsuccessful. Additional studies were not discovered. Predicting the ammonia in ash is extremely difficult due to the many factors influencing the adsorption and deposition of ammonia in fly ash. Some of the factors include coal processing – fineness, coal heating value, ash mineral composition, ammonia slip, and other boiler settings responsible for influencing the formation of SO_3 in the flue gas. For example, SO_3 production promotes the formation of ammonium sulfates driving the ammonia toward fly ash deposition; therefore any plant operating conditions which influence SO_3 production would also influence the adsorption and deposition of ammonia in fly ash. Each of these physical and combustion characteristics is very different between the various ranks of coals. One study illustrated the variability of ammonia adsorption throughout an ESP with concentrations ranging from 51 ppm_w to 740 ppm_w. (This test used a 4 ppm_w injection rate for ammonia and also has SO_3 injection.) The same study also found the ammonia concentration variability within an ESP to range from 3 ppm_w to 30 ppm_w from another SCR controlled unit. Both tests were conducted at facilities burning eastern bituminous coal. This specific example illustrates the site specific qualities associated with ammonia injection pollution control technology.

If you require further information please feel free to give me a call. Thank you.

Deb Nelson
Environmental Services
Great River Energy
(763)445-5208
dnelson@grenergy.com

ENVIRONMENTAL & COAL TECHNOLOGY

PROJECT FACTS

UNIVERSITY OF KENTUCKY
CENTER FOR APPLIED ENERGY RESEARCH

AMMONIATED FLY ASH

Objective

The goal of this project was to develop practical guidelines for handling and using ammoniated fly ash in concrete, in order to prevent a decrease in the use of fly ash for this application. The objective was to determine the amount of ammonia that is released, over the short- and long-term, from concrete that contains ammoniated fly ash.

Background

The Clean Air Act Amendments of 1990 require large reductions in NO_x emissions from coal-fired electric utility boilers. This will require ammonia injection, such as in selective catalytic reduction (SCR), in many power plants, resulting in ammonia deposition on fly ash. The presence of ammonia could create a barrier to fly ash utilization in concrete because of odor concerns. Although there have been limited studies of ammonia emission from concrete, little is known about the quantity of ammonia emitted during mixing and curing, and the kinetics of ammonia release. This is manifested as widely varying opinions within the concrete and ash marketing industry regarding the maximum acceptable levels of ammonia in fly ash. Therefore, practical guidelines for using ammoniated fly ash are needed in advance of the installation of many more SCR systems.

Conclusion

Ammonia release from mortar and concrete during mixing, placement, and curing was measured. Short-term levels in the air were found to be noticeable; however longterm effects were minimal. Work initially focused on laboratory mortar experiments to develop fundamental data on ammonia diffusion characteristics. Larger-scale laboratory experiments were then conducted to study ammonia emission from concrete containing ammoniated fly ash. The final phase comprised monitoring ammonia emissions from large concrete slabs. The data indicated that only 10 - 20% of the initial ammonia diffused from the concrete during 30-40 minutes of mixing, depending on the mix proportions and batch size. When placing concrete in an enclosed space, with negligible ventilation, it is recommended that the ammonia concentration in the concrete mix water should not exceed 110 mg NH_3/L, if the NIOSH exposure limit of 25 ppm in the air is not to be exceeded. If even a modicum of ventilation is present, then the maximum ammonia concentration in the concrete water would be approximately 170 mg/L. Long-term experiments indicated that ammonia diffusion from concrete was relatively slow, with greater than 50% of the initial ammonia content remaining in a concrete slab after 1 month. In general, during the mixing and placement of ammonia-laden concrete, no safety concerns were encountered. After one to two days, the ammonia level decreases to a point where it cannot be smelled. The only location where the ammonia concentration attained high levels (i.e. > 25 ppm in the air) was within the concrete mixing drum.

These findings are being distributed throughout the industry. The other project participants represent some of the country's largest ash marketers and a major utility; and will include these recommendations during interactions with cement companies. It is further hoped that the information will be used to adopt standards for use of ammoniated fly ash.

PARTICIPANTS

University of Kentucky
Center for Applied Energy Research
Boral Material Techn.
ISG Resources
LaFarge North America
Southern Company Serv.

SPONSORS

US Department of Energy

PROJECT VALUE

DOE Cost: $149,815
Prime Contractor Cost Share: $90,511
Partner Cost Share: $60,000

CONTACT

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GREAT RIVER
ENERGY℠

February 9, 2010

Lewis Dendy
North Dakota Department of Health
Division of Air Quality
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Dear Lew,

Great River Energy (GRE) respectfully submits our response to questions raised by US EPA concerning ammonia in fly ash relevant to our Coal Creek Station (CCS). To address the issues raised by Amy Platt of US EPA in a November 30, 2009 email message to Tom Bachman of NDDH, GRE provides the following responses:

1. Response to Amy Platt's email
2. Fly Ash usage and properties

Response to Amy Platt's email

Amy Platt's email references Dynegy's Baldwin Energy Complex and Progress Energy's Roxboro Generating Station as facilities that have post combustion NOx control and market their fly ash. Both facilities have Selective Catalytic Reduction (SCR) installed, not Selective Non-Catalytic Reduction (SNCR) technology. It is typical for SCR technology to operate with lower ammonia injection and slippage rates than comparable SNCR technology. With SCR technology additional mixing and chemical reaction assistance is introduced in the catalyst packing resulting in reduction in NOx emissions. SNCR technologies require additional ammonia injection to ensure contact with the NO_X molecules in the flue gas, as they do not benefit from additional mixing or the benefit of enhanced chemical reactions provided by the catalyst packing. Headwaters Resources, GRE's fly ash marketer, on average sees ammonia content in ash from 200-600 ppm for SNCR units and from 50-400 ppm for SCR units. *See Attachment 3 section.*

Dynegy's 1,800 MW Baldwin Energy Complex has 3 units burning Powder River Basin (PRB) coal. Two of the units have SCR installed, the third unit has no post-combustion NO_X control technology. Headwaters Resources, GRE's fly ash marketer, is also the ash marketer for the Baldwin Energy Complex. Headwaters only markets ash from the one pulverized coal unit that does not have either SCR or SNCR installed and therefore the ash sold does not contain ammonia. Please see attached letter from Herbert Moeckel of Headwaters Resources. *In Attachments 1 section*.

Currently there are no installations of SCR or SNCR burning North Dakota Fort Union lignite. As GRE does not have any data or experience with ammoniated ash we have asked our fly ash marketer, Headwaters Resources, to respond to Amy Platt's chemistry statement that alkaline ashes experience lower uptake of ammonia. Headwaters has extensive experience with ammoniated ash and they have observed higher ammonia odor emissions from a plant (East Lake Plant, OH) producing a higher alkaline ash. The mechanism for this higher evolution of ammonia has not been identified and is currently being investigated. *See email thread of December 29, 2009-in Attachment 2 section.* Without empirical evidence on uptake of ammonia on ash from ND lignite GRE cannot assume ammonia slippage rates or retention rates on fly ash. We have also presented the question about expected ammonia in ash for lignite units to Tony Facchiano, Sr. Program Manager at the Electric Power Research Institute (EPRI) and although they have done work for other types of coal they have not conducted research with ND lignite and would not be able to correlate the ammonia in ash with ammonia slip at this time.

As there are no data from Fort Union lignite on SNCR ammonia retention in ash we have provided testimony from GRE customers. As noted by our customers, ammonia-impregnated ash would have an economic impact not only on GRE but also to our marketers who sell the ash. *See enclosures from Lafarge and GCC of America in the Attachment 1 section.*

Fly Ash

Fly ash for use in concrete is classified in 3 classes: Class N – raw or calcined natural pozzolans that comply with ASTM C618-08; Class F - typically produced from burning anthracite or bituminous coal, but lignite also; Class C – typically produced from burning lignite's, but may also be produced from burning anthracite or bituminous coal as long as the total calcium contents are higher than 10% and the ash has some cementitious properties. CCS ash is classified as a Class F ash. Introduction of ammonia will not affect the class of our fly ash but will decrease the desirability and thus the marketability of our ash if the customer perceives a health risk or is able to procure the same material without the objectionable qualities.

The original investments made in the infrastructure for the marketing of fly ash was predicated on the fact that CCS is a mine mouth plant with a consistent coal source which is producing a high quality fly ash which is very desirable in the concrete market. The introduction of undesirable characteristics into the fly ash, such as an odor or inhalation risk, will force our concrete customers to pursue alternate marketers for their feedstock. *See testimonials from Headwaters Resouces, Lafarge, and GCC in the Attachments 1 section.*

Please contact me at 763-445-5208 regarding any questions or comments.

Sincerely,

GREAT RIVER ENERGY

Debra Nelson

Debra Nelson

c: Diane Stockdill
File

Attachment 1: Testimonials

HEADWATERS
RESOURCES

Adding Value to Energy

January 28, 2010

Mr. Al Christianson
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Dear Mr. Christianson:

I am writing in regards to the Dynegy Midwest Generation – Baldwin Energy Complex located in Baldwin, Illinois. Headwaters Resources is the marketing company for all five Dynegy Midwest Generation plants located in Illinois.

The Baldwin Energy Complex is composed of three – 600 MW units, totaling 1800 MW. Units 1 and 2 are cyclone fired boilers and Unit 3 is a pulverized coal boiler, all three units are burning PRB coal. Units 1 and 2 are equipped / operating with an SCR and Unit 3 has neither a SCR or SNCR installed.

Headwaters Resources has mainly marketed the cyclone boiler fly ash produced from Units 1 and 2 into the cement industry as a raw feed ingredient since 1998. Since 2000, we were able to market approximately 17,000 tons of this material into "flowable fill" on a few mine subsidence projects in the East St. Louis, Illinois area. We have performed ammonia testing on the fly ash produced from Unit 1 and 2 utilizing the Headwaters SOP using dragger tubes. This material fluctuates between 35 and 125 ppm ammonia in the fly ash. The ammonia odor was noticeable when used on the flowable fill mixes which contained high volumes of fly ash per yard. The ammonia odor did not have an impact on our sales agreement with Buzzi Unicem, since they were using the material as a raw feed ingredient in the production of cement. Starting in July 2009 new mercury regulation forced the power stations in Illinois to use activated carbon injection to reduce mercury emissions. Units 1 and 2 did begin activated carbon injection in July 2009 at which time the material was no longer allowed to be used in the production of cement. At this time 100% of the fly ash material produced from these units is being disposed of in an on site impoundment. Dynegy is constructing SDA scrubbers which should be complete by 2013, at which time the injection point of the activated carbon will be moved allowing the use of the fly ash material in cement production. The fly ash produced from these two units is not suitable for use in concrete.

Unit 3 at the Baldwin Energy Complex was granted a temporary variance which did not force this unit to inject activated carbon until the SDA / Bag house is operational at the end of 2010. Headwaters Resources has marketed the ASTM C618 Class C fly ash produced from unit 3 into ready mix concrete, concrete paving, and soil stabilization since 1998.

Please feel free to contact me at 612-963-7093 regarding any questions or comments.

Respectfully

Herbert Moeckel
Technical Sales Representative
Headwaters Resources
P.O. Box 566
Osage Beach, MO 65065
P: 612-963-7093
F: 866-449-8130

GCC
of America

January 21, 2010

Mr. Al Christianson
GREnergy
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Al,

We would like to take this opportunity to express concern about GRE's potential injection of ammonia into the flue gas during coal burning operations as an effort to reduce NOx emissions. As a wholesale marketer and end-user of your fly ash from the Coal Creek facility in North Dakota, our concern surrounds the impact this process will have on the fly ash when used in concrete.

The ammonia in fly ash is not present as ammonia gas. Rather, it is in the fly ash as ammonium sulfate. Once in the high alkaline environment of concrete the ammonia is released. This becomes a problem because of the odor, especially in enclosed spaces such as residential basements. The smell of ammonia is objectionable and would potentially impact external fly ash sales for GCC of America and internal use in the concrete operations owned by GCC Ready Mix..

Our professional experience with this situation in the past had been limited to the senses, i.e. eye and nose irritation and unpleasant odor. The corrective action taken was at the expense of the concrete producer, causing those customers to do business elsewhere.

We value our relationship with your company and prefer to use your product because of its quality and performance. Please do not allow these attributes to be compromised. If you should have any questions, or if we may be of further assistance, please contact either of us our Denver offices at (303) 739-5900.

Sincerely,

Joe Finnegan

Mark R. Lukkarila,
Technical Services Manager
GCC of America

Joseph E. Finnegan,
Regional Sale Manager
GCC of America

Building Together

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HEADWATERS
RESOURCES

Adding Value to Energy™

January 11, 2010

Mr. Al Christianson
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Dear Mr. Christianson:

The Eastlake power plant in Eastlake, Ohio had a SNCR installed over 2 years ago. Prior to the installation the plant produced a high quality F-ash which was sold out every year during the construction season. The ammonia level was between 200-400 PPM after the installation which was when the problems started. Anything over 100 PPM seemed to be a noticeable at this plant.

We started shipping the material when it was in the 100-200 PPM range and the customers, batch plants and several contractors started calling with complaints especially in confined spaces such as buildings and basements. In one case a Ready Mix plant employee stuck his head in the back of the truck to add air entraining agent and it burned his eyes. He spent the night in the emergency room getting his eyes washed out not knowing it was the fly ash causing the ammonia smell.

We quit shipping anything over 100 PPM and business started dropping off; contractors did not want fly ash in their mixes. Since you're only checking a small amount of ammonia in the load it would test for less than 100 PPM but in some cases the Ready Mix producer still had problems which indicated the entire load was not less than 100 PPM. We shut down a block plant and the customer made us take the fly ash out of his silo and he quit buying fly ash from us.

Bill Newkirk

Bill Newkirk
Headwaters Resources
Technical Sales Rep
440-725-0088

2761 Port Neal Circle
Salix, IA 51052
P: 712.943.4049 F: 712.943.2876

LAFARGE
NORTH AMERICA

Cement

January 26, 2010

Mr. Al Christianson
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Subject: Ammonia Injection in Fly Ash

Lafarge has used fly ash from power sources where SNCR ammonia injection units have been installed. We have found that when the ammonia levels exceed 40 parts per million in the fly ash that the consumer notices the ammonia and find it to be objectionable.

Lafarge is concerned that if ammonia injection units are installed at Great River Energy's Coal Creek Station it may cause the fly ash that is produced to be unmarketable. Lafarge currently purchases a large percentage of the fly ash that is produced at this station and would be placed at an economic disadvantage if we were no longer able to market this high quality ash to our ready mix customers.

This would cause our customers in turn to be at an economic disadvantage if they had to use fly ash from another source that is further away or use slag cement that perhaps would be more expensive than Coal Creek ash.

Roy V. Sander, Jr

Roy Sander/General Manager

LAFARGE Dakota.
684 15th Ave. SW. PO Box 757, Valley City, ND 58072
Telephone: (701) 845-2421 Fax: (701) 845-1849 Toll Free: 1-800-533-8662

Attachment 2: Email Thread Headwater to GRE

From: Stockdill, Diane GRE-CC
Sent: Tuesday, December 29, 2009 3:38 PM
To: Nelson, Debra GRE-MG
Subject: FW: Where are we at?
Attachments: STI ammonia removal.pdf

Let's talk tomorrow

-----Original Message-----
From: Christianson, Al GRE-BI
Sent: Tuesday, December 29, 2009 3:35 PM
To: Stockdill, Diane GRE-CC
Subject: FW: Where are we at?

Fyi, they are working on it. al

Al Christianson
Manager, North Dakota Business Development & Governmental Affairs
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Bismarck, ND 58503
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701-442-7664 Direct
701-220-4881 Cell
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achristianson@grenergy.com
www.greatriverenergy.com

-----Original Message-----
From: Jerry Smith [mailto:jsmith@headwaters.com]
Sent: Tuesday, December 29, 2009 3:34 PM
To: Christianson, Al GRE-BI
Subject: FW: Where are we at?

Al: Attached is Bruce's response to your latest inquiry. It appears that we are still waiting on Mr. O'Conner (EPRI) to review our data on Sammis and East Lake ash. The attached brochure from STI may be helpful in the comparison of SNCRs and SCRs in regard to ammonia being introduced into the ash. I don't know if this is sufficient for your needs. If not, I suggest that we (Diane, you, and I) get on a conference call with Bruce to discuss what else we may be able to provide. Just let me know. Thanks.

____

From: Bruce Boggs
Sent: Tuesday, December 29, 2009 2:35 PM
To: Jerry Smith
Subject: RE: Where are we at?

Jerry,

There was no official document generated by EPRI to circulate on this issue. The curious finding that the more alkaline ashes had higher ammonia odor emissions was reported to EPRI but the reason for the finding was never identified. Dave O'Connor at EPRI will review our data showing the data on Sammis and East Lake comparisons.
The data from our East Lake plant with SNCR and higher alkaline ash should be available shortly to compare with the much lower levels of ammonia from an SNCR associated with low alkalinity ash at Sammis.

STI found it necessary to develop an ammonia removal/treatment system in addition to the carbon removal system they operate at several locations. I do not know if the Roxboro plant uses this system but I would point out that with the storage dome at Coal Creek, the ammonia levels that could accumulate would be extremely hazardous. A little know fact is that ammonia is an explosive gas at certain levels when it accumulates with air present. See attached STI brochure on ammonia removal. In that brochure they support the fact that SNCR units will introduce much more ammonia to the ash than SCRs but both can prevent ash from being used in the market.

Bruce

From: Jerry Smith
Sent: Tuesday, December 29, 2009 2:46 PM
To: Bruce Boggs
Subject: FW: Where are we at?

Bruce: Please see Al's and Diane's comments below. Have we heard anything from EPRI on this issue? Thanks.

From: Christianson, Al GRE-BI [AChristianson@GREnergy.com]
Sent: Tuesday, December 29, 2009 1:22 PM
To: Jerry Smith
Subject: FW: Where are we at?

Anything new, people want to know?

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www.greatriverenergy.com<http://www.greatriverenergy.com>

From: Stockdill, Diane GRE-CC
Sent: Tuesday, December 29, 2009 1:15 PM
To: Christianson, Al GRE-BI

Subject: Where are we at?

Where is Headwaters at on the SNCR justification documentation? I saw the waiting for EPRI response but when do they plan on having something to us?

Attachment 3: Headwaters information on SCR vs. SNCR

Ammonia Contamination Levels

Air Pollution Control Process	NH_3 “Slip” ppm_v	NH_3 in Ash mg/kg
SCR	2 to 10	50 to 400
SNCR	5 to 20	200 to 600
SO_3 Control	10 to 20	300 to 600
ESP Conditioning	20 to 30	600 to 1200

Actual ammonia concentrations will depend on ammonia injection rates, coal type, sulfur content, and other operating parameters.

GREAT RIVER
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Stanton Station Unit 1

Best Available Retrofit Technology Analysis

Revised January, 2008

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Executive Summary

This report describes the background and methods for the selection of the Best Available Retrofit Technology (BART) as proposed by Great River Energy (GRE) for the Stanton Station located in Stanton, ND. Stanton Station's BART eligible Unit 1 is a front-wall fired boiler that started operation in 1966. The boiler is currently permitted to burn both Lignite and Powder River Basin (PRB) coal. Stanton Station has one turbine with a capacity of up to 188 megawatts. Preliminary visibility modeling conducted by the North Dakota Department of Health (NDDH) found that the Stanton Station emissions 'cause or contribute to visibility impairment' in a federally protected Class 1 area, therefore making the facility subject to BART.

Guidelines included in 40 CFR §51 Appendix Y were used to determine BART for Unit 1. The existing pollution control equipment includes an ESP for particulate matter and low NOx burners (LNB) for NOx control. The CALMET/CALPUFF/CALBART dispersion modeling sequence was used to assess the post-BART visibility impacts associated with the proposed BART emission limits.

Stanton Station is currently permitted to burn either Lignite or Powder River Basin (PRB) coal. The BART analysis was originally premised on Lignite as a worse case fuel. At the request of NDDH, GRE includes PRB as an operational control that is evaluated in conjunction with traditional controls. Great River Energy intends to burn a single fuel on an annual basis. Therefore, the BART controls and corresponding emission rates are determined to be fuel specific without consideration for blending. Based on the results of visibility modeling, economic impacts analyses and consideration for other non-air quality energy and environmental factors, GRE establishes the following as BART:

- For Particulate matter (PM), the BART emission limit is 0.1 lb/MMBtu based upon the existing ESP. Additional PM controls, including condensable PM (CPM) controls, would provide insignificant visibility improvement and require significant capital expenditures. Therefore, the current PM performance standard of 0.1 lb/MMBtu is considered BART for either Lignite or PRB.

- Overfire air (OFA) and Low NOx Burners (LNB) is considered BART to control NOx with a proposed 30-day rolling emission rate of 0.35 lb/MMBtu under normal operational conditions on either fuel.

- SO_2 emissions will be reduced using a non-specific dry scrubbing technology. The scrubber is being designed to achieve 90% removal with a proposed BART limit of 0.24 lb/MMBtu on a 30-day rolling basis for Lignite fuel. Stanton Station is also permitted to burn Powder River Basin (PRB) coal, which is currently a lower sulfur fuel. As discussed in Section 5, Dry Sorbent Injection (DSI) with the existing ESP is considered BART for PRB with a corresponding 30-day rolling emission rate of 0.36 lb/MMBtu.

BART Emission Limits

Pollutant	Existing Permit Limit	BART Limit
PM_{10}	0.10 lb/MMBtu	0.10 lb/MMBtu
NOx	0.46 lb/MMBtu	0.35 lb/MMBtu
SO_2 Lignite	3.0 lb/MMBtu	0.24 lb/MMBtu
SO_2 PRB	3.0 lb/MMBtu	0.36 lb/MMBtu

The proposed BART controls will result in visibility improvements of 60% to 70% for both the 90th and 98th percentile comparisons. According to Pre-BART modeling, Unit 1 is estimated to contribute 1.675 Δ-dV to background at Theodore Roosevelt National Park's (TRNP) South unit in the year 2002, which is the worst case meteorological conditions of the baseline years, with 29 days above 0.5 Δ-dV. Modeling with the proposed BART controls for TRNP South shows an improvement of 1.0 Δ-dV, or a contribution of only 0.666 Δ-dV above background, with 13 days above 0.5 Δ-dV. These reductions represent a significant improvement to assist the state in meeting its reasonable progress goals.

Additional Considerations and Associated Potential Reductions

Great River Energy is evaluating other generation options at Stanton Station including the installation of a new clean coal technology (i.e., integrated gasification combined cycle (IGCC) system capable of carbon capture and sequestration (CCS). If installed, IGCC would allow for either early Unit 1 retirement or significantly reduced utilization while IGCC is brought on-line. The current BART economic evaluations assume at least 20 years of capital depreciation levelized across projected pollution reductions. Clearly, Unit 1 early retirement would completely affect the BART cost effectiveness determinations contained in this evaluation.

Based on our conversations with the NDDH staff on October 31, 2007, the installation of a 'clean coal technology' will require additional air permitting in which proposed BART controls could be re-evaluated in light of lesser Unit 1 utilization. Obviously, Unit 1 retirement in support of a 'clean coal technology' would need to provide comparable, if not greater, visibility improvements. Great River Energy will need to commit to either the IGCC technology or spray dry baghouse technology well in advance of applicable BART requirements in 2013.

If Great River Energy does not pursue a clean coal alternative generation project, the spray dry baghouse will be installed to cover the range of fuels permitted at Stanton at $79 million in 2005 dollars. Even though BART is considered DSI with existing ESP for PRB, Great River Energy would offer additional reductions with construction of the spray dry baghouse and comply with 0.15 lb/MMBtu SO_2 emission limit on a 30-day rolling basis for PRB. This emission rate is inclusive of both the expected dry scrubbing effectiveness with baghouse and the PRB sulfur ranges discussed in Appendix E. Further, with respect to PM emissions based on installation of a baghouse, Great River Energy would offer additional reductions, and comply with a 0.07 lb/MMBtu or 0.05 lb/MMBtu emission rate, for Lignite and PRB, respectively. These additional particulate reductions incorporate the relative ash differences between the fuels and additional particulate control provided by the baghouse.

Stanton Station Unit 1- Additional Reductions to Support Visibility Improvements

Pollutant	Permit Limit	Alternative Lower Limit
PM_{10} Lignite	0.10 lb/MMBtu	0.07 lb/MMBtu
PM_{10} PRB		0.05 lb/MMBtu
NOx	0.46 lb/MMBtu	0.35 lb/MMBtu
SO_2 Lignite	3.0 lb/MMBtu	0.24 lb/MMBtu
SO_2 PRB	3.0 lb/MMBtu	0.15 lb/MMBtu

For reasonable glide path modeling, NDDH can choose to use the higher values between projected PRB and Lignite emission rates rather than the BART emission rates. For PM, this would mean a 0.07 lb/MMBtu emission rate based on lignite. The additional PM reduction does not provide a significant modeled improvement as discussed in Section 7. For SO_2, the modeling value is 0.29 lb/MMBtu, which is based upon the 30-rolling limit of 0.24 lb/MMBtu, as a worse case, 24-hr maximum value. For NOx, there is no proposed difference between BART controls for the permitted fuels at a 30 day rolling emission rate of 0.35 lb/MMBtu. Consequently, the modeled value is 665.3 lb/hr as a 24-hr maximum. The most favorable combined effect of all proposed additional reductions results in an average incremental improvement of only ~ 0.1 dV.

1.0 Introduction

On July 15, 2005, the U.S. Environmental Protection Agency (EPA) published the final rules for regional haze and best available retrofit technology (BART). The BART rules[1], originally promulgated in September 1999, were in effect as of September 6, 2005.

The rules require that each state develop a Regional-Haze State Implementation Plan (RH SIP) to improve visibility impairment in federally-protected national parks and wilderness areas (Class I areas). The SIP must require BART on all BART-eligible sources and mandate a plan to achieve natural background visibility by 2064. Figure 1-1 illustrates the 6 BART eligible units and 4 Class 1 areas in North Dakota. Each state must submit an RH SIP by December 17, 2007 that includes milestones for establishing reasonable progress towards the visibility improvement goals, and plans for the first five-year period. Upon submission of the SIP, states must make the requirements for BART sources enforceable through rules, administrative orders or Title V permit amendments.

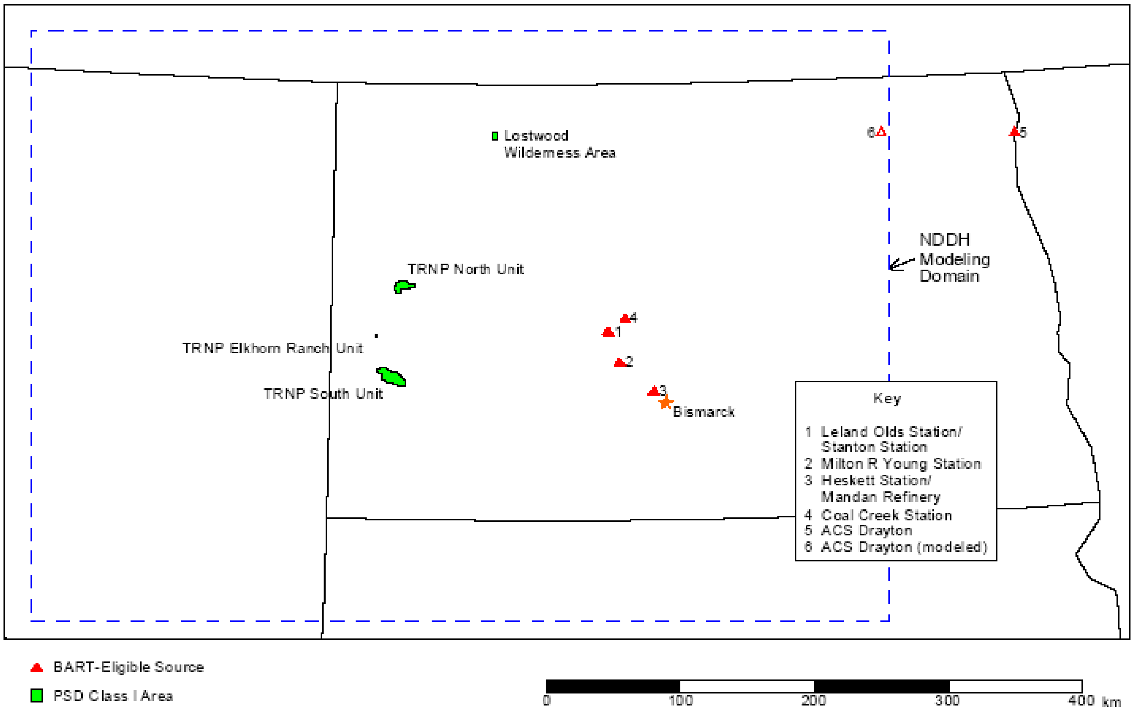

Figure 1-1 North Dakota's BART Geography: The North Dakota SIP will address the 4 PSD Class I Areas and 6 BART Eligible Units illustrated above. (Source *Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota, Final version)*

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[1] 40 CFR §51 and Clean Air Act §169A and 169B

By definition, reasonable progress means that the 20 best-visibility days must get no worse, and the 20 worst-visibility days must become as good as the 20 worst days under natural conditions. Assuming a uniform rate of progress, the default glide path, as illustrated in Figure 1-2, would require 1 to 2 percent improvement per year in visibility on the 20 worst days. The state must submit progress reports every five years to establish their advancement toward the Class 1 area natural visibility backgrounds. If a state feels it may be unable to adopt the default glide path, a slower rate of improvement may be proposed on the basis of cost or time required for compliance and non-air quality impacts.

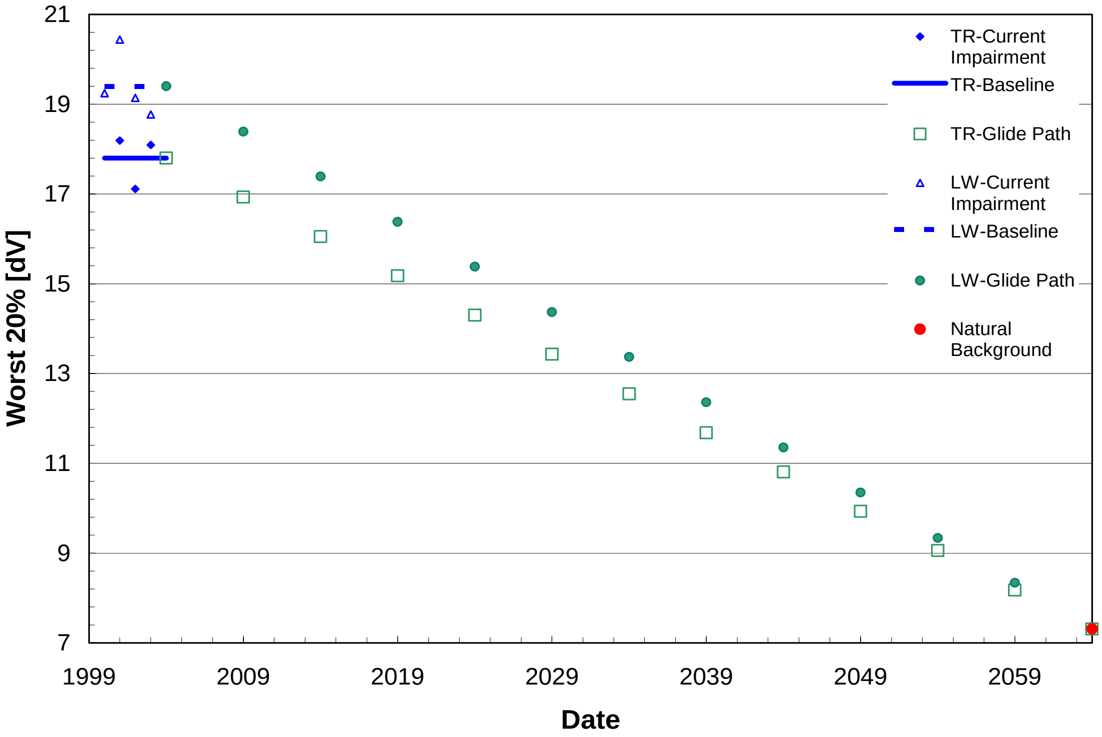

Figure 1-2 Theodore Roosevelt NP and Lostwood WA, ND. Current impairment includes both natural and anthropogenic contributions. (Data from VIEWS database trend analyzer, http://vista.cira.colostate.edu/views/web/AnnualSummaryDev/Trends.aspx DOA 06 Dec 2005)

1.1 BART Eligibility

BART eligibility is established on the basis on 3 criteria. In order to be BART eligible, sources must meet the following three conditions:

1. Contain emission units in one or more of the 26 listed source categories under the PSD rules (e.g., fossil-fuel-fired steam electric plants larger than 250 MMBtu/hr, fossil-fuel boilers larger than 250 MMBtu/hr, petroleum refineries, coal cleaning plants, sulfur recovery plants, etc.)
2. Were in existence on August 7, 1977, but were not in operation before August 7, 1962

3. Have total potential emissions from the emission units meeting the two criteria above greater than 250 tons per year for at least one visibility-impairing pollutant

Under the BART rules, large sources that have previously installed pollution-control equipment required under another standard (e.g., MACT, NSPS and BACT) will be required to conduct visibility analyses. Installation of additional controls may be required to further reduce emissions of visibility impairing pollutants such as PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and possibly VOCs and ammonia. Sources built before the implementation of the Clean Air Act (CAA), which had previously been grandfathered, may also have to conduct such analyses and possibly install controls, even though they have been exempted to date from any other CAA requirements.

Once BART eligibility is determined, a source must then determine if it is ‘subject to BART.’ A source is subject to BART if emissions ‘cause or contribute’ to visibility impairment at any Class I area. Visibility modeling conducted with CALPUFF or another EPA-approved visibility model is necessary to make a definitive visibility impairment determination (>0.5 deciviews). Sources that do not cause or contribute to visibility impairment are exempt from BART requirements, even if they are BART-eligible.

1.2 BART Determinations

Each source that is subject to BART must determine BART on a case-by-case basis. Even if a source was previously part of a group BART determination, individual BART determinations must be made for each source. The BART analysis takes into account six criteria and is analyzed using five steps. The six criteria that comprise the engineering analysis include: the availability of the control technology, existing controls at a facility, the cost of compliance, the remaining useful life of a source, the energy and non-air quality environmental impacts of the technology, and the visibility impacts.[2] The five steps of a BART analysis are:

Step 1 - Identify all Control Technologies
The first step in the analysis is to identify all available retrofit control technologies for each applicable emission unit.

Step 2 - Eliminate Technically Infeasible Options
In the second step, the technical feasibility of each control option identified in step one is evaluated with respect to source-specific factors. Technically infeasible technologies are eliminated from further consideration.

Step 3 - Evaluate Control Effectiveness
In step three, the remaining controls are ranked based on the control efficiency at the expected emission rate (post BART) as compared to the

---

[2] 40 CFR 51 Appendix Y

emission rate before addition of controls (pre-BART) for the pollutant of concern.

Step 4 - *Evaluate Impacts and Document Results*
In the forth step, an engineering analysis documents the impacts of each remaining control technology option. The economic analysis compares dollar per ton of pollutant removed for each technology. In addition it includes incremental dollar per ton cost analysis to illustrate the economic effectiveness of one technology in relation to the others. Finally, Step Four includes an assessment of energy impacts and other non-air quality environmental impacts.

Economic impacts were analyzed using the procedures found in the EPA Air Pollution Control Cost Manual-Sixth Edition (EPA 452/B-02-001). Vendor cost estimates for this project were used when applicable. Equipment cost estimates from the EPA Control Cost Manual or EPA's Air Compliance Advisor (ACA) Air Pollution Control Technology Evaluation Model version 7.5 were used if no vendor data were available. The source of the control equipment cost data are noted in each of the control cost analysis worksheets as found in Appendix A.

Step 5 - *Evaluate Visibility Impacts*
The fifth step requires a modeling analysis conducted with EPA-approved models such as CALPUFF. The modeling protocol[3], including receptor grid, meteorological data, and other factors used for this part of the analysis were provided by the North Dakota Department of Health. The model outputs, including 98th and 90th percentile visibility impairment days are used to establish the degree of improvement that can be reasonably attributed to each technology.

The established BART for Unit 1 was selected based on the results of information obtained in Steps 4 and 5.

---

[3] *Protocol for BART-Related Visibility Modeling Analyses in North Dakota*, Final Version, November, 2005.

2.0 Stanton Station BART Determination

As defined by federal guidance and Section 33-25-25-01 of North Dakota's Air Pollution Control Rules, a source "causes or contributes to visibility impairment" if the 98th percentile of any year's modeling results meets or exceeds the threshold of five-tenths of a deciview (dV) at a Class I area receptor. The pre-BART modeled emission rates for eligible sources represent the highest 24-hour average emissions from the years 2000 through 2002. Pre-BART evaluations conducted by the North Dakota Department of Health using the CALPUFF[3] visibility model identified 6 'subject to BART' sources, including Stanton Station, that cause or contribute to visibility impairment in North Dakota.

Using a streamline method for BART determination, BART eligible sources at Stanton Station can be divided into groups based on function, utilization and actual emissions.

2.1 BART Eligible Units

Great River Energy's (GRE) Stanton Station is located on the bank of the Missouri River near Stanton, ND. Stanton Station has one main turbine generator that is run by Unit 1 and Unit 10. The 'BART Eligible' Unit 1 coal-fired boiler has a dry bottom, front wall fired configuration with ratings of 1,800 MMBtu/hr; or an output of 188 megawatts on PRB. Stanton Station is currently permitted to fire both Lignite and PRB coal. For Unit 1, PM is currently controlled with an electrostatic precipitator (ESP). NOx is controlled with low NOx burners (LNB). There are no post combustion SO_2 controls. The use of two coals with different sulfur contents offers a degree of complexity in terms of SO_2 emissions for Unit 1. To respond to NDDH's request, PRB has been included as an operational control in conjunction with post combustion control technologies. GRE does not intend to blend fuels. Therefore, BART controls and associated limits can be determined based upon each fuel, cost effectiveness and most importantly, expected deciview improvements.

At least three sets of emission parameters must be considered to successfully determine BART. As noted in Table 2-1, the current Title V permitted emission limits represent the maximum allowable emission rates. The baseline actual emissions are derived from historical emissions inventories (2000-2004) and represent the 2 highest years for each pollutant. They are used in comparison with design basis emission rates for potential retrofit technologies as noted in Appendix A. The 'BART Screen' emission rate represents the maximum 24-hour average emission rate, for 2000-2002, and it is used as a baseline for visibility modeling analysis. Table 2-1 describes these three data parameters for Unit 1. It is important to note that Stanton is not categorically subject to presumptive BART limits because Unit 1 has a capacity of less than 200 megawatts and the total facility capacity is less than 750 megawatts. Therefore, the presumptive limits are viewed as guidance levels only.

Table 2-1 Unit 1 Emission Bases

Pollutant	Permit Limit	Baseline Actual	BART Screen	Proposed BART Limit
PM_{10}	0.10 lb/MMBtu	33 lb/hr[4] 0.02 lb/MMBtu	36 lb/hr 0.02 lb/MMBtu	0.10 lb/MMBtu
NOx	0.46 lb/MMBtu	554 lb/hr 0.44 lb/MMBtu	669 lb/hr 0.37 lb/MMBtu[5]	0.35 lb/MMBtu
SO_2 - Lignite	3.0 lb/MMBtu	2,267 lb/hr 1.82 lb/MMBtu	3,420 lb/hr 1.90 lb/MMBtu	0.24 lb/MMBtu
SO_2 PRB	3.0 lb/MMBtu	2,267 lb/hr 1.82 lb/MMBtu	3,420 lb/hr 1.90 lb/MMBtu	0.36 lb/MMBtu

The ‘Baseline Actual’ and ‘BART Screen’ emissions included in Table 2-1 reflect an average utilization of 68% for Unit 1. The swinging of Unit 1 significantly affects NOx emission rates. Under normal station operating conditions, Unit 10 is run at full utilization while Unit 1 varies (swings) to meet Midwest ISO (MISO) power demands. Unit 1 has a wider range than Unit 10 to swing to meet load. Because of this variable load, the lb/MMBtu emission rate may increase over a rolling period, but the overall lb/hr emission rate remains less than what is derived from converting the lb/MMBtu emission rate with the full boiler duty of 1,800 MMBtu/hr. The lb/hr emission rate is arguably a more appropriate metric since it is ultimately used for regional haze modeling. However, since the presumptive levels are expressed in lb/MMBtu units, the proposed BART emission rate is proposed in the same units as 0.35 lb/MMBtu.

The BART analysis, as described in Section 1.2 of this document, will be presented on a pollutant-by-pollutant basis for Unit 1 with the exception of the assessment of visibility impacts for SO_2 and NOx (Step 5). The visibility analysis for SO_2 and NOx was performed using a multi-pollutant approach, and can be found in Section 7.0 of this document. Stanton Station is currently permitted for PRB and Lignite coal.

2.2 Other BART Eligible Units

Other than Unit 1, the remaining BART eligible emission units at Stanton are exempt from BART analysis because they do not cause or contribute to visibility impairment, and are included under one of the following three categories.

i. Additional Capacity

Stanton Unit 10 is a second coal fired boiler with a nominal rating of 642 MMBtu/hr that was operational in 1982. As such, it is not subject to BART. Unit 10 emissions are currently controlled with a spray dry scrubber in

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[4] Emission rate differs from BART screen value due to rounding.

[5] The maximum lb/hr emissions rate was required for pre-BART visibility modeling. The 0.37 lb/MMBtu emission rate was back calculated based on the maximum capacity of 1800 MMBtu/hr.

addition to a baghouse. Emissions from Unit 10 are vented through a common stack with Unit 1.

Given the higher PRB Btu content, Stanton Station has additional steam capacity on this fuel. In addition to evaluating IGCC, Great River Energy is evaluating maximizing generation on Unit 1, which would make Unit 10 available for additional capacity. Obviously, any new generation will require a separate permitting action from the BART analysis.

ii. *Low Utilization Units*

Based on the hours of operation, some emission units can be classified as low emitters. Table 2-2 lists the emergency and auxiliary units at Stanton and their 2005 actual or estimated emissions. Both restricted and limited operation of these units makes additional controls economically infeasible. There would be no measurable visibility improvement associated with installing controls on these low utilization units. No further BART analysis is required.

Table 2-2 Stanton Station Low Utilization Units

Unit Description	Fuel	Maximum Heat Input	Hours of Operation	NOx (tpy)	SO_2 (tpy)	PM (tpy)	PM_{10} (tpy)	Source
Auxiliary Boiler (EUI 3)	No. 2 Fuel Oil	38 MMBtu/hr	93	0.14	0.36	0.01	0.02	2000-2004 averaged actual emissions.
Emergency Diesel Generator (EUI 4)	No. 2 Fuel Oil	10.35 MMBtu/hr	500	8.00	1.30	0.20	0.20	Potential to emit based on 500 hours of operation.[6]
Emergency Fire Pump Engine (EUI 5)	No. 2 Fuel Oil	370 hp	350	1.93	0.13	0.14	0.14	Estimated emission based on 350 hours of operation.[6]

iii. *Material Handling and Fugitive Sources*

All material handling units (EUI M1 through EUI M5 as listed in the Title V Permit), including coal and lime handling operations and fly ash silos, are controlled through the use of fabric filter baghouses. Baghouses are currently recognized as best available control technology (BACT) for PM emitting sources. No further BART analysis is required for emission units employing BACT or equivalent controls.

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[6] Annual emissions are conservatively estimated based on potential to emit at 500 hours per year according to EPA definition for emergency-only generators. The fire pump is restricted to 500 hours per year in the Title V permit. Actual emissions are conservatively estimated at 350 hours per year.

In step three of the BART guidance, the Federal Register[7] states, "Fugitive emissions, to the extent quantifiable, must be counted." The emissions from the coal storage sources listed in Table 2-3 consist of PM only. Because sulfates and nitrates are the primary contributors to visibility impairment, PM sources will not significantly contribute to visibility impairment in Class I areas. The tanks, and other units with no specific permit limits listed below (EUI T1 through EUI T8), are classified as insignificant activities. There would be no measurable visibility improvement associated with installing controls on these sources. For this reason, no further BART analysis is required.

Table 2-3 Stanton Station Fugitive Sources

Fugitive Source/Insignificant Activity Name
FS 1 Active coal storage pile
FS 2 Inactive coal storage pile
T1 and 2 Fuel Oil Storage Tanks (2)
T3 Main Generator Transformer
T4 Spare Main Generator Transformer
T5 Spare Startup Transformer
T6 Sulfuric Acid Storage Tank
T7 Caustic Storage Tank
T8 Turbine Oil Vapor Extractor

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[7] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Rules and Regulations.

3.0 Particulate Matter (PM) BART Analysis

Historical particulate emission tests show that under normal operation, Stanton Station Unit 1 emits PM below the permitted limit. The existing ESP controls filterable particulate at 98% or more.

EPA has interpreted 'total particulate' to include condensable particulate matter (CPM) and NDDH has requested that CPM be addressed as part of the BART analysis. As such, Section 6 provides an estimation of CPM. It concludes that CPM emissions from Unit 1 do not significantly impact visibility impairment and will be reduced by the proposed SO_2 BART controls. Further, pre-BART modeling demonstrates that Unit 1 PM contribution to visibility impairment is negligible in comparison to the impairment attributed to sulfates and nitrates.

As illustrated in Section 7.0, Unit 1 post-BART modeling shows a 1.0 Δ-dV improvement in visibility for the proposed SO_2 and NOx controls as compared to a maximum 0.02 Δ-dV improvement for particulate controls[8]. This incremental improvement is an order of magnitude less than the perceptibility threshold set by EPA. It is statistically insignificant given the uncertainty associated with the modeling. Therefore, additional PM controls are not warranted.

3.1 Identify PM Control Options

Table 3-1 lists the available retrofit PM options for Stanton Unit 1.

Table 3-1 Available PM Control Technologies

PM Control Options
ESP – Current Control
WESP
Mechanical Collector (Multiclone)
Fabric Filter/Baghouse

3.2 Eliminate Infeasible PM Control Options

3.2.1 Electrostatic Precipitator (ESP)

An electrostatic precipitator applies electric forces to separate suspended particles from the flue gas stream. In an ESP, an intense electrostatic field is maintained between high-voltage discharge electrodes, which are typically wires or rigid frames, and grounded collecting electrodes, which are typically plates. A corona discharge from the discharge electrodes ionizes the gas passing through the precipitator, and gas ions subsequently ionize the particles. The electric field drives the negatively charged particles to the collecting electrodes. Periodically, the collecting electrodes are rapped mechanically to dislodge collected particulate

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[8] 98th percentile comparison of modeling results.

matter, which falls into hoppers for removal. Collector dust is removed from the precipitator for disposal or recycling.

ESP control efficiency under normal load conditions is typically in the range of 98% to 99%+. Reduced efficiencies will occur when the inlet particle concentration is low. Outlet particle concentrations can be reduced to as low as 0.005 gr/dscf. The actual outlet concentration will depend on the size range and nature of the particles. An ESP is currently used to control particulate emissions from the Unit 1. According to BART, ESP replacement or modification is technically feasible.

3.2.2 Wet Electrostatic Precipitator (WESP)

A wet electrostatic precipitator operates in the same manner as a dry ESP; it applies electric forces to separate suspended particles from the flue gas stream. In a WESP, an intense electrostatic field is maintained between high-voltage discharge electrodes, which are typically wires or rigid frames, and grounded collecting electrodes, which are typically plates. A corona discharge from the discharge electrodes ionizes the gas passing through the precipitator, and gas ions subsequently ionize the particles. The electric field drives the negatively charged particles to the collecting electrodes. Particle removal in a WESP is accomplished with water sprays instead of mechanical cleaning methods. As a result of using water sprays, WESPs generate wastewater that must be treated to remove suspended particles and dissolved solids.

Since WESPs use electrical forces for particle collection, the electrical properties of the particles can adversely impact WESP operation. Particles with high resistivity may not readily accept an electric charge and will be difficult to collect. Particles with high conductivity or magnetic properties will strongly adhere to the collection plates and be difficult to remove; WESP water sprays may reduce this problem. However, WESP water spray systems will require more maintenance than dry ESP’s in order to keep the water spray system working properly.

WESP control efficiency under normal loading conditions is typically in the range of 98% to 99%+. Reduced efficiencies will occur when the inlet particle concentration is low. Outlet particle concentrations can be reduced to as low as 0.005 gr/dscf. The actual outlet concentration will depend on the size range and nature of the particles. WESP technology has been demonstrated on similar coal-fired boilers. Therefore, replacement of the existing ESP with a WESP is technically feasible as BART for Unit 1.

3.2.3 Mechanical Collector

Cyclone separators are designed to remove particles by inducing a vortex as the gas stream enters the chamber, which causes the exhaust gas stream to flow in a spiral pattern. Centrifugal forces cause the larger particles to concentrate on the outside of the vortex and consequently slide down the outer wall and fall to the bottom of the cyclone, where they are removed. The cleaned gas flows out of the top the cyclone.

There are two principal types of cyclones: tangential entry and axial entry. In tangential entry cyclones, the exhaust gas enters an opening located on the tangent at the top of the unit. In axial flow cyclones, the exhaust gases enter at the middle of one end of a cylinder and flows through vanes that cause the gas to spin. A peripheral stream removes collected particles while the cleaned gas exits at the center of the opposite end of the cylinder.

Overall cyclone control efficiencies range from 50% to 99% with higher efficiencies being achieved with large particles and low efficiencies for smaller particles (< PM_{10}). Mechanical separators are often used upstream of other PM control devices to reduce the loading on the primary control device. This improves overall control efficiency and may reduce the overall cost of the control system when the exhaust is heavily laden with particulate matter.

According to a 2005 report by EPRI[9] on the current controls used for coal-fired power plants, mechanical collectors have only been permitted for use on one similar unit that is not yet operational. Due to the fact that a multiclone has not been successfully demonstrated on a comparable unit, it is a technically infeasible retrofit for Unit 1, and will not be considered further in this analysis.

3.2.4 Fabric Filter/Baghouse

A fabric filter or baghouse consists of a number of fabric bags placed in parallel inside of an enclosure. Particulate matter is collected on the surface of the bags as the gas stream passes through them. The dust cake, which forms on the filter from the collected particulate, can contribute significantly to increasing the collection efficiency.

Two major fabric filter types are the reverse-air fabric filter and the pulse-jet fabric filter. In a reverse-air fabric filter, the flue gas flows upward through the insides of vertical bags that open downward. The particulate matter thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the fabric filter is taken off-line, and the gas flow in this compartment is reversed. This causes the bags to collapse and the collected dust falls from the bags into hoppers. Shaking or other methods are sometimes employed to dislodge the dust from the bags. The cleaning cycle in a reverse-air fabric filter typically lasts about three minutes per compartment. Because reverse-air cleaning is gentle, reverse-air fabric filters typically require a low air-to-cloth ratio of 2 ft/min. In a pulse-jet fabric filter, dirty air flows from the outside of the bags inward, and the bags are mounted on cages to keep them from collapsing. Dust that collects on the outsides of the bags is removed by a reverse pulse of high-pressure air. This cleaning does not require isolation of the bags from the flue gas flow, and thus may be done on-line.

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[9] *Status and Performance of Best Available Control Technologies*, EPRI, Palo Alto, CA: 2005. 1008114

The main operating concern for a baghouse is that its operating temperature is limited by the bag material. Most filter materials are limited to 200ºF – 300º F. Some materials like glass fiber or Nomex may be operated at 400ºF, but are more expensive.

Baghouse control efficiency under normal loading conditions is typically in the range of 98% to 99%+. Reduced efficiencies will occur when the inlet particle concentration is low. Outlet particle concentrations can be as low as 0.005 gr/dscf. However, like ESPs, outlet concentrations will depend on the size range and nature of the particles being filtered. Baghouses are currently considered BACT and are commonly used to control particulate emissions from coal-fired boilers. Therefore, they are technically feasible as BART for Unit 1.

3.3 Evaluate the Effectiveness of Feasible PM Options

Based on the current degree of control being achieved on Unit 1, a new ESP, WESP and baghouse technologies are estimated to reasonably provide a 20% reduction in actual emissions from existing annual average emissions[10]. Table 3-2 describes the expected emissions from each of the three remaining control options.

Table 3-2 Control Effectiveness of Technically Feasible PM Control Options

Control Technology	Expected Control Efficiency[10]	Controlled Emissions lb/MMBtu
Dry ESP	20%	0.015
Polishing WESP	20%	0.015
Baghouse	20%	0.015

3.4 Evaluate the Impacts of Feasible PM Options

As illustrated above in Table 3-2, the three technically feasible options are estimated provide identical degrees of increased control. Therefore, in order to differentiate, the economic and environmental impacts for each are presented below.

3.4.1 Economic Impacts

Each technology is estimated to provide controlled emissions of about 73 tons per year, which is a theoretical 20% (17 ton) improvement from the pre-BART historical baseline. The high cost of PM control retrofits in combination with the small reduction in emissions results in a high dollar per ton cost. Table 3-3 details

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[10] Control efficiency reflects improvement beyond the performance of the existing ESP. Historic particulate performance test results suggest that sampling variability is expected depending on the test method. This indicates that an additional 20% control represents a high performance estimate for potential retrofit controls.

the expected costs associated with each technology based on the EPA cost model and site specific information. Due to site space constraints, the retrofit of PM controls at Stanton Station would require significant additional expenses that were not included in the control cost evaluation below. Therefore, the cost estimates are best case.

Table 3-3 PM Control Cost Summary

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)
Polishing WESP	$6.90	$2.03	$119,268
Baghouse	$33.65	$4.98	$292,702
Dry ESP	$38.57	$5.80	$340,570

Because the technologies provide identical levels of control, an incremental analysis of the costs is not beneficial. All three options require significant capital investments and large increases in expected operation and maintenance costs. The pollution control costs confirm that additional particulate control for Unit 1would involve an unjustified investment for only an estimated 20% reduction in already low particulate emissions. Economically, additional controls are not justified for achieving regional haze visibility improvements.

3.4.2 Energy and Environmental Impacts

Generally, there are no other energy or non-air quality environmental impacts that would discourage the use of a new ESP, WESP or baghouse as BART. For the WESP, however, there are additional waste water environmental impacts that would need to be addressed. All three options would require energy usage comparable to the existing ESP. The flyash systems needed to handle the solid waste generated by particulate controls are already in place at Stanton, but some modification and additional costs could be expected. In short, there are generally no significant energy or environmental impacts that would preclude installation of the feasible PM controls.

3.5 PM Visibility Impacts

Most importantly, the visibility impact analysis demonstrates that additional PM controls provide negligible improvements in the Class 1 areas. Figure 3-1 illustrates the visibility improvement of particulate controls. Reducing PM emissions from the existing permit limit of 0.1 lb/MMBtu to 0.015 lb/MMBtu results in a maximum visibility improvement of only 0.02 Δ-dV or an average visibility improvement of 0.01 Δ-dV. This improvement is completely insignificant in comparison to the improvement attributed to SO_2 and NOx control as illustrated in Section 7.0. It is an order of magnitude less than EPA's perceptibility threshold and is statistically unreliable given the myriad of modeling assumptions and uncertainties. Therefore, from a visibility impact perspective, additional PM controls, including lowering the permitted limited, are not justified for visibility improvements.

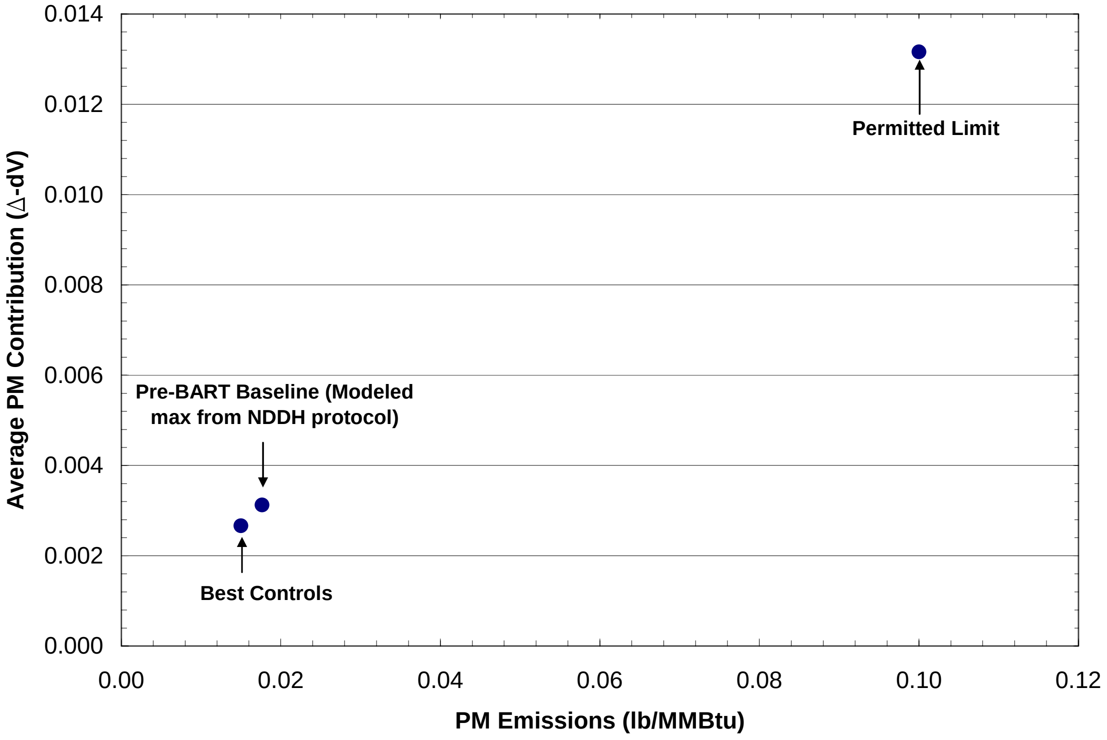

Figure 3-1 Three modeled scenarios illustrate the negligible visibility impacts attributed to particulate matter. All scenarios except for "Pre-BART" were modeled with NOx and SO_2 at their respective proposed BART emission rates. Results represent the average PM visibility impairment contributions from Lostwood Wilderness Area, Theodore Roosevelt National Park (TRNP) South Unit, and TRNP North Unit on the 98th percentile from 2002.

3.6 Proposed BART for PM

Based on the above analysis and the visibility impacts found in Figure 3-1 and Section 7.0, BART is 0.1 lb/MMBtu for particulate emissions based upon the existing ESP. A modification to the existing ESP or the retrofit to another technically feasible control is not cost effective on a dollar per ton basis. Also, most importantly, any additional particulate reductions will provide negligible improvement in visibility. GRE will follow the existing PM CAM plan to comply with the 0.1 lb/MMBtu limit as BART.

PRB BART controls for SO_2 involve the use of dry sorbent injection with the existing ESP, which will lead to additional particulate loading. It is further supportive of maintaining the existing PM permit limit of 0.1 lb/MMBtu. The Unit 1 ESP will continue to operate with automated controls at greater than 98% effectiveness.

Although historical EPA Method 17 particulate emission tests show that Unit 1 can perform below 0.1 lb/MMBtu, a lower BART emission limits is not warranted for the purpose of providing regional haze visibility improvements.

BART PM Emission Limit

Pollutant	Permit Limit	BART Limit
PM_{10}	0.10 lb/MMBtu	0.10 lb/MMBtu

4.0 Nitrogen Oxides (NOx) BART Analysis

Historical NOx emissions for Unit 1 on Lignite are controlled with low NOx burners (LNB) to approximately 0.44 lb/MMBtu. Unit 1 NOx emissions are affected by regional electricity needs as set by MISO and by plant operational protocols. In other words, Stanton's Unit 10 operates at full capacity and Unit 1 is used to meet the remaining power requirements. Unit fluctuations to meet electricity demands from MISO result in variable NOx emissions from Unit 1, with an average utilization of 68%.

There are three mechanisms by which NOx production occurs: thermal, fuel and prompt NOx. Fuel bound NOx is a primary concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. The secondary mechanism of NOx production is through thermal NOx formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air. The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

Downstream of the flame, significant amounts of NO_2 can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \qquad (2)$$

Thermal oxidation is a function of the residence time, free oxygen, and peak reaction temperature. Prompt NOx is a form of thermal NOx which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of NOx are emitted as prompt NOx.

4.1 NOx Control Options

Table 4-1 lists the available retrofit NOx options for Stanton's Unit 1.

Table 4-1 Available NOx Control Technologies

NOx Control Options
Pre-Combustion Controls
• Fuel Switching
Combustion Controls
• External Flue Gas Recirculation
• Overfire Air
• Low NOx Burners
Post Combustion Controls
• Selective Catalytic Reduction (SCR) - High Dust - Low Dust
• Selective Non- Catalytic Reduction (SCNR) - NOxOUT®
• Low Temperature Oxidation - Tri-NOx® - LoTOx
• Non Selective Catalytic Reduction
• Novel Multi-pollutant Controls - Rotating Opposed Fire Air (ROFA ®) - Electro-Catalytic Oxidation - Pahlman Process

4.2 Eliminate Infeasible NOx Control Options

4.2.1 Pre-Combustion Controls

Fuel Switching

Fuel switching represents a viable pre-combustion method of reducing NOx emissions through the use of coals with higher BTU content. Historically, Unit 1 has burned Lignite coal, but is currently permitted to burn both Lignite and PRB coals. The PRB fuel switch has reduced NOx emissions from the Lignite base case on an annual basis.

4.2.2 Combustion Controls

Various combustion controls exist for Unit 1 NOx reduction. However, as discussed in this section, there are essentially only a few feasible controls that include overfire air (OFA), low NOx burners (LNB) adjustment and SNCR. Combustion tuning is an inherent part of any LNB/OFA installation.

External Flue Gas Recirculation (FGR)

Flue gas recirculation is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizer or air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through adsorption of the combustion heat by the relatively inert flue gas, and to reduce the oxygen concentration in the combustion zone. FGR reduces thermal NOx generation in high-temperature emission sources.

Additional ductwork and a blower would be required to recirculate flue gas. These elements must fit in the limited space around the burner's coal mill. The space constraints and the lowered flame temperature created by FGR make it incompatible with the existing combustion controls on Unit 1. The addition of FGR could further result in reduced boiler capacity. Flue gas recirculation is therefore a technically infeasible control option and will not be considered further.

Overfire Air (OFA)

Overfire air diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. OFA is the typical NOx control technology used in coal-fired boilers and is primarily geared to reduce thermal NOx. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NOx by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NOx is most likely to be formed. Based on engineering analyses[11] performed on Unit 1, OFA is compatible with the existing LNB and is a technically feasible option for further NOx reduction. However, Alstom's design targets have some uncertainty because Unit 1 has a relatively short firebox, which may make OFA less effective than on other larger units. Further, with OFA, there is a potential for increased carbon monoxide (CO) emissions from Unit 1, especially on Lignite, as noted on Page 2-1 of the Alstom Report, which will limit the NOx reduction effectiveness.

Low NOx Burners (LNB)

LNB technology utilizes advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NOx formation is limited by either one of two methods. Under staged air rich (high fuel) condition, low oxygen levels limit flame temperatures resulting in less NOx formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel lean (low fuel) conditions, excess air will reduce flame

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[11] *NOx Reduction Technologies Firing Powder River Basin Coal*. Alstom Power Inc. March 8, 2006. (Appendix D)

temperature to reduce NOx formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOx formation. Low NOx burners typically achieve NOx emission reductions of 25% - 50%.

LNB are currently used to control NOx emissions from Unit 1. Alone or in combination with additional controls, additional LNB is a technically feasible option to further reduce emissions. Based on the currently achieved emission rates and used in conjunction with OFA, reduction in the range of 15%-30% would be expected depending on operational conditions.

4.2.3 Post Combustion Controls

For post combustion controls, NOx can be reduced to molecular nitrogen (N_2) in add-on systems located downstream of the furnace area of the combustion process. The two main techniques in commercial service include the selective non-catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process. There are a number of different process systems in each of these categories of control techniques.

In addition to these treatment systems, there are a large number of other processes being developed and tested on the market. These approaches involve innovative techniques of chemically reducing, absorbing, or adsorbing NOx downstream of the combustion chamber. One example of these alternatives is nonselective catalytic reduction (NSCR).

Selective Catalytic Reduction (SCR)

Selective catalytic reduction is a post combustion NOx control technology in which ammonia (NH_3) is injected into the flue gas stream in the presence of a catalyst. SCR control efficiency is typically 70% - 90%. NOx is removed through the following chemical reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_20 \qquad (1)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_20 \qquad (2)$$

The catalyst bed lowers the activation energy required for NOx decomposition. The catalyst contains an active phase such as vanadium pentoxide on a carrier such as titanium dioxide. These are used for their ability to lower the activation energy required for NOx decomposition. SCR requires an optimum temperature range of 650-800°F. There are two types of SCR.

High-dust SCR occurs upstream of particulate control. Typical applications require soot blowers for catalyst cleaning. Firing Lignite coal results in an exhaust stream heavily laden with particulate matter, which can contain catalyst poisons such as sodium. The catalyst plugging observed at the Lignite-fired boiler at Coyote Station [12] was caused by materials that could not be cleaned by a soot blower system. Because of Coyote's experience and the potential for comparable catalyst surface plugging at Stanton, a high-dust SCR is determined to be technically infeasible on Unit 1 on Lignite. Since Stanton Station is permitted for both Lignite and PRB, SCR cannot be installed as a PRB control option because of the lignite limitations as discussed. Therefore, High Dust SCR on either fuel will not be considered further.

Low-dust SCR occurs downstream of particulate control. For Unit 1, it requires reheat to bring the flue gas temperature back to the effective range after it is cooled for particulate removal. With reheat, it is a technically feasible option for NOx reduction. Based on an engineering assessment[11] and current NOx emissions, a low-dust SCR could provide additional reduction in the range of 80%-90%.

Selective Non-Catalytic Reduction (SNCR)

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N_2, and water. SNCR control efficiency is typically 25% - 50%. Without a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

$$NO + NH_3 + \frac{1}{4}O_2 \rightarrow N_2 + 3/2 H_2O \qquad (1)$$

$$NH_3 + \frac{1}{4}O_2 \rightarrow NO + 3/2 H_2O \qquad (2)$$

At temperature ranges of 1470 to 1830°F reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate.

NOxOUT®

NOxOUT® is a commercially available, urea based, SNCR process for the reduction of NOx from stationary sources. The process requires injection of stabilized urea liquid into the combustion flue gas in a location where the temperature range is 1,600 - 2,000 °F.

Based on an SNCR engineering assessment[11] that included the temperature, residence time and the current level of NOx control, an emissions reduction of approximately 15-30% would be expected. However, there are many operational effects to consider. Ideally, SNCR operates at steady state reagent addition rates. Due to the swinging of Unit 1 to meet MISO demands, reagent addition, and corresponding NOx emissions, would vary considerably. Variable reagent addition leads to the formation of

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[12] *SCR catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals.* Steven A. Benson; Jason D. Laumb; Charlene R. Crocker; John H. Pavlish. 7/1/2004 (Appendix F)

ammonium sulfate, which can cause plugging and corrosion. Some estimates suggest that the air heaters must be cleaned quarterly for approximately 2-3 days. If unplanned outages were included, it would only increase the average cost effectiveness. Finally, the engineering assessment did not incorporate Unit 1 load changes due to demand requirements, which would further exacerbate air heater fouling. Therefore, percent reductions are simply estimates. It is important to note that the economic analysis does not include unplanned outages to clean the ammonium sulfate from the air heaters because SNCR was already considered well outside the average cost effective ranges in the BART rule (See Appendix B).

Low Temperature Oxidation (LTO)

The LTO system utilizes an oxidizing agent, such as ozone, to oxidize various pollutants including NOx. In the LTO system, NOx in the flue gas is oxidized to form nitrogen pentoxide (equations 1, 2, and 3). The nitrogen pentoxide forms nitric acid vapor as it contacts the water vapor in the flue gas (4). Then the nitric acid vapor is absorbed as dilute nitric acid and is neutralized by the sodium hydroxide or lime in the scrubbing solution, which forms sodium nitrate (5) or calcium nitrate. The nitrates are removed from the scrubbing system and discharged to an appropriate water treatment system.

$$NO + O_3 \rightarrow NO_2 + O_2 \qquad (1)$$

$$NO_2 + O_3 \rightarrow NO_3 + O_2 \qquad (2)$$

$$NO_3 + NO2 \rightarrow N_2O_5 \qquad (3)$$

$$N_2O_5 + H_2O \rightarrow 2HNO_3 \qquad (4)$$

$$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O \qquad (5)$$

LTO systems, including the commercially available Tri-NOx® and LoTOx describer below, generally represent a technically feasible control option for Unit 1, with an expected control efficiency of 80%-90%.

Tri-NOx®

This technology uses an oxidizing agent such as ozone or sodium chlorite to oxidize NO to NO_2 in a primary scrubbing stage. Then NO_2 is removed through caustic scrubbing in a secondary stage. The reactions are as follows:

$$O_3 + NO \rightarrow O_2 + NO_2 \qquad (1)$$

$$2NaOH + 2NO_2 + ½\ O_2 \rightarrow 2NaNO_3 + H_2O \qquad (2)$$

Tri-NOx® is a commercially available multi-staged wet scrubbing process in industrial use. Several process columns, each assigned a separate processing stage, are involved. In the first stage, the incoming material is quenched to reduce its temperature. The second, oxidizing stage, converts NO to NO_2. Subsequent stages reduce NO_2 to nitrogen gas, while the oxygen becomes part of a soluble salt. A major advantage of the Tri-NOx® process is that concurrent scrubbing of SO_2 can be achieved. Tri-NOx is typically applied at small to medium sized sources with high NOx concentration in the exhaust gas (1,000 ppm NOx). Under these conditions control efficiencies of 99% can be achieved.

LoTOx

BOC[13] Gases' Lo-TOx is an example of a commercially available version of an LTO system. LoTOx technology uses ozone to oxidize NO to NO_2 and NO_2 to N_2O_5 in a wet scrubber (absorber). This can be done in the same scrubber used for particulate or sulfur dioxide removal, The N_2O_5 is converted to HNO_3 in a scrubber, and is removed with lime or caustic. Ozone for LoTOx is generated on site with an electrically powered ozone generator. The ozone generation rate is controlled to match the amount needed for NOx control. Ozone is generated from pure oxygen. In order for LoTOx to be economically feasible, a source of low cost oxygen must be available from a pipeline or on site generation. The normal NOx control efficiency range for Lo-TOx is 80% to 95%.

Non-Selective Catalytic Reduction (NSCR)

A non-selective catalytic reduction (NSCR) system is a post combustion add-on exhaust gas treatment system. NSCR is often referred to as a three-way conversion catalyst because it simultaneously reduces NOx, unburned hydrocarbons (UBH), and CO. Typically, NSCR can achieve NOx emission reductions of 90 percent. In order to operate properly, the combustion process must be near stoichiometric conditions. Under these conditions, in the presence of a catalyst, NOx is reduced by CO, resulting in nitrogen (N_2) and carbon dioxide (CO_2). The most important reactions for NOx removal are:

$$2CO + 2NO \rightarrow 2CO_2 + N_2 \qquad (1)$$

$$[UBH] + NO \rightarrow N2 + CO_2 + H_2O \quad (2)$$

NSCR catalyst has been applied primarily in natural gas combustion applications. This is due in large part to the catalyst being very sensitive to poisoning, as could be expected with coal exhaust streams. Based on a cursory industry review, there were no

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[13] BOC Gases is a part of The BOC Group plc. (www.boc.com)

commercial installations of NSCR on a coal fired boiler. Therefore, NSCR is viewed as technically infeasible as BART for Unit 1.

Novel Multi-Pollutant Controls

Rotating Opposed Fire Air – ROFA®

ROFA technology utilizes the injection of air through nozzles at asymmetrical positions on opposite sides of a boiler to introduce a swirling quality to the combustion gas. The swirling generates turbulence and rotation throughout the furnace. The rotation prevents laminar flow, resulting in greater utilization of the entire volume of the boiler. Efficiency is improved as a resulted of the lowered temperature provided by the swirling combustion gases. Using of ROFA technology results in a reduction of excess air without an increase in CO emissions. Further, the decrease in oxygen as a result of the excess air reduction leads to a decrease in NOx. As mentioned above, Unit 1 has a short fire box, which could limit the effectiveness of the ROFA technology.

Electro-Catalytic Oxidation (ECO)

ECO technology utilizes a reactor in which SO_2 and NOx and mercury are oxidized to nitrogen dioxide (NO_2), sulfuric acid and mercuric oxide, respectively, using non-thermal plasma. The NO_2 and remaining SO_2 are then removed and concentrated in a scrubber with ammonia injection. This technology is intended for use on low-dust streams and must be located downstream of existing particulate controls.

Pahlman Process

The Pahlman process involves the treatment of flue gas with a sorbent containing magnesium oxide. Using the solubility properties of magnesium at different ionization states, SO_2 and NOx are captured and dissolved in a spray dry system. The sorbent is then captured at a downstream baghouse and can be regenerated.

ECO and the Pahlman process technologies are still in the testing and development phase. They are not currently considered commercially available. Therefore, they are not technically feasible as BART for Unit 1. ROFA is a commercially available OFA alternative, but a site specific applicability study has not been performed for Unit 1 at this time to determine the feasibility of installation. Progress on these technologies will be monitored as the BART implementation timeline progresses.

4.3 Evaluate the Effectiveness of Feasible NOx Options

The results of the engineering analysis performed by Alstom Power presented options for the addition of SNCR and OFA in addition to the existing LNB control. Because these technologies are not mutually exclusive, they are also evaluated in combination. The Alstom Report is presented in Appendix D. Alstom projects NOx target emission rates for OFA that are comparable to presumptive limits.

It is important to note that there are several uncertainties associated with Alstom's estimates. First, the Alstom analysis was expedited in an attempt to meet March 1 deadline under NDDH's accelerate BART schedule. The summary results are simply 'targets' as stated in the report. Second, Alstom proposes emission ranges based on specific operational scenarios that are 'representative' of normal operations. These target emission rates represent specific static operational scenarios that may not be reflective of future operation or inclusive of variable load Specifically, GRE may give preference to Unit 1 in the future with the addition of a new scrubber, which would cause heat input to increase over any shorter term averaging period. Third, for the existing low NOx burners that were installed in 1998 Alstom had provided a contractually guaranteed emission rate that was difficult to meet under all boiler operating conditions and burner tuning at that time.

The attached Alstom report estimates that certain 'target' emissions can be met. This is not as certain as a contractual guarantee. Alstom was eventually able to meet their 1998 LNB commitment through significant additional work, but it is an indication of the complexity of predicting NOx emission reductions from Unit 1. Unit 1 has a relatively short fire box, which adds uncertainty to targeted estimates because overfire requires additional space above the burners for ample mixing. Finally, as previously mentioned, carbon monoxide is expected to increase as a result of installing OFA, which may also limit OFA effectiveness for NOx control. For these reasons, a risk factor is appropriate for adjusting the lb/MMBtu equivalents from the Alstom report. Table 4-2 describes the recalculation methodology to adjust the Alstom report to a 30-day rolling BART emission rates.

Table 4-2 Alstom Emissions

Control	Design Emissions for PRB from Alstom Report[14] (BART Annual)	Alstom Design % Reduction from 0.40 lb/MMBtu	Recalculated Lignite Emission Rates at Historic Baseline of 0.44 lb/MMBtu (BART 30-Day)	
			lb/MMBtu	lb/hr based on 1,800 MMBtu/hr
LNB/OFA	0.32 lb/MMBtu	20%	0.35 lb/MMBtu	633.6 lb/hr
SNCR	0.29 lb/MMBtu	27%	0.32 lb/MMBtu	574.2 lb/hr
LNB/OFA +SNCR	0.22 lb/MMBtu	45%	0.24 lb/MMBtu	435.6 lb/hr

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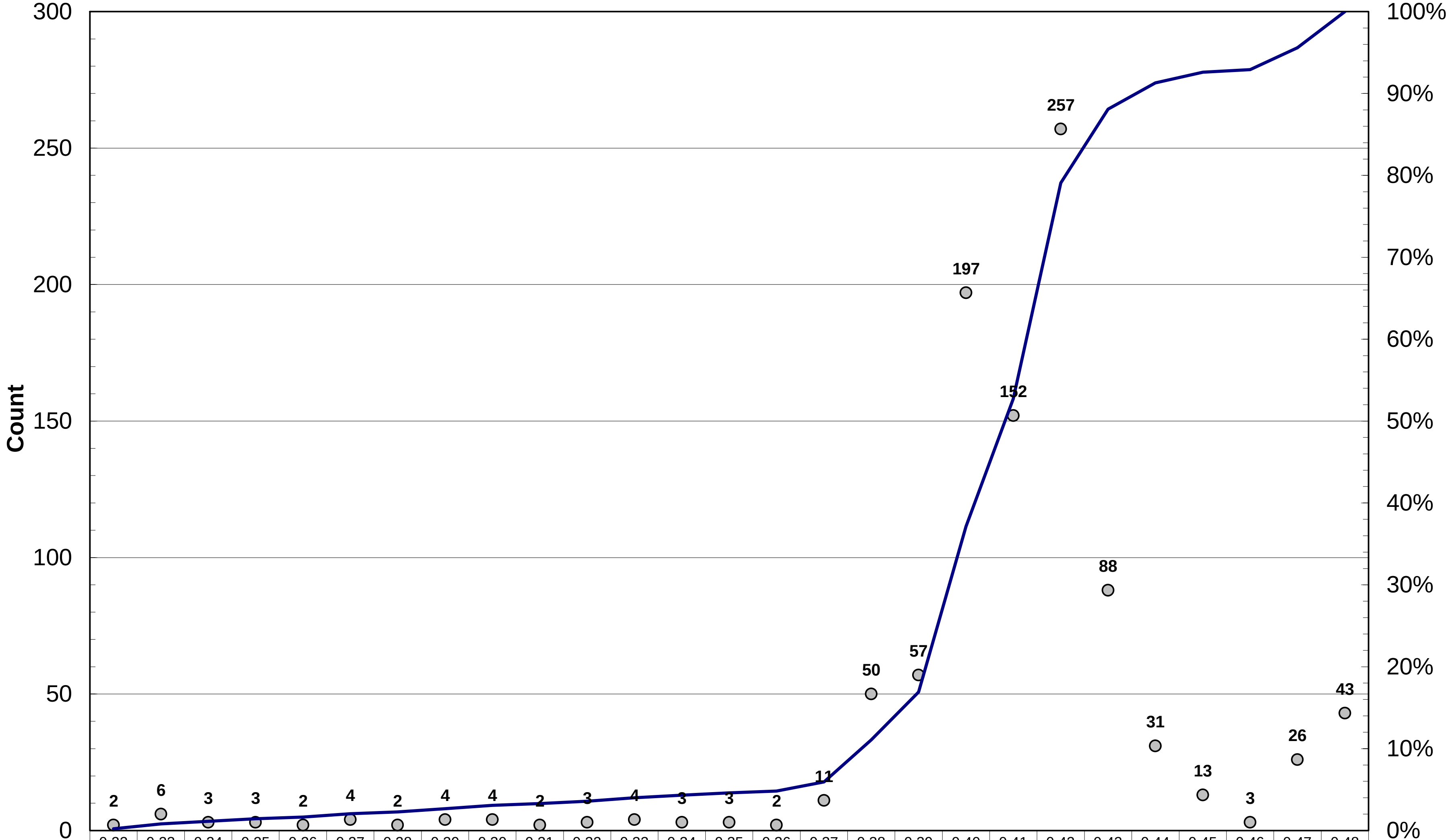
[14] Design emission rates used as annual estimates for projecting ton per year reductions.

Based on the current utilization and design degree of control being achieved on Unit 1, Table 4-3 describes the expected annual emissions from each of the remaining feasible control options.

Table 4-3 Control Effectiveness of Technically Feasible NOx Control Options

Control Technology	Expected Control Efficiency	Controlled Emissions lb/MMBtu	Controlled Emissions ton/year
SCR with Reheat	90%	0.044	210.2
LTO	90%	0.044	210.2
SNCR + PRB + Alstom LNB + OFA	55%	0.196	946.1
SNCR + PRB	47%	0.230	1111.3
Alstom LNB + OFA + SNCR	45%	0.239	1156.3
SNCR	33%	0.290	1401.2
Alstom LNB + OFA + PRB	34%	0.286	1381.9
Alstom LNB + OFA	26%	0.320	1546.2
Fuel Switch to PRB	4%	0.360	1739.5

Figure 4-1 is a statistical analysis of past Unit 1 NOx emissions on a lb/MMBtu basis. It illustrates that an emission rate of 0.44 lb/MMBtu is required to be representative of 90% of historical operating scenarios.



	0.22	0.23	0.24	0.25	0.26	0.27	0.28	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.41	0.42	0.43	0.44	0.45	0.46	0.47	0.48
○ Count	2	6	3	3	2	4	2	4	4	2	3	4	3	3	2	11	50	57	197	152	257	88	31	13	3	26	43
— Cumulative %	0.2%	0.8%	1.1%	1.4%	1.6%	2.1%	2.3%	2.7%	3.1%	3.3%	3.6%	4.0%	4.3%	4.6%	4.8%	5.9%	11.1%	16.9%	37.1%	52.7%	79.1%	88.1%	91.3%	92.6%	92.9%	95.6%	100.0

Emission Values and Cumulative Percentage

Figure 4-1 Historical Distribution of 30 -Day Rolling NOx lb/MMBtu Statistical analysis of historical EDRs for Unit 1 emissions from 2000 through 2002.

4.4 Evaluate the Impacts of Feasible NOx Options

As illustrated above in Table 4-3, the technically feasible control options provide varying levels of emission reduction. Therefore, it is necessary to consider the economic and energy/environmental impacts to better differentiate as presented below.

4.4.1 Economic Impacts

Table 4-4 details the expected costs associated with each technology based on pre-BART historical baseline emissions, the EPA cost model and site specific information. Factors affecting the control cost estimates include extensive renovations necessitated by space constraints, extended downtime for installation, and reagent costs. The detailed cost analysis for each technology is provided in Appendix A.

Table 4-4 NOx Control Cost Summary

Control Technology [15]	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
SCR with Reheat	$56.55	$12.49	$6,478	$10,036
LTO	$43.88	$44.78	$23,217	Inferior
SNCR + PRB + Alstom LNB + OFA	$10.67	$5.31	$4,452	$6,910 (D2)
SNCR + PRB	$8.41	$5.01	$4,877	Inferior
Alstom LNB + OFA + SNCR	$10.66	$3.00	$3,053	$6,927
SNCR	$8.39	$2.70	$3,661	Inferior
Alstom LNB + OFA + PRB	$2.27	$2.30	$3,037	$836 (D2)
Alstom LNB + OFA	$2.27	$0.30	$504	NA-Base
Fuel Switch to PRB	$0.00	$2.00	$5,006	NA-Base PRB (D2)[16]

The incremental control cost listed in Table 4-4 represents the incremental value of each technology as compared to the technology with the next highest level of control. Control technologies listed as “inferior” do not represent cost effective options in comparison to the dominant control technologies on an incremental dollar per ton basis. In this analysis, dominant controls are located on the least cost envelope, as illustrated graphically in Figure 4-2[17].

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[15] Cost estimates for LNB and OFA controls rely on March 2006 Alstom evaluation. SNCR Cost revised in November 2007 to reflect estimate by WGI.

[16] (D2) = Secondary dominant control. The addition of PRB fuel scenarios creates parallel least cost envelopes as illustrated in Figure 4-2. Secondary dominant controls represent the alternative incremental scenario, incorporating additional fuel switching controls.

[17] The annual emission reduction shown for LNB/OFA represents ‘normal’ annual operation and excludes instances of Unit 10 downtime. Future emission rates may vary from historical as discussed.

To reflect PRB fuel and associated NOx controls, a 'Dominant 2 (D2)' scenario has been added to differentiate between incremental costs associated with Lignite reductions.

Based on the BART final rule and other similar regulatory programs like CAIR and BACT, cost-effective NOx controls are in the range of $300 to $1,300 per ton removed as illustrated in Appendix B. EPA presumptive NOx limits were set based on average cost effectiveness of less than $1300/ton. Accordingly, fuel switching, SNCR alone or in combination with LNB/OFA, SCR with reheat, and LTO can arguably be eliminated from BART consideration on the basis of cost effectiveness. All of these technologies represent capital investments that are not justified on a cost per ton or incremental cost basis. In addition to cost effective arguments, the incremental deciview reductions associated with the various controls further support OFA/LNB for either Lignite or PRB as BART. Please refer to Section 7 for more discussion on projected deciview improvements.

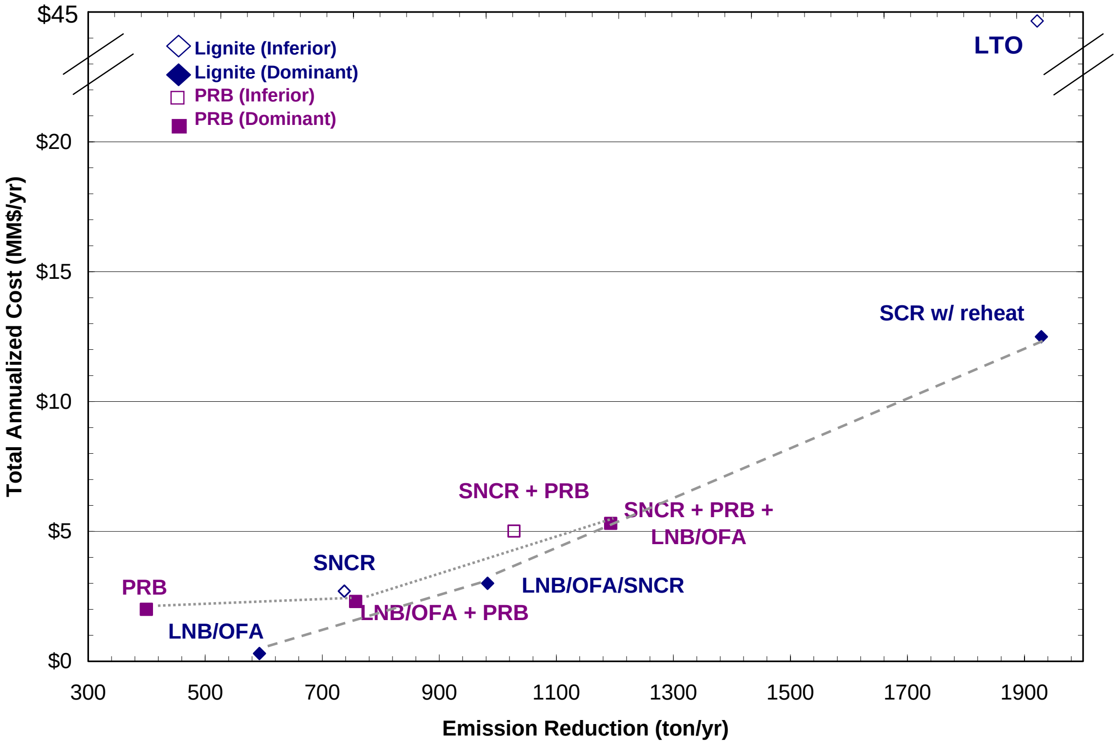

Figure 4-2 Incremental NOx Analysis The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year. Dominant and inferior controls are represented by darkened or empty diamonds, respectively; secondary dominant controls (PRB scenarios) are shown with darkened or empty squares.

4.4.2 Energy and Environmental Impacts

The energy and non-air quality environmental impacts for OFA/LNB options, SNCR, SCR, and LTO are described in Table 4-5.

Table 4-5 NOx Control Technology Impacts Assessment

Control Option	Energy Impacts	Other Impacts
LTO	- The blower, circulation pump ozone generation and wastewater discharge require additional electrical usage.	- Waste water generated by LTO technologies requires bio-treatment. - Stanton site is limited for additional wastewater controls.
SCR with Reheat	- The reheat required to make SCR technically feasible will result in high energy use and associated costs.	- Reheat would require additional natural gas use, which is not currently available and would require installation of a natural gas line. - Ammonia slip concerns, which contributes to regional haze. - Additional safety and regulatory concerns associated with ammonia storage on site.
SNCR (or SNCR with OFA/LNB)	- Minimal additional energy impacts.	- Ammonia slip concerns, which contributes to regional haze. - Additional safety and regulatory concerns associated with ammonia storage on site. - Variably operating conditions caused by unit swinging will necessitate extensive O&M requirements.[18] - Loss of fly ash re-use. - Potential for an increase in CO emissions as described in Section 2.1 and 2.2 of Appendix D. Any CO increase may require permitting actions and approval from NDDH.
OFA/LNB	- Minimal energy impacts.	- Potential for an increase in CO emissions as described in Section 2.1 of Appendix D. Any CO emissions increase may require permitting actions and approval from NDDH. - Potential for tube wastage.

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[18] Unit 1 load swings will cause reagent control problems with SNCR or LNB/OFA/SNCR option leading to ammonium sulfate formation and potential corrosion and plugging issues. Since the SNCR technology is not justified economically, these impacts were not more thoroughly assessed, but would be significant. Some estimates predict quarterly outages of 2-3 days to clean fouled air heater. If incorporated into the economic analysis, it would further increase costs beyond EPA's average cost effective levels.

4.5 Proposed BART for NOx

It is important to precede the control determination with an understanding that Stanton Station Unit 1 is a non-presumptive unit at <200MW. As such, economies of scale for pollution control costs are not realized and emission reductions provide relatively less regional visibility improvements. All factors must be weighed in making the BART control determination.

Based on the above analysis, and the visibility impacts found in Section 7.0, GRE establishes OFA with additional LNB adjustments as BART for NOx reduction at Stanton's Unit 1. From a top down analysis, SCR can be ruled out on $/ton basis as not cost effective. The SNCR/OFA/LNB option can be ruled out on several points including economic arguments ($/ton and incremental $/ton cost effectiveness higher than BART presumptive ranges), several qualitative 'Energy and Environmental Impacts' and most significantly, relatively insignificant incremental visibility improvement over LNB/OFA. The OFA/LNB option represents the most cost effective retrofit technology for further controlling NOx emissions from Stanton Station Unit 1.[19]

The proposed BART emissions limit for Unit 1 is 0.35 lb/MMBtu on a 30-day rolling average. This limit will allow the station to maintain compliance while accommodating Unit 1 swinging as a result of MISO requirements as well as to use currently permitted fuels. GRE will use its existing continuous emissions monitoring systems (CEMS) to demonstrate compliance with the proposed BART limit.

BART NOx Emission Limit

Pollutant	Permit Limit	BART Limit
NOx	0.46 lb/MMBtu	0.35 lb/MMBtu

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[19] It is worth noting that EPA established presumptive NOx emission rates for >750MW units based upon combustion controls including OFA and LNB. Other than cyclone units, EPA did not require post combustion controls for BART compliance for these presumptive units. Many preliminary BART analyses, as well as state efforts including the Colorado BART SIP, are finding that OFA/LNB are BART and that post combustion controls are not warranted given cost effectiveness considerations in conjunction with incremental deciview analyses.

5.0 Sulfur Dioxide (SO_2) BART Analysis

5.1 SO_2 Control Options

Stanton Station is permitted for either Lignite or PRB coal. Accordingly, the analysis must consider SO_2 control options with respect to different sulfur contents associated with permitted fuels. There is a detailed discussion in Appendix E regarding the expected sulfur range for PRB and Lignite. Since the current coal contract for PRB expires in late 2009, there are a range of sulfur contents that must be incorporated into the BART limit. Table 5-1 lists the available SO_2 control options for Stanton Unit 1.

Table 5-1 Available SO_2 Control Technologies

SO_2 Control Options
Pre-Combustion Controls
Flue Gas Desulfurization
Dry Sorbent Injection
Spray Dry Absorber
Wet Lime/Limestone Absorber
Novel Control: TurboSorp®

5.2 Eliminate Infeasible SO_2 Control Options

The pollutant SO_2 is formed when sulfur present in fuels is oxidized by either process conditions or by combustion. Pre-combustion controls utilize methods for improving the physical or chemical properties of the fuel before it is combusted. Existing methods for post-combustion SO_2 control can be categorized as either dry or wet flue gas desulfurization (FGD).

5.2.1 Pre-Combustion Controls

Several options exist for the beneficiation of coal. Coal impurities can be reduced through pretreatment options such as coal washing and coal drying. No information could be located in support of the effectiveness of washing Lignite coal. Coal drying is being explored at GRE’s Coal Creek Station as a potentially viable option for Lignite fired boilers. In this process, raw coal is crushed and screened to remove rocks and other impurities, such as pyretic sulfur. The crushed coal is then thermally processed to remove excess moisture. It is currently under development as a commercial scale, demonstration at the GRE’s Coal Creek Station. Contingent upon the success of this demonstration, it may be evaluated at a later time for Stanton to provide more operational flexibility for SO_2 control. Since it has not been demonstrated commercially at full scale, coal drying will not be further evaluated in this report.

It is worth adding that different boilers have different sulfur removal rates based on the characteristics of the mined coal. The amount of sulfur removed in the boiler at any one time may change. And yet, sulfur removed in the boiler is sulfur being removed from the flue gas stream and not being emitted to the environment.

Reducing the amount of sulfur present in the fuel is another pre-combustion control for SO_2 reductions. It can be achieved by switching to a lower sulfur containing coal. Unit 1 is currently permitted to burn both Lignite and PRB coals. Although Unit 1 could theoretically coal blend as an element of post-BART operational flexibility for added SO_2 control, Stanton Station intends to burn either Lignite or PRB on a long term basis.[20]

5.2.2 Flue Gas Desulfurization (FGD)

The FGD systems commonly used to control SO_2 emissions can be classified as either wet or dry systems. Both systems rely on creating turbulence in the gas stream to increase contact with the absorbing medium. Wet systems are commonly capable of achieving higher removal efficiencies than dry systems because it is easier to mix a gas with a liquid than a solid. FGD requires the use of an alkali slurry powder. Lime (or limestone) is the most widely used compound for acid gas absorption. Sodium based reagents are also available, and while they provide better SO_2 solubility, they are significantly more expensive. Reagent addition at greater than stoichiometric rates is required for dry systems and can improve removal efficiencies in wet systems.

Wet FGD systems may discard all of the waste by-product streams or regenerate and reuse them. Wet systems generally require more extensive networks of pumps and piping than dry systems to recirculate, collect and treat the scrubbing liquid. As implied by the name, dry scrubbers require less water than wet systems but also require higher temperatures to ensure that all moisture has been evaporated before leaving the scrubber. There are many available FGD systems including wet scrubbing, spray dryer absorption, and dry sorbent injection.

Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime (CaO) or limestone ($CaCO_3$) in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite ($CaSO_3 \cdot 2H_2O$) and calcium sulfate (CaSO4). As applied to Unit 1, wet scrubbing is capable of achieving approximately 95% control. In addition to 100% wet scrubbing scenario, a 10% flue gas bypass of the scrubber will be evaluated below. Both scenarios of wet scrubbing are technically feasible as BART for Unit 1 on either fuel.

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[20] For testing or fuel switching, it is possible that a secondary fuel may be brought on site for a short period. In discussions with NDDH, it was proposed that for a limited time, the alternative fuel and associated limit would apply on a daily basis for the purpose of calculating towards a 30-day rolling BART limit. As an example, if Stanton switches back to Lignite or wishes to test dried Lignite, the Lignite limit would apply to each 24 hour period in which Lignite was the primary fuel.

Spray Dry Absorption and Baghouse

Spray dry absorption is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the droplets. The absorption of the SO_2 leads to the formation of calcium sulfite ($CaSO_3 \cdot 2H_2O$) and calcium sulfate ($CaSO_4$) within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder, which is carried out with the gas and collected with a fabric filter baghouse. Spray dryer absorption control efficiency is typically in the 70% to 90% range. A spray dry scrubber is technically feasible as BART for Unit 1 on either fuel.

Dry Sorbent Injection (DSI)

Dry sorbent injection involves the injection of a lime or limestone powder into the exhaust gas stream. The stream is then passed through a baghouse or ESP to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 50% and 70%. In combination with the existing ESP, DSI is only expected to achieve about 35% removal or less. For Unit 1 on Lignite, the existing ESP could not handle the additional particulate loading without a corresponding increase in particulate emissions. Therefore, it is ‘technically’ feasible, but is not viable as a retrofit due to an increase in PM emissions for Lignite. If the DSI is accompanied with a new baghouse, removal is expected to be 55% for Lignite. On the other hand, given PRB’s lower sulfur content, DSI provides additional cost effective reductions that make it both feasible and viable. ESP performance testing would need to occur in advance of the BART regulatory deadline to confirm ESP control effectiveness as well as to confirm that any increase in PM is within regulatory limits. DSI is therefore technically feasible as BART for Unit 1 on either fuel.

Novel Multi-Pollutant Control: TurboSorp®

TurboSorp® is a dry FGD technology in which the flue gas is pushed through an open chamber reactor. The flue gas enters the reactor through a nozzle with venturi geometry for optimum distribution of gas flow. The fluidized bed of particles circulates above the venturi inlet inside the vessel and water is injected to maintain outlet temperatures in the range of 45ºF to 55ºF above saturation temperature. Recycled particles from the baghouse along with hydrated lime are injected at this location to control outlet SO_2. The stream is then passed through a fabric filter or ESP to remove large particulate before discharge through the stack.

A booster fan would be required at the outlet to control the gas flow rate. The system would also require installation of a hydrator or pug mill to facilitate the lime hydration process. Test plants are currently operating in Europe and the United

States. Though not considered technically feasible due to its lack of commercial availability at this time, TurboSorp® may be considered in future control technology assessments as GRE evaluates BART implementation.

Additional novel controls including ECO and the Pahlman process for NOx and SO_2 are included in Section 4.2.3 for NOx Controls.

5.3 Evaluate the Effectiveness of Feasible SO_2 Options

Table 5-2 describes the expected emissions from each of the remaining feasible control options. Estimated emission rates are based on the control technology's expected reduction, which is then applied to annual emission rates from 2000-2004. (For more information, please refer to the cost analysis spreadsheets in Appendix A.) It is important to note that actual control efficiency will differ from these calculated values based upon the installed control technology's actual performance and the specific fuel characteristics at that time.

Further, these values differ from the emission rates that are used for modeling visibility impact, which are representative of the emission rates that are consistently achievable over any 30-day period. Caution should be used when attempting to derive short term emission rates from calculated annual emission reductions based on general control design values. Finally, this analysis is based only on the sulfur content of the PRB currently used. When Stanton Station's PRB contract expires in 2009, there will no longer be a low sulfur guarantee on the PRB. As presented in Appendix E, there are a range of realistic PRB sulfur contents.

Table 5-2 Control Effectiveness of Technically Feasible SO_2 Control Options

Control Technology	Expected Control Efficiency	Controlled Emissions[21] (lb/MMBtu)	Controlled Emissions (ton/year)
Absorber (Wet Scrubber)	95%	0.091	438.4
Spray Dry Baghouse + PRB	92%[21]	0.150	724.8
Spray Dry Baghouse	90%	0.181	876.9
DSI Baghouse + PRB	86%	0.248	1,195.9
Absorber 10% Bypass	86%	0.263	1,271.4
DSI Existing ESP + PRB	80%	0.358	1,727.4
Fuel Switch to PRB	70%	0.550	2,657.5
DSI Baghouse	55%	0.817	3,945.9
DSI Existing ESP	35%	1.180	5,699.6

5.4 Evaluate the Impacts of Feasible SO_2 Options

The economic and environmental/non-air quality impacts of the remaining controls are illustrated below.

5.4.1 Economic Impacts

Table 5-3 details the expected costs associated with each technology based on pre-BART historical baseline emissions, the EPA cost model and site specific information. The detailed cost analysis for each technology is provided in Appendix A. Based on the BART final rule, EPA set the SO_2 presumptive level for units >750MW based upon an average cost effectiveness of $919 per ton as illustrated in Appendix B.

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[21] Controlled emission reductions are projected from pre-BART baseline and historical Lignite operating conditions. Future Lignite could potentially include higher sulfur coal than the baseline. Therefore 24-hour max and 30-day rolling emission will be higher.

Table 5-3 SO_2 Control Cost Summary

Control Technology	Installed Capital Cost (MM$)	Annualized Operating Cost (MM$/yr)	Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
Absorber (Wet Scrubber)	$88.16	$13.18	$1,617	$4,484
Spray Dry Baghouse + PRB	$79.51	$13.31	$1,692	$8,083 (D2)
Spray Dry Baghouse	$77.84	$11.22	$1,454	$4,385
DSI Baghouse + PRB	$57.20	$10.43	$1,411	Inferior
Absorber 10% Bypass	$65.64	$9.49	$1,296	$1,420
DSI Existing ESP + PRB	$11.52	$5.20	$758	$3,444 (D2)
Fuel Switch to PRB	$0.00	$2.00	$337	NA- Base PRB (D2) [22]
DSI Baghouse	$57.20	$8.43	$1,814	Inferior
DSI Existing ESP	$11.52	$3.20	$1,105	NA-Base

The incremental control costs listed in Table 5-3 represent the incremental value of each technology as compared to the technology with the next highest level of control. Control technologies listed as “inferior” do not represent cost effective options in comparison to the dominant control technologies on an incremental dollar per ton basis. In this analysis, dominant controls are located on the least cost envelope, as illustrated graphically in Figure 5-1.

Figure 5-1 shows two dominant curves depending on fuel. To cover the expected range of PRB sulfur contents discussed in Appendix E, the 92% calculated PRB SO_2 Scenario is used to establish the PRB dominant curve. We did not include a PRB Absorber Scenario for both qualitative and quantitative reasons. Qualitatively, Stanton Station Unit 10 already has a spray dry baghouse, which generally supports selection of this control technology for Unit 1 on lignite due to operator knowledge of the control systems as well as potential ability to share existing systems, such as ash and lime handling. Wet scrubbing has several qualitative limitations listed in Table 5-4 Other Impacts. Quantitatively, wet scrubbing with lignite did not represent a significant visibility improvement over dry scrubbing that when combined with cost per ton and incremental cost per ton analyses generally supports dry scrubbing as BART on lignite.

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[22] (D2) = Secondary dominant control. The addition of PRB fuel scenarios creates parallel least cost envelopes as illustrated in Figure 5-1. Secondary dominant controls represent the alternative incremental scenario, incorporating additional fuel switching controls.

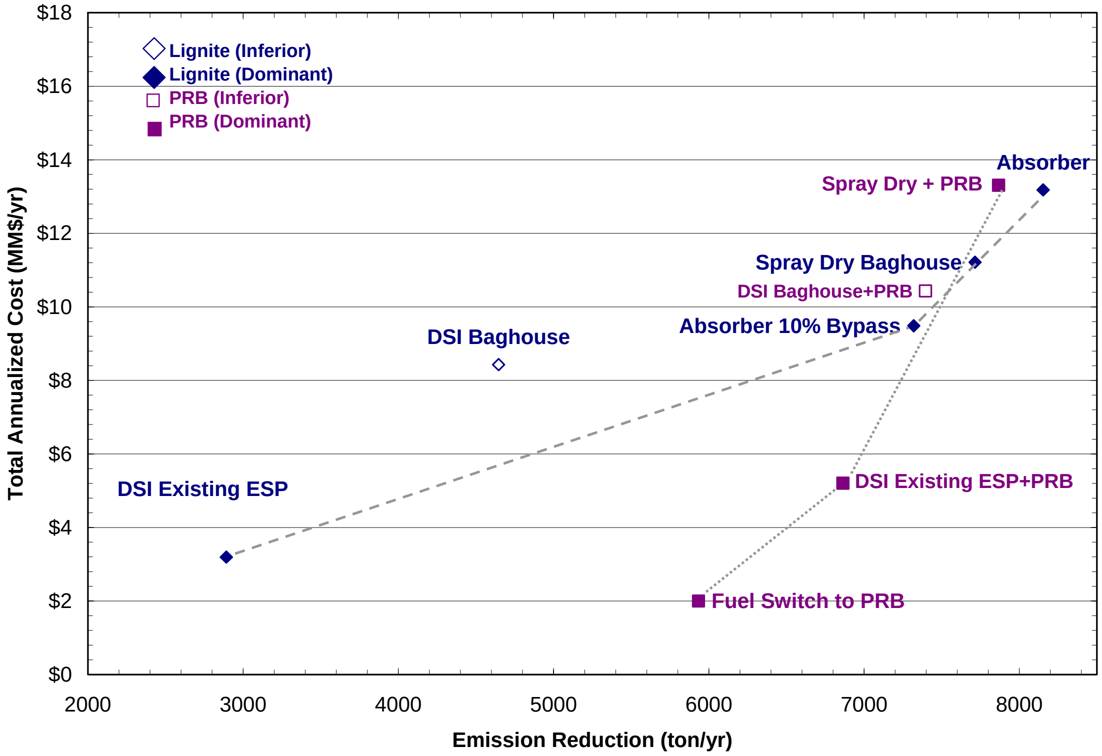

Figure 5-1 Incremental SO$_2$ Analysis The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year. Dominant and inferior controls are represented by darkened or empty diamonds respectively. Secondary dominant controls (PRB scenarios) are presented as darkened or empty squares.

The DSI baghouse scenarios can be eliminated because they represent inferior controls on an incremental cost basis. All of these technologies represent significant capital investments that are not strictly justified on a cost per ton or incremental cost basis. Most importantly, for final BART determinations, one must evaluate visibility improvements for the various scenarios as discussed in Section 7.0.

5.4.2 Energy and Environmental Impacts

The energy and non-air quality impacts for absorber wet and dry scrubbing options are presented in Table 5-4. No significant environmental impacts are associated with a fuel switch to PRB.

Table 5-4 SO_2 Control Technology Impacts Analysis

Control Option	Energy Impacts	Other Impacts
Wet Scrubbing (0% and 10% bypass)	- Blower requires increased energy use.	- Ponding for scrubber discharge will be limited because of site space constraints. The space that could potentially be used for wet scrubber ponding was formerly an ash pond[23]. Due to geologic instabilities and proximity to river, the ash had to be removed. - Extensive process downtime for installation, requiring replacement power. - Loss of fly ash re-use. EPA Coal Combustion Products Action Plan prefers dry over wet scrubbers. - Wet stack modifications required. - Due to space constraints, the existing storage warehouse must be relocated. - Additional water consumption and wastewater generation. - Waste water discharge will increase mercury loading in the Missouri River.
DSI with Existing ESP	- An ESP upgrade would require additional energy use.	- For Lignite, sorbent injection would result in increase particulate loading, resulting in higher PM emissions. The existing ESP would need to be upgraded to comply with existing PM limits. - Increased particulate loading rules out the possibility of using carbon injection for future mercury control. - For PRB, performance testing with DSI and/or carbon for mercury would need to occur to ensure compliance with PM limit. It is assumed that an ESP upgrade would not be needed for DSI.
DSI Baghouse	- Blower requires increased energy use.	- Requires process downtime and replacement power during installation. - Due to space constraints, the existing storage warehouse must be relocated.
Spray Dry Baghouse	- Blower requires increased energy use.	- Requires process downtime and replacement power during installation. - Due to space constraints, the existing storage warehouse must be relocated.

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[23] See plot plan in Appendix G.

5.5 Proposed BART for SO_2

It is important to precede the control determination with an understanding that Stanton Station Unit 1 is a non-presumptive unit at <200MW. As such, economies of scale for pollution control costs are not realized and emission reductions provide relatively less regional visibility improvements. All factors must be weighed in making the BART control determination.

From a top down analysis, the wet scrubber on either fuel can arguably be eliminated based on dollar per ton and incremental dollar per ton assessments as well as more qualitative Energy and Environmental Impacts as discussed. This determination is further supported by the incremental dV analysis in Section 7.

The next option is dry scrubber and baghouse technology. For lignite, the cost per ton and incremental cost per ton are well above the EPA average cost effective values. Since the spray dry baghouse is modeled to provide perceptible dV reductions on lignite, Great River Energy has agreed to install a spray dry baghouse for lignite. This determination is further supported by the concerns, as discussed, associated with the next level of control as DSI and ESP on lignite.

Because of PRB's relatively lower sulfur content as compared to lignite, both the dollar per ton and incremental dollar per ton cost effectiveness are higher than comparable lignite control scenarios. More importantly, the lower sulfur PRB provides significant dV reductions unscrubbed. Therefore, scrubbed PRB offers relatively less dV improvements than scrubbed lignite fuels. Given careful consideration of the BART requirements, a spray dry baghouse for PRB can arguably be ruled out on both cost per ton and incremental cost per ton effectiveness. This is supported by the incremental dV analyses in Section 7.

The next PRB control option is DSI using the existing ESP. It is the most effective control option based both on cost per ton and incremental cost per ton. Since it is consistent with EPA's average cost effectiveness threshold, it is considered BART for PRB. This determination is further supported by the incremental dV analyses in Section 7.

In order to encompass future operating scenarios, maintain fuel flexibility and ensure SO_2 emission reductions, GRE is therefore proposing a split permit limit reflective of the BART control determinations associated with each fuel. For Lignite, based on installation of a spray dry baghouse, the BART emission is 0.24 lb/MMBtu on a 30-day rolling average period. This value is derived from maximum sulfur concentrations, illustrated in Appendix E, as found in North Dakota Lignite. For PRB, based on installation of DSI with existing ESP, the BART emission limit is 0.36 lb/mmbtu on a 30-day rolling average basis.

BART SO_2 Emission Limits

Pollutant	Permit Limit	BART Limit
SO_2 Lignite	3.0 lb/MMBtu	0.24 lb/MMBtu
SO_2 PRB	3.0 lb/MMBtu	0.36 lb/MMBtu[24]

GRE will use its existing continuous emissions monitoring systems (CEMS) to demonstrate compliance with the proposed lb/MMBtu BART limit.

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[24] Please refer to the Executive Summary section entitled Additional Considerations.

6.0 Condensable Particulate Matter (CPM) BART Analysis

Based on EPA's interpretation that 'total particulate' includes condensable particulate matter (CPM) and at NDDH's request, GRE provides an estimate of CPM from Stanton Station's Unit 1. It is important to note that ND utilities are not required to test for CPM. They are only required to test for particulate using Methods 5 or 17, depending on plant permit requirements. Stanton's Title V permit for Unit 1 includes a particulate limit and compliance is demonstrated based on a correlation curve with opacity that was developed using EPA Method 17.

Since GRE does not have stack test data for CPM, a literature review was conducted to estimate CPM emissions based on a correlation to tested filterable values. Unfortunately, there is wide variability in CPM emissions when correlated to filterable emissions, regardless of the methodology selected. Some of the variability it associated with Method 202 and sulfate interference. Since CPM exists in several forms such as ammonia salts and sulfur containing particles, Method 202 cannot compensate for sulfate levels, and consequently overestimates CPM emissions. AP-42 is another methodology that provides a linear relationship between sulfur content and CPM emissions, which is arguably inaccurate, especially at higher sulfur concentrations. Nevertheless, for the purpose of this BART analysis, CPM emissions are approximated and assessed according to BART requirements.

6.1 Identify CPM Control Options

It is generally accepted that CPM is largely formed by ammonia salts and sulfur containing particles. In the absence of ammonia from NO_X controls, no ammonium salts are expected in Unit 1 indicating that the majority of CPM is in the form of sulfuric acid mist (SAM). In general, the inorganic portion of CPM far exceeds the organic portion and is composed primarily of sulfates, which emanate from SO_2. Sulfuric acid mist is formed from sulfur trioxide (SO_3) reacting with water in exhaust streams. SO_3 (and SO_2) is formed when sulfur present in the coal is oxidized by either process conditions or by combustion. Accordingly, the majority of control options for CPM are the SO_2 control technologies described previously in Section 5.0 and listed in Table 6-1 below.

Table 6-1 Available CPM Control Technologies.

CPM Control Options
Wet Electrostatic Precipitator
Dry Sorbent Injection
Spray Dry Absorber
Wet Lime/Limestone Absorber

6.2 Eliminate Infeasible CPM Control Options

Wet Electrostatic Precipitator

In applications where a wet electrostatic precipitator (WESP) is used for particulate removal, it may also be used for SAM removal. A WESP uses a water spray to remove particulate matter from the ESP collection plates. For SAM removal, caustic is added to the water spray system, allowing the spray system to function as an SAM absorber. As indicated in Section 3.0, WESP control is a technically feasible but economically infeasible control option. CPM emissions do not significantly change the economic analysis. As such, WESP is economically infeasible for CPM control. If added to the particulate analysis in Section 3, CPM emissions do not significantly change the economic impacts. No additional PM controls are necessary.

Dry Sorbent Injection (DSI)

Dry sorbent (pulverized lime or limestone) is directly injected into the duct upstream of the fabric filter. SAM reacts with sorbent and the solid particles are collected with a fabric filter. This process was developed as a lower cost option to conventional spray dry absorption (SDA) technology. DSI is technically feasible for controlling CPM. However, as indicated in Section 5.0, DSI represents a lower degree of control than will be achieved by the proposed SO_2 BART controls for Stanton Station.

Spray Dry Absorption

Spray dryer absorption is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the pollutants (SO_2 and SAM) are absorbed by the droplets. The absorption of the SO_2 and SAM leads to the formation of calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate ($CaSO_4$) within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder, which is carried out with the gas and collected with a fabric filter. Dry scrubbing is the proposed SO_2 BART control technology for Stanton Station Unit 1. It is technically feasible for controlling CPM and is expected to provide a corresponding decrease in SAM as the primary component of CPM.

Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing flue gas stream with a slurry comprised of lime (CaO) or limestone ($CaCO_3$) in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO_2 and SAM in the gas stream reacts with the lime or limestone slurry to form calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate ($CaSO_4$). Based on the visibility impacts presented in Section 7.0 and the economic and environmental impacts presented in Section 5.4, wet scrubbing is eliminated as a BART control option.

6.3 Evaluate the Effectiveness of Feasible CPM Options

A number of methods exist with which to estimate CPM emissions. However, consistent and accurate CPM estimates vary widely due in large part to the uncertainties currently associated with CPM emissions measurements as presented below.

EPA's AP-42 emission factor uses a linear relationship between CPM and the sulfur content of coal. Historical coal sulfur contents have ranged from 0.40% to 1.56% for Stanton Station with an average of 1.30%. There are two issues relevant to the uncertainty associated with using AP-42 emission factors: how well they represent the results of Method 202 measurements and the known artifacts in the inorganic portion of Method 202. (Namely, condensable sulfates are formed in the aqueous measurement process that would not otherwise form CPM in the atmosphere. These sulfates are generally termed "pseudo particulates" and their formation results in inflated CPM values when using Method 202[25].)

Five tests from coal-burning boilers in various locations provide some indication of the relationship between Method 202 measurements and AP-42 calculations. These sites all used wall fired boilers and pulverized coal and were equipped with a particulate control (ESP or fabric filter) but had no NO_X or SO_2 controls.

In the AP-42 calculations, CPM varies linearly with sulfur content. However, Method 202 measurements do not yield such a linear relationship. This suggests that the AP-42 correlation with coal sulfur is not appropriate. There is not sufficient data to assess if CPM measurements corrected for pseudo particulates would have a linear relationship with coal sulfur content. At higher sulfur contents, AP-42 calculations appear to overestimate CPM compared to Method 202, which already overestimates CPM. For very low sulfur content coal Method 202 may provide the more conservative estimate.

Since GRE does not have Method 202 test data from its boilers, CPM emissions are estimated by using a ratio of 4:1 for CPM to filterable PM (Method 5) based on the literature data presented in both Figure 6-1 and Table 6-2 below. The bar graph and table below summarizes the sulfur content, Method 202 CPM and AP-42 CPM, as well as the ratio of condensable to filterable PM using these two techniques from these five sites. The tests give a range of condensable to filterable PM ratios of 1.44-6.69 using Method 202, with an average ratio of 3.61.

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[25] A comparison of Method 202 with a modified version to correct for pseudo particulates was performed at the Xcel Energy (previously Northern States Power) Black Dog Station, which at the time of the test fired pulverized coal at 0.25% sulfur content with wall-fired burners. The boilers were equipped with electrostatic precipitators for particulate control, but did not have ammonia-based NOX controls or SO2 controls. The comparison was accomplished by measuring CPM with standard Method 5 and Method 202 techniques and then repeating the measurements using a cold filter in the Method 5 train to simulate conditions for formation of CPM in the atmosphere. At Method 5 temperatures, sulfate based CPM can pass through the collection filter. A cold filter will capture these sulfate and sulfuric acid particulates so that any sulfate measured in the impingers of Method 202 may be considered pseudo particulates. This comparison indicates as much as an 83% overestimation of CPM using Method 202.

Table 6-2 Filterable and Condensable PM Comparison[26,27].

Source	Average Coal Sulfur Content	AP-42 CPM (lb/MMBtu)	Method (M) 202 CPM (lb/MMBtu)	Ratio of Condensable (M 202) to Filterable, (M 5) PM	Ratio of Condensable (AP-42) to Filterable, (M 5) PM
Logan Generating Company, L.P. Cogen Facility	1.13	0.083	0.0208	4.56	18.20
PSE & G - Mercer Station Unit 1	0.75	0.045	0.0373	3.00	3.61
PSE & G- Mercer Station Unit 2	0.75	0.045	0.0563	6.69	5.34
Deseret Generation and Trans. Coop.- Bonanza Power Plant	0.47	0.017	0.0096	1.44	2.55
Xcel Energy Black Dog Station	0.25	0.01	0.0437	2.36	0.54
Xcel Energy Black Dog Station – corrected for pseudo particulates (Modified M 202)	*0.25*	*0.01*	*0.0076*	*0.41*	*0.05*
Average Ratio CPM: Filterable				**3.61**	**6.05**

As described above, the existing methodologies for approximating CPM emissions all have their limitations. The Electric Power Research Institute (EPRI) is currently working with the EPA to revise Method 202 in an effort to produce more accurate CPM emission estimates. For the sole purpose of approximating CPM from its Lignite-fired boilers for this BART analysis, GRE has chosen to multiply its filterable particulate matter (PM), as determined using EPA Method 5 test data, by a factor of 4. This ratio is based on literature data comparing the results of CPM measured by EPA Method 202[28] to filterable particulates as measured by EPA Method 5. It is also reflective of recent BACT permit limits[29], which show a range of CPM ratios from roughly 2 to 4 times the corresponding PM limit. Accordingly, the proposed CPM emission factor will conservatively estimate CPM emissions for the purposes of this BART evaluation.

As shown in Figure 6-1, a modified Method 202 can correct for pseudo-particulates. It is shown that Method 202 alone can overestimate CPM by as much as 83%, on a relatively low sulfur coal.

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[26] "In Stack Condensible Particulate Matter Measurements and Issues" by Louis A. Corio and John Sherwell in the Journal of Air & Waste Management Association: 50:207-218.

[27] “Measurement of Condensible Particulate Matter: A Review of Alternatives to EPA Method 202, EPRI, Palo Alto, CA: 1998. Report TR-111327.

[28] CPM may be directly measured using EPA Method 202, or it may be estimated using EPA’s AP-42 emissions factor document. Method 202 measures the amount of particulates that condense in water-filled impingers in the “back half” of a Method 5 stack sampling system.

[29] CPM information sources for CFB boiler emission limit determinations. Email from Tom Bachman <tbachman@nd.gov> of NDDH, 15 June 2006.

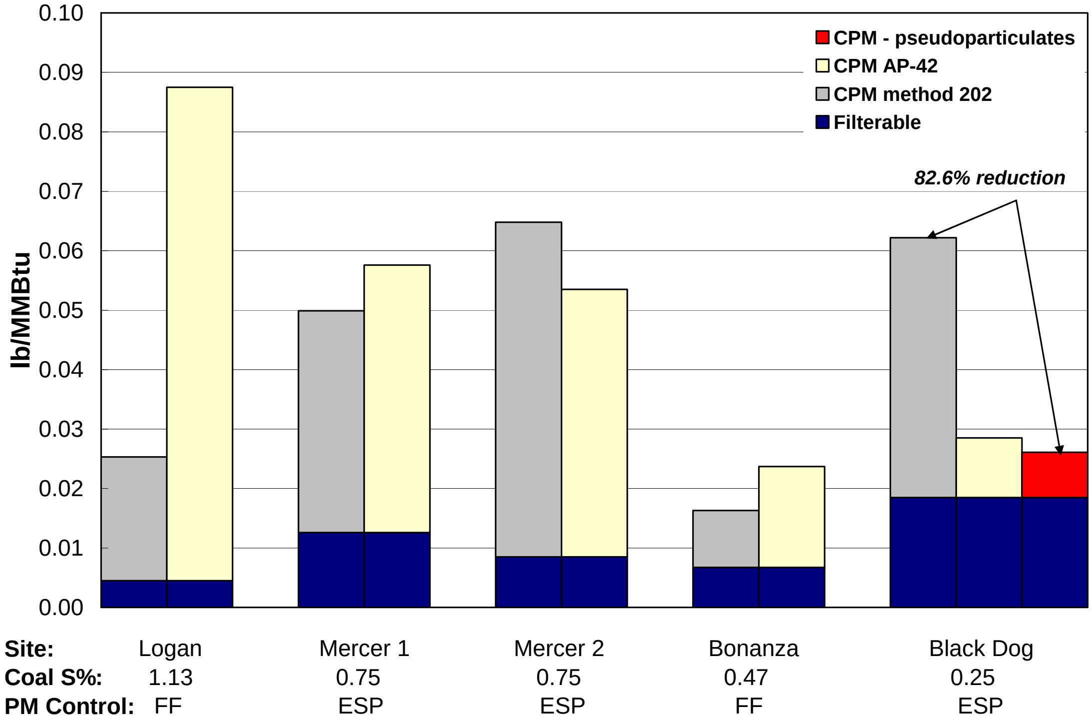

Figure 6-1. Comparison of Method 202 and AP-42. Breakdown of particulate matter is illustrated for 5 power plants[30,31].

Table 6-3 provides CPM estimates using Method 202 and also attempts to correct for pseudo-particulate.

Table 6-3 Annual CPM Emissions Estimate Based on Method 202 Approximation

Unit 1 Method 5 Result (lb/MMBtu)	PM (filterable) Emissions	CPM w/ pseudo-particulates (lb/MMBtu)	CPM w/o pseudo-particulate (lb/MMBtu)	CPM w/ pseudo-particulates (ton/yr)	CPM w/o pseudo-particulate (ton/yr)
0.02	97.3 tpy[32]	0.08	0.014	389.2	67.7

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[30] "In Stack Condensible Particulate Matter Measurements and Issues" by Louis A. Corio and John Sherwell in the Journal of Air & Waste Management Association: 50:207-218.

[31] “Measurement of Condensible Particulate Matter: A Review of Alternatives to EPA Method 202, EPRI, Palo Alto, CA: 1998. Report TR-111327.

[32] Annual emissions are based on past actual operations for Stanton Station Unit 1. 7,947 annual operating hours with a utilization rate of 68%. (0.02 lb/MMBtu x 1224 MMBtu/hr x 7947 hr/yr/2000 = 97.27 tpy)

6.4 Evaluate the Impacts of Feasible CPM Options

Baseline SO_2 emissions for Unit 1 are calculated to be 8,592 tons per year. As illustrated in Table 6-3, CPM emissions are estimated at approximately 389.2 tons per year, or only 4.5% of the SO_2 emissions. If corrected for pseudo-particulates, CPM emissions may be as low as 67.7 tons per year, or only 0.8% of the SO_2 emissions. Detailed economic and environmental impacts for the available SO_2 control technologies have been presented in Section 5.4. With either the corrected or uncorrected value, the incorporation of CPM emissions will not significantly change the SO_2 economic evaluation. Further, as discussed in Section 3 and as modeled in Section 7, existing PM controls at the permit limit of 0.1 lb/MMBtu are considered BART. With an uncorrected CPM emission rate (0.08 lb/MMBtu) estimated at 4 times filterable PM (0.02 lb/MMBtu), Unit 1 is still conservatively operating below the filterable emission rate (0.1 lb/MMBtu), which has been modeled and contributes a maximum 0.02 Δ-dV to regional haze (see Section 7.5). Therefore, comparable to the SO_2 determination, CPM emissions do not significantly change the PM determination in Section 3.

6.5 CPM Visibility Impacts

As illustrated in Section 3.5, visibility impairment due to particulate matter is negligible in comparison to the contributions attributed to sulfates and nitrates. For Stanton Station, the modeled comparison of the current Method 5 PM results (0.02 lb/MMBtu) and the existing PM permit limit (0.1 lb/MMBtu) yielded an additional visibility impairment of only 0.02 Δ-dV on the 98th percentile for the fivefold increase in emissions. As stated above, it is assumed that total particulate emissions (uncorrected condensable + filterable) will be 5 times the filterable contribution, or in this case, slightly less than 0.1 lb/MMBtu, given the uncertainties with the methodologies. Consequently, the total visibility impairment attributed to uncorrected CPM is estimated to be less than 0.02 Δ-dV. These results indicate that total particulate emissions (uncorrected condensable + filterable) will have a negligible influence on overall visibility impacts. Therefore, even if CPM emissions are as high 4 times filterable PM, the modeled visibility impairment would not be significant and additional SO_2 and PM controls are not economically justifiable.

6.6 Proposed BART for CPM

GRE has reviewed, summarized and discussed the limitations of various methodologies for estimating CPM emissions. GRE proposes no additional control for CPM as supported by the visibility analysis in Section 6.5. It is recognized that proposed BART SO_2 controls will reduce CPM, or specifically sulfuric acid mist (SAM) as the major component of CPM, by as much as 90% with a dry scrubber technology, or a slightly lower amount with PRB dry sorbent injection. .

7.0 Visibility Impacts Analysis

The degree of visibility improvement is arguably the most critical component of the BART determination process. As indicated in EPA's final BART guidance[33], states are required to consider the degree of visibility improvement resulting from the retrofit technologies in combination with other factors, such as economic, energy and other non-air quality, when determining BART for an individual source. By incorporating visibility improvements, the BART analysis is distinctly different than a traditional Best Available Control Technology (BACT) analysis, which relies more heavily on cost considerations.

The CALPUFF program models how a pollutant contributes to visibility impairment with consideration for the background atmospheric ammonia, ozone and meteorological data. Additionally, the interactions between the visibility impairing pollutants NOx, SO_2 and PM_{10} can play a large part in predicting impairment. It is therefore important to take a multi-pollutant approach when assessing visibility impacts.

7.1 Assessing Visibility Impairment

The CALPUFF program models how a pollutant contributes to visibility impairment with consideration for the background atmospheric ammonia, ozone and meteorological data. Additionally, the interactions between the visibility impairing pollutants NOx, SO_2 and PM_{10} can play a large part in predicting impairment. It is therefore important to take a multi-pollutant approach when assessing visibility impacts.

The visibility impairment contribution for different emission rate scenarios can be determined using the CALMET, CALPUFF, POSTUTIL, and CALBART modeling templates provided by the North Dakota Department of Health (NDDH). The North Dakota BART modeling protocol[34] describes the CALPUFF model inputs including the meteorological data set and background atmospheric ammonia and ozone concentrations along with the functions of the POSTUTIL and CALBART post processing elements. The CALBART output files provide three methods with which to assess the expected post-BART visibility improvement: the 98th percentile, 90th percentile, and the number of days on which a source exceeds an impairment threshold.

As defined by federal guidance and Section 33-15-25-01 of the North Dakota Air Pollution Control Rules, [35] a source "contributes to visibility impairment" if the 98th percentile of any year's modeling results meets or exceeds the threshold of five-tenths of a deciview (dV) at a Federally protected Class I area receptor. The pre-BART evaluation of this criterion conducted by the North Dakota Department of Health identified Stanton Station Unit 1 as subject to BART[36] because it 'causes or contributes' to visibility impairment at the four North Dakota Class I areas.

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[33] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Rules and Regulations p. 39106.

[34] *Protocol for BART-Related Visibility Modeling Analyses in North Dakota,* Final Version, November, 2005.

[35] Chapter 33-15-25 is a new rule on public notice through May 15, 2006.

[36] Subject to BART notification from NDDH is included in Appendix C.

In addition to establishing whether or not a source contributes to impairment on the 98th percentile, the severity of the visibility impairment contribution, or reasonably attributed visibility impairment, can be gauged by assessing the number of days on which a source exceeds 0.5 Δ-dV.

As a worst case, pre-BART modeling of Stanton Station indicated a maximum of 29 days above 0.5 Δ-dV occurred at TRNP South Unit in 2002. There were fewer days above 0.5 Δ-dV for 2000 and 2001. Finally, the determination of reasonable progress along the predicted glide path can be assessed using the 90th percentile prediction.

7.2 Predicting 24-Hour Maximum Emission Rates

Pursuant to verbal guidance from NDDH staff and consistent with use of the highest daily emissions for pre-BART visibility impacts, the post-BART emissions to be used for the visibility impacts analysis should reflect a maximum 24-hour average projected emission rate. The projected 24-hour maximum emission rate was estimated for each control technology considered in this analysis. These predictions were based on a 30-day expected emission rate for each technology, taking into consideration some potential for operational and fuel-based variability for that technology.[37] Table 7-1 and Table 7-2 provide a summary of the modeled 24-hour emission rates and their computational basis for the evaluated NOx and SO_2 control technologies, respectively.[38] For modeling simplification, other stack parameters such as exit temperature and velocity, height, elevation and diameter were not changed and can be found in the protocol[39].

As discussed in Section 4.0, NOx emission rates are highly dependent on Unit 1 load swings due to MISO demands, which can result in a wide range of lb/MMBtu emission rates. For this reason, the 24-hour maximum NOx emissions are presented as lb/hr rates, which is consistent with visibility modeling inputs. Although the 24-hour maximum emission rate for the proposed BART of LNB with OFA shows negligible improvement from pre-BART on either fuel, LNB/OFA will provide more significant reductions with respect to 30-day and annual time periods.

Table 7-1 NOx Predicted 24-hour Maximum Emission Rates

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[37] Since the PRB scenario was added after completion of modeling, Barr developed a correlation curve based on existing modeling and used it to extrapolate PRB dV improvements. This information is included in Appendix C.

[38] As noted in the Executive Summary, under Additional Considerations and Associated Potential Reductions, Great River Energy is committing to either installation of a dry scrubbing technology with baghouse or converting Unit 1 to a clean coal technology, such as IGCC. For determining appropriate 24-hr modeling values, it is therefore appropriate to use the lignite SO_2 emission rates in Table 7-2 as worse case. The NOx values are essentially the same between lignite and PRB in Table 7-1. For Particulate, a value of 0.07 lb/mmbtu can be used consistent with worse case fuel assumptions and installation of a baghouse as noted in the Executive Summary.

[39] *Protocol for BART-Related Visibility Modeling Analyses in North Dakota*, Final Version, November, 2005.

Control Strategy	30-day Rolling Emission Rate	24-hour Max. Emission Rate	Basis[40]
Pre-BART Baseline	--	669 lb/hr	Actual emissions data from 2000 – 2002. Represents the highest NOx emission rate per calendar day.
LNB/OFA	633.6 lb/hr	665.3 lb/hr	20% design control efficiency and 5% variability.
SNCR	574.2 lb/hr	631.6 lb/hr	27.5% design control efficiency and 10% variability.
LNB/OFA + SNCR	435.6 lb/hr	479.2 lb/hr	45% design control efficiency and 10% variability.
Low-Dust SCR	79.2 lb/hr	87.1 lb/hr	90% design control efficiency and 10% variability.

With respect to projected maximum SO_2 emission rates, it is important to recall that Stanton Station is currently permitted for both lignite and PRB. Since the current PRB fuel contract expires in 2009, there are a range of possible sulfur contents for either lignite or PRB that must be considered. As discussed in Appendix E, SO_2 maximum emission rates are based on a projected worst case fuel, which is lignite comparable to Milton R. Young. (It is lignite that is located on the same side of Missouri River as Stanton Station and is the closest operating lignite mine.) Past SO_2 emissions from MRY Unit 1 and historical Stanton Station data were used to establish 1.56% as the worst case coal sulfur content. Emission rates were then calculated in Table 7-2 using the expected control efficiencies and AP-42 conversion factor. Please refer to Appendix E for more specific information on projected sulfur values associated with lignite and PRB fuels.

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[40] Design rates are based on normal operating conditions and are subject to the conditions described in the Alstom engineering assessment (Appendix D).

Table 7-2 SO_2 Predicted 24-hour Maximum Emission Rates

Control Strategy	30-day Rolling Emission Rate	Control Efficiency	24-hour Maximum Emission Rate	Basis
Pre-BART Baseline	--	--	3,418.0 lb/hr 1.90 lb/MMBtu	Actual emissions data from 2000 – 2002. Represents the highest SO_2 emission rate per calendar day.
Wet Scrubber	216.0 lb/hr 0.12 lb/MMBtu	95%	263.3 lb/hr 0.15 lb/MMBtu	Projected Lignite Values [41]
Spray Dry Baghouse	432.0 lb/hr 0.24 lb/MMBtu	90%	526.5 lb/hr 0.29 lb/MMBtu	Projected Lignite Values [40]
DSI Baghouse	1,944.0 lb/hr 1.08 lb/MMBtu	55%	2,369.3 lb/hr 1.32 lb/MMBtu	Projected Lignite Values [40]
DSI and ESP w/PRB	0.36 lb/MMBtu	80%	778 lb/hr 0.43 lb/MMBtu	Projected PRB Values[42]
Fuel Switch to PRB	0.55 lb/MMBtu	70%	0.66 lb/MMBtu	Projected PRB Values[41]

SO_2 emission rate is based on the control efficiency with 0% variability and the average maximum coal sulfur content for Stanton Unit 1 and Milton R. Young Unit 2 as determined by past coal data or EDR[43] emission calculations.

7.3 Modeled Results

Visibility impairment is modeled using the meteorological data for the years 2000, 2001 and 2002 for the scenarios described below. In addition to the 15 combinations of SO_2 and NOx controls, results for the baseline pre-BART emissions and for the post-BART PM control visibility contribution scenarios, which were presented in Section 3.5, are also included. Results for the 90th, 98th and number of days above 0.5 dV at

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[41] Values are derived from maximum sulfur concentrations as found in North Dakota Lignite reserves as could be expected over any 30-day rolling period and are different than the predictions based on past actual operations presented in Section 5.0.

[42] See Appendix E for more information.

[43] Historical (1998 through 2004) Lignite emissions inventories for Stanton Station show a maximum coal sulfur content of 1.55% and EDRs for Milton R. Young Station years 2004 and 2005 show a maximum coal sulfur content of 1.57%. (EDRs available at http://www.epa.gov/airmarkets/emissions/raw/index.html.) See also Appendix E.

each of the Class I areas are included in Table 7-4 through Table 7-6. Additionally, Figure 7-1 illustrates scenarios 1 through 15 on a dollar per dV basis. The figure focuses on year 2002 modeling results because it is the year that showed the most severe pre-BART visibility impairment.

Table 7-3 Visibility Modeling Parameters

Scenario	Description [1]		Emission Rate Input [2]							
			PM_{10}		$PM_{2.5}$ (fine)	PM (coarse)	SO_2		NOx	
	SO_2	NOx	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr
0 pre-BART	Base case	Base Case - LNB	0%	31.8	1.9	29.9	0%	3,418.0	0%	669.0
1	Dry Scrubber	Base Case - LNB	0%	31.8	1.9	29.9	85%	526.5	0%	669.0
2 Proposed BART	Dry Scrubber	LNB/OFA	0%	31.8	1.9	29.9	85%	526.5	1%	665.3
3	Dry Scrubber	SNCR	0%	31.8	1.9	29.9	85%	526.5	6%	631.6
4	Dry Scrubber	LNB/OFA + SNCR	0%	31.8	1.9	29.9	85%	526.5	28%	479.2
5	Dry Scrubber	SCR	0%	31.8	1.9	29.9	85%	526.5	87%	87.1
6	DSI BH	Base Case - LNB	0%	31.8	1.9	29.9	31%	2,369.3	0%	669.0
7	DSI BH	LNB/OFA	0%	31.8	1.9	29.9	31%	2,369.3	1%	665.3
8	DSI BH	SNCR	0%	31.8	1.9	29.9	31%	2,369.3	6%	631.6
9	DSI BH	LNB/OFA + SNCR	0%	31.8	1.9	29.9	31%	2,369.3	28%	479.2
10	DSI BH	SCR	0%	31.8	1.9	29.9	31%	2,369.3	87%	87.1
11	Wet Scrubber	Base Case - LNB	0%	31.8	1.9	29.9	92%	263.3	0%	669.0
12	Wet Scrubber	LNB/OFA	0%	31.8	1.9	29.9	92%	263.3	1%	665.3
13	Wet Scrubber	SNCR	0%	31.8	1.9	29.9	92%	263.3	6%	631.6
14	Wet Scrubber	LNB/OFA + SNCR	0%	31.8	1.9	29.9	92%	263.3	28%	479.2
15	Wet Scrubber	SCR	0%	31.8	1.9	29.9	92%	263.3	87%	87.1
16 [3]	PRB	PRB	0%	31.8	1.9	29.9	70%	1,188.0	17%	648.0
17 [3]	PRB	LNB/OFA + PRB	0%	31.8	1.9	29.9	70%	1,188.0	34%	514.8
18 [3]	DSI/ESP + PRB	LNB/OFA + PRB	0%	31.8	1.9	29.9	80%	774.0	34%	514.8
19 [3]	DSI BH + PRB	LNB/OFA + PRB	0%	31.8	1.9	29.9	86%	446.4	34%	514.8
20 [3]	Dry Scrubber + PRB	LNB/OFA + PRB	0%	31.8	1.9	29.9	92%	270.0	34%	514.8
21	Scenario 2 + Best PM Controls		15%	27.0	1.6	25.4	85%	526.5	1%	665.3
22	Scenario 2 + Permit Limit PM		-466%	180.0	10.8	169.2	85%	526.5	1%	665.3

[1] All scenarios except 16 and 17 have the existing ESP as particulate control.

[2] Percent reduction as compared to pre-BART base case (Scenario 0). SO_2 % reduction represents the modeled emission rates comparison and do not directly indicate the design control efficiencies. Emission rates were determined using the maximum expected coal sulfur content (Appendix E) and the design control efficiencies.

[3] Scenarios 16 through 20 added to reflect PRB fuel use. Updated scenarios were not modeled formally, but visibility impacts were estimated using the correlation provided in Appendix C.

Table 7-4 Model Results for the Year 2000

	Description [1]			Visibility Impairment											
				TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
Scenario	SO_2	NOx	Average Improvement [2]	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
0 pre-BART	Base case	Base Case - LNB	0%	17	0.228	0.937	17	0.221	0.947	10	0.184	0.868	23	0.344	0.991
1	Dry Scrubber	Base Case - LNB	68%	3	0.066	0.320	4	0.080	0.458	2	0.054	0.224	4	0.118	0.340
2 Proposed BART	Dry Scrubber	LNB/OFA	68%	3	0.066	0.318	4	0.080	0.456	2	0.054	0.224	4	0.117	0.338
3	Dry Scrubber	SNCR	69%	3	0.065	0.305	4	0.077	0.438	2	0.054	0.222	4	0.113	0.323
4	Dry Scrubber	LNB/OFA + SNCR	73%	2	0.055	0.253	4	0.065	0.356	2	0.049	0.215	3	0.096	0.260
5	Dry Scrubber	SCR	85%	1	0.035	0.144	1	0.034	0.144	1	0.028	0.131	1	0.052	0.154
6	DSI BH	Base Case - LNB	24%	12	0.174	0.691	12	0.171	0.770	8	0.139	0.696	13	0.262	0.755
7	DSI BH	LNB/OFA	24%	12	0.174	0.690	12	0.171	0.769	8	0.139	0.694	13	0.261	0.754
8	DSI BH	SNCR	25%	12	0.173	0.679	12	0.165	0.752	8	0.137	0.680	13	0.256	0.744
9	DSI BH	LNB/OFA + SNCR	29%	12	0.162	0.663	11	0.157	0.672	8	0.130	0.614	12	0.240	0.701
10	DSI BH	SCR	43%	9	0.137	0.553	8	0.122	0.557	6	0.106	0.445	11	0.191	0.591
11	Wet Scrubber	Base Case - LNB	75%	2	0.048	0.290	4	0.062	0.369	2	0.040	0.183	3	0.094	0.320
12	Wet Scrubber	LNB/OFA	75%	2	0.048	0.289	4	0.062	0.368	2	0.040	0.182	3	0.094	0.318
13	Wet Scrubber	SNCR	77%	2	0.046	0.277	4	0.059	0.354	2	0.038	0.174	2	0.090	0.303
14	Wet Scrubber	LNB/OFA + SNCR	80%	2	0.039	0.221	3	0.048	0.292	2	0.033	0.135	2	0.074	0.236
15	Wet Scrubber	SCR	91%	0	0.020	0.079	0	0.021	0.097	0	0.017	0.086	0	0.034	0.090
16-20 [3]	Scenarios not directly modeled, see Appendix C for calculation and correlation data.														
21	Scenario 2 + Best PM Controls		68%	3	0.066	0.318	4	0.080	0.455	2	0.054	0.223	1	0.117	0.338
22	Scenario 2 + Permit Limit PM		67%	3	0.071	0.326	4	0.081	0.466	3	0.055	0.236	4	0.122	0.349

[1] All scenarios except 16 and 17 have the existing ESP as particulate control.

[2] Average improvement represents the 90th percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.

[3] Scenarios 16 through 20 added to reflect PRB fuel use. Updated scenarios were not modeled formally, but visibility impacts were estimated using the correlation provided in Appendix C.

Table 7-5 Model Results for the Year 2001

	Description [1]			Visibility Impairment											
				TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
Scenario	SO_2	NOx	Average Improvement [2]	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
0 pre-BART	Base case	Base Case - LNB	0%	17	0.214	0.901	21	0.319	1.205	13	0.144	0.733	30	0.386	1.351
1	Dry Scrubber	Base Case - LNB	69%	4	0.061	0.322	5	0.089	0.385	2	0.036	0.241	8	0.160	0.526
2 Proposed BART	Dry Scrubber	LNB/OFA	69%	4	0.061	0.321	5	0.089	0.383	2	0.036	0.240	8	0.159	0.524
3	Dry Scrubber	SNCR	70%	4	0.059	0.313	5	0.086	0.369	2	0.036	0.234	8	0.153	0.506
4	Dry Scrubber	LNB/OFA + SNCR	73%	1	0.054	0.261	4	0.073	0.318	1	0.034	0.203	7	0.133	0.422
5	Dry Scrubber	SCR	85%	0	0.032	0.141	1	0.049	0.190	0	0.022	0.115	2	0.059	0.210
6	DSI BH	Base Case - LNB	24%	13	0.160	0.715	17	0.245	0.937	10	0.105	0.541	27	0.311	1.062
7	DSI BH	LNB/OFA	24%	13	0.160	0.714	17	0.245	0.936	10	0.105	0.541	27	0.311	1.060
8	DSI BH	SNCR	25%	12	0.158	0.701	17	0.241	0.915	10	0.103	0.535	27	0.306	1.042
9	DSI BH	LNB/OFA + SNCR	30%	12	0.149	0.641	16	0.222	0.854	9	0.101	0.515	24	0.272	0.963
10	DSI BH	SCR	41%	8	0.124	0.544	12	0.201	0.733	6	0.086	0.439	20	0.213	0.821
11	Wet Scrubber	Base Case - LNB	77%	2	0.043	0.270	5	0.061	0.334	1	0.024	0.178	7	0.139	0.449
12	Wet Scrubber	LNB/OFA	77%	2	0.043	0.269	5	0.061	0.333	1	0.023	0.177	7	0.138	0.447
13	Wet Scrubber	SNCR	78%	1	0.041	0.257	5	0.059	0.319	1	0.023	0.169	7	0.132	0.429
14	Wet Scrubber	LNB/OFA + SNCR	81%	1	0.036	0.203	1	0.053	0.255	0	0.021	0.143	6	0.106	0.344
15	Wet Scrubber	SCR	91%	0	0.019	0.091	0	0.029	0.110	0	0.012	0.063	1	0.039	0.129
16-20 [3]	Scenarios not directly modeled, see Appendix C for calculation and correlation data.														
21	Scenario 2 + Best PM Controls		69%	4	0.061	0.321	5	0.088	0.383	2	0.036	0.240	8	0.159	0.524
22	Scenario 2 + Permit Limit PM		68%	4	0.062	0.323	5	0.093	0.389	2	0.036	0.242	8	0.166	0.531

[1] All scenarios except 16 and 17 have the existing ESP as particulate control.

[2] Average improvement represents the 90th percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.

[3] Scenarios 16 through 20 added to reflect PRB fuel use. Updated scenarios were not modeled formally, but visibility impacts were estimated using the correlation provided in Appendix C.

Table 7-6 Model Results for the Year 2002

Scenario	Description [1]		Average Improv-ement [2]	Visibility Impairment											
				TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
	SO$_2$	NOx		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
0 pre-BART	Base case	Base Case - LNB	0%	29	0.310	1.675	23	0.312	1.540	14	0.233	1.432	25	0.308	1.150
1	Dry Scrubber	Base Case - LNB	69%	13	0.096	0.668	12	0.097	0.595	8	0.074	0.517	5	0.088	0.410
2 Proposed BART	Dry Scrubber	LNB/OFA	70%	13	0.095	0.666	11	0.096	0.593	8	0.074	0.515	5	0.088	0.408
3	Dry Scrubber	SNCR	71%	13	0.092	0.648	9	0.094	0.569	7	0.071	0.499	5	0.085	0.395
4	Dry Scrubber	LNB/OFA + SNCR	75%	8	0.080	0.565	6	0.083	0.460	6	0.060	0.426	4	0.073	0.334
5	Dry Scrubber	SCR	85%	3	0.047	0.270	1	0.047	0.241	2	0.035	0.232	0	0.048	0.183
6	DSI BH	Base Case - LNB	22%	22	0.243	1.293	21	0.239	1.221	13	0.191	1.111	19	0.236	0.886
7	DSI BH	LNB/OFA	22%	22	0.243	1.291	21	0.239	1.220	13	0.191	1.109	19	0.235	0.885
8	DSI BH	SNCR	22%	22	0.242	1.272	21	0.235	1.208	13	0.191	1.095	19	0.230	0.872
9	DSI BH	LNB/OFA + SNCR	29%	21	0.220	1.196	20	0.219	1.104	13	0.165	1.028	19	0.218	0.813
10	DSI BH	SCR	43%	18	0.186	0.957	18	0.183	0.780	12	0.125	0.782	15	0.168	0.685
11	Wet Scrubber	Base Case - LNB	75%	10	0.089	0.556	9	0.072	0.516	6	0.050	0.429	4	0.078	0.341
12	Wet Scrubber	LNB/OFA	76%	10	0.088	0.553	8	0.071	0.514	6	0.050	0.427	4	0.077	0.339
13	Wet Scrubber	SNCR	77%	9	0.084	0.528	7	0.069	0.490	6	0.047	0.411	4	0.074	0.326
14	Wet Scrubber	LNB/OFA + SNCR	80%	5	0.066	0.422	5	0.059	0.392	2	0.045	0.337	3	0.059	0.264
15	Wet Scrubber	SCR	91%	0	0.029	0.159	1	0.030	0.160	0	0.023	0.140	0	0.028	0.107
16-20 [3]	Scenarios not directly modeled, see Appendix C for calculation and correlation data.														
21	Scenario 2 + Best PM Controls		70%	13	0.095	0.665	11	0.096	0.592	8	0.074	0.515	5	0.088	0.408
22	Scenario 2 + Permit Limit PM		68%	14	0.101	0.686	12	0.097	0.611	8	0.075	0.525	5	0.093	0.411

[1] All scenarios except 16 and 17 have the existing ESP as particulate control.

[2] Average improvement represents the 90th percentile comparison to the base case (Scenario 0) averaged for the 4 Class 1 areas.

[3] Scenarios 16 through 20 added to reflect PRB fuel use. Updated scenarios were not modeled formally, but visibility impacts were estimated using the correlation provided in Appendix C.

Table 7-7 Dollar per Deciview Scenario Descriptions

Scenario	SO_2	NOx	Average Calculated Visibility Improvement (dV)[44]
1	Dry Scrubber	Base Case	N/A, See modeling Tables 7-3 through 7-6
2	Dry Scrubber	LNB/OFA	
3	Dry Scrubber	SNCR	
4	Dry Scrubber	OFA + SNCR	
5	Dry Scrubber	SCR	
6	DSI BH	Base Case	
7	DSI BH	LNB/OFA	
8	DSI BH	SNCR	
9	DSI BH	OFA + SNCR	
10	DSI BH	SCR	
11	Wet Scrubber	Base Case	
12	Wet Scrubber	LNB/OFA	
13	Wet Scrubber	SNCR	
14	Wet Scrubber	OFA + SNCR	
15	Wet Scrubber	SCR	
16	PRB	PRB	0.759
17	PRB	LNB/OFA + PRB	0.836
18	DSI/ESP + PRB	LNB/OFA + PRB	0.946
19	DSI BH + PRB	LNB/OFA + PRB	1.009
20	Dry Scrubber + PRB	LNB/OFA + PRB	1.065

As illustrated by the dollar per deciview analysis in Figure 7-1, there are a range of potential BART control combinations and associated visibility improvements. It is important to note that the range of potential deciview improvements spans from a low of 0.3 dV to a maximum of 1.3 dV. With respect to determining the cost effectiveness of the various scenarios, the annualized cost for each scenario was plotted against the average visibility improvement in Figure 7-1. There are two curves representing control options for Lignite and PRB. The inherently lower sulfur PRB causes the curve to shift significantly to the right, providing more deciview reductions for comparable control costs.

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[44] See addendum to Appendix C on modeling correlation based on previously modeled scenarios.

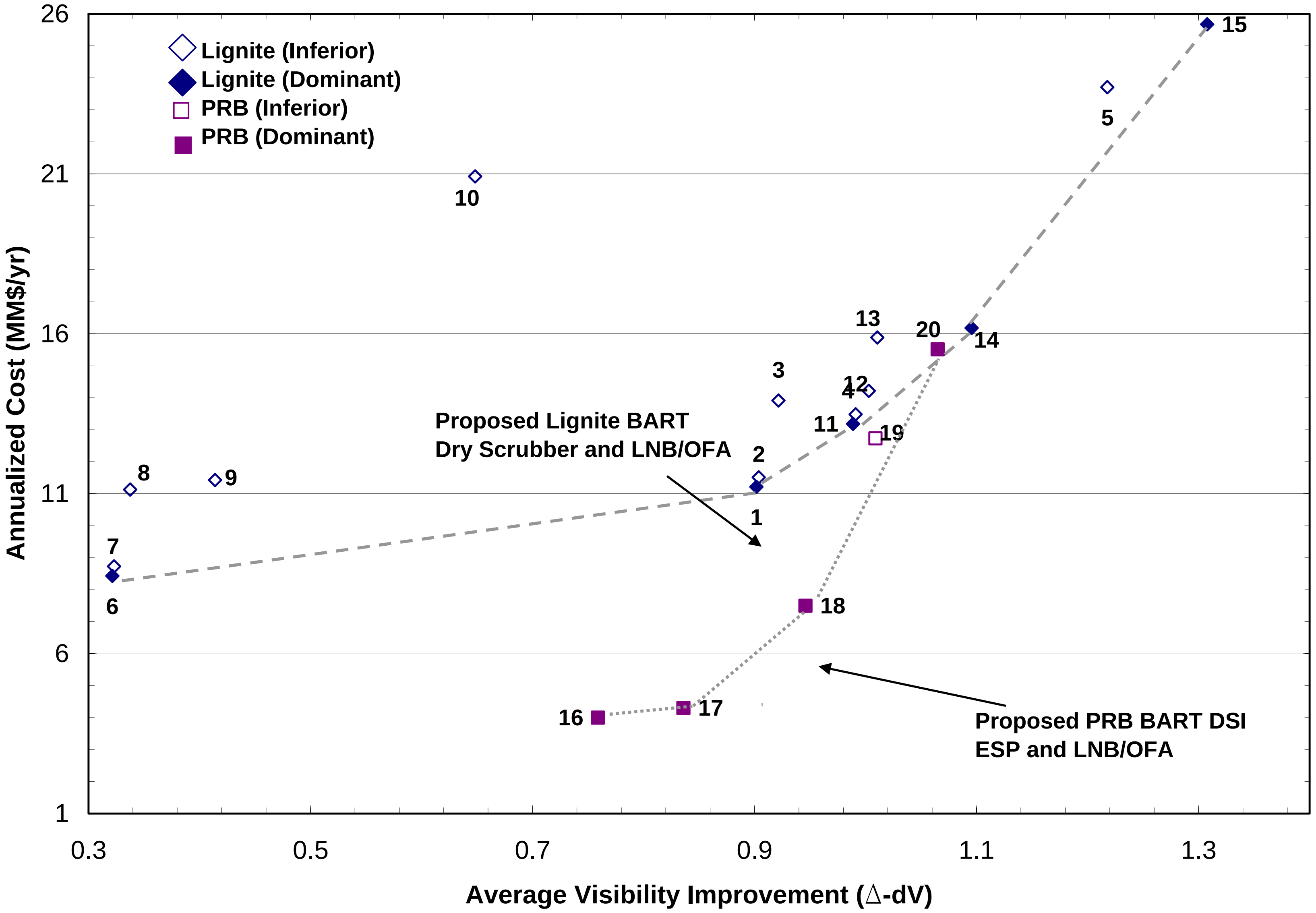

Figure 7-1 Dollar per Deciview Analysis. Scenarios 1 through 15 are plotted for the 98th percentile of 2002 based on the total annualized cost and the average visibility improvement for the 4 Class 1 areas. Dominant controls are presented as filled diamonds and inferior controls are represented as empty diamonds and secondary dominant controls (PRB scenarios) are represented with filled or empty squares. See Table 7-7 for additional scenario description.

The first cluster of Scenarios 6, 7, 8 and 9 represent roughly 0.3 to 0.4 dV improvement from the baseline. Scenario 6 represents the most cost effective Scenario in this cluster and is the start of the least cost envelope curve. The next scenario cluster occurs at an average visibility improvement of 0.9 to 1.0 dV. This second cluster includes Scenario 1, and 2 as part of the least cost envelope curve.

The slope of the least cost envelope increases significantly after Scenario 2. The SNCR addition (Scenarios 4 and 14) causes the curve to rise sharply, which is a graphical representation of the relative significance of additional costs combined with limited dV improvements. After Scenario 2, the graph demonstrates that for an additional 0.1 to 0.2 dV improvement, there will be annualized cost increase from $12.4MM to $15.1MM annualized cost.

Finally, Scenario 2 OFA/LNB did not provide significant modeled deciview improvements from Scenario 1 LNB, which would generally support Scenario 1 as BART from a strictly visibility perspective. Nevertheless, Great River Energy recognizes that the Scenario 2 OFA/LNB will provide 30-day and annual NOx reduction benefits that are supportive of visibility improvements even though the 24-hr modeled effects are not readily apparent.

For the secondary curve based upon PRB control scenarios 16-20, the curve demonstrates that PRB unscrubbed Scenarios 16 and 17 provides approximately the same absolute dV improvement as the Lignite Scenario 2 determined to be BART. The secondary curve climbs to DSI and ESP as the next control. Since it was viewed as cost effective based on dollar per ton and incremental dollar per ton assessments, it is established as BART for PRB. Scenario 20 only provides an additional ~0.1 dV improvement. Therefore, from a visibility perspective in conjunction with cost effectiveness arguments, it is not considered BART on PRB. Since Scenario 2 provides a lesser dV improvement over Scenario 18, Scenario 2 will be used as a conservative basis for further discussion.

7.4 Visibility Impacts of the Proposed BART

Scenario 2 represents a significant reduction in modeled visibility impairment from the baseline in the four North Dakota Class 1 Areas. For example, on average, for the 2002 98th percentile, over a 0.9 Δ-dV improvement is expected from the average baseline of 1.45 dV. Interestingly, the Scenario 2, 0.9 Δ-dV BART average reduction places Stanton Unit 1 only slightly above (at 0.55 dV) EPA’s 0.5 dV ‘cause or contribute’ threshold, which is considered imperceptible to the human eye.

Table 7-8 provides the expected percent visibility improvement for the proposed BART Scenario 2 along with pre-BART and post-BART days above the 0.5 dV contribution threshold. With the 98th percentile correction[45], the eighth highest daily visibility impairment is less than 0.5 Δ-dV at all but one station[46] for the modeled years 2000 and 2001.

Table 7-8 Proposed BART Scenario 2 - Average Improvement Over Baseline

Year	Average Percentile Improvement		Average Days Above 0.5 Δ-dV		
	90th	98th	Pre-BART	Improvement	Post-BART
2000	68%	64%	17	14	3
2001	69%	65%	20	16	4
2002	70%	63%	23	14	9

Additional reductions associated with Scenarios 4, 14, and 15 in Table 7-6, as the worst case year, will not reduce the number of days above the contribution threshold from Scenario 2 without significant additional costs as demonstrate in Figure 7-1. The most significant incremental reductions occur in 2002 in TRNP South Unit. For these reasons, the visibility impacts analysis support Scenario 2 as BART for Stanton Station Unit 1.

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[45] As stated in the modeling protocol, the 98th percentile is roughly the eighth-highest daily prediction. By this estimation, any modeled scenario with fewer than 7 days above 0.5 Δ-dV has a 98th percentile below 0.5Δ-dV.

[46] The eighth highest daily impairment for Lostwood NWA in 2001 is only 0.524 Δ-dV

8.0 Summary of Proposed BART

Based on careful consideration of all factors included in this BART analysis, Scenario 2 (Dry Scrubber/Baghouse and OFA/LNB) is considered BART for Stanton Station Unit 1. In order to arrive at this determination, one must first quantitatively assess the average and incremental cost effectiveness of individual pollutant controls as well as qualitatively assess energy and other environmental impacts. As discussed in Sections 3 thru 6, these individual pollutant assessments are then viewed in conjunction with combined control scenarios as part of the visibility assessment in Section 7 to ultimately determine BART.

With respect to particulate controls (PM), as a single pollutant, GRE will maintain the current PM performance standard of 0.1 lb/MMBtu. Section 3.0 PM analysis confirms that additional PM controls are not economically justified on a dollar per ton basis. More importantly, the modeled benefits associated with potential PM reductions are less than 0.02 dV, which is considered an insignificant deciview reduction for North Dakota's Class 1 areas. Therefore, the combined assessment of cost and insignificant deciview improvements support maintaining a PM emission limit of 0.1 lb/MMBtu.

For NOx controls, GRE establishes LNB with OFA as BART as described in Section 4.0. A low dust SCR with reheat can be ruled out on cost per ton and incremental cost effectiveness arguments. SNCR, by itself, and LTO are also arguably above the average cost effective thresholds used by EPA to set presumptive BART limits. EPA clearly did not intend for larger emission units >750MW to install post combustion NOx controls by setting presumptive emission rates consistent with LNB/OFA technologies. Large cyclone units are the only emission units required to install post combustion NOx controls. Figure 7-1 shows that LTO and SNCR without LNB/OFA, are inferior controls since they are not on the dominant curve. The combination of SNCR with OFA can be ruled out on cost per ton and incremental cost per ton along with other operational, energy, environmental impacts as noted in Table 4-4. Further, the operational limitations of SNCR (Scenarios 4 and 14), also support the selection of Scenario 2 as BART. This determination, is most importantly, supported by the visibility analysis, which demonstrates only a 0.1 Δ-dV associated with SNCR (Figure 7-1 – Scenario 2 to Scenario 4). While LNB with OFA shows little modeled improvement with respect to the 24-hour projected maximum emission rate, this control will provide approximately 20-25% reduction on a 30-day and annual basis from the baseline. Potential changes in load variability for Unit 1 as well as visibility modeling support a BART limit of 0.35 lb/MMBtu on a 30-day rolling average rather than a lb/hr limit.

For SO_2 control, GRE proposes to install a dry scrubber technology with 90% design removal efficiency and a 0.24 lb/MMBtu 30-day rolling average BART limit on lignite. Alternatively, a fuel switch to PRB coal in addition to DSI technology utilizing the existing ESP controls is considered BART and would establish a 30-day rolling limit of 0.36 lb/MMBtu.

From a top down analysis, Scenario 15 (Wet FGD & SCR) is considered above the EPA average cost effective thresholds that were used to set presumptive BART limits. More importantly, the incremental deciview improvements from Scenario 2 (Dry scrubber & SCR) are only 0.1 dV, which is viewed as insignificant. There are other qualitative non-air quality, environmental impacts and site limitations, which would preclude wet scrubber from consideration.

In continuing the top down analysis, as discussed in Sections 4 and 5, Scenario 14 (wet FGD & LNB/OFA/SNCR) can arguably be considered above the EPA average cost effective thresholds for SO2 and NOx. Further, the incremental dV improvement from Scenario 2 to Scenario 14 is <0.1dV. Therefore, the combined effective of cost per/ton, incremental cost per ton and incremental deciview improvement strongly supports Scenario 2 as BART.

Scenario 4, which includes SNCR as the only difference with Scenario 2, can be ruled out because the LNB/OFA/SNCR cost per ton reductions are outside of the cost effective range according to BART guidelines. Further, the incremental dollar per ton for SNCR is extremely high and there are other energy and environmental impacts that would preclude it from consideration. In terms of incremental visibility improvement, there would be approximately 0.1 dV improvement from Scenario 2 to Scenario 4.

Arguably, between Scenario 1 and 2, there is not much of a modeled visibility improvement. Because LNB/OFA provides monthly and annual reductions and because the technology is a cost effective retrofit, it is established as BART.

BART Emission Limits

Pollutant	Permit Limit	BART Limit
PM_{10}	0.10 lb/MMBtu	0.10 lb/MMBtu
NOx	0.46 lb/MMBtu	0.35 lb/MMBtu
SO_2 Lignite	3.0 lb/MMBtu	0.24 lb/MMBtu
SO_2 PRB	3.0 lb/MMBtu	0.36 lb/MMBtu

In combination, the Scenario 2 BART controls will provide an average visibility improvement of over 0.9 Δ-dV compared to the pre-BART baseline that will significantly contribute to the state’s effort in meeting its reasonable progress goals under the Regional Haze Rule. From a visibility standpoint, other BART control scenarios do not provide significant incremental improvements and are not justified on cost per ton and incremental cost per ton effectiveness arguments at this time.

Appendices

Appendix A. Economic Evaluations

Appendix B. Cost Threshold Documentation

Appendix C. Visibility Modeling

Appendix D. Alstom NOx Evaluation

Appendix E. Sulfur Content Statistical Analysis

Appendix F. SCR catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals

Appendix G. Stanton Station Site Plan

Appendix A

Economic Evaluations

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-1A: Cost Summary Lignite Basis

Added PRB scenario

Updated per additional cost data, November 2007

PM/PM10 Control Cost Summary

Baseline 0.019 lb/MMBtu

Case	Control Technology	Controlled Emissions lb/MMBtu	Percent Reduction % [2]	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Polishing Wet ElectroStatic Precipitator (WESP)	**0.015**	**20%**	**72.5**	**1**	**17.0**	**$6.90**	**$2.03**	**$119,268**	**D**	**NA-Base**	**A-4**
2	Dry ElectroStatic Precipitator (ESP)	**0.015**	**20%**	**72.5**	**--**	**17.0**	**$38.57**	**$5.80**	**$340,570**	**I**	**NA**	**A-5**
3	PM Baghouse	**0.015**	**20%**	**72.5**	**--**	**17.0**	**$33.65**	**$4.98**	**$292,702**	**I**	**NA**	**A-6**

SO_2 Control Cost Summary

Baseline 1.815 lb/MMBtu

Case	Control Technology	Controlled Emissions lb/MMBtu	Percent Reduction % [2]	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Absorber	**0.091**	**95%**	**438.4**	**4**	**8153.1**	**$88.16**	**$13.18**	**$1,617**	**D**	**$4,484**	**A-7**
2	Spray Dry Baghouse+PRB	**0.150**	**92%**	**724.8**	**D2-3**	**7866.8**	**$79.51**	**$13.31**	**$1,692**	**D2**	**$8,083**	**A-8**
3	Spray Dry Baghouse	**0.181**	**90%**	**876.9**	**3**	**7714.7**	**$77.84**	**$11.22**	**$1,454**	**D**	**$4,385**	**A-9**
4	DSI Baghouse+PRB	**0.248**	**86%**	**1195.9**	**--**	**7395.7**	**$57.20**	**$10.43**	**$1,411**	**I**	**NA**	**A-10**
5	Absorber 10% Bypass	**0.263**	**86%**	**1271.4**	**2**	**7320.1**	**$65.64**	**$9.49**	**$1,296**	**D**	**$1,420**	**A-11**
6	DSI Existing ESP+PRB	**0.358**	**80%**	**1727.4**	**D2-2**	**6864.2**	**$11.52**	**$5.20**	**$758**	**D2**	**$3,444**	**A-14A**
7	Fuel Switch to PRB	**0.550**	**70%**	**2657.5**	**D2-1**	**5934.0**	**$0.00**	**$2.00**	**$337**	**D2**	**NA- Base PRB**	**A-12**
8	DSI Baghouse	**0.817**	**55%**	**3945.9**	**--**	**4645.7**	**$57.20**	**$8.43**	**$1,814**	**I**	**NA**	**A-13**
9	DSI Existing ESP	**1.180**	**35%**	**5699.6**	**1**	**2892.0**	**$11.52**	**$3.20**	**$1,105**	**D**	**NA-Base**	**A-14B**

PRB SO_2 Scenario Comparisons

Control Technology	Emission Reduction T/yr Compared to PRB Base	Pollution Control Cost $/ton Compared to PRB Base	Annual Incremental Cost $/ton Compared to PRB Base
Spray Dry Baghouse+PRB (92%)	**1932.7**	**$6,885**	**$6,100**
DSI Baghouse+PRB	**1461.6**	**$7,138**	**$9,841**
DSI Existing ESP+PRB	**930.1**	**$5,594**	**$3,444**
Fuel Switch to PRB	**0.0**	**$0**	**NA-Base**

NO_x Control Cost Summary

Baseline 0.435 lb/MMBtu

Case	Control Technology	Controlled Emissions lb/MMBtu	Percent Reduction % [2]	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Selective Catalytic Reduction (SCR) w/Reheat	**0.044**	**90%**	**210.2**	**3**	**1928.7**	**$56.55**	**$12.49**	**$6,478**	**D**	**$10,036**	**A-15, A-16**
2	Low Temperature Oxidation (LoTOx)	**0.044**	**90%**	**210.2**	**--**	**1928.7**	**$43.88**	**$44.78**	**$23,217**	**I**	**NA**	**A-17**
3	SNCR + PRB + Alstom LNB + OFA	**0.196**	**55%**	**946.1**	**D2-3**	**1192.9**	**$10.67**	**$5.31**	**$4,452**	**D2**	**$6,910**	**A-18, A20**
4	SNCR + PRB	**0.230**	**47%**	**1111.3**	**--**	**1027.7**	**$8.41**	**$5.01**	**$4,877**	**I**	**NA**	**A-18**
5	Alstom LNB + OFA + SNCR	**0.239**	**45%**	**1156.3**	**2**	**982.7**	**$10.66**	**$3.00**	**$3,053**	**D**	**$6,927**	**A-19, A-21**
6	Selective Non-Catalytic Reduction (SNCR)	**0.290**	**33%**	**1401.2**	**--**	**737.7**	**$8.39**	**$2.70**	**$3,661**	**I**	**NA**	**A-19**
7	Alstom LNB + OFA + PRB	**0.286**	**34%**	**1381.9**	**D2-2**	**757.1**	**$2.27**	**$2.30**	**$3,037**	**D2**	**$836**	**A-20**
8	Alstom LNB + OFA	**0.320**	**26%**	**1546.2**	**1**	**592.8**	**$2.27**	**$0.30**	**$504**	**D**	**NA-Base**	**A-21**
9	Fuel Switch to PRB	**0.360**	**4%**	**1739.5**	**D2-1**	**399.5**	**$0.00**	**$2.00**	**$5,006**	**D2**	**NA-Base PRB**	**A-12**

[1] Control Technology Classification- D=Dominant, D2=Secondary Dominant,I=Inferior. Only dominant costs are used to calculate incremental cost effectiveness. Secondary dominant control evaluation does not include 97% control option.

[2] Percent reduction on a lb/MMBtu basis compared to baseline.

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-1B: GRE Stanton Station Unit 1 FGD Estimates (2012$)

Table 7-1. Capital Cost Estimates for S1 FGD Systems

Capital Cost Component		**LSFO**	**2005 $**	**LSD + FF**	**2005 $**
Area 10: Reagent Feed System	$	$13,400,000	$11,122,000	$3,800,000	$3,154,000
Area 20: SO2 Removal System	$	$23,600,000	$19,588,000	$15,900,000	$13,197,000
Area 30: Flue Gas System	$	$14,200,000	$11,786,000	$18,100,000	$15,023,000
Area 40: Regeneration	$	$0	$0	$0	$0
Area 50: Byproduct Handling	$	$0	$0	$0	$0
Area 60: Solids Handling	$	$2,600,000	$2,158,000	$600,000	$498,000
Area 70: General Support Equipment	$	$1,200,000	$996,000	$1,100,000	$913,000
Area 80: Miscellaneous Equipment*	$	$13,800,000	$11,454,000	$2,000,000	$1,660,000
Fabric Filter	$	N/A		$23,200,000	$19,256,000
TOTAL	**$**	**$68,800,000**	**$57,104,000**	**$64,700,000**	**$53,701,000**
	$/kW	$370	$307	$340	$282
General Facilities	$	$6,900,000	$5,727,000	$6,500,000	$5,395,000
Engineering and Home Office Fees	$	$6,900,000	$5,727,000	$6,500,000	$5,395,000
Process Contingency	$	$1,700,000	$1,411,000	$1,600,000	$1,328,000
Project Contingency	$	$12,700,000	$10,541,000	$11,900,000	$9,877,000
Total Plant Cost (TPC)	**$**	**$97,000,000**	**$80,510,000**	**$91,000,000**	**$75,530,000**
	$/kW	$520	$432	$480	$398
Total Cash Expended (TCE)	**$**	**$94,200,000**	**$78,186,000**	**$89,300,000**	**$74,119,000**
	$/kW	$500	$415	$470	$390
Allowance for Funds (AFDC)	$	$5,100,000	$4,233,000	$4,800,000	$3,984,000
Total Plant Investment (TPI)	**$**	**$99,300,000**	**$82,419,000**	**$93,200,000**	**$77,356,000**
	$/kW	$530	$440	$500	$415
Preproduction Costs	$	$2,400,000	$1,992,000	$2,200,000	$1,826,000
Inventory Capital	$	$47,000	$39,010	$100,000	$83,000
Initial Catalyst and Chemicals	$	$0	$0	$0	$0
Prepaid Royalties	$	$340,000	$282,200	$300,000	$249,000
Total Capital Requirement (TCR)	**$**	**$102,087,000**	**$84,732,210**	**$95,800,000**	**$79,514,000**
	$/kW	$540	$448	$510	$423

*Miscellaneous equipment includes costs for power hook-ups, CEMS replacement, and warehouse demolition and relocation. The LSFO cases also include costs for installation of a new wet stack and waste water treatment plant.

Table 7-2: Operating Parameters for FGD Systems at S1

FGD System		LSFO	LSFO	LSD + FF	LSD + FF
		2012 $	2005 $	2012 $	2005 $
Operating Parameters					
Fuel	Type	PRB		PRB	
Percent Sulfur	%	0.36%		0.36%	
SO2 Removal	%	95%		95%	
NOx Removal	%	N/A		N/A	
Hg Removal	%	N/A		N/A	
SO2 Removed	tons/year	6,100		6,100	
SO2 emitted	lbs/MMBtu	0.04		0.04	
Reagent Type		Limestone		Lime	
Reagent Cost	$/ton	$47.80	$39.67	$119.40	$99
Byproduct Credit	$/ton	$0.00	$0.00	$0.00	$0
Solids Disposal Cost	$/ton	$4.80	$3.98	$4.80	$4
Consumption & Production Rates					
FGD Power Consumption	kW	2,800		1,500	
Fabric Filter Power Consumption	kW	N/A		50	
Reagent Required*	tons/yr	10,600		7,200	**
FGD Solid Waste Disposal	tons/yr	17,400		60,400	
Solid Waste Disposal Volume	yd^3/20 yrs	0			
FGD Byproduct	tons/yr	129,000		0	
Water	1000 gal/yr	0		115,000	
Methane		2,800		0	

*Assumes limestone composition of 94% $CaCO_3$ and Lime composition of 90% available CaO/10% inerts.

** The lime feed rate is based on a Ca/S inlet ratio of 1.15 moles CaO/mole of SO_2 inlet in each case. This feed rate was derived from a database available in EPRI report No. 1004706. The actual feed rate required would be provided by the process vendor based on their guarantee, use of recycle, lime quality, coal analyses, approach temperature, inlet gas temperature, etc.

Table 7-3: Fixed and Variable Operating Cost Summary for FGD Systems

FGD System		LSFO	LSFO	LSD + FF	LSD + FF
		2012 $	**2005 $**	**2012 $**	**2005 $**
Fixed O&M Costs			$0		$0
Number of Operators	#	8		7	
Operating Labor Cost	$/yr	$954,000	$791,820	$835,000	$693,050
Maintenance Labor and Materials Cost	$/yr	$3,620,000	$3,004,600	$2,180,000	$1,809,400
Administrative and Support Labor	$/yr	$720,000	$597,600	$512,000	$424,960
Fabric Filter First Year Fixed Cost	$/yr	$0	$0	$870,000	$722,100
TOTAL First Year Fixed O&M Cost	**$/yr**	**$5,294,000**	**$4,394,020**	**$4,047,000 ***	**$3,359,010**
Variable Operating Costs					
Reagent Costs	$/yr	$508,000	$421,640	$857,000	$711,310
Sludge Disposal Cost for FGD System	$/yr	$83,000	$68,890	$288,000	$239,040
Credit for Byproduct	$/yr	$0	$0	$0	$0
SO2 Credits (see Table 3-9 for basis)	$/yr	($1,600,000)	($1,328,000)	($1,600,000)	($1,328,000)
Steam Costs	$/yr	$0	$0	$0	$0
Water Cost - Fresh	$/yr	$0	$0	$3,000	$2,490
Water Cost - Blowdown	$/yr	$0	$0	$0	$0
Additional Power Costs	$/yr	$981,000	$814,230	$527,000	$437,410
Methane Cost	$/yr	$0	$0	$0	$0
Fabric Filter First Year Variable Cost	$/yr	$0	$0	$117,000	$97,110
TOTAL First Year Variable Cost	**$/yr**	**($28,000)**	**($23,240)**	**$15,000 ****	**$12,450**

*LSD+FF assumes that the ESPs will be taken out of service. The Total First Year Fixed O&M Costs includes a $350,000 credit for ESP O&M costs.

**LSD+FF assumes that the ESPs will be taken out of service. The Total First year variable cost includes a $177,000 credit for ESP power consumption.

Table 7-4: First-Year and Levelized Costs for FGD Systems

FGD System		**LSFO**	**LSFO**	**LSD + FF**	**LSD + FF**
Turbine Arrangement		**2012 $**	**2005 $**	**2012 $**	**2005 $**
First-Year Costs :					
Fixed O&M:	$	$5,294,000	$4,394,020	$4,047,000	$3,359,010
	Mills/KWh	3.6		2.8	
	$/ton SO2 removed	$870	$722	$700	$581
Variable O&M:	$	($28,000)	($23,240)	$15,000	$12,450
	Mills/KWh	-0.02		0.01	
	$/ton SO2 removed	($10)	($8)	$2.00	$2
Fixed Charges:	$	$12,600,000	$10,458,000	$11,800,000	$9,794,000
	Mills/KWh	8.7		8.1	
	$/ton SO2 removed	$2,060	$1,710	$1,900	$1,577
Total:	**$**	**$17,866,000**	**$14,828,780**	**$15,862,000**	**$13,165,460**
	Mills/KWh	12.3		10.9	
	$/ton SO2 removed	$2,920	$2,424	$2,600	$2,158
Levelized Current Dollars:					
Fixed O&M:	Mills/KWh	4.8		3.6	
	$/ton SO2 removed	$1,100		$900	
Variable O&M:	Mills/KWh	-0.1		-0.03	
	$/ton SO2 removed	($20)		($10)	
Fixed Charges:	Mills/KWh	6.5		6.1	
	$/ton SO2 removed	$1,500		$1,400	
Total:	Mills/KWh	11.1		9.7	
	$/ton SO2 removed	$2,600		$2,300	

GRE Stanton Station Unit 1 NOx Estimates (2012$)

Table 7-9. Operating Parameters for S1 NOx Control Methods

***Operating* Parameters**		**SNCR**	**2005 $**	**Mobotec**	**2005 $**
NOx Removal	%	30%		50%	
Baseline NOx Emissions	lbs/MMBtu	0.35		0.35	
NOx Removed	tons/yr	840		1400	
NOx Emitted	lbs/MMBtu	0.25		0.18	
Reagent Type		Urea		19% Aqueous Ammonia	
Reagent Cost	$/ton	$235	$195	$175	$145
Reagent Usage	tons/yr	3,400		3,800	
Water	gpm	30		0	
Additional Power	kW	35		1240	

Table 7-10. Capital and Operating Cost Estimates for S1 NOx Control Methods

Capital Cost Component		**SNCR**	**2005 $**	**Mobotec**	**2005 $**
Total Capital Requirement (TCR)	$	$8,570,000	$7,113,100	$9,280,000	$7,702,400
	$/kW	$45.60	$38	$49.40	$41
			$0		$0
Total First Year Fixed O&M	$/yr	$129,000	$107,070	$312,000	$258,960
Variable O&M Costs			$0		$0
Reagent Cost	$/yr	$791,000	$656,530	$659,000	$546,970
Water Cost	$/yr	$290,000	$240,700	$0	$0
Additional Power Cost	$/yr	$12,000	$9,960	$440,000	$365,200
NOx Credits	$/yr	$0	$0	$0	$0
Total First Year Variable O&M	**$/yr**	**$1,093,000**	**$907,190**	**$1,100,000**	**$913,000**

First Year & Levelized Costs		**SNCR**	**2005 $**	**Mobotec**	**2005 $**
First-Year Cost:					
Fixed O&M:	$	$129,000	$107,070	$312,000	$258,960
	Mills/KWh	0.09		0.22	
	$/ton NOx removed	$150	$125	$220	$183
Variable O&M:	$	$1,090,000	$904,700	$1,100,000	$913,000
	Mills/KWh	0.75		0.76	
	$/ton NOx removed	$1,300	$1,079	$800	$664
Fixed Charges:	$	$1,050,000	$871,500	$1,140,000	$946,200
	Mills/KWh			0.79	
	$/ton NOx removed	$1,250	$1,038	$810	$672
Total First-Year Cost:	$	$2,280,000	$1,892,400	$2,550,000	$2,116,500
	Mills/KWh	1.6		1.8	
	$/ton NOx removed	$2,710	$2,249	$1,820	$1,511
Levelized Cost:			$0		$0
Fixed O&M:	Mills/KWh	0.12		0.28	
	$/ton NOx removed	$200	$166	$290	$241
Variable O&M:	Mills/KWh	0.98		0.95	
	$/ton NOx removed	$1,690	$1,403	$990	$822
Fixed Charges::	Mills/KWh	0.54		0.59	
	$/ton NOx removed	$940	$780	$610	$506
Total Levelized Cost:	Mills/KWh	1.6		1.8	
	$/ton NOx removed	$2,830	$2,349	$1,890	$1,569

Great River Energy Stanton

BART Emission Control Cost Analysis

Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Coal Use/Properties								
	2004 EI	**2004 EI**	**2003 EI**	**2002 EI**	**2001 EI**	**2000 EI**	**Average**	**Period**
Coal Type	**PRB [2]**	**Lignite**	**Lignite**	**Lignite**	**Lignite**	**Lignite**	**Lignite**	
Use	113,459	634,265	679,593	808,083	744,341	666,577	776,212	2001-2002
%Ash	7.24	14.7	9.1	8.13	8.7	9.14	8.4	2001-2002
%S	0.31	0.65	0.64	0.66	0.72	0.64	0.69	2001-2002
Heating Value	9257	6514	6558	6551	6694	6764	6,623	2001-2002
Na in Ash	6.03	2.63	3.09	3.91	3.37	2.56	3.64	2001-2002
Op Hrs		8659	7077	8553	8479	7415	7,947	2001-2002
Heat Input		1.036E+07	8.913E+06	1.075E+07	9.965E+06	9.02E+06	1.04E+07	2001-2002
MMBtu/hr		1,197	1,259	1,257	1,175	1,216	1,196	2001-2002
% of Capacity		66.5%	70.0%	69.8%	65.3%	67.6%	67.6%	2001-2002
SO2 lb/MMbtu	[3]	1.519	1.814	1.590	1.816	1.699	1.70	2001-2002
PM lb/MMBtu	[3]	0.012	0.012	0.013	0.019	0.019	0.016	2001-2002
NOx lb/MMBtu	[3]	0.400	0.440	0.430	0.410	0.410	0.42	2001-2002

🟨 Highest 2 years on pollutant basis

Emission Inventory Unit 1 Emissions - Tons per Year					
Year	**2004**	**2003**	**2002**	**2001**	**2000**
PM10	62	53	70	94	85
PM	63	53	70	95	86
NOx	2,073	1,961	2,312	2,044	1,849
SO2	7,871	8,084	8,548	9,046	7,660

Uncontrolled PM Emission Rate Using AP-42 - For SW Disposal Rates

	Total	Filterable	Condensable
T/yr	32,844	32,659	185
lb/Hr	8266	8219	47

Filterable PM Emission Factor	84.2	lb/ton coal
Condensable PM Emission Factor - Lignite	0.039	lb/MMBtu

BART Baseline Emissions [1]
2 Year Averages

	T/yr	**lb/hr**	**lb/MMBtu**	**Period**
PM10	**90**	**33.3**	**0.019**	2000, 2001
PM	**91**	**33.7**	**0.019**	2000, 2001
NOx	**2,139**	**783.2**	**0.44**	2002, 2003
SO2	**8,592**	**3266.5**	**1.81**	2001, 2003

[1] SO2 and NOx lb/MMBtu is the average of the two highest years (excluding 2004 because both types of coal were used) plus one standard deviation of the years 2000-2003

[2] PRB calculations:
SO2 PRB lb/MMBtu = lb/MMBtu on Lignite * PRB % S / Lignite % S
SO2 PRB lb/hr calculated using lb/MMBtu SO2 * design duty
lb/hr = average emission rate adjusted to 100% utilization

[3] lb/MMBtu in 2004 includes PRB and Lignite

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit: Unit 1 **Study Year** 2005
Emission Unit Number NA
Stack/Vent Number NA

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37.00	$/hr	37.00	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37.00	$/hr	37.00	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.051	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Natural Gas	6.85	$/kscf		2005	Average natural gas spot price July 04 - June 05, Henry La Hub.,	WTRG Economics, WWW.wtrg.com/daily/small/ngspot.gig
Water	0.31	$/kgal	0.31	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.27	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsrobers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.31	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.64	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.15	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal	4.37	$/ton	4.00	2002	Vision 21 Report by Stone & Webster	cost adjusted for 3% inflation
Hazardous Waste Disposal	273.18	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.55	$/ton-mi	0.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
PRB Coal	2,000,000	$/yr	4,000,000	2005	GRE	Incremental cost to fire PRB Coal $5M/yr Cost - $1M/yr reduced operating cost, total of $4M/yr divided by 2, for a per pollutant basis.
Chemicals & Supplies						
Lime	90.00	$/ton		2005	GRE per Diane Stockdill 12/6/05 email	
Caustic	305.21	$/ton		2005	GRE per Diane Stockdill 12/6/05 email	
Urea	405	$/ton		2005	Hawkins Chemical	50% solution of urea in water, includes delivery
Soda Ash		$/ton				
Oxygen	15.00	kscf	15.00	2005	Get cost from Air Prod Website	
EPA Urea	179.1	$/ton				
Ammonia	0.2	$/lb			$400/ton for 30% aqueous solution.	
Nahcolite	233.52	$/ton	195.57	1999	Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999	
Catayst & Replacement Parts						
SCR Catalyst	500	$/ft^3				
CO Catalyst	650	$/ft^3				
Catalyst #3						
Catalyst #4						
Catalyst #5						
Filter Bags	160.00	$/bag	160	2005	GRE cost per Steve Smokey	
Tower Packing	100	$/ft^3				
Replacement Parts						
Replacement Parts						
Replacement Parts						
Other						
Sales Tax	0	%				
Interest Rate	5.5%	%			GRE per Diane Stockdill	
Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal						
Operating Information						
Annual Op. Hrs	7,947	Hours				Stanton Emission Inventories
Utilization Rate	**68%**			Per 12/30 Telcon, G Archer GRE, use existing utilization rate for consistency in calculations		
Equipment Life	20	yrs				Engineering Estimate
Desgin Capacity	1,800	MMBtu/hr				
Standardized Flow Rate	**498,970**	scfm @ 32º F				
Temperature	**330**	Deg F				
Moisture Content	**13.3%**					
Actual Flow Rate	**801,500**	acfm		Lignite Vision 21, Steve Smokey verified		
Standardized Flow Rate	**535,480**	scfm @ 68º F				
Dry Std Flow Rate	**464,261**	dscfm @ 68º F				
F factor lignite	**15,475**	dscf/MMBtu			EPA Method 19	**F-Factor+O2 correction factor for 6.1% O2**
Design Basis	**Baseline Emis.**	**Baseline Emis.**	**Max Emis. (Model)**			
Pollutant	**T/yr**	**lb/MMBtu**	**lb/hr**			
PM10	89.5	0.019	31.8			Baseline-2001, 2002 Stanton Emission Inventories. Max-ND Protocol
Total Particulates	90.5	0.019	31.8			Baseline-2001, 2002 Stanton Emission Inventories. Max-ND Protocol
Nitrogen Oxides (NOx)	2,139	0.435	669.0			Baseline-2001, 2002 Stanton Emission Inventories. Max-ND Protocol
Sulfur Dioxide (SO_2)	8,592	1.815	3,418.0			Baseline-2001, 2002 Stanton Emission Inventories. Max-ND Protocol

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-4: PM Control - Wet ESP Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F
Expected Utiliztion Rate	68%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F
			Dry Std Flow Rate	464,261	dscfm @ 68º F

Chemical Engineering Chemical Plant Cost Index	
1997	386.5
2005	465
Inflation Adj	1.20

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)								
Purchased Equipment (A)						2005	3,969,555	2,042,478
Purchased Equipment Total (B)	15%	of control device cost (A)						**2,348,849**
Installation - Standard Costs	69%	of purchased equip cost (B)						1,620,706
Installation - Site Specific Costs								1,646,400
Installation Total								3,267,106
Total Direct Capital Cost, DC								3,969,555
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)						1,338,844
Total Capital Investment (TCI) = DC + IC								**6,900,919**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						974,279
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,055,930
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**2,030,210**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	27.0	0.015	72.5	17.0	119,268
Total Particulates	90.5	27.0	0.015	72.5	18.0	112,650
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using GRE cost estimate from Coal Creek, 19% as compared to dry ESP cost.
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3
3 ESP Maintenance costs Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
4 ESP Maintenance Materials Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
5 Used an ESP SCA grid factor of 553 ft^2/1000 acfm per GRE, D. Stockdill.
6 High control cost is due to the small additional decrease in emissions as compared to existing controls.
7 Assumed WESP size is 20% of IAPCS model calculated size for electricity and spray water use.
8 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-4: PM Control - Wet ESP Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**2,042,478**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	204,248
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	102,124
Purchased Equipment Total (B)	15%		**2,348,849**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	93,954
Handling & erection	50%	of purchased equip cost (B)	1,174,425
Electrical	8%	of purchased equip cost (B)	187,908
Piping	3%	of purchased equip cost (B)	70,465
Insulation	2%	of purchased equip cost (B)	46,977
Painting	2%	of purchased equip cost (B)	46,977
Installation Subtotal Standard Expenses	69%		**1,620,706**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Replacement Power - One 14 day outage [8]	1,646,400
Total Site Specific Costs			1,646,400
Installation Total			**3,267,106**
Total Direct Capital Cost, DC			**3,969,555**
Indirect Capital Costs			
Engineering, supervision	20%	of purchased equip cost (B)	469,770
Construction & field expenses	20%	of purchased equip cost (B)	469,770
Contractor fees	10%	of purchased equip cost (B)	234,885
Start-up	1%	of purchased equip cost (B)	23,488
Performance test	1%	of purchased equip cost (B)	23,488
Model Studies	2%	of purchased equip cost (B)	46,977
Contingencies	3%	of purchased equip cost (B)	70,465
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)	**1,338,844**
Total Capital Investment (TCI) = DC + IC			**5,308,399**
		Retrofit TCI (TCI*1.3)	**6,900,919**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**6,900,919**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Supervisor	48%	% of Operator Costs.	17,642
Maintenance			
Maintenance Labor	443,229	ft2 grid area, 0.8 $/ft2 of grid area	365,664
Maintenance Materials	1	1% of purchased equipment cost	23,488
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,524 kW-hr, 7947 hr/yr, 68% utilization	416,996
NA	NA		-
Water	0.31	$/kgal, 160 gpm, 7947 hr/yr, 68% utilization	16,112
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization	97,621
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**974,279**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	266,130
Administration (2% total capital costs)	2%	of total capital costs (TCI)	106,168
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	53,084
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	53,084
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	577,464
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,055,930**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**2,030,210**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-4: PM Control - Wet ESP Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower Baghouse & ESP	801,500		4.48			649.9	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.46
	Liq flow	Liquid SPGR	Δ P ft H2O	Efficiency	Hp	kW	
WESP Pump	801 gpm	1.000	40	0.5		12.1	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
WESP H2O WW Disch	160 gpm	1.000	40	0.5		2.4	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
SCA Factor	553	ft^2/1000 acfm					
ESP Grid	443,229	ft^2	1.94E-03	kW/ft^2		859.9	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.48
Total						1524.3	

Reagent Use & Other Operating Costs							
WESP Pump	160,300	acfm	5	gpm/kacfm	801	gpm	EPA Cost Cont Manual 6th ed Section 6 Chapter 3.4.1.9
WESP Water Makeup Rate/WW Disch			20%	of circulating water rate =	160 gpm		

Operating Cost Calculations				**Annual hours of operation:**		**7,947**	
				Utilization Rate:		**68%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
Supervisor	48%	of Operator Costs.			NA	17,642	% of Operator Costs.
Maintenance							
Maint Labor	443,229	ft2 grid area	0.825	$/ft^2 of grid area		365,664	ft2 grid area, 0.8 $/ft2 of grid area
Maint Mtls	1	% of purchased equipment cost			NA	23,488	1% of purchased equipment cost
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	1524.3	kW-hr	8,237,045	416,996	$/kwh, 1,524 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	160.3	gpm	51,975	16,112	$/kgal, 160 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatement	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	4.1	ton/hr	22,334	97,621	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	Mi	0	0	$/ton-mi, 0 Mi, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1 Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-5: PM Control - Dry ESP Lignite Coal

Operating Unit: **Unit 1**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997 [2]	17,365,400	
Purchased Equipment (A)						2005	20,892,396	10,878,623
Purchased Equipment Total (B)	15%	of control device cost (A)						**12,510,417**
Installation - Standard Costs	67%	of purchased equip cost (B)						8,381,979
Installation - Site Specific Costs								1,646,400
Installation Total								10,028,379
Total Direct Capital Cost, DC								22,538,796
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)						7,130,938
Total Capital Investment (TCI) = DC + IC								**38,570,653**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,055,823
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						4,741,455
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,797,278**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	27.0	0.015	72.5	17.0	340,570
Total Particulates	90.5	27.0	0.015	72.5	18.0	321,673
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton

2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3

3 ESP Maintenance costs Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
4 ESP Maintenance Materials Eq 3.45 EPA Cont Cost Manual Section 6 Chapter 3
5 Used an ESP SCA grid factor of 553 ft^2/1000 acfm per GRE, D. Stockdill.
6 High control cost is due to the small additional decrease in emissions as compared to existing controls.
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-5: PM Control - Dry ESP Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**10,878,623**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,087,862
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	543,931
Purchased Equipment Total (B)	15%		**12,510,417**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	500,417
Handling & erection	50%	of purchased equip cost (B)	6,255,208
Electrical	8%	of purchased equip cost (B)	1,000,833
Piping	1%	of purchased equip cost (B)	125,104
Insulation	2%	of purchased equip cost (B)	250,208
Painting	2%	of purchased equip cost (B)	250,208
Installation Subtotal Standard Expenses	67%		**8,381,979**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			1,646,400
Installation Total			**10,028,379**
Total Direct Capital Cost, DC			**22,538,796**
Indirect Capital Costs			
Engineering, supervision	20%	of purchased equip cost (B)	2,502,083
Construction & field expenses	20%	of purchased equip cost (B)	2,502,083
Contractor fees	10%	of purchased equip cost (B)	1,251,042
Start-up	1%	of purchased equip cost (B)	125,104
Performance test	1%	of purchased equip cost (B)	125,104
Model Studies	2%	of purchased equip cost (B)	250,208
Contingencies	3%	of purchased equip cost (B)	375,313
Total Indirect Capital Costs, IC	57%	of purchased equip cost (B)	**7,130,938**
Total Capital Investment (TCI) = DC + IC			**29,669,733**
		Retrofit TCI (TCI*1.3)	**38,570,653**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**38,570,653**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Supervisor	48%	% of Operator Costs.	17,642
Maintenance			
Maintenance Labor	443,229	ft2 grid area, 0.8 $/ft2 of grid area	365,664
Maintenance Materials	1	1% of purchased equipment cost	125,104
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,510 kW-hr, 7947 hr/yr, 68% utilization	413,036
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization	97,621
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**1,055,823**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	327,099
Administration (2% total capital costs)	2%	of total capital costs (TCI)	593,395
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	296,697
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	296,697
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	3,227,566
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,741,455**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**5,797,278**

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-5: PM Control - Dry ESP Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:			
Equipment Life	5	years	
CRF	0.0000		
Rep part cost per unit	500	$/ft^3	
Amount Required	0	ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/h	OAQPS list replacement times from 5 - 20 min per bag
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower Baghouse & ESP	801,500		4.48			649.9	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.46
	Liq flow	Liquid SPGR	Δ P ft H2O	Efficiency	Hp	kW	
WESP Pump	0 gpm	1.000	40	0.5		0.0	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
WESP H2O WW Disch	0 gpm	1.000	40	0.5		0.0	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.47
SCA Factor	553	ft^2/1000 acfm					
ESP Grid	443,229	ft^2	1.94E-03	kW/ft^2		859.9	EPA Cost Cont Manual 6th ed Section 6 Chapter 3 Eq 3.48
Total						1509.8	

Reagent Use & Other Operating Costs					
WESP Pump	acfm	5	gpm/kacfm	0 gpm	EPA Cost Cont Manual 6th ed Section 6 Chapter 3.4.1.9
WESP Water Makeup Rate/WW Disch		20%	of circulating water rate =	0 gpm	

	Operating Cost Calculations			**Annual hours of operation:**			**7,947**	
				Utilization Rate:			**68%**	
	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	48%	of Operator Costs.			NA	17,642	% of Operator Costs.
	Maintenance							
	Maint Labor	443,229	ft2 grid area	0.825	$/ft^2 of grid area		365,664	ft2 grid area, 0.8 $/ft2 of grid area
	Maint Mtls	1	% of purchased equipment cost			NA	125,104	1% of purchased equipment cost
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	1509.8	kW-hr	8,158,820	413,036	$/kwh, 1,510 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatement	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	4.1	ton/hr	22,334	97,621	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	Mi	0	0	$/ton-mi, 0 Mi, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-6: PM Control -Baghouse Lignite Coal

Operating Unit: **Unit 1**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						2012 [2]	23,200,000	
Purchased Equipment (A)						2005	19,256,000	9,623,188
Purchased Equipment Total (B)	15%	of control device cost (A)						**11,066,667**
Installation - Standard Costs	74%	of purchased equip cost (B)						8,189,333
Installation - Site Specific Costs								1,646,400
Installation Total								9,835,733
Total Direct Capital Cost, DC								20,902,400
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)						4,980,000
Total Capital Investment (TCI) = DC + IC								**33,647,120**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,036,754
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						3,945,692
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**4,982,446**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	27.0	0.015	72.5	17.0	292,702
Total Particulates	90.5	27.0	0.015	72.5	18.0	276,460
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1. Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
   Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2. WGI total direct installed cost estimate adjusted for inflation 10/2/2007
3. Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4. Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5. High control cost is due to the small additional decrease in emissions as compared to existing controls.
6. Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-6: PM Control -Baghouse Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**9,623,188**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	962,319
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	481,159
Purchased Equipment Total (B)	15%		**11,066,667**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	442,667
Handling & erection	50%	of purchased equip cost (B)	5,533,333
Electrical	8%	of purchased equip cost (B)	885,333
Piping	1%	of purchased equip cost (B)	110,667
Insulation	7%	of purchased equip cost (B)	774,667
Painting	4%	of purchased equip cost (B)	442,667
Installation Subtotal Standard Expenses	74%		**8,189,333**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Replacement Power - One 14 day outage [6]	1,646,400
Total Site Specific Costs			1,646,400
Installation Total			**9,835,733**
Total Direct Capital Cost, DC			**20,902,400**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,106,667
Construction & field expenses	20%	of purchased equip cost (B)	2,213,333
Contractor fees	10%	of purchased equip cost (B)	1,106,667
Start-up	1%	of purchased equip cost (B)	110,667
Performance test	1%	of purchased equip cost (B)	110,667
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	332,000
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**4,980,000**
Total Capital Investment (TCI) = DC + IC			**25,882,400**
		Retrofit TCI (TCI*1.3)	**33,647,120**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**33,647,120**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr	73,510
Supervisor	15%	15% of Operator Costs	11,026
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization	396,876
NA	NA		-
NA	NA		-
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization	97,621
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**1,036,754**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,828
Administration (2% total capital costs)	2%	of total capital costs (TCI)	517,648
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	258,824
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	258,824
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	2,815,568
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**3,945,692**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,982,446**

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-6: PM Control -Baghouse Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$\$/\text{ft}^3$
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag
Annualized Cost	**224,403**		

Electrical Use						
	Flow acfm	ΔP in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500	10			1450.7	
Baghouse Shaker	0.0	Gross fabric area ft^2			0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other						
Other						
Other						
Other						
Other						
Total					1450.7	

Baghouse Filter Cost						
						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0 ft long	0 in dia	0.00	area/cage ft^2		$/cage
Bags	0	$/ft2 of fabric				$/bag
Total						
Lime Use	0.00	lb/hr SO2	0.96	lb Lime/lb SO2	0.00	lb/hr Lime

Operating Cost Calculations — **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	2.0	hr/8 hr shift	1,987	73,510	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	11,026	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	1450.7	kW-hr	7,839,605	396,876	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralizatior	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	4.1	ton/hr	22,334	97,621	$/ton, 4 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-7: SO2 Control - Wet Scrubber Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	2002	395.6
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465.0
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.18
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Year		
Direct Capital Costs (1)			2012 [1]	68,800,000	
Purchased Equipment (A)			2005	57,104,000	26,840,893
Purchased Equipment Total (B)	15%	of control device cost (A)			**30,867,027**
Installation - Standard Costs	85%	of purchased equip cost (B)			26,236,973
Installation - Site Specific Costs					7,646,400
Installation Total					33,883,373
Total Direct Capital Cost, DC					64,750,400
Total Indirect Capital Costs, IC	76%	of purchased equip cost (B)			23,406,000
Total Capital Investment (TCI) = DC + IC					**88,156,400**
Operating Costs					
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.			2,243,462
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost			10,937,858
Total Annual Cost (Annualized Capital Cost + Operating Cost)					**13,181,320**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	163.3	0.09	438.4	8,153.1	1,617

Notes & Assumptions

1. WGI total direct installed cost estimate adjusted for inflation 10/2/2007
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1
3. Liquid/Gas ratio = 38 L/G = Gal/1,000 acf
4. Water Makeup Rate/Wastewater Discharge = 2.0% of circulating water rate
5. Evaporation rate calculated from steam table in Basic Principles and Calculations in Chemical Engineering Third Edition.
6. NDDH expected efficiency 4/21/06
7. Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-7: SO2 Control - Wet Scrubber Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**26,840,893**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,684,089
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	1,342,045
Purchased Equipment Total (B)	15%		**30,867,027**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	3,704,043
Handling & erection	40%	of purchased equip cost (B)	12,346,811
Electrical	1%	of purchased equip cost (B)	308,670
Piping	30%	of purchased equip cost (B)	9,260,108
Insulation	1%	of purchased equip cost (B)	308,670
Painting	1%	of purchased equip cost (B)	308,670
Installation Subtotal Standard Expenses	85%		**26,236,973**
Site Preparation, as required		Sludge Pond	5,000,000
Buildings, as required		Warehouse Relocation, stack modification	1,000,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			7,646,400
Installation Total			**33,883,373**
Total Direct Capital Cost, DC			**64,750,400**
Indirect Capital Costs			
Engineering, supervision	19%	of purchased equip cost (B)	5,727,000
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees	19%	of purchased equip cost (B)	5,727,000
Start-up	0%	of purchased equip cost (B)	0
Performance test	0%	of purchased equip cost (B)	0
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	39%	of purchased equip cost (B)	11,952,000
Total Indirect Capital Costs, IC	76%	of purchased equip cost (B)	**23,406,000**
Total Capital Investment (TCI) = DC + IC			**88,156,400**
		Retrofit TCI (TCI*correction factor)	**88,156,400**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**88,156,400**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Supervisor	15%	15% of Operator Costs	2,757
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Maintenance Materials	100%	of maintenance labor costs	18,377
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 2,800 kW-hr, 7947 hr/yr, 68% utilization	766,004
NA	NA		-
Water	0.31	$/kgal, 2,943 gpm, 7947 hr/yr, 68% utilization	295,826
NA	NA		-
NA	NA		-
WW Treat Neutralization	1.64	$/kgal, 609 gpm, 7947 hr/yr, 68% utilization	323,730
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization	800,014
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**2,243,462**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	34,733
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,763,128
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	881,564
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	881,564
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	7,376,868
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**10,937,858**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**13,181,320**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-7: SO2 Control - Wet Scrubber Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Scrubber	801,500		8.55	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	Δ P ft H2O	Efficiency	Hp	kW	
Circ Pump	30456.99612	1	60	0.7 -		0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	2943 gpm	1	60	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
FGD Power Consumption						2800	WGI Cost tables 10/2/2007
Total						2800.0	

Reagent Use & Other Operating Costs

Caustic Use	3418	lb/hr SO2	2.5	lb NaOH/lb SO2	8545	lb/hr Caustic
Lime Use	3418	lb/hr SO2	0.9625	lb Lime/lb SO2	3289.825	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio
Liquid/Gas ratio	38	* L/G = Gal/1,000 acf				
Circulating Water Rate	30,457	gpm				
Water Makeup Rate/WW Disch =			0.02	of circulating water rate + evap. loss =	2943.14	
Evaopration Loss =			0.793030594			

Design Basis	**Baseline Emis.** **T/yr**	**Baseline Emi** **lb/MMBtu**	**Max Emis. (Model)** **lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				95%	0.09
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37.0	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	2,757	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	18,377	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	2800.0	kW-hr	15,131,088	766,004	$/kwh, 2,800 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	2,943.1	gpm	954,277	295,826	$/kgal, 2,943 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	609.1	gpm	197,506	323,730	$/kgal, 609 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, ($5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost)/2
1	Lime	90.0	$/ton	3289.8	lb/hr	8,889	800,014	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-8: SO2 Control - Spray Dryer and Baghouse Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	2002	395.6
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465.0
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.18
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Year		
Direct Capital Costs (1)			2012 [1]	64,700,000	
Purchased Equipment (A)			2005	53,701,000	26,837,081
Purchased Equipment Total (B)	15%	of control device cost (A)			**30,862,644**
Installation - Standard Costs	74%	of purchased equip cost (B)			22,838,356
Installation - Site Specific Costs					2,146,400
Installation Total					24,984,756
Total Direct Capital Cost, DC					55,847,400
Total Indirect Capital Costs, IC	71%	of purchased equip cost (B)			21,995,000
Total Capital Investment (TCI) = DC + IC					**79,514,000**
Operating Costs					
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.			#REF!
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost			9,235,943
Total Annual Cost (Annualized Capital Cost + Operating Cost)					**13,307,617**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	270.0	0.15	724.8	7,866.8	1,692

Notes & Assumptions

1 WGI total direct installed cost estimate adjusted for inflation 10/2/2007
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Bag replacement costs for baghouse need to be updated. Bag costs from EPA example calculations were used. Bags for Stanton would be larger and more expensive.
6 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-8: SO2 Control - Spray Dryer and Baghouse Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**26,837,081**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,683,708
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	1,341,854
Purchased Equipment Total (B)	15%		**30,862,644**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,234,506
Handling & erection	50%	of purchased equip cost (B)	15,431,322
Electrical	8%	of purchased equip cost (B)	2,469,011
Piping	1%	of purchased equip cost (B)	308,626
Insulation	7%	of purchased equip cost (B)	2,160,385
Painting	4%	of purchased equip cost (B)	1,234,506
Installation Subtotal Standard Expenses	74%		**22,838,356**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Warehouse Relocation	500,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			2,146,400
Installation Total			**24,984,756**
Total Direct Capital Cost, DC			**55,847,400**
Indirect Capital Costs			
Engineering, supervision	17%	of purchased equip cost (B)	5,395,000
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees/General	17%	of purchased equip cost (B)	5,395,000
Start-up	0%	of purchased equip cost (B)	0
Performance test	0%	of purchased equip cost (B)	0
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	36%	of purchased equip cost (B)	11,205,000
Total Indirect Capital Costs, IC	71%	of purchased equip cost (B)	**21,995,000**
Total Capital Investment (TCI) = DC + IC			**77,842,400**
		Retrofit TCI (TCI*correction factor)	**79,514,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**79,514,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 8.0 hr/8 hr shift, 7947 hr/yr	294,039
Supervisor	15%	15% of Operator Costs	44,106
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,550 kW-hr, 7947 hr/yr, 68% utilization	424,038
NA	NA		-
Water	0.31	$/kgal, 219 gpm, 7947 hr/yr, 68% utilization	21,992
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	38,432
NA	NA		-
NA	NA		-
PRB Coal	2,000,000	$/yr, ($5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost)/2	2,000,000
Lime	90.00	$/ton, 3,254 lb/hr, 7947 hr/yr, 68% utilization	791,346
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**4,071,674**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	246,993
Administration (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	6,653,678
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**9,235,943**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**13,307,617**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-8: SO2 Control - Spray Dryer and Baghouse Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	\$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	\$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = \$29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			0.0	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
FDG Power Consumtion						1,500.0	WGI Cost tables 10/2/2007
Fabric Filter Power Consumption						50.0	WGI Cost tables 10/2/2007
Other							
Other							
Other							
Total						1550.0	

Baghouse Filter Cost							See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2					
Cages	0	ft long	0 in dia	0.00	area/cage ft^2	0.000	\$/cage
Bags	0	\$/ft2 of fabric				0.00	\$/bag
		H2O Use (1)		218.8	gpm	0.000	Total
Lime Use	3232.45	lb/hr SO2		1.01	lb Lime/lb SO2	3254.18	lb/hr lime, lime addition at 1.15 times the stoichiometric ratio

Design Basis	**Baseline Emi T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				92%	0.15
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

	Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.0	\$/Hr	8.0	hr/8 hr shift	7,947	294,039	\$/Hr, 8.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	44,106	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	\$/Hr	1.0	hr/8 hr shift	993	36,755	\$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	\$/kwh	1550.0	kW-hr	8,376,138	424,038	\$/kwh, 1,550 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	\$/kscf	0	scfm	0	0	\$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	\$/kgal	218.8	gpm	70,942	21,992	\$/kgal, 219 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	\$kgal	0.0	gpm	0	0	\$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	\$/kscf	2	scfm/kacfm	519,753	159,808	\$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	\$/ton	1.6	ton/hr	8,793	38,432	\$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	\$/ton-mi	0.0	ton/hr	0	0	\$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	\$/yr	0.0	ton/hr	1	2,000,000	\$/yr, (\$5.1MM/yr extra for PRB - \$1MM/yr Lower O&M Cost)/2
1	Lime	90.0	\$/ton	3254.2	lb/hr	8,793	791,346	\$/ton, 3,254 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	\$/ft3	0	ft^3	0	0	\$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	\$/bag	0	bags	NA	224,403	\$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-9: SO2 Control - Spray Dryer and Baghouse Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	2002	395.6
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465.0
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.18
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						2012 [1]	64,700,000	
Purchased Equipment (A)						2005	53,701,000	26,837,081
Purchased Equipment Total (B)	15%	of control device cost (A)						**30,862,644**
Installation - Standard Costs	74%	of purchased equip cost (B)						22,838,356
Installation - Site Specific Costs								2,146,400
Installation Total								24,984,756
Total Direct Capital Cost, DC								55,847,400
Total Indirect Capital Costs, IC	71%	of purchased equip cost (B)						21,995,000
Total Capital Investment (TCI) = DC + IC								**77,842,400**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,119,304
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						9,096,065
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**11,215,368**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	326.7	0.18	876.9	7,714.7	1,454

Notes & Assumptions

1 WGI total direct installed cost estimate adjusted for inflation 10/2/2007
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Bag replacement costs for baghouse need to be updated. Bag costs from EPA example calculations were used. Bags for Stanton would be larger and more expensive.
6 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-9: SO2 Control - Spray Dryer and Baghouse Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**26,837,081**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,683,708
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	1,341,854
Purchased Equipment Total (B)	15%		**30,862,644**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,234,506
Handling & erection	50%	of purchased equip cost (B)	15,431,322
Electrical	8%	of purchased equip cost (B)	2,469,011
Piping	1%	of purchased equip cost (B)	308,626
Insulation	7%	of purchased equip cost (B)	2,160,385
Painting	4%	of purchased equip cost (B)	1,234,506
Installation Subtotal Standard Expenses	74%		**22,838,356**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Warehouse Relocation	500,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			2,146,400
Installation Total			**24,984,756**
Total Direct Capital Cost, DC			**55,847,400**
Indirect Capital Costs			
Engineering, supervision	17%	of purchased equip cost (B)	5,395,000
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees/General	17%	of purchased equip cost (B)	5,395,000
Start-up	0%	of purchased equip cost (B)	0
Performance test	0%	of purchased equip cost (B)	0
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	36%	of purchased equip cost (B)	11,205,000
Total Indirect Capital Costs, IC	71%	of purchased equip cost (B)	**21,995,000**
Total Capital Investment (TCI) = DC + IC			**77,842,400**
		Retrofit TCI (TCI*correction factor)	**77,842,400**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**77,842,400**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 8.0 hr/8 hr shift, 7947 hr/yr	294,039
Supervisor	15%	15% of Operator Costs	44,106
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,550 kW-hr, 7947 hr/yr, 68% utilization	424,038
NA	NA		-
Water	0.31	$/kgal, 219 gpm, 7947 hr/yr, 68% utilization	21,992
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	40,638
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 3,441 lb/hr, 7947 hr/yr, 68% utilization	836,770
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**2,119,304**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	246,993
Administration (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	778,424
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	6,513,800
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**9,096,065**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**11,215,368**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-9: SO2 Control - Spray Dryer and Baghouse Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			0.0	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
FDG Power Consumtion						1,500.0	WGI Cost tables 10/2/2007
Fabric Filter Power Consumption						50.0	WGI Cost tables 10/2/2007
Other							
Other							
Other							
Total						1550.0	

Baghouse Filter Cost						
						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0 ft long	0 in dia	0.00	area/cage ft^2	0.000	$/cage
Bags	0	$/ft2 of fabric			0.00	$/bag
		H2O Use (1)	218.8	gpm	0.000	Total
Lime Use	3418.00	lb/hr SO2	1.01	lb Lime/lb SO2	3440.97	lb/hr lime, lime addition at 1.15 times the stoichiometric ratio

Design Basis	**Baseline Emi** **T/yr**	**Baseline Emi** **lb/MMBtu**	**Max Emis. (Model)** **lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				90%	0.18
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37.0	$/Hr	8.0	hr/8 hr shift	7,947	294,039	$/Hr, 8.0 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	44,106	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	1550.0	kW-hr	8,376,138	424,038	$/kwh, 1,550 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	218.8	gpm	70,942	21,992	$/kgal, 219 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	1.7	ton/hr	9,297	40,638	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1 Lime	90.0	$/ton	3441.0	lb/hr	9,297	836,770	$/ton, 3,441 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997	26,255,500	
Purchased Equipment (A)						2005 [6]	38,531,255	19,256,000
Purchased Equipment Total (B)	15%	of control device cost (A)						**22,144,400**
Installation - Standard Costs	74%	of purchased equip cost (B)						16,386,856
Installation - Site Specific Costs								2,146,400
Installation Total								18,533,256
Total Direct Capital Cost, DC								40,677,655
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)						3,321,660
Total Capital Investment (TCI) = DC + IC								**57,199,110**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						3,792,681
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						6,641,183
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**10,433,865**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	445.5	0.25	1195.9	7,395.7	1,411

Notes & Assumptions

1. Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3. Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4. Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5. Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6. WGI total direct installed cost estimate for baghouse adjusted for inflation 10/2/2007
7. Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**19,256,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,925,600
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	962,800
Purchased Equipment Total (B)	15%		**22,144,400**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	885,776
Handling & erection	50%	of purchased equip cost (B)	11,072,200
Electrical	8%	of purchased equip cost (B)	1,771,552
Piping	1%	of purchased equip cost (B)	221,444
Insulation	7%	of purchased equip cost (B)	1,550,108
Painting	4%	of purchased equip cost (B)	885,776
Installation Subtotal Standard Expenses	74%		**16,386,856**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Warehouse Relocation	500,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			2,146,400
Installation Total			**18,533,256**
Total Direct Capital Cost, DC			**40,677,655**
Indirect Capital Costs			
Engineering, supervision [6]	5%	of purchased equip cost (B)	1,107,220
Construction & field expenses [6]	0%	of purchased equip cost (B)	0
Contractor fees [6]	5%	of purchased equip cost (B)	1,107,220
Start-up	1%	of purchased equip cost (B)	221,444
Performance test	1%	of purchased equip cost (B)	221,444
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	664,332
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**3,321,660**
Total Capital Investment (TCI) = DC + IC			**43,999,315**
		Retrofit TCI (TCI*1.3)	**57,199,110**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**57,199,110**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr	73,510
Supervisor	15%	15% of Operator Costs	11,026
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization	396,876
NA	NA		-
Water	0.31	$/kgal, 146 gpm, 7947 hr/yr, 68% utilization	14,681
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	38,853
NA	NA		-
NA	NA		-
PRB Coal	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost	2,000,000
Lime	90.00	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization	800,014
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**3,792,681**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,828
Administration (2% total capital costs)	2%	of total capital costs (TCI)	879,986
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	439,993
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	439,993
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	4,786,383
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,641,183**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,433,865**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-10: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			1450.7	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						1450.7	

Baghouse Filter Cost						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0 ft long	5 in dia	0.00	area/cage ft^2	0.000	$/cage
Bags	0	$/ft2 of fabric			0.00	$/bag
		H2O Use (6)	146.06	gpm	0.000	Total
Lime Use	3418.00	lb/hr SO2	0.96	lb Lime/lb SO2	3289.83	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio

Design Basis	**Baseline Emis. T/yr**	**Baseline Emis. lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				86%	0.25
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations

Annual hours of operation: **7,947**
Utilization Rate: **68%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37.00	$/Hr	2.0	hr/8 hr shift	1,987	73,510	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	11,026	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	1450.7	kW-hr	7,839,605	396,876	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	146.1	gpm	47,360	14,681	$/kgal, 146 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	1.6	ton/hr	8,889	38,853	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	1	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1 Lime	90.0	$/ton	3289.8	lb/hr	8,889	800,014	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Wet Scrubber Lignite Coal 10% Bypass

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	2002	395.6
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.18
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			Year		
Direct Capital Costs (1)			2012 [1]	48,306,383	
Purchased Equipment (A)			2005	40,094,298	18,845,733
Purchased Equipment Total (B)	15%	of control device cost (A)			**21,672,593**
Installation - Standard Costs	85%	of purchased equip cost (B)			18,421,704
Installation - Site Specific Costs					7,146,400
Installation Total					25,568,104
Total Direct Capital Cost, DC					47,240,698
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)			3,250,889
Total Capital Investment (TCI) = DC + IC					**65,639,063**
Operating Costs					
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.			1,938,045
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost			7,547,030
Total Annual Cost (Annualized Capital Cost + Operating Cost)					**9,485,075**

Uncontrolled SO2 Emission Rate	8,592	lb/hr
Scrubber Control Efficiency	95.0%	[6]
Scrubber Bypass	10.0%	

Emission Control Cost Calculation

Pollutant	Baseline Emis. T/yr	Predicted Limit lb/hr	Cont. Emis. lb/MMBtu	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	473.6	0.26	1271.4	7,320.1	1,296

Notes & Assumptions

1 WGI total direct installed cost estimate for baghouse adjusted for inflation 10/2/2007
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1
3 Liquid/Gas ratio = 38 L/G = Gal/1,000 acf
4 Water Makeup Rate/Wastewater Discharge = 2.0% of circulating water rate
5 Evaporation rate calculated from steam table in Basic Principles and Calculations in Chemical Engineering Third Edition.
6 NDDH expected efficiency 4/21/06
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Wet Scrubber Lignite Coal 10% Bypass

CAPITAL COSTS

Direct Capital Costs			
Purchased Equipment (A) (1)			**18,845,733**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,884,573
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	942,287
Purchased Equipment Total (B)	15%		**21,672,593**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	2,600,711
Handling & erection	40%	of purchased equip cost (B)	8,669,037
Electrical	1%	of purchased equip cost (B)	216,726
Piping	30%	of purchased equip cost (B)	6,501,778
Insulation	1%	of purchased equip cost (B)	216,726
Painting	1%	of purchased equip cost (B)	216,726
Installation Subtotal Standard Expenses	85%		**18,421,704**
Site Preparation, as required		Sludge Pond	5,000,000
Buildings, as required		Warehouse Relocation	500,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			7,146,400
Installation Total			**25,568,104**
Total Direct Capital Cost, DC			**47,240,698**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	1,083,630
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees	5%	of purchased equip cost (B)	1,083,630
Start-up	1%	of purchased equip cost (B)	216,726
Performance test	1%	of purchased equip cost (B)	216,726
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	650,178
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**3,250,889**
Total Capital Investment (TCI) = DC + IC			**50,491,587**
		Retrofit TCI (TCI*1.3)	**65,639,063**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**65,639,063**

OPERATING COSTS

Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Supervisor	15%	15% of Operator Costs	2,757
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Maintenance Materials	100%	of maintenance labor costs	18,377
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,684 kW-hr, 7947 hr/yr, 68% utilization	460,586
NA	NA		-
Water	0.31	$/kgal, 2,943 gpm, 7947 hr/yr, 68% utilization	295,826
NA	NA		-
NA	NA		-
WW Treat Neutralization	1.64	$/kgal, 609 gpm, 7947 hr/yr, 68% utilization	323,730
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization	800,014
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**1,938,045**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	34,733
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,009,832
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	504,916
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	504,916
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	5,492,633
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**7,547,030**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,485,075**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-11: SO2 Control - Wet Scrubber Lignite Coal 10% Bypass

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160.00	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		**Δ P in H2O**	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	801,500		8.55	0.7	-	1,145.4	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	30,457 gpm	1	60	0.7	-	490.8	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	2943 gpm	1	60	0.7	-	47.4	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
Other							
Total						1683.6	

Reagent Use & Other Operating Costs						
Caustic Use	3418.00	lb/hr SO2	2.50	lb NaOH/lb SO2	8545.00	lb/hr Caustic
Lime Use	3418.00	lb/hr SO2	0.96	lb Lime/lb SO2	3289.83	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio
Liquid/Gas ratio	38.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	30,457	gpm				
Water Makeup Rate/WW Disch =	2.0%	of circulating water rate + evap. loss =			2943 gpm	
Evaopration Loss =	79.30%					

Design Basis	**Baseline Emi T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				86%	0.26
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	2,757	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	18,377	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	1683.6	kW-hr	9,098,091	460,586	$/kwh, 1,684 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	2,943.1	gpm	954,277	295,826	$/kgal, 2,943 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	609.1	gpm	197,506	323,730	$/kgal, 609 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1 Lime	90.0	$/ton	3289.8	lb/hr	8,889	800,014	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-12: SO_2/NOx Control - Fuel Switch to PRB Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F
Expected Utiliztion Rate	68%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F
			Dry Std Flow Rate	464,261	dscfm @ 68º F

Chemical Engineering Chemical Plant Cost Index	
1997	386.5
2005	465
Inflation Adj	1.20

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997	0	
Purchased Equipment (A)						2005 [7]	0	0
Purchased Equipment Total (B)	15%	of control device cost (A)						**0**
Installation - Standard Costs	74%	of purchased equip cost (B)						0
Installation - Site Specific Costs								NA
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**0**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,000,000
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						0
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**2,000,000**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	648.0	0.36	1739.5	399.5	5,006
Sulfur Dioxide (SO_2)	8,591.6	990.0	0.55	2657.5	5,934.0	337

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton

2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8

4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.

5 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.

6 JXK Revised 1/11 controlled emission rate to account for reduced control effectiveness due to short residence time in available ductwork

7 Stone and Webster 2002 total direct installed cost estimate adjusted for inflation

8 Operation cost is presented on a per pollutant basis, total annual operating cost for a PRB fuel switch is $4,000,000. This cost is divided in half to represent the total cost attributed to each of the pollutant that will show emission reductions as the result of the fuel switch (SO2, NOx).

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-12: SO2/NOx Control - Fuel Switch to PRB Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**0**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	0
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	0
Purchased Equipment Total (B)	15%		**0**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	0
Handling & erection	50%	of purchased equip cost (B)	0
Electrical	8%	of purchased equip cost (B)	0
Piping	1%	of purchased equip cost (B)	0
Insulation	7%	of purchased equip cost (B)	0
Painting	4%	of purchased equip cost (B)	0
Installation Subtotal Standard Expenses	74%		**0**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**0**
Total Direct Capital Cost, DC			**0**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	0
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees	5%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	0
Performance test	1%	of purchased equip cost (B)	0
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	0
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**0**
Total Capital Investment (TCI) = DC + IC			**0**
		Retrofit TCI (TCI*1.3)	**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**0**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	NA		-
Maintenance Materials	NA	of maintenance labor costs	-
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
PRB Coal	#########	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost	2,000,000
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**2,000,000**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	0
Administration (2% total capital costs)	2%	of total capital costs (TCI)	0
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	0
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	0
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	-
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**0**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,000,000**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-12: SO2/NOx Control - Fuel Switch to PRB Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	\$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	\$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = \$29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10				
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						0.0	

Baghouse Filter Cost						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0 ft long	5 in dia	0.00	area/cage ft^2	0.000	\$/cage
Bags	0	\$/ft2 of fabric			0.00	\$/bag
		H2O Use	0.00	gpm	0.000	Total
Lime Use	3418.00	lb/hr SO2	0.96	lb Lime/lb SO2	0.00	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio

Design Basis	**Baseline Emi T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				70%	0.55
Nitrogen Oxides (NOx)	2138.98	0.435	669.00	Reduce to reflect short residence time in available ductwork	
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations

Annual hours of operation: **7,947**

Utilization Rate: **68%**

Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37.00	\$/Hr	0.0	hr/8 hr shift	0	0	\$/Hr, 0.0 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	\$/Hr	0.0	hr/8 hr shift	0	0	\$/Hr, 0.0 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	0	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	\$/kwh	0.0	kW-hr	0	0	\$/kwh, 0 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	\$/kscf	0	scfm	0	0	\$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	\$kgal	0.0	gpm	0	0	\$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	\$/kscf	0	scfm/kacfm	0	0	\$/kscf, 0 scfm/kacfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	\$/ton-mi	0.0	ton/hr	0	0	\$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	\$/yr	0.0	ton/hr	1	2,000,000	\$/yr, \$5.1MM/yr extra for PRB - \$1MM/yr Lower O&M Cost
1 Lime	90.0	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	\$/ft3	0	ft^3	0	0	\$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160	\$/bag	0	bags	NA	0	\$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-13: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997	26,255,500	
Purchased Equipment (A)						2005 [6]	38,531,255	19,256,000
Purchased Equipment Total (B)	15%	of control device cost (A)						**22,144,400**
Installation - Standard Costs	74%	of purchased equip cost (B)						16,386,856
Installation - Site Specific Costs								2,146,400
Installation Total								18,533,256
Total Direct Capital Cost, DC								40,677,655
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)						3,321,660
Total Capital Investment (TCI) = DC + IC								**57,199,110**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,787,350
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						6,641,183
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,428,533**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	1,469.9	0.82	3945.9	4,645.7	1,814

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6 WGI total direct installed cost estimate for baghouse adjusted for inflation 10/2/2007
7 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-13: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**19,256,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,925,600
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	962,800
Purchased Equipment Total (B)	15%		**22,144,400**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	885,776
Handling & erection	50%	of purchased equip cost (B)	11,072,200
Electrical	8%	of purchased equip cost (B)	1,771,552
Piping	1%	of purchased equip cost (B)	221,444
Insulation	7%	of purchased equip cost (B)	1,550,108
Painting	4%	of purchased equip cost (B)	885,776
Installation Subtotal Standard Expenses	74%		**16,386,856**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Warehouse Relocation	500,000
Site Specific - Other		Replacement Power - One 14 day outage [7]	1,646,400
Total Site Specific Costs			2,146,400
Installation Total			**18,533,256**
Total Direct Capital Cost, DC			**40,677,655**
Indirect Capital Costs			
Engineering, supervision [6]	5%	of purchased equip cost (B)	1,107,220
Construction & field expenses [6]	0%	of purchased equip cost (B)	0
Contractor fees [6]	5%	of purchased equip cost (B)	1,107,220
Start-up	1%	of purchased equip cost (B)	221,444
Performance test	1%	of purchased equip cost (B)	221,444
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	664,332
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**3,321,660**
Total Capital Investment (TCI) = DC + IC			**43,999,315**
		Retrofit TCI (TCI*1.3)	**57,199,110**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**57,199,110**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr	73,510
Supervisor	15%	15% of Operator Costs	11,026
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization	396,876
NA	NA		-
Water	0.31	$/kgal, 93 gpm, 7947 hr/yr, 68% utilization	9,350
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	38,853
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization	800,014
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**1,787,350**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,828
Administration (2% total capital costs)	2%	of total capital costs (TCI)	879,986
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	439,993
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	439,993
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	4,786,383
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,641,183**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,428,533**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-13: SO2 Control - Dry Sorbent Injection and Baghouse Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$\$/\mathrm{ft}^3$
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			1450.7	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						1450.7	

Baghouse Filter Cost						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0 ft long	5 in dia	0.00	area/cage ft^2	0.000	$/cage
Bags	0	$/ft2 of fabric			0.00	$/bag
		H2O Use (6)	93.02	gpm	0.000	Total
Lime Use	3418.00	lb/hr SO2	0.96	lb Lime/lb SO2	3289.83	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio

Design Basis	**Baseline Emis.** **T/yr**	**Baseline Emis.** **lb/MMBtu**	**Max Emis. (Model)** **lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				55%	0.82
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations

Annual hours of operation: **7,947**
Utilization Rate: **68%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37.00	$/Hr	2.0	hr/8 hr shift	1,987	73,510	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	11,026	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	1.0	hr/8 hr shift	993	36,755	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	1450.7	kW-hr	7,839,605	396,876	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	93.0	gpm	30,161	9,350	$/kgal, 93 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	2	scfm/kacfm	519,753	159,808	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	1.6	ton/hr	8,889	38,853	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1 Lime	90.0	$/ton	3289.8	lb/hr	8,889	800,014	$/ton, 3,290 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160	$/bag	0	bags	NA	224,403	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14A: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F
Expected Utiliztion Rate	68%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F
			Dry Std Flow Rate	464,261	dscfm @ 68º F

Chemical Engineering Chemical Plant Cost Index	
1997	386.5
2005	465
Inflation Adj	1.20

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997	6,783,500	
Purchased Equipment (A)						2005 [7]	8,161,261	4,078,591
Purchased Equipment Total (B)	15%	of control device cost (A)						**4,690,380**
Installation - Standard Costs	74%	of purchased equip cost (B)						3,470,881
Installation - Site Specific Costs								NA
Installation Total								3,470,881
Total Direct Capital Cost, DC								8,161,261
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)						703,557
Total Capital Investment (TCI) = DC + IC								**11,524,264**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						3,789,472
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,413,763
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,203,235**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	643.5	0.36	1727.4	6,864.2	758

Notes & Assumptions

1. Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
   Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3. Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4. Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5. Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6. JXK Revised 1/11 controlled emission rate to account for reduced control effectiveness due to short residence time in available ductwork
7. Stone and Webster 2002 total direct installed cost estimate adjusted for inflation

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14A: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**4,078,591**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	407,859
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	203,930
Purchased Equipment Total (B)	15%		**4,690,380**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	187,615
Handling & erection	50%	of purchased equip cost (B)	2,345,190
Electrical	8%	of purchased equip cost (B)	375,230
Piping	1%	of purchased equip cost (B)	46,904
Insulation	7%	of purchased equip cost (B)	328,327
Painting	4%	of purchased equip cost (B)	187,615
Installation Subtotal Standard Expenses	74%		**3,470,881**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,470,881**
Total Direct Capital Cost, DC			**8,161,261**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	234,519
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees	5%	of purchased equip cost (B)	234,519
Start-up	1%	of purchased equip cost (B)	46,904
Performance test	1%	of purchased equip cost (B)	46,904
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	140,711
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**703,557**
Total Capital Investment (TCI) = DC + IC			**8,864,818**
		Retrofit TCI (TCI*1.3)	**11,524,264**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,524,264**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr	73,510
Supervisor	15%	15% of Operator Costs	11,026
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization	396,876
NA	NA		-
Water	0.31	$/kgal, 136 gpm, 7947 hr/yr, 68% utilization	13,651
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	38,752
NA	NA		-
NA	NA		-
PRB Coal	2,000,000.00	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost	2,000,000
Lime	90.00	$/ton, 3,281 lb/hr, 7947 hr/yr, 68% utilization	797,936
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**3,789,472**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,828
Administration (2% total capital costs)	2%	of total capital costs (TCI)	177,296
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	88,648
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	88,648
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	964,343
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,413,763**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,203,235**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14A: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	\$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	\$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = \$29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			1450.7	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						1450.7	

Baghouse Filter Cost							
							See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2					
Cages	0	ft long	5 in dia	0.00	area/cage ft^2	0.000	\$/cage
Bags	0	\$/ft2 of fabric				0.00	\$/bag
		H2O Use		135.81	gpm	0.000	Total
Lime Use	3418.00	lb/hr SO2		0.96	lb Lime/lb SO2	3281.28	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio

Design Basis	**Baseline Emi T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				80%	0.36
Nitrogen Oxides (NOx)	2138.98	0.435	669.00	Reduce to reflect short residence time in available ductwork	
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

	Item	Unit Cost \$	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37.00	\$/Hr	2.0	hr/8 hr shift	1,987	73,510	\$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	11,026	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	\$/Hr	1.0	hr/8 hr shift	993	36,755	\$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	\$/kwh	1450.7	kW-hr	7,839,605	396,876	\$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	\$/kscf	0	scfm	0	0	\$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	\$/kgal	135.8	gpm	44,036	13,651	\$/kgal, 136 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	\$kgal	0.0	gpm	0	0	\$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	\$/kscf	2	scfm/kacfm	519,753	159,808	\$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	\$/ton	1.6	ton/hr	8,866	38,752	\$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	\$/ton-mi	0.0	ton/hr	0	0	\$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	\$/yr	0.0	ton/hr	1	2,000,000	\$/yr, \$5.1MM/yr extra for PRB - \$1MM/yr Lower O&M Cost
1	Lime	90.0	\$/ton	3281.3	lb/hr	8,866	797,936	\$/ton, 3,281 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	\$/ft3	0	ft^3	0	0	\$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	\$/bag	0	bags	NA	224,403	\$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14B: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1997	386.5
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.20
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs						Year		
Direct Capital Costs (1)						1997	6,783,500	
Purchased Equipment (A)						2005 [7]	8,161,261	4,078,591
Purchased Equipment Total (B)	15%	of control device cost (A)						**4,690,380**
Installation - Standard Costs	74%	of purchased equip cost (B)						3,470,881
Installation - Site Specific Costs								NA
Installation Total								3,470,881
Total Direct Capital Cost, DC								8,161,261
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)						703,557
Total Capital Investment (TCI) = DC + IC								**11,524,264**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,781,771
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,413,763
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**3,195,534**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	-		2139.0	-	NA
Sulfur Dioxide (SO_2)	8,591.6	2,123.3	1.18	5699.6	2,892.0	1,105

Notes & Assumptions

1 Total Direct Capital Cost Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a, EPA May 1999
Model input scaled to 312 MW (=192 MW * 801500 ACFM / 493400 ACFM) to account for high stack flow rates at Stanton
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4 Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5 Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6 JXK Revised 1/11 controlled emission rate to account for reduced control effectiveness due to short residence time in available ductwork
7 Stone and Webster 2002 total direct installed cost estimate adjusted for inflation

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14B: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**4,078,591**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	407,859
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	203,930
Purchased Equipment Total (B)	15%		**4,690,380**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	187,615
Handling & erection	50%	of purchased equip cost (B)	2,345,190
Electrical	8%	of purchased equip cost (B)	375,230
Piping	1%	of purchased equip cost (B)	46,904
Insulation	7%	of purchased equip cost (B)	328,327
Painting	4%	of purchased equip cost (B)	187,615
Installation Subtotal Standard Expenses	74%		**3,470,881**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,470,881**
Total Direct Capital Cost, DC			**8,161,261**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	234,519
Construction & field expenses	0%	of purchased equip cost (B)	0
Contractor fees	5%	of purchased equip cost (B)	234,519
Start-up	1%	of purchased equip cost (B)	46,904
Performance test	1%	of purchased equip cost (B)	46,904
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	140,711
Total Indirect Capital Costs, IC	15%	of purchased equip cost (B)	**703,557**
Total Capital Investment (TCI) = DC + IC			**8,864,818**
		Retrofit TCI (TCI*1.3)	**11,524,264**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,524,264**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr	73,510
Supervisor	15%	15% of Operator Costs	11,026
Maintenance			
Maintenance Labor	37.00	$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr	36,755
Maintenance Materials	100%	of maintenance labor costs	36,755
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization	396,876
NA	NA		-
Water	0.31	$/kgal, 59 gpm, 7947 hr/yr, 68% utilization	5,950
NA	NA		-
Comp Air	0.31	$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization	159,808
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization	38,752
NA	NA		-
NA	NA		-
NA	NA		-
Lime	90.00	$/ton, 3,281 lb/hr, 7947 hr/yr, 68% utilization	797,936
NA	NA		-
NA	NA		-
NA	NA		-
Filter Bags	160.00	$/bag, 0 bags, 7947 hr/yr, 68% utilization	224,403
Total Annual Direct Operating Costs			**1,781,771**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	94,828
Administration (2% total capital costs)	2%	of total capital costs (TCI)	177,296
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	88,648
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	88,648
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	964,343
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,413,763**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,195,534**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-14B: SO2 Control - Dry Sorbent Injection and Existing ESP, Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalsyt:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	\$/ft^3
Amount Required	0	ft^3
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:	**Filter bags & cages**		
Equipment Life	4	years	
CRF	0.2853		
Rep part cost per unit	160	\$/bag	
Amount Required	4410		
Total Rep Parts Cost	740,880	Cost adjusted for freight & sales tax	
Installation Labor	45,688	10 min per bag, Labor + Overhead (68% = \$29.65/hr)	EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**786,568**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**224,403**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	801,500		10			1450.7	
Baghouse Shaker	0.0	Gross fabric area ft^2				0	EPA Cost Cont Manual 6th ed Section 6 Chapter 1 Eq 1.14
Other							
Other							
Other							
Other							
Other							
Total						1450.7	

Baghouse Filter Cost						
						See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Gross BH Filter Area	0	ft^2				
Cages	0 ft long	5 in dia	0.00	area/cage ft^2	0.000	\$/cage
Bags	0	\$/ft2 of fabric			0.00	\$/bag
		H2O Use	59.20	gpm	0.000	Total
Lime Use	3418.00	lb/hr SO2	0.96	lb Lime/lb SO2	3281.28	lb/hr lime, lime addition at 1.1 times the stoichiometric ratio

Design Basis	**Baseline Emi** **T/yr**	**Baseline Emi** **lb/MMBtu**	**Max Emis. (Model)** **lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				35%	1.18
Nitrogen Oxides (NOx)	2138.98	0.435	669.00	Reduce to reflect short residence time in available ductwork	
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		

Operating Cost Calculations — **Annual hours of operation:** **7,947**; **Utilization Rate:** **68%**

	Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	\$/Hr	2.0	hr/8 hr shift	1,987	73,510	\$/Hr, 2.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	11,026	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	\$/Hr	1.0	hr/8 hr shift	993	36,755	\$/Hr, 1.0 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	36,755	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	\$/kwh	1450.7	kW-hr	7,839,605	396,876	\$/kwh, 1,451 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	\$/kscf	0	scfm	0	0	\$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	\$/kgal	59.2	gpm	19,194	5,950	\$/kgal, 59 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	\$kgal	0.0	gpm	0	0	\$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	\$/kscf	2	scfm/kacfm	519,753	159,808	\$/kscf, 2 scfm/kacfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	\$/ton	1.6	ton/hr	8,866	38,752	\$/ton, 2 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	\$/ton-mi	0.0	ton/hr	0	0	\$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	\$/yr	0.0	ton/hr	0	0	\$/yr, \$5.1MM/yr extra for PRB - \$1MM/yr Lower O&M Cost/2
1	Lime	90.0	\$/ton	3281.3	lb/hr	8,866	797,936	\$/ton, 3,281 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	\$/ft3	0	ft^3	0	0	\$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160	\$/bag	0	bags	NA	224,403	\$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Catalytic Reduction (SCR) with Reheat, Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs							Year	
Direct Capital Costs	EPRI Correlation						1998	
Purchased Equipment (A)							2005	38,000,000
Purchased Equipment Total (B)	0%	of control device cost (A)					SCR Only	**38,000,000**
Installation - Standard Costs	15%	of purchased equip cost (B)					SCR Only	5,988,085
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC							SCR + Reheat	**56,554,445**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					SCR + Reheat	7,676,364
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					SCR + Reheat	4,818,174
Total Annual Cost (Annualized Capital Cost + Operating Cost)							SCR + Reheat	**12,494,538**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	78.3	0.04	210.2	1,928.7	6,478
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2. Scaled to reflect Alstom March 2006 cost estimate for SCR without reheat.
2 For Calculation purposes, duty reflects increased flow rate, not actual duty.
3 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
4 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.36 -2.43
5 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.32 - 2.35
6 SCR Catalyst Volume per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.18 - 2.24
7 SCR Reactor Size per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.25 - 2.31
8 SCR Catalyst Replacement per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.50 - 2.53
9 SCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.48
10 SCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.46
11 Control Efficiency = 90% reduction which is typically the upper range of normal SCR control efficiency
12 Adusted cost for high flow from excess are by ratio of Stanton F Factor to Method 19 Lignite F Factor 15,476 dscf/MMBtu Stanton vs 9,860 dscf/MMBtu for Lignite
13 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW
14 Per March 2006 Alstom report, catalyst replacement every 8000 hours. This requires an additional 2 week outage per 3 year outage cycle, annualized to 4.7 days.

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Catalytic Reduction (SCR) with Reheat, Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**38,000,000**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0.0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**38,000,000**
Indirect Installation			
General Facilities	0%	of purchased equip cost (A)	0
Engineering & Home Office	0%	of purchased equip cost (A)	0
Process Contingency	0%	of purchased equip cost (A)	0
Site Specific-Other	5%	Replacement Power, two weeks	1,920,567
Total Indirect Installation Costs (B)	5%	of purchased equip cost (A)	**1,920,567**
Project Contingeny (C)	15%	of (A + B)	**5,988,085**
Total Plant Cost D		A + B + C	**45,908,652**
Allowance for Funds During Construction (E)		Additional 10 week outage for installation	**8,232,000**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**1,082,813**
Inventory Capital		Reagent Vol * $/gal	**55,904**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**55,279,369**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**NA**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	829,191
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 2,793 kW-hr, 7947 hr/yr, 68% utilization	764,056
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Cat. Replacement [14]	35.00	Catalyst Replacement	548,800
NA	NA		-
Ammonia	0.20	$/lb, 1,647 lb/hr, 7947 hr/yr, 68% utilization	1,780,439
NA	NA		-
SCR Catalyst	500.00	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization	659,187
NA	NA		-
Total Annual Direct Operating Costs			**4,581,674**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	4,625,741
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,625,741**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,207,414**

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Catalytic Reduction (SCR) with Reheat, Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst				
Equipment Life	24,000	hours		
FCW	0.3157			
Rep part cost per unit	500	$/ft^3	# of Layers	14
Replacement Factor	14	ayers replaced per year =		1
Amount Required	4,177	ft^3		
Catalyst Cost	2,088,321			
Y catalyst life factor	3	Years		
Annualized Cost	**659,187**			

SCR Capital Cost per EPRI Method			**23,757,633**					
Duty	2,825	MMBtu/hr	Catalyst Area	1,363	ft^2		413	*f* (h SCR)
Q flue gas	1,308,420	acfm	Rx Area	1,567			1	*f* (h NH_3)
NOx Cont Eff	90%	(as faction)	Rx Height	39.6	ft		-728	*f* (h New) new= -728, Retrofit = 0
NOx in	0.44	lb/MMBtu	n layer	14	layers	Y		Bypass? Y or N
Ammonia Slip	2	ppm	h layer	15.3	ft		127	*f* (h Bypass)
Fuel Sulfur	0.67	wt % (as %)	n total	15	layers		14,033,519	*f* (vol catalyst)
Temperature	330	Deg F	h SCR	98	ft			*f* (h SCR)
Catalyst Volume	**58,473**	ft^3	New/Retrofit	N	N or R			

Electrical Use				
Duty	2,825	MMBtu/hr		kW
NOx Cont Eff	90%	(as faction)	Power	2,792.9
NOx in	0.44	lb/MMBtu		
n catalyst layers	15	layers		
Press drop catalyst	1	in H_2O per layer		
Press drop duct	3	in H_2O		
Total				2792.9

Reagent Use & Other Operating Costs								
Ammonia Use			56.0	lb/ft^3 Density				
	478	lb/hr Neat	220.1	gal/hr				
	29%	solution	Volume 14 day inventory		73,943	gal	$55,904	Inventory Cost
	1647	lb/hr						

Design Basis	**Baseline Emi** **T/yr**	**Baseline Emi** **lb/MMBtu**	**Max Emis. (Model)** **lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				90%	0.04
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		
Actual	15,475	dscf/MMBtu			
Method 19 Factor	9,860	dscf/MMBtu			
Adjusted Duty	2,825	MMBtu/hr			

Operating Cost Calculations — **Annual hours of operation:** **7,947**; **Utilization Rate:** **68%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37.00	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	1.5	% of Total Capital Investment				829,191	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	2792.9	kW-hr	15,092,622	764,056	$/kwh, 2,793 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0.0	scfh	0	0	$/kscf, 0 scfh, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	0.0	gph	0	0	$/kgal, 0 gph, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	Cat. Replacement [14]	35	$/MW-hr	140.0	mw	112	548,800	Catalyst Replacement
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
7	Ammonia	0.2	$/lb	1647	lb/hr	8,902,197	1,780,439	$/lb, 1,647 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	659,187	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-16: Cost of Flue Gas Re-Heating (Thermal Oxidizer)

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			688,672
Purchased Equipment Total (B)	15%	of control device cost (A)	**791,972**
Installation - Standard Costs	30%	of purchased equip cost (B)	237,592
Installation - Site Specific Costs			NA
Installation Total			237,592
Total Direct Capital Cost, DC			1,029,564
Total Indirect Capital Costs, IC	31%	of purchased equip cost (B)	245,511
Total Capital Investment (TCI) = DC + IC			**1,275,076**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	3,094,690
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	192,434
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,287,124**

Notes & Assumptions

1 Equipment cost estimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-16: Cost of Flue Gas Re-Heating (Thermal Oxidizer)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**688,672**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	68,867
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	34,434
Purchased Equipment Total (B)	15%		**791,972**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	63,358
Handling & erection	14%	of purchased equip cost (B)	110,876
Electrical	4%	of purchased equip cost (B)	31,679
Piping	2%	of purchased equip cost (B)	15,839
Insulation	1%	of purchased equip cost (B)	7,920
Painting	1%	of purchased equip cost (B)	7,920
Installation Subtotal Standard Expenses	30%		**237,592**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**237,592**
Total Direct Capital Cost, DC			**1,029,564**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	79,197
Construction & field expenses	5%	of purchased equip cost (B)	39,599
Contractor fees	10%	of purchased equip cost (B)	79,197
Start-up	2%	of purchased equip cost (B)	15,839
Performance test	1%	of purchased equip cost (B)	7,920
Model Studies		of purchased equip cost (B)	0
Contingencies	3%	of purchased equip cost (B)	23,759
Total Indirect Capital Costs, IC	31%	of purchased equip cost (B)	**245,511**
Total Capital Investment (TCI) = DC + IC			**1,275,076**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**1,275,076**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Supervisor	15%	15% of Operator Costs	2,757
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Maintenance Materials	100%	of maintenance labor costs	18,377
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 2,970 kW-hr, 7947 hr/yr, 68% utilization	812,390
Natural Gas	6.85	$/kscf, 1,002 scfm, 7947 hr/yr, 68% utilization	2,224,411
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**3,094,690**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	34,733
Administration (2% total capital costs)	2%	of total capital costs (TCI)	25,502
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	12,751
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	12,751
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	106,697
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**192,434**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,287,124**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-16: Cost of Flue Gas Re-Heating (Thermal Oxidizer)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:	**Catalyst**	
Equipment Life	2	years
CRF	0.5416	
Rep part cost per unit	650	$/ft^3
Amount Required	39	ft^3
Catalyst Cost	26,618	Cost adjusted for freight & sales tax
Installation Labor	3,993	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use

	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Thermal	801,500		19	0.6		2,969.6	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	801,500		23	0.6		3,594.7	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				2969.6	

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	2,757	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	18,377	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	2969.6	kW-hr	16,047,368	812,390	$/kwh, 2,970 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	1,002	scfm	324,732	2,224,411	$/kscf, 1,002 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
2	CO Catalyst	650	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-16: Cost of Flue Gas Re-Heating (Thermal Oxidizer)

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

Auxiliary Fuel Use Equation 3.19

T_{wi}	300	Deg F - Temperature of waste gas into heat recovery
T_{fi}	450	Deg F - Temperature of Flue gas into of heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	70%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	405	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	345	Deg F - Temperature of flue gas into of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2684	Btu/lb - Deg F Heat Capacity of waste gas (air)
p_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
p_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	535,480	scfm - Flow of waste gas
Q_{af}	1,002	scfm - Flow of auxiliary fuel

Year 2005 Inflation Rate 3.0%
Cost Calculations 536,482 scfm Flue Gas Cost in 1989 $'s $577,596
Current Cost Using CHE Plant Cost Index $688,672

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Indurator Flue Gas Heat Capacity - Basis Typical Composition

		100	scfm	359	scf/lbmole		
		Gas Composition		lb/hr f	wt %	Cp Gas	Cp Flue
28	mw CO	0	v %	0			
44	mw CO2	15	v %	184	22.0%	0.24	0.0528
18	mw H2O	10	v %	50	6.0%	0.46	0.0276
28	mw N2	60	v %	468	56.0%	0.27	0.1512
32	mw O2	15	v %	134	16.0%	0.23	0.0368
	Cp Flue Gas	100	v %	836	100.0%		0.2684

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators
(EPA 453/B-96-001)

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-17: NOx Control - LoTOx - (Low Temperature Oxidation), Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F
Expected Utiliztion Rate	68%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F
			Dry Std Flow Rate	464,261	dscfm @ 68º F

	Control Eff	NOx in lb/MMBtu
NOx loading & efficiency for sizing	90.0%	0.44

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								4,989,702
Purchased Equipment Total (B)	15%	of control device cost (A)						**5,738,157**
Installation - Standard Costs	85%	of purchased equip cost (B)						4,877,433
Installation - Site Specific Costs								2,146,400
Installation Total								7,023,833
Total Direct Capital Cost, DC								12,761,990
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)						2,008,355
Total Capital Investment (TCI) = DC + IC								**43,877,532**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						39,318,066
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						5,461,477
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**44,779,543**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	78.3	0.04	210.2	1,928.7	23,217
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 Sept 2005 Cost Estimate Procedure from **BOC Gases**
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1 (absorbers)
3 Liquid/Gas ratio = 10 L/G = Gal/1,000 acf
4 Water Makeup Rate/Wastewater Discharge = 20% of circulating water rate
5 WWTP cost basis sending waste water to municipal system; consider developing cost for installation and operation of biotreatment system.
6 Per GRE 3/22/02 cost estimate $35/MW-hr, 140 MW

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-17: NOx Control - LoTOx - (Low Temperature Oxidation), Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**4,989,702**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	498,970
ND Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	249,485
Purchased Equipment Total (B)	15%		**5,738,157**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	688,579
Handling & erection	40%	of purchased equip cost (B)	2,295,263
Electrical	1%	of purchased equip cost (B)	57,382
Piping	30%	of purchased equip cost (B)	1,721,447
Insulation	1%	of purchased equip cost (B)	57,382
Painting	1%	of purchased equip cost (B)	57,382
Installation Subtotal Standard Expenses	85%		**4,877,433**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Stack Replacement	500,000
Site Specific - Other		Replacement Power - One 14 day outage [8]	1,646,400
Total Site Specific Costs			2,146,400
Installation Total			**7,023,833**
Total Direct Capital Cost, DC			**12,761,990**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	573,816
Construction & field expenses	10%	of purchased equip cost (B)	573,816
Contractor fees	10%	of purchased equip cost (B)	573,816
Start-up	1%	of purchased equip cost (B)	57,382
Performance test	1%	of purchased equip cost (B)	57,382
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	172,145
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**2,008,355**
Ozone Generator, Installed Cost			**29,107,187**
Total Capital Investment (TCI) = DC + IC			**43,877,532**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**43,877,532**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Supervisor	15%	15% of Operator Costs	2,757
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr	18,377
Maintenance Materials	100%	of maintenance labor costs	18,377
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 17,088 kW-hr, 7947 hr/yr, 68% utilization	4,674,748
NA	NA		-
Water	0.31	$/kgal, 1,603 gpm, 7947 hr/yr, 68% utilization	161,123
Cooling Water	0.27	$kgal, 8,663 gpm, 7947 hr/yr, 68% utilization	754,623
NA	NA		-
NA	NA		-
WW Treat Biotreatement	4.15	$/kgal, 1,603 gpm, 7947 hr/yr, 68% utilization	2,158,202
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Oxygen	15.00	kscf, 389 kscf/hr, 7947 hr/yr, 68% utilization	31,511,481
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**39,318,066**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	34,733
Administration (2% total capital costs)	2%	of total capital costs (TCI)	877,551
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	438,775
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	438,775
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	3,671,642
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,461,477**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**44,779,543**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-17: NOx Control - LoTOx - (Low Temperature Oxidation), Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use	Flow acfm		**Δ P in H2O**	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	801,500		10	0.7	-	1,339.6	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	8,015 gpm	1	60	0.7	-	129.2	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	1603 gpm	1	60	0.7	-	25.8	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				15,593	
Other							
Total						17087.8	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	3,465.1	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion	34,651	lb/hr O2	388,746	scfh O2
LTO Cooling Water	150	gal/lb O3	8,663	gpm		
Liquid/Gas ratio	10.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	8,015	gpm				
Water Makeup Rate/WW Disch =	20.0%	of circulating water rate =	1603 gpm			
Scrubber Cost	10	$/scfm Gas	$4,989,702		Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$29,107,187	Installed	Installed cost factor per BOC.	

Operating Cost Calculations **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	2,757	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.5	hr/8 hr shift	497	18,377	$/Hr, 0.5 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	18,377	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	17087.8	kW-hr	92,341,607	4,674,748	$/kwh, 17,088 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	1,603.0	gpm	519,753	161,123	$/kgal, 1,603 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	8,662.9	gpm	2,808,823	754,623	$kgal, 8,663 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	1,603.0	gpm	519,753	2,158,202	$/kgal, 1,603 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost
1 Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	388.7	kscf/hr	2,100,765	31,511,481	kscf, 389 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-18: NOx Control - Selective Non-Catalytic Reduction (SNCR), PRB Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F		
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs							Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s							
Purchased Equipment (A)							2005	**7,113,100**
Purchased Equipment Total (B)	0%	of control device cost (A)						**7,113,100**
Installation - Standard Costs	15%	of purchased equip cost (B)						1,066,965
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**8,406,968**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						4,308,007
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						703,489
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,011,496**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	414.0	0.23	1111.3	1,027.7	4,877
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 Estimated Equipment Cost per WGI report November, 2007. Installation cost included.
2 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.19
3 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
4 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
5 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
6 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
7 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
8 Lignite Coal Assumptions 6,054 Btu/lb (wet) Ash 6.2% 42% moisture $10.20/ton delivered

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-18: NOx Control - Selective Non-Catalytic Reduction (SNCR), PRB Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**7,113,100**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0.0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**7,113,100**
Indirect Installation [1]			
General Facilities	0%	of purchased equip cost (A)	0
Engineerin & Home Office	0%	of purchased equip cost (A)	0
Process Contingency	0%	of purchased equip cost (A)	0
Total Indirect Installation Costs (B)	0%	of purchased equip cost (A)	**0**
Project Contingeny (C)	15%	of (A + B)	**1,066,965**
Total Plant Cost D		A + B + C	**8,180,065**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**163,601**
Inventory Capital		Reagent Vol * $/gal	**63,302**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**8,406,968**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**8,406,968**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	15.00	% of Total Capital Investment	1,261,045
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 98 kW-hr, 7947 hr/yr, 68% utilization	26,771
NA	NA		-
Water	0.31	$/kgal, 446 gph, 7947 hr/yr, 68% utilization	747
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization	1,346
NA	NA		-
NA	NA		-
PRB Coal	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2	2,000,000
NA	NA		-
Urea	405.00	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization	1,018,098
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**4,308,007**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	703,489
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**703,489**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,011,496**

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-18: NOx Control - Selective Non-Catalytic Reduction (SNCR), PRB Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		**<-** Enter Equipment Name to Get Cost	
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	500	$/ft^3	
Amount Required	12	ft^3	
Packing Cost	6,300	Cost adjusted for freight & sales tax	
Installation Labor	945	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:		**<-** Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	160	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.44	lb/MMBtu	kW
NSR	1.61		
Power			97.9
Total			97.9

Reagent Use & Other Operating Costs			Urea Use			
37.30	Coal Moisture Content %		465	lb/hr Neat		
1.16	Coal Sulfur Content		50%	solution	71.0	lb/ft^3 Density 50% Solution
6,580	Btu/lb Coal		930	lb/hr	98.0	gal/hr
9.95	wt % Ash (wet)	Volume 14 day inventory	32,938	gal	$63,302	Inventory Cost
Water Use	446 gal/hr	Inject at 10% solution		Fuel Use	7.54	MMBtu/hr
				Ash Generation	113.96	lb/hr

Design Basis	**Baseline Emi T/yr**	**Baseline Emi lb/MMBtu**	**Max Emis. (Model) lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				47%	**0.23**
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		
Actual	15,475	dscf/MMBtu			
Method 19 Factor	9,860	dscf/MMBtu			
Adjusted Duty	2,825	MMBtu/hr			

Operating Cost Calculations — **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	15	% of Total Capital Investment				1,261,045	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	97.9	kW-hr	528,811	26,771	$/kwh, 98 kW-hr, 7947 hr/yr, 68% utilization
	Coal	0.00		0.0	MMBtu/hr	0	0	, 0 MMBtu/hr, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	445.9	gph	2,410	747	$/kgal, 446 gph, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	0.057	ton/hr	308	1,346	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	1	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
3	Urea	405	$/ton	0.4652	ton/hr	2,514	1,018,098	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-19: NOx Control - Selective Non-Catalytic Reduction (SNCR), Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering**	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utiliztion Rate	68%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F		
			Dry Std Flow Rate	464,261	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs							Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s							
Purchased Equipment (A)							2005	**7,113,100**
Purchased Equipment Total (B)	0%	of control device cost (A)						**7,113,100**
Installation - Standard Costs	15%	of purchased equip cost (B)						1,066,965
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**8,388,450**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,998,959
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						701,940
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**2,700,899**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	522.0	0.29	1401.2	737.7	3,661
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 Estimated Equipment Cost per WGI report November, 2007. Installation cost included.
2 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.19
3 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
4 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
5 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
6 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
7 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
8 Lignite Coal Assumptions 6,054 Btu/lb (wet) Ash 6.2% 42% moisture $10.20/ton delivered

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-19: NOx Control - Selective Non-Catalytic Reduction (SNCR), Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**7,113,100**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0.0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**7,113,100**
Indirect Installation [1]			
General Facilities	0%	of purchased equip cost (A)	0
Engineerin & Home Office	0%	of purchased equip cost (A)	0
Process Contingency	0%	of purchased equip cost (A)	0
Total Indirect Installation Costs (B)	0%	of purchased equip cost (A)	**0**
Project Contingeny (C)	15%	of (A + B)	**1,066,965**
Total Plant Cost D		A + B + C	**8,180,065**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**163,601**
Inventory Capital		Reagent Vol * $/gal	**44,784**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**8,388,450**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**8,388,450**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	15.00	% of Total Capital Investment	1,258,268
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 69 kW-hr, 7947 hr/yr, 68% utilization	18,939
NA	NA		-
Water	0.31	$/kgal, 315 gph, 7947 hr/yr, 68% utilization	529
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	4.37	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization	952
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	405.00	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization	720,271
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**1,998,959**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	701,940
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**701,940**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,700,899**

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-19: NOx Control - Selective Non-Catalytic Reduction (SNCR), Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		**<-** Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	500	\$/ft^3
Amount Required	12	ft^3
Packing Cost	6,300	Cost adjusted for freight & sales tax
Installation Labor	945	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		**<-** Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	160	\$/ft^3	
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = \$29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.44	lb/MMBtu	kW
NSR	1.14		
Power			69.2
Total			69.2

Reagent Use & Other Operating Costs			Urea Use				
	37.30	Coal Moisture Content %		329	lb/hr Neat		
	1.16	Coal Sulfur Content		50%	solution	71.0	lb/ft^3 Density 50% Solution
	6,580	Btu/lb Coal		658	lb/hr	69.4	gal/hr
	9.95	wt % Ash (wet)	Volume 14 day inventory	23,302	gal	\$44,784	Inventory Cost
Water Use	315	gal/hr	Inject at 10% solution		Fuel Use	5.33	MMBtu/hr
					Ash Generation	80.62	lb/hr

Design Basis	**Baseline Emi** **T/yr**	**Baseline Emi** **lb/MMBtu**	**Max Emis. (Model)** **lb/hr**	**Control Eff (%)**	**Cont. Emis (lb/MMBtu)**
				33%	**0.29**
Nitrogen Oxides (NOx)	2138.98	0.435	669.00		
Sulfur Dioxide (SO2)	8591.56	1.815	3418.00		
Actual	15,475	dscf/MMBtu			
Method 19 Factor	9,860	dscf/MMBtu			
Adjusted Duty	2,825	MMBtu/hr			

Operating Cost Calculations — **Annual hours of operation:** **7,947**; **Utilization Rate:** **68%**

	Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	\$/Hr	0.0	hr/8 hr shift	0	0	\$/Hr, 0.0 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	15	% of Total Capital Investment				1,258,268	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	\$/kwh	69.2	kW-hr	374,117	18,939	\$/kwh, 69 kW-hr, 7947 hr/yr, 68% utilization
	Coal	0.00		0.0	MMBtu/hr	0	0	, 0 MMBtu/hr, 7947 hr/yr, 68% utilization
	Water	0.31	\$/kgal	315.5	gph	1,705	529	\$/kgal, 315 gph, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	\$kgal	0.0	gpm	0	0	\$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	\$/kscf	0.0	scfm/kacfm**	0	0	\$/kscf, 0 scfm/kacfm**, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	\$/kgal	0.0	gpm	0	0	\$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	\$/ton	0.040	ton/hr	218	952	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	\$/ton	0.0	ton/hr	0	0	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	\$/ton-mi	0.0	ton/hr	0	0	\$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	\$/yr	0.0	ton/hr	0	0	\$/yr, \$5.1MM/yr extra for PRB - \$1MM/yr Lower O&M Cost/2
1	Lime	90.00	\$/ton	0.0	lb/hr	0	0	\$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
3	Urea	405	\$/ton	0.3291	ton/hr	1,778	720,271	\$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	\$/ft3	0	ft^3	0	0	\$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	\$/bag	0	bags	0	0	\$/bag, 0 bags, 7947 hr/yr, 68% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-20: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), PRB Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F
Expected Utiliztion Rate	68%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F
			Dry Std Flow Rate	464,261	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**1,460,000**
Purchased Equipment Total (B)	15%	of control device cost (A)	**1,679,000**
Installation - Standard Costs	0%	of purchased equip cost (B)	0
Installation - Site Specific Costs			NA
Installation Total			0
Total Direct Capital Cost, DC			1,679,000
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	587,650
Total Capital Investment (TCI) = DC + IC			**2,266,650**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	2,011,578
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	287,284
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,298,862**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	514.8	**0.29 [5]**	1381.9	757.1	3,037
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1 March 2006 Cost Estimate from Alstom Power Inc, Option 2 . Installation cost included.

2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)

3 Control efficiency basis 0.2 lb NOx/MMBtu average per May 2005 Cost Estimate from Alstom Power Inc, Option 2

4 Assumed 0.1 hr/shift operatior and maintenance labor for LNB

5 Additional control for lower Nox inherent with PRB coal.

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-20: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), PRB Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,460,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	146,000
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	73,000
Purchased Equipment Total (B)	15%		**1,679,000**
Installation [1]			
Foundations & supports	0%	of purchased equip cost (B)	0
Handling & erection	0%	of purchased equip cost (B)	0
Electrical	0%	of purchased equip cost (B)	0
Piping	0%	of purchased equip cost (B)	0
Insulation	0%	of purchased equip cost (B)	0
Painting	0%	of purchased equip cost (B)	0
Installation Subtotal Standard Expenses	0%		**0**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**0**
Total Direct Capital Cost, DC			**1,679,000**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	167,900
Construction & field expenses	10%	of purchased equip cost (B)	167,900
Contractor fees	10%	of purchased equip cost (B)	167,900
Start-up	1%	of purchased equip cost (B)	16,790
Performance test	1%	of purchased equip cost (B)	16,790
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	50,370
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**587,650**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC			**2,266,650**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**2,266,650**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr	3,675
Supervisor	15%	15% of Operator Costs	551
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr	3,675
Maintenance Materials	100%	of maintenance labor costs	3,675
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
PRB Coal	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2	2,000,000
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**2,011,578**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	6,947
Administration (2% total capital costs)	2%	of total capital costs (TCI)	45,333
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	22,667
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	22,667
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	189,672
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**287,284**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,298,862**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-20: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), PRB Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Scrubber	801,500		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	Δ P ft H2O	Efficiency	Hp	kW	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O$_3$				
LTO Electric Use	4.5	kW/lb O$_3$				0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion	0	lb/hr O2	0	scfh O2
LTO Cooling Water	150	gal/lb O3	0	gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	0	gpm				
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0	gpm		
Scrubber Cost	10	$/scfm Gas	$0	Incremental cost per BOC. Need to increase vessel size over standard absorber.		
Ozone Generator	$350	lb O3/day	$0 Installed	Installed cost factor per BOC.		

Operating Cost Calculations **Annual hours of operation:** **7,947**
Utilization Rate: **68%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37.00	$/Hr	0.1	hr/8 hr shift	99	3,675	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr
Supervisor	15%	of Op.			NA	551	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	99	3,675	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,675	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7947 hr/yr, 68% utilization
Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
PRB Coal	2,000,000	$/yr	0.0	ton/hr	1	2,000,000	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1 Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2 Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5 Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1 SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1 Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-21: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), Lignite Coal

Operating Unit: **Unit 1**

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	1,800	MMBtu/hr	Standardized Flow Rate	498,970	scfm @ 32º F
Expected Utiliztion Rate	68%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,947	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	801,500	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	535,480	scfm @ 68º F
			Dry Std Flow Rate	464,261	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**1,460,000**
Purchased Equipment Total (B)	15%	of control device cost (A)	**1,679,000**
Installation - Standard Costs	0%	of purchased equip cost (B)	0
Installation - Site Specific Costs			NA
Installation Total			0
Total Direct Capital Cost, DC			1,679,000
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	587,650
Total Capital Investment (TCI) = DC + IC			**2,266,650**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	11,578
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	287,284
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**298,862**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Predicted Limit lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10	89.5	-		89.5	-	NA
Total Particulates	90.5	-		90.5	-	NA
Nitrogen Oxides (NOx)	2,139.0	576.0	**0.32**	1546.2	592.8	504
Sulfur Dioxide (SO_2)	8,591.6	-		8591.6	-	NA

Notes & Assumptions

1. March 2006 Cost Estimate from Alstom Power Inc, Option 2 . Installation cost included.
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)
3. Control efficiency basis 0.2 lb NOx/MMBtu average per May 2005 Cost Estimate from Alstom Power Inc, Option 2
4. Assumed 0.1 hr/shift operatior and maintenance labor for LNB

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-21: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,460,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	146,000
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	73,000
Purchased Equipment Total (B)	15%		**1,679,000**
Installation [1]			
Foundations & supports	0%	of purchased equip cost (B)	0
Handling & erection	0%	of purchased equip cost (B)	0
Electrical	0%	of purchased equip cost (B)	0
Piping	0%	of purchased equip cost (B)	0
Insulation	0%	of purchased equip cost (B)	0
Painting	0%	of purchased equip cost (B)	0
Installation Subtotal Standard Expenses	0%		**0**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**0**
Total Direct Capital Cost, DC			**1,679,000**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	167,900
Construction & field expenses	10%	of purchased equip cost (B)	167,900
Contractor fees	10%	of purchased equip cost (B)	167,900
Start-up	1%	of purchased equip cost (B)	16,790
Performance test	1%	of purchased equip cost (B)	16,790
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	50,370
Total Indirect Capital Costs, IC	35%	of purchased equip cost (B)	**587,650**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC			**2,266,650**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**2,266,650**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	37.00	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr	3,675
Supervisor	15%	15% of Operator Costs	551
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr	3,675
Maintenance Materials	100%	of maintenance labor costs	3,675
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**11,578**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	6,947
Administration (2% total capital costs)	2%	of total capital costs (TCI)	45,333
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	22,667
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	22,667
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	189,672
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**287,284**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**298,862**

See Summary page for notes and assumptions

Great River Energy Stanton
BART Emission Control Cost Analysis
Table A-21: NOx Control - Alstom LNB (Low NOx Burners) + Over Fire Air (OFA), Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:			
Equipment Life	5	years	
CRF	0.0000		
Rep part cost per unit	500	$/ft^3	
Amount Required	0	ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		**Δ P in H2O**	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	801,500		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion	0	lb/hr O2	0	scfh O2
LTO Cooling Water	150	gal/lb O3	0	gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	0	gpm				
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0	gpm		
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0	Installed	Installed cost factor per BOC.	

	Operating Cost Calculations			**Annual hours of operation:**			**7,947**	
				Utilization Rate:			**68%**	
	Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
	Operating Labor							
	Op Labor	37.00	$/Hr	0.1	hr/8 hr shift	99	3,675	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr
	Supervisor	15%	of Op.			NA	551	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	99	3,675	$/Hr, 0.1 hr/8 hr shift, 7947 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	3,675	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7947 hr/yr, 68% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7947 hr/yr, 68% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7947 hr/yr, 68% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7947 hr/yr, 68% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	WW Treat Biotreatemen	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7947 hr/yr, 68% utilization
	SW Disposal	4.37	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7947 hr/yr, 68% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 7947 hr/yr, 68% utilization
	PRB Coal	2,000,000	$/yr	0.0	ton/hr	0	0	$/yr, $5.1MM/yr extra for PRB - $1MM/yr Lower O&M Cost/2
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7947 hr/yr, 68% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7947 hr/yr, 68% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 7947 hr/yr, 68% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 7947 hr/yr, 68% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix B

Cost Threshold Documentation

Summary of Relevant Economic Feasibility ($/ton) Control Costs

		Avg. Expected Values ($/ton)		Limiting/Marginal values ($/ton)		
Reference	**Regulatory Body/Rule**	**SO_2**	**NOx**	**SO_2**	**NOx**	**Comments**
FR Notice 6JULY05 Final Rule	BART	100 - 1000	100 - 1000			70 FR 39135
	BART		281 - 1296			70 FR 39135 Table 3
	BART	919				70 FR 39133
	BART					Guidelines disparagingly reference "thousands of dollars per ton" in commenting on the need to exceed MACT and its general unreasonableness.
70 FR 25210 CAIR	CAIR		1300			Estimated Marginal cost 2009
FR Notice 5MAY04 Proposed Rule	BART(proposed rule)	200-1000				BART proposed lists this as values for 90-95% SO2 control, which is still assumed, or .1 to .15 lb/MMBtu. Dropped from final to give states flexibility to require more. Says for scrubbers, bypasses aren't BART, only 100% scrubbing is BART.
	BART(proposed rule)					0.2 lb/MMBtu for NOx is assumed reasonable. Recognizes that some sources may need SCR to get this level. For those, state discretion of the cost vs. visibility value is necessary.
Midwest RPO Report Referencing CAIR	CAIR(using IPM)			1000	1500	
	CAIR (2009 in 1999$)		900		2400	
	CAIR (2015 in 1999$)		1800		3000	
	CAIR (depending on Nat'l emissions)			1200 - 3000	1400- 2100	This was modeled with TRUM (Technology Retrofitting Updating Model) to develop the marginal values.
Kammer EPA Decision	Kammer Decision			> 1000	> 1000	
LADCO Midwest RPO Boiler Analysis	LADCO/Midwest RPO	1240 - 3822	607 - 4493			
MANE-VU BART Control Assessment	MANE-VU			200 - 500	200 - 1500	
Bowers vs. SWAPCA	Bowers vs. SWAPCA	300	300	1000	1000	954-1134 was ruled too much, in favor of 256-310 for SO2. This did consider incremental value. Sections XVII to XIX
WRAP Trading Program Methodology	WRAP			3000		
	EPA - Referenced by Wrap					References EPA-600S\7-90-018. Low is <$500/ton, Moderate is $500-3000/ton, High is over $3000/ton

The dollars per ton estimates cited above were obtained from BART guidance, documentation of similar regulatory programs such as CAIR, and relevant court decisions. These materials indicate that most EPA sanctioned documents, including the final BART ruling, concretely support an average expected reasonable cost range of $1,300 to $1,800 per ton of NOx removed and a range of $1,000 to $1,300 per ton of SO_2 removed. The BART presumptive limits were set based on cost effective controls that were on average less than these ranges. As an example, the presumptive SO_2 limit was established based on an average cost effectiveness of less than $1,000/ton. As the cost analysis extends into RPO, WRAP and other regional planning documentation, the cost ranges become more variable and difficult to predict. For ease of comparison, the federally established ranges for NOx and SO_2 were used as a BART cost threshold basis.

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GREAT RIVER
ENERGY®

17845 East Highway 10 • PO Box 800 • Elk River, Minnesota 55330-0800 • 763-441-3121 • Fax 763-241-2366

July 3, 2007

Mr Terry O'Clair
North Dakota Department of Health
Division of Air Quality
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

RE: Great River Energy – Coal Creek and Stanton Stations
Supplemental Information for Cost Effectiveness under BART

Dear Mr O'Clair:

As follow-up to our June 4, 2007, meeting with you and Mr. David Glatt, this document serves to outline information relevant to determining an appropriate cost effectiveness threshold for evaluations under Best Available Retrofit Technology (BART). Great River Energy (GRE) submits this information as an addendum to the BART analyses and proposal documents that have been submitted to the North Dakota Department of Health (NDDH) for GRE's Coal Creek and Stanton stations. This information and proposal is for your consideration, and we look forward to continuing our dialogue with you on this matter.

Cost effectiveness is one of several important factors evaluated to determine BART in accordance with U.S. Environmental Protection Agency (EPA) rules and guidance. The EPA is specific in its assignment of presumptive BART emission rates and cost effectiveness expectations.[1] Alternative cost effectiveness values referenced through Section 309 of the Clean Air Act are of interest, but are not as specifically tailored to the goals of the BART rules.

The NDDH has suggested a value deemed cost effective for purposes of economic impacts under BART. This value stems from a reference in the 2004 proposed rule for BART determinations.[2] Specifically, the proposed BART Rule references a draft technical support document[3] (TSD) for

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[1] Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking – Setting BART SO_2 Limits for Electric Generating Units: Control Technology and Cost Effectiveness, April 2005. Note that scatter plot evaluations for NOx and SO_2 illustrate that presumptive levels are established from large electricity generating units (EGUs) to ensure the highest visibility reduction.

[2] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule; F.R. Vol. 69, No. 87, May 5, 2004, p. 25198

[3] Western Regional Air Partnership Regional Haze BART (Trading Program Option) TSD 6A, Draft: July 16, 1999

the Western Regional Air Partnership's (WRAP) Annex[4] to a report submitted to the EPA by the Grand Canyon Visibility Transport Commission (GCVTC) in 1996.[5]

The cost effectiveness ranges stated in this WRAP TSD reference an EPA assessment of NOx and SO_2 controls for coal-fired boilers that was published in 1990.[6,7] While the information presented is of interest to BART, a straight inflation adjustment from an analysis performed in the late 1980s and published in 1990 does not provide an accurate reflection of current pollution control technologies and associated capital and operating cost effectiveness

The 1990 EPA document presents a range of control costs that vary by coal sulfur content, boiler type, and generating capacity. It further states that cost estimates rely heavily on site-specific parameters and that both cost and pollutant removal efficiency should be balanced when selecting a control technology for a given boiler. At the time of the report, many technologies considered for BART, including selective non-catalytic reduction (SNCR) for NOx, were not commercially available and are therefore not reflected in the analysis. With the wide variety of specific control costs presented in the document, the range of \$500 to \$3,000 presented as moderate in the WRAP TSD is a subjective number that broadly incorporated all NOx and SO_2 costs for every type and size of utility.

The document states that \$3,000 was used as an approximation to exclude controls that meet BACT level emissions. While BACT controls have been accepted as BART in many cases, the opposite is not necessarily true. Therefore, while BACT average and incremental cost effectiveness thresholds may be reviewed while determining BART cost effectiveness, the EPA's BART Rule and TSDs as well as associated visibility improvements should ultimately be the determinative guidance.

The WRAP TSD was produced under the assumption that BART may not be required for EGUs, which is the premise of the WRAP trading program. Further, in the executive summary to the WRAP annex, it is explained that the goal of WRAP is to employ reductions that are "better than BART" to achieve greater reductions than dictated by reasonable progress goals

For these reasons, WRAP cost estimates include more than just "BART-eligible sources." As a final WRAP comment, note that the WRAP Annex explicitly sets program penalties at \$5,000/ton of excess emissions.[8] This penalty is established at "three to four times greater than the expected market trading price," which is, by definition, an expected cost effectiveness of approximately \$1,200/ton to \$1,600/ton.

---

[4] Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and A Backstop Market Trading Program, September 29, 2000

[5] Report from Grand Canyon Visibility Transport Commission to the United States Environmental Protection Agency, June 1996

[6] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule; F.R. Vol. 69, No. 87, May 5, 2004, p. 25198.

[7] Assessment of Control Technologies for Reducing Emissions of SO_2 and NOx from Existing Coal-Fired Utility Boilers, EPA-600/7-90-018, September 1990

[8] Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and A Backstop Market Trading Program, September 29, 2000, p. 47

Given the outdated nature of the EPA control assessment that is at the root of WRAP's $500 to $3,000/ton range, it is critically important to rely on more recent cost documentation as provided by the EPA in the BART Rule and associated technical support documents and as provided in GRE's BART analyses reports to the NDDH.

With respect to cost effectiveness as defined in the BART Final Rule,[9] the expected control costs range from $900/ton to $2,400/ton for SO_2 removal and from $300/ton to $1,300/ton for NOx, with most NOx estimates at less than $1,000/ton. Again, these estimates rely heavily on boiler type, capacity, and the fuel burned. The following two excerpted figures illustrate not only the EPA's intent to evaluate BART cost effectiveness on the type and size of boiler, but also confirms that average cost effectiveness is established at a much lower level than that suggested by the NDDH. As an example, highlighted in the two excerpted figures are the rows that would apply to Stanton Station.

FIGURE 1

Unit capacity (MW)	Tons (K) of SO_2 emitted in 2001	Percent of BART eligible coal-fired unit's 2001 emissions	Calculated average cost effectiveness for MW grouping ($/ton SO_2 removed)	Percent of estimated removable BART SO_2 emissions from coal-fired units*
<50 MW	26	0.4	1962	0.9
50–100 MW	93	1.4	2399	1.6
100–150 MW	171	2.5	1796	2.2
150–200 MW	235	3.5	1324	3.4
200–250 MW	253	3.8	1282	3.1
250–300 MW	281	3.2	1128	4.0
>300 MW	5712	85.2	......	84.8
All Units	6707	100	984	100
BART Units (>200MW)	6246	92.2	919	91.9

TABLE 3.—AVERAGE COST-EFFECTIVENESS OF NOx CONTROLS FOR BART-ELIGIBLE COAL-FIRED UNITS

Unit type	Coal type	Number units nation-wide	National average ($/ton)
Dry-bottom wall-fired	Bituminous	114	1229
	Sub-bituminous	66	576
	Lignite	3	1296
Tangential-fired	Bituminous	105	567
	Sub-bituminous	72	281
	Lignite	9	614
Cell Burners	Bituminous	32	1287
	Sub-bituminous	3	1021
Dry-turbo-fired	Bituminous	7	775
	Sub-bituminous	7	599
Wet-bottom	Bituminous	6	378
Cyclones (with SCR)	All	56	900

In the determination of NOx control cost effectiveness the NDDH should also be cognizant of determinations made by other states in EPA Region 8. As an example, in Colorado's final BART guidance[10] it has been stated that no post-combustion NOx controls will be required, precluding the need to consider SNCR and selective catalytic reduction (SCR) as potential control options.

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[9] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule; F.R. Vol. 70, No. 128, July 6, 2005, p. 39133-39135

[10] Colorado BART, March 16, 2006

In the proposed BART Rule[11] the EPA also states that post-combustion NOx controls should not be necessary, other than on cyclone units.

The BART Final Rule further supports that visibility impacts are a key component of the BART determination. If one control technology provides a significant improvement in visibility over another, the State may and should consider this information in its BART determination. Under this assumption, one cost effectiveness threshold would not be appropriate for all units because there would be varying degrees of visibility improvements.

In terms of visibility improvement, a 0.5 deciview (dV) level has already been determined by the EPA to be a "contribution threshold" for states in determining BART-eligible sources that cause or contribute to visibility impairment and thus become "subject to BART." It can be asserted that any change in impairment from an individual facility with BART-eligible sources less than 0.5 dV can and should be deemed insignificant by a state. In the 2005 document from the NDDH addressing regional haze status[12] the NDDH determined that a newly permitted coal-fired ethanol production facility and a new 175-MW power plant that will be located closer to Class I areas than GRE's facilities would not adversely affect visibility in the North Dakota Class I areas. The fact that these two projects have already been deemed insignificant supports a *de minimis* contribution threshold.

We understand that regional-scale dispersion modeling for BART is pending. Until this analysis is completed it is unknown whether North Dakota will meet its reasonable further progress goals. Accordingly, before requiring emission controls beyond BART, the regional-scale dispersion modeling analysis should be completed with source attribution assessments including those from North Dakota, other contributing states and Canadian sources with their projected reductions. If it can be shown that sources outside the United States are preventing North Dakota Class I areas from meeting their glide path goals, consideration should be given to revising the natural background goal to account for sources that cannot be controlled under the EPA regional haze rules.

Cost effectiveness thresholds have been determined for many other regulatory programs similar to BART. However, BART has the distinct goal of improving/reducing regional haze and is unique in its consideration of visibility impacts. Regardless of the references used to determine cost effectiveness thresholds, it is obvious that pollutant specific thresholds are supported by the EPA. GRE maintains that based on the EPA BART Rule with ranges of $900/ton to $2,400/ton for SO_2 removal and $300/ton to $1,300/ton for NOx removal, and associated references presented in this document, a value of $1,500/ton or less is appropriate for determining cost effectiveness for both NOx and SO_2 control technologies under BART.

---

[11] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule; F.R. Vol. 69, No. 87, May 5, 2004, p. 25202

[12] Report on Progress Made Toward the National Visibility Goal, November 2005.

Should you have any questions regarding this submittal, please contact me or Greg Archer at 763-241-2278.

Sincerely,

GREAT RIVER ENERGY

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

c: David Glatt – NDDH
Greg Archer – GRE
Deb Nelson – GRE
Steve Smokey – GRE, Stanton
Diane Stockdill – GRE, Coal Creek
Joel Trinkle – Barr Engineering Co.

Appendix C

Visibility Modeling

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
1200 Missouri Avenue, Bismarck, ND 58504-5264
P.O. Box 5520, Bismarck, ND 58506-5520
701.328.5200 (fax)
www.ndhealth.gov

November 30, 2005

Mr. Steve Smokey
Environmental Coordinator
Great River Energy
4001 Highway 200A
Stanton, ND 58571

Dear Mr. Smokey:

As specified in the June 15, 2005 final amendments to the EPA July, 1999 regional haze rule, the Department has completed visibility modeling to determine which North Dakota BART-eligible (Best Available Retrofit Technology) sources are subject to BART. The Department's visibility analysis for this BART screening followed the protocol outlined in "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota" (North Dakota Department of Health, November, 2005).

As you are aware, the Great River Energy Stanton Generating Station Unit 1 is a BART-eligible source. Completed visibility modeling for Stanton Station Unit 1 indicates that the maximum 98th percentile delta-deciview prediction for the facility exceeds the BART screening threshold of 0.5 deciviews. Therefore, Stanton Unit 1 is subject to BART.

Two summaries of modeling results are enclosed. Attachment A provides a summary of 98th percentile predictions for the worst-case meteorological year for all BART-eligible facilities. Attachment B provides more detailed results specific to the Stanton Station Unit 1. Included in Attachment B are results for all delta-deciview metrics recommended in the North Dakota protocol, for each year of meteorological data. Also provided are worst-case day and receptor, and the percent contribution for each species.

If you have any questions regarding these results, please contact Steve Weber or Rob White of my staff at (701)328-5188. We look forward to working with you to develop an appropriate BART control strategy for Stanton Station Unit 1.

Sincerely,

Steve Weber for

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/SW:csc
Enc:
xc/enc: Deb Nelson - Great River Energy

Attachment A

Summary of BART Screening Results
98th Percentile Prediction for Worst-case Met. Year (2000-2002)
(24-hr Delta-Deciview)

	TRNP South	TRNP North	TRNP Elk. Ranch	Lostwood NWA
Leland Olds Station	6.22	5.32	4.49	5.42
Milton R Young Station	6.69	5.58	6.10	4.88
Coal Creek Station	4.48	3.56	3.04	4.04
Stanton Station Unit 1	1.68	1.54	1.43	1.35
Heskett Station Unit 2	0.82	0.54	0.61	0.58
Mandan Refinery	0.05	0.04	0.04	0.04

29-Nov-05

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CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Base Case) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        3.134     5.367     2.234    2000   74    48    102   2.80    82.39   17.54    0.05    0.01
  98th %tile Delta-DV     0.937     3.170     2.234    2000   71    45     45   2.80    73.49   26.34    0.14    0.02
  90th %tile Delta-DV     0.228     2.356     2.127    2000  110    49    103   2.30    52.31   46.77    0.79    0.13

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        3.031     5.264     2.234    2000   36    82     71   2.80    70.43   29.39    0.15    0.03
  98th %tile Delta-DV     0.947     3.181     2.234    2000   44    83    112   2.80    62.34   37.42    0.20    0.04
  90th %tile Delta-DV     0.221     2.327     2.106    2000  261    83    112   2.20    91.67    7.86    0.41    0.07

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        3.787     6.020     2.234    2000   74    90     72   2.80    83.38   16.56    0.05    0.01
  98th %tile Delta-DV     0.868     3.101     2.234    2000   44    90     72   2.80    66.10   33.73    0.14    0.03
  90th %tile Delta-DV     0.184     2.312     2.127    2000  100    90     72   2.30    80.07   19.68    0.21    0.04

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     6
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        4.385     6.660     2.275    2000   47    97     79   2.90    86.50   13.42    0.06    0.01
  98th %tile Delta-DV     0.991     3.267     2.275    2000   72    97     79   2.90    80.71   19.22    0.06    0.01
  90th %tile Delta-DV     0.344     2.576     2.232    2000  212    99     81   2.70    98.41    1.47    0.09    0.03

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 1) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.059     3.293     2.234    2000   74    48    102   2.80    41.84   57.94    0.17    0.05
  98th %tile Delta-DV     0.320     2.574     2.255    2000   11    51    105   2.90    30.84   68.92    0.17    0.06
  90th %tile Delta-DV     0.066     2.215     2.149    2000  199    45     45   2.40    67.89   30.40    1.47    0.24

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.352     3.585     2.234    2000   36    82     71   2.80    26.53   73.03    0.36    0.08
  98th %tile Delta-DV     0.458     2.691     2.234    2000   44    83    112   2.80    20.23   79.27    0.42    0.08
  90th %tile Delta-DV     0.080     2.207     2.127    2000  101    82     71   2.30    33.14   66.16    0.60    0.10

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.278     3.511     2.234    2000   74    90     72   2.80    43.39   56.40    0.17    0.05
  98th %tile Delta-DV     0.224     2.330     2.106    2000  247    90     72   2.20    84.32   14.46    1.06    0.16
  90th %tile Delta-DV     0.054     2.182     2.127    2000   98    90     72   2.30    33.90   65.82    0.22    0.06

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.698     3.974     2.275    2000   47    97     79   2.90    39.61   60.15    0.19    0.04
  98th %tile Delta-DV     0.340     2.615     2.275    2000   88    91     73   2.90    11.97   87.33    0.56    0.14
  90th %tile Delta-DV     0.118     2.350     2.232    2000  185    91     73   2.70    61.29   37.88    0.70    0.13

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 2) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.056     3.289     2.234    2000   74    48    102   2.80    41.98   57.80    0.17    0.05
  98th %tile Delta-DV     0.318     2.573     2.255    2000   11    51    105   2.90    30.96   68.80    0.18    0.06
  90th %tile Delta-DV     0.066     2.215     2.149    2000  199    45     45   2.40    68.00   30.28    1.47    0.24

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.347     3.580     2.234    2000   36    82     71   2.80    26.64   72.92    0.36    0.08
  98th %tile Delta-DV     0.456     2.689     2.234    2000   44    83    112   2.80    20.32   79.18    0.43    0.08
  90th %tile Delta-DV     0.080     2.207     2.127    2000  101    82     71   2.30    33.26   66.04    0.60    0.10

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.274     3.508     2.234    2000   74    90     72   2.80    43.52   56.26    0.17    0.05
  98th %tile Delta-DV     0.224     2.330     2.106    2000  247    90     72   2.20    84.39   14.39    1.06    0.16
  90th %tile Delta-DV     0.054     2.182     2.127    2000   98    90     72   2.30    34.02   65.69    0.22    0.06

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.693     3.968     2.275    2000   47    97     79   2.90    39.75   60.02    0.19    0.04
  98th %tile Delta-DV     0.338     2.613     2.275    2000   88    91     73   2.90    12.02   87.27    0.57    0.14
  90th %tile Delta-DV     0.117     2.350     2.232    2000  185    91     73   2.70    61.42   37.75    0.70    0.13

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 3) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                              SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.026     3.260     2.234    2000   74    48    102   2.80    43.26   56.51    0.18    0.05
  98th %tile Delta-DV     0.305     2.581     2.276    2000  336     6      6   3.00    15.23   83.87    0.80    0.10
  90th %tile Delta-DV     0.065     2.214     2.149    2000  199    45     45   2.40    69.06   29.21    1.50    0.24

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.300     3.534     2.234    2000   36    82     71   2.80    27.66   71.88    0.37    0.09
  98th %tile Delta-DV     0.438     2.671     2.234    2000   44    83    112   2.80    21.17   78.30    0.44    0.08
  90th %tile Delta-DV     0.077     2.310     2.234    2000   76    82     71   2.80    28.03   71.69    0.22    0.07

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.239     3.473     2.234    2000   74    90     72   2.80    44.82   54.95    0.18    0.05
  98th %tile Delta-DV     0.222     2.328     2.106    2000  247    90     72   2.20    85.00   13.77    1.07    0.16
  90th %tile Delta-DV     0.054     2.202     2.149    2000  187    90     72   2.40    94.08    5.37    0.45    0.09

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.644     3.920     2.275    2000   47    97     79   2.90    41.03   58.73    0.20    0.04
  98th %tile Delta-DV     0.323     2.599     2.275    2000   88    91     73   2.90    12.58   86.68    0.59    0.15
  90th %tile Delta-DV     0.113     2.345     2.232    2000  197    99     81   2.70    16.41   82.50    0.84    0.25

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 4) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.891     3.124     2.234    2000   74    48    102   2.80    50.19   49.55    0.21    0.06
  98th %tile Delta-DV     0.253     2.529     2.276    2000  335    53    107   3.00    37.01   61.86    1.01    0.13
  90th %tile Delta-DV     0.055     2.182     2.127    2000  287    46     46   2.30    57.89   41.62    0.41    0.08

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.086     3.320     2.234    2000   36    82     71   2.80    33.47   65.97    0.45    0.10
  98th %tile Delta-DV     0.356     2.483     2.127    2000   98    71     60   2.30    24.61   74.15    1.09    0.15
  90th %tile Delta-DV     0.065     2.192     2.127    2000  101    82     71   2.30    40.84   58.30    0.74    0.13

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.081     3.315     2.234    2000   74    90     72   2.80    51.79   47.95    0.20    0.06
  98th %tile Delta-DV     0.215     2.321     2.106    2000  247    90     72   2.20    87.91   10.82    1.10    0.17
  90th %tile Delta-DV     0.049     2.219     2.170    2000  155    90     72   2.50    58.32   41.36    0.24    0.09

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.422     3.697     2.275    2000   47    97     79   2.90    47.99   51.73    0.23    0.05
  98th %tile Delta-DV     0.260     2.557     2.297    2000   14    91     73   3.00    37.05   62.43    0.45    0.07
  90th %tile Delta-DV     0.096     2.329     2.232    2000  203    91     73   2.70    81.78   17.60    0.53    0.08

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 5) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.538     2.771     2.234    2000   74    48     102   2.80    84.63   14.93    0.35    0.09
  98th %tile Delta-DV     0.144     2.377     2.234    2000   71    45      45   2.80    76.68   22.22    0.93    0.16
  90th %tile Delta-DV     0.035     2.162     2.127    2000  110    49     103   2.30    53.45   40.45    5.25    0.86

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.513     2.747     2.234    2000   36    82      71   2.80    72.90   25.89    0.99    0.22
  98th %tile Delta-DV     0.144     2.377     2.234    2000   44    83     112   2.80    65.55   32.81    1.37    0.26
  90th %tile Delta-DV     0.034     2.161     2.127    2000  101    82      71   2.30    78.20   20.14    1.42    0.24

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.669     2.902     2.234    2000   74    90      72   2.80    85.50   14.08    0.33    0.09
  98th %tile Delta-DV     0.131     2.365     2.234    2000   44    90      72   2.80    69.45   29.40    0.96    0.19
  90th %tile Delta-DV     0.028     2.156     2.127    2000  100    90      72   2.30    81.42   16.94    1.37    0.27

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        0.840     3.116     2.275    2000   47    97      79   2.90    83.64   15.87    0.40    0.09
  98th %tile Delta-DV     0.154     2.429     2.275    2000   72    97      79   2.90    83.50   16.05    0.38    0.07
  90th %tile Delta-DV     0.052     2.197     2.145    2000  131    91      73   2.30    46.47   51.85    1.44    0.24

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 6) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.432     4.665     2.234    2000   74    48    102   2.80    76.42   23.49    0.07    0.02
  98th %tile Delta-DV     0.691     2.946     2.255    2000   11    51    105   2.90    66.90   32.98    0.08    0.03
  90th %tile Delta-DV     0.174     2.302     2.127    2000  287    46     46   2.30    81.90   17.95    0.13    0.03

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.456     4.689     2.234    2000   36    82     71   2.80    62.09   37.68    0.19    0.04
  98th %tile Delta-DV     0.770     3.004     2.234    2000   44    83    112   2.80    53.36   46.35    0.25    0.05
  90th %tile Delta-DV     0.171     2.426     2.255    2000   16    82     71   2.90    33.45   66.31    0.17    0.06

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        2.950     5.183     2.234    2000   74    90     72   2.80    77.56   22.35    0.07    0.02
  98th %tile Delta-DV     0.696     2.929     2.234    2000   44    90     72   2.80    57.43   42.36    0.18    0.04
  90th %tile Delta-DV     0.139     2.267     2.127    2000  100    90     72   2.30    73.50   26.17    0.27    0.05

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        3.652     5.928     2.275    2000   47    97     79   2.90    74.87   25.04    0.08    0.02
  98th %tile Delta-DV     0.755     3.030     2.275    2000   72    97     79   2.90    74.35   25.56    0.07    0.01
  90th %tile Delta-DV     0.262     2.407     2.145    2000  125    94     76   2.30    40.36   59.12    0.34    0.18

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 7) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        2.429     4.662     2.234    2000   74     48    102   2.80    76.52   23.39    0.07    0.02
  98th %tile Delta-DV     0.690     2.945     2.255    2000   11     51    105   2.90    67.03   32.86    0.08    0.03
  90th %tile Delta-DV     0.174     2.302     2.127    2000  287     46     46   2.30    81.98   17.86    0.13    0.03

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.451     4.685     2.234    2000   36     82     71   2.80    62.22   37.55    0.19    0.04
  98th %tile Delta-DV     0.769     3.002     2.234    2000   44     83    112   2.80    53.50   46.21    0.25    0.05
  90th %tile Delta-DV     0.171     2.425     2.255    2000   16     82     71   2.90    33.57   66.19    0.17    0.06

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        2.947     5.180     2.234    2000   74     90     72   2.80    77.66   22.25    0.07    0.02
  98th %tile Delta-DV     0.694     2.928     2.234    2000   44     90     72   2.80    57.57   42.22    0.18    0.04
  90th %tile Delta-DV     0.139     2.267     2.127    2000  100     90     72   2.30    73.61   26.06    0.27    0.05

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        3.648     5.923     2.275    2000   47     97     79   2.90    74.97   24.93    0.08    0.02
  98th %tile Delta-DV     0.754     3.029     2.275    2000   72     97     79   2.90    74.46   25.45    0.08    0.01
  90th %tile Delta-DV     0.261     2.407     2.145    2000  125     94     76   2.30    40.49   58.99    0.34    0.18

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 8) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.403     4.636     2.234    2000   74    48    102   2.80    77.45   22.46    0.07    0.02
  98th %tile Delta-DV     0.679     2.934     2.255    2000   11    51    105   2.90    68.16   31.72    0.08    0.03
  90th %tile Delta-DV     0.173     2.300     2.127    2000  287    46     46   2.30    82.73   17.11    0.13    0.03

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.410     4.643     2.234    2000   36    82     71   2.80    63.42   36.35    0.19    0.04
  98th %tile Delta-DV     0.752     2.985     2.234    2000   44    83    112   2.80    54.80   44.89    0.25    0.05
  90th %tile Delta-DV     0.165     2.419     2.255    2000   16    82     71   2.90    34.74   65.02    0.18    0.07

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        2.917     5.151     2.234    2000   74    90     72   2.80    78.56   21.35    0.07    0.02
  98th %tile Delta-DV     0.680     2.914     2.234    2000   44    90     72   2.80    58.85   40.93    0.18    0.04
  90th %tile Delta-DV     0.137     2.265     2.127    2000  100    90     72   2.30    74.60   25.06    0.28    0.06

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        3.609     5.884     2.275    2000   47    97     79   2.90    75.95   23.95    0.08    0.02
  98th %tile Delta-DV     0.744     3.020     2.275    2000   72    97     79   2.90    75.46   24.44    0.08    0.01
  90th %tile Delta-DV     0.256     2.401     2.145    2000   98    91     73   2.30    69.20   30.61    0.16    0.03

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 9) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.285     4.518     2.234    2000   74    48    102   2.80    81.94   17.96    0.08    0.02
  98th %tile Delta-DV     0.663     2.897     2.234    2000   71    45     45   2.80    72.99   26.78    0.20    0.03
  90th %tile Delta-DV     0.162     2.289     2.127    2000  110    49    103   2.30    51.29   47.41    1.12    0.18

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.220     4.454     2.234    2000   36    82     71   2.80    69.51   30.23    0.21    0.05
  98th %tile Delta-DV     0.672     2.906     2.234    2000   44    83    112   2.80    61.53   38.13    0.29    0.05
  90th %tile Delta-DV     0.157     2.327     2.170    2000  153    83    112   2.50    40.21   59.07    0.62    0.10

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        2.784     5.018     2.234    2000   74    90     72   2.80    82.89   17.02    0.07    0.02
  98th %tile Delta-DV     0.614     2.848     2.234    2000   44    90     72   2.80    65.37   34.38    0.20    0.04
  90th %tile Delta-DV     0.129     2.256     2.127    2000  100    90     72   2.30    79.45   20.19    0.30    0.06

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        3.429     5.704     2.275    2000   47    97     79   2.90    80.69   19.20    0.09    0.02
  98th %tile Delta-DV     0.701     2.976     2.275    2000   72    97     79   2.90    80.32   19.58    0.08    0.02
  90th %tile Delta-DV     0.240     2.472     2.232    2000  212    99     81   2.70    98.30    1.53    0.14    0.04

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 10) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.979     4.212     2.234    2000   74    48    102   2.80    96.12    3.76    0.09    0.02
  98th %tile Delta-DV     0.553     2.659     2.106    2000  238     3      3   2.20    98.62    0.59    0.69    0.10
  90th %tile Delta-DV     0.137     2.371     2.234    2000   41    47    101   2.80    80.52   18.01    1.29    0.19

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.714     3.948     2.234    2000   36    82     71   2.80    92.41    7.25    0.28    0.06
  98th %tile Delta-DV     0.557     2.705     2.149    2000  184    58     47   2.40    98.95    0.78    0.23    0.04
  90th %tile Delta-DV     0.122     2.228     2.106    2000  238    85    114   2.20    98.95    0.68    0.32    0.05

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        2.438     4.672     2.234    2000   74    90     72   2.80    96.37    3.52    0.08    0.02
  98th %tile Delta-DV     0.445     2.678     2.234    2000   44    90     72   2.80    91.11    8.56    0.28    0.06
  90th %tile Delta-DV     0.106     2.234     2.127    2000  110    90     72   2.30    75.80   21.05    2.68    0.47

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        2.957     5.233     2.275    2000   47    97     79   2.90    95.85    4.02    0.10    0.02
  98th %tile Delta-DV     0.591     2.866     2.275    2000   72    97     79   2.90    95.80    4.09    0.10    0.02
  90th %tile Delta-DV     0.191     2.531     2.340    2000  362    99     81   3.20    95.02    4.91    0.05    0.02

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 11) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV   DV(Total)   DV(BKG)   YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.847     3.080     2.234    2000   74     48    102  2.80    26.46   73.27    0.22    0.06
  98th %tile Delta-DV     0.290     2.566     2.276    2000  316     46     46  3.00    20.40   79.25    0.30    0.04
  90th %tile Delta-DV     0.048     2.175     2.127    2000  287     46     46  2.30    33.12   66.32    0.47    0.09

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.184     3.417     2.234    2000   36     82     71  2.80    15.29   84.21    0.41    0.09
  98th %tile Delta-DV     0.369     2.603     2.234    2000   74     67     56  2.80    26.18   73.60    0.16    0.06
  90th %tile Delta-DV     0.062     2.295     2.234    2000   56     82     71  2.80    19.27   79.98    0.66    0.09

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.014     3.248     2.234    2000   74     90     72  2.80    27.70   72.02    0.22    0.06
  98th %tile Delta-DV     0.183     2.311     2.127    2000  110     90     72  2.30     4.87   93.32    1.55    0.27
  90th %tile Delta-DV     0.040     2.168     2.127    2000   97     90     72  2.30    14.28   85.35    0.29    0.08

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.385     3.660     2.275    2000   47     97     79  2.90    24.70   75.02    0.24    0.05
  98th %tile Delta-DV     0.320     2.595     2.275    2000   88     91     73  2.90     6.36   92.89    0.60    0.15
  90th %tile Delta-DV     0.094     2.434     2.340    2000  362     99     81  3.20    21.56   78.30    0.10    0.05

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 12) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.843     3.077     2.234    2000   74    48    102   2.80    26.56   73.16    0.22    0.06
  98th %tile Delta-DV     0.289     2.565     2.276    2000  316    46     46   3.00    20.49   79.16    0.30    0.04
  90th %tile Delta-DV     0.048     2.175     2.127    2000  287    46     46   2.30    33.24   66.20    0.47    0.09

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.178     3.412     2.234    2000   36    82     71   2.80    15.36   84.13    0.42    0.09
  98th %tile Delta-DV     0.368     2.601     2.234    2000   74    67     56   2.80    26.29   73.49    0.16    0.06
  90th %tile Delta-DV     0.062     2.295     2.234    2000   56    82     71   2.80    19.35   79.89    0.66    0.09

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.011     3.244     2.234    2000   74    90     72   2.80    27.81   71.91    0.22    0.06
  98th %tile Delta-DV     0.182     2.310     2.127    2000  110    90     72   2.30     4.89   93.28    1.56    0.27
  90th %tile Delta-DV     0.040     2.168     2.127    2000   97    90     72   2.30    14.35   85.28    0.29    0.08

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.379     3.654     2.275    2000   47    97     79   2.90    24.80   74.91    0.24    0.05
  98th %tile Delta-DV     0.318     2.593     2.275    2000   88    91     73   2.90     6.40   92.85    0.60    0.15
  90th %tile Delta-DV     0.094     2.433     2.340    2000  362    99     81   3.20    21.65   78.20    0.10    0.05

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 13) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.813     3.046     2.234    2000   74     48    102  2.80    27.60   72.11     0.23    0.06
  98th %tile Delta-DV     0.277     2.553     2.276    2000  316     46     46  3.00    21.39   78.25     0.31    0.05
  90th %tile Delta-DV     0.046     2.174     2.127    2000  287     46     46  2.30    34.40   65.02     0.48    0.10

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.131     3.364     2.234    2000   36     82     71  2.80    16.04   83.43     0.43    0.10
  98th %tile Delta-DV     0.354     2.588     2.234    2000   74     67     56  2.80    27.32   72.45     0.17    0.06
  90th %tile Delta-DV     0.059     2.293     2.234    2000   56     82     71  2.80    20.17   79.05     0.69    0.10

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.975     3.208     2.234    2000   74     90     72  2.80    28.88   70.83     0.23    0.06
  98th %tile Delta-DV     0.174     2.301     2.127    2000  110     90     72  2.30     5.13   92.95     1.63    0.29
  90th %tile Delta-DV     0.038     2.166     2.127    2000   97     90     72  2.30    15.00   84.61     0.30    0.09

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.329     3.604     2.275    2000   47     97     79  2.90    25.81   73.89     0.25    0.05
  98th %tile Delta-DV     0.303     2.579     2.275    2000   88     91     73  2.90     6.71   92.49     0.63    0.16
  90th %tile Delta-DV     0.090     2.430     2.340    2000  362     99     81  3.20    22.55   77.29     0.10    0.05

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 14) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV   DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.674     2.908     2.234    2000   74    48    102   2.80    33.50   66.14    0.28    0.07
  98th %tile Delta-DV     0.221     2.454     2.234    2000   46    48    102   2.80     7.24   91.91    0.71    0.14
  90th %tile Delta-DV     0.039     2.167     2.127    2000  100    46     46   2.30    19.58   79.47    0.79    0.16

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.913     3.146     2.234    2000   36    82     71   2.80    20.09   79.24    0.54    0.12
  98th %tile Delta-DV     0.292     2.526     2.234    2000   74    67     56   2.80    33.19   66.53    0.21    0.08
  90th %tile Delta-DV     0.048     2.281     2.234    2000   56    82     71   2.80    24.92   74.11    0.85    0.12

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.812     3.046     2.234    2000   74    90     72   2.80    34.94   64.71    0.27    0.08
  98th %tile Delta-DV     0.135     2.262     2.127    2000  110    90     72   2.30     6.61   90.91    2.10    0.37
  90th %tile Delta-DV     0.033     2.266     2.234    2000   56    90     72   2.80    31.31   68.14    0.46    0.10

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.099     3.374     2.275    2000   47    97     79   2.90    31.57   68.06    0.30    0.06
  98th %tile Delta-DV     0.236     2.511     2.275    2000   88    91     73   2.90     8.65   90.33    0.81    0.21
  90th %tile Delta-DV     0.074     2.241     2.167    2000  286    99     81   2.40    27.46   71.08    1.28    0.18

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 15) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.314     2.547     2.234    2000   74    48    102   2.80    73.36   25.87    0.61    0.16
  98th %tile Delta-DV     0.079     2.249     2.170    2000  164    46     46   2.50    95.16    1.87    2.59    0.38
  90th %tile Delta-DV     0.020     2.147     2.127    2000  287    46     46   2.30    77.54   21.15    1.08    0.22

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP NORTH UNIT

  Largest Delta-DV        0.329     2.563     2.234    2000   36    82     71   2.80    57.34   40.75    1.55    0.35
  98th %tile Delta-DV     0.097     2.225     2.127    2000   98    71     60   2.30    45.55   49.87    4.04    0.54
  90th %tile Delta-DV     0.021     2.149     2.127    2000  287    85    114   2.30    71.28   27.60    0.91    0.21

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP ELKHORN RANCH

  Largest Delta-DV        0.388     2.622     2.234    2000   74    90     72   2.80    74.67   24.59    0.58    0.16
  98th %tile Delta-DV     0.086     2.319     2.234    2000   44    90     72   2.80    53.19   45.04    1.48    0.29
  90th %tile Delta-DV     0.017     2.144     2.127    2000  138    90     72   2.30    80.36   18.94    0.53    0.17

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


LOSTWOOD NWA

  Largest Delta-DV        0.498     2.773     2.275    2000   47    97     79   2.90    71.88   27.28    0.69    0.15
  98th %tile Delta-DV     0.090     2.365     2.275    2000   72    97     79   2.90    71.68   27.55    0.65    0.12
  90th %tile Delta-DV     0.034     2.179     2.145    2000  125    94     76   2.30    35.26   60.64    2.66    1.44

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0
```

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CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 21) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                    SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.055     3.289     2.234    2000   74    48    102   2.80    41.99   57.82    0.15    0.04
  98th %tile Delta-DV     0.318     2.573     2.255    2000   11    51    105   2.90    30.97   68.83    0.15    0.05
  90th %tile Delta-DV     0.066     2.215     2.149    2000  199    45     45   2.40    68.18   30.36    1.25    0.20

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.346     3.579     2.234    2000   36    82     71   2.80    26.66   72.97    0.31    0.07
  98th %tile Delta-DV     0.455     2.582     2.127    2000   98    71     60   2.30    19.14   80.05    0.72    0.10
  90th %tile Delta-DV     0.080     2.207     2.127    2000  101    82     71   2.30    33.29   66.11    0.51    0.09

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.274     3.507     2.234    2000   74    90     72   2.80    43.54   56.28    0.14    0.04
  98th %tile Delta-DV     0.223     2.329     2.106    2000  247    90     72   2.20    84.54   14.42    0.90    0.14
  90th %tile Delta-DV     0.054     2.181     2.127    2000   98    90     72   2.30    34.04   65.72    0.19    0.05

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.693     3.968     2.275    2000   47    97     79   2.90    39.76   60.04    0.16    0.03
  98th %tile Delta-DV     0.338     2.613     2.275    2000   88    91     73   2.90    12.04   87.36    0.48    0.12
  90th %tile Delta-DV     0.117     2.349     2.232    2000  185    91     73   2.70    61.50   37.80    0.59    0.11

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 22) for Year 2000 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND          % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.066     3.300     2.234    2000   74    48    102   2.80    41.55   57.21    0.98    0.26
  98th %tile Delta-DV     0.326     2.602     2.276    2000  335    53    107   3.00    28.64   66.38    4.41    0.58
  90th %tile Delta-DV     0.071     2.220     2.149    2000  203    51    105   2.40    45.14   53.33    1.28    0.25

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.373     3.606     2.234    2000   36    82     71   2.80    26.10   71.44    2.00    0.46
  98th %tile Delta-DV     0.466     2.700     2.234    2000   44    83    112   2.80    19.85   77.35    2.36    0.45
  90th %tile Delta-DV     0.081     2.314     2.234    2000   76    82     71   2.80    26.60   71.84    1.19    0.36

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        1.286     3.520     2.234    2000   74    90     72   2.80    43.09   55.69    0.95    0.27
  98th %tile Delta-DV     0.236     2.342     2.106    2000  247    90     72   2.20    79.83   13.61    5.68    0.88
  90th %tile Delta-DV     0.055     2.204     2.149    2000  187    90     72   2.40    91.48    5.51    2.50    0.52

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.710     3.985     2.275    2000   47    97     79   2.90    39.32   59.38    1.07    0.23
  98th %tile Delta-DV     0.349     2.624     2.275    2000   88    91     73   2.90    11.64   84.47    3.10    0.79
  90th %tile Delta-DV     0.122     2.354     2.232    2000  185    91     73   2.70    59.13   36.34    3.80    0.73

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Base Case) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                         SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.736     3.970     2.234    2001   64     52    106   2.80    84.43   15.53    0.04    0.01
  98th %tile Delta-DV     0.901     3.177     2.276    2001  329     53    107   3.00    69.58   30.05    0.30    0.07
  90th %tile Delta-DV     0.214     2.447     2.234    2001   43     52    106   2.80    82.16   17.79    0.04    0.02

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        4.052     6.307     2.255    2001   12     83    112   2.90    82.21   17.66    0.11    0.02
  98th %tile Delta-DV     1.205     3.438     2.234    2001   42     82     71   2.80    82.36   17.57    0.06    0.02
  90th %tile Delta-DV     0.319     2.467     2.149    2001  195     85    114   2.40    97.64    2.29    0.06    0.01

  Number of days with Delta-Deciview > 0.50:    21
  Number of days with Delta-Deciview > 1.00:    12
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        2.026     4.280     2.255    2001   12     90     72   2.90    81.37   18.57    0.05    0.01
  98th %tile Delta-DV     0.733     2.839     2.106    2001  261     90     72   2.20    93.65    6.27    0.07    0.02
  90th %tile Delta-DV     0.144     2.271     2.127    2001   94     90     72   2.30    82.66   17.29    0.04    0.01

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        4.914     7.254     2.340    2001  326     91     73   3.20    82.39   17.50    0.09    0.02
  98th %tile Delta-DV     1.351     3.626     2.275    2001   41     91     73   2.90    73.92   25.97    0.09    0.02
  90th %tile Delta-DV     0.386     2.596     2.211    2001  179     93     75   2.60    69.89   29.70    0.37    0.04

  Number of days with Delta-Deciview > 0.50:    30
  Number of days with Delta-Deciview > 1.00:    16
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 1) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.729     2.835     2.106    2001  258     36     36  2.20    18.15   80.61    1.11    0.13
  98th %tile Delta-DV     0.322     2.556     2.234    2001   63     53    107  2.80    49.33   50.52    0.12    0.03
  90th %tile Delta-DV     0.061     2.336     2.276    2001  310     54    108  3.00    31.86   67.61    0.38    0.15

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.465     3.719     2.255    2001   12     83    112  2.90    40.89   58.71    0.35    0.05
  98th %tile Delta-DV     0.385     2.661     2.276    2001  315     82     71  3.00    26.72   72.96    0.26    0.06
  90th %tile Delta-DV     0.089     2.195     2.106    2001  248     83    112  2.20    63.77   30.83    4.76    0.64

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.696     2.950     2.255    2001   12     90     72  2.90    40.31   59.48    0.17    0.04
  98th %tile Delta-DV     0.241     2.474     2.234    2001   63     90     72  2.80    54.55   45.31    0.12    0.03
  90th %tile Delta-DV     0.036     2.185     2.149    2001  195     90     72  2.40    87.37   12.24    0.32    0.07

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.798     4.138     2.340    2001  326     91     73  3.20    40.83   58.83    0.29    0.05
  98th %tile Delta-DV     0.526     2.801     2.275    2001   41     91     73  2.90    30.30   69.41    0.23    0.05
  90th %tile Delta-DV     0.160     2.370     2.211    2001  179     93     75  2.60    26.32   72.68    0.89    0.11

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 2) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.726     2.832     2.106    2001  258    36     36   2.20    18.23   80.52    1.11    0.13
  98th %tile Delta-DV     0.321     2.555     2.234    2001   63    53    107   2.80    49.48   50.38    0.12    0.03
  90th %tile Delta-DV     0.061     2.336     2.276    2001  310    54    108   3.00    31.98   67.49    0.38    0.15

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.460     3.715     2.255    2001   12    83    112   2.90    41.02   58.58    0.35    0.05
  98th %tile Delta-DV     0.383     2.659     2.276    2001  315    82     71   3.00    26.83   72.85    0.26    0.06
  90th %tile Delta-DV     0.089     2.195     2.106    2001  248    83    112   2.20    63.88   30.71    4.77    0.64

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.693     2.948     2.255    2001   12    90     72   2.90    40.45   59.35    0.17    0.04
  98th %tile Delta-DV     0.240     2.474     2.234    2001   63    90     72   2.80    54.69   45.16    0.12    0.03
  90th %tile Delta-DV     0.036     2.184     2.149    2001  195    90     72   2.40    87.43   12.18    0.32    0.07

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.793     4.132     2.340    2001  326    91     73   3.20    40.97   58.69    0.29    0.05
  98th %tile Delta-DV     0.524     2.799     2.275    2001   41    91     73   2.90    30.42   69.29    0.23    0.05
  90th %tile Delta-DV     0.159     2.370     2.211    2001  179    93     75   2.60    26.43   72.57    0.90    0.11

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 3) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND          % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.697     2.803     2.106    2001  258    36     36   2.20    19.01   79.70    1.16    0.13
  98th %tile Delta-DV     0.313     2.546     2.234    2001   63    53    107   2.80    50.82   49.03    0.12    0.03
  90th %tile Delta-DV     0.059     2.334     2.276    2001  310    54    108   3.00    33.10   66.35    0.39    0.16

  Number of days with Delta-Deciview > 0.50:      4
  Number of days with Delta-Deciview > 1.00:      0
  Max number of consecutive days with Delta-Deciview > 0.50:      2


TRNP NORTH UNIT

  Largest Delta-DV        1.419     3.674     2.255    2001   12    83    112   2.90    42.29   57.30    0.36    0.06
  98th %tile Delta-DV     0.369     2.645     2.276    2001  315    82     71   3.00    27.87   71.79    0.27    0.07
  90th %tile Delta-DV     0.086     2.320     2.234    2001   85    79     68   2.80    16.67   82.63    0.61    0.08

  Number of days with Delta-Deciview > 0.50:      5
  Number of days with Delta-Deciview > 1.00:      1
  Max number of consecutive days with Delta-Deciview > 0.50:      1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.673     2.927     2.255    2001   12    90     72   2.90    41.73   58.06    0.17    0.04
  98th %tile Delta-DV     0.234     2.468     2.234    2001   63    90     72   2.80    56.05   43.79    0.12    0.03
  90th %tile Delta-DV     0.036     2.184     2.149    2001  195    90     72   2.40    87.98   11.62    0.32    0.07

  Number of days with Delta-Deciview > 0.50:      2
  Number of days with Delta-Deciview > 1.00:      0
  Max number of consecutive days with Delta-Deciview > 0.50:      1


LOSTWOOD NWA

  Largest Delta-DV        1.744     4.083     2.340    2001  326    91     73   3.20    42.22   57.42    0.30    0.06
  98th %tile Delta-DV     0.506     2.781     2.275    2001   41    91     73   2.90    31.56   68.14    0.24    0.05
  90th %tile Delta-DV     0.153     2.364     2.211    2001  179    93     75   2.60    27.45   71.51    0.93    0.11

  Number of days with Delta-Deciview > 0.50:      8
  Number of days with Delta-Deciview > 1.00:      2
  Max number of consecutive days with Delta-Deciview > 0.50:      2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 4) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                    SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.567     2.673     2.106    2001  258    36     36   2.20    23.53   74.87    1.44    0.16
  98th %tile Delta-DV     0.261     2.537     2.276    2001  339    37     37   3.00    16.37   82.99    0.56    0.08
  90th %tile Delta-DV     0.054     2.224     2.170    2001  163    51    105   2.50    57.01   42.19    0.67    0.12

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.234     3.488     2.255    2001   12    83    112   2.90    49.12   50.39    0.42    0.06
  98th %tile Delta-DV     0.318     2.552     2.234    2001   42    82     71   2.80    50.19   49.52    0.23    0.07
  90th %tile Delta-DV     0.073     2.243     2.170    2001  182    86    115   2.50    23.40   74.18    2.14    0.28

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.580     2.834     2.255    2001   12    90     72   2.90    48.65   51.10    0.20    0.04
  98th %tile Delta-DV     0.203     2.437     2.234    2001   84    90     72   2.80    39.00   60.49    0.43    0.07
  90th %tile Delta-DV     0.034     2.267     2.234    2001   82    90     72   2.80    53.03   46.66    0.25    0.06

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.519     3.859     2.340    2001  326    91     73   3.20    49.03   50.56    0.34    0.06
  98th %tile Delta-DV     0.422     2.697     2.275    2001   41    91     73   2.90    37.93   61.71    0.29    0.06
  90th %tile Delta-DV     0.133     2.279     2.145    2001  267    99     81   2.30    13.17   85.13    1.42    0.28

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 5) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.280     2.514     2.234    2001   64     52    106   2.80    86.64   13.03    0.28    0.05
  98th %tile Delta-DV     0.141     2.417     2.276    2001  329     53    107   3.00    71.17   26.33    2.02    0.48
  90th %tile Delta-DV     0.032     2.266     2.234    2001   43     52    106   2.80    84.78   14.83    0.28    0.11

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP NORTH UNIT

  Largest Delta-DV        0.742     2.997     2.255    2001   12     83    112   2.90    83.70   15.48    0.71    0.11
  98th %tile Delta-DV     0.190     2.423     2.234    2001   42     82     71   2.80    84.74   14.76    0.38    0.11
  90th %tile Delta-DV     0.049     2.177     2.127    2001   94     82     71   2.30    83.50   16.20    0.26    0.05

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.340     2.595     2.255    2001   12     90     72   2.90    83.84   15.74    0.35    0.08
  98th %tile Delta-DV     0.115     2.242     2.127    2001   92     90     72   2.30    73.90   24.86    1.05    0.19
  90th %tile Delta-DV     0.022     2.149     2.127    2001   94     90     72   2.30    85.01   14.71    0.23    0.05

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


LOSTWOOD NWA

  Largest Delta-DV        0.917     3.257     2.340    2001  326     91     73   3.20    83.72   15.58    0.59    0.11
  98th %tile Delta-DV     0.210     2.355     2.145    2001  259     97     79   2.30    92.58    6.71    0.60    0.11
  90th %tile Delta-DV     0.059     2.398     2.340    2001  337     91     73   3.20    60.98   36.57    2.14    0.32

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 6) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                          SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         -----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.312     3.546     2.234    2001   64    52    106   2.80    78.97   20.96    0.06    0.01
  98th %tile Delta-DV     0.715     2.991     2.276    2001  329    53    107   3.00    61.32   38.21    0.39    0.09
  90th %tile Delta-DV     0.160     2.394     2.234    2001   43    52    106   2.80    76.14   23.78    0.06    0.02

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        3.201     5.456     2.255    2001   12    83    112   2.90    75.80   24.03    0.14    0.02
  98th %tile Delta-DV     0.937     3.170     2.234    2001   63    82     71   2.80    84.92   15.03    0.04    0.01
  90th %tile Delta-DV     0.245     2.372     2.127    2001   94    82     71   2.30    74.85   25.09    0.05    0.01

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.570     3.825     2.255    2001   12    90     72   2.90    75.17   24.75    0.07    0.01
  98th %tile Delta-DV     0.541     2.817     2.276    2001  328    90     72   3.00    77.96   21.98    0.04    0.01
  90th %tile Delta-DV     0.105     2.232     2.127    2001  302    90     72   2.30    40.62   58.79    0.51    0.08

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.897     6.237     2.340    2001  326    91     73   3.20    76.02   23.84    0.12    0.02
  98th %tile Delta-DV     1.062     3.337     2.275    2001   41    91     73   2.90    66.27   33.59    0.11    0.02
  90th %tile Delta-DV     0.311     2.457     2.145    2001   93    91     73   2.30    71.18   28.65    0.13    0.05

  Number of days with Delta-Deciview > 0.50:    27
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 7) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.311     3.545     2.234    2001   64    52    106   2.80    79.07   20.87    0.06    0.01
  98th %tile Delta-DV     0.714     2.990     2.276    2001  329    53    107   3.00    61.44   38.08    0.39    0.09
  90th %tile Delta-DV     0.160     2.394     2.234    2001   43    52    106   2.80    76.24   23.68    0.06    0.02

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        3.197     5.452     2.255    2001   12    83    112   2.90    75.90   23.93    0.14    0.02
  98th %tile Delta-DV     0.936     3.169     2.234    2001   63    82     71   2.80    85.00   14.95    0.04    0.01
  90th %tile Delta-DV     0.245     2.372     2.127    2001   94    82     71   2.30    74.95   24.99    0.05    0.01

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.568     3.823     2.255    2001   12    90     72   2.90    75.27   24.64    0.07    0.02
  98th %tile Delta-DV     0.541     2.816     2.276    2001  328    90     72   3.00    78.06   21.88    0.04    0.01
  90th %tile Delta-DV     0.105     2.232     2.127    2001  302    90     72   2.30    40.75   58.66    0.52    0.08

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.893     6.232     2.340    2001  326    91     73   3.20    76.12   23.74    0.12    0.02
  98th %tile Delta-DV     1.060     3.335     2.275    2001   41    91     73   2.90    66.40   33.46    0.11    0.03
  90th %tile Delta-DV     0.311     2.456     2.145    2001   93    91     73   2.30    71.29   28.53    0.13    0.05

  Number of days with Delta-Deciview > 0.50:    27
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 8) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.298     3.531     2.234    2001   64    52   106   2.80    79.93   20.00    0.06    0.01
  98th %tile Delta-DV     0.701     2.976     2.276    2001  329    53   107   3.00    62.64   36.87    0.39    0.09
  90th %tile Delta-DV     0.158     2.392     2.234    2001   43    52   106   2.80    77.20   22.72    0.06    0.02

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        3.164     5.419     2.255    2001   12    83   112   2.90    76.84   22.99    0.15    0.02
  98th %tile Delta-DV     0.915     3.042     2.127    2001   92    71    60   2.30    46.93   52.39    0.61    0.07
  90th %tile Delta-DV     0.241     2.475     2.234    2001   55    82    71   2.80    65.53   34.40    0.05    0.02

  Number of days with Delta-Deciview > 0.50:    17
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.550     3.804     2.255    2001   12    90    72   2.90    76.24   23.67    0.07    0.02
  98th %tile Delta-DV     0.535     2.810     2.276    2001  328    90    72   3.00    78.97   20.98    0.04    0.01
  90th %tile Delta-DV     0.103     2.251     2.149    2001  196    90    72   2.40    96.89    3.01    0.09    0.02

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.854     6.194     2.340    2001  326    91    73   3.20    77.04   22.82    0.12    0.02
  98th %tile Delta-DV     1.042     3.317     2.275    2001   41    91    73   2.90    67.58   32.28    0.12    0.03
  90th %tile Delta-DV     0.306     2.452     2.145    2001   93    91    73   2.30    72.35   27.47    0.13    0.05

  Number of days with Delta-Deciview > 0.50:    27
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 9) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.237     3.471     2.234    2001   64    52    106   2.80    84.08   15.85    0.06    0.01
  98th %tile Delta-DV     0.641     2.917     2.276    2001  329    53    107   3.00    68.70   30.76    0.43    0.10
  90th %tile Delta-DV     0.149     2.383     2.234    2001   43    52    106   2.80    81.80   18.12    0.06    0.02

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        3.012     5.266     2.255    2001   12    83    112   2.90    81.37   18.45    0.15    0.02
  98th %tile Delta-DV     0.854     3.088     2.234    2001   42    82     71   2.80    81.95   17.94    0.08    0.02
  90th %tile Delta-DV     0.222     2.371     2.149    2001  195    85    114   2.40    97.53    2.36    0.08    0.02

  Number of days with Delta-Deciview > 0.50:    16
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.466     3.721     2.255    2001   12    90     72   2.90    80.94   18.97    0.07    0.02
  98th %tile Delta-DV     0.515     2.621     2.106    2001  261    90     72   2.20    93.29    6.59    0.10    0.02
  90th %tile Delta-DV     0.101     2.228     2.127    2001   94    90     72   2.30    82.24   17.70    0.05    0.01

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.677     6.016     2.340    2001  326    91     73   3.20    81.52   18.33    0.13    0.02
  98th %tile Delta-DV     0.963     3.238     2.275    2001   41    91     73   2.90    73.43   26.42    0.13    0.03
  90th %tile Delta-DV     0.272     2.612     2.340    2001  311    97     79   3.20    51.12   48.66    0.17    0.05

  Number of days with Delta-Deciview > 0.50:    24
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 10) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.085     3.318     2.234    2001   64     52    106   2.80    96.69    3.23    0.07    0.01
  98th %tile Delta-DV     0.544     2.819     2.276    2001  328     45     45   3.00    96.24    3.69    0.05    0.02
  90th %tile Delta-DV     0.124     2.230     2.106    2001  248     47    101   2.20    99.49    0.22    0.23    0.05

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.611     4.865     2.255    2001   12     83    112   2.90    95.87    3.92    0.18    0.03
  98th %tile Delta-DV     0.733     2.966     2.234    2001   42     82     71   2.80    96.16    3.72    0.10    0.03
  90th %tile Delta-DV     0.201     2.477     2.276    2001  316     82     71   3.00    93.03    6.78    0.15    0.04

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.252     3.506     2.255    2001   12     90     72   2.90    95.88    4.01    0.09    0.02
  98th %tile Delta-DV     0.439     2.715     2.276    2001  328     90     72   3.00    96.56    3.37    0.05    0.02
  90th %tile Delta-DV     0.086     2.213     2.127    2001   94     90     72   2.30    96.23    3.70    0.06    0.01

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        3.204     5.543     2.340    2001  326     91     73   3.20    95.92    3.90    0.15    0.03
  98th %tile Delta-DV     0.821     3.054     2.232    2001  196     91     73   2.70    99.01    0.83    0.14    0.02
  90th %tile Delta-DV     0.213     2.358     2.145    2001  265     99     81   2.30    96.15    3.35    0.43    0.08

  Number of days with Delta-Deciview > 0.50:    20
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 11) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.665     2.771     2.106    2001  258    36     36   2.20     9.98   88.66    1.22    0.14
  98th %tile Delta-DV     0.270     2.398     2.127    2001   92    51    105   2.30    14.66   84.84    0.43    0.07
  90th %tile Delta-DV     0.043     2.170     2.127    2001  131    53    107   2.30    21.78   77.82    0.31    0.09

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.183     3.437     2.255    2001   12    83    112   2.90    25.69   73.81    0.44    0.07
  98th %tile Delta-DV     0.334     2.610     2.276    2001  315    82     71   3.00    15.42   84.21    0.30    0.07
  90th %tile Delta-DV     0.061     2.188     2.127    2001  145    71     60   2.30    13.45   85.17    1.23    0.15

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.559     2.814     2.255    2001   12    90     72   2.90    25.24   74.50    0.21    0.05
  98th %tile Delta-DV     0.178     2.453     2.276    2001  338    90     72   3.00     9.61   89.09    1.15    0.15
  90th %tile Delta-DV     0.024     2.299     2.276    2001  345    90     72   3.00    25.13   74.43    0.37    0.07

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.506     3.846     2.340    2001  327    99     81   3.20    20.50   79.18    0.26    0.06
  98th %tile Delta-DV     0.449     2.725     2.275    2001   41    91     73   2.90    17.87   81.79    0.27    0.06
  90th %tile Delta-DV     0.139     2.349     2.211    2001  179    93     75   2.60    15.16   83.69    1.03    0.12

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 12) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                    SEQ    ND          % of Modeled Extinction by Species
                         DELTA-DV   DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)    %_SO4   %_NO3   %_PMC   %_PMF
                         ----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.662      2.768     2.106    2001  258    36     36    2.20    10.03   88.60    1.23    0.14
  98th %tile Delta-DV     0.269      2.396     2.127    2001   92    51    105    2.30    14.74   84.76    0.43    0.07
  90th %tile Delta-DV     0.043      2.170     2.127    2001  131    53    107    2.30    21.88   77.72    0.32    0.09

  Number of days with Delta-Deciview > 0.50:      2
  Number of days with Delta-Deciview > 1.00:      0
  Max number of consecutive days with Delta-Deciview > 0.50:      1


TRNP NORTH UNIT

  Largest Delta-DV        1.178      3.433     2.255    2001   12    83    112    2.90    25.79   73.70    0.44    0.07
  98th %tile Delta-DV     0.333      2.608     2.276    2001  315    82     71    3.00    15.50   84.13    0.30    0.07
  90th %tile Delta-DV     0.061      2.188     2.127    2001  302    86    115    2.30     9.43   89.50    0.94    0.13

  Number of days with Delta-Deciview > 0.50:      5
  Number of days with Delta-Deciview > 1.00:      1
  Max number of consecutive days with Delta-Deciview > 0.50:      1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.557      2.812     2.255    2001   12    90     72    2.90    25.35   74.39    0.21    0.05
  98th %tile Delta-DV     0.177      2.453     2.276    2001  338    90     72    3.00     9.65   89.04    1.15    0.15
  90th %tile Delta-DV     0.023      2.299     2.276    2001  345    90     72    3.00    25.23   74.32    0.38    0.07

  Number of days with Delta-Deciview > 0.50:      1
  Number of days with Delta-Deciview > 1.00:      0
  Max number of consecutive days with Delta-Deciview > 0.50:      1


LOSTWOOD NWA

  Largest Delta-DV        1.500      3.839     2.340    2001  327    99     81    3.20    20.59   79.09    0.26    0.06
  98th %tile Delta-DV     0.447      2.722     2.275    2001   41    91     73    2.90    17.95   81.71    0.28    0.06
  90th %tile Delta-DV     0.138      2.349     2.211    2001  179    93     75    2.60    15.23   83.62    1.04    0.12

  Number of days with Delta-Deciview > 0.50:      7
  Number of days with Delta-Deciview > 1.00:      2
  Max number of consecutive days with Delta-Deciview > 0.50:      2
```

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CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 13) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ------------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.633     2.739     2.106    2001  258    36     36   2.20    10.50   88.07    1.28    0.15
  98th %tile Delta-DV     0.257     2.384     2.127    2001   92    51    105   2.30    15.43   84.04    0.45    0.08
  90th %tile Delta-DV     0.041     2.168     2.127    2001  131    53    107   2.30    22.82   76.76    0.33    0.09

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.136     3.391     2.255    2001   12    83    112   2.90    26.80   72.67    0.46    0.07
  98th %tile Delta-DV     0.319     2.594     2.276    2001  315    82     71   3.00    16.20   83.42    0.31    0.08
  90th %tile Delta-DV     0.059     2.293     2.234    2001   89    82     71   2.80    28.58   71.22    0.14    0.06

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.536     2.791     2.255    2001   12    90     72   2.90    26.36   73.37    0.22    0.05
  98th %tile Delta-DV     0.169     2.403     2.234    2001   63    90     72   2.80    38.95   60.84    0.17    0.04
  90th %tile Delta-DV     0.023     2.298     2.276    2001  345    90     72   3.00    26.22   73.32    0.39    0.07

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.443     3.782     2.340    2001  327    99     81   3.20    21.47   78.20    0.27    0.06
  98th %tile Delta-DV     0.429     2.704     2.275    2001   41    91     73   2.90    18.75   80.90    0.29    0.06
  90th %tile Delta-DV     0.132     2.343     2.211    2001  179    93     75   2.60    15.91   82.88    1.08    0.13

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 14) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                          SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.502     2.608     2.106    2001  258    36     36   2.20    13.34   84.85    1.63    0.19
  98th %tile Delta-DV     0.203     2.330     2.127    2001   92    51    105   2.30    19.59   79.74    0.57    0.10
  90th %tile Delta-DV     0.036     2.185     2.149    2001  190    46     46   2.40    93.48    3.37    2.80    0.34

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.945     3.199     2.255    2001   12    83    112   2.90    32.55   66.81    0.55    0.09
  98th %tile Delta-DV     0.255     2.530     2.276    2001  315    82     71   3.00    20.34   79.18    0.39    0.10
  90th %tile Delta-DV     0.053     2.159     2.106    2001  248    83    112   2.20    53.58   37.36    7.99    1.07

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.442     2.696     2.255    2001   12    90     72   2.90    32.14   67.53    0.27    0.06
  98th %tile Delta-DV     0.143     2.377     2.234    2001   63    90     72   2.80    46.07   53.69    0.20    0.05
  90th %tile Delta-DV     0.021     2.148     2.127    2001   99    90     72   2.30    41.82   57.96    0.14    0.07

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


LOSTWOOD NWA

  Largest Delta-DV        1.181     3.520     2.340    2001  327    99     81   3.20    26.59   73.00    0.33    0.08
  98th %tile Delta-DV     0.344     2.620     2.275    2001   41    91     73   2.90    23.43   76.13    0.36    0.08
  90th %tile Delta-DV     0.106     2.316     2.211    2001  179    93     75   2.60    19.95   78.53    1.36    0.16

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 15) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ----------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.160     2.393     2.234    2001   64    52    106   2.80    76.44   22.98    0.49    0.10
  98th %tile Delta-DV     0.091     2.367     2.276    2001  329    53    107   3.00    55.25   40.87    3.13    0.75
  90th %tile Delta-DV     0.019     2.252     2.234    2001   43    52    106   2.80    73.58   25.74    0.49    0.19

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP NORTH UNIT

  Largest Delta-DV        0.438     2.693     2.255    2001   12    83    112   2.90    71.96   26.62    1.22    0.19
  98th %tile Delta-DV     0.110     2.343     2.234    2001   42    82     71   2.80    73.52   25.62    0.66    0.20
  90th %tile Delta-DV     0.029     2.178     2.149    2001  205    58     47   2.40    93.12    2.64    3.78    0.46

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP ELKHORN RANCH

  Largest Delta-DV        0.199     2.454     2.255    2001   12    90     72   2.90    72.18   27.09    0.60    0.13
  98th %tile Delta-DV     0.063     2.339     2.276    2001  328    90     72   3.00    75.67   23.83    0.39    0.11
  90th %tile Delta-DV     0.012     2.140     2.127    2001   94    90     72   2.30    73.94   25.58    0.41    0.08

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


LOSTWOOD NWA

  Largest Delta-DV        0.544     2.883     2.340    2001  326    91     73   3.20    71.97   26.83    1.01    0.19
  98th %tile Delta-DV     0.129     2.404     2.275    2001   41    91     73   2.90    62.93   35.89    0.97    0.21
  90th %tile Delta-DV     0.039     2.250     2.211    2001  168    93     75   2.60    88.04   10.00    1.71    0.25

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 21) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.724     2.830     2.106    2001  258    36     36   2.20    18.27   80.68    0.95    0.11
  98th %tile Delta-DV     0.321     2.555     2.234    2001   63    53    107   2.80    49.49   50.39    0.10    0.02
  90th %tile Delta-DV     0.061     2.336     2.276    2001  310    54    108   3.00    32.00   67.55    0.32    0.13

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.459     3.714     2.255    2001   12    83    112   2.90    41.05   58.61    0.30    0.05
  98th %tile Delta-DV     0.383     2.659     2.276    2001  315    82     71   3.00    26.85   72.88    0.22    0.05
  90th %tile Delta-DV     0.088     2.194     2.106    2001  248    83    112   2.20    64.41   30.97    4.09    0.54

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.693     2.948     2.255    2001   12    90     72   2.90    40.46   59.37    0.14    0.03
  98th %tile Delta-DV     0.240     2.474     2.234    2001   63    90     72   2.80    54.71   45.17    0.10    0.03
  90th %tile Delta-DV     0.036     2.184     2.149    2001  195    90     72   2.40    87.48   12.19    0.27    0.06

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.792     4.131     2.340    2001  326    91     73   3.20    40.99   58.72    0.24    0.05
  98th %tile Delta-DV     0.524     2.799     2.275    2001   41    91     73   2.90    30.44   69.32    0.20    0.04
  90th %tile Delta-DV     0.159     2.369     2.211    2001  179    93     75   2.60    26.46   72.68    0.76    0.09

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 22) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                    SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.766     2.872     2.106    2001  258    36     36   2.20    17.24   76.12    5.96    0.69
  98th %tile Delta-DV     0.323     2.557     2.234    2001   63    53    107   2.80    49.14   50.03    0.67    0.16
  90th %tile Delta-DV     0.062     2.338     2.276    2001  310    54    108   3.00    31.20   65.86    2.10    0.84

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.486     3.740     2.255    2001   12    83    112   2.90    40.27   57.50    1.93    0.30
  98th %tile Delta-DV     0.389     2.665     2.276    2001  315    82     71   3.00    26.44   71.77    1.44    0.36
  90th %tile Delta-DV     0.093     2.326     2.234    2001   85    79     68   2.80    15.46   80.88    3.21    0.44

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.700     2.954     2.255    2001   12    90     72   2.90    40.07   58.79    0.94    0.20
  98th %tile Delta-DV     0.242     2.475     2.234    2001   63    90     72   2.80    54.32   44.85    0.66    0.17
  90th %tile Delta-DV     0.036     2.185     2.149    2001  195    90     72   2.40    85.87   11.96    1.79    0.38

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.819     4.158     2.340    2001  326    91     73   3.20    40.32   57.77    1.60    0.30
  98th %tile Delta-DV     0.531     2.806     2.275    2001   41    91     73   2.90    30.02   68.38    1.31    0.29
  90th %tile Delta-DV     0.166     2.377     2.211    2001  179    93     75   2.60    25.24   69.32    4.86    0.58

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Base Case) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        3.841     6.074     2.234    2002   73    49    103   2.80    78.06   21.83    0.09    0.02
  98th %tile Delta-DV     1.675     3.781     2.106    2002  233    53    107   2.20    86.14   13.70    0.14    0.02
  90th %tile Delta-DV     0.310     2.416     2.106    2002  270    48    102   2.20    55.36   44.28    0.30    0.06

  Number of days with Delta-Deciview > 0.50:    29
  Number of days with Delta-Deciview > 1.00:    17
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        4.809     7.042     2.234    2002   73    89    118   2.80    72.40   27.42    0.16    0.02
  98th %tile Delta-DV     1.540     3.774     2.234    2002   50    71     60   2.80    63.26   36.45    0.26    0.04
  90th %tile Delta-DV     0.312     2.546     2.234    2002   91    82     71   2.80    77.06   22.87    0.05    0.02

  Number of days with Delta-Deciview > 0.50:    23
  Number of days with Delta-Deciview > 1.00:    14
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        4.345     6.579     2.234    2002   73    90     72   2.80    76.06   23.81    0.11    0.02
  98th %tile Delta-DV     1.432     3.666     2.234    2002   39    90     72   2.80    78.88   20.97    0.12    0.03
  90th %tile Delta-DV     0.233     2.467     2.234    2002   83    90     72   2.80    51.30   48.24    0.41    0.05

  Number of days with Delta-Deciview > 0.50:    14
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        2.442     4.717     2.275    2002   74    97     79   2.90    81.69   18.24    0.05    0.01
  98th %tile Delta-DV     1.150     3.489     2.340    2002  363    97     79   3.20    77.19   22.76    0.04    0.01
  90th %tile Delta-DV     0.308     2.541     2.232    2002  195    99     81   2.70    71.54   27.70    0.68    0.09

  Number of days with Delta-Deciview > 0.50:    25
  Number of days with Delta-Deciview > 1.00:    11
  Max number of consecutive days with Delta-Deciview > 0.50:     4
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 1) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ     ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)    %_SO4   %_NO3   %_PMC   %_PMF
                         ----------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.555     3.810     2.255    2002   26     48    102  2.90     27.55   72.02    0.37    0.06
  98th %tile Delta-DV     0.668     2.774     2.106    2002  250     56    110  2.20     43.65   55.68    0.52    0.15
  90th %tile Delta-DV     0.096     2.223     2.127    2002  105     45     45  2.30     14.51   84.26    1.05    0.18

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.155     4.388     2.234    2002   73     89    118  2.80     28.64   70.89    0.41    0.05
  98th %tile Delta-DV     0.595     2.829     2.234    2002   83     71     60  2.80     17.47   81.65    0.76    0.11
  90th %tile Delta-DV     0.097     2.267     2.170    2002  155     82     71  2.50     50.00   49.90    0.07    0.03

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        1.779     4.012     2.234    2002   73     90     72  2.80     32.75   66.88    0.31    0.05
  98th %tile Delta-DV     0.517     2.751     2.234    2002   39     90     72  2.80     35.26   64.31    0.33    0.09
  90th %tile Delta-DV     0.074     2.308     2.234    2002   82     90     72  2.80     21.20   78.34    0.39    0.07

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        0.821     3.096     2.275    2002   74     97     79  2.90     40.69   59.10    0.18    0.04
  98th %tile Delta-DV     0.410     2.749     2.340    2002  363     97     79  3.20     34.36   65.50    0.12    0.03
  90th %tile Delta-DV     0.088     2.234     2.145    2002  134     97     79  2.30     12.59   86.14    1.06    0.21

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 2) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.550     3.804     2.255    2002   26     48    102  2.90    27.66   71.90    0.38    0.06
  98th %tile Delta-DV     0.666     2.772     2.106    2002  250     56    110  2.20    43.78   55.55    0.52    0.15
  90th %tile Delta-DV     0.095     2.329     2.234    2002   91     47    101  2.80    34.60   65.34    0.02    0.04

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.147     4.380     2.234    2002   73     89    118  2.80    28.76   70.77    0.42    0.05
  98th %tile Delta-DV     0.593     2.826     2.234    2002   83     71     60  2.80    17.55   81.57    0.76    0.12
  90th %tile Delta-DV     0.096     2.266     2.170    2002  155     82     71  2.50    50.14   49.76    0.07    0.03

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        1.772     4.006     2.234    2002   73     90     72  2.80    32.88   66.76    0.32    0.05
  98th %tile Delta-DV     0.515     2.749     2.234    2002   39     90     72  2.80    35.38   64.19    0.34    0.09
  90th %tile Delta-DV     0.074     2.307     2.234    2002   82     90     72  2.80    21.30   78.24    0.39    0.07

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        0.818     3.094     2.275    2002   74     97     79  2.90    40.82   58.96    0.18    0.04
  98th %tile Delta-DV     0.408     2.748     2.340    2002  363     97     79  3.20    34.48   65.37    0.12    0.03
  90th %tile Delta-DV     0.088     2.233     2.145    2002  134     97     79  2.30    12.65   86.07    1.06    0.21

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 3) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.497     3.752     2.255    2002   26    48    102   2.90    28.71   70.84    0.39    0.06
  98th %tile Delta-DV     0.648     2.754     2.106    2002  250    56    110   2.20    45.02   54.29    0.54    0.16
  90th %tile Delta-DV     0.092     2.326     2.234    2002   91    47    101   2.80    35.80   64.14    0.02    0.04

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.076     4.310     2.234    2002   73    89    118   2.80    29.85   69.67    0.43    0.06
  98th %tile Delta-DV     0.569     2.802     2.234    2002   83    71     60   2.80    18.32   80.77    0.79    0.12
  90th %tile Delta-DV     0.094     2.264     2.170    2002  155    82     71   2.50    51.45   48.45    0.07    0.03

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        1.716     3.950     2.234    2002   73    90     72   2.80    34.05   65.58    0.33    0.05
  98th %tile Delta-DV     0.499     2.733     2.234    2002   39    90     72   2.80    36.55   63.01    0.35    0.10
  90th %tile Delta-DV     0.071     2.304     2.234    2002   82    90     72   2.80    22.22   77.30    0.41    0.07

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        0.794     3.069     2.275    2002   74    97     79   2.90    42.12   57.66    0.18    0.04
  98th %tile Delta-DV     0.395     2.734     2.340    2002  363    97     79   3.20    35.68   64.17    0.12    0.03
  90th %tile Delta-DV     0.085     2.317     2.232    2002  185    97     79   2.70    42.09   57.28    0.50    0.14

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 4) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.256     3.511     2.255    2002   26    49    103   2.90    34.89   64.56    0.47    0.08
  98th %tile Delta-DV     0.565     2.671     2.106    2002  250    56    110   2.20    51.83   47.37    0.62    0.18
  90th %tile Delta-DV     0.080     2.186     2.106    2002  220    51    105   2.20    62.90   36.83    0.21    0.07

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.751     3.985     2.234    2002   73    89    118   2.80    35.98   63.43    0.52    0.07
  98th %tile Delta-DV     0.460     2.693     2.234    2002   83    71     60   2.80    22.78   76.09    0.99    0.15
  90th %tile Delta-DV     0.083     2.189     2.106    2002  241    82     71   2.20    88.85   10.73    0.36    0.06

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.460     3.694     2.234    2002   73    90     72   2.80    40.55   59.00    0.39    0.06
  98th %tile Delta-DV     0.426     2.659     2.234    2002   39    90     72   2.80    43.00   56.48    0.41    0.11
  90th %tile Delta-DV     0.060     2.208     2.149    2002  189    90     72   2.40    95.24    3.19    1.36    0.22

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        0.685     2.960     2.275    2002   74    97     79   2.90    49.11   50.63    0.21    0.05
  98th %tile Delta-DV     0.334     2.674     2.340    2002  363    97     79   3.20    42.30   57.52    0.14    0.04
  90th %tile Delta-DV     0.073     2.305     2.232    2002  185    97     79   2.70    48.91   50.35    0.58    0.16

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 5) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)
                                                                    SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.675     2.908     2.234    2002   73    49    103   2.80    80.64   18.62    0.63    0.11
  98th %tile Delta-DV     0.270     2.504     2.234    2002   74    49    103   2.80    83.18   16.29    0.44    0.09
  90th %tile Delta-DV     0.047     2.281     2.234    2002   75    51    105   2.80    89.89    9.95    0.11    0.06

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        0.876     3.110     2.234    2002   73    89    118   2.80    75.20   23.57    1.09    0.14
  98th %tile Delta-DV     0.241     2.474     2.234    2002   50    71     60   2.80    66.67   31.32    1.76    0.25
  90th %tile Delta-DV     0.047     2.323     2.276    2002  352    71     60   3.00    71.29   28.00    0.56    0.15

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.779     3.012     2.234    2002   73    90     72   2.80    78.70   20.42    0.76    0.12
  98th %tile Delta-DV     0.232     2.465     2.234    2002   39    90     72   2.80    79.76   19.28    0.76    0.21
  90th %tile Delta-DV     0.035     2.269     2.234    2002   67    90     72   2.80    54.80   41.79    3.01    0.39

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        0.405     2.680     2.275    2002   74    97     79   2.90    84.28   15.27    0.37    0.08
  98th %tile Delta-DV     0.183     2.479     2.297    2002   29    97     79   3.00    81.45   17.91    0.54    0.09
  90th %tile Delta-DV     0.048     2.344     2.297    2002   31    97     79   3.00    88.69   11.16    0.11    0.04

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 6) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        3.047     5.281     2.234    2002   73    49    103   2.80    71.12   28.74    0.12    0.02
  98th %tile Delta-DV     1.293     3.526     2.234    2002   74    49    103   2.80    74.28   25.62    0.09    0.02
  90th %tile Delta-DV     0.243     2.413     2.170    2002  178    55    109   2.50    88.70   11.11    0.16    0.03

  Number of days with Delta-Deciview > 0.50:    22
  Number of days with Delta-Deciview > 1.00:    10
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        3.926     6.160     2.234    2002   73    89    118   2.80    64.45   35.32    0.21    0.03
  98th %tile Delta-DV     1.221     3.370     2.149    2002  199    79     68   2.40    78.42   20.66    0.82    0.10
  90th %tile Delta-DV     0.239     2.473     2.234    2002   91    82     71   2.80    69.96   29.95    0.06    0.03

  Number of days with Delta-Deciview > 0.50:    21
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.489     5.722     2.234    2002   73    90     72   2.80    68.73   31.10    0.15    0.02
  98th %tile Delta-DV     1.111     3.344     2.234    2002   39    90     72   2.80    71.65   28.15    0.15    0.04
  90th %tile Delta-DV     0.191     2.297     2.106    2002  255    90     72   2.20    92.29    6.91    0.68    0.12

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.884     4.159     2.275    2002   74    97     79   2.90    75.55   24.36    0.07    0.02
  98th %tile Delta-DV     0.886     3.226     2.340    2002  363    97     79   3.20    70.13   29.80    0.05    0.01
  90th %tile Delta-DV     0.236     2.576     2.340    2002  313    99     81   3.20    51.02   48.84    0.08    0.06

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 7) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        3.043     5.277     2.234    2002   73    49   103   2.80    71.23   28.62    0.12    0.02
  98th %tile Delta-DV     1.291     3.524     2.234    2002   74    49   103   2.80    74.39   25.51    0.09    0.02
  90th %tile Delta-DV     0.243     2.413     2.170    2002  178    55   109   2.50    88.76   11.05    0.16    0.03

  Number of days with Delta-Deciview > 0.50:    22
  Number of days with Delta-Deciview > 1.00:    10
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        3.920     6.153     2.234    2002   73    89   118   2.80    64.58   35.19    0.21    0.03
  98th %tile Delta-DV     1.220     3.369     2.149    2002  199    79    68   2.40    78.50   20.58    0.82    0.10
  90th %tile Delta-DV     0.239     2.472     2.234    2002   91    82    71   2.80    70.08   29.83    0.06    0.03

  Number of days with Delta-Deciview > 0.50:    21
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.484     5.717     2.234    2002   73    90    72   2.80    68.85   30.98    0.15    0.02
  98th %tile Delta-DV     1.109     3.343     2.234    2002   39    90    72   2.80    71.76   28.04    0.15    0.04
  90th %tile Delta-DV     0.191     2.297     2.106    2002  255    90    72   2.20    92.33    6.87    0.68    0.12

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.881     4.157     2.275    2002   74    97    79   2.90    75.66   24.26    0.07    0.02
  98th %tile Delta-DV     0.885     3.224     2.340    2002  363    97    79   3.20    70.25   29.69    0.05    0.01
  90th %tile Delta-DV     0.235     2.575     2.340    2002  313    99    81   3.20    51.16   48.70    0.08    0.06

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 8) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                          SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        3.004     5.238     2.234    2002   73    49    103   2.80    72.30   27.55    0.12    0.02
  98th %tile Delta-DV     1.272     3.505     2.234    2002   64    53    107   2.80    56.33   43.31    0.31    0.05
  90th %tile Delta-DV     0.242     2.412     2.170    2002  178    55    109   2.50    89.29   10.52    0.16    0.03

  Number of days with Delta-Deciview > 0.50:    22
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        3.861     6.094     2.234    2002   73    89    118   2.80    65.77   33.99    0.21    0.03
  98th %tile Delta-DV     1.208     3.357     2.149    2002  199    79     68   2.40    79.31   19.76    0.83    0.10
  90th %tile Delta-DV     0.235     2.469     2.234    2002   91    82     71   2.80    71.16   28.75    0.07    0.03

  Number of days with Delta-Deciview > 0.50:    21
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.436     5.670     2.234    2002   73    90     72   2.80    69.96   29.86    0.15    0.02
  98th %tile Delta-DV     1.095     3.328     2.234    2002   39    90     72   2.80    72.77   27.03    0.15    0.04
  90th %tile Delta-DV     0.190     2.296     2.106    2002  255    90     72   2.20    92.66    6.54    0.68    0.12

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.859     4.135     2.275    2002   74    97     79   2.90    76.62   23.29    0.07    0.02
  98th %tile Delta-DV     0.872     3.212     2.340    2002  363    97     79   3.20    71.34   28.60    0.05    0.01
  90th %tile Delta-DV     0.230     2.569     2.340    2002  313    99     81   3.20    52.45   47.41    0.08    0.06

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 9) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.828     5.061     2.234    2002   73    49    103   2.80    77.53   22.31    0.13    0.02
  98th %tile Delta-DV     1.196     3.302     2.106    2002  233    53    107   2.20    85.67   14.10    0.20    0.03
  90th %tile Delta-DV     0.220     2.326     2.106    2002  270    48    102   2.20    54.39   45.10    0.42    0.09

  Number of days with Delta-Deciview > 0.50:    21
  Number of days with Delta-Deciview > 1.00:     9
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        3.591     5.824     2.234    2002   73    89    118   2.80    71.73   28.01    0.23    0.03
  98th %tile Delta-DV     1.104     3.337     2.234    2002   50    71     60   2.80    62.58   37.00    0.37    0.05
  90th %tile Delta-DV     0.219     2.452     2.234    2002   91    82     71   2.80    76.51   23.39    0.07    0.03

  Number of days with Delta-Deciview > 0.50:    20
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        3.222     5.455     2.234    2002   73    90     72   2.80    75.48   24.34    0.16    0.02
  98th %tile Delta-DV     1.028     3.261     2.234    2002   39    90     72   2.80    77.76   22.03    0.16    0.05
  90th %tile Delta-DV     0.165     2.398     2.234    2002   83    90     72   2.80    50.50   48.85    0.58    0.07

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     8
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.761     4.037     2.275    2002   74    97     79   2.90    81.30   18.60    0.08    0.02
  98th %tile Delta-DV     0.813     3.153     2.340    2002  363    97     79   3.20    76.69   23.24    0.06    0.02
  90th %tile Delta-DV     0.218     2.450     2.232    2002  195    99     81   2.70    70.61   28.30    0.97    0.12

  Number of days with Delta-Deciview > 0.50:    19
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     3
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 10) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        2.372     4.605     2.234    2002   73    51    105   2.80    95.08    4.73    0.17    0.03
  98th %tile Delta-DV     0.957     3.233     2.276    2002  337    55    109   3.00    92.67    7.19    0.10    0.04
  90th %tile Delta-DV     0.186     2.292     2.106    2002  241    49    103   2.20    99.30    0.63    0.06    0.01

  Number of days with Delta-Deciview > 0.50:    18
  Number of days with Delta-Deciview > 1.00:     7
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP NORTH UNIT

  Largest Delta-DV        2.871     5.104     2.234    2002   73    89    118   2.80    93.19    6.47    0.30    0.04
  98th %tile Delta-DV     0.780     3.014     2.234    2002   50    71     60   2.80    90.00    9.39    0.53    0.08
  90th %tile Delta-DV     0.183     2.310     2.127    2002  116    82     71   2.30    82.69   16.36    0.79    0.16

  Number of days with Delta-Deciview > 0.50:    18
  Number of days with Delta-Deciview > 1.00:     4
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        2.655     4.889     2.234    2002   73    90     72   2.80    94.34    5.43    0.20    0.03
  98th %tile Delta-DV     0.782     2.910     2.127    2002  293    90     72   2.30    90.34    8.81    0.72    0.13
  90th %tile Delta-DV     0.125     2.231     2.106    2002  233    90     72   2.20    92.40    6.25    1.20    0.15

  Number of days with Delta-Deciview > 0.50:    12
  Number of days with Delta-Deciview > 1.00:     5
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        1.511     3.786     2.275    2002   74    97     79   2.90    96.02    3.86    0.09    0.02
  98th %tile Delta-DV     0.685     2.982     2.297    2002   29    97     79   3.00    95.19    4.65    0.14    0.02
  90th %tile Delta-DV     0.168     2.400     2.232    2002  195    99     81   2.70    91.95    6.63    1.26    0.16

  Number of days with Delta-Deciview > 0.50:    15
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 11) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         -------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.355     3.610     2.255    2002   26    48    102   2.90    15.98   83.52    0.43    0.07
  98th %tile Delta-DV     0.556     2.831     2.276    2002  336    54    108   3.00     6.52   92.60    0.77    0.11
  90th %tile Delta-DV     0.089     2.216     2.127    2002  105    45     45   2.30     7.82   90.85    1.13    0.19

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.874     4.107     2.234    2002   73    89    118   2.80    16.71   82.74    0.48    0.06
  98th %tile Delta-DV     0.516     2.644     2.127    2002  294    79     68   2.30     6.77   92.08    1.01    0.14
  90th %tile Delta-DV     0.072     2.178     2.106    2002  220    82     71   2.20    28.32   71.27    0.31    0.10

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        1.509     3.742     2.234    2002   73    90     72   2.80    19.58   79.98    0.38    0.06
  98th %tile Delta-DV     0.429     2.663     2.234    2002   39    90     72   2.80    21.34   78.14    0.40    0.11
  90th %tile Delta-DV     0.050     2.177     2.127    2002  296    90     72   2.30    10.99   88.36    0.58    0.07

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        0.773     3.112     2.340    2002  337    91     73   3.20     5.24   94.25    0.39    0.12
  98th %tile Delta-DV     0.341     2.680     2.340    2002  363    97     79   3.20    20.74   79.08    0.14    0.04
  90th %tile Delta-DV     0.078     2.223     2.145    2002  122    97     79   2.30    15.11   84.21    0.44    0.24

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 12) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.349     3.604     2.255     2002   26     48    102   2.90    16.05   83.44    0.44    0.07
  98th %tile Delta-DV     0.553     2.829     2.276     2002  336     54    108   3.00     6.55   92.56    0.78    0.11
  90th %tile Delta-DV     0.088     2.216     2.127     2002  105     45     45   2.30     7.86   90.80    1.14    0.19

  Number of days with Delta-Deciview > 0.50:    10
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.866     4.099     2.234     2002   73     89    118   2.80    16.79   82.66    0.49    0.06
  98th %tile Delta-DV     0.514     2.641     2.127     2002  294     79     68   2.30     6.81   92.04    1.01    0.14
  90th %tile Delta-DV     0.071     2.177     2.106     2002  220     82     71   2.20    28.44   71.15    0.31    0.10

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.502     3.736     2.234     2002   73     90     72   2.80    19.67   79.89    0.38    0.06
  98th %tile Delta-DV     0.427     2.661     2.234     2002   39     90     72   2.80    21.43   78.04    0.41    0.11
  90th %tile Delta-DV     0.050     2.177     2.127     2002  296     90     72   2.30    11.05   88.30    0.58    0.07

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        0.769     3.109     2.340     2002  337     91     73   3.20     5.27   94.22    0.39    0.12
  98th %tile Delta-DV     0.339     2.679     2.340     2002  363     97     79   3.20    20.84   78.99    0.14    0.04
  90th %tile Delta-DV     0.077     2.223     2.145     2002  122     97     79   2.30    15.18   84.14    0.44    0.24

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 13) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                         SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.296     3.550     2.255    2002   26    48    102   2.90    16.76   82.71    0.46    0.07
  98th %tile Delta-DV     0.528     2.803     2.276    2002  336    54    108   3.00     6.87   92.20    0.82    0.12
  90th %tile Delta-DV     0.084     2.212     2.127    2002  105    45     45   2.30     8.25   90.35    1.20    0.20

  Number of days with Delta-Deciview > 0.50:     9
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.793     4.027     2.234    2002   73    89    118   2.80    17.54   81.89    0.51    0.07
  98th %tile Delta-DV     0.490     2.618     2.127    2002  294    79     68   2.30     7.14   91.65    1.06    0.14
  90th %tile Delta-DV     0.069     2.175     2.106    2002  220    82     71   2.20    29.57   70.01    0.32    0.11

  Number of days with Delta-Deciview > 0.50:     7
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.445     3.678     2.234    2002   73    90     72   2.80    20.51   79.03    0.39    0.06
  98th %tile Delta-DV     0.411     2.644     2.234    2002   39    90     72   2.80    22.30   77.16    0.42    0.12
  90th %tile Delta-DV     0.047     2.175     2.127    2002  296    90     72   2.30    11.58   87.73    0.61    0.08

  Number of days with Delta-Deciview > 0.50:     6
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        0.733     3.073     2.340    2002  337    91     73   3.20     5.53   93.93    0.41    0.12
  98th %tile Delta-DV     0.326     2.665     2.340    2002  363    97     79   3.20    21.72   78.10    0.15    0.04
  90th %tile Delta-DV     0.074     2.220     2.145    2002  122    97     79   2.30    15.85   83.44    0.46    0.26

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 14) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                   SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        1.050     3.304     2.255    2002   26    48    102   2.90    20.95   78.39    0.57    0.09
  98th %tile Delta-DV     0.422     2.528     2.106    2002  250    56    110   2.20    34.90   64.03    0.83    0.24
  90th %tile Delta-DV     0.066     2.193     2.127    2002  105    45     45   2.30    10.59   87.61    1.54    0.26

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP NORTH UNIT

  Largest Delta-DV        1.458     3.692     2.234    2002   73    89    118   2.80    21.94   77.35    0.63    0.08
  98th %tile Delta-DV     0.392     2.625     2.234    2002   75    82     71   2.80    27.21   72.27    0.42    0.10
  90th %tile Delta-DV     0.059     2.229     2.170    2002  155    82     71   2.50    41.18   58.67    0.11    0.04

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP ELKHORN RANCH

  Largest Delta-DV        1.181     3.415     2.234    2002   73    90     72   2.80    25.43   74.01    0.49    0.08
  98th %tile Delta-DV     0.337     2.570     2.234    2002   39    90     72   2.80    27.32   72.02    0.52    0.15
  90th %tile Delta-DV     0.045     2.151     2.106    2002  240    90     72   2.20    83.95   15.32    0.63    0.11

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        0.572     2.911     2.340    2002  337    91     73   3.20     7.16   92.15    0.53    0.16
  98th %tile Delta-DV     0.264     2.604     2.340    2002  363    97     79   3.20    26.83   72.95    0.18    0.05
  90th %tile Delta-DV     0.059     2.205     2.145    2002  122    97     79   2.30    19.82   79.29    0.57    0.32

  Number of days with Delta-Deciview > 0.50:     3
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 22) for Year 2001 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                             SEQ    ND        % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3    %_PMC    %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        0.766     2.872     2.106    2001  258    36     36   2.20    17.24   76.12    5.96    0.69
  98th %tile Delta-DV     0.323     2.557     2.234    2001   63    53    107   2.80    49.14   50.03    0.67    0.16
  90th %tile Delta-DV     0.062     2.338     2.276    2001  310    54    108   3.00    31.20   65.86    2.10    0.84

  Number of days with Delta-Deciview > 0.50:     4
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        1.486     3.740     2.255    2001   12    83    112   2.90    40.27   57.50    1.93    0.30
  98th %tile Delta-DV     0.389     2.665     2.276    2001  315    82     71   3.00    26.44   71.77    1.44    0.36
  90th %tile Delta-DV     0.093     2.326     2.234    2001   85    79     68   2.80    15.46   80.88    3.21    0.44

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     1
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.700     2.954     2.255    2001   12    90     72   2.90    40.07   58.79    0.94    0.20
  98th %tile Delta-DV     0.242     2.475     2.234    2001   63    90     72   2.80    54.32   44.85    0.66    0.17
  90th %tile Delta-DV     0.036     2.185     2.149    2001  195    90     72   2.40    85.87   11.96    1.79    0.38

  Number of days with Delta-Deciview > 0.50:     2
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


LOSTWOOD NWA

  Largest Delta-DV        1.819     4.158     2.340    2001  326    91     73   3.20    40.32   57.77    1.60    0.30
  98th %tile Delta-DV     0.531     2.806     2.275    2001   41    91     73   2.90    30.02   68.38    1.31    0.29
  90th %tile Delta-DV     0.166     2.377     2.211    2001  179    93     75   2.60    25.24   69.32    4.86    0.58

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 21) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                 SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         ---------------------------------------------------------------------------------------------

TRNP SOUTH UNIT

  Largest Delta-DV        1.549     3.803     2.255    2002   26    48    102   2.90    27.68   71.95    0.32    0.05
  98th %tile Delta-DV     0.665     2.771     2.106    2002  250    56    110   2.20    43.83   55.60    0.44    0.13
  90th %tile Delta-DV     0.095     2.329     2.234    2002   91    47    101   2.80    34.61   65.34    0.02    0.03

  Number of days with Delta-Deciview > 0.50:    13
  Number of days with Delta-Deciview > 1.00:     3
  Max number of consecutive days with Delta-Deciview > 0.50:     2


TRNP NORTH UNIT

  Largest Delta-DV        2.146     4.379     2.234    2002   73    89    118   2.80    28.78   70.82    0.35    0.05
  98th %tile Delta-DV     0.592     2.826     2.234    2002   83    71     60   2.80    17.58   81.68    0.65    0.10
  90th %tile Delta-DV     0.096     2.266     2.170    2002  155    82     71   2.50    50.15   49.77    0.06    0.02

  Number of days with Delta-Deciview > 0.50:    11
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     3


TRNP ELKHORN RANCH

  Largest Delta-DV        1.772     4.005     2.234    2002   73    90     72   2.80    32.89   66.80    0.27    0.04
  98th %tile Delta-DV     0.515     2.748     2.234    2002   39    90     72   2.80    35.40   64.23    0.29    0.08
  90th %tile Delta-DV     0.074     2.307     2.234    2002   82    90     72   2.80    21.32   78.29    0.33    0.06

  Number of days with Delta-Deciview > 0.50:     8
  Number of days with Delta-Deciview > 1.00:     2
  Max number of consecutive days with Delta-Deciview > 0.50:     2


LOSTWOOD NWA

  Largest Delta-DV        0.818     3.093     2.275    2002   74    97     79   2.90    40.84   58.98    0.15    0.03
  98th %tile Delta-DV     0.408     2.748     2.340    2002  363    97     79   3.20    34.49   65.39    0.10    0.03
  90th %tile Delta-DV     0.088     2.233     2.145    2002  134    97     79   2.30    12.68   86.24    0.90    0.18

  Number of days with Delta-Deciview > 0.50:     5
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1
```

```
CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Stanton Station Unit 1 (Scenario 15) for Year 2002 Meteorological Data

Title lines from CALPUFF (POSTUTIL) output file:

Stanton Station Unit 1 - BART Protocol - Postutil 1.4
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

                                                                          SEQ    ND         % of Modeled Extinction by Species
                         DELTA-DV  DV(Total)  DV(BKG)  YEAR  DAY  RECEP  RECEP  F(RH)   %_SO4   %_NO3   %_PMC   %_PMF
                         --------------------------------------------------------------------------------------------


TRNP SOUTH UNIT

  Largest Delta-DV        0.408     2.642     2.234    2002   73    49     103   2.80    67.56   31.21    1.05    0.19
  98th %tile Delta-DV     0.159     2.392     2.234    2002   74    49     103   2.80    71.20   27.89    0.75    0.16
  90th %tile Delta-DV     0.029     2.156     2.127    2002   95    46      46   2.30    48.73   48.93    2.00    0.34

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


TRNP NORTH UNIT

  Largest Delta-DV        0.556     2.789     2.234    2002   73    89     118   2.80    60.25   37.78    1.74    0.23
  98th %tile Delta-DV     0.160     2.309     2.149    2002  199    79      68   2.40    70.06   22.54    6.61    0.78
  90th %tile Delta-DV     0.030     2.136     2.106    2002  270    68      57   2.20    36.62   57.15    5.44    0.78

  Number of days with Delta-Deciview > 0.50:     1
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     1


TRNP ELKHORN RANCH

  Largest Delta-DV        0.480     2.713     2.234    2002   73    90      72   2.80    64.88   33.68    1.25    0.19
  98th %tile Delta-DV     0.140     2.374     2.234    2002   39    90      72   2.80    66.26   32.13    1.26    0.35
  90th %tile Delta-DV     0.023     2.129     2.106    2002  233    90      72   2.20    57.27   35.17    6.72    0.84

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0


LOSTWOOD NWA

  Largest Delta-DV        0.236     2.511     2.275    2002   74    97      79   2.90    72.84   26.39    0.63    0.14
  98th %tile Delta-DV     0.107     2.447     2.340    2002  363    97      79   3.20    66.89   32.54    0.45    0.12
  90th %tile Delta-DV     0.028     2.260     2.232    2002  204    99      81   2.70    92.15    5.12    2.30    0.43

  Number of days with Delta-Deciview > 0.50:     0
  Number of days with Delta-Deciview > 1.00:     0
  Max number of consecutive days with Delta-Deciview > 0.50:     0
```

Great River Energy - Stanton Station
BART Modeling 2002, 98th Percentile
Lignite Basis
Previously Modeled Emission Rate Correlations

Additional modeling runs were not performed to determine the visibility impacts of the PRB fuel scenarios added in the November 2007 report revisions. Instead, previous modeling data (from presentations to NDDH in 2006 and 2007) as well as the modeling results presented in the original report were used to develop a correlation between dV reductions and changes in SO2 and NOx emission rates. The correlations assume that one of the pollutants (either SO2 or NOx) is varried while all other modeled pollutant emission rates remain constant. These correlations are then used to calculate the impacts of control scenarios incorporating the use of fuel switching to PRB coal. (Basis for Scenarios 16-20 in report Section 7)

NOx Constant, Changing SO2

NOx lb/MMBtu	SO2 lb/MMBtu	dV	Notes
0.26	0.60	0.848	y = -0.5513x + 1.1794 R2 = 0.9996
	0.42	0.948	
	0.13	1.111	
	0.08	1.134	
	0.05	1.148	
0.11	0.60	0.974	y = -0.6081x + 1.3385 R2 = 1
	0.42	1.082	
	0.13	1.257	
	0.08	1.292	
	0.05	1.306	
0.37	1.90	0.000	y = -0.5658x + 1.07 R2 = 0.9999
	0.29	0.902	
	0.15	0.989	
	1.32	0.322	
0.23	0.60	0.870	y = -0.5622x + 1.2108 R2 = .9995
	0.42	0.979	
	0.13	1.139	
	0.08	1.166	
	0.05	1.179	

NOx lb/MMBtu	m	b
0.26	-0.5513	1.1794
0.37	-0.5658	1.07
0.11	-0.6081	1.3385
0.23	-0.5622	1.2108
avg	**-0.57185**	**b= -1.0335 *NOx +1.4503**
stdev	**0.0249405**	**R2 = .9996**

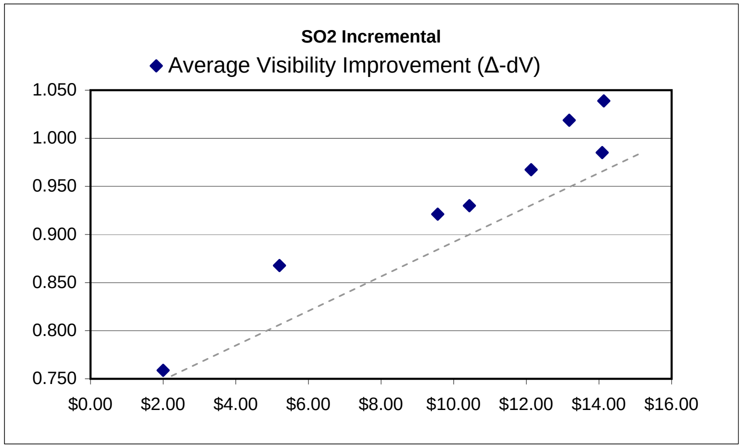
SO2 Constant, Changing NOx

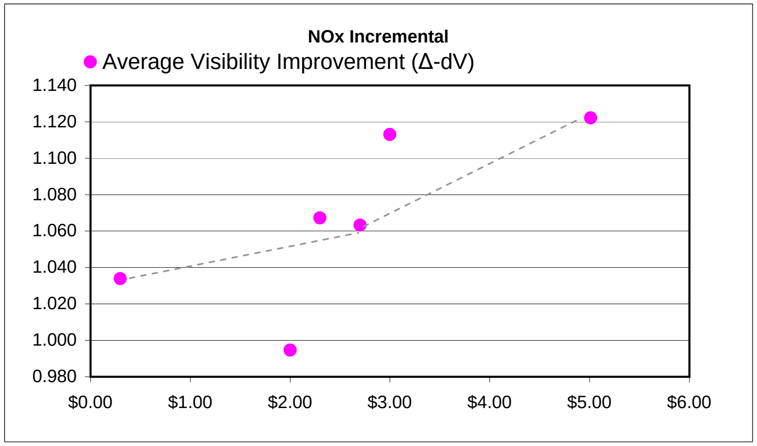
SO2 lb/MMBtu	NOx lb/MMBtu	dV	Notes
0.05	0.36	1.047	y = -1.0221x + 1.4143 R2 = 0.9999
	0.26	1.148	
	0.23	1.179	
	0.11	1.306	
	0.04	1.376	
1.32	0.37	0.322	y = -1.0132x + 0.6939 R2 = 0.9981
	0.37	0.323	
	0.35	0.338	
	0.27	0.414	
	0.05	0.648	
0.29	0.37	0.902	y = -0.9777x + 1.2646 R2 = 1
	0.37	0.904	
	0.35	0.922	
	0.27	1.003	
	0.05	1.218	
0.6	0.36	0.756	y = -0.9116x + 1.0822 R2 = 0.9971
	0.26	0.848	
	0.23	0.870	
	0.11	0.974	
	0.04	1.057	

SO2 lb/MMBtu	m	b
0.05	-1.0221	1.4143
1.32	-1.0132	0.6939
0.29	-0.9777	1.2646
0.6	-0.91116	1.0822
avg	**-0.98104**	**b= -0.5639 *SO2 +1.4324**
stdev	**0.0503804**	**R2 = .999**

Great River Energy - Stanton Station
BART Modeling 2002, 98th Percentile
Lignite Basis - $/dV Summary

Pollutant Info	Control	Emissions (lb/MMBtu)	Annual Operating Cost (MM$)	Average Visibility Improvement (Δ-dV)	Annual MM$/dV	Incremental MM$/dV [1]
SO2 (Assume constant NOx at 0.37)	Spray Dry Baghouse+PRB (97%)	0.055	$14.13	**1.039**	$13.60	$43.32
	Absorber	0.091	$13.18	**1.019**	$12.94	$43.03
	Spray Dry Baghouse+PRB (92%)	0.150	$14.09	**0.985**	$14.30	$53.40
	Spray Dry Baghouse	0.181	$12.13	**0.967**	$12.54	$48.60
	DSI Baghouse+PRB	0.248	$10.43	**0.930**	$11.22	$49.28
	Absorber 10% Bypass	0.263	$9.56	**0.921**	$10.38	$46.58
	DSI with Existing ESP+PRB	0.358	$5.20	**0.868**	$6.00	$29.41
	Fuel Switch to PRB	0.550	$2.00	**0.759**	$2.64	Base
NOx (Assume constant SO2 at 0.15)	SNCR + PRB	0.230	$5.01	**1.122**	$4.47	$691.26
	Alstom LNB + OFA + SNCR	0.239	$3.00	**1.113**	$2.70	Inferior
	SNCR	0.290	$2.70	**1.063**	$2.54	$81.62
	Alstom LNB + OFA + PRB	0.286	$2.30	**1.067**	$2.15	-$102.45
	Alstom LNB + OFA	0.320	$0.30	**1.034**	$0.29	Base
	Fuel Switch to PRB	0.360	$2.00	**0.995**	$2.01	Inferior





[1] For SO2 controls, incremental cost from base case to selected technology; no clearly defined least-cost envelope exists (only 2 dominant controls).

[2] Equation for NOx dV improvement at 0.15 lb/MMBtu SO2 emission rate interpolated from correlations of previously modeled scenarios.

Appendix D

Alstom NOx Evaluation

ALSTOM

A Final Report to

GREAT RIVER ENERGY

Stanton Generating Station Boiler No. 1

FOR:

NOx Reduction Technologies Firing Powder River Basin Coal

SUBMITTED BY:

ALSTOM POWER INC.
BOILER RETROFIT GROUP – U.S. OPERATION
WINDSOR, CONNECTICUT

ENGINEERING STUDY PROJECT
CONTRACT NO. 11070606
ALSTOM PROPOSAL NO. 43033142-00
March 8, 2006

This document has been carefully prepared by ALSTOM Power Inc. (ALSTOM). It is based in part on observations and/or analyses, and any conclusions and recommendations made in this document are based in part on experience and judgment. Another qualified consultant might reach different conclusions and provide different recommendations. The data furnished in this report relating to the performance of the boiler, or condition of equipment, has been carefully evaluated qualitatively and/or quantitatively. This data, however, may be based on assumptions and/or information furnished by others, and is not guaranteed except to the extent set forth in this document.

This document is furnished for your benefit only, and not for the benefit of any third party.

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Executive Summary

The Boiler Retrofits Group of ALSTOM Power Inc. (ALSTOM) is pleased to submit this report to Great River Energy (GRE) Stanton Generating Station. This report details the results of a Phase 1 review of the current PRB and previous Lignite fuels and the available technologies that would reduce NOx emissions to less than 0.29#/mmBtu when firing lignite coal and 0.23 #/mmBtu firing Power Powder River Basin coal, in boiler 1. This study work was authorized by GRE under GRE Contract No. 6072846, dated 01/12/06, and executed under ALSTOM's Engineering Study Contract No. 011070606. Report technical input are from ALSTOM's Firing Systems Engineering – Windsor, CT, and Environmental Controls Systems, Knoxville, TN, and Fuel Tech of Stamford, CT.

A recent Spring Creek, PRB, coal analysis is the base coal for this study, as is lignite coal fired during the original ALSTOM Low NOx burner retrofit contract guarantee tests. The chemical analysis of these fuels can be found in Appendix 5.1. The following table is a summary of the costs and predicted NOx reductions for each technology evaluated specifically for Stanton 1 boiler, firing PRB coal, bottom 2 mills in service at 800k lb/hr feedwater flow: The predicted reductions are based on separate technology capabilities and not the predicted reductions of any combination of technologies:

NOx Reduction Method	**COST ESTIMATE ($m)**						
	Material	**Install**	**Operating**	**Total**	**NOx Reduction**	**Outage**	**Cost/NOx Red.**
RSFC Burner Mods	**0.664**	**0.8**	**0**	**1.46**	**15% - 25%**	**3 wks**	**5.8 to 9.7**
SNCR (Fuel Tech)	**0.8**	**1.8**	**0.1**	**2.7**	**15%**	**4 wks**	**18.0**
SCR (ALSTOM)	**15***	**23**	**2****	**38**	**90%**	**14 wks**	**42.2**

* Indicative pricing does NOT include: new trisector air preheater, SCR gas inlet temperature control device(s), ID Fan alterations, furnace/flue path NFPA Code reinforcements.

** Operating cost includes: 1 yr catalyst replacement + ammonia consumption ~ 340 lb/hr @ full load, $500/ton

1.0 INTRODUCTION

GRE requested a detailed feasibility engineering evaluation of the predicted emissions impacts and the resultant project budgetary estimates of available “in-furnace” and “gas treatment technologies” to further reduce the NOx emissions rate. GRE indicated that the target NOx emissions rate to be considered in this proposed feasibility study is 0.23 lb/mmBtu with 2 mill operation firing PRB and 0.29 lb/mmBtu with 3 mill operation firing lignite. GRE’s emission rate targets are based on a 30 day rolling average. The evaluation considers only ALSTOM designed products or new design technologies that are within ALSTOM’s experience/expertise. The evaluation also considers NOx reduction improvements that may be applied to the RSFC™ burners in combination with “back-end” gas treatment technologies on boiler 1 at Great River Energy’s Stanton Generating Station, located in Stanton, ND.

A. Inquiry Background

In Spring, 2004, GRE began an extended test-burn of the Powder River Basin (PRB) coal from Kennecott Energy Company’s, Spring Creek Mine, located in Montana. ALSTOM Power’s, Technical Services assisted GRE with boiler and burner performance consultation, and with collecting boiler operating data under various loads and furnace conditions on both boiler 1 and 10. Subsequently, GRE converted the Stanton Station to sustained PRB coal firing in November, 2004 marking the start of a five-year coal purchase contract with Kennecott.

Spring Creek Mine coal was test-fired in both boilers 1 & 10 in November, 1996. GRE’s operational results of the PRB test-burn experiences, furnace and mill impacts, and lessons learned during the 1 month test burn were documented and submitted to ALSTOM. The main problem encountered was coal pulverizers running too hot, and causing pulverizer internal fires. The firing of PRB then, presented many coal and ash handling related problems, as well. ALSTOM is also in receipt of overall plant emissions and proximate coal analysis of the PRB fired during the November, 1996 test-burn. In 1997, boiler 1 originally equipped round burners were removed and retrofitted with new Low NOx technology RSFC™ round burners, designed by ABB C-E Services, Inc. (ABB C-E Services Inc., a predecessor to ALSTOM Power).

GRE’s December 7, 2005 request letter specifies that the primary focus of the study will be the available “in-furnace” NOx reduction burner technologies with less emphasis on “back-end” gas treatment technologies. GRE cautions that due to the furnace volume and furnace retention duration, use of over-fire air (OFA) to reduce NOx, may not be a practical solution. ALSTOM agrees that further detailed studies would be required to carefully assess the furnace conditions and dynamics to arrive at confident NOx reduction strategies. GRE requested that this feasibility study include recommendations to address firing of either the current PRB coal or the former Lignite coal from Dakota Coal Company. GRE requests that the ultimate outcome of the study include a set of feasible NOx reduction alternatives identifying the predicted NOx emissions and their correlating recommended equipment budgetary estimates for both “in-furnace” and “back-end” technologies. A site visit by key members of the ALSTOM Study team was conducted on January 17 and 18, 2006 as the initial study activity.

B. Intent and Objective of Study

The intent of this study is to provide Great River Energy a feasibility engineering evaluation of the potential equipment retrofit alternatives that would allow further NOx emissions reductions by implementing "in-furnace" or "back-end" technologies. Budgetary material estimates (+/-25% accuracy) are developed of the recommended modifications resulting from this proposed study. GRE has also requested that the recommendations should consider the flexibility to revert to either North Dakota Lignite or PRB coal types.

C. Unit Description

Boiler 1, designed and supplied by Foster Wheeler, under FW Contract # 2-79-2009, as a lignite, pulverized coal, front wall fired unit. The boiler was designed for balanced draft furnace operation, natural boilerwater circulation, with a split backpass and attemporator spray flow for SH and RH outlet temperature control, radiant superheat division walls, platen superheater and convective reheater surface The original design maximum continuous rating (MCR) is 1,200,000 lb/hr at 1875 psig and 1005°F superheat outlet steam conditions with 463°F economizer feedwater temperature. There are 2 secondary air and 1 primary air regenerative air preheaters for flue gas heat recovery. Furnace dimensions are 27'- 1-1/4" in depth and 48' – 11-3/4" in width, by 80'-9" in height.

Boiler 1 was originally equipped with 3 – MB 23 Foster Wheeler mills which were later replaced with 3 – 943 RP Combustion Engineering Pulverizers, in 1979. These three mills presently connect to 12 **RSFC™** round burners in a four burner – 3 row arrangement. The originally supplied 20 inch diameter coal pipes were changed to 22 inch coal pipes, in 1979. Each of the 943 RP mills is designed to process 115,900 lbs/hr raw coal feed at 1-1/4 x 0 size, 40 HGI, @ 656°F mill inlet temperature to 65% fineness through the 200 mesh screen.

D. Study Deliverables

ALSTOM deliverables under this study contract are:

1. Provide commentary on coal pipe sizing as it relates to the impact of firing of PRB fuel vs lignite and what, if any, compromise may be expected with NOx emissions between a system that is designed specifically for one fuel vs. a system designed to fire either fuel.
2. Provide commentary on predicted changes in unit NOx, CO, and unburned carbon emissions
3. Provide input on additional changes to the firing system design that may be implemented to address detrimental impacts of PRB firing
4. Provide a list of at least two NOx reduction alternatives categorized by both "in furnace" and "back end" technologies, with budgetary estimates for materials .
5. Where necessary to illustrate a potential modification recommended in the report, ALSTOM will provide conceptual sketches of the suggested modification.
6. Budgetary pricing estimates (+/- 25%) will be provided on a final engineering and material supply basis for suggested modifications to the firing system and back end gas treatment system on boiler #1
7. Preparation of a draft report (for GRE comment) prior to final report release.
8. Study kick off meeting and engineering data gathering on site

E. Study Assumptions

While preparing this study , ALSTOM has made numerous assumptions regarding our analysis ,in conjunction with information gathered during and subsequent to the site scoping trip and kick off meeting. Should GRE desire that ALSTOM revise our assumptions or exceptions, ALSTOM would be pleased to discuss these changes with GRE . The items currently identified as assumptions are as follows:

1. ALSTOM's engineering study estimated NOx based on ten(10) different operating conditions , based on feedwater flow, coal type, and number of mills in service. The specific cases were agreed to between GRE and ALSTOM during the site meeting January 17 & 18, 2006.
2. The PRB analysis used for the study was identified as Sample # 05069253-Sa (Dakota Gasification Company Great Plains Synfuels plant) dated 12/16/2005 ,9:46 am . The complete analysis is shown in Appendix 5.1.
3. The Lignite coal analysis used in the study is that fired during the Alstom Low Nox burner retrofit contract (76797) .The complete analysis of this coal is shown in Appendix 5.1.
4. Alstom has evaluated application of overfire air technology to the unit, assuming current best practice approach to the design, installation, and operation of the overfire system.
5. ALSTOM's study scope does not include the detailed assessment of boiler thermal performance or steam flow capacity, tubing metal temperatures in any section of SH or RH, slagging or fouling or the capability of any boiler equipment such as fans, mills, etc., in achieving the operating conditions used for the basis of the NOx emission predictions.
6. ALSTOM's emission modeling assumes firing 100% of each candidate coal at indicated feedwater flow and conditions assuming the burner /overfire air system optimized for the specific fuel. Additional modeling was performed to predict NOx emissions at all ten(10) different operating conditions, assuming the firing system (burner and overfire air system) is modified to accommodate firing either fuel interchangeably. The study has not included any consideration for blended fuels.
7. ALSTOM's assessment of the current Low NOx system is limited to the equipment originally supplied by C-E (C-E, a predecessor to ALSTOM Power).
8. ALSTOM has assumed that all of the boiler firing and pulverizer equipment and the pressure parts are in good working condition. The assessment offered in this proposal is not intended to serve as a condition assessment of pressure parts or other boiler equipment.

2.0 CONCLUSIONS

2.1 Firing Systems Performance and Emissions Predictions

1. The target NOx level of 0.23 lb/mmBtu appears achievable on the PRB with burner modifications and the addition of an overfire air system, with mill #13 (top mill) out of service, at the "normal, current" feedwater flow of 800 k lb/hr. ALSTOM would predict NOx in the range of 0.18-0.23 lb/mmBtu under these conditions, depending upon final operating excess air and the amount of overfire air used.

2. The target NOx level of 0.29 lb/mmBtu appears achievable on the lignite coal with burner modifications and the addition of an overfire air system, with all mills in service, at the "normal, current" feedwater flow of 870 k lb/hr. ALSTOM would predict NOx in the range of 0.27-0.31 lb/mmBtu under these conditions, depending upon final operating excess air and the amount of overfire air used.

3. Generally, NOx will be reduced at feedwater flows below the above conditions, and, conversely, NOx will increase as feedwater flow increases above those conditions cited above. This is due to the relative contribution from Zeldovitch mechanism NOx, commonly referred to as thermal NOx. Thermal NOx is formed by the atmospheric fixation of nitrogen and oxygen at high (> 2600ºF) temperatures. Higher feedwater (steam) flows require greater coal feed rates, which contribute to higher furnace gas temperatures. A detailed breakdown of predicted NOx for the seven(7) PRB coal firing cases and the three (3) Lignite coal firing cases is given in Appendix 5.2 of this report.

4. Based on prior testing at GRE Stanton Unit 1, as well as ALSTOM field experience elsewhere, lowest NOx will be achieved with Mill 13 (top mill) out of service, as compared with having Mill 12 (bottom mill) out of service. The unit operates in a "simulated overfire air mode" with the top mill out of service, which tends to reduce overall NOx emissions. ALSTOM would predict similar result given the assumption of future modifications to the firing system to add overfire air technology.

5. Operation of Unit 1 above the current feedwater (steam) flow levels of 800k lb/hr on PRB coal (i.e. with all mills in service) would reduce the potential for meeting the 0.23 lb/mmBtu NOx target for this fuel. ALSTOM would anticipate NOx in the overall range of 0.36-0.40 lb/mmBtu with the current low NOx burner only arrangement with all mills in service at feedwater flows in the 900-1100 k lb/hr range. With low NOx burner modifications and an overfire air system retrofits implemented, ALSTOM would estimate NOx in the range of 0.25 –0.32 lb/mmBtu, at feedwater flows in the 900-1100 k lb/hr range with all mills in service on the PRB fuel. The study did not consider operation of the unit on lignite at feedwater flows in excess of 870 k lb/hr per agreement with GRE.

6. CO emissions are a strong function of the efficiency of combustion, which is dependent on a multitude of system design and operating parameters. Operating excess air (O2) levels in the furnace, fuel reactivity, furnace residence time, and fuel/air mixing effectiveness all have a first order effect on CO emission levels. Based on historical CO emission data from prior unit testing with the PRB fuel, using the multipoint grid in the flue gas stream, the current CO levels on PRB can be less than 10 ppm, but appear to be more typically on the order of 100ppm average(corrected to 3% O2). Measured CO level during the low NOx burner retrofit guarantee tests was 32 ppm (corrected to 3% O2), but can be higher based on operational variables. From ALSTOM field experience with firing both PRB and lignite coals in utility boilers, the CO would be expected to increase somewhat post retrofit to an overfire air system, as staged

combustion slightly delays the fuel/air mixing (to lower thermal and fuel NOx) necessary to minimize CO. ALSTOM would therefore anticipate CO emissions on the order of 100 to 300 ppm post retrofit to a low NOx system using overfire air on PRB coal. CO emissions on the order of 100 to 300ppm would be likely on the lignite coal. These values are very sensitive to firing system and boiler controls tuning and operation, and may vary substantially based on unit condition and operation variations. CO can increase exponentially as excess O2 is lowered or allowed to vary below nominal threshold levels .

7. Unburned carbon in flyash (UBC) levels are typically less than 1% by weight with the current low NOx burner system. Both the PRB and lignite coals fired are reactive coals, in terms of both ignitability and carbon burnout characteristics. One measure of a coal's relative reactivity is its fixed carbon to volatile matter ratio. The specified PRB coal has a FC/VM ratio of 1.22, and the lignite ratio is 0.99, these ratio values are indicative of very reactive coals with low unburned carbon in flyash levels expected. Some increase in UBC may be expected with the addition of an overfire system, due to the inherent fuel/air staging as well as limited upper furnace residence time in Unit #1. It is expected that UBC levels would remain below 2% post retrofit to an overfire air low NOx system.

8. A review was conducted of current coal pipe size (diameter) vs. coal /mill transport air velocity at measured transport air/fuel ratios on the PRB coal. The standard maximum airflow thru a 943 RP mill is 3300 lb/min. For PRB, the expected transport air/coal (A/F) ratio should be 3.55 at the "typical" feedwater flow of 800k lb/hr, with two (2) mills in service. This is generally consistent with the measured values of A/F ratio in ALSTOM test report dated Dec, 2005. Under these conditions, coal velocities of 93.5 ft/sec can be expected firing PRB, calculated for a 21" I.D. coal pipe. This velocity slightly exceeds the ALSTOM design standard velocity of 70-90 ft/sec. ALSTOM would expect negligible negative impact on firing system performance at the calculated velocity. ALSTOM would also expect negligible impact on erosive wear in the coal pipes and/or coal nozzle at the calculated velocity.

9. A review was conducted of current coal pipe size (diameter) vs. coal /mill transport air velocity at measured transport air/fuel ratios on the lignite coal . The standard maximum airflow thru a 943 RP mill is 3300 lb/min. For lignite, the expected transport air/coal (A/F) ratio should be 3.62 at the "typical" feedwater flow of 870k lb/hr, with three (3) mills in service. Under these conditions, coal velocities of 94.7 ft/sec can be expected firing lignite, calculated for a 21" I.D. coal pipe. This velocity slightly exceeds the ALSTOM design standard velocity of 70-90 ft/sec. ALSTOM would expect negligible negative impact on firing system performance at the calculated velocity. ALSTOM would also expect negligible impact on erosive wear in the coal pipes and/or coal nozzle at the calculated velocity.

10. ALSTOM has reviewed the current coal piping and future low NOx burner/overfire air system in terms of flexibility of operation on either PRB coal or lignite coal, and has determined that either fuel could be fired interchangeably, in terms of coal pipe/ and burner coal nozzle velocity within ALSTOM design limits. This conclusion is valid with two (2) mills in service firing PRB @ feedwater flow of 800k lb/hr, and with three (3) mills in service firing lignite @ feedwater flow of 870 k lb/hr. It should be noted that ALSTOM expects NOx emissions to vary dependent on the fuel fired, as above.

11. For reference, ALSTOM has calculated expected coal (pipe) velocities when firing PRB with all three mills in service at a feedwater flow of 900k, 1000k, and 1100 k lb/hr (consistant with Case's 5, 6 and 7). Although the boiler cannot currently sustain these feedwater flow levels, it is noted that the coal (pipe) and burner coal nozzle tip velocity will be on the order of 93.3,

93.4, 93.5 ft/sec, respectively, which slightly exceeds the ALSTOM design standard velocity of 70-90 ft/sec. ALSTOM would expect negligible negative impact on firing system performance at the calculated velocity. ALSTOM would also expect negligible impact on erosive wear in the coal pipes and/or coal nozzle at the calculated velocity.

12. 12. ALSTOM has reviewed how long term operation with PRB may affect firing system performance. Beyond the emissions impacts cited above, it is suggested that refractory throat modifications be made along with air register modifications. These modifications would be required in conjunction with installation of an overfire air system. The modifications would serve two purposes. First, they would account for the percentage of secondary air flow diverted from the burner air registers to the overfire air ports, required to optimize secondary air velocity thru the burner register with overfire air in operation (consistant with Company design standards) and to achieve best burner performance in terms of emissions, turn down, flame shaping, and flame stability. Secondly, the refractory throat modifications would reflect latest ALSTOM field experience to minimize or avoid slagging or “burner eyebrows”.

13. Based on preliminary firing system design of a Low NOx system incorporating burner modifications with overfire air, the current burner air register should be modified for a target heat input consistent with a realistically achievable steam flow target. In general, the current air registers are oversized for the “typical”, current day, feedwater flows in the 800-870 k lb/hr range. <u>IF</u> GRE plans to continue operation at these feedwater flows, and add overfire air to further reduce NOx in the future (with either 2 mill operation on PRB or 3 mill operation on lignite), ALSTOM would recommend modifications to downsize the burner air registers.

14. If GRE intends to operate with three mills in service with PRB coal at feedwater flow rates in excess of the current 870 k lb/hr “typical“ MCR condition, it is suggested that a comprehensive boiler thermal performance study would also be recommended to access feasibility of same and equipment modifications that may be required to achieve same.

15. ALSTOM has completed a preliminary design for an overfire air system based on target NOx reduction requirements, boiler physical layout, equipment interferences and obstructions as determined in the site scoping trip, and current day “typical “ operating feedwater flows. The preliminary design is comprised of four (4) each overfire air ports, located directly above each column of burners on the front wall of the boiler. The centerline of the overfire air ports would be located at approx elevation of 1754’. The main burner windbox would be the source of (secondary) air for the overfire air ports, four (4) each simple ducts (with flexible joint) would be installed at the top of the windbox to divert a portion of the main windbox secondary air to the overfire air assemblies. This location has proven successful in several Company installations of RSFC burners with overfire air. Side wall overfire air was considered, but optimum performance would not be expected with this configuration. Side wall overfire air would also require more extensive (and expensive) ductwork installation, with takeoffs from each side of the main burner windbox. A schematic of the proposed overfire air arrangement is shown in the attached conceptual drawing.

16. The estimated budgetary cost (engineering and materials) for the proposed overfire air system and associated RSFC burner modifications is $644,000.00. More detail of the cost estimate and scope of material supply is shown in section 3.0.

2.2 SNCR Conclusions

The following table summarizes the SNCR conclusions. See Appendix 5.4 at the rear of this report for more detailed material information.

DESIGN CRITERIA	**Case 1**	**Case 2**	**Case 3**
Type of Furnace	FW PC		
Fuel Fired	PRB	PRB	Lignite
Mills in Operation	3	2	3
Maximum Heat Input (mmBtu/hr)	1489	1191	1295
Uncontrolled NOx; (lb/mmBtu)	0.38	0.27	0.40
lb/hr	566	322	518
Percent NOx Reduction	20%	15%	27.5%
Controlled NOx (lb/mmBtu)	0.304	0.23	0.29
lb/hr	453	274	378
NOx Removed lb/hr	113	48	142
Expected NOxOUT® A Flow (gph)	84	38	94
Furnace CO, (ppm)	<200	<200	<200
Expected Ammonia Slip (ppm,as measured)	5	5	10
Flue Gas Temp (°F)	2150 to	2000 to	2050 to
	2250	2100	2150
Injectors – Level 1 Wall Injectors	9	9	9

2.3 SCR Conclusions

The following table summarizes the SCR conclusions. See Appendix 5.5 at the rear of this report for more detailed material information.

NO_x removal	90% minimum 24 hour average
Draft Loss	Not to exceed 4 inches of WG, from the economizer outlet to the air heater inlet.
Ammonia Slip	Not to exceed 2 ppm
Catalyst life	8000 hr. of operation, or 12 months from initial operation, whichever occurs first.
SO_3 Oxidation.	Less than 1.2% as measured during the first month of operation.
Ammonia consumption as NH3	Not to exceed 370 lb./hr

3.0 RECOMMENDATIONS

3.1 Modifications to Radially Stratified Flame Core (RSFC™) Burners

Item	Quantity	Description
1.	Twelve (12)	RSFC™ burner air register modifications ,comprised of a cylindrical sleeve in teriary air zone .and revised inserts in primary and secondary zone swirler assemblies .
2.	One (1) Set	Drawings for revised burner throat refractory profile to meet RSFC™ requirements
3.	One (1) Lot	SAMA control diagrams which illustrate proposed function of burner /SOFA dampers
4.	One (1) Lot	General arrangement drawings illustrating burner modification installation instructions and weights

Equipment Required for Separated Overfire Air (SOFA) Installation

5.	Four (4) each	SOFA registers with two (2) compartments, top and bottom crotch cooling air; complete with manual adjustable yaw and tilt nozzle tips, partition plates, dampers and necessary linkages
6.	Four(4) each	Seal boxes for above SOFA registers(tube sheet to SOFA register seal
6.	Four(4) each	Shop optimized tube panel assemblies (26” wide, 2.5” OD fined tubes on 3.25” centerlines)
7.	Four(4) each	OFA ductwork to connect SOFA registers to takeoff at top of existing burner windboxes (with flexible joint)
8.	Eight (8)	Electric rotary drive mechanisms for the OFA register damper control – [Two (2) per register](modulation with steam flow rate)
9.	As Required	SOFA guides, windbox structural modifications, Insulation and lagging
10.	One (1) Lot	General arrangement drawings illustrating SOFA and SOFA ductwork installation instructions and weights
11.	One(1) Lot	Commissioning staff for a three week period to observe final burner/SOFA installation, make initial burner adjustments prior to post outage boiler startup, support demonstration of design heat input operation, tuning to make final adjustments to firing system to meet predicted levels of performance, and observation and support during final guarantee tests. Includes supply of temporary economizer outlet gas sampling test probes grid (O2/CO/NOx) and instrumentation to support initial burner /SOFA commissioning and tuning

3.2 SNCR Recommendations

The proposed NOxOUT® SNCR system for all three design cases would consist of a 20,000 gallon FRP heated and insulated Reagent Storage Tank that would feed into a Circulation Module (SLP3-C) installed in a heated enclosure located near the tank. This would provide reagent feed to a Redundant Pump Metering Module (SPL3-RP) that will automatically meter the reagent into a dilution water stream based on the demands of the system.

The diluted reagent is then pumped to a distribution module that will then control the flow of diluted reagent and atomizing air to one level of 9 wall injectors installed through the waterwalls in the upper furnace. The flow to the injectors is automatically controlled based on the operation of the unit and is determined during start-up and optimization of the system. See Appendix 5.4 for greater detail of recommended system components

3.3 SCR Recommendations

The following equipment is recommended to achieve 90% NOx reduction

QUAN.	ITEM	DESCRIPTION
SCR Reactor and Accessories		
1 Only	**SCR Reactor**	SCR Reactor, carbon steel
4 Only	**Soot Blowers**	Sonic type soot blowers
60 Only	**SCR Catalyst Modules**	High dust type catalyst.
1 Lot	**Access**	Access at each catalyst level
1 Lot	**Catalyst Handling Equipment**	catalyst handling and hoisting equipment,.
1 Lot	**Ductwork**	1/4” carbon steel ductwork.

Mechanical Equipment, Ammonia System

QUANTITY	ITEM	DESCRIPTION
2 Only	**Dilution Fans**	One (1) operating, one (1) spare unit.
1 Lot	**Ammonia Vapor Piping**	from ammonia storage tank to injectors
1 Only	**Ammonia Injection Grid and mixer**	Ammonia injection grid inlet of SCR

ELECTRICAL Equipment

QUANTITY	ITEM	DESCRIPTION
SCR, Ammonia and Ash Systems		
1 Only	**Field Instruments**	Instrumentation and controls
1 Only	**PLC and Control Logic**	PLC controller with I/O
1 Only	**SCR Inlet Gas Analyzer & Monitoring System**	Complete with microprocessor based NOx, and oxygen analyzers

4.0 Discussion/Study Methodology

4.1 Discussion

During the site visit, GRE raised a question concerning the reasons and logistics of constructing a single cell SCR versus construction of three (3) separate SCRs for each of the three air preheaters.

ALSTOM responds to this question with the following: The current temperatures at the economizer outlet are too high for SCR operation at some load conditions and too low at other load conditions. This is made more extreme if one considers the three air heaters separately. The existing economizer needs to be reworked with either a water or gas bypass or some alternate form of SCR gas inlet temperature control and the existing three small airheaters replaced with one or two modern design trisector air heaters. ALSTOM ECS is basing the design at Stanton on the use of a single SCR reactor.

The ALSTOM ECS conceptual drawings of the SCR includes work termination points (ductwork points) in correlation to the material estimate.

The SCR gas inlet conditions of 0.5 lb/mmBtu is the basis upon which the 0.05 lb/mmBtu controlled outlet NOx is predicted (90% reduction). The output NOx predictions is based on an inlet NOx and an bulk inlet gas temperature between 600°F and 800°F.

After review of the operating data and plant GA drawings, ALSTOM ECS has the following comment to the SCR design:

> The flue gas temperatures leaving the economizer often vary outside the normal range of operation for the SCR. This will require modification to the economizer and air heaters in order to bring the temperature within an acceptable range. The three air heater design is typically unsuitable for use with an SCR system. We would recommend that they be replaced with a trisector design. The SCR reactor is best located above the air heater section of the building. In order to properly route the ductwork from the economizer to the air heater, extensive modification to the building will be necessary. After completion of these modifications, NOx emissions of .05 lb/MBtu should be achievable.

4.2 Methodology

To address the impact of firing 100% Spring Creek, lignite, or a combination of the two, ALSTOM's methodology was to:

- Review the laboratory coal analysis of coals provided by GRE.
- Using test data from PRB testing (supported by ALSTOM field staff) during April and May of 2004, and Sept/Oct 2005, as well as the final low NOx burner guarantee tests (on lignite) as a baseline, ALSTOM's Firing Systems Engineering (FSE) assessed potential impacts that may occur in the firing system with the current low NOx burner arrangement and with future overfire air installation.

4.3 NOx Predictions at Specified Conditions

ALSTOM completed a detailed series of NOx predictions under several operating conditions. These results can be found in Appendix 5.2

APPENDIX 5.1 PRB and Lignite FUEL ANALYSIS

Table 6

Unit #1	PRB* As received % by wt	Lignite** As received % by wt
Moisture	25.08	35.47
Ash	3.75	8.17
Sulfur	0.35	0.68
Gross Calorific value (Btu/lb)	9350	6896
Sodium oxide total in ash	5.57	n/a
Volatiles	32.1	28.35
Fixed carbon	39.1	28.01
Carbon	55.2	41.43
Hydrogen	6.55	2.63
Nitrogen	0.648	0.65
Oxygen	33.5	10.97

* Ref: Dakota Gasification Company, Sample 05069253-Sa , dated 12/16/2005 , 9: 46:21 AM
** Ref: 1996 Low NOx burner guarantee tests

Table 6 Coal Analysis Comparisons

The Spring Creek coal analysis presents a typical analysis for a Sub. Bit "C" Powder River Basin coal. This coal is highly reactive with a low FC/VM ratio of 1.22 and is conducive to low NOx emissions, low sulfur emissions and low flyash unburned carbon levels. The Spring Creek coal has a heating value approximately 25% higher than the lignite coal. The Lignite coal, which is also very reactive, has a lower FC/VM ratio of 0.99 compared to the PRB. As received coal sulfur levels for the lignite coal is approximately twice the level of the PRB coal (0.68 % by weight vs 0.35 % by weight), but on a corrected lb/mmBtu basis , lignite is approximately 1.0 lb/mmBtu sulfur, vs, approximately 0.4 lb/mmBtu sulfur for PRB.

APPENDIX 5.2

NOX Predictions - GRE Stanton #1 (cases per site meeting 1/17/06) **Page 1 of 2** RCL 2/15/06

Note : Mill #13 top, Mill # 12 bottom) Note - Use FW flow ,not steam flow(per plant eng)

PRB Coal - (FC/VM = 1.22 , 0.65 % N ,sample 05069253-SA,12/16/05)

FW Flow(#/hr) (2 mills -#12 off)	NOx w/o ofa	NOx w ofa	FW Flow(#/hr) (2 mills -#13 off)	NOx w/o ofa	NOx w ofa	FW Flow(#/hr) (all 3 mills)	NOx w/o ofa	NOx w ofa
Case 1-800 k (3% O2)	0.32-0.34	0.24-0.29	Case 3-800 k (3% O2)	0.26-0.28	0.18-0.23	Case 5-1100 k (3% O2)	0.38-0.40	0.27-0.32
Case 2-600k (4.3% O2)	0.3-0.32	0.22-0.27	Case 4-600k (4.3% O2)	0.26-0.28	0.18-0.23	Case 6-1000k (3% O2)	0.37-0.39	0.26-0.31
						Case 7 -900k	0.36-.38	0.25-0.30

Reference field data :

Test #11 (Pete F.)	Test #2 (Alex K)	Tests # 6&7(Pete F)	Test # 8 (Pete F)	Test #16 (Pete F)
1170k FW	998 k FW	1090/1120 k FW	1086 k FW	1225 k FW
0.38#/mbtu	0.34-0.38 #/mbtu NOx	0..28-0.29 #/mbtu NOx	0.38 #/mbtu	0.41-0.43 #/mbtu NOx
3.1% O2	3.4% O2	3% O2	3.09% O2	3.1% O2
	#12 mill out	#13 mill out		

Assumptions - Use 500F sec air temp, 130 F mill outlet temp, 5.0" w to f DP,3.73 transport air/coal ratio, 3% O2 at econ. Outlet(except as noted)

Case # 3 is "normal " unit operation on PRB

Case # 6 is "design" case

APPENDIX 5.2

NOX Predictions - GRE Stanton #1 (cases per site meeting 1/17/06) **Page 2 of 2**

Note : Mill #13 top, Mill # 12 bottom)

Note - Use FW flow ,not steam flow(per plant eng)

Lignite Coal - (FC/VM = 0.99 , 0.65 % N ,sample taken original contract post mod guarantee tests)

FW Flow(#/hr) (2 mills -#12 off)	NOx (#/mbtu) w/o ofa	NOx w/ofa	FW Flow(#/hr) (all 3 mills)	NOx(#/mbtu) w/o ofa	NOx w/ofa
Case 8 -430 k (O2 TBD)	0.36-0.38	0.25-0.30	Case 9-870 k (O2 TBD)	0.39-0.41	0.27-0.32
			Case 10 -670k (O2 TBD)	0.36-0.38	0.25-.30

Reference field data :

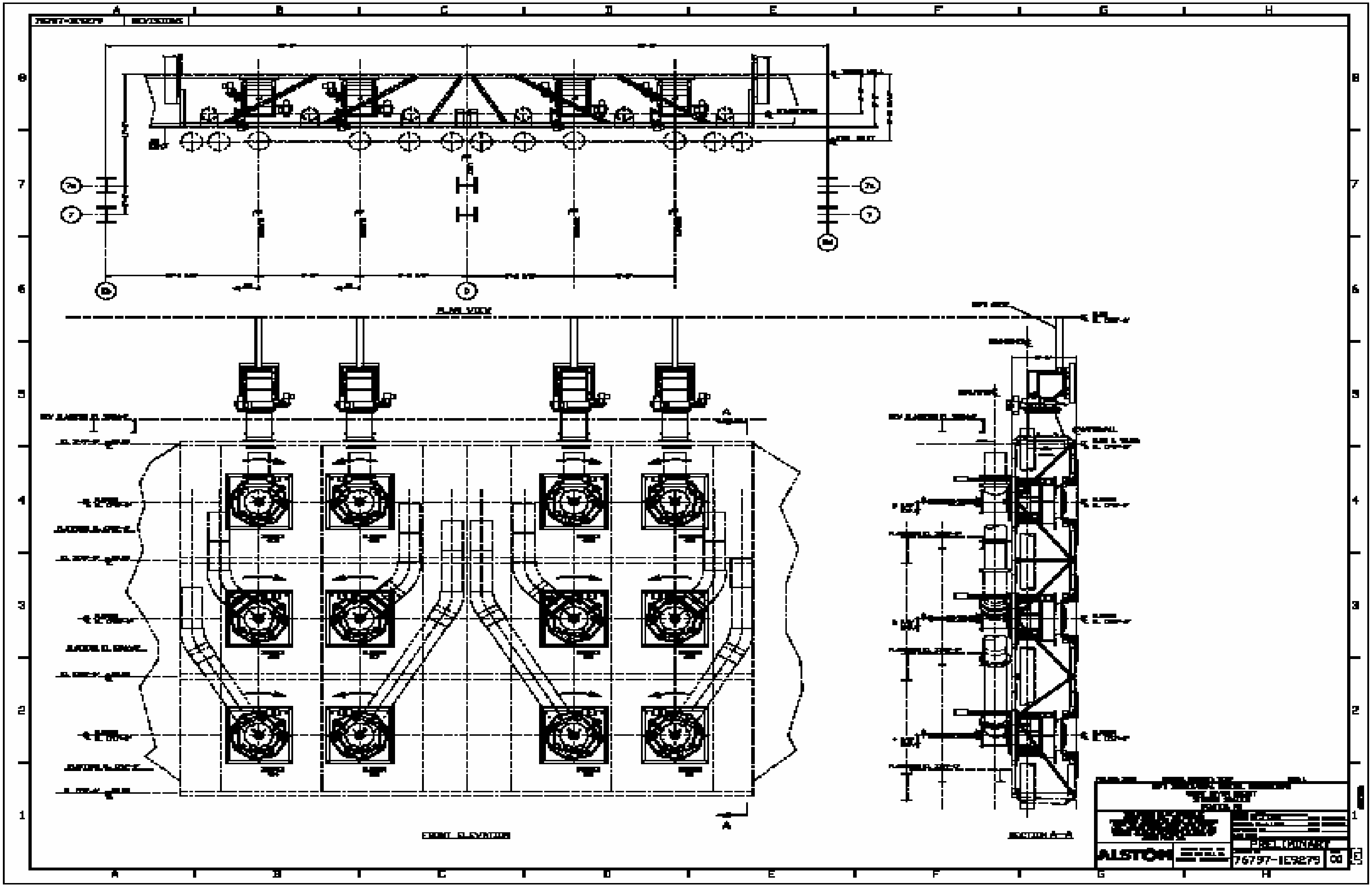
1998/1999 Original contract field data (0.39 #/mbtu NOx , 4 % O2(CR) ,900 k fw flow (typ max mill load with lignite))

Case 8 - NOx range from 0.34-0.43 #/mbtu (Brian Goven to confirm)
Case 9 - NOx range from 0.36-0.37 #/mbtu (Brian Goven to confirm)
Case 10 - NOx range from 0.36-0.39 #/mbtu (Brian Goven to confirm)

Assumptions - Use 500F sec air temp, 140 F mill outlet temp, 5.0" w to f DP,2.59 transport air/coal ratio, O2 at econ. outlet per contract data

Case #9 is "normal" lignite operation

APPENDIX 5.3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APPENDIX 5.4 SNCR Proposal Letter

For this application, the following cases have been evaluated:

Case 1: For 3 mill operation burning PRB, the SNCR System will provide a 20% NOx reduction from a baseline of 0.38lbs/mmBTU with 5 ppm ammonia slip.

Case 2: For 2 mill operation burning PRB, the SNCR System will provide the requested 15% NOx reduction from a baseline of 0.27lbs/mmBTU with 5 ppm ammonia slip.

Case 3: For 3 mill operation burning Lignite, the SNCR System will provide the requested 27.5% NOx reduction from a baseline of 0.40lbs/mmBTU with 10 ppm ammonia slip..

The proposed NOxOUT® SNCR system for all the cases would consist of a 20,000 gallon FRP heated and insulated Reagent Storage Tank that would feed into a Circulation Module (SLP3-C) installed in a heated enclosure located near the tank. This would provide reagent feed to a Redundant Pump Metering Module (SPL3-RP) that will automatically meter the reagent into a dilution water stream based on the demands of the system.

The diluted reagent is then pumped to a distribution module that will then control the flow of diluted reagent and atomizing air to one level of 9 wall injectors installed through the water walls in the upper furnace. The flow to the injectors is automatically controlled based on the operation of the unit and is determined during start-up and optimization of the system.

The NOxOUT® Process incorporates the controlled injection of a 50% urea based reagent in to the furnace at gas temperatures of 1600 to 2200 ^{0}F to reduce NOx to N_2, CO_2 and H_20. The Process has been successfully applied to nearly 350 units worldwide include more than 30 utility boilers up 700MW.

The NOxOUT® A reagent, a 50% urea based solution, would be supplied by tank truck from licensed suppliers.

The budgetary proposal for the NOxOUT® SNCR system is as follows:

PROCESS DESIGN TABLE

	Case 1	**Case 2**	**Case 3**
Type of Furnace	FW PC		
Fuel Fired	PRB	PRB	Lignite
Mills in Operation	3	2	3
Maximum Heat Input (mmBtu/hr)	1489	1191	1295
Uncontrolled NOx; (lb/mmBtu)	0.38	0.27	0.40
lb/hr	566	322	518
Percent NOx Reduction	20%	15%	27.5%
Controlled NOx (lb/mmBtu)	0.304	0.23	0.29
lb/hr	453	274	378
NOx Removed lb/hr	113	48	142
Expected NOxOUT® A Flow (gph)	84	38	94
Furnace CO, (ppm)	<200	<200	<200
Expected Ammonia Slip (ppm,as measured)	5	5	10
Flue Gas Temp (°F)	2150 to	2000 to	2050 to
	2250	2100	2150
Injectors – Level 1 Wall Injectors	9	9	9

II. FUEL TECH EQUIPMENT SCOPE

a. 1 20,000 gallon heated and insulated FRP Storage Tank
b. 1 Circulation Module (SLP3-C) installed in a heated building
c. 1 Redundant Pump Metering Module (SLP3-RP)
d. 1 Distribution Module (SLP3-D-4)
e. 1 Distribution Module (SLP3-D-5)
f. 9 Wall Injector Assemblies
g. 1 Controls Package
h.

III. ENGINEERING

a. Internal Project Engineering
b. Process Engineering to Include CFD and CKM Modeling as required
c. CAD Drawings and Manuals
d. 30 Mandays for Installation and Startup

IV. UTILITIES

a. Power: (480 VAC, 3-Φ, 60 Hz) 60kw
b. Dilution Water: 9 gpm
c. Plant Air: @ 60 to 80psig 110 scfm

V. SNCR SYSTEM PRICE:

For the Equipment, Engineering and Start-up of the SNCR system, the following is the budgetary quote for the material listed above:

EIGHT HUNDRED THOUSAND DOLLARS

($800,000.00 US)

This price is quoted F.O.B. Point of Manufacture.

APPENDIX 5.5 *SCR Assessment*

1.0 DESIGN INFORMATION

1.1. GENERAL

The following description applies to the SCR systems for the Stanton plant.

Selective Catalytic Reduction (SCR) is a method of reducing the amount of nitrogen oxides (NO and NO_2) in the flue gas of fossil-fired industrial and electric utility equipment. The SCR system is comprised of various components, with the central component being the catalytic reactor that contains the catalyst. This catalyst is typically an active phase of vanadium pentoxide on a carrier of titanium dioxide, formed into elements of a parallel flow configuration. Plates or extruded ceramics (honeycomb design) are used as the substrate for the elements onto which the active material is deposited. Elements are then assembled into larger blocks called modules, which are combined into layers in the reactor. The reactor has one layers of catalyst modules, and operating temperature for the catalyst/reactor is normally 650° to 800°F.

The SCR technique uses a reducing agent, ammonia, to convert the NO_x to nitrogen (N_2) and water vapor on the catalyst surface. The ammonia is introduced into the flue gas duct ahead of the SCR reactor and catalyst, and is diluted with air before injection to aid in distribution. On the catalyst surface, the primary chemical reactions that occur are:

$$4\ NO + 4\ NH_3 + O_2 \Rightarrow 4\ N_2 + 6\ H_2O$$

$$NO + NO_2 + 2\ NH_3 \Rightarrow 2\ N_2 + 3\ H_2O$$

Other reactions between NO_x and ammonia will also take place but to a minor extent. The main components produced are nitrogen and water, which both are harmless compounds. One mole of ammonia reacts with one mole of NO_x. Some ammonia will leave the catalyst unreacted, and is referred to as ammonia slip.

ALSTOM has endeavored to provide a system that matches the plant requirements as closely as possible. ALSTOM would be pleased to discuss the design premises in detail to clarify any assumptions and provide GRE with the most economical and reliable system possible.

BASE BID:

For the Base Bid, ALSTOM offers to provide an SCR Reactor system to reduce the NO_x emissions by 90%. The scope will generally include:

- SCR reactor and catalyst
- static mixers
- sonic sootblowers
- analyzer system
- anhydrous ammonia injection system
- controls and instrumentation for the equipment and processes offered
- cold flow modeling

SCR System for GRE Stanton

ALSTOM is proposing the use of one (1) SCR reactor to treat the flue gas at the Stanton Plant. Flue gas from the boiler after the economizer sections will pass through the SCR and then through the air heaters. The ammonia injection system will employ anhydrous ammonia from an existing storage facility.

Plate type catalyst will be used in the reactor, with a 6.4 mm pitch spacing to meet a 90% NOx reduction.

The reactor is designed with a superficial velocity of about 12 feet per second. Each catalyst layer will be comprised of modules, with the installed module size being approximately 1 meter x 2 meter x 1.5 meter high.

The reactor is designed to accommodate one layer of catalyst. A second layer is provided as a warehouse spare. These layers will be exchanged when necessary to maintain continued performance. The used layer will be washed and stored for reuse at the next scheduled exchange point.

1.2 Operating and Design Conditions

1.2.1 Economizer Outlet Conditions

Alstom is using the customer specified design conditions for the SCR system.

2.0 ADDITIONAL TECHNICAL INFORMATION

EQUIPMENT DESCRIPTIONS

SCR System

The SCR System offered consists of catalyst modules, framework, pedal protection (grating), and sonic sootblowers. The catalyst modules are located in one, high dust, vertical downflow reactor. The reactor is located between the boiler economizer outlet and the air heater inlet. The SCR reactors are of outdoors design, operating under negative pressure conditions.

Catalyst System

The operating life of the catalyst is 8,000 hours of operation between washings.

To minimize the catalyst cost over the plant lifetime, the catalyst activity must be monitored. The objective is to maximize the useful life of the catalyst with minimum investment cost. Accumulation of Vanaduim containing flyash will over time cause the SO2 to SO3 oxidation rate to increase. When this reaches an unacceptable level the catalyst should be removed and washed. Tests have shown that after washing the catalyst performance will return to its original level. A second warehouse spare layer of catalyst has been provided to allow for expeditious exchange of the installed catalyst layer followed by washing on a more relaxed schedule.

To gauge the deactivation of the catalyst, a number of coupons may be installed with the initial catalyst in the reactor. These pieces are periodically removed and tested for their remaining activity in a laboratory. ALSTOM proposes that testing be carried out by removing several plates from an installed module. Annual activity testing on a total of 3 coupons is included for the estimate period.

Catalyst Handling System

The catalyst handling system is designed allow the removal and replacement of the catalyst layer when necessary. Replacement of a catalyst layer is considered to be an outage activity and generally can be accomplished within approximately one (1) work week with the removal system offered.

The catalyst is supplied in modules, approximately 1m x 2m in plan area and 1.5m high. (3’-3” x 6’-6” x 5’ high). Each module weighs approximately 3000 lb. The modules consist of a steel box filled with catalyst and with top lifting attachment points. The modules are base supported on beams with sealing strips when installed.

Lifting equipment supplied by ALSTOM includes carts for transport of the modules inside the reactor, special lifting beams for attachment of hoists to the module attachment points, air powered chain hoists for transport of the modules into and out of the reactor.

The handling procedure for addition of new catalyst to the empty layer is as follows: The new catalyst modules are delivered to the plant and stored at grade. A plant forklift is used to bring the catalyst modules to the lifting points under the electric cable lift. The special lifting beam is attached to the module. The cable lift is used to bring the module up from grade to the installation level. The cable lift is mounted on a beam or jib crane that can move under power and set the module on a work platform at the catalyst entrance door to the reactor. After the cable hoist is unhooked, the air powered chain hoist is used to lift the module a few inches off the platform for transport into the reactor. The chain hoist also has an air powered trolley. Inside the reactor, the module is lowered onto the cart for final transport between support beams to its final installed position. Sealing strips are attached to the top of the support beams before the module is lowered onto them. The workers push the cart into position, lower the module onto the strips and pull the cart back to receive the next module. The air-powered hoist can be used to move the cart from track to track. The only manual moving of the module is rolling the cart a maximum of 20 ft. All other operations are powered.

Removal of spent modules is accomplished in reverse of the above procedure.

Replacement Program/Design Margins

Based upon results from catalyst coupon tests at the Stanton plant, a deactivation rate of 10% per operating year is expected. To cover these ranges, a safety margin has been included in the catalyst design. Certain additional margin has been included for uneven distribution of flue gas parameters such as velocity, temperature, NO_x concentrations and stoichiometric ratios. Also based on coupon tests, the SO2 to SO3 oxidation is expected to increase significantly over time due to Vanadium contamination from the fly ash.

Catalyst Sealing System

To avoid flue gas leakage, the modules are placed on seals between the support structure and the modules. On top of the modules there will be baffle plates installed between adjacent modules to avoid dust deposits in that area.

Ammonia Injection / Mixing

The purpose of the ammonia injection system is to expose the entire catalyst section with an even distribution of ammonia upstream of the first catalyst layer. ALSTOM typically designs to a specific gas flow variation coefficient upstream of the injection grid. This is achieved by means of proper duct design, utilizing ALSTOM's experience with gas modeling, duct bends and vaning. The process uses ammonia gas from the existing storage tanks and meters it, as required by boiler load, into a constant flow of hot dilution air. This 20:1 dilution avoids any risk of handling an explosive mixture of ammonia in air. A static mixer is located in the dilution air pipe downstream of the ammonia line to ensure proper mixing of the ammonia in the dilution air. Ammonia concentration is kept below the lower flammability limit. The ammonia/air mixture is injected into the flue gas duct, through a specially designed injection grid, upstream of the catalyst. This grid has been designed to work together with a sophisticated flue gas mixer to assure uniform distribution of the ammonia and NOx. The flue gas mixer allows the design of the grid to be greatly simplified. Only 28 injection points are required for this application. This design does not require tuning the AIG, thus eliminating all the balancing valves and flow meters on the grid. Use of a nonadjustable grid reduces the time needed to commission the system and also reduces the annual maintenance required.

ALSTOM proposes to use the patented Sulzer type SMV flue gas mixer as illustrated above. A static SMV gas mixer is made up of one or more mixing elements. These consist of corrugated plates which form intersecting channels. The mixing effect takes place between two neighboring plates by a relative displacement of part of each flow, as well as due to the increased turbulence at the open channel intersections. Two mixing elements, oriented 90 degrees from each other, are required to produce a homogenous mixture across both the x and y axes of the duct. Two additional stages of mixing take place in the open duct immediately downstream of each mixing element. This is due to the segmented flow streams that exit the SMV element at various angles to the main axis of the duct and intersect with each other in free space.

Sulzer Chemtech is the worlds leading supplier of static mixers, mixer-heat exchangers and plug-flow reactors. More than 25 years of experience in static mixing results in unique technology, proven design, economical solutions and competent support.

Anhydrous ammonia, per the specification, is being employed as the ammonia type. This ammonia gas is extracted from existing connections on the top of the existing ammonia storage tanks. A new pipeline will run along the existing piperack to transport this gas from the ammonia tanks to the boiler building. Flow from the tanks to the dilution air duct is regulated by a control valve, which receives its signal from the overall SCR control logic.

Fans located near the ammonia injection grid supply dilution air. This dilution airflow is fixed and is set to maintain approximately a 20:1 air/ammonia ratio at maximum ammonia flow to the system. This air/ammonia mixture will be directed to the ammonia feed duct at the nozzle grid.

The preliminary design of the ammonia injection grid calls for 28 injection pipes entering the gas duct ahead of the SCR reactor. Each pipe is about 3 inches in diameter. The location of these 28 injection points is coordinated with the design of the mixer. Duct penetrations are staggered to reduce flue gas pressure drop but, at the same time, provide good mixing of ammonia with the flue gas.

Sootblowers

Sonic Sootblowers are being included to aid in the prevention of the accumulation of deposits. They have proven themselves effective in high dust plants with both coal and oil firing. All reactor levels should be cleaned from reactor top to reactor bottom. An initial cleaning frequency of at least once per hour is recommended, with adjustments made as required.

NO_x Control System

General Control Principles

The most common way of controlling the ammonia injection is to use a set point for the outlet NOx concentration, thus keeping the NOx emission at a constant level across the entire load range of the SCR reactor. The objective is to maintain the emission just below the design point in order to reduce ammonia consumption at lower boiler loads, and lowest achievable ammonia slip.

Alternatively, NOx removal efficiency can be fixed and the control system will calculate a required outlet NOx concentration at any operating condition. The operator would select the choice of control method.

Operation

The required outlet NOx emission initiates process control. As described, the outlet will either be fixed directly or calculated based on the inlet concentration and the desired removal efficiency. Measured NOx concentrations at the SCR inlet, provided by Alstom, and outlet, using the existing CEM, are corrected to standard O_2 levels.

The inlet NOx concentration is used in conjunction with the fixed or calculated NOx outlet value and the flue gas flow rate to determine the mass flow of NOx to be removed. This mass flow is used by the control logic in conjunction with the required mole ratio (NH3/NOx) to determine the mass flow of ammonia needed for the reduction. The controller increases or decreases the ammonia flow, depending on the difference between the NOx outlet set point and the actual NOx outlet value measured downstream of the SCR reactor.

Electrical Controls and Instrumentation

ALSTOM will provide all field instrumentation, PLC hardware, and control logic for the SCR system described herein, including engineering design, drafting and documentation for ALSTOM supplied equipment.

ALSTOM will also provide training and assistance to the customer during the installation of the control equipment for the entire SCR system and its associated processes.

SCR/Ammonia Start up And Shut down Procedures

To start up and shut down the SCR system, the following general procedures and sequences shall be followed. Depending upon the overall system design and layout, certain modifications to the procedure may be necessary and, if so, will be provided by ALSTOM.

Start Up Procedure

1. Prepare the unit for purge by positioning boiler gas path dampers according to manufacturers recommendations, starting fans and airheaters.
2. Purge the boiler, SCR reactor, airheater, and duct.
3. Verify ammonia tank level and pressure. Verify that all isolation valves from the ammonia tank to the flow control valve are open. However do not open the ammonia flow control valve to the dilution air duct.
4. Verify that the sootblowing sequence is activated and that correct airflow and pressure is available to the soot blowers..
5. Place auxiliary fuel firing equipment in service as required for boiler warm-up.
6. Wait until the SCR reactor has passed the established acid dew point temperature, and the flue gas temperature leaving the reactor is above 300 °F.
7. Begin firing solid fuel.
8. Heat the SCR reactor with flue gas until the temperature in the SCR reactor is above the minimum catalyst operating temperature.
9. Start the ammonia injection system control loop and slowly open the ammonia control valve.

Shut Down Procedure

1. Shut off the ammonia supply valve and stop the ammonia injection system control loop.
2. Stop fuel feed to the boiler and continue operation of fans until flue gas has been purged from the entire gas path.

Air Heater Washing

It has been our experience that properly operated plants using SCR units designed for less than 3 ppm of ammonia slip require minimal (once or twice per year) washing of the air heater to control bisulfate formation. Operation outside of the design conditions for the system can easily result in excessive slip and high air heater pressure drop. It is important that the system be both properly designed and operated for satisfactory performance.

Flue Gas Flow Modeling

Gas flow design and modeling is one of ALSTOM Power's primary areas of expertise. We maintain two in house laboratories for gas flow modeling and an extensive staff of people experienced in building, testing, and interpreting the results of gas flow models. The proper design and operation of most of our pollution control equipment, low NOx burners, and large fans are dependent on well-controlled gas flow distribution in the equipment and surrounding ductwork.

ALSTOM has been designing SCR equipment for large boilers since 1985. Every plant is unique and requires a custom solution to achieving proper gas distribution. We have included a gas flow model for Stanton in our proposal to assure optimum performance of the SCR.

3.0 CONSTRUCTION/DESIGN FEATURES

Reactor Vessel

The SCR Reactor will be fabricated from carbon steel plate and will be externally stiffened. The Reactor is configured to hold one layer of catalyst. A second layer will be also be supplied and stored by Haldor Topsoe for future installation when needed. Flow turning, straightening, and mixing vanes are provided in the reactor to optimize the removal of NO_x and maintain minimum flue gas pressure loss.

Catalyst Modules

Catalyst modules, completely assembled and ready for installation into each reactor chamber, will be provided. The catalyst material will be titanium dioxide with tungsten and molybdenum oxides and vanadium pentoxide as the active components. Molybdenum oxide provides protection against poisoning by trace elements. Lifting lugs are provided on each catalyst module for ease of installation and maintenance into and out of the reactor chamber. To avoid flue gas leakage, the modules are placed on sealing strips between the support structure and the modules. On the tops of the modules baffle plates are installed between the modules to avoid dust deposits.

Framework for Modules

The framework for the catalyst modules will be fabricated from steel. Hot-rolled steel shapes and plates will be ASTM-A36. High strength bolts will be ASTM-A307 and/or ASTM-A490. Machine bolts will be ASTM-A307. Structural welding will conform to the Structural Welding Code AWS D1.1. All framework materials will be compatible with the catalytic material. Proper internal module sealing between the plate catalyst and module frame will be provided, where applicable. To facilitate placement and removal of the individual modules, spacing will be provided along two (2) adjacent sides of each reactor, with flashing installed once the modules are in place.

Grating

Grating (pedal protection) on each module face will be furnished. The grating is provided for ease of internal maintenance and inspection. Grating material is of stainless steel, providing corrosion and erosion resistance. Both grating and structural detail drawings will be provided to GRE, and will be compatible with the process and operating requirements.

Special Tools

All special tools required for the installation and normal maintenance of the modules will be provided. A cart will be provided within the reactor chamber for individual module positioning. An overhead electric crane will be positioned to allow for the removal and replacement of the modules.

4.0 SCOPE OF SUPPLY - Typical each boiler.

4.1 Mechanical Equipment, SCR System

QUAN.	ITEM	DESCRIPTION
SCR Reactor and Accessories		
1 Only	**SCR Reactor**	SCR Reactor, fabricated from carbon steel plate, externally stiffened. The Reactor is configured to hold one layer of catalyst. Flow turning, straightening, and mixing vanes are provided to optimize the removal of NO_x and maintain minimum flue gas pressure loss.
4 Only	**Soot Blowers**	Sonic type soot blowers to maintain gas passages through the SCR catalyst system.
60 Only	**SCR Catalyst Modules**	High dust type catalyst. The catalyst material is furnished installed in a steel framework with a nominal size of 1m x 2m plan area and a height of approximately 1.5m. The catalyst pitch is nominally 6.4mm (including 1 wall at 0.8 mm).
1 Lot	**Access**	Access will be provided at each catalyst level, including 2’ x 3’ quick opening doors for internal inspection and larger doors for catalyst removal and replacement.

1	Lot	**Catalyst Handling Equipment**	The SCR Reactor is equipped with a complete set of catalyst handling and hoisting equipment, including carts, air powered hoist, electric hoist, and crane beams that provide a permanently installed method of removing and replacing catalyst blocks. This handling equipment is further described in section 5.
1	Lot	**Ductwork**	1/4” carbon steel ductwork with appropriate stiffening and supports. Ductwork extends from the economizer outlet to the SCR and from the SCR to the air heater.

4.2 Mechanical Equipment, Ammonia System

QUANTITY		**ITEM**	**DESCRIPTION**
Ammonia Injection System and Accessories			
2	Only	**Dilution Fans**	One (1) operating, one (1) spare unit. Dilution air fans taking suction from the air heater hot air discharge and diluting the ammonia vapor 20:1 before injection into the duct.
1	Lot	**Ammonia Vapor Piping**	Ammonia vapor / air mixture piping and distribution from the ammonia storage tank to the duct injection grids. Dilution air duct from the existing hot combustion air duct to the dilution air fans and from the fans to the AIG.
1	Only	**Ammonia Injection Grid and mixer**	Ammonia injection grid in the SCR inlet flue gas duct followed by a flue gas mixer.

4.3 ELECTRICAL Equipment

QUANTITY		ITEM	DESCRIPTION
SCR, Ammonia and Ash Systems			
1	Only	**Field Instruments**	Instrumentation and other related accessories for the operation of the SCR by the Alstom provided PLC system.
1	Only	**PLC and Control Logic**	PLC controller with I/O as needed to control the operation of the SCR. A data highway port will be provided for communication with the owners DCS. PLC cabinet to be located in the owners DCS room. PLC will be provided with Engineering design, drafting, documentation, configuration of controls, and logic diagrams, factory testing of logic, supply of display and control graphics displays for the ALSTOM supplied equipment.
1	Only	**SCR Inlet Gas Analyzer & Monitoring System**	Complete with microprocessor based NO_x, and oxygen analyzers, flow monitors, sampling system, to be housed in the owner's DCS room.

SCOPE BY OTHERS

The following items are not included in the ALSTOM scope and are to be furnished, as required, by others.

1. Existing DCS system (ALSTOM to provide SCR PLC with interface card for communication with DCS)
2. 460V Power feed to Alstom MCC
3. Existing stack CEM to provide SCR with NOx emission value for control of ammonia feed.
4. Existing ammonia storage and unloading facility (ALSTOM to tie in new pipeline to SCR)
5. Subgrade electrical grounding grid.
6. Performance testing
7. Operating personnel and consumables for commissioning and start up.

4.4 List of Major Equipment Suppliers and Subcontractors

MAJOR VENDOR LIST	
PRODUCT	VENDORS
SCR SYSTEM	
Chamber Fabrication	PSP, or equal
Catalyst	Haldor Topsoe or equal
Duct Fabrication	PSP, or equal
Expansion Joints	Effox, or equal
Sootblowing System	Drayton, or equal
AMMONIA SYSTEM	
Storage Tanks	By Others
Vaporizer System	By Others
CONTROLS	
NOx Analyzer	Thermo Electron, or equal

5.0 PERFORMANCE ESTIMATES-SCR SYSTEM

Following the completion of the installation of the proposed equipment and subject to the performance conditions contained in Section 7.1 of this Proposal, ALSTOM estimates the following under steady state conditions as defined in this proposal section 3.2.1:

NO_x removal	90% minimum 24 hour average
Draft Loss	Not to exceed 4 inches of WG, from the economizer outlet to the air heater inlet.
Ammonia Slip	Not to exceed 2 ppm
Catalyst life	8000 hr. of operation, or 12 months from initial operation, whichever occurs first.
SO_3 Oxidation.	Less than 1.2% as measured during the first month of operation.
Ammonia consumption as NH3	Not to exceed 370 lb./hr

5.1 PERFORMANCE CONDITIONS

1. A mutually acceptable test program will determine the estimate testing performance values.
2. Installation of the proposed equipment will be in accordance with ALSTOM's drawings and instructions.
3. Operation and maintenance of the equipment will be in accordance with ALSTOM's instructions and good engineering and operating principles.
4. Performance testing will be conducted with no unusual circumstances. For example, feedwater heaters out of service, no hindrances due to incapacitated FD fans, convection pass dampers, flue gas cleaning equipment, ash handling system, sootblowers, wall blowers, and boiler controls.
5. The fuel fired will fall within the range of the fuel as listed in the specification.
6. Recording devices for operating parameters will be maintained by the Customer and made available to ALSTOM.
7. All replacement parts will be of ALSTOM's manufacture or supply or approved equal.
8. The equipment will be started up in the presence of appropriate ALSTOM personnel.

Documentation

A records system shall be established and maintained to provide documentary evidence of the quality of items and activities affecting quality. ALSTOM will ensure that the following documents, as appropriate, are furnished to GRE:

a) Certificate of Compliance, stating that all equipment and materials furnished comply with the Purchaser's specification.

b) Material Test Reports

c) Material Certifications

d) Foundation Design Drawings

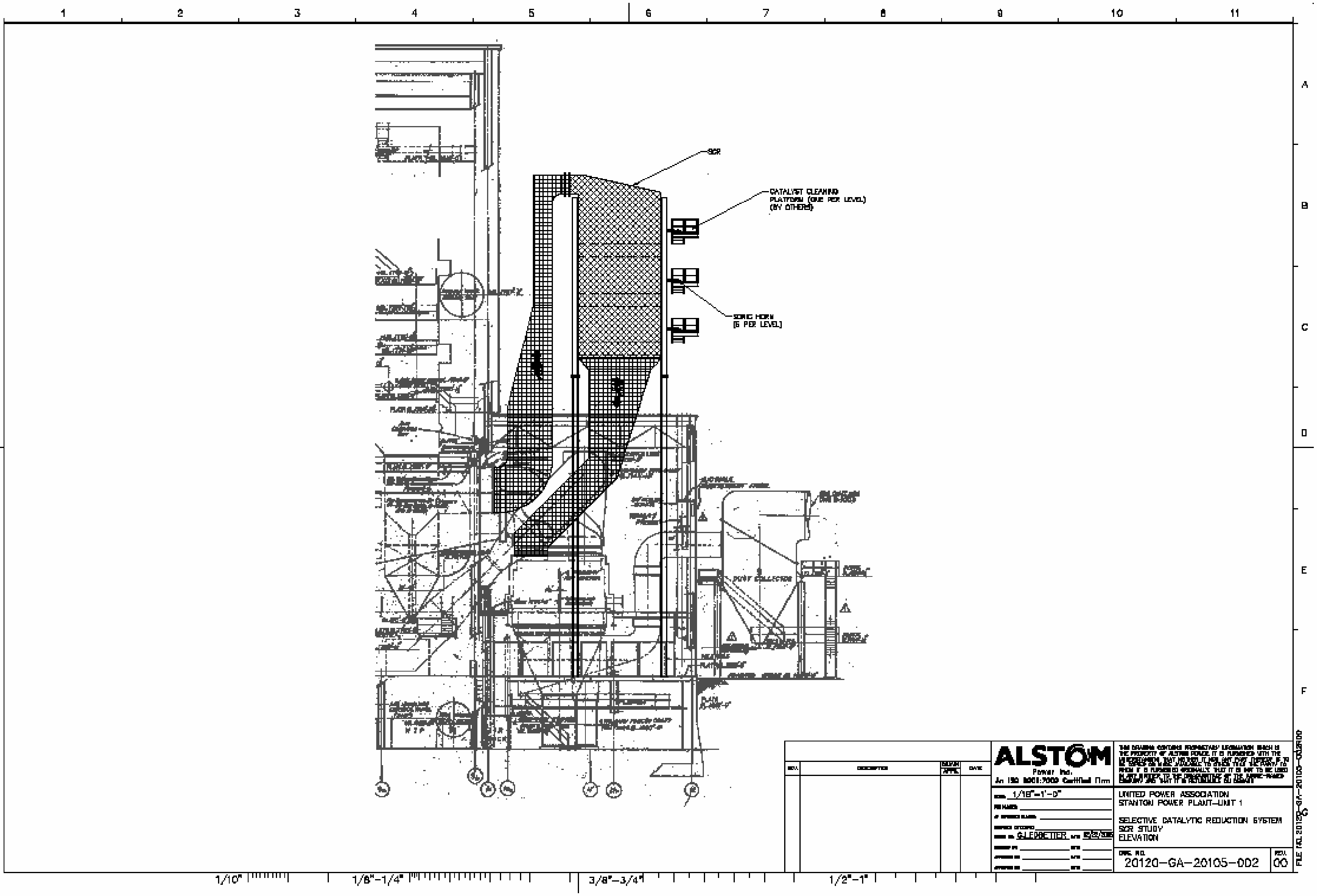
e) Performance Test Results

f) Electrical Test Results and Instrumentation Specifications

g) Documents identifying deviations and their acceptance.

h) Structural Loading Data

APPENDIX 5.6


1
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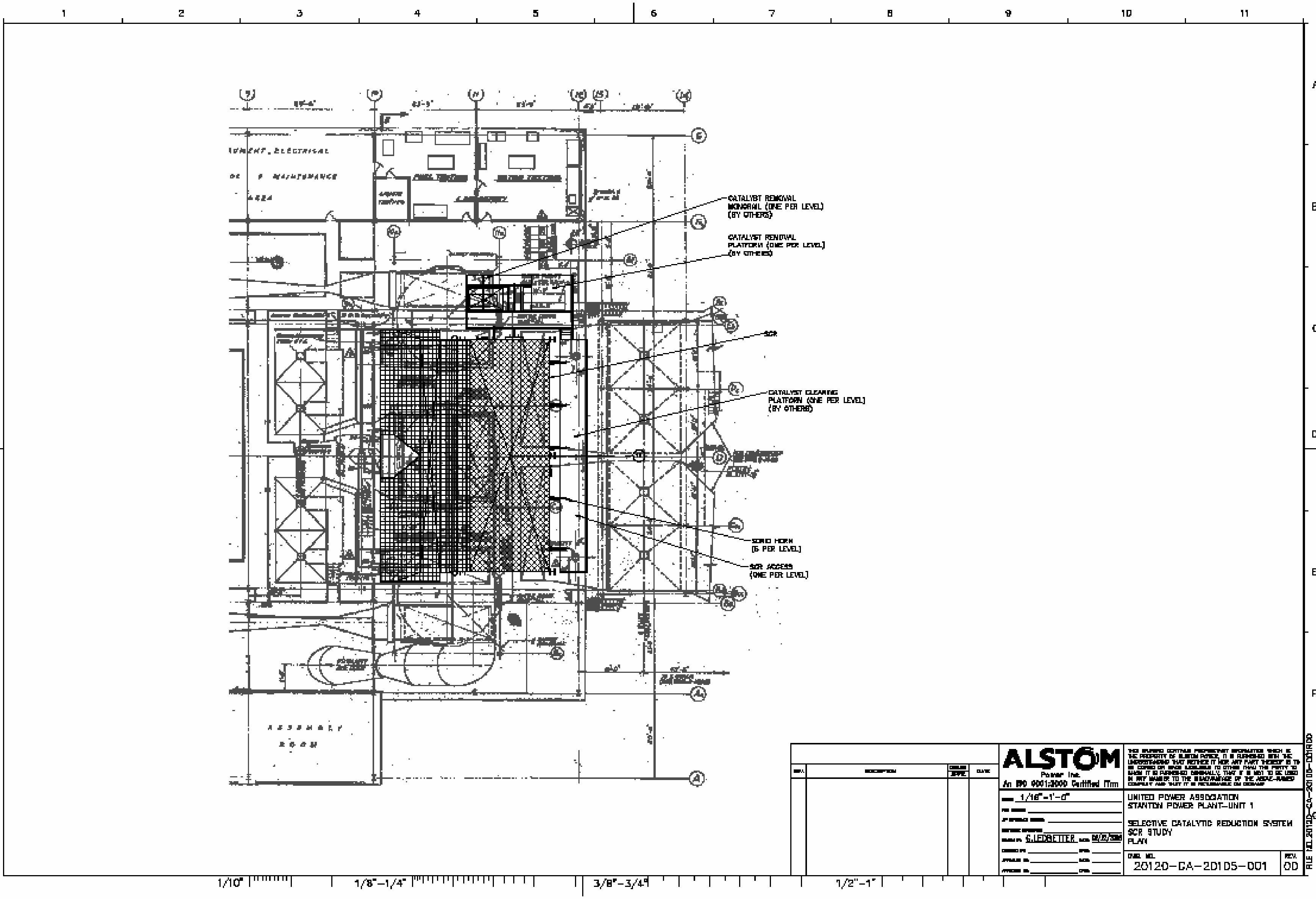
A
B
C
D
E
F
SCR
CATALYST CLEANING PLATFORM (ONE PER LEVEL) (BY OTHERS)
SONIC HORN (6 PER LEVEL)
DUST COLLECTOR
ALSTOM
Power Inc.
An ISO 9001:2000 Certified Firm
REV.
DESCRIPTION
APPD.
DATE
1/16"=1'-0"
G.LEDBETTER
UNITED POWER ASSOCIATION
STANTON POWER PLANT—UNIT 1
SELECTIVE CATALYTIC REDUCTION SYSTEM
SCR STUDY
ELEVATION
DWG. NO.
20120-GA-20105-002
REV.
00
1/10"
1/8"-1/4"
3/8"-3/4"
1/2"-1"


1
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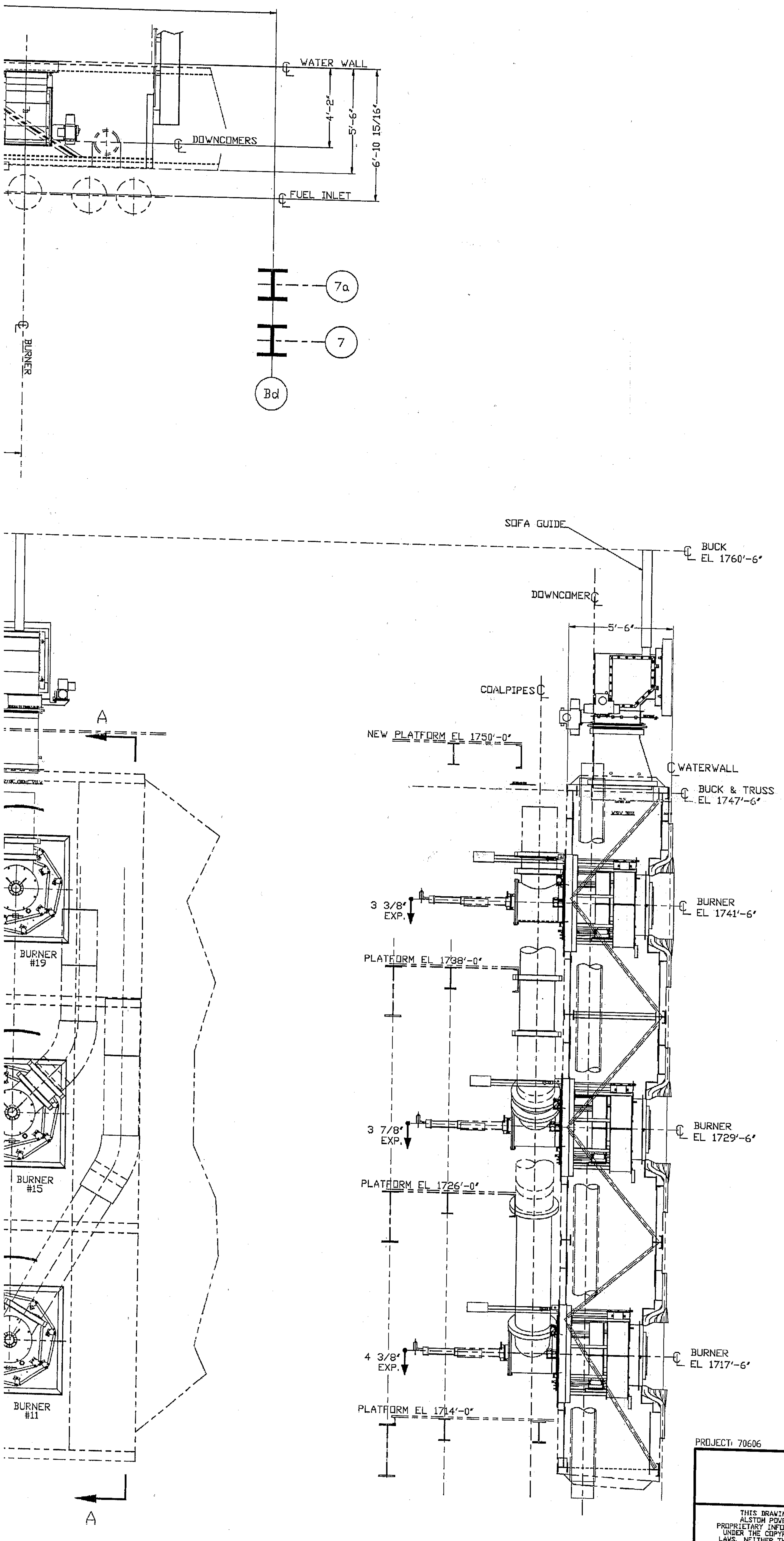
11
CATALYST REMOVAL MONORAIL (ONE PER LEVEL) (BY OTHERS)
CATALYST REMOVAL PLATFORM (ONE PER LEVEL) (BY OTHERS)
SCR
CATALYST CLEANING PLATFORM (ONE PER LEVEL) (BY OTHERS)
SONIC HORN (6 PER LEVEL)
SCR ACCESS (ONE PER LEVEL)
ASSEMBLY ROOM
ALSTOM
Power Inc.
An ISO 9001:2000 Certified Firm
1/16"=1'-0"
G.LEDBETTER
UNITED POWER ASSOCIATION
STANTON POWER PLANT-UNIT 1
SELECTIVE CATALYTIC REDUCTION SYSTEM
SCR STUDY
PLAN
DWG. NO.
20120-GA-20105-001
REV.
0D
1/10"
1/8"-1/4"
3/8"-3/4"
1/2"-1"

END OF REPORT



SECTION A-A

PROJECT: 70606 ORIGINAL CONTRACT: 76797 UNIT: 1

RSFC BURNER/SOFA GENERAL ARRANGEMENT
GREAT RIVER ENERGY
STANTON STATION
STANTON, ND

SCALE: NTS
DRAWN BY: J. Lewis DATE: 02/23/06
CHECKED BY: J. Lewis DATE: 02/23/06
APPROVED BY: DATE:
WBS CODE:

PRELIMINARY

ALSTOM

ALSTOM POWER INC.
2000 DAY HILL RD.
WINDSOR, CONNECTICUT

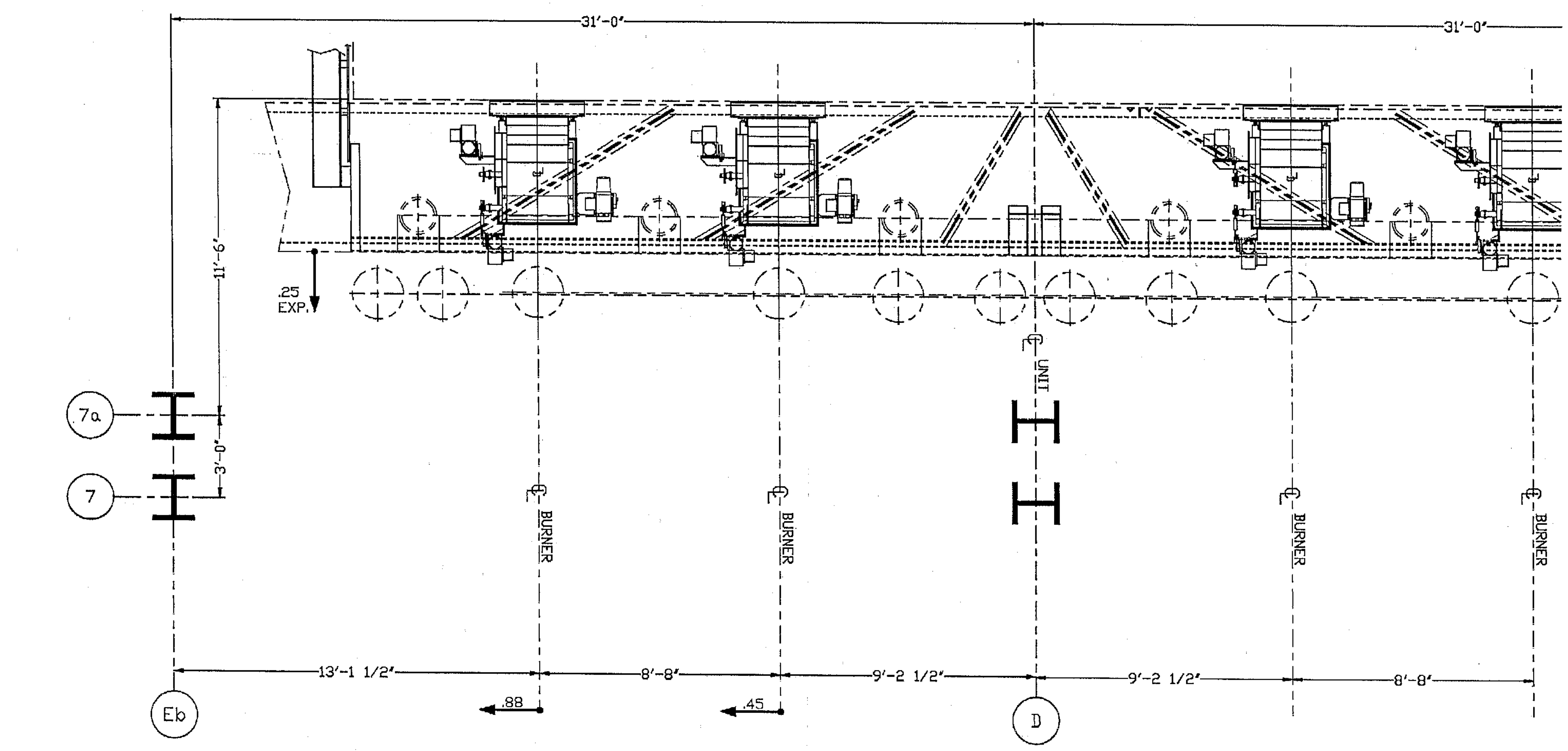
DRAWING NO. 76797-1E9279 REV. 00

E

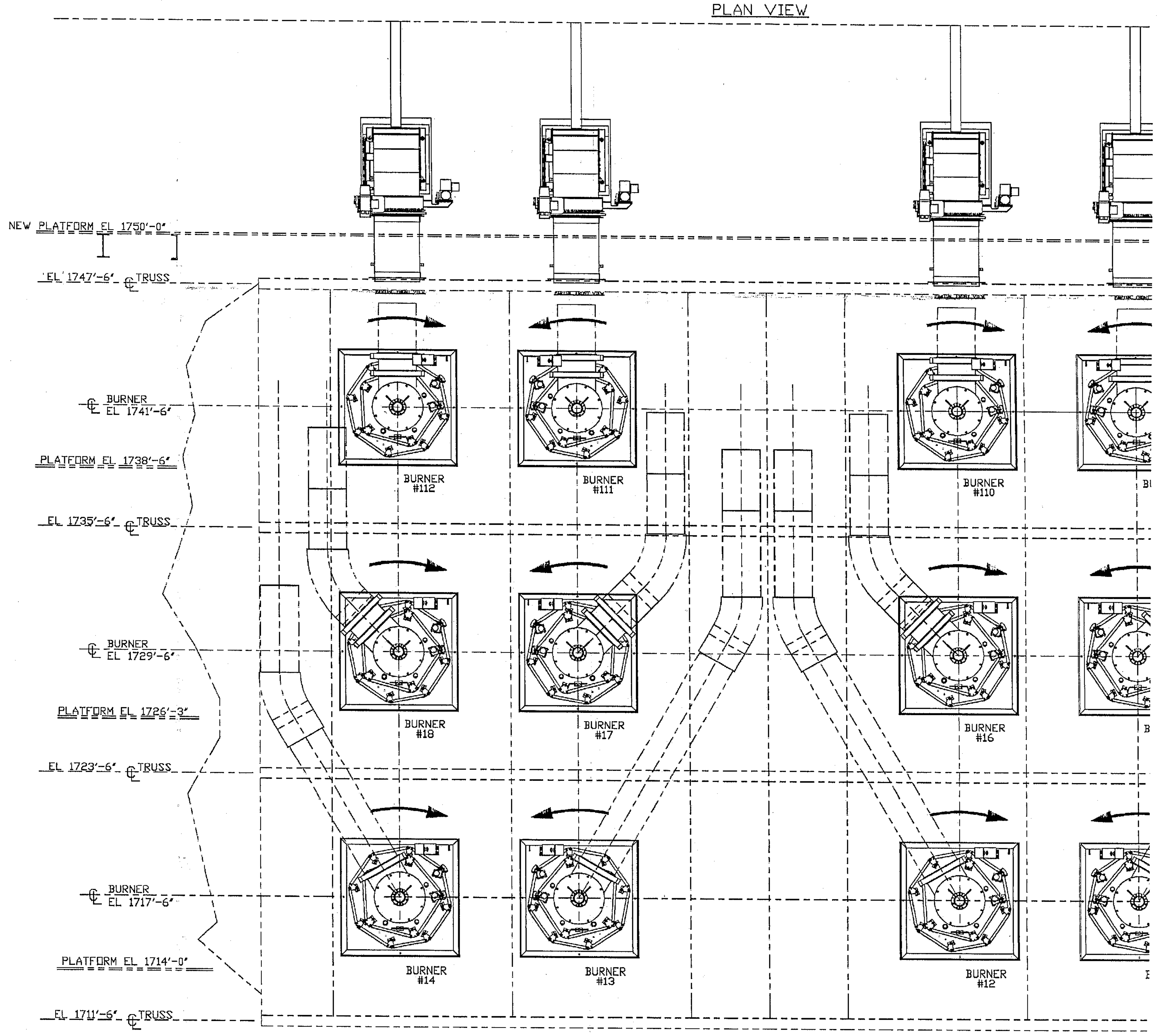
CHECKED

76797-1E9279

REVISIONS



PLAN VIEW



FRONT ELEVATION

SNCR Feasibility with LNB/OFA

An excerpt from an April 13, 2006 email from Alstom is included below. It describes the technical feasibility of using SNCR in combination with LNB/OFA on Stanton’s Unit 1, and includes expected emissions reductions.

Regarding the NOx reduction using both SOFA and SNCR technologies as a combined/cascade system (SOFA + SNCR):
The general consensus between ALSTOM and Fuel Tech is that for the most part, yes, the two systems should work and should reduce NOx ALMOST to the aggregate of each system capability separately however, with the following exceptions:

1. SNCR technology will work slightly less effectively than it would as a sole NOx reduction system.
2. The combined SOFA and SNCR technologies assumes the upper furnace combustion zone, with SOFA modifications implemented, does not exceed 500ppm CO.
3. ALSTOM has not performed any CFD modeling that would otherwise allow more confident predictions on the effectiveness of SOFA + SNCR cascaded technologies.

	Baseline NOx	Case 1 (w/SOFA + mods)/% red.	Case 1(w/SNCR only)/% red	Case 1 (w/SOFA & mods + SNCR) - % red.
Case 1 (1.1m lb/hr fw 3mills, PRB)	0.38 - 0.40	0.27 - 0.32/20%-29%	0.304/20%	20% - 29% + **18% - 20%** = **38% - 49%** Total
Ammonia slip		5 ppm	5ppm	
Case 2 (.80m lb/hr fw #13 off, PRB)	0.27	0.18 - 0.23/15-33%	**0.23/15%	15 - 33% + 17.5% - 20% = 32.5% - 53% Total
Ammonia slip		5 ppm	5ppm	

** Note: the original evaluation had a target NOx of 0.23, which provided the targeted reduction of 15%. The SNCR process is capable of approx. 20% NOx reduction from the baseline.

Case 3 (.9m lb/hr fw Lignite)	0.40	0.27 - 0.32/20 - 33%	0.29/27.5%	20% - 33% + 25% to 27%(20% - 25%)=45% - 60% Total
Ammonia Slip		10 ppm	10 ppm(5ppm)	

Appendix E

Sulfur Content Statistical Analysis

Coal Sulfur Content Statistical Analysis

Lignite Coal

For the purpose of establishing SO_2 emission rates for Lignite, two sources of data were considered.

1) Historical Stanton coal from the Freedom Mine- For Freedom Mine, the maximum daily sulfur content was 1.55% as reported in the 2001 emission inventory.

,

2) MR Young coal from the Center Mine - Milton R. Young's Unit 1 is a lignite fired boiler that does not currently have a scrubber installed for SO_2 control. Emissions from MR Young Unit 1 indicate that the lignite sulfur content has been higher in recent years (2004 through 2005) than historically recorded at Stanton Station. Based on SO_2 emissions[1] from M.R. Young Unit 1, the daily percent sulfur content for lignite was calculated and is presented in Table 3. The top 10 highest daily coal sulfur contents, as listed in Table 3, confirm that the highest daily sulfur content of 1.57% is not a statistical outlier.

Table 1. Sulfur Content Statistical Analysis

	Date	**% Sulfur in Lignite[2]**
Average 2004-2005		1.01
Minimum Daily	4/10/2005	0.04
Maximum Daily	7/2/2005	1.57
Average + 2 Standard Deviations		1.31

These data are consistent with North Dakota lignite reserves as could be used by Stanton over the expected life of the plant. Given that the MR Young data is slightly higher than Stanton, it was chosen as a representative daily maximum sulfur percentage for future Stanton lignite combustion. Using the statistical analysis of this data presented in Tables 1 and 2, 1.31% sulfur (2.44 lb/MMBtu) and 1.57% sulfur (2.94 lb/MMBtu) were determined to be representative for a future predicted 30-day rolling average and a 24-hour maximum sulfur content, respectively.

---

[1] Daily SO_2 emissions data for M. R. Young's Unit 1, years 2004 and 2005 from electronic data records located at <http://www.epa.gov/airmarkets/emissions/raw/index.html> (attached)

[2] % Sulfur in Lignite is calculated based on the SOx emission factor from AP-42 Chapter 1-7, Table 1.7-1. The emission factor is given as 30S lb/ton where S is the weight % sulfur content of wet lignite. To convert to lb/MMBtu the emission factor is multiplied by 0.0625. Therefore, S = lb/MMBtu SO_2/0.0625/30

Table 2. Predicted Emissions Calculations

	30-Day Rolling	24-Hour Maximum
Sulfur %	1.30	1.57
lb/MMBtu	2.44	2.94
Dry Scrubber Control Efficiency	90%	90%
Predicted Emissions	0.24 lb/MMBtu	0.29 lb/MMBtu
	432.0 lb/hr	526.5 lb/hr

Table 3. Top 10 Highest Daily Sulfur Contents

Rank	Date	% Sulfur in LigniteError! Bookmark not defined.
1	7/2/2005	1.57
2	3/9/2005	1.56
3	7/6/2005	1.46
4	12/8/2004	1.45
5	12/6/2005	1.45
6	9/15/2005	1.42
7	12/7/2005	1.41
8	5/18/2005	1.40
9	5/17/2005	1.38
10	7/3/2005	1.36

PRB Coal

Stanton Station is currently permitted to burn both lignite and PRB coals. Currently, Stanton receives coal from the Spring Creek Mine located in eastern Montana. The mine uses a sulfur reject value of 1.2 lb/MMBtu with a contractual guarantee of 0.8 lb/MMBtu. According to the contract, the financial penalty is only the incremental value of SO_2 allowances for any overage from the 0.8 lb/mmbtu value. Although most shipments conform to the 0.8 lb/MMBtu requirement, it is not uncommon to receive shipments with a sulfur content of 1.0 lb/MMBtu as could be expected during a 30-day rolling period. Consequently, for the purpose of establishing a regulatory limit, it is prudent to use the mine's reject value at 1.2 lb/MMBtu.

Given that the existing PRB contract expires in 2009, it is necessary to incorporate sulfur contents from other potential Montana PRB mines. Table 4 presents 3 realistic examples of Montana PRB mines and their average sulfur characteristics.

Table 4. Montana PRB Mine Characteristics[3]

Montana Coal Mine	Average Sulfur Content (%)	HHV (Btu/lb)	SO_2 Emissions (lb/MMBtu)[4]
Spring Creek	0.34	9,350	0.64
Absaloka	0.64	8,750	1.28
Rosebud	0.80	8,750	1.60

Assuming a 90% SO_2 control scenario, an SO_2 limit of 0.15 to 0.16 lb/MMBtu is justified to cover the range of expected PRB fuels as well as possible sulfur variability within a mine. Based on this information, it is clear that a compliance limit set at or slightly above 0.15lb/mmbtu is justified for the life-of-plant.

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[3] Coal specification data from BNSF information, included in attachments.

[4] Calculation method in EPA AP-42, Chapter 1: External Combustion Sources.
SO_2 Emissions (lb/MMBtu) = (35 x sulfur content (%)) / HHV (Btu/lb) / 2000 (lb/ton) x 1E6 (Btu/MMBtu)

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
1/1/2004	4792.5	1.57	0.83
1/2/2004	5118.7	1.61	0.86
1/3/2004	5638.5	1.80	0.96
1/4/2004	4758.5	1.59	0.85
1/5/2004	4940.1	1.61	0.86
1/6/2004	5296.3	1.76	0.94
1/7/2004	5510.1	1.89	1.01
1/8/2004	5839.6	1.92	1.02
1/9/2004	6373.4	2.04	1.09
1/10/2004	4750.4	1.76	0.94
1/11/2004	3840.0	1.82	0.97
1/12/2004	4837.5	1.70	0.90
1/13/2004	5263.6	1.86	0.99
1/14/2004	5181.7	1.78	0.95
1/15/2004	4963.6	1.73	0.92
1/16/2004	5020.3	1.70	0.91
1/17/2004	5584.4	1.87	1.00
1/18/2004	4928.0	1.65	0.88
1/19/2004	4946.6	1.64	0.87
1/20/2004	6101.8	2.01	1.07
1/21/2004	6159.7	1.99	1.06
1/22/2004	5745.7	1.85	0.99
1/23/2004	6158.9	2.07	1.11
1/24/2004	6040.5	1.93	1.03
1/25/2004	5677.7	1.75	0.94
1/26/2004	5310.9	1.59	0.85
1/27/2004	5669.3	1.70	0.91
1/28/2004	6489.4	1.91	1.02
1/29/2004	6309.5	1.89	1.01
1/30/2004	6293.0	1.90	1.02
1/31/2004	6696.3	2.04	1.09
2/1/2004	5694.0	1.75	0.93
2/2/2004	5287.7	1.62	0.86
2/3/2004	5692.2	1.74	0.93
2/4/2004	5894.1	1.80	0.96
2/5/2004	5352.3	1.65	0.88
2/6/2004	5537.3	1.71	0.91
2/7/2004	5727.5	1.79	0.96
2/8/2004	5340.2	1.68	0.90
2/9/2004	4513.8	1.41	0.75
2/10/2004	5894.6	1.86	0.99
2/11/2004	5286.3	1.63	0.87
2/12/2004	5791.1	1.77	0.95
2/13/2004	5851.9	1.81	0.97
2/14/2004	6157.5	1.90	1.01
2/15/2004	4827.2	1.62	0.86
2/16/2004	4198.8	1.39	0.74
2/17/2004	4610.2	1.61	0.86
2/18/2004	4988.1	1.74	0.93
2/19/2004	6525.1	2.21	1.18
2/20/2004	5743.8	1.94	1.04
2/24/2004	1287.3	0.80	0.43
2/25/2004	4412.2	1.82	0.97
2/26/2004	5775.7	2.13	1.14
2/27/2004	6667.4	2.49	1.33
2/28/2004	6145.6	2.28	1.22
2/29/2004	4917.3	1.84	0.98
3/1/2004	4506.3	1.65	0.88
3/2/2004	5609.9	2.05	1.10
3/3/2004	5237.3	1.91	1.02
3/4/2004	4616.7	1.70	0.91
3/5/2004	5323.2	1.96	1.04
3/6/2004	4651.4	1.71	0.91
3/7/2004	4585.0	1.66	0.89
3/8/2004	4544.9	1.62	0.86
3/9/2004	4882.5	1.77	0.95
3/10/2004	5087.4	1.82	0.97
3/11/2004	5393.8	1.85	0.99
3/12/2004	4756.6	1.73	0.92
3/13/2004	5070.0	1.77	0.95
3/14/2004	4433.4	1.57	0.84
3/15/2004	4668.3	1.68	0.89
3/16/2004	5553.1	2.02	1.08
3/17/2004	5133.7	1.88	1.00
3/18/2004	4915.2	1.79	0.95
3/19/2004	4536.5	1.62	0.87
3/20/2004	5249.9	1.90	1.01
3/21/2004	4427.4	1.63	0.87
3/22/2004	4097.7	1.49	0.79
3/23/2004	5449.5	2.01	1.07
3/24/2004	5300.7	2.01	1.07
3/25/2004	5159.3	1.89	1.01
3/26/2004	5928.2	2.17	1.16
3/27/2004	5558.7	2.04	1.09
3/28/2004	5033.0	1.84	0.98
3/29/2004	4873.2	1.77	0.94
3/30/2004	5395.0	1.93	1.03
3/31/2004	4822.6	1.67	0.89
4/1/2004	4769.8	1.68	0.90
4/2/2004	4943.0	1.74	0.93
4/3/2004	5487.4	1.95	1.04
4/4/2004	4906.3	1.73	0.92
4/5/2004	4504.9	1.59	0.85
4/6/2004	5466.5	1.90	1.01
4/7/2004	5000.2	1.73	0.92
4/8/2004	5192.5	1.77	0.94
4/9/2004	4683.6	1.60	0.85
4/10/2004	4597.3	1.55	0.83
4/11/2004	4672.3	1.63	0.87
4/12/2004	4555.8	1.64	0.87
4/13/2004	4185.8	1.45	0.77
4/14/2004	5752.5	2.11	1.12
4/15/2004	4031.9	1.61	0.86
4/16/2004	3511.1	1.39	0.74
4/17/2004	2666.4	1.38	0.74
4/18/2004	2749.2	1.45	0.77

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
4/19/2004	3490.0	1.41	0.75
4/20/2004	3059.4	1.85	0.99
4/22/2004	5657.8	1.99	1.06
4/23/2004	5601.8	2.05	1.09
4/24/2004	5641.6	2.07	1.10
4/25/2004	5385.6	1.97	1.05
4/26/2004	5280.9	1.94	1.04
4/27/2004	5514.9	2.05	1.09
4/28/2004	6038.0	2.19	1.17
4/29/2004	6647.8	2.43	1.30
4/30/2004	5964.0	2.13	1.14
5/1/2004	5340.0	1.89	1.01
5/2/2004	5468.8	1.95	1.04
5/3/2004	5429.2	1.95	1.04
5/4/2004	4959.2	1.75	0.93
5/5/2004	5203.7	1.83	0.98
5/6/2004	5314.1	1.89	1.01
5/7/2004	5784.0	2.05	1.09
5/8/2004	6672.5	2.31	1.23
5/9/2004	5805.3	2.00	1.07
5/10/2004	5433.4	1.92	1.02
5/11/2004	6427.9	2.19	1.17
5/12/2004	5749.3	1.93	1.03
5/13/2004	5672.6	1.91	1.02
5/14/2004	5590.7	1.87	1.00
5/15/2004	6352.1	2.18	1.17
5/16/2004	5507.9	1.87	1.00
5/17/2004	5125.8	1.75	0.93
5/18/2004	6445.3	2.20	1.17
5/19/2004	6258.1	2.18	1.17
5/20/2004	6757.9	2.49	1.33
5/21/2004	6928.8	2.50	1.33
5/22/2004	6567.7	2.32	1.24
5/23/2004	6189.5	2.21	1.18
5/24/2004	6403.0	2.28	1.22
5/25/2004	6101.4	2.07	1.11
5/26/2004	6202.0	2.12	1.13
5/27/2004	5545.6	1.91	1.02
5/28/2004	5620.3	1.93	1.03
5/29/2004	6024.2	2.07	1.11
5/30/2004	5779.1	2.01	1.07
5/31/2004	5855.5	2.05	1.09
6/1/2004	6010.4	2.08	1.11
6/2/2004	5851.7	2.06	1.10
6/3/2004	5685.4	1.94	1.03
6/4/2004	6070.2	2.07	1.10
6/5/2004	6136.3	2.12	1.13
6/6/2004	5689.5	1.99	1.06
6/7/2004	5655.3	1.93	1.03
6/8/2004	5570.1	1.95	1.04
6/9/2004	5469.0	1.82	0.97
6/10/2004	5480.5	1.81	0.97
6/11/2004	4523.3	1.52	0.81
6/12/2004	4082.3	1.45	0.77
6/13/2004	4143.9	1.52	0.81
6/14/2004	4838.9	1.72	0.92
6/15/2004	4686.4	1.64	0.88
6/16/2004	4633.5	1.58	0.84
6/17/2004	4556.2	1.60	0.85
6/22/2004	2802.1	1.53	0.82
6/23/2004	4244.3	1.63	0.87
6/24/2004	4154.3	1.56	0.83
6/25/2004	3651.7	1.51	0.80
6/26/2004	3753.9	1.53	0.82
6/27/2004	3636.5	1.48	0.79
6/28/2004	3512.8	1.43	0.76
6/29/2004	4187.9	1.71	0.91
6/30/2004	4467.1	1.81	0.96
7/1/2004	5114.4	2.07	1.10
7/2/2004	5221.5	2.10	1.12
7/3/2004	5257.8	2.08	1.11
7/4/2004	5115.1	2.06	1.10
7/5/2004	4425.1	1.83	0.97
7/6/2004	4010.5	1.63	0.87
7/7/2004	5493.5	2.16	1.15
7/8/2004	5486.0	2.12	1.13
7/9/2004	5597.2	2.13	1.13
7/10/2004	5435.5	2.06	1.10
7/11/2004	5218.2	2.01	1.07
7/12/2004	4529.4	1.81	0.96
7/13/2004	4928.2	1.94	1.04
7/14/2004	4435.9	1.73	0.92
7/15/2004	4593.2	1.79	0.96
7/16/2004	3966.6	1.52	0.81
7/17/2004	4782.1	1.83	0.97
7/18/2004	4518.5	1.72	0.92
7/19/2004	3926.2	1.50	0.80
7/20/2004	4430.7	1.76	0.94
7/21/2004	5732.8	2.20	1.18
7/22/2004	5742.8	2.22	1.19
7/23/2004	5620.0	2.25	1.20
7/24/2004	5611.4	2.25	1.20
7/25/2004	4796.5	1.97	1.05
7/26/2004	4702.8	1.90	1.02
7/27/2004	5648.5	2.19	1.17
7/28/2004	5375.5	2.12	1.13
7/29/2004	5675.4	2.27	1.21
7/30/2004	5331.5	2.10	1.12
7/31/2004	5608.0	2.21	1.18
8/1/2004	5321.2	2.10	1.12
8/2/2004	5122.1	2.04	1.09
8/3/2004	5313.9	2.10	1.12
8/4/2004	5274.6	2.12	1.13
8/5/2004	5190.4	2.03	1.08
8/6/2004	5239.0	2.06	1.10
8/7/2004	6037.6	2.41	1.29

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
8/8/2004	5121.3	2.07	1.10
8/9/2004	4525.3	1.85	0.99
8/10/2004	5276.4	2.10	1.12
8/11/2004	4326.0	1.68	0.90
8/12/2004	4510.3	1.75	0.93
8/13/2004	5513.9	2.13	1.14
8/14/2004	5444.4	2.09	1.11
8/15/2004	4850.1	1.87	1.00
8/16/2004	4630.8	1.79	0.95
8/17/2004	5308.0	2.03	1.08
8/18/2004	5350.8	2.05	1.09
8/19/2004	5296.6	2.10	1.12
8/20/2004	5515.1	2.08	1.11
8/21/2004	5303.7	2.01	1.07
8/22/2004	4977.1	1.91	1.02
8/23/2004	4658.0	1.80	0.96
8/24/2004	5544.8	2.19	1.17
8/25/2004	5589.3	2.19	1.17
8/26/2004	5426.3	2.16	1.15
8/27/2004	4706.0	1.90	1.01
8/28/2004	5557.0	2.19	1.17
8/29/2004	5197.2	2.06	1.10
8/30/2004	4768.6	1.90	1.01
8/31/2004	4802.4	1.86	0.99
9/1/2004	4834.2	1.89	1.01
9/2/2004	4795.0	1.91	1.02
9/3/2004	5064.2	1.99	1.06
9/4/2004	3918.5	1.71	0.91
9/5/2004	4547.9	1.78	0.95
9/6/2004	4562.5	1.75	0.93
9/7/2004	4273.5	1.69	0.90
9/8/2004	3957.0	1.51	0.81
9/9/2004	4809.0	1.81	0.97
9/10/2004	5462.3	2.10	1.12
9/11/2004	5291.7	2.05	1.10
9/12/2004	4720.1	1.81	0.96
9/13/2004	4417.5	1.68	0.90
9/14/2004	4327.7	1.65	0.88
9/15/2004	4565.2	1.73	0.92
9/16/2004	4666.3	1.77	0.95
9/17/2004	5034.1	1.90	1.01
9/18/2004	4435.6	1.68	0.89
9/19/2004	4279.6	1.63	0.87
9/20/2004	4220.2	1.62	0.86
9/21/2004	5230.0	2.03	1.08
9/22/2004	5481.6	2.09	1.12
9/23/2004	4453.9	1.70	0.91
9/24/2004	4514.8	1.72	0.92
9/25/2004	5174.8	1.98	1.06
9/26/2004	4838.2	1.90	1.01
9/27/2004	4485.8	1.78	0.95
9/28/2004	4511.8	1.73	0.93
9/29/2004	5236.1	1.97	1.05

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
9/30/2004	4246.0	1.61	0.86
10/1/2004	4186.8	1.60	0.85
10/2/2004	4289.8	1.66	0.89
10/3/2004	4342.4	1.66	0.88
10/4/2004	4108.1	1.59	0.85
10/5/2004	4809.4	1.82	0.97
10/6/2004	4619.7	1.74	0.93
10/7/2004	5336.1	2.01	1.07
10/8/2004	4650.1	1.75	0.93
10/9/2004	4449.8	1.68	0.90
10/10/2004	4428.6	1.67	0.89
10/11/2004	4329.5	1.65	0.88
10/12/2004	4660.9	1.75	0.93
10/13/2004	4964.7	1.84	0.98
10/14/2004	5416.5	2.04	1.09
10/15/2004	4765.2	1.77	0.95
10/16/2004	5418.4	1.98	1.06
10/17/2004	4368.4	1.65	0.88
10/18/2004	4205.5	1.56	0.83
10/19/2004	4716.0	1.75	0.93
10/20/2004	5731.7	2.11	1.12
10/21/2004	5832.8	2.21	1.18
10/22/2004	5035.7	1.87	1.00
10/23/2004	6204.0	2.34	1.25
10/24/2004	5264.0	1.95	1.04
10/25/2004	4949.1	1.80	0.96
10/26/2004	4873.0	1.80	0.96
10/27/2004	5723.7	2.09	1.11
10/28/2004	4031.5	1.62	0.87
10/29/2004	4687.8	1.91	1.02
11/2/2004	2000.2	1.27	0.68
11/3/2004	4994.6	1.99	1.06
11/4/2004	5373.1	2.12	1.13
11/5/2004	5743.6	2.27	1.21
11/6/2004	5626.0	2.20	1.17
11/7/2004	5326.9	2.06	1.10
11/8/2004	5203.2	2.02	1.08
11/9/2004	5782.5	2.28	1.22
11/10/2004	4551.0	1.84	0.98
11/11/2004	3666.0	1.44	0.77
11/12/2004	3894.7	1.53	0.82
11/13/2004	4933.5	1.94	1.04
11/14/2004	4429.9	1.76	0.94
11/15/2004	4021.4	1.61	0.86
11/16/2004	4501.1	1.82	0.97
11/17/2004	5090.8	1.99	1.06
11/18/2004	4998.1	1.97	1.05
11/19/2004	5263.3	2.03	1.08
11/20/2004	4970.3	1.87	1.00
11/21/2004	4590.3	1.79	0.96
11/22/2004	4625.1	1.73	0.92
11/23/2004	4764.6	1.76	0.94
11/24/2004	6107.9	2.26	1.21

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
11/25/2004	4989.3	1.82	0.97
11/26/2004	5049.0	1.83	0.98
11/27/2004	4840.7	1.79	0.96
11/28/2004	4622.4	1.70	0.91
11/29/2004	4627.5	1.71	0.91
11/30/2004	4559.4	1.67	0.89
12/1/2004	4047.1	1.51	0.81
12/2/2004	4728.8	1.78	0.95
12/3/2004	6441.9	2.40	1.28
12/4/2004	6116.5	2.28	1.22
12/5/2004	4992.3	1.85	0.99
12/6/2004	4513.3	1.64	0.87
12/7/2004	5836.1	2.12	1.13
12/8/2004	6967.8	2.73	1.45
12/11/2004	3428.7	1.93	1.03
12/12/2004	5411.3	2.09	1.12
12/13/2004	5241.7	2.02	1.08
12/14/2004	4612.3	1.77	0.95
12/15/2004	5103.4	1.92	1.02
12/16/2004	4958.7	1.82	0.97
12/17/2004	4729.8	1.74	0.93
12/18/2004	4546.4	1.64	0.88
12/19/2004	4446.7	1.62	0.87
12/20/2004	4166.9	1.54	0.82
12/21/2004	5129.1	1.85	0.99
12/22/2004	4991.6	1.83	0.97
12/23/2004	5434.3	1.99	1.06
12/24/2004	5277.9	1.91	1.02
12/25/2004	4287.0	1.57	0.84
12/26/2004	4592.2	1.63	0.87
12/27/2004	4705.4	1.66	0.89
12/28/2004	5055.1	1.79	0.96
12/29/2004	5059.3	1.81	0.97
12/30/2004	4636.6	1.65	0.88
12/31/2004	5446.7	1.91	1.02
1/1/2005	5276.5	1.87	1.00
1/2/2005	4361.3	1.56	0.83
1/3/2005	4465.2	1.55	0.83
1/4/2005	4162.1	1.41	0.75
1/5/2005	5316.4	1.84	0.98
1/6/2005	5558.9	2.02	1.08
1/7/2005	5362.7	2.04	1.09
1/8/2005	6201.1	2.38	1.27
1/9/2005	4483.1	1.70	0.91
1/10/2005	3974.9	1.48	0.79
1/11/2005	5315.7	1.98	1.06
1/14/2005	5266.0	2.42	1.29
1/15/2005	5066.0	2.05	1.09
1/16/2005	5308.9	2.18	1.16
1/17/2005	4830.4	2.01	1.07
1/18/2005	5983.1	2.21	1.18
1/19/2005	5246.5	1.91	1.02
1/20/2005	4397.7	1.75	0.93

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
1/21/2005	4535.5	1.74	0.93
1/22/2005	5994.5	2.07	1.10
1/23/2005	4786.2	1.89	1.01
1/24/2005	4130.1	1.63	0.87
1/25/2005	5159.4	1.99	1.06
1/26/2005	4910.0	1.93	1.03
1/27/2005	5318.4	2.10	1.12
1/28/2005	5606.8	2.16	1.15
1/29/2005	5555.1	2.11	1.12
1/30/2005	4908.6	1.94	1.03
1/31/2005	4779.2	1.86	0.99
2/1/2005	5429.3	2.07	1.10
2/2/2005	4904.3	1.89	1.01
2/3/2005	5076.2	1.95	1.04
2/4/2005	5475.1	2.10	1.12
2/5/2005	5537.1	2.12	1.13
2/6/2005	4866.6	1.88	1.00
2/7/2005	4415.7	1.63	0.87
2/8/2005	4570.6	1.65	0.88
2/9/2005	5368.8	1.98	1.05
2/10/2005	4573.0	1.69	0.90
2/11/2005	5220.1	1.94	1.03
2/12/2005	4971.6	1.84	0.98
2/13/2005	4223.9	1.64	0.87
2/14/2005	4359.8	1.54	0.82
2/15/2005	5441.7	1.97	1.05
2/16/2005	4925.3	1.80	0.96
2/17/2005	5780.1	2.13	1.14
2/18/2005	6048.1	2.20	1.18
2/19/2005	6140.2	2.25	1.20
2/20/2005	5670.8	2.06	1.10
2/21/2005	5095.0	1.86	0.99
2/22/2005	5139.0	1.92	1.02
2/23/2005	6107.2	2.22	1.18
2/24/2005	4222.6	1.57	0.84
2/25/2005	4500.2	1.62	0.86
2/26/2005	4343.6	1.56	0.83
2/27/2005	5037.9	1.76	0.94
2/28/2005	4487.6	1.65	0.88
3/1/2005	5686.5	2.21	1.18
3/2/2005	5561.6	2.13	1.14
3/3/2005	5103.0	1.99	1.06
3/6/2005	40.2	0.07	0.04
3/7/2005	3331.3	1.62	0.86
3/8/2005	5393.0	2.10	1.12
3/9/2005	6948.3	2.92	1.56
3/10/2005	5126.9	2.03	1.08
3/11/2005	4713.5	1.86	0.99
3/12/2005	4737.8	1.85	0.99
3/13/2005	4665.9	1.87	1.00
3/14/2005	4570.6	1.86	0.99
3/15/2005	4257.2	1.82	0.97
3/16/2005	4790.6	1.93	1.03

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
3/17/2005	5039.7	2.20	1.17
3/18/2005	4035.9	1.82	0.97
3/19/2005	4406.3	1.99	1.06
3/20/2005	4107.9	1.83	0.98
3/21/2005	3925.8	1.70	0.91
3/22/2005	3534.6	1.52	0.81
3/23/2005	5171.2	2.27	1.21
3/24/2005	4237.9	1.88	1.00
3/25/2005	3411.6	1.51	0.81
3/26/2005	3689.3	1.65	0.88
3/27/2005	3415.5	1.52	0.81
3/28/2005	3315.7	1.46	0.78
3/29/2005	3184.0	1.39	0.74
3/30/2005	3092.3	1.36	0.72
3/31/2005	3778.6	1.67	0.89
4/1/2005	3703.0	1.66	0.89
4/2/2005	4027.8	1.78	0.95
4/3/2005	3304.4	1.47	0.79
4/4/2005	3209.5	1.40	0.75
4/5/2005	3849.5	1.68	0.89
4/6/2005	4128.3	1.76	0.94
4/7/2005	4435.3	1.86	0.99
4/8/2005	4369.4	1.91	1.02
4/9/2005	3755.7	1.67	0.89
4/10/2005	2477.9	1.23	0.66
4/11/2005	2932.9	1.37	0.73
4/12/2005	4371.5	2.01	1.07
4/13/2005	3198.1	1.55	0.83
4/14/2005	3269.1	1.64	0.88
4/15/2005	3876.2	1.70	0.91
4/16/2005	4062.1	1.77	0.95
4/17/2005	3616.3	1.60	0.86
4/18/2005	3639.7	1.51	0.80
4/19/2005	4010.9	1.56	0.83
4/20/2005	3766.2	1.46	0.78
4/21/2005	4714.0	1.83	0.98
4/22/2005	4269.7	1.69	0.90
4/23/2005	4135.1	1.65	0.88
4/24/2005	3810.3	1.52	0.81
4/25/2005	3873.7	1.54	0.82
4/26/2005	4999.3	2.00	1.06
4/27/2005	4039.0	1.60	0.86
4/28/2005	4790.9	1.89	1.01
4/29/2005	5117.8	2.01	1.07
4/30/2005	5148.1	2.08	1.11
5/1/2005	4642.2	1.87	1.00
5/2/2005	4070.3	1.65	0.88
5/3/2005	4495.2	1.79	0.96
5/4/2005	4395.0	1.76	0.94
5/5/2005	4070.1	1.62	0.86
5/6/2005	4063.4	1.61	0.86
5/7/2005	3583.1	1.45	0.77
5/8/2005	4113.6	1.61	0.86
5/9/2005	4235.8	1.66	0.89
5/10/2005	4338.3	1.71	0.91
5/11/2005	4936.5	1.96	1.05
5/12/2005	4080.7	1.63	0.87
5/13/2005	3759.8	1.49	0.79
5/14/2005	5247.5	2.05	1.09
5/15/2005	4750.8	1.91	1.02
5/16/2005	4351.0	1.76	0.94
5/17/2005	6505.2	2.58	1.38
5/18/2005	6494.3	2.63	1.40
5/19/2005	6176.9	2.50	1.33
5/20/2005	5082.5	2.02	1.08
5/21/2005	5125.0	2.03	1.08
5/22/2005	5171.5	2.06	1.10
5/23/2005	5020.4	2.04	1.09
5/24/2005	4998.0	2.05	1.09
5/25/2005	4768.5	1.99	1.06
5/26/2005	4295.2	1.79	0.96
5/27/2005	4301.3	1.79	0.96
5/28/2005	4546.2	1.90	1.01
5/29/2005	4480.2	1.88	1.00
5/30/2005	4144.4	1.74	0.93
5/31/2005	4172.6	1.74	0.93
6/1/2005	4545.8	1.91	1.02
6/2/2005	4067.7	1.70	0.91
6/5/2005	4600.6	1.89	1.01
6/6/2005	4261.0	1.78	0.95
6/7/2005	4571.6	1.96	1.04
6/8/2005	5116.4	2.13	1.14
6/9/2005	4557.2	1.91	1.02
6/10/2005	5004.3	2.14	1.14
6/11/2005	5572.5	2.41	1.29
6/12/2005	4181.9	1.78	0.95
6/13/2005	4118.5	1.74	0.93
6/14/2005	5363.1	2.31	1.23
6/15/2005	5081.7	2.32	1.24
6/16/2005	4711.9	2.03	1.08
6/17/2005	4886.4	2.13	1.14
6/18/2005	4693.1	2.13	1.13
6/28/2005	3526.2	2.18	1.16
6/29/2005	4581.4	2.26	1.21
6/30/2005	5880.6	2.38	1.27
7/1/2005	5244.0	2.31	1.23
7/2/2005	6599.5	2.94	1.57
7/3/2005	5924.4	2.55	1.36
7/4/2005	5371.9	2.33	1.24
7/5/2005	5654.3	2.44	1.30
7/6/2005	6256.9	2.73	1.46
7/7/2005	4826.1	2.04	1.09
7/8/2005	3991.7	1.70	0.91
7/9/2005	4199.9	1.80	0.96
7/10/2005	4733.1	2.03	1.08
7/11/2005	4682.2	2.01	1.07

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
7/12/2005	4394.7	1.87	1.00
7/13/2005	4773.2	2.04	1.09
7/14/2005	4522.0	1.92	1.02
7/15/2005	4716.2	2.02	1.08
7/16/2005	4394.2	1.90	1.01
7/17/2005	4125.6	1.77	0.94
7/18/2005	3952.8	1.71	0.91
7/19/2005	4144.1	1.78	0.95
7/20/2005	4872.5	2.10	1.12
7/21/2005	4934.6	2.12	1.13
7/22/2005	4748.6	2.06	1.10
7/23/2005	5644.1	2.42	1.29
7/24/2005	4718.3	2.05	1.09
7/25/2005	4695.2	2.02	1.08
7/26/2005	5804.7	2.48	1.32
7/27/2005	5610.1	2.40	1.28
7/28/2005	5189.6	2.20	1.18
7/29/2005	5108.6	2.11	1.12
7/30/2005	5825.1	2.40	1.28
7/31/2005	5284.6	2.20	1.17
8/1/2005	5284.6	2.20	1.17
8/2/2005	5284.6	2.20	1.17
8/3/2005	5992.1	2.45	1.31
8/4/2005	5427.6	2.25	1.20
8/5/2005	5081.7	2.11	1.13
8/6/2005	4143.8	1.71	0.91
8/7/2005	4566.4	1.89	1.01
8/8/2005	4044.4	1.66	0.89
8/9/2005	4007.1	1.63	0.87
8/10/2005	3812.9	1.56	0.83
8/11/2005	3452.1	1.41	0.75
8/12/2005	3706.9	1.56	0.83
8/13/2005	3558.0	1.55	0.83
8/14/2005	3337.9	1.43	0.76
8/15/2005	3379.6	1.41	0.75
8/16/2005	4062.4	1.71	0.91
8/17/2005	4251.2	1.77	0.95
8/18/2005	4144.5	1.73	0.92
8/19/2005	3834.1	1.56	0.83
8/20/2005	3882.8	1.60	0.85
8/21/2005	3742.8	1.56	0.83
8/22/2005	3809.3	1.58	0.84
8/23/2005	4225.0	1.75	0.93
8/24/2005	4554.3	1.89	1.01
8/25/2005	5368.7	2.24	1.20
8/26/2005	4929.6	2.05	1.10
8/27/2005	4547.3	1.95	1.04
8/28/2005	4449.4	1.89	1.01
8/29/2005	4586.2	1.94	1.03
8/30/2005	5449.3	2.31	1.23
8/31/2005	5428.2	2.30	1.23
9/1/2005	5641.5	2.39	1.28
9/2/2005	5220.3	2.21	1.18

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
9/3/2005	5373.6	2.25	1.20
9/4/2005	5049.4	2.17	1.16
9/5/2005	5007.0	2.11	1.12
9/6/2005	4579.4	1.98	1.06
9/7/2005	4749.4	2.05	1.09
9/8/2005	5115.0	2.23	1.19
9/9/2005	5022.4	2.30	1.22
9/10/2005	4908.3	2.19	1.17
9/11/2005	4760.2	2.10	1.12
9/12/2005	4555.8	2.00	1.07
9/13/2005	4785.8	2.13	1.14
9/14/2005	5308.5	2.37	1.26
9/15/2005	5815.1	2.66	1.42
9/16/2005	5319.2	2.30	1.23
9/17/2005	4478.0	1.95	1.04
9/18/2005	4553.7	1.97	1.05
9/19/2005	4391.2	1.93	1.03
9/20/2005	5523.1	2.37	1.26
9/21/2005	4958.8	2.18	1.16
9/25/2005	2657.2	1.42	0.76
9/26/2005	4506.6	1.99	1.06
9/27/2005	4624.0	2.04	1.09
9/28/2005	5714.8	2.52	1.34
9/29/2005	5596.4	2.38	1.27
9/30/2005	5028.2	2.03	1.08
10/3/2005	3554.2	1.62	0.86
10/4/2005	3793.6	1.60	0.85
10/5/2005	4574.2	1.94	1.03
10/6/2005	4446.7	1.82	0.97
10/7/2005	4629.7	1.94	1.03
10/8/2005	3365.0	1.40	0.75
10/9/2005	3888.5	1.63	0.87
10/10/2005	3938.2	1.66	0.88
10/11/2005	5381.7	2.22	1.18
10/12/2005	4333.7	1.78	0.95
10/13/2005	4134.0	1.69	0.90
10/14/2005	3969.7	1.65	0.88
10/15/2005	4567.5	1.89	1.01
10/16/2005	4270.7	1.78	0.95
10/17/2005	3896.2	1.62	0.86
10/18/2005	4589.6	1.91	1.02
10/19/2005	5457.2	2.30	1.23
10/20/2005	5360.5	2.25	1.20
10/21/2005	5385.4	2.29	1.22
10/22/2005	4629.0	1.94	1.04
10/23/2005	4589.6	1.92	1.03
10/24/2005	4686.4	2.02	1.08
10/25/2005	5740.9	2.46	1.31
10/26/2005	4781.3	2.06	1.10
10/27/2005	5509.1	2.38	1.27
10/28/2005	4992.2	2.16	1.15
10/29/2005	5247.9	2.21	1.18
10/30/2005	4673.6	2.00	1.06

Date	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (lb/MMBtu)	% Sulfur in Lignite
10/31/2005	4453.6	1.90	1.02
11/1/2005	4942.9	2.10	1.12
11/2/2005	4861.0	2.06	1.10
11/3/2005	5029.4	2.13	1.13
11/4/2005	5116.6	2.14	1.14
11/5/2005	4747.8	1.98	1.05
11/6/2005	4508.8	1.88	1.00
11/7/2005	4117.3	1.74	0.93
11/8/2005	4448.9	1.85	0.99
11/9/2005	4516.2	1.84	0.98
11/10/2005	4231.8	1.78	0.95
11/11/2005	4805.0	2.00	1.07
11/12/2005	4571.1	1.89	1.01
11/13/2005	4156.9	1.73	0.92
11/14/2005	4368.8	1.80	0.96
11/15/2005	4469.6	1.83	0.97
11/16/2005	4338.1	1.76	0.94
11/17/2005	4557.2	1.86	0.99
11/18/2005	5936.0	2.44	1.30
11/19/2005	4662.5	1.92	1.02
11/20/2005	4971.2	2.03	1.08
11/21/2005	4294.3	1.74	0.93
11/22/2005	4170.8	1.71	0.91
11/23/2005	4326.6	1.77	0.94
11/24/2005	4932.8	1.96	1.05
11/25/2005	4715.5	1.90	1.01
11/26/2005	3619.3	1.46	0.78
11/27/2005	3924.0	1.60	0.85
11/28/2005	3782.2	1.55	0.83
11/29/2005	4901.5	1.98	1.06
11/30/2005	4291.2	1.72	0.92
12/1/2005	5820.1	2.36	1.26
12/2/2005	6072.4	2.47	1.32
12/3/2005	5944.6	2.43	1.29
12/4/2005	5545.1	2.26	1.21
12/5/2005	5811.1	2.35	1.25
12/6/2005	6684.0	2.71	1.45
12/7/2005	6557.5	2.64	1.41
12/8/2005	4806.9	2.17	1.15
12/9/2005	4982.1	2.16	1.15
12/10/2005	5427.1	2.25	1.20
12/11/2005	5367.7	2.22	1.18
12/12/2005	5030.3	2.08	1.11
12/13/2005	5495.2	2.31	1.23
12/14/2005	5545.1	2.29	1.22
12/15/2005	5523.8	2.29	1.22
12/16/2005	5547.6	2.28	1.22
12/17/2005	4776.6	1.92	1.02
12/18/2005	4805.2	1.93	1.03
12/19/2005	4783.9	1.94	1.03
12/20/2005	3787.5	1.54	0.82
12/21/2005	4297.0	1.76	0.94
12/22/2005	4224.9	1.76	0.94
12/23/2005	4023.8	1.68	0.90
12/24/2005	3935.9	1.63	0.87
12/25/2005	3873.6	1.65	0.88
12/26/2005	4276.9	1.81	0.96
12/27/2005	3889.8	1.64	0.88
12/28/2005	3253.2	1.36	0.72
12/29/2005	4066.9	1.72	0.92
12/30/2005	4041.0	1.71	0.91
12/31/2005	3687.6	1.58	0.84

2005 dates only with a full 24 hours of records are included.

SPRING CREEK COAL MINE
2002 QUALITY SPECIFICATIONS

Trainload reject parameters: 9000 BTU; 1.2 lbs SO2 per mmbtu

QUALITY PARAMETER	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE		TYPICAL DRY VALUE	TYPICAL MOISTURE-ASH FREE VALUE
			-2 STD DEV	+2 STD DEV		
PROXIMATE						
% Moisture	24.80	0.61	23.58	26.02		
% Ash	3.90	0.33	3.24	4.56	5.19	
% Volatile	32.43	0.81	30.81	34.05	43.13	45.48
% Fixed Carbon	38.54	0.80	36.94	40.14	51.25	54.05
BTU/lb	9360	103	9154	9566	12447	13128
MAFBTU	13128	80.08	12967	13288		
Dry BTU	12447	93.71	12259	12634		
% Sulfur	0.33	0.07	0.19	0.47	0.44	0.46
ULTIMATE						
% Moisture	24.80	0.56	23.68	26.02		
% Carbon	53.88	3.28	47.32	60.44	71.65	75.57
% Hydrogen	3.72	0.23	3.26	4.18	4.95	5.22
% Nitrogen	0.72	0.09	0.54	0.90	0.96	1.01
% Chlorine	0.02	0.01	0.01	0.03	0.03	0.03
% Sulfur	0.33	0.07	0.19	0.47	0.44	0.46
% Ash	3.90	0.33	3.24	4.56		
% Oxygen	12.63	0.70	11.23	14.03	16.80	17.71
SULFUR FORMS						
Pyritic Sulfur (%)	0.05	0.03	0.00	0.11	0.07	0.07
Sulfate Sulfur (%)	0.01	0.015	0.00	0.04	0.01	0.01
Organic Sulfur (%)	0.27	0.06	0.15	0.39	0.36	0.38
Total Sulfur (%)	0.33	0.07	0.19	0.47	0.44	0.46
MINERAL ANALYSIS OF ASH						
% Silicon Dioxide (Silica, SiO2)	30.00	2.78	24.44	35.56	39.89	42.08
% Aluminum Oxide (Alumina, Al2O3)	17.67	1.09	15.49	19.85	23.50	24.78
% Titanium Dioxide (Titania TiO2)	1.21	0.10	1.01	1.41	1.61	1.70
% Iron Oxide (Ferric Oxide, Fe2O3)	4.80	0.47	3.86	5.74	6.38	6.73
% Calcium Oxide (Lime. CaO)	15.98	1.41	13.16	18.80	21.25	22.41
% Magnesium Oxide (Magnesia MgO)	4.42	0.85	2.72	6.12	5.88	6.20
% Potassium Oxide (K2O)	0.63	0.14	0.35	0.91	0.84	0.88
% Sodium Oxide (Na2O)	6.90	2.00	2.90	10.90	9.18	9.68
% Sulfur Trioxide (SO3)	15.09	2.50	10.09	20.09	20.07	21.16
% Phosphorous Pentoxide (P2O5)	0.31	0.06	0.19	0.43	0.41	0.43
% Strontium Oxide (SrO)	0.73	0.22	0.29	1.17	0.97	1.02
% Barium Oxide (BaO)	1.31	0.31	0.69	1.93	1.74	1.84
% Undetermined	0.95	1.00	0.00	2.95	1.26	1.33
Base/Acid Ratio	0.67	0.08	0.51	0.83		
Base Value	32.73	2.20	28.33	37.13		
Acid Value	48.88	3.00	42.88	54.88		
ASH FUSION TEMPERATURES						
Reducing (^{o}F)						
Initial	2078	37	2003	2153		
Softening (H=W)	2109	36	2036	2182		
Hemispherical (H=1/2W)	2126	39	2047	2205		
Fluid	2159	51	2057	2261		
Fluid-Initial Temp Difference	81	40	1	161		
Oxidizing (^{o}F)						
Initial	2349	98	2154	2544		
Softening (H=W)	2394	81	2232	2556		
Hemispherical (H=1/2W)	2423	73	2277	2569		
Fluid	2466	77	2311	2621		
Fluid-Initial Temp Difference	117	60	0	237		

SPRING CREEK COAL MINE
QUALITY SPECIFICATIONS (Continued)

QUALITY PARAMETER	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE	
			-2 STD DEV	+2 STD DEV
ADDITIONAL ANALYSES AND CALCULATED VALUES				
T250 Temperature (°F)	2177	91.88	1993	2361
HGI (at as-received moisture)	54.8	5.6	44	66
HGI % Moisture	22.29	3.88	15	30
Critical Viscosity Temperature (°F)	0	0	0	0
Critical Viscosity (Poises)	0	0	0	0
% Equilibrium Moisture	23.84	0.56	22.72	24.96
Specific Gravity	1.10	0.015	1.07	1.13
%Alkalies NA2O Dry (Total Alkali Content on Coal)	0.379	0.070	0.24	0.52
%Water Soluble Alk - Na2O	0.000	0.000	0.00	0.00
%Water Soluble Alk - K2O	0.000	0.000	0.00	0.00
%Na2O - Dry Coal	0.36	0.03	0.30	0.42
%Na2O As-received Coal	0.27	0.02	0.23	0.31
Silica Value (Silica Ratio)	54.35			
Slag Factor	0.28	0.14	0.00	0.56
Slag factor per Fusion Temperature	2147	85	1977	2317
Dolomite Ratio	62.33	3.25	55.83	68.83
Ash Precipitation Index	4.74	10.1	0.00	24.94
Silica to Alumina Ratio	1.70	0.14	1.42	1.98
Calcium to Silica Ratio	0.53	0.34	0.00	1.21
Iron to Calcium Ratio	0.30	0.07	0.16	0.44
Fouling Factor (Fouling Index)	4.62	1.41	1.80	7.44
SO2/MMBTU	0.71	0.075	0.56	0.86
lbs S/MMBTU	0.35	0.075	0.20	0.50
lbs Sodium/MMBTU	0.288	0.023	0.24	0.33
lbs Ash/MMBTU	4.17	0.5	3.17	5.17

TYPICAL COAL SIZE 2 inch

Size Fraction	Wt. Percent	Cumulative Wt. Percent	Wt. Percent Passing Top
+3" RD	0%	0%	100%
3" RD x 2" RD.	4%	4%	100%
2" RD. x 1" RD.	20%	24%	96%
1" RD. x 1/2" RD	28%	52%	76%
1/2" RD. x 4 M	20%	71%	48%
4 M x 60 M	13%	84%	29%
60 M x 0	16%	100%	16%

TRACE ELEMENT SUMMARY

Parts Per Million Whole Coal Dry Basis	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE	
			-2 STD DEV	+2 STD DEV
ANTIMONY (Sb)	0.00	0.00	0.00	0.00
ARSENIC (As)	1.50	1.00	0.00	3.50
BARIUM (Ba)	0.00	0.00	0.00	0.00
BERYLLIUM (Be)	0.21	0.08	0.06	0.36
BORON (B)	0.00	0.00	0.00	0.00
BROMIDE (Br)	0.00	0.00	0.00	0.00
CADMIUM (Cd)	0.18	0.02	0.14	0.22
CHLORINE (Cl)	200.00	55.00	90.00	310.00
CHROMIUM (Cr)	2.40	0.75	0.90	3.90
COBALT (Co)	0.00	0.00	0.00	0.00
COPPER (Cu)	0.00	0.00	0.00	0.00
FLUORINE (F)	41.90	11.00	19.90	63.90
LITHIUM (Li)	0.00	0.00	0.00	0.00
MANGANESE Mn)	16.20	7.90	0.40	32.00
MERCURY (Hg)	0.07	0.03	0.01	0.13
MOLYBDNEUM (Mo)	0.00	0.00	0.00	0.00
NICKEL (Ni)	1.53	1.00	0.00	3.53
LEAD (Pb)	2.60	1.00	0.60	4.60
SELENUIM (Se)	1.20	0.90	0.00	3.00
SILVER (Ag)	0.00	0.00	0.00	0.00
STRONTIUM (Sr)	0.00	0.00	0.00	0.00
THALLIUM (Tl)	0.00	0.00	0.00	0.00
THORIUM (Th)	0.00	0.00	0.00	0.00
TIN (Sn)	0.00	0.00	0.00	0.00
URANIUM (U)	0.00	0.00	0.00	0.00
VANADIUM (V)	0.00	0.00	0.00	0.00
ZIRCONIUM (Zr)	0.00	0.00	0.00	0.00
ZINC (Zn)	0.00	0.00	0.00	0.00

" **All negative numbers were converted to 0.00**

Revised 3/29/2000

Powder River Basin - Montana Mines

Spring Creek Mine - Rio Tinto Energy America

Type of Mine	Surface - dragline operation
Loading Station	Nerco Jct., Montana (Big Horn County) 30 miles northeast of Sheridan, Wyoming
Marketing Contact	Matt Lever - General Manager Sales and Marketing Rio Tinto Energy America 8000 E. Maplewood Avenue Building 5, Suite 250 Greenwood Village, CO 80111 Phone: (720) 377-2043 E-mail: matt.lever@riotinto.com Website: www.rtea.com

Coal Specifications

Proximate Analysis (as received)	**Typical**
Fixed Carbon	39.23%
Volatile Matter	31.26%
Moisture	25.60%
Ash	4.32%
Sodium as % of Ash	8.24%
Sulfur	0.34%
Btu/lb	9,350
Size	2" x 0"
Ash Fusion Temp/Reducing Atmosphere:	
Initial	2106°F
Fluid	2164°F

Recoverable Reserves	290 million tons
Annual Production	Permitted for 15 million tons/year 2002 – 8.9 million tons 2003 – 8.9 million tons 2004 – 12.0 million tons
Storage Capacity	35,000 tons (barn storage)
Storage Recharge Rate	3,000 tons per hour
Loading & Weighing	Flood loading with belt scale
Loading Rate	4,100 tons per hour
Track Configuration	Loop track holds two unit trains on site

Powder River Basin - Montana Mines

Absaloka Mine - Westmoreland Coal Co.

Type of Mine	Surface - dragline operation
Loading Station	Kuehn, Montana (Big Horn County) 60 miles southwest of Forsyth, Montana
Marketing Contact	Dave Simpson Westmoreland Resources Inc P. O. Box 449 Hardin, Montana 59034 Phone: (406) 342-5241 / Fax: (406) 342-5401 E-mail dws@mcn.net

Coal Specifications

Proximate Analysis (as received)	**Typical**
Fixed Carbon	36 27%
Volatile Matter	30 23%
Moisture	24 50%
Ash	9 00%
Sodium as % of Ash	2 00%
Sulfur	0 64%
Btu/lb	8 750
Size	3" x 0"
Ash Fusion Temp/Reducing Atmosphere:	
Initial	2130°F
Fluid	2215°F

Recoverable Reserves	70 million tons
Annual Production	Permitted for 7 million tons/year 2002 – 4 0 million tons 2003 – 5 3 million tons 2004 – 4.5 million tons
Storage Capacity	44,000 tons (trough-type storage barn)
Storage Recharge Rate	18,000 tons per day
Loading & Weighing	250-ton surge bin with belt scale
Loading Rate	4,000 tons per hour
Track Configuration	Loop track holds one unit train on site

Powder River Basin - Montana Mines

Rosebud Mine - Westmoreland Coal Co

Type of Mine
Surface - dragline operation

Loading Station
Colstrip, Montana (Rosebud County)
35 miles southwest of Forsyth, Montana

Marketing Contact
James Kelly. Vice President Westmoreland Coal Sales
Ed DeMeter, Vice President, Westmoreland Coal Sales
2 North Cascade Avenue, 14th Floor
Colorado Springs, Colorado 80903
Phone: (719) 442-2600 / Fax: (719) 448-5824
E-mail Jim.Kelly@westmoreland.com
E-mail Ed.Demeter@westmoreland.com

Coal Specifications

Proximate Analysis (as received)	**Typical**
Fixed Carbon	38 33%
Volatile Matter	27 72%
Moisture	25 50%
Ash	8 45%
Sodium as % of Ash	0 32%
Sulfur	0 80%
Btu/lb	8 750
Size	3" x 0" 1" x 0"
Ash Fusion Temp/Reducing Atmosphere:	
Initial	2200°F
Fluid	2330°F

Recoverable Reserves
573 million tons

Annual Production
Permitted for 18 million tons
2002 – 10.0 million tons
2003 – 11.0 million tons

Storage Capacity
90,000 tons

Storage Recharge Rate
60 000 tons per day

Loading & Weighing
Rapid-discharge loadout with belt scale

Loading Rate
3,750 tons per hour

Track Configuration
Loop track holds one unit train on site

Information
Rosebud Mine sells most of its production to The Colstrip Station with the remaining tonnage sold to outside utility and industrial markets

Appendix F

SCR catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals

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SCR catalyst performance in flue gases derived from subbituminous and lignite coals

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Abstract

Lignite and subbituminous coals from the United States of America have characteristics that impact the performance of catalysts used in selective catalytic reduction (SCR) for nitrogen oxide removal and mercury oxidation. Typically, these coals contain ash-forming components that consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. The alkali and alkaline-earth elements are partitioned between reactions with minerals and reactions to form alkali and alkaline-earth-rich oxides during combustion. The particles resulting from the reaction with minerals produce low-melting-point phases that cause a wide range of fireside deposition problems. The alkali and alkaline-earth-rich oxides consist mainly of very small particles (<5 μm) that are carried into the backpasses of the combustion system and react with flue gas to form sulfates, and possibly carbonates. These particles cause low-temperature deposition, blinding, and plugging problems in SCR systems. These coals also contain the very low levels of chlorine that are necessary for mercury oxidation. Slipstream testing was conducted at two selected subbituminous-fired power plants and one lignite-fired power plant to determine the impacts of ash on SCR plugging, blinding, and mercury oxidation. The results indicated a high potential for

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blinding and plugging due to the formation of sulfate-bonded deposits and no evidence for mercury oxidation.

Keywords: Coal; Selective catalytic reduction (SCR); Blinding; NO_x; Mercury; Oxidation

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1. Introduction

Selective catalytic reduction (SCR) for NO_x control and mercury oxidation was investigated using a slipstream reactor at power plants firing subbituminous and lignite coals to determine the potential for ash plugging, catalyst blinding, and mercury oxidation. SCR units lower NO_x emissions by reducing NO_x to N_2 and H_2O. Ammonia (NH_3) is the most common reducing agent used for the SCR of NO_x. The SCR process involves the use of a metal oxide catalyst such as titanium dioxide-supported vanadium pentoxide catalyst (V_2O_5). These units are operated at about 340–370 °C (650–700 °F). Subbituminous and lignitic coals are known for their ability to produce alkali and alkaline-earth sulfate-bonded deposits at low temperature (<1000 °C) in utility boilers. The mechanisms of the formation of low-temperature sulfates have been extensively examined and modeled by the Energy and Environmental Research Center (EERC) in work termed Project Sodium and Project Calcium in the early 1990s [1,2]. Deposit buildup of this type blinds or masks the catalyst, diminishing its reactivity for converting NO_x to N_2 and water and potentially creating increased ammonia slip [3]. Elemental mercury oxidation has been observed in laboratory-, pilot-, and full-scale testing using SCR catalysts [4–6]. In these studies, the metal oxides, V_2O_5 and TiO_2, have been shown to promote the conversion of elemental mercury to oxidized and/or particulate-bound mercury. Full-scale tests in Europe [7] and the United States [8] have indicated that the V_2O_5 and TiO_2 catalyst may promote the formation of oxidized mercury. The ability to oxidize mercury is largely dependent on the composition of the coal [8].

Lignite and subbituminous coals produce ash that plug and blind catalysts [9–12]. The problems currently being experienced on SCR catalysts include the formation of sulfate- and phosphate-based blinding materials on the surface of catalysts and the carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing them on top of the SCR catalysts [3]. The most significant problem that limits the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates, phosphates, and possibly carbonates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency [3,11–14]. The degree of the ash-related impacts on SCR catalyst performance depends upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design [11–15].

Cichanowicz and Broske [13] conducted tests on a South African and a German Ruhr Valley coal and found that the German Ruhr Valley coal significantly increased the pressure drop across the catalyst because of the accumulation of ash. They found that the German coal produced a highly adhesive ash consisting of alkali (K and Na) sulfates. In addition, they reported that the alkali elements are in a water-soluble form and highly

Table 1
Description of power plants tested

	Baldwin	Columbia	Coyote
Unit #	1	2	1
Utility	Dynegy	Alliant	Otter Tail
Boiler type	Cyclone	T-Fired	Cyclone
Fuel type	Antelope—subbituminous	Caballo—subbituminous	Beulah—Zap lignite
Load	Base	Base	Base
Location	Baldwin, IL	Portage, WI	Beulah, ND
MW	600	520	425

mobile and will migrate throughout the catalyst material, reducing active sites. The water-soluble form is typical of organically associated alkali elements in coals. The German Ruhr Valley coal has about 9.5% ash and 0.9% S on an as-received basis, and the ash consists mainly of Si (38.9%), Al (23.2%), Fe (11.6%), and Ca (9.7%), with lower levels of K (1.85%) and Na (0.85%) [13]. Cichanowicz and Muzio [14] summarized the experience in Japan and Germany and indicated that the alkali elements (K and Na) reduced the acidity of the catalyst sites for total alkali content (K+Na+Ca+Mg) of 8–15% of the ash in European power plants. Licata et al. also found that alkaline-earth elements such as calcium react with SO_3 on the catalyst, resulting in plugging of pores and a decrease in the ability of NH_3 to bond to catalyst sites. The levels of calcium in the coals that caused blinding ranged from 3% to 5% of the ash. Studies conducted on the impact of alkali elements associated with biomass found that, when biomass is fired, poisoning and blinding of SCR catalysts occurred [16,17].

The slipstream reactors were installed at three power plants. Two of the plants were cyclone fired: one with lignite and one with subbituminous coal. The third plant was a pulverized-coal, tangentially fired unit with subbituminous coal. The slipstream reactors were designed to expose SCR catalysts to flue gas and particulate matter under conditions that simulate gas velocities, temperatures, and ammonia injection of a full-scale plant. The control system maintains catalyst temperature, pulse air to remove accumulated deposits, constant gas flow across the catalyst, and records pressure drops and temperatures. The reactor was operated in an automated mode and can be controlled via modem connection. Testing at each power plant was conducted over a 6-month period. The reactor was inspected and cleaned at 2-month intervals, and a catalyst section was removed for analysis. The

Table 2
Key selection criteria

Field test 1—Columbia Station
Tangentially fired boiler to show differences in ash partitioning as compared to cyclone-fired systems. High-potential-blinding coal in Caballo, which can be burned nearly 100% for the entire test.
Field test 2—Baldwin Station
Plant is cyclone fired. Units are already equipped to do slipstream testing. Plant currently fires a blend of Antelope and tires; plant is willing to fire 100% Antelope. High potential blinding coal in Antelope.
Field test 3—Coyote Station
Cyclone-fired with lignite. High potential blinding with high alkali and alkaline-earth elements. Coal can have very high sodium contents and is known to cause significant low-temperature deposition.

Table 3
Ultimate analysis results (dry basis)

	Antelope	Caballo	Beulah
Ash content	7.28	6.59	11.62
Total sulfur	0.33	0.51	1.49
Carbon	69.97	67.88	61.50
Hydrogen	4.77	4.83	3.96
Nitrogen	1.05	1.24	1.08
Oxygen (by difference)	16.61	18.96	20.35

catalysts and associated ash deposits were analyzed to determine the characteristics of the ash on the surface and in the pores. In addition, the mercury speciation in the flue gas upstream and downstream of the catalyst was conducted at 2-month intervals during the testing at the lignite-fired plant. The ability of the SCR catalyst materials to catalyze gaseous elemental mercury ($Hg^0[g]$) to a more soluble and chemically reactive $Hg^{2+}X(g)$ forms was evaluated, along with the potential increase in particle-associated mercury, Hg(p). Increasing the oxidized and particulate fractions of mercury has the potential to increase the capture efficiency of mercury by conventional control devices such as wet flue gas desulfurization (FGD) scrubbers and electrostatic precipitators (ESPs).

This paper summarizes pressure drop, formation of deposits that blind the surface of the catalyst, and the ability of SCR catalysts to oxidize mercury.

2. Experimental

2.1. Overview of test program and fuel characteristics

A portable SCR slipstream reactor system was designed and constructed to conduct full-scale evaluation of the SCR catalyst ash plugging and blinding and mercury oxidation. A particle-laden flue gas slipstream was isokinetically extracted from the flue gas duct ahead of the air heater at full-scale utilities using an induced-draft fan. Two systems were constructed

Table 4
Ash composition (wt.% equivalent oxide)

Oxide	Antelope	Caballo	Beulah
SiO_2	24.82	26.70	16.50
Al_2O_3	13.55	16.60	13.30
TiO_2	1.39	1.10	0.80
Fe_2O_3	7.52	5.10	16.60
CaO	26.68	25.10	19.50
MgO	7.14	8.00	7.40
K_2O	0.17	0.30	0.20
Na_2O	1.47	1.00	5.20
P_2O_5	0.90	1.70	0.00
SO_3	16.33	14.40	19.80

so that data may be collected simultaneously from two full-scale sites. Testing was conducted at three boilers, including tests on a cyclone boiler firing Powder River Basin (PRB) coal, a lignite-fired cyclone boiler, and a pulverized coal boiler burning PRB. SCR catalysts were exposed to flue gases and combustion-derived fly ash particles for 6-month time periods to study the blinding effect of fly ash and ash deposits on catalyst performance.

The electric utility units selected for testing are shown in **Table 1**. The plants where the SCR slipstream system was installed included Alliant Energy's Columbia Station, Dynegy's Baldwin Station, and Otter Tail Power Company's Coyote Station. **Table 1** describes the plants, and **Table 2** summarizes the characteristics and selection criteria.

The units tested were selected based on the fuels fired, boiler type, and availability of the unit for sampling. The average composition of the coals fired during the testing is

Table 5
CCSEM analysis results for Beulah, Antelope, and Caballo (values are wt.% on a mineral basis)

	Caballo	Antelope	Beulah
Total mineral wt % on a coal basis	2.8	3.2	8.4
Quartz	40.4	31.5	11.0
Iron oxide	0.0	2.4	4.4
Periclase	0.0	0.0	0.0
Rutile	2.4	0.3	0.0
Alumina	0.0	0.0	1.1
Calcite	0.0	0.4	0.1
Dolomite	0.0	0.5	0.0
Ankerite	0.0	0.0	0.2
Kaolinite	23.7	17.1	4.9
Montmorillonite	0.4	6.5	6.6
K Al-silicate	0.0	1.6	7.2
Fe Al-silicate	0.0	0.8	9.0
Ca Al-silicate	0.1	1.0	2.6
Na Al-silicate	0.0	0.0	0.1
Aluminosilicate	0.7	3.3	3.2
Mixed Al-silicate	0.0	1.0	5.5
Fe silicate	0.0	0.0	0.0
Ca silicate	0.0	0.4	0.0
Ca aluminate	0.0	0.0	0.0
Pyrite	16.2	0.0	0.8
Pyrrhotite	0.0	4.8	18.4
Oxidized pyrrhotite	0.0	0.5	0.5
Gypsum	0.4	0.0	0.5
Barite	0.8	0.5	3.0
Apatite	0.0	0.2	0.0
Ca Al-P	8.5	13.5	0.1
KCl	0.0	0.0	0.0
Gypsum/barite	0.0	0.1	0.0
Gypsum/Al-silicate	0.1	0.9	4.0
Si-rich	0.3	3.7	4.9
Ca-rich	0.0	0.0	0.0
Ca–Si-rich	0.0	0.1	0.0
Unclassified	3.2	8.7	11.9
Total	100.0	100.0	100.0

listed in **Tables 3 and 4**. The subbituminous coals were typically low ash, nominally 4.5% to 5.5% with very high levels of calcium in the ash. In comparison, the lignite contains higher levels of ash and lower calcium but higher levels of sodium. The alkali and alkaline-earth elements are primarily associated with the organic matrix of the coal as salts of carboxylic acid groups [18]. The portion of the ash-forming components that are associated with the organic matrix of the coal for subbituminous coal ranges from 30% to 60% [18]; for the lignite coal, the portion is about 20% to 40%. The remaining ash-forming components consist of mineral grains. For these coals, the percent organically associated is 29% for the Antelope, 36% for Caballo, and 19% for Beulah. The minerals present in the coals determined by computer-controlled scanning electron microscopy (CCSEM) analyses are listed in **Table 5**. The primary minerals present in the subbituminous coals include quartz and various clay minerals with some pyrite and a mineral that is rich in Ca, Al, and P. This mineral has been identified in some coals as crandalite. The primary minerals found in the Beulah coal include clay minerals (kaolinite), pyrite, and quartz.

2.2. SCR slipstream system

The SCR slipstream system consists of two primary components: the control room and the SCR reactor. The reactor section consists of a catalyst section, an ammonia injection system, and sampling ports for NO_x at the inlet and exit of the catalyst section. The control

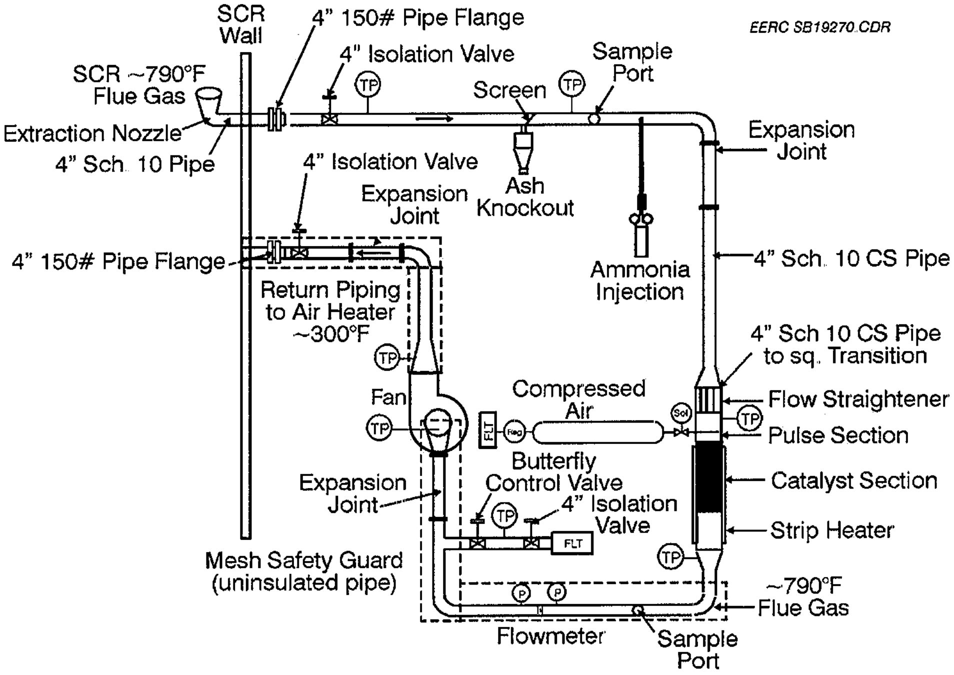


Fig. 1. Schematic diagram of SCR slipstream system.

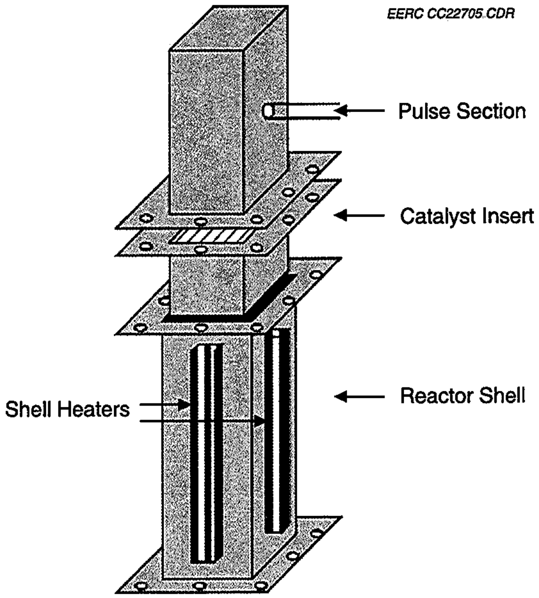


Fig. 2. Diagram of reactor section SCR slipstream system.

room houses a computer system that logs data and controls the gas flow rates, temperatures, pressure drop across the catalyst, and sootblowing cycles. The computer was programmed to maintain constant temperature of the catalyst, gas flow rates, sootblowing cycles, and ammonia injection. The computer is equipped with a modem that

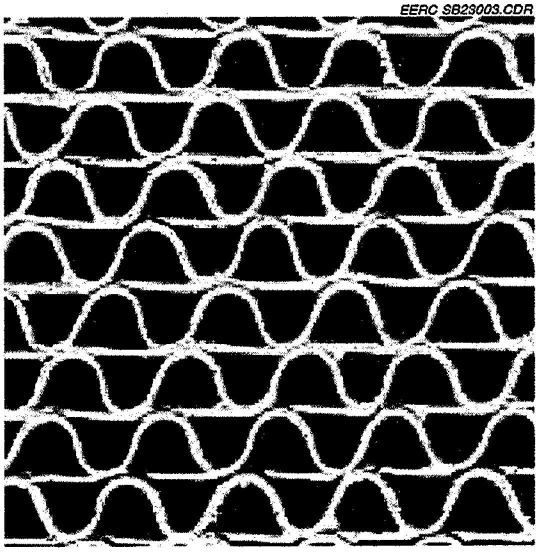


Fig. 3. Haldor Topsoe SCR catalyst showing the gas flow passages.

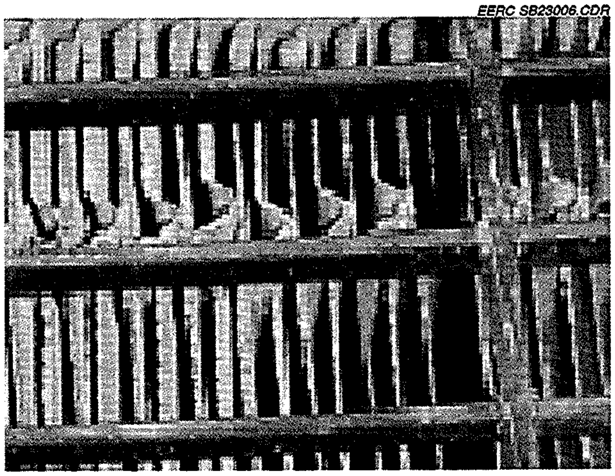


Fig. 4. Babcock Hitachi SCR catalyst showing the gas flow passages.

allowed for downloading of data and modification of the operation of the reactor from a remote computer located at the EERC.

A schematic diagram of the SCR slipstream system is shown in Fig. 1. Flue gas is isokinetically extracted from the convective pass of the boiler upstream of the air heater. The temperature is typically about 790 °F. The flue gases pass through a 4-in. pipe equipped with sampling, thermocouple, and pressure ports. Ammonia is injected into the piping upstream of the reactor section. The reactor consists of a steel housing that is approximately 8.5 in. square and 8 ft long. The reactor section illustrated in Fig. 2 has three components, including a flow straightener, a pulse section or sootblower, and a catalyst test section. A metal honeycomb is used as a flow straightener upstream of the catalyst section and is about 6 in. long. A purge section was installed ahead of the catalyst test section to remove accumulated dust and deposits. The catalyst test section is located downstream of the purge section. The entire catalyst section is insulated and equipped with strip heaters for temperature control. The catalyst test section is 3.28 ft (1 m) in length and houses three catalyst sections. Thermocouple and pressure taps are located in the purge sections for measurements before and after each section.

The induced-draft fan is used to extract approximately 400 acfm (200 scfm) of flue gas from the convective pass of the utility boiler to achieve an approach velocity of 5.2 m/s

Table 6
Selected operating conditions of the SCR catalysts

Plant name	Average SCR inlet temperature (°F)	Average SCR outlet temperature (°F)	Air pulse frequency	Flue gas flow rate (acfm)
Baldwin	645	549	Once per day and on demand	393
Columbia	672	662	Once per day and on demand	385
Coyote	675	667	Once per day and on demand	385

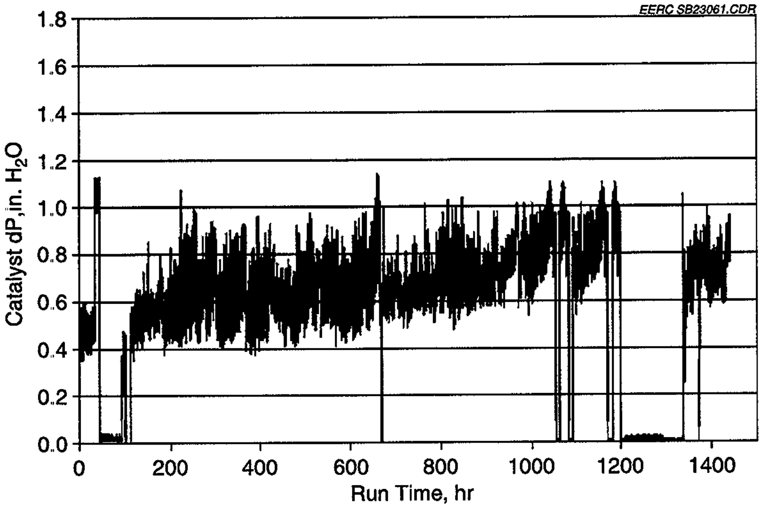


Fig. 5. Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.

(17.0 ft/s). The total gas flow through the reactor represents a thermal load of approximately 300 kW.

The range of operating conditions for the reactor is listed below:

- Gas temperature: ~700–800 °F
- Gas flow rate: 400–500 acfm
- Approach velocity range: 5.0–5.5 m/s
- Ammonia injection rate: 0.5:1 with NO_x level
- Tempering air for fan: ~50–200 scfm

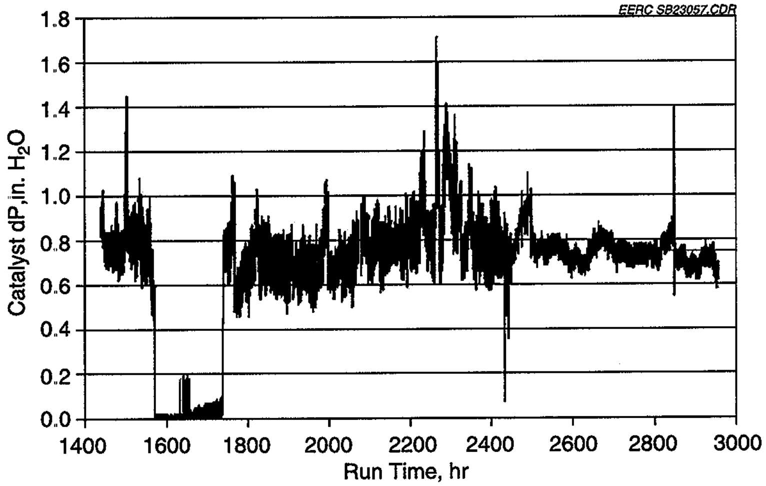


Fig. 6. Catalyst pressure drop at Baldwin Station at 2 to 4 months of operation.

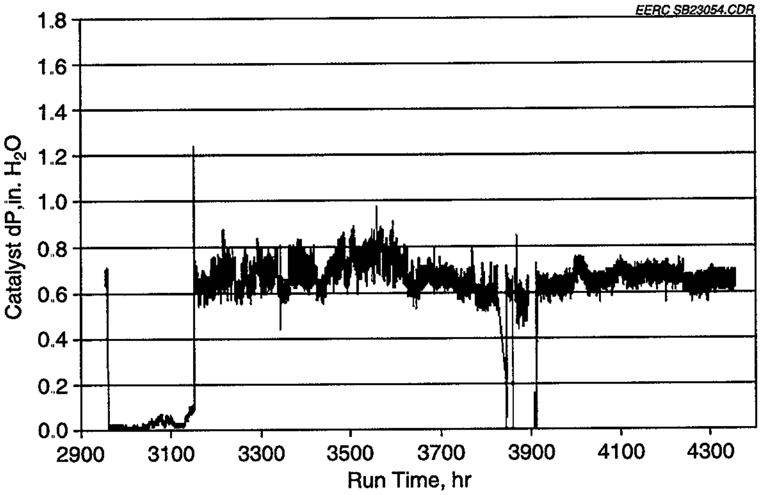


Fig. 7. Catalyst pressure drop at Baldwin Station at 4 to 6 months of operation.

- Catalyst dP: 0.5–1.0 in. water column
- Fan sized for up to 30 in. water column.

2.2.1. SCR catalyst

The catalyst installed at the Baldwin and Coyote Stations was the Haldor Topsoe catalyst. Topsoe's DNX-series of catalysts comprises SCR DENOX catalysts tailored to suit a comprehensive range of process requirements. DNX-series catalysts are based on a corrugated, fiber-reinforced titanium dioxide (TiO_2) carrier impregnated with the active components vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels. The unique catalyst design provides a highly porous structure with a large surface area and an ensuing

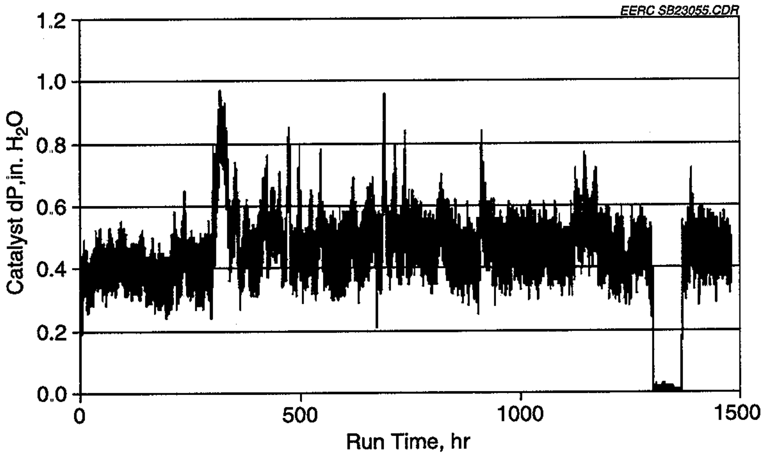


Fig. 8. Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.

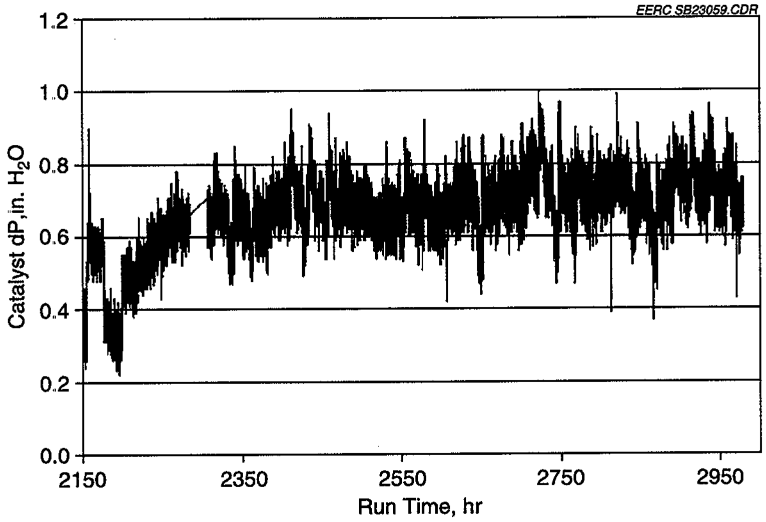


Fig. 9. Catalyst pressure drop at Columbia Station at 2 to 4 months of operation.

large number of active sites. Fig. 3 is an image of the Haldor Topsoe SCR catalyst. The pitch of the catalyst was approximately 6 mm.

The catalyst installed at the Columbia Station was a Babcock Hitachi plate-type catalyst. This catalyst is a TiO_2-based plate catalyst, developed and manufactured by Hitachi. Fig. 4 shows the design of the catalyst. The pitch of the catalyst was approximately 10 mm.

2.2.2. System performance measurement

Upon installation at each utility boiler unit, flue gas temperature, composition, and velocity measurements were obtained using portable equipment. Shakedown testing of the

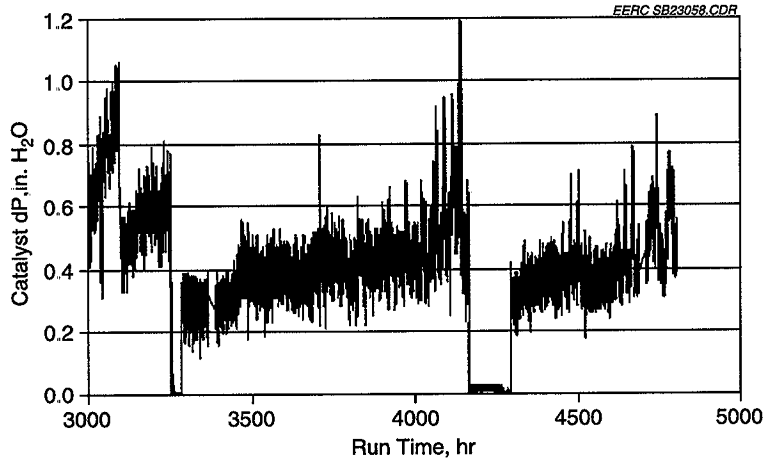


Fig. 10. Catalyst pressure drop at Columbia Station at 4 to 6 months of operation.

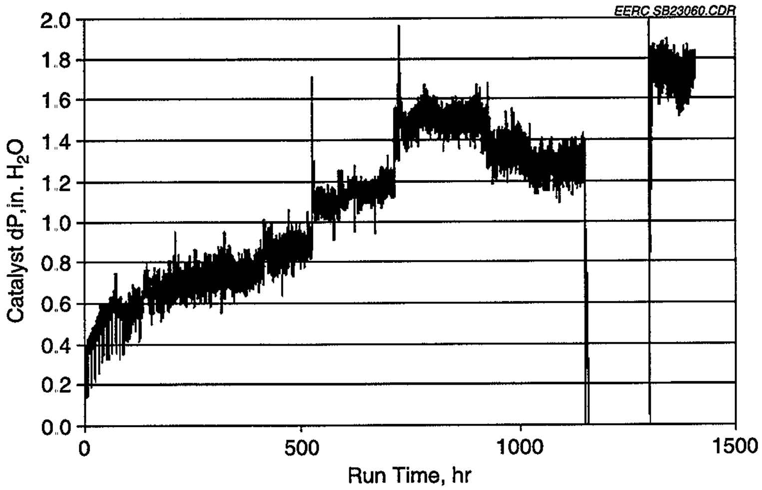


Fig. 11. Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.

unit was conducted to ensure that all components were operating properly and that data were being logged and could be retrieved. After installation and shakedown were completed, the reactor was operated in a computer-controlled, automated mode and monitored on a daily basis to ensure proper operation and data quality. During operation of the SCR slipstream system, catalyst temperature, sootblowing frequency, and pressure drop across the catalyst were monitored and logged. Samples of the exposed SCR catalyst and associated deposits were obtained after exposure to flue gas and particulate for 2, 4, and 6 months. The samples of the catalyst were analyzed to determine the components that were bonding and filling pores, resulting in decreased reactivity.

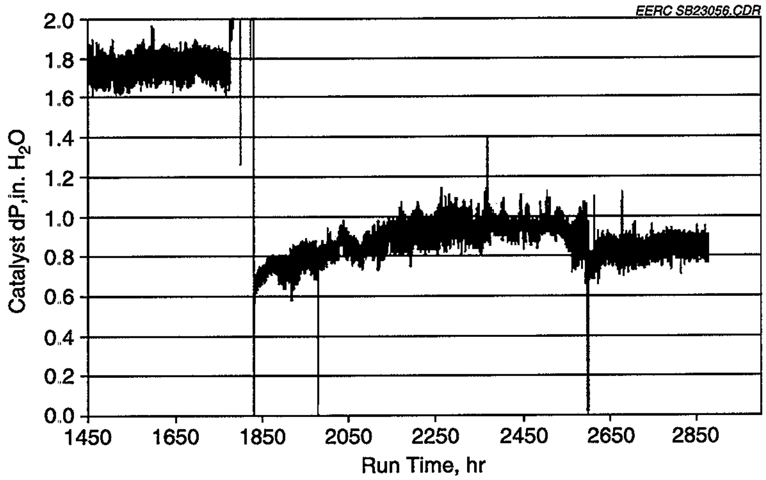


Fig. 12. Catalyst pressure drop at Coyote Station 2 to 4 months of operation.

The characteristics of ash that accumulated on the catalyst were examined using SEM–X-ray microanalysis and X-ray diffraction (XRD) [18]. Correlations between the physical and chemical characteristics of any ash deposits on the SCR test section and entrained-ash sample collected at the chamber inlet and the coal inorganic composition will be made to

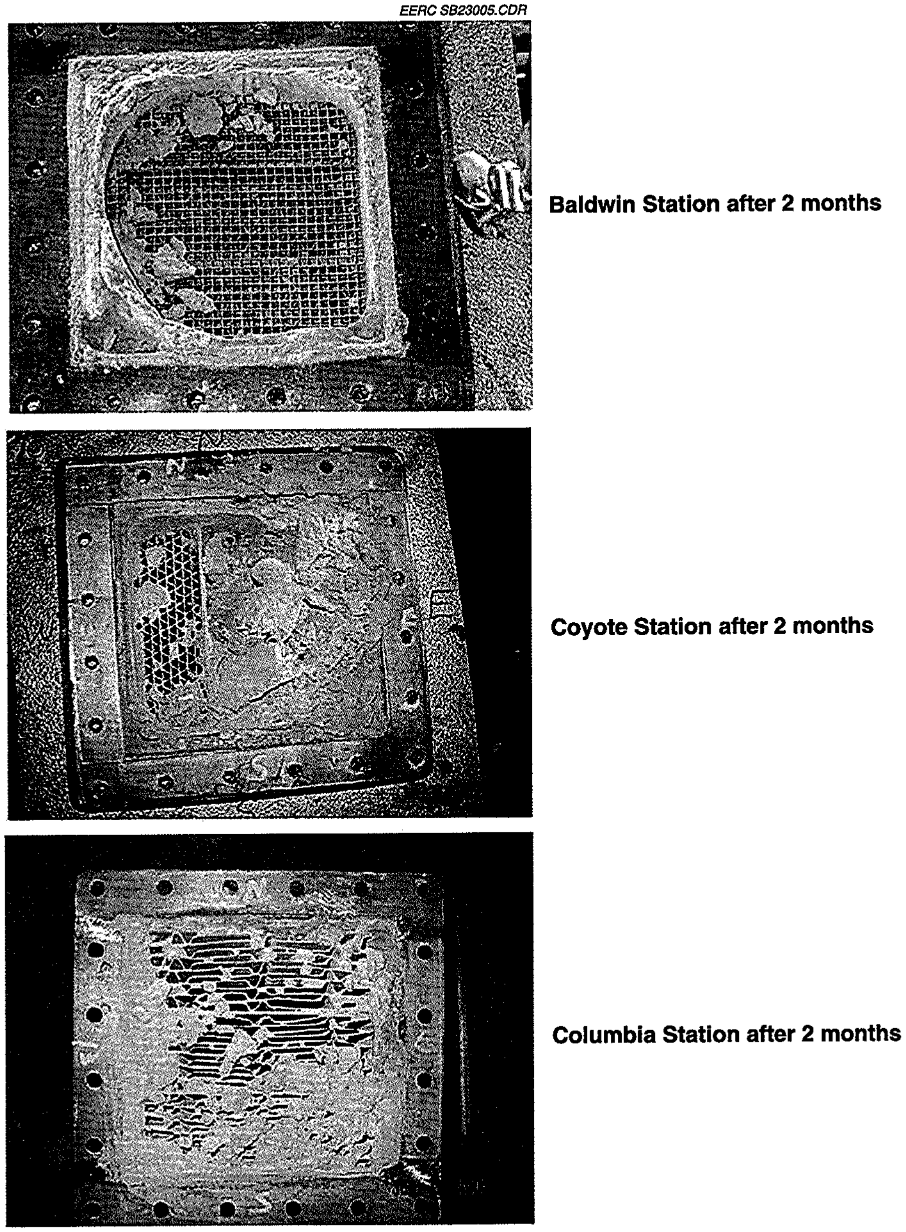


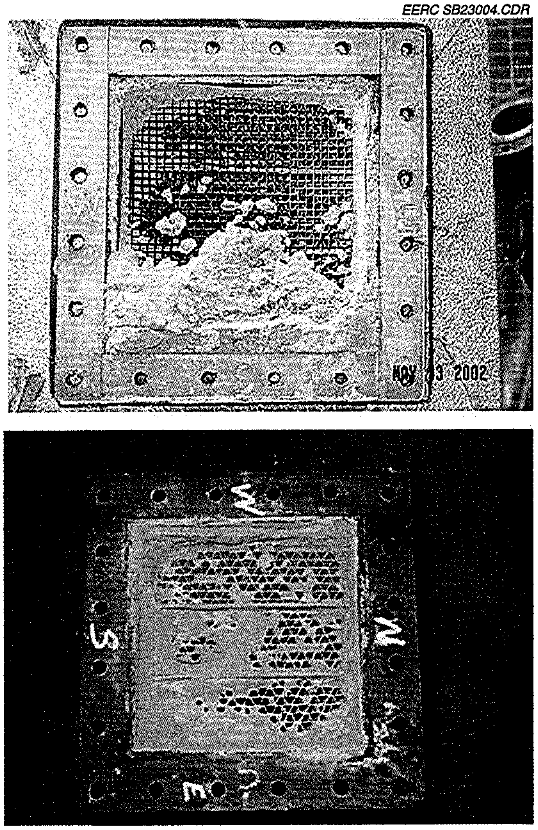
Fig. 13. Pictures of catalyst inlet after about 2 months of testing at each plant.

discern mechanisms of SCR blinding. Entrained ash was collected at Columbia Station only and characterized to composition and size.

2.3. Analysis of flue gas constituents across the catalyst—Ontario Hydro method for mercury speciation

At the Coyote Station, the Ontario Hydro (OH) mercury speciation sampling train was used to determine mercury forms across the SCR test section. The OH extractive mercury speciation sampling technique was used to measure potential mercury conversion across the SCR system over a period of several hours after fresh installation of the SCR test chamber and again just prior to removal of SCR catalyst sections.

The procedure used to conduct the mercury speciation sampling was American Society for Testing and Materials (ASTM) Method 06784-02 entitled "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" [19].



Baldwin Station after 4 months

Coyote Station after 4 months

Fig. 14. Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.

The OH method follows standard EPA methods for isokinetic flue gas sampling (EPA Methods 1–3 and EPA Method 5/17). A sample is withdrawn from the flue gas stream isokinetically through the filtration system, which is followed by a series of impingers in

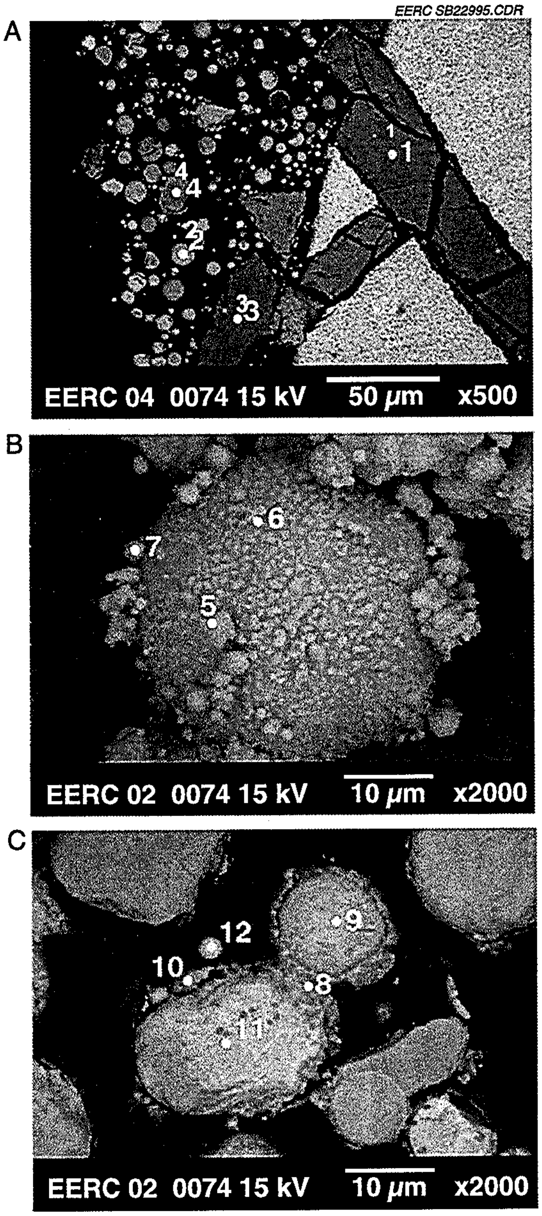


Fig. 15. SEM images of ash collected on catalyst surface at the Baldwin Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) high-magnification image of coated ash particle, and (C) high-magnification image of polished cross section showing coatings on particles.

an ice bath. Particulate-bound mercury is collected on the filter; Hg^{2+} is collected in impingers containing 1 N potassium chloride solution; and elemental mercury is collected in one impinger containing a 5% nitric acid and 10% peroxide solution and in three impingers containing a solution of 10% sulfuric acid and 4% potassium permanganate. An impinger containing silica gel collects any remaining moisture. The filter media is quartz fiber filters. The filter holder is glass or Teflon-coated. An approximate 2-h sampling time was used, with a target sample volume of 1 standard cubic meter.

3. Results and discussion

3.1. Pressure drop

3.1.1. Testing at the Baldwin Station

The reactor was installed at the Baldwin Station and operated for a 6-month time period on the Haldor Topsoe catalyst. The information obtained from testing included pressure drop, sootblowing cycles, and reactor temperatures. Table 6 summarizes the operating conditions of the reactors during the testing periods at all plants. Figs. 5–7 show the pressure drop across the catalyst test periods from 0 to 2 months, 2 to 4 months, and 4 to 6 months, respectively. During the first 2 months of operation, the pressure shown in Fig. 6 was about 0.5 in. of water; at the end of 2 months, the pressure drop was about 0.8 in. of water, indicating plugging had occurred. The air was pulsed a minimum of every 8 h in an attempt to maintain cleanliness. The reactor was monitored on a daily basis, and adjustments in pulsing cycles were made in order to minimize deposit accumulation. However, for the first 2 months, the pressure drop steadily increased. There are several periods where the unit was taken off-line; during those times, the temperature of the catalyst was maintained. At 2-month intervals, a section of catalyst was removed and replaced with a new one.

Table 7
Chemical composition of selected points and areas in Fig. 15

Element (wt.%)												
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
Na_2O	0.2	0.0	0.2	2.3	2.5	3.0	3.6	0.7	0.6	1.6	0.4	0.9
MgO	0.0	6.3	0.0	3.1	3.0	1.3	1.6	2.5	4.5	3.0	3.6	3.5
Al_2O_3	3.6	17.9	6.9	29.6	8.4	5.5	4.4	5.4	22.7	12.2	21.2	14.2
SiO_2	92.1	5.9	86.5	39.9	3.4	53.2	15.7	3.4	16.1	1.0	8.1	2.3
P_2O_5	0.1	0.4	0.0	0.0	1.8	0.0	1.5	0.3	0.5	2.3	0.0	4.6
SO_3	3.3	0.4	5.2	0.1	51.8	18.1	52.4	53.0	0.0	46.4	0.0	19.7
K_2O	0.0	0.0	0.0	0.6	0.4	0.5	0.7	0.2	0.0	0.1	0.0	0.0
CaO	0.0	49.4	0.1	18.6	16.4	14.6	13.0	28.8	41.5	27.1	51.1	39.2
TiO_2	0.7	4.5	0.4	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe_2O_3	0.0	14.6	0.7	3.6	12.3	3.8	7.1	5.7	14.2	6.5	15.6	15.6
BaO	0.0	0.6	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	100	100	100	100	100	100	100	100	100	100	100	100

For Months 2 through 4, the pressure drop was highly variable initially but was about 0.8 in. of water. From Months 4 through 6, the pressure drop was maintained between 0.6 and 0.8 in. of water. This is due to the installation of a fresh catalyst section and leaving two thirds of the catalysts in place that partially plugged. The gas velocity in the single section of new, clean catalyst was high because of channeling, and the result of the high gas flow was less deposition and accumulation. Gas velocity has a significant impact on the potential for deposits to form. However, at high gas velocity, low NO_x conversion is likely.

3.1.2. Testing at Columbia

The reactor was installed at the Columbia Station and operated for a 6-month period of time for the Babcock Hitachi catalyst. The information obtained from the testing included pressure drop information, sootblowing cycles, and reactor temperature. Table 6 shows the reactor temperature, air-pulsing cycles, and airflow rates. Figs. 8–10 show the test periods from 0 to 2 months, 2 to 4 months, and 4 to 6 months, respectively. The pressure drop across the SCR upon installation was about 0.4 in. of water and increased to an average of

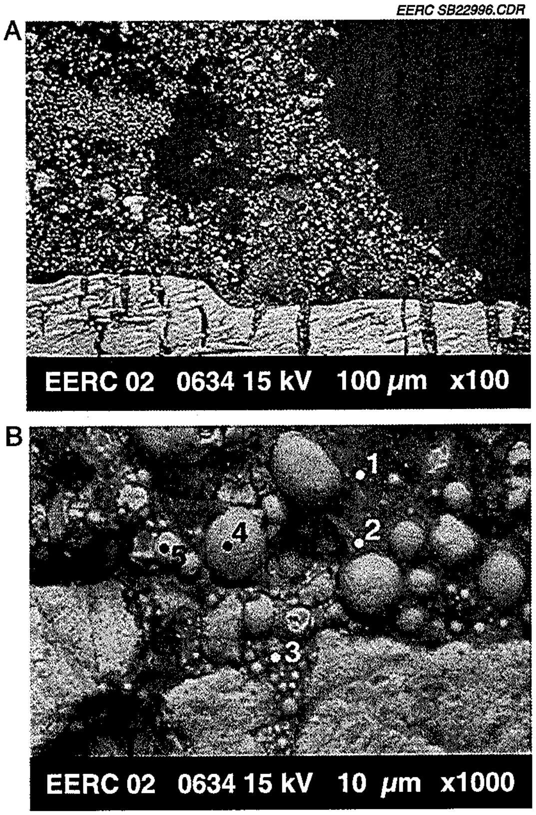


Fig. 16. SEM images of ash collected on catalyst surface at the Baldwin Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, and (B) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

about 0.5 in. of water, but ranged from less than 0.4 to greater than 0.8 in. of water. **Fig. 9** shows the pressure drop for Months 2 to 4. The pressure drop increased from about 0.5 to 0.7 in. of water because of accumulation of ash. **Fig. 10** shows a rapid increase in pressure drop across the catalyst at about 3000 h of operation, and aggressive pulsing brought it down to 0.4 in. of water until the catalyst section was changed out at about 3200 h. After cleaning the reactor and replacing one catalyst section, the pressure drop was about 0.3 but increased to over 0.6 in. of water up to about 4100 h. There was an outage at the plant, and aggressive pulsing of the reactor was conducted; the pressure drop was brought back down to 0.3 but rapidly increased to over 0.5 in. of water within 500 h.

3.1.3. *Testing at Coyote*

The same reactor that was installed at the Baldwin Station was moved and installed at the Coyote Station. In addition, the same Haldor Topsoe catalyst was used in the reactor. The cleaning cycles, temperatures, and gas flow rates are listed in **Table 6**. The reactor was operated for a 6-month period of time. **Figs. 11 and 12** show the test periods from 0 to 2 months and 2 to 4 months. As this paper is being prepared, the reactor is still operating on-site. The pressure drop across the catalyst upon installation was about 0.4 in. of water. After only 750 h, the pressure drop was 1.5 in. of water, indicating significant plugging. Very aggressive air pulsing was conducted, with little success in removing the deposits. The pressure drop for the catalyst was over two times greater than the pressure drop observed for the Baldwin Station utilizing the same reactor and same catalyst. At about 1700 h, the reactor was cleaned, and a section of catalyst was removed for characterization. The pressure drop after cleaning was about 0.8 to 1.0 in. of water. The pressure drop did not increase as rapidly because of the higher velocities through the clean section of the catalyst.

3.1.4. *Visual observations of deposit characteristics*

The tops of the catalysts were photographed during inspection and sampling of the catalyst sections. **Fig. 13** shows the ash materials that accumulated on the catalyst inlet after 2 months of operation. The most significant accumulation was noted for the Coyote

Table 8
Chemical composition of selected points and areas in Fig. 16

Element (wt.%)					
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5
Na_2O	1.7	2.3	0.0	0.3	1.0
MgO	5.9	3.0	1.2	1.8	3.8
Al_2O_3	3.7	2.5	3.3	5.7	6.3
SiO_2	9.7	31.5	13.3	70.0	18.5
P_2O_5	3.1	2.7	0.8	0.0	2.6
SO_3	48.1	31.0	35.8	0.0	32.1
K_2O	0.5	0.7	0.0	1.5	0.0
CaO	22.0	8.8	38.0	13.9	14.7
TiO_2	1.8	10.8	4.1	1.6	15.1
Fe_2O_3	2.1	6.6	3.4	4.2	5.9
BaO	1.4	0.0	0.0	0.9	0.0
Total	100	100	100	100	100

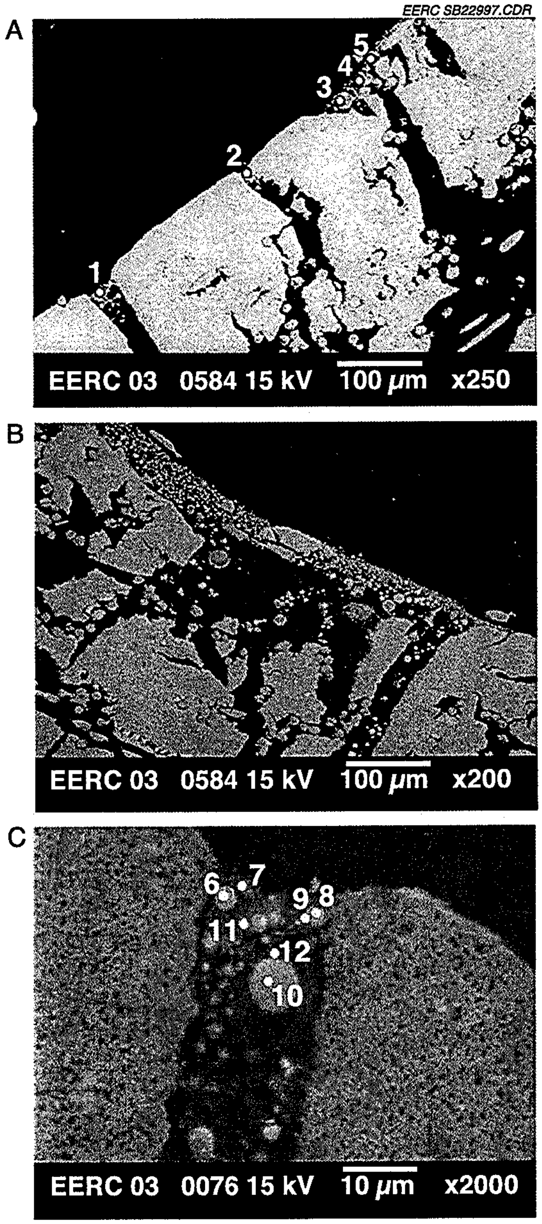


Fig. 17. SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure. (A and B) Low-magnification images of ash deposit on catalyst surface and (C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

Station, followed by Columbia and Baldwin. The Coyote Station had some larger pieces of ash deposit material on the surface as well as plugging of the catalyst passages. The Baldwin Station showed some obvious deposition along the walls of the reactor and some accumulation on the inlet sections. The Columbia Station showed more significant accumulation and plugging than the Baldwin Station.

After 4 months, the tops of the catalysts were photographed during inspection and sampling of the catalyst sections, as shown in Fig. 14. The most significant accumulation was noted for the Coyote Station and some accumulation for the Baldwin Station.

3.2. Deposit characteristics

The characteristics of the ash materials that collected on the catalyst surfaces and pores were characterized by SEM and X-ray microanalysis and, in selected cases, XRD was used to determine the crystalline phases present. The catalysts were sampled after 2, 4, and 6 months. The sections were sampled, and approximately 2.5-cm squares were mounted for SEM analysis on double-stick tape and in epoxy resin. The double-stick tape samples allowed for characterization of the external morphology of the particles and catalyst surface. The samples mounted in resin were cross-sectioned and polished, which allowed for more detailed and quantitative analysis of the bonding materials and materials that accumulated in the pores of the catalyst.

3.2.1. Plugging deposit characteristics

3.2.1.1. Baldwin Station deposits. Samples of catalyst were removed from the Baldwin Station after exposure to flue gases and particulate after 2, 4, and 6 months. Fig. 15 shows the characteristics of the ash deposit material on the SCR catalyst after 2 months of exposure. This is a polished cross section of a deposit on the surface of the catalyst. Fig. 15A shows particles on the surface of the catalyst that range in size from <1 to 15 μm. The larger particles range from oxides of solely silicon and iron to complex mixtures rich in

Table 9
Chemical composition of selected points and areas in Fig. 17

Element (wt.%)												
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
Na_2O	0.6	1.0	2.1	0.3	0.5	2.7	1.7	0.4	0.5	2.2	1.3	1.7
MgO	4.3	2.5	6.3	0.7	1.6	7.6	4.5	6.4	5.9	5.0	3.4	6.4
Al_2O_3	14.8	16.0	15.6	15.5	14.7	0.9	5.0	2.4	3.0	19.2	10.8	3.8
SiO_2	3.3	7.8	18.8	57.7	7.7	47.3	8.4	18.4	18.5	31.0	17.9	16.7
P_2O_5	2.3	2.1	0.5	0.6	1.8	0.0	1.8	0.9	1.0	0.0	1.7	1.2
SO_3	30.7	20.4	17.7	0.0	29.0	0.8	37.9	1.7	5.3	0.0	22.5	13.9
K_2O	0.7	0.0	1.0	0.4	0.9	0.9	0.4	0.0	0.0	0.9	0.8	0.0
CaO	28.8	28.7	28.1	22.5	34.9	28.4	31.4	52.6	49.0	28.9	30.6	45.4
TiO_2	2.0	7.2	2.2	0.3	1.3	1.1	1.9	6.9	7.4	2.4	2.0	1.1
Fe_2O_3	11.4	12.9	6.2	0.0	7.6	7.9	7.1	5.7	6.0	6.3	6.1	6.5
BaO	1.1	1.4	1.4	2.0	0.0	2.5	0.0	4.6	3.5	4.2	2.9	3.3
Total	100	100	100	100	100	100	100	100	100	100	100	100

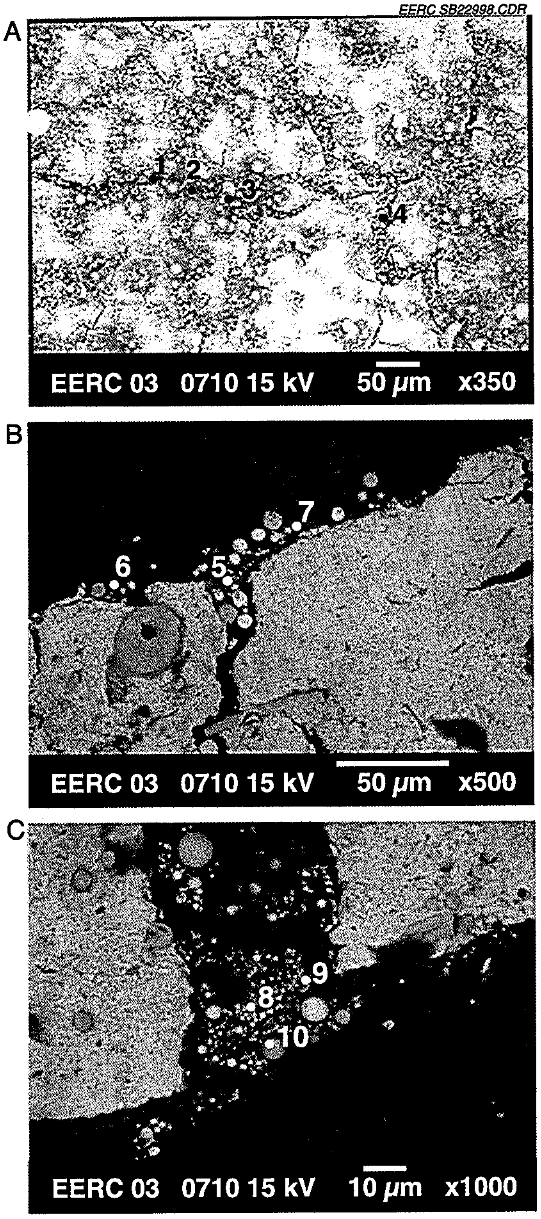


Fig. 18. SEM images of ash collected on catalyst surface at the Columbia Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

aluminum and calcium; aluminum, silicon, and calcium; aluminum, calcium, and iron; and sodium, calcium, aluminum, and silicon. Chemical analysis of selected particles is summarized in Table 7. The samples of ash mounted on double-stick tape allow for the characterization of the external surfaces of the particles. The surface of a typical particle that is accumulating on the surface of the catalyst is shown in **Fig. 15B**. The blebs on the surface are composed of calcium and sulfur, with some iron and minor amounts of sodium and potassium. **Fig. 15C** shows a cross section of the deposited particles showing calcium- and aluminum-rich particles bonded together with a calcium- and sulfur-rich phase. This phase is in the form of calcium sulfate based on XRD analysis conducted on the deposited ash samples.

The 4-month sample from the Baldwin Station showed more extensive sulfation of the alkaline-earth elements present in the deposits. **Fig. 16** shows the images of a polished cross section of an ash deposit on the surface of the catalyst. The deposit formed both on the surface of the catalyst and within the catalyst pores as shown in **Fig. 16A**. **Fig. 16B** shows a higher magnification view of the deposit on the catalyst surface. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical composition of selected points shown in **Table 8** shows high levels of calcium and sulfur. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample.

The 6-month sample from the Baldwin Station showed extensive sulfation of the alkaline-earth elements present in the deposits. **Fig. 17A and B** shows regions of the catalyst where all the pores were blocked and a minimal amount of deposit on the surface of the catalyst. **Fig. 17C** shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical compositions of selected points that indicate the presence of high levels of calcium and sulfur are listed in **Table 9**. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample. In addition, there are some regions of high levels of calcium, aluminum, and sulfur present. The calcium aluminum materials are likely derived from the calcium aluminum phosphate minerals found in the coal fired at this plant.

Table 10
Chemical composition of selected points and areas in Fig. 18

Element (wt.%)										
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10
Na_2O	0.0	0.9	1.3	0.1	0.3	0.0	0.6	1.0	0.5	1.8
MgO	0.7	1.5	3.2	3.9	0.9	0.0	1.5	2.9	1.4	0.7
Al_2O_3	12.2	17.6	20.9	12.2	5.9	5.5	12.4	13.6	9.0	20.7
SiO_2	10.8	4.1	23.3	7.3	6.3	9.4	6.1	15.4	7.9	61.8
P_2O_5	0.9	0.1	0.0	1.4	2.6	1.2	0.6	1.7	3.1	0.2
SO_3	15.2	17.6	16.8	17.1	32.3	33.3	22.0	19.5	30.7	0.0
K_2O	0.2	0.0	0.5	0.0	0.1	0.0	0.0	0.1	0.2	2.5
CaO	14.1	43.1	25.0	42.0	34.9	44.1	48.5	34.1	38.3	4.4
TiO_2	44.8	2.8	1.1	10.5	5.2	0.5	4.4	2.4	2.6	2.2
Fe_2O_3	1.1	12.3	3.9	5.5	11.5	3.1	2.3	6.0	6.3	4.4
BaO	0.0	0.0	4.2	0.0	0.0	2.8	1.6	3.3	0.0	1.3
Total	100	100	100	100	100	100	100	100	100	100

3.2.1.2. Columbia Station deposits. The 2-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst, as shown in Fig. 18. Fig. 18A shows the external morphology of the catalyst surface showing

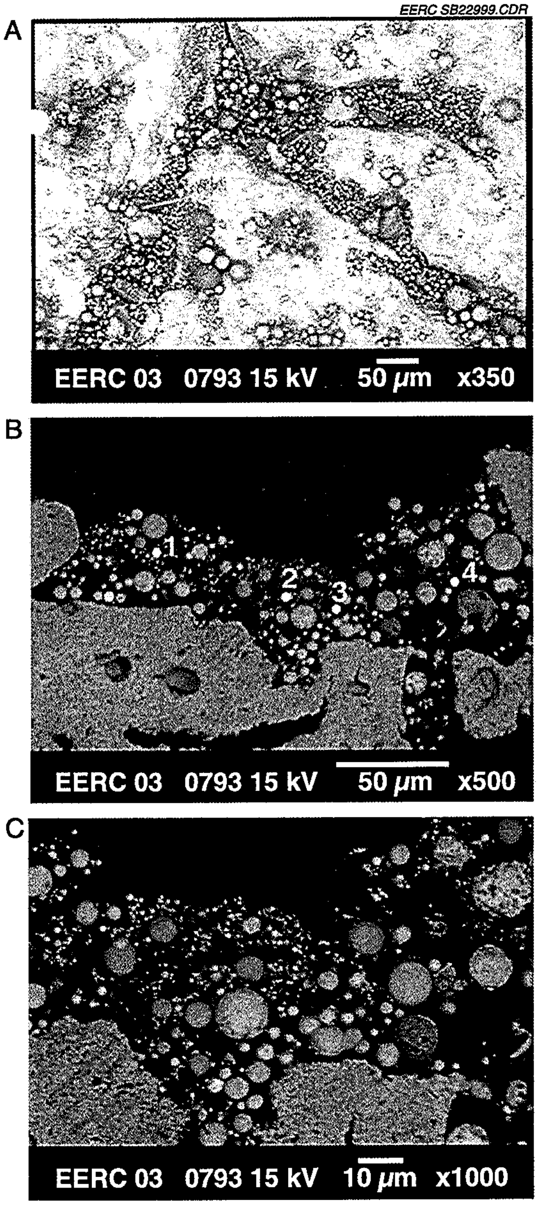


Fig. 19. SEM images of ash collected on catalyst surface at the Columbia Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in **Table 10**. The 2-month sample shows significant evidence of sulfation after only 2 months of exposure. It appears to be more significant than that observed for the Baldwin 2-month sample. **Fig. 18B** and C shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate.

The 4-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst, as shown in **Fig. 19**. **Fig. 19A** shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in **Table 11**. It appears to be more significant than that observed for the Baldwin 2-month sample. **Fig. 19B** and C shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate.

The 6-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst as shown in **Fig. 20**. **Fig. 20A** shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in **Table 12**. **Fig. 20B** and C shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The 6-month samples show the most extensive degree of sulfation of the Columbia Station samples.

3.2.1.3. Coyote Station deposits. The 2-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst as shown in **Fig. 21**. **Fig. 21A** shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in **Table 13**.

Table 11
Chemical composition of selected points and areas in Fig. 19

Element (wt.%)				
Oxide	Point 1	Point 2	Point 3	Point 4
Na_2O	0.5	0.0	0.6	0.3
MgO	3.3	1.9	3.2	2.4
Al_2O_3	13.1	10.2	13.0	6.3
SiO_2	12.4	8.4	8.4	3.6
P_2O_5	1.3	0.5	2.1	0.6
SO_3	27.7	29.9	32.2	47.4
K_2O	0.2	0.6	0.1	0.8
CaO	32.1	38.1	28.9	33.2
TiO_2	1.0	2.7	1.3	0.0
Fe_2O_3	6.3	6.3	7.6	2.6
BaO	2.0	1.4	2.5	2.6
Total	100	100	100	100

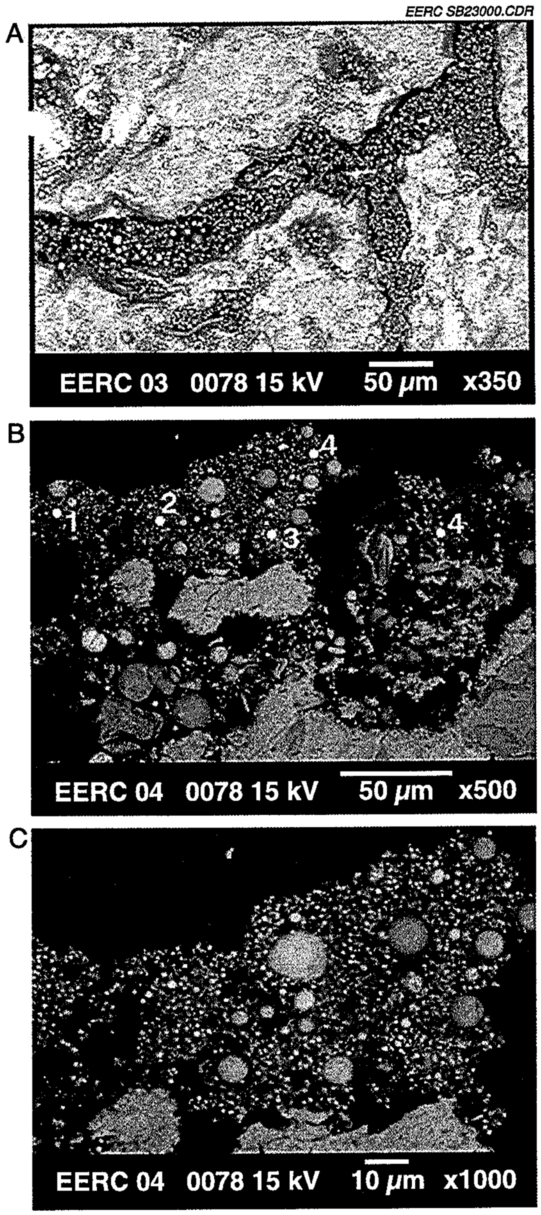


Fig. 20. SEM images of ash collected on catalyst surface at the Columbia Station after 6 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

The 2-month sample shows significant evidence of sulfation after only 2 months of exposure and was much more pronounced than the 2-month samples for the Baldwin and Columbia Stations that are fired on PRB coals. Fig. 21B and C shows a higher

Table 12
Chemical composition of selected points and areas in **Fig. 20**

Element (wt.%)				
Oxide	Point 1	Point 2	Point 3	Point 4
Na_2O	0.1	0.0	0.3	0.6
MgO	1.8	0.7	1.7	2.2
Al_2O_3	10.9	9.6	6.2	11.3
SiO_2	13.1	11.3	12.4	19.5
P_2O_5	3.9	4.8	0.2	2.1
SO_3	27.6	34.0	35.5	30.0
K_2O	0.5	0.3	0.1	1.2
CaO	33.0	25.9	39.8	25.8
TiO_2	0.8	2.5	1.6	3.3
Fe_2O_3	6.1	9.7	1.9	2.9
BaO	2.1	1.2	0.0	1.1
Total	100.00	100.00	100.00	100.00

magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The presence of sodium enhances the bonding and sulfation of the particles to form a strongly bonded matrix.

The 4-month sample from the Coyote Station showed particles adhering to the surface and completely filling and masking the pores in the catalyst as shown in **Fig. 22**. **Fig. 22A** shows the external morphology of the catalyst surface showing the masking of the catalyst surface. Chemical compositions of selected points are shown in **Table 14**. The 4-month sample shows more sulfation than the 2 months of exposure samples. **Fig. 22B and C** shows a higher magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of sodium-, calcium-, and sulfur-rich material, likely in the form of calcium sulfate. The presence of sodium and potassium enhances the bonding and sulfation of the particles to form a strongly bonded matrix. Significant sodium was found in the deposits, as shown in **Table 14**.

3.2.2. Deposit formation mechanisms

The mechanism for the formation of deposits that blind SCR catalysts involves the transport of very small particles rich in alkali and alkaline-earth elements, the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. The formation of SO_3 from SO_2 is catalyzed by the SCR; this, in turn, increases the reaction rate of SO_3 to form sulfates. In some cases, the alkali and alkaline-earth elements will also react with CO_2 to form carbonates. XRD analysis shown in **Fig. 23** identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements including sodium, magnesium, calcium, and potassium, in addition to mineral phases. The primary minerals present in these coals include quartz, clay minerals, carbonates, sulfates, sulfides, and phosphorus-containing minerals [18].

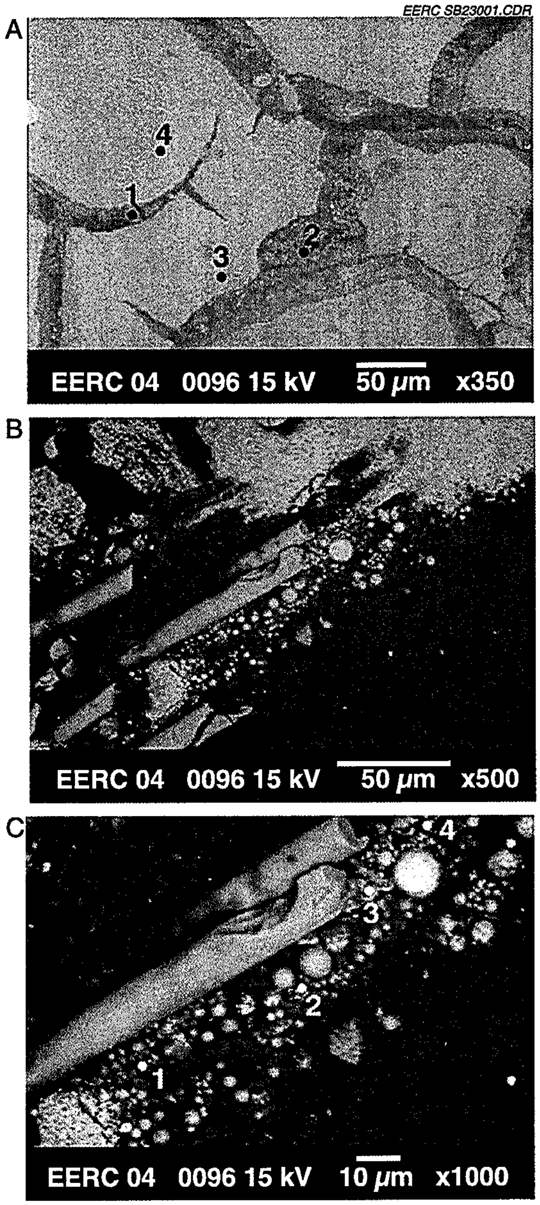


Fig. 21. SEM images of ash collected on catalyst surface at the Coyote Station after 2 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component, their association in the coal, and combustion system design and operating conditions. There has been

Table 13
Chemical composition of selected points and areas in **Fig. 21**

Oxide	Point 1	Point 2	Point 3	Point 4
Na_2O	0.9	0.7	1.2	1.0
MgO	5.0	1.6	5.6	1.7
Al_2O_3	12.3	5.8	11.9	5.5
SiO_2	24.6	3.1	21.1	2.6
P_2O_5	0.7	0.0	0.5	0.0
SO_3	23.5	44.0	17.4	31.8
K_2O	0.5	0.3	0.8	0.4
CaO	14.9	36.4	19.6	46.9
TiO_2	7.2	1.9	8.0	2.1
Fe_2O_3	9.2	5.5	11.8	6.9
BaO	1.3	0.7	2.1	1.1
Total	100	100	100	100

significant research conducted on ash formation mechanisms and relationships to impacts on power plant performance [18–34]. Typically, during combustion the inorganic components associated with western subbituminous and lignite coal are distributed into various size fractions of ash, as shown in **Fig. 24**. The results shown in Fig. 24 were obtained from isokinetic sampling and aerodynamically size-fractionating ash particles from a full-scale pulverized-coal-fired boiler firing subbituminous coal and analyzing each size fraction. The results show that the smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. These ash particles are largely derived from the organically associated cations in the coal. The larger size fraction has higher levels of aluminum and silicon derived from the mineral fraction of the ash-forming component of the coal. Entrained ash was extracted from the Columbia Station at the point of the inlet to the SCR reactor and was aerodynamically classified and analyzed. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst, as shown in Fig. 25. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-μm size fraction. The deposited material shows significantly more sulfation than the entrained-ash size fraction, indicating that the sulfation process occurs after the particles are deposited in the catalyst.

The mechanism of SCR catalyst blinding when firing lignite or subbituminous coals is shown in Fig. 26 [35]. The requirements for the formation of deposits that blind SCR catalyst include firing a coal that produces significant levels of <5-μm-sized particles. The particles are transported into the pores of the catalyst and subsequently reacted with SO_3 to form sulfates. The sulfate forms a matrix that bonds other ash particles. The SCR catalyzes the formation of SO_3 and thereby increases the rate of sulfation [9,15]. The sulfation of CaO increases the molar volume, resulting in the filling of the pore. For coals that have high sodium contents, formation of low-melting-point phases such as pyrosulfates are possible [36]. Pyrosulfate materials can melt at temperatures as low as 535 °F in coal-fired power systems.

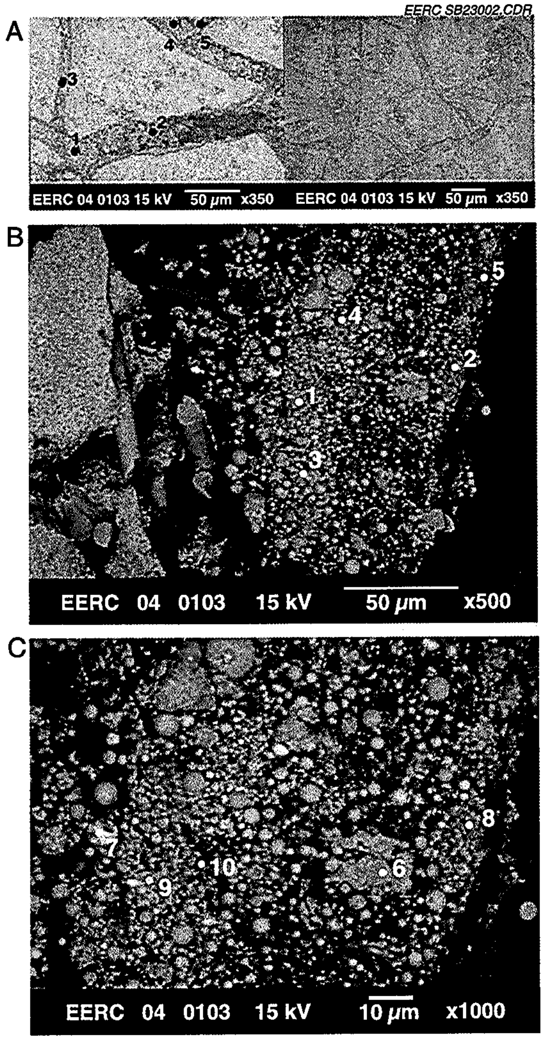


Fig. 22. SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure. (A) Low-magnification image of ash deposit on catalyst surface, (B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, (C) higher magnification image of bonding.

3.3. Flue gas measurements

3.3.1. Mercury transformations

The ability of mercury to be oxidized across the SCR catalyst was investigated at the Coyote Station. The Coyote Station is fired on North Dakota lignite, and the flue gases are dominated by elemental mercury. Measurement of mercury speciation was conducted using the OH method at the inlet and the outlet of the SCR catalyst. The measurements were made upon installation of the catalyst and after 2 and 4 months of operation. The

Table 14
Chemical composition of selected points and areas in Fig. 22

Element (wt.%)										
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	Point 10
Na_2O	6.7	1.9	7.1	6.2	3.1	9.5	2.6	10.4	8.9	4.4
MgO	1.1	1.7	1.1	2.6	3.2	1.2	1.9	1.3	3.0	3.7
Al_2O_3	2.6	8.8	4.0	4.8	10.5	2.6	8.6	4.2	4.9	10.6
SiO_2	7.0	21.1	11.3	5.6	32.2	6.3	18.2	10.5	5.0	28.9
P_2O_5	0.2	2.4	0.0	0.2	0.9	0.1	1.9	0.0	0.1	0.7
SO_3	54.7	38.5	56.4	57.5	30.4	41.8	28.4	44.9	44.5	23.4
K_2O	2.0	2.8	0.7	2.8	2.4	3.2	4.3	1.2	4.4	3.8
CaO	18.0	3.4	15.8	9.3	2.3	24.5	4.4	22.5	12.8	3.1
TiO_2	0.6	0.8	1.1	1.3	1.5	0.6	0.8	1.3	1.5	1.8
Fe_2O_3	5.8	5.1	2.1	6.5	9.8	7.7	6.6	2.9	8.9	13.2
BaO	1.4	13.5	0.5	3.4	3.6	2.4	22.3	0.9	5.9	6.3
Total	100	100	100	100	100	100	100	100	100	100

results of the mercury speciation measurement at the inlet and outlet of the SCR catalyst conducted upon installation are shown in Fig. 27. The inlet and outlet measurements were repeated three times and are shown in Fig. 27. The level of elemental mercury at the inlet was approximately 76% to 92%, with the remaining in the oxidized form ranging from 8% to 24%. Very little was in the form of particulate mercury at the inlet. Measurement of mercury speciation was conducted with the ammonia on and off. The results with the ammonia off showed an increase in the oxidized mercury to 43% of the total mercury occurring across the SCR catalyst. However, when the ammonia was introduced into the

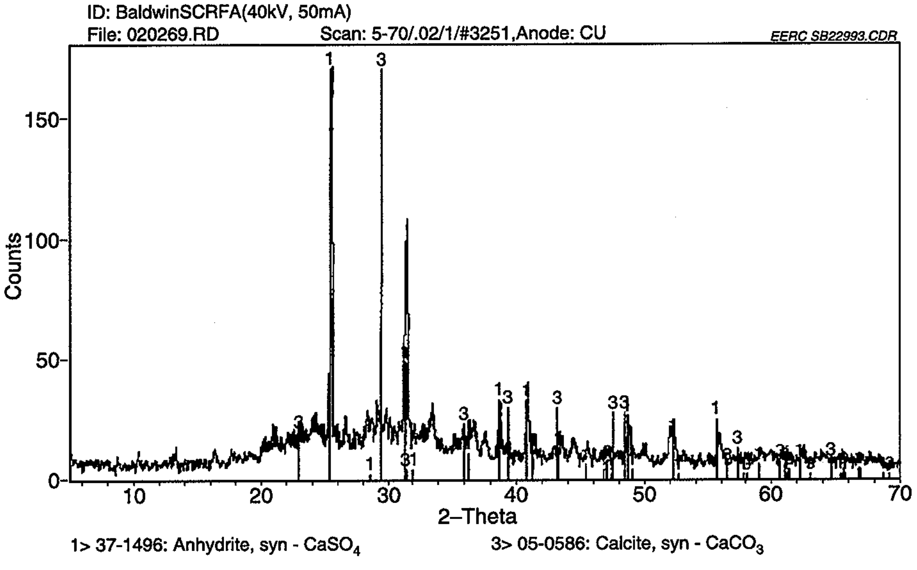
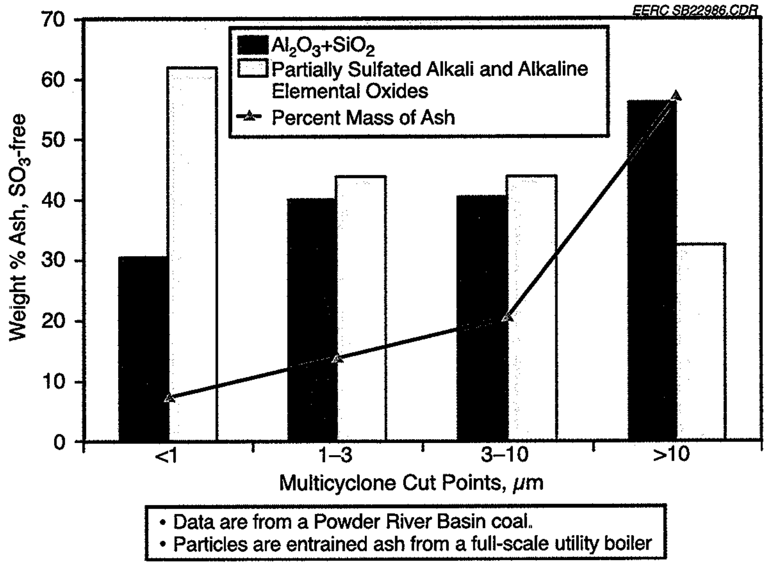


Fig. 23. X-ray diffraction of ash collected on SCR catalyst (1—$CaSO_4$, 2—$Ca_3Mg(SiO_4)_2$, and 3—$CaCO_3$).



- Data are from a Powder River Basin coal.
- Particles are entrained ash from a full-scale utility boiler

Fig. 24. Simplified illustration of ash partitioning in combustion systems [18].

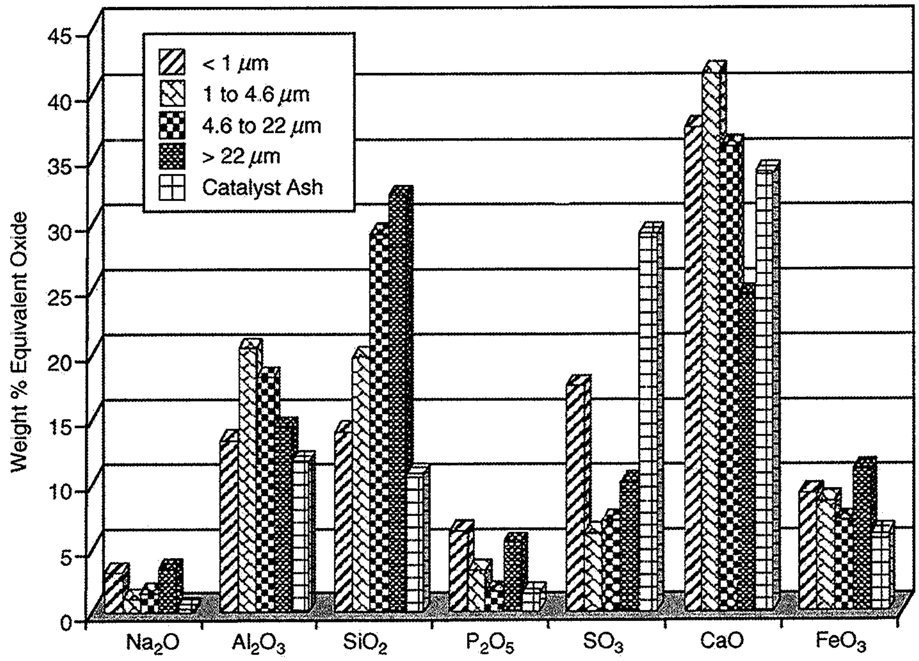


Fig. 25. Comparison of entrained ash and deposited ash on catalyst for Columbia Station.

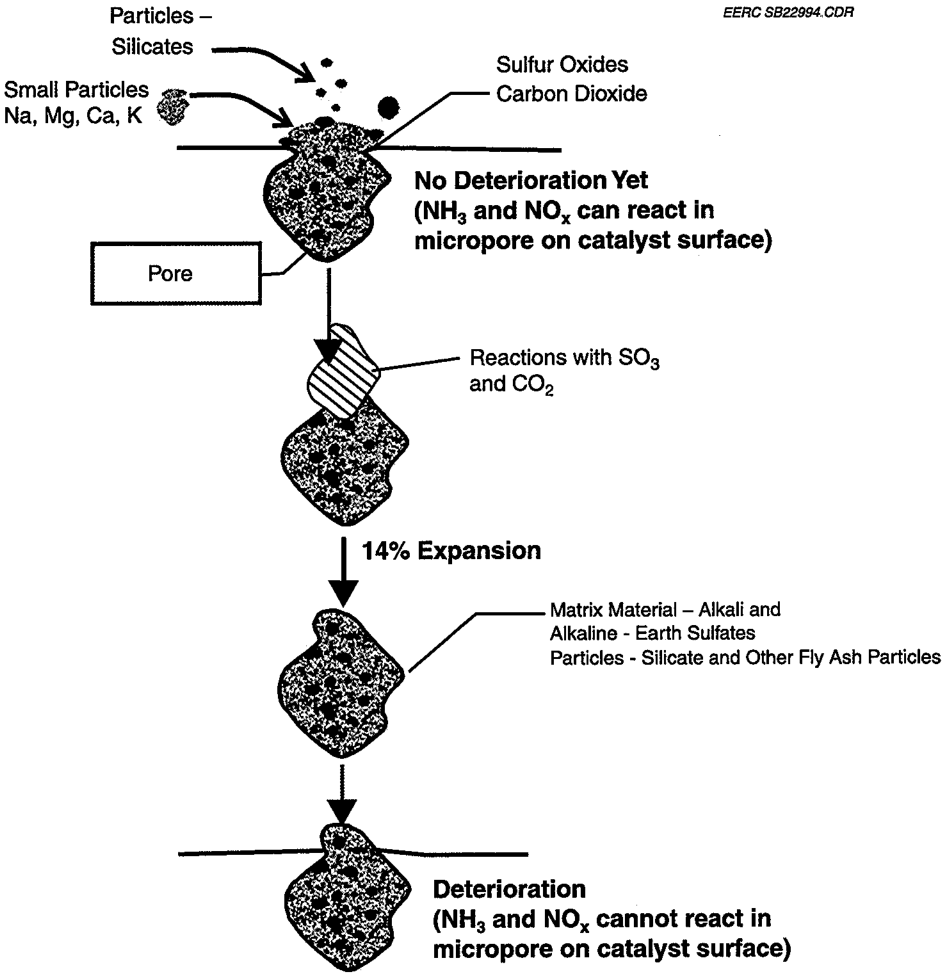


Fig. 26. Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard et al. [35]).

SCR catalyst, the amount of mercury oxidation decreased from 43% to 19%. There was an increase in the particulate mercury from 1.0% to 7.2%.

The mercury oxidation after the SCR catalyst was exposed to flue gas and particulate for 2 months is shown in Fig. 28. The level of oxidized mercury at the inlet ranges from 7.5% to 11.1% of the total mercury. The level of oxidized mercury at the outlet ranged from 7.6% to 14% of the total mercury. The level of particulate mercury increased from a negligible level to 3% of the total mercury at the outlet.

The results of mercury oxidation across the SCR catalyst after 4 months of exposure to flue gases and particulate are shown in Fig. 29. The results show a higher level of oxidized mercury at the inlet as compared to testing conducted at installation and after 2 months. The level of oxidized mercury at the inlet ranges from 32% to 38% of the total,

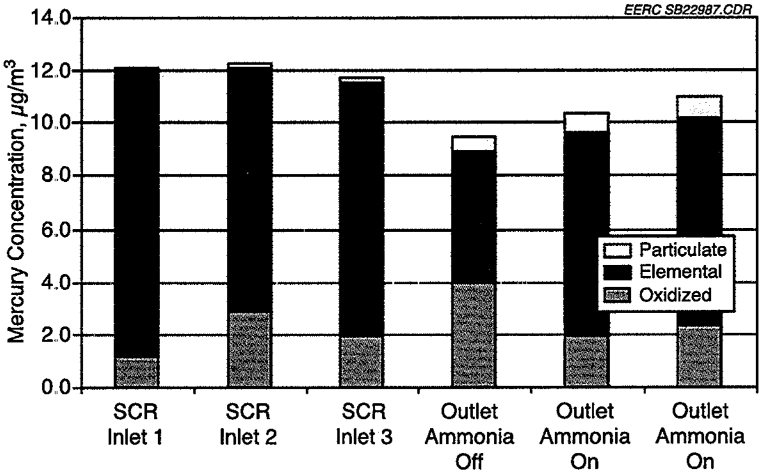


Fig. 27. Mercury speciation measurement at the inlet and outlet of the SCR catalyst upon installation of the catalyst.

with about 5% of the total in the particulate form. The outlet levels of oxidized mercury decrease after passing through the catalyst to about 20% of the total. The level of particulate mercury remained about the same across the catalyst.

4. Conclusions

A slipstream reactor is designed to expose SCR catalyst to coal combustion-derived flue gases and particulate. The system is computer-controlled and operates in an automated

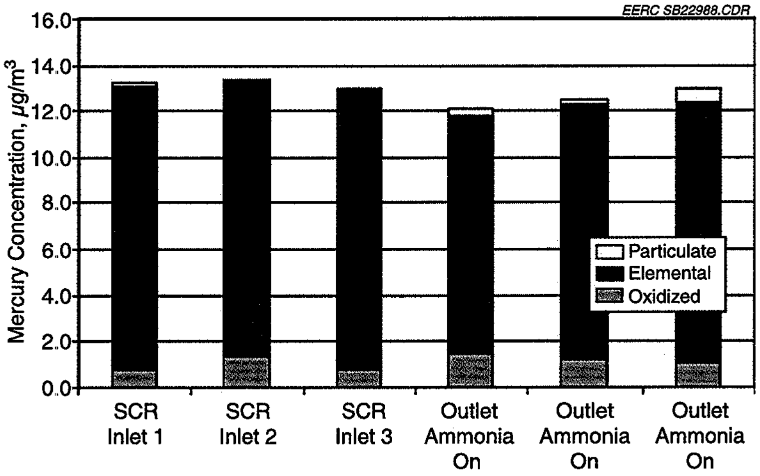


Fig. 28. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gases and particulate for 4 months.

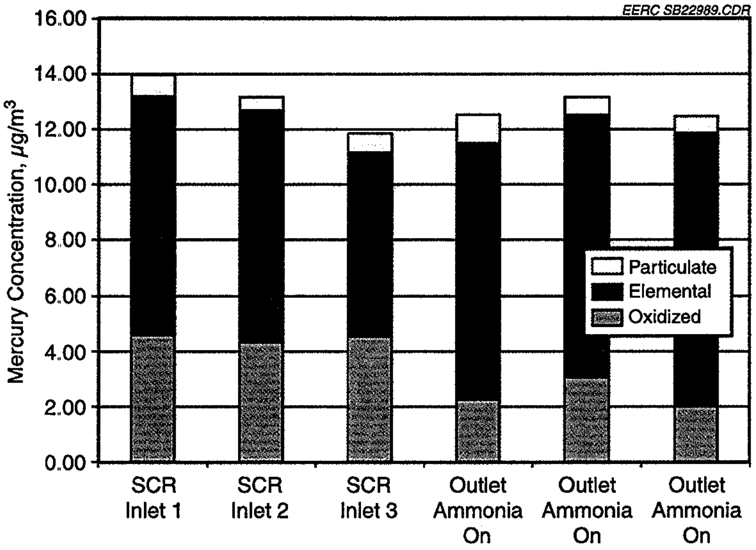


Fig. 29. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gases and particulate for 2 months.

mode. The system can be operated and monitored remotely through a modem connection. SCR catalyst testing was conducted at two subbituminous-fired plants and one lignite-fired plant. The boiler configurations for the subbituminous-fired plants included a cyclone- and a tangentially fired boiler. The boiler configuration for the lignite plant was a cyclone-fired system.

The pressure drop across the catalyst was found to be the most significant for the lignite-fired plant as compared to the subbituminous-fired plants. Both coals had significant accumulations of ash on the catalyst, on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation.

The deposits on the surfaces and within the pores of the catalyst consisted of mainly alkali and alkaline-earth element-rich phases that have been sulfated. The mechanism for the formation of the sulfate materials involves the formation of very small particles rich in alkali and alkaline-earth elements, transport of the particles to the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. XRD analysis identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements, including sodium, magnesium, calcium, and potassium in addition to mineral phases. During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component and their association in the coal and combustion system design and operating conditions. The results of this testing found that the smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-μm size fraction.

The ability of mercury to be oxidized across the SCR catalyst was investigated at the Coyote Station. The Coyote Station is fired on North Dakota lignite, and the flue gases are dominated by elemental mercury. Measurement of mercury speciation was conducted using the OH method at the inlet and the outlet of the SCR catalyst. These results show limited oxidation of mercury across the SCR catalyst when firing lignite coals. The reasons for the lack of mercury oxidation include the following: no or low chlorine present in the coal and flue gas to catalytically enhance the oxidation of Hg^0, high levels of alkali and alkaline-earth elements acting as sorbents for any chlorine present in the flue gas, and low levels of acid gases present in the flue gas.

Acknowledgments

This investigation was supported by Alliant Energy, AmerenUE, Dynegy Midwest Generation, Kinectrics, Ontario Power Generation, Otter Tail Power, EPRI, the Industrial Commission of North Dakota, Hitachi and Haldor Topsoe through the EERC Jointly Sponsored Research Program, which is supported by the U.S. Department of Energy National Energy Technology Laboratory under Cooperative Agreement No. DE-FC26-98FT40321.

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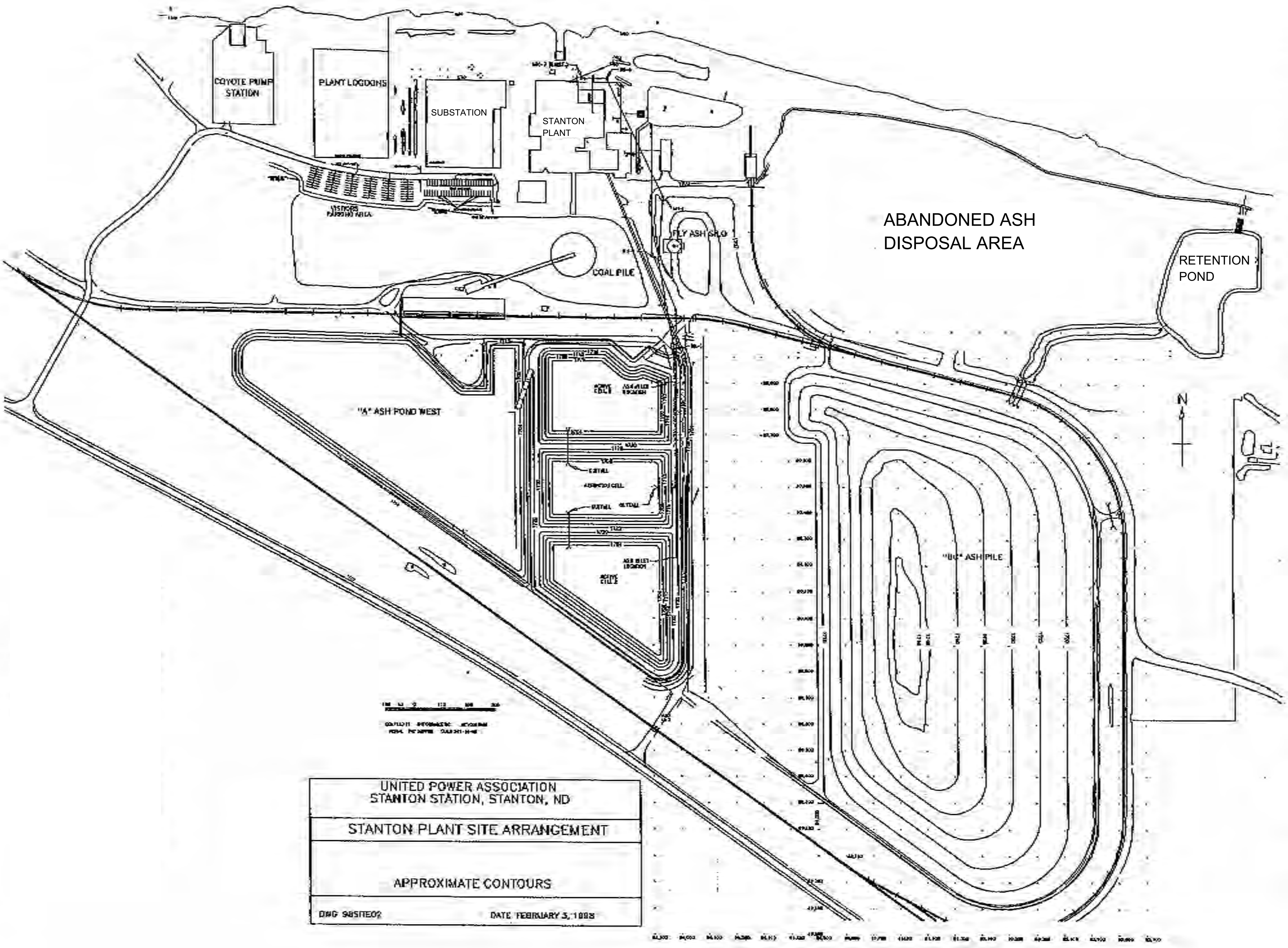
Appendix G

Stanton Station Site Plan



UNITED POWER ASSOCIATION
STANTON STATION, STANTON, ND

STANTON PLANT SITE ARRANGEMENT

APPROXIMATE CONTOURS

DWG 98SITE02

DATE FEBRUARY 3, 1998

Thorstenson, Craig D.

From: Archer, Greg GRE/MG [garcher@GREnergy.com]
Sent: Friday, September 19, 2008 12:06 PM
To: Thorstenson, Craig D.
Cc: Roth, Mary Jo GRE/MG; Smokey, Steve GRE/SS; jtrinkle@barr.com
Subject: Stanton Draft Reponses to Select EPA FLM Comments
Attachments: 080918 draft Stanton BART responses to FLM.doc

Craig,

Here are Stanton's Draft Responses to the EPA FLM comments. Please take a look and let me know if any areas need more or less information. I will be out of the office thru Wednesday next week and will respond upon return.

Also, we would like to meet the department in the next few weeks to discuss long term options for Stanton. I would suggest sometime after Oct 2. Please let me know availability from your end and I will try to match schedules on ours.

Thanks in advance!

Greg Archer | Environmental Administrator
Great River Energy
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DRAFT Responses – 9/19/08

The Federal Land Managers and EPA recently commented on the State's Draft BART SIP and Stanton's Draft Permit-to-Construct, which incorporates the State's proposed BART limits. In response to certain EPA/FLM questions, GRE provides the following responses, at the request of NDDH.

EPA NOx Comment 48 (B) – "The State's proposal of LNB+OFA+SNCR is commendable since it goes beyond what can be achieved with just combustion controls. However, the BART limit should be tightened since current (pre-BART) emissions using PRB coal at Stanton are already very close to the proposed limit (0.26 lb/mmbtu vs. 0.23 lb/mmbtu)"

GRE Response – As discussed in Stanton's BART analysis, there are several justifications for the proposed NOx limits. While it is true that Stanton has hit roughly 0.26 lb/mmbtu NOx as an annual average, this emission rate must be viewed within the context of Stanton's operational configuration and with respect to the BART limit that is expressed as a 30-day rolling average, inclusive of startup and shutdown emissions.

In terms of operational justifications for a higher NOx emission rate, there are many. First, NOx emissions are impacted by variable load operations over shorter averaging periods. Under normal station operating conditions, Unit 10 is run at full utilization while Unit 1 varies (swings) to meet Midwest Independent System Operators (MISO) power demands. Unit 1 has a wider load range than Unit 10 to swing to meet load. (As the larger unit, Unit 1 swings rather than Unit 10 because of back draft problems that can cause Unit 10 to trip.) On PRB, Unit 1 only needs to operate 2 of its 3 mills at any time to follow load. So, by rotating the 2 mill configuration over a year, they have demonstrated an ability to operate at 0.26 lb/mmbtu as an annual average. Again, short term operational variability is muted as an annual average, but becomes more of a concern over shorter term compliance limits such as 30 days.

Specifically, Stanton rotates mill operation so that they all wear equally. However, if the lower mill is out-of-service, the upper two mills must support the load. The lower mill can have a mechanical breakdown, which requires it to be taken out of service. Therefore, over shorter term averaging periods, NOx emissions will be higher while running on the two upper mills.

Second, if Unit 10 trips due to a tube leak or other maintenance problem, Unit 1 needs to operate all three mills in order to fully supply steam to the single turbine. Under the three mill operational scenario, NOx emission rates are higher than two mill operation. Depending on the extent of the unplanned Unit 10 outage, it is possible for Unit 1 to operate on all three mills for as much as 30-days.

Third, nitrogen can vary by coal type, which will impact NOx emissions. Fuel bound nitrogen association with the range of lignite and PRB coals available to Stanton was inherently included in the safety factors that were applied to the Alstom target emission rates.

As discussed in the Alstom NOx Evaluation (Stanton BART Analysis Appendix D) and as discussed in Section 4.3 of Stanton's BART Analysis. The proposed BART limits are reflective of these operational scenarios.

EPA Wet Scrubber Comment 45 – "A wet scrubber was eliminated from consideration based on environmental considerations, but it is not clear how significant these other considerations and why they were not important at other plants."

GRE Response – In addition to cost effectiveness and incremental deciview arguments described in Stanton's BART analysis, there are other environmental considerations that would also support ruling out a wet scrubber as BART. Most importantly, Stanton Station, unlike other plants in ND, currently has a spray dry baghouse on its Unit 10. Therefore, in addition to other environmental considerations described below, there are significant operational efficiencies associated with installing another spray dry baghouse on Unit 1.

Site Constraints – Stanton Station is located on the Missouri River, which is immediately north of the plant, and is bounded by the state highway on the south. Basin Electric is located immediately east and Coyote Pump house and existing rail lines constrict the western boundary. See BART Analysis Appendix G – Site Diagram. There are realistically only two potential areas on site that could be considered for the additional ponding associated with a wet scrubber. They are either, the existing ash pile, which would need to be excavated and moved, or the abandoned ash disposal area adjacent to the river, which reportedly has geotechnical deficiencies. The levee along this area had started to erode, which instigated the abandonment of the Old Ash Disposal Area.

Water Use – The wet scrubbing technology will use more water than dry scrubbing. According to Washington Group's preliminary estimates, wet scrubbing can use as much as 20% more water or approx. 15MM gallons/yr. Since water use in the western United States has been and will continue to be a contentious issue, the plant must be cognizant of it as a resource use. Further, with respect to Clean Water Act 316(b) requirements, an increase in water withdrawal may trigger alternative cooling water intake requirements such as cooling towers. These additional costs were not fully incorporated into the analysis, but present other environmental considerations and regulatory risks as part of the BART analysis.

Wastewater Discharge – It is assumed that a wet scrubber system would require additional on-site ponding. Again, it is important to note the site diagram and the proximity to the river. Although there appears to be an available area immediately adjacent to the river, this area is geologically unsound for scrubber sludge ponding. Since a comprehensive geological site assessment including structural improvements and pond lining was not completed, this item was listed as a non-air quality environmental consideration. Any wastewater generated by wet scrubbing is expected to have concentrations that may require further on-site treatment prior to discharge. Finally, once mercury controls are installed, it is logical to assume that some mercury will be transferred to the wastewater ponds and treatment system, which will prove problematic for discharge.

Operational Efficiencies with Dry Scrubbing Technology – Stanton Station Unit 10 currently has a spray dry baghouse to control SO2. The plant is very familiar with this technology. There are cost savings associated with lime handling, ash handling and operator coverage if an additional spray dry baghouse combination is installed on Unit 1.

Pending Mercury Air Emission Controls – For almost 10 years, Stanton has consistently conducted mercury reduction research in conjunction with EPRI, EERC, DOE, NDIC, LEC and others. This research has not only supported national efforts to reduce mercury through the development of improved carbons, but it has provided plant specific mercury control information that will be used to comply with CAMR, if re-instated, or MACT requirements when promulgated. A great deal of Stanton's research was conducted with the Unit 10 spray dry baghouse. It is clear that spray dry baghouse with carbon injection combinations work substantially better than wet scrubber mercury controls, especially on western coals, like PRB and Lignite, that have a higher elemental mercury percentage. If a wet scrubber technology were required, Stanton would have to work much harder to remove the same amount of mercury from the exhaust gas. Further, there would be wastewater issues associated with mercury, and other exhaust gas constituents as mentioned. .

In addition to cost effectiveness and incremental deciview arguments in Stanton's BART analysis, it is the combination of these other environmental considerations that support our proposed BART controls and associated emission rates.

EPA Comments 44, 45 and 46– "We believe that the 'inferior' control technology proposed for Stanton Unit 1 (spray dryer/fabric filter) coupled with, what we find to be, an inflated uncontrolled emission rate, produces too high of an SO2 limit (0.24 for lignite and 0.16 for PRB)."

'Inferior' Control - Stanton Station has completed a BART analysis for SO2 controls that includes wet scrubber, spray dryer/fabric filter, dry sorbent injection and other SO2 controls. According to the five factor analysis, the spray dryer/fabric filter was determined to be the most appropriate control to cover the range of permitted fuels and sulfur contents.

As discussed in Section 5.1 of Great River Energy's Stanton Station BART Analysis (Rev Jan 2008), the plant is currently permitted for both PRB and Lignite coals. The current fuel contract expires in November 2009 and the plant is evaluating several coal suppliers. Appendix E of Stanton' BART analysis provides detailed discussion for some future coals and their potential uncontrolled sulfur emissions.

As one example, Stanton Station recently completed a test burn of Absaloka PRB. According to the CEMS data (See Table), there was significant hourly variability associated with sulfur emissions from one train of the Absaloka. We do not have enough familiarity with the Absaloka or the Rosebud Mine plans in order to speculate on future sulfur content or consistent sulfur content within deliveries over a 30 day period. Although limited, the CEMS data for part of trial burn is supportive of NDDH's uncontrolled emission calculations, which was actually based on the higher sulfur Rosebud Mine. The NDDH proposed SO2 PRB emission rate is reflective of these prospective fuel options and sulfur uncertainties.

As described in Appendix E of the Stanton's BART analysis, the nearest active lignite mine on Stanton's side of the Missouri River is at Minnkota's plant. Sulfur emission rates were derived from this mine as representative of uncontrolled emissions associated with a prospective lignite fuel source. Although different than historical lignite emission rates, it is reflective of the most probable lignite fuel available to Stanton at this time.

Absaloka SO2 CEMS Data

Average	1.30
Minimum	0.89
Maximum	2.12
Summation	124.66
Included Data Points	96
Total number of Data Points	96

Additional GRE Comments on 5/29/08 Draft Permit to Construct

General Information Section C) Owner/Operator address should be updated to 12300 Elm Creek Blvd, Maple Grove, MN 55369-4718

Permit Conditions A.3 – CEMS – The monitoring location is listed as (Main Stack). However, Unit 1 currently monitors both the East and West ducts. With the scrubber installation, the monitoring location is likely to change.

BART DETERMINATION STUDY

for

Milton R. Young Station Unit 1 and 2
Minnkota Power Cooperative, Inc.

October 2006

41440

Minnkota Power
COOPERATIVE, INC.
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INDEX AND CERTIFICATION

BART Determination Study
Milton R. Young Station Unit 1 and 2
Minnkota Power Cooperative, Inc.

Project 41440

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Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by the Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the laws and rules of the North Dakota State Board of Registration under Title 28 Administrative Code.

STEPHEN W. VOSS
4945

10-4-06

Minnkota Power Cooperative, Inc.
Milton R. Young Station
Units 1 and 2
Best Available Retrofit Technology Analysis

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EXECUTIVE SUMMARY

On July 6, 2005, the U.S. EPA finalized the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations. The final regulations require eligible sources to be analyzed to determine a BART emission limit for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). The North Dakota Department of Health (NDDH) reviewed the operational history of North Dakota sources and determined which sources were BART eligible and provided a state specific modeling protocol for use in the analysis. Minnkota Power Cooperative, Inc.'s (Minnkota's) Units 1 and 2 at the Milton R. Young Station (MRYS) were determined to be BART eligible by the NDDH. As discussed in the introduction to the analysis, small emission units at MRYS produce emissions in levels anticipated to be too small to affect visibility in Class 1 areas and were excluded from further consideration in the study. This BART determination was conducted in accordance with the eligibility conclusion made by NDDH and follows the NDDH protocol.

Once a source is determined to be eligible, there are five predefined steps for conducting a BART analysis for each pollutant. The result of conducting this five step analysis is a list of control technologies for regulated pollutants that provides a cost effective system of emission reduction and visibility impact reduction. However, prior to the completion of this analysis, Minnkota entered into a Consent Decree (CD) that requires the MRYS to install Best Available Control Technology-level (BACT-level) controls for NO_X, SO_2, and PM. As discussed in detail within the report, BACT is considered to be more stringent than BART. Thus, the BART analysis was reduced to an evaluation of the BACT-level control technologies and emission reductions specified by the CD. Because BACT and BART analyses have similar steps, the only remaining step for recommending BART was to perform a visibility impairment impact analysis and discern if there was an acceptable impact reduction.

Based upon an evaluation of the 90th percentile visibility impairment modeling results, the control technologies and emission reductions specified by the CD for all pollutants and both units had an acceptable impact reduction. Because there was an impact reduction in all cases, the BART recommendation consists of the control technologies recommended as BACT for NO_X emissions and those specified by the CD for SO_2 and PM emissions at the modeled emission rates. The BART recommendations for each pollutant and each unit are summarized in the tables below. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

MRYS Unit 1 Recommended BART 30-Day Rolling Average

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.36*
SO_2	Dry Flue Gas Desulfurization (FGD) Process	0.24
PM	Fabric Filter Baghouse	0.015**

* Excludes startups. See Appendix A for a detailed discussion.

** See discussion in Section 5.1

MRYS Unit 2 Recommended BART 30-Day Rolling Average

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.35*
SO_2	Upgrade of Existing Wet Flue Gas Desulfurization (FGD) Process	0.31
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See Appendix A for a detailed discussion.

1.0 INTRODUCTION

The U.S. EPA finalized the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations[1] in the Federal Register on July 6, 2005 (70 FR 39104). BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). This document presents the BART analysis for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Minnkota Power Cooperative, Inc.'s (Minnkota's) Units 1 and 2 at the Milton R. Young Station (MRYS) located near Center, North Dakota.

A BART eligible source is one that meets three criteria identified by EPA in the guidelines for the determination of BART. A source is BART eligible if operations fall within one of 26 specifically listed source categories (70 FR 39158), the source entered into service between August 7, 1962 and August 7, 1977, and the source has the potential to emit 250 tons per year or more of a visibility-impairing air pollutant (SO_2, NO_X or PM). The North Dakota Department of Health (NDDH) reviewed the operational history of sources within North Dakota and independently determined which sources are BART eligible. The NDDH classified the electric generating units (EGUs) at Milton R. Young Station as BART eligible. For the purposes of this report, the NDDH's determination will be used and Units 1 and 2 at MRYS are assumed to be subject to a BART analysis.

Where a particular source is determined to be eligible, the general steps for determining BART for each pollutant are as follows (70 FR 39164):

STEP 1 - Identify all available retrofit control technologies (within the BART Guidelines).
STEP 2 - Eliminate technically infeasible options.
STEP 3 - Evaluate control effectiveness of remaining control technologies.

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[1] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations"; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.

STEP 4 - Evaluate the following impacts for each feasible control technology and document results: (70 FR 39166).

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

STEP 5 – Evaluate the visibility impacts.

Minnkota Power Cooperative, Inc. retained Burns & McDonnell to assist in the completion of the Best Available Retrofit Technology analysis for Milton R. Young Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services to the power industry since the 1970s. As a result of their long history providing these services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies and control technology analysis similar to a BART analysis.

1.1 BACKGROUND

Minnkota Power Cooperative, Inc. operates the Milton R. Young Station near Center, North Dakota. MRYS is a steam electric generating plant with two units. Unit No. 1 is a Babcock & Wilcox (B&W) cyclone-type coal-fired boiler burning lignite coal, serving a turbine generator with a nameplate rating of 257 MW.[2] Particulate control is provided by a Research-Cottrell Electrostatic Precipitator rated at approximately 99% control. Unit 1 has no sulfur dioxide (SO_2) control system and exhausts to a 300 foot tall stack. Unit No. 2 is a B&W cyclone-fired unit burning lignite coal, with a turbine-generator name plate rating of 477 MW.[2] Particulate control for Unit 2 is provided by a Wheelabrator-Lurgi precipitator rated at approximately 99% control. Unit 2 has a Combustion Equipment Associates wet flue gas desulfurization (FGD) system (modified by Combustion Engineering) that treats approximately 78 percent of the flue gas with the remaining flue gas by-passed for stack gas reheat. The FGD system achieves approximately 75 percent SO_2 removal and exhausts to a 550 foot tall stack. Unit 1 began commercial operation on November 20, 1970 and Unit 2 on May 11, 1977.

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[2] "Generator Nameplate Data"; Emissions & Generation Resource Integrated Database (eGRID); U.S. Environmental Protection Agency; April, 2003.

On 17 June 2002, Minnkota Power Cooperative, Inc. received a Notice of Violation (NOV) from EPA. The NOV states that Minnkota allegedly violated the Prevention of Significant Deterioration (PSD) regulations. The NOV was issued pursuant to Section 113 of the Clean Air Act. The alleged violation was caused by modifications to both Unit 1 and 2 at MRYS which allegedly resulted in a potential increase of SO_2, NO_X and PM. Without an admission of liability, Minnkota entered into a settlement in the form of a Consent Decree (CD) with the EPA and NDDH to resolve the issues. The CD requires that Minnkota install a level of control for SO_2, NO_X and PM on both Unit 1 and 2 at MRYS, equivalent to BACT. The effect of the CD on the BART analysis and the requirement to install BACT-level controls are discussed later in the report.

1.2 APPROACH

The purpose of the Regional Haze Rule is to address visibility impairment in mandatory Class 1 areas that results from the emission of SO_2, NO_X, PM, Volatile Organic Compounds (VOCs) and ammonia from certain major sources. The only control method for VOCs identified in the RACT/BACT/LAER Clearinghouse (RBLC) database is good combustion practices. This control technique is already in place at MRYS. If an analysis were performed for VOCs, good combustion practices would be the most probable method chosen for BART. The visibility impact of VOCs and ammonia are considered negligible for a BART analysis, according to the NDDH's November 2005 modeling protocol[3], and are not addressed further in this report. Before the actual BART analysis can begin for SO_2, NO_X, and PM, the approach used to conduct the analysis should be addressed. The following sections present specific subjects related to MRYS's background, which warrant mention due to their effects on the contents of the report.

1.2.1 CONTROL TECHNOLOGY EVALUATION AND BACT VS. BART

As stated above, once a source is determined to be eligible, there are general steps for conducting a BART analysis for each pollutant. All retrofit control technologies are first identified. A brief review of the processes and their capabilities is then performed to determine availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to control capability and an analysis then reviews the probable impacts of each technology.

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[3] "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota"; North Dakota Department of Health, Division of Air Quality; November, 2005.

The visibility impact is included in the impact analysis. Finally, the results of the analyses are tabulated and possible BART control options are listed.

As stated in the proposed BART guidelines dated 5 May 2004 (69 FR 25218), a BART analysis is similar to a Best Available Control Technology (BACT) analysis.

> "The process for a BART analysis is very similar to the BACT review as described in the New Source Review Workshop Manual (Draft, October 1990). Consistent with the Workshop Manual, the BART engineering analysis requires that all available control technologies be ranked in descending order of control effectiveness (i.e. percent control). You [meaning States] must examine the most stringent alternative first. That alternative is selected as the ''best'' unless you demonstrate and document that the alternative cannot be justified based upon the consideration of the five statutory factors discussed below. If you eliminate the most stringent technology in this fashion, you then consider the next most stringent alternative, and so on.
>
> Although very similar in process, BART reviews differ in several respects from the BACT review described in the NSR Draft Manual."

The proposed guidelines stated that a BART analysis is similar to a BACT review and provided a few examples of similarities and differences, but it did not explicitly state how the two analyses could be used in conjunction to obtain a determination. Because BACT and BART are similar, there are many aspects that can be combined to reduce the steps of an analysis. However, because there are some differences, a BART analysis must address some additional aspects that a BACT review does not.

A BART analysis is always conducted for existing sources and a BACT review is usually conducted for a new source. Because BACT is usually performed for a source that is a new design or reconstruction, the review must take into account all available technologies and must include the most effective controls that have been demonstrated on similar units. BACT is considered to be more stringent than BART because it usually is not limited by the design of existing equipment or current operating conditions as is required for a retrofit application. Although MRYS is eligible to perform an analysis to determine BART, the Consent Decree (CD) also requires that MRYS install levels of control equivalent to BACT. Thus, the BART analysis can be shortened to only include the BACT-level control technologies specified in the CD.

With the specification of BACT-level technologies in the CD, the first four evaluation steps of the BART analysis can be eliminated. The first four steps of BART are usually used to identify technologies, determine feasibility and evaluate cost, energy, non-air quality and useful life impacts. Because the control technologies are already specified by the CD, the visibility impacts evaluation is the only remaining step in the determination that must be performed to satisfy BART. This analysis evaluates the visibility impairment impacts of the BACT-level control technologies specified in the CD and provides a BART recommendation based upon an acceptable degree of visibility improvement in Class 1 areas.

1.2.2 CONDENSABLE PARTICULATE

Particulate matter emissions are composed of filterable and condensable particles. The filterable particles are characterized using EPA standard reference methods (i.e., Method 5, 17, 201, or 201A). The reference method used for characterization is dependent upon the size of the particle and the temperature of the flue gas, and is usually specified in the applicable permit. Solid particles are captured using a heated filter while the majority of condensable particles are not collected as they are in the gaseous form until after the flue gas has passed through the filter.

Condensable particulate matter (condensable PM) may react with atmospheric or flue gas constituents as flue gas moves through the different processes and then either condenses into a droplet, coalesces into a solid particle, or forms a solid particle as more volatile components evaporate. Condensable PM is characterized using EPA standard reference Method 202. Using Method 202, the flue gas passes through a heated filter to remove filterable PM and condensable flue gas constituents are condensed by bubbling them through water at 20^oC. During post-test sample recovery, the water is evaporated and the remaining residue is weighed to determine condensable PM emissions. However, Method 202 has an inherent flaw because the means by which condensable particulate is collected differs from how particulate condenses in the stack. Method 202 can result in inaccurate measurements due to the creation of PM artifacts in the sampling water that would not normally condense in the stack plume (e.g., SO_2 and NH_3 compounds). For a fixed operating condition, Method 202 can provide inconsistent emission rate measurements and can result in overstatement of emission rates. Thus, there is considerable uncertainty surrounding emissions measured with Method 202 for the purpose of PM compliance demonstration.

Condensable PM may include both organic and inorganic constituents. Organic constituents in the flue gas can exist as a vapor at stack temperatures and a liquid or solid at ambient temperatures. Control technologies designed to minimize the formation of condensable organic emissions are the same technologies that are used to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions. A review of the RBLC database shows that good combustion practices are universally used to control CO/VOC emissions for similar units. Both MRYS units already practice good combustion practices while maintaining combustion efficiency in the boiler and controlling NO_X emissions. Because good combustion practices would likely be considered BART and are already in use at both units, the organic portion of condensable PM is not addressed further in this report.

Sulfuric acid (H_2SO_4) mist is the most widely recognized form of inorganic condensable PM emitted by combustion sources. Other inorganic condensable PM constituents may include to a lesser extent other acid gases, ammonium sulfate ($(NH_4)_2SO_4$), and unidentified inorganic species. Control technologies designed to reduce sulfuric acid mist will also reduce the other inorganic constituents. H_2SO_4 is typically generated in the flue gas when sulfur trioxide (SO_3) reacts with water. SO_3 is a by-product created during the combustion of fuels containing sulfur and is formed when sulfur dioxide (SO_2) in the flue gas is oxidized. Limited data is available on the quantity of SO_2 that will be converted to SO_3 in a lignite fired unit. Estimates of the conversion range from 0.2 to 1.0 percent.

Combustion controls commonly used to control NO_X (e.g., staged combustion and separated overfire air) provide a co-benefit of sulfuric acid mist control by limiting the oxygen available in the boiler and reducing formation of SO_3 in the boiler. The H_2SO_4 vapor will adsorb on the fly ash as the flue gas cools under appropriate temperature and moisture conditions. Consequently, when those conditions exist, H_2SO_4 is removed from the gas stream by particulate control equipment. Control technologies designed to remove SO_2 will also achieve SO_3 removal and reduce emissions of H_2SO_4. Typical SO_3 removal associated with a wet FGD process is 40 to 60 percent, and higher removal is typical for semi-dry FGD processes. The Southern Company estimates a minimum 50% reduction in H_2SO_4 emissions for use of a FGD process.[4] Thus, control technologies used to control NO_X, SO_2 and filterable PM are also able to provide H_2SO_4 control.

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[4] "An Updated Method for Estimating Total Sulfuric Acid Emissions from Stationary Power Plants"; Monroe, Larry S. & Harrison, Keith E.; Southern Company Generation and Energy Marketing; Revised March, 2003.

Recommended BART for condensable PM is the co-benefit of NO_X, SO_2 and filterable PM control devices to be analyzed in this report and is not addressed further. Therefore this BART analysis for particulate emissions investigates control methods to reduce filterable PM only.

1.2.3 EMISSION SOURCE APPLICABILITY

There are two subjects within the Guidelines related to the applicability of BART to emission sources. The first subject deals with the presumptive BART emission limits and their application to power plants smaller than 750 MW in size. The Guidelines for BART Determination include the following statement with regard to presumptive BART for SO_2 (70 FR 39171):

> "You [meaning States] must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lbs/mmBtu, for each EGU greater than 200 MW that is currently uncontrolled unless you determine that an alternative control level is justified based on a careful consideration of the statutory factors. For a currently uncontrolled EGU greater than 200 MW in size, but located at a power plant smaller than 750 MW in size, such controls are generally cost effective and could be used in your BART determination….."

Similarly for NO_X, the EPA states (70 FR 39171):

> "For coal-fired EGUs greater than 200 MW located at greater than 750 MW power plants and operating without post-combustion controls, we have provided presumptive NO_X limits differentiated by boiler design and type of coal burned. You may determine that an alternative control level is appropriate based on a careful consideration of the statutory factors. For coal-fired EGUs greater than 200 MW located at power plants 750 MW or less in size and operating without post-combustion controls, you should likewise presume that these same levels are cost-effective."

For power plants greater than 750 MW in size, the EPA requires state agencies to apply the presumptive limits for BART as a floor for NO_X control. However, for power plants smaller than 750 MW in size, the presumptive limits are described as being "cost-effective" but not set as a minimum performance requirement. Thus, BART for EGUs at power plants smaller than 750 MW in size, like MRYS, is not required to meet the presumptive limits. This BART analysis for MRYS will evaluate potential control options that achieve the BACT-level limits set forth in the Consent Decree.

Consequently, based upon the visibility analysis, the recommended control options may not achieve the EPA's presumptive BART limits.

The second part of the Guidelines that should be addressed relates to which emission units are subject to BART for a particular pollutant. The Guidelines state that:

> "Once you determine that a source is subject to BART for a particular pollutant, you must establish BART for that pollutant. The BART determination must address air pollution control measures for each emissions unit or pollutant emitting activity subject to review." (70 FR 39163)

According to this statement, the BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2 and PM) regardless of size. The BART analysis for MRYS will review control options for the main boilers for Unit 1 and Unit 2. Smaller emissions sources at the facility are anticipated to provide negligible contribution to visibility impacts from MRYS in Class 1 areas. Smaller sources at MRYS are discussed in Section 1.2.4 and 1.2.5.

1.2.4 SMALL SOURCE EMISSION UNITS

The BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2 and PM) regardless of size. However, smaller emissions sources (e.g., auxillary boilers and emergency generators) at the facility are anticipated to provide negligible contributions to visibility impairment in Class 1 areas. The nearest Class 1 area is Theodore Roosevelt National Park (TRNP) located approximately 160 km to the west. Although technically eligible, smaller source emissions units were not reviewed because they have limited hours of operation or they are material handling sources with a level of emissions anticipated to be too small to affect visibility impact on TRNP. Consequently, small emission sources are excluded from further consideration in the study.

1.2.5 FUGITIVE DUST

The primary source of fugitive dust is from the outside coal storage area and other plant activities normally found at a coal-fired electrical generating facility. The coal stockpile, access roads and plant activities are performed and maintained with good operating practices. On the coal stockpile and on other applicable fugitive sources, dust suppression is achieved through the use of water sprays or surfactants. The level of fugitive PM emissions is not expected to affect the visibility in Class 1 areas based upon the approximate 160 km distance to the nearest Class 1 area, the large particle size and relatively small emission rates. As such, fugitive sources were not evaluated in this BART analysis for MRYS.

1.2.6 METHODOLOGY FOR VISIBILITY IMPACTS DETERMINATION

In the BART Determination Guidelines, as discussed in Section 1.0 of this report, the EPA provides five basic steps for a case-by-case BART analysis. The fifth step involves evaluating visibility impacts utilizing dispersion modeling. Visibility impairment impacts for modeled pre-control and post-control emission levels and visibility improvements are to be assessed in deciViews (dV). The BART guidelines describe the thresholds for visibility impairment as:

> "A single source that is responsible for a 1.0 dV change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 dV change may still contribute to visibility impairment..... any threshold that you (the States) use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 dV." (70 FR 39161)

The NDDH BART protocol does not distinguish between a source that "causes" or "contributes" to visibility impairment but follows the EPA's Regional Haze Rule threshold recommendations. Thus, 0.5 dV is the deminimis threshold level of visibility impairment impact for an otherwise BART-eligible source under the NDDH BART protocol. In other words, a BART-eligible source for which modeling predicts a visibility impairment impact of greater than 0.5 dV is deemed to have a visibility impairment impact and thus is subject to a BART analysis under the NDDH BART protocol. A BART-eligible source for which the modeling predicts less than a 0.5 dV impact would be deemed to not have a visibility impairment impact, and thus could be exempted from BART on that basis. Most noticeably, the EPA refrains from addressing the question of whether or not a difference in visibility impairment impact improvement of less than 0.5 dV between two BART alternatives would constitute equivalency under the visibility analysis, or if any difference in the model results, no matter how slight, should be interpreted as ranking one solution over the other.

The approach taken in the BART analysis for MRYS incorporates the visibility impact analysis results as a verification of visibility improvement. Because the Consent Decree specifies the control level and technology that must be used for SO_2 control, the emission rate for control of PM, and the use of a BACT "Top Down" analysis for NO_X emissions control, the visibility analysis is not used to differentiate between control technologies used to control each pollutant. Rather, the visibility analysis is used to determine if control levels and technologies specified in the Consent Decree provide visibility improvement in Class 1 areas.

1.3 THE ROLE OF MODELING AND CALPUFF IN A BART ANALYSIS

The BART guidelines list visibility impact at a Class I area as one of the factors in a BART determination. The EPA interpreted the statutory provision of Section 169A of the Clean Air Act to require that a BART-eligible source is one that is "reasonably anticipated to cause or contribute" to regional haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area (70 FR 39161). A Class I area, as listed by the EPA, is an area of the country with pristine air quality that is sensitive to changes in visibility. Two Class 1 areas have been identified for inclusion in the visibility analysis for MRYS. These are the Theodore Roosevelt National Park (TRNP), and the Lostwood National Wildlife Refuge (Lostwood NWR), which are approximately 160 and 180 km (100 and 112 miles), from Milton R. Young Station, respectively. For Class I areas more than 50 km from a source, the EPA has identified CALPUFF as a guideline model for long-range transport that is suitable for predicting potential changes in visibility. CALPUFF is a non-steady-state meteorological and air quality dispersion modeling system used to access long-range transport of pollutants.

The NDDH modeling protocol confirmed that the two Class I areas to be considered for visibility impairment analysis are the TRNP and Lostwood NWR. However, the three units or areas of the TRNP are to be treated as separate Class I areas for the analysis.

1.3.1 CALPUFF MODELING METHODOLOGY

Visibility impairment is caused by a combination of particles and gases in the atmosphere. Some particles and gases scatter light, others absorb light. The combined effect of scattering and absorption is called "light extinction" which is most commonly seen as haze. This haziness is measured in deciView (dV) units, and is related to light extinction coefficient by the following equation:

$$dV = 10 \ln(b_{ext}/10)$$

Where b_{ext} is light extinction coefficient in inverse megameters.

Visibility impairment is a function of light extinction. Light extinction occurs when light energy is either scattered or absorbed by particles in the air. The amount of moisture in the air also plays a role in light extinction. Certain gases combine with moisture in the air to form small light scattering particles. These gases, most notably SO_2 and NO_X, are significant components of coal-fired power plant emissions. Particulate Matter (PM) also contributes to light extinction. In the BART Determination Guidelines, the EPA states that "You [the State] may use PM_{10} as an indicator for particulate matter. We do not recommend the use of Total Suspended Particulates (TSP). As emissions of PM_{10} include the components of $PM_{2.5}$ as a subset, there is no need to have separate 250 ton thresholds for PM_{10} and $PM_{2.5}$; 250 tons of PM_{10} represents at most 250 tons of $PM_{2.5,}$ and at most 250 tons of any individual particulate species such as elemental carbon, crustal material, etc." (70 FR 39160). The NDDH modeling protocol states that particulate matter emissions should be specified as either coarse (PM_{10} minus $PM_{2.5}$) or fine ($PM_{2.5}$). The distinction between coarse and fine particulate occurs in the modeling.

The NDDH modeling protocol recommends a specific version of the CALPUFF modeling system as modified by the NDDH to specifically address terrain, climate, and emission characteristics of MRYS. (CALMET and CALPUFF were recompiled by the NDDH while the CALPOST executable used for this visibility analysis was the EPA guideline executable). Along with the CALPUFF modeling system, the NDDH also provided the RUC2-MM5 gridded wind field data (2000-2002), surface, upper air, and precipitation files, and CALMET and CALPUFF input files. The input files contained the specific coordinate grid points, wind field options, terrain, dispersion options, receptor coordinates and plume characteristics and other model parameters that the NDDH has determined best represents the region. The NDDH version of CALPUFF was used for modeling.

In order to predict the change in light extinction at TRNP and Lostwood NWR areas, SO_2, NO_X, and PM were modeled with CALPUFF using pre-control and post-control emission scenarios. A variety of post-control scenarios were used to determine the reduction in visibility impact for each control technology. The NDDH identified 104 receptors allocated over both TRNP and Lostwood NWR. These receptors are location points for which CALPUFF was used to perform a visibility calculation.

The BART guideline states that a visibility improvement is based upon the modeled change in visibility impacts, measured in deciViews, for the pre-control and post-control emission scenarios. The comparison should be made for the 98th percent days (70 FR 39170). The NDDH modeling protocol provides additional clarification about BART applicability by stating, "…the context of the

98th percentile 24-hour delta-deciView prediction is with respect to days of the year, and is not receptor specific. A 24-hour prediction greater than 0.5 delta-deciView at any receptor in a Class I area would constitute a day of exceedance, and up to 7 days of exceedance would be allowed per year per Class I area (i.e., the 98th percentile is approximated by the eighth-highest daily prediction)." In other words, visibility impacts should be compared on an annual basis using the eighth highest day for comparison (365 * (1-.98) = 7 days of acceptable exceedance). However, NDDH subsequently advised that the delta-deciView comparison should be made at the 90th percentile to be consistent with the Western Regional Air Partnership (WRAP) protocol. Therefore, the visibility impairment impact reduction presented for each control scenario in this section is based on the 90th percentile value.

1.3.2 MODELING SCENARIOS

Since a BART analysis is based on the degree of reduction achieved by the application of control technologies, the CALPUFF analysis examined multiple operating scenarios based upon the feasible control technologies identified for each pollutant. These scenarios represent the emissions of SO_2, NO_X, and PM under the following conditions:

- NDDH BART Modeling Protocol emission rates
- Post-Control emissions based upon BACT-level emission rates as required by the Consent Decree

The emission rates modeled in each scenario are presented in Table 1.3-1.

Table 1.3-1 – Milton R. Young Station Modeling Scenarios

Scenario	Unit 1			Unit 2		
	NO_X (lb/hr)	SO_2 (lb/hr)	PM Coarse/Fine (lb/hr)	NO_X (lb/hr)	SO_2 (lb/hr)	PM Coarse/Fine (lb/hr)
Screening	Protocol	Protocol	Protocol	Protocol	Protocol	Protocol
1	1,070.7	Protocol	Protocol	2,011.6	Protocol	Protocol
2	Protocol	723.1	Protocol	Protocol	1,574.4	Protocol
3	Protocol	Protocol	38.5 / 5.8	Protocol	Protocol	133.7 / 21.0
4	1,070.7	723.1	38.5 / 5.8	2,011.6	1,574.4	133.7 / 21.0
5	1,070.7	723.1	38.5 / 5.8	2,011.6	1,574.4	133.7 / 21.0

These scenarios represent the emission rates evaluated for consideration in making a BART recommendation. The emission rates presented in Table 1.3-1 correspond to control options and efficiencies required by the Consent Decree. The scenario from the NDDH BART modeling protocol is based on the historical, maximum 24-hour emission rates for MRYS between 2000 and 2002. These rates were supplied to the NDDH by Minnkota, but were based upon operations that were not representative of stack conditions associated with new or modified retrofit control technologies. Due to analyses performed on plant operations and historical emissions data, Minnkota has determined that unit operating conditions associated with these protocol rates are not representative of future maximum 24-hour emissions and has requested NDDH to allow the use of an alternative baseline for modeled post-control emission rates. NDDH agreed to the use of an alternative baseline. The alternative baseline post-control scenarios are based upon various control technology emission reductions being applied to emissions from a maximum 24-hour average heat input of 2,955 mmBtu/hr for Unit 1 and 5,158 mmBtu/hr for Unit 2. The emission rates associated with each scenario are discussed in the section related to the controlled pollutant.

As shown in Table 1.3-1, multiple modeling scenarios were conducted to determine the specific visibility impact reduction associated with the control of each pollutant. To determine a specific visibility impact, the emission rate for the pollutant of concern was changed from the protocol rate to the post-control rate. Thus, any visibility impairment impact reduction for that modeling scenario was due solely to the application of the individual pollutant's control technology. This methodology was used for NO_X, SO_2, and PM. Additional modeling runs were conducted to determine the overall visibility impairment impact reduction caused by simultaneous application of all control technologies. In Table 1.3-1, modeling scenario 4 was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies for each unit individually. Modeling scenario 5 was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies for both units combined. The modeling results are summarized and discussed in the sections below.

2.0 NO_X BART EVALUATION

The BART analyses for NO_X emissions from MRYS Unit 1 and Unit 2 are described in this section. Technical descriptions of MRYS Unit 1 and Unit 2 boilers and existing air pollution control equipment are provided. As discussed in the introduction, Minnkota has entered into a Consent Decree (CD) that requires MRYS to install BACT-level NO_X control technologies on both units. For NO_X, the CD required that a complete BACT analysis be performed to determine the applicable control technologies for each unit. The BACT analysis report is included as Appendix A. Because BACT is considered to be more stringent than BART, the analysis can be shortened to use control technologies identified by the NO_X BACT analysis for meeting BART. The remaining portion of the BART analysis considers visibility impairment impacts on the nearest Class 1 area.

2.1 NO_X EVALUATION BASIS – UNIT 1

Milton R. Young Station Unit 1 includes a Babcock and Wilcox steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. Original unit design steam generating capacity is 1.714 million lbs/hr at 1,920 psi with a fuel heat input of 2,510 mmBtu/hr. The boiler is fired by seven ten-foot diameter cyclone burners, arranged “three over four” across the front wall of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the electrostatic precipitator (ESP). Unit 1 has a nominal 235 MW net design output capacity rating, is typically capable of sustained output of approximately 253 MW gross, and has an ultimate short-term maximum gross output (URGE) rating of 278 MW. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boiler.

The modeling for Unit 1 uses two NO_X emission rates as a basis for the visibility impairment impacts. One emission rate was based upon the NDDH Modeling Protocol value of 2,855.2 lb NO_X/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The second emission rate of 1,070.7 lb NO_X/hr was based upon application of Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Overfire Air (ASOFA) at a more representative maximum heat input of 2,955 mmBtu/hr. According to the BACT analysis required by the Consent Decree, SNCR used in conjunction with ASOFA was considered the best technology and therefore was evaluated as BART for Unit 1.

2.1.1 NO$_X$ VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the BART NO$_X$ analysis was to conduct a visibility improvement determination for Unit 1. Due to the association of the Consent Decree and requisite BACT analysis, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the BACT analysis resulted in one control technology, only one related emission rate was modeled to determine the visibility impairment impacts. The NDDH BART protocol[5] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then compared with the results predicted from a modeled post-control NO$_X$ emission rate based upon the control technology specified for Unit 1 in the BACT analysis.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 1. The post-control CALPUFF model scenario for MRYS Unit 1 was conducted with the protocol SO$_2$ and PM emission rates and the post-control NO$_X$ emission rate as discussed in Section 2.1 and Table 1.3-1.

The results of the visibility modeling at the protocol baseline NO$_X$ emission rate for MRYS Unit 1 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control NO$_X$ emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for all Class 1 areas at the post-control BACT-level NO$_X$ emission rate was below the 0.50 dV threshold level. The modeling results are presented in Table 2.1-1.

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[5] "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final)", November, 2005, North Dakota Department of Health (NDDH), Division of Air Quality.

Table 2.1-1 – NO_X Visibility Impairment Impacts and Reductions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.549	0.376	0.173
TRNP-North Unit	0.628	0.410	0.218
TRNP-Elkhorn Ranch	0.374	0.263	0.111
Lostwood NWR	0.750	0.487	0.263

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

2 - NO_X emissions reduction by 62.5% over protocol baseline case. This scenario assumes protocol emission rates for SO_2 and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 2.1-2. Similarly, the same information for the post-control NO_X emission rates is summarized and shown in Table 2.1-2. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control NO_X emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 1. The impact in terms of days exceeding 0.50 dV varies from an approximately 17% reduction for TRNP – Elkhorn in 2001 to an approximately 40% reduction for TRNP – South in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 15% for TRNP – Elkhorn in 2002 to approximately 53% for TRNP – South in 2000.

Table 2.1-2 – Visibility Impairment Improvements – MRYS Unit 1 NO$_X$ Scenarios

Class 1 Area	NO$_X$ Control Technique	Days[1] Exceeding 0.5 dV in 2000	Days[1] Exceeding 0.5 dV in 2001	Days[1] Exceeding 0.5 dV in 2002	Days[1] Exceeding 1.0 dV in 2000	Days[1] Exceeding 1.0 dV in 2001	Days[1] Exceeding 1.0 dV in 2002	Consecutive Days[1] Exceeding 0.5 dV 2000	Consecutive Days[1] Exceeding 0.5 dV 2001	Consecutive Days[1] Exceeding 0.5 dV 2002
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	SNCR w/ ASOFA	23	20	35	9	11	19	2	3	3
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	SNCR w/ ASOFA	24	31	38	9	13	20	2	4	4
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	SNCR w/ ASOFA	18	20	27	6	8	17	2	3	4
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	SNCR w/ ASOFA	38	36	33	17	19	20	3	3	4

1 - Number of days for predicted visibility impairment impacts provided in Appendix B.

2.2 NO$_X$ EVALUATION BASIS – UNIT 2

Milton R. Young Unit 2 is a Babcock and Wilcox steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. Original unit design steam generating capacity is 3.20 million lbs/hr at 2,620 psi with a fuel heat input of 4,696 mmBtu/hr. The boiler is fired by twelve ten-foot diameter cyclone burners, arranged "three over three" across the front and rear walls of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 2 has a nominal 439 MW net design output capacity rating, is capable of sustained output of approximately 462 MW gross, and has an ultimate short-term maximum gross output (URGE) of 512 MW. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boilers.

The modeling for Unit 2 uses two NO$_X$ emission rates as a basis for the visibility impairment impacts. One emission rate was based upon the NDDH Modeling Protocol value of 5,364.2 lb NO$_X$/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The second emission rate of 2,011.6 lb NO$_X$/hr was based upon application of Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Overfire Air (ASOFA) at a more representative maximum heat input of 5,158 mmBtu/hr. According to the BACT analysis required by the Consent Decree, SNCR used in conjunction with ASOFA was considered the best technology and therefore was evaluated as BART for Unit 2.

2.2.1 NO$_X$ VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the BART NO$_X$ analysis was to conduct a visibility improvement determination for Unit 2. Due to the association of the Consent Decree and requisite BACT analysis, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the BACT review resulted in one control technology, only one related emission rate was modeled to determine the visibility impairment impacts. The NDDH BART protocol[6] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then

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[6] Ibid, NDDH Modeling Protocol.

compared with the result predicted from a modeled post-control NO_X emission rate based upon the control technology specified for Unit 2 in the BACT analysis.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 2. The post-control CALPUFF model scenario for MRYS Unit 2 was conducted with the protocol SO_2 and PM emission rates and the post-control NO_X emission rate as discussed in Section 2.2 and Table 1.3-1.

The results of the visibility modeling at the protocol baseline NO_X emission rate for MRYS Unit 2 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control NO_X emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for three of the Class 1 areas at the post-control BACT- level NO_X emission rate were below the 0.50 dV threshold level. The Lostwood NWR Class 1 area had a modeled visibility impairment impact of 0.544 dV. The modeling results are presented in Table 2.2-1.

Table 2.2-1 – NO_X Visibility Impairment Impacts and Reductions, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.580	0.406	0.174
TRNP-North Unit	0.619	0.438	0.181
TRNP-Elkhorn Ranch	0.360	0.277	0.083
Lostwood NWR	0.775	0.544	0.231

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

2 - NO_X emissions reduction by 62.5% over protocol baseline case. This scenario assumes protocol emission rates for SO_2 and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 2.2-2. Similarly, the same information for the post-control NO_X emission rates is summarized and shown in Table 2.2-2. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control NO_X emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 2. The impact in terms of days exceeding 0.50 dV varies from an approximately 9% reduction for TRNP – Elkhorn in 2001 to an approximately 37% reduction for TRNP – South in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 15% for TRNP – Elkhorn in 2002 to approximately 50% for TRNP – North in 2000.

Table 2.2-2 – Visibility Impairment Improvements – MRYS Unit 2 NO_X Scenarios

Class 1 Area	NO_X Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	SNCR w/ ASOFA	26	20	40	11	11	21	2	3	3
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	SNCR w/ ASOFA	24	32	40	9	13	23	2	4	4
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	SNCR w/ ASOFA	22	21	30	7	10	17	2	3	4
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	SNCR w/ ASOFA	41	39	34	19	22	20	3	3	4

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control NO_X emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix B.

3.0 SO_2 BART EVALUATION

In this section, the BART analysis for Milton R. Young Station (MRYS) is described for SO_2 and a brief description of the existing control technology for MRYS Unit 2 is presented. Unit 1 does not currently use SO_2 controls. As discussed in the introduction, Minnkota has entered into a Consent Decree (CD) that requires MRYS to install or modify SO_2 control technologies on both units to achieve BACT-level emission rates. Because BACT is considered to be more stringent than BART, the analysis can be shortened to use CD identified control technologies for meeting BART. The remaining portion of the analysis assess technologies for their potential visibility impairment impact reduction capability via visibility modeling results.

3.1 SO_2 EVALUATION BASIS – UNIT 1

Milton R. Young Station Unit 1 is a Babcock and Wilcox steam generator including a lignite-fired boiler with multiple cyclone-furnaces. The original unit design has a fuel heat input of 2,510 mmBtu/hr. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site. The lignite significantly influences the resulting SO_2 concentration of the flue gases emitted from the boilers. Unit 1 currently does not use any SO_2 control technology.

The modeling for Unit 1 uses two SO_2 emission rates as a basis for the visibility impairment impacts. One emission rate was based upon the NDDH Modeling Protocol value of 7,231.2 lb SO_2/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The second emission rate of 723.1 lb SO_2/hr was based upon application of dry Flue Gas Desulfurization (FGD) process applied to a more representative maximum heat input of 2,955 mmBtu/hr. The Consent Decree defines the BACT-level SO_2 control technology options and removal efficiencies applicable for installation on MRYS Unit 1. The control technologies included in the CD are a wet FGD process achieving 95% removal efficiency, a dry FGD process achieving 90% removal efficiency or an equivalent alternative technology to be approved by the NDDH. At the time of this report, Minnkota had not selected the SO_2 control technology for MRYS Unit 1. Thus, a dry FGD process that achieves a worst case 90% removal was selected and evaluated as BART for Unit 1. Because a dry FGD process was evaluated as worst case, this analysis will still be applicable if Minnkota chooses to utilize an equivalent or more efficient control technology.

3.1.1 SO_2 VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the BART SO_2 analysis was to conduct a visibility improvement determination for Unit 1. Due to the association of the Consent Decree, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the CD specified applicable BACT-level control technologies, one technology (i.e., the dry FGD process) and related emission rate was selected for modeling to determine the visibility impairment impacts. The NDDH BART protocol[7] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then compared with the result predicted from a modeled post-control SO_2 emission rate based upon the BACT-level control technology specified in the CD.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 1. The post-control CALPUFF model scenario for MRYS Unit 1 was conducted with the protocol NO_X and PM emission rates and the post-control SO_2 emission rate as discussed in Section 3.1 and Table 1.3-1.

The results of the visibility impairment modeling at the protocol baseline SO_2 emission rate for MRYS Unit 1 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control SO_2 emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for all Class 1 areas at the post-control SO_2 emission rate was below the 0.50 dV threshold level. The modeling results are presented in Table 3.1-1.

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[7] Ibid, NDDH Modeling Protocol.

Table 3.1-1 – SO_2 Visibility Impairment Impacts and Reductions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.549	0.250	0.299
TRNP-North Unit	0.628	0.269	0.359
TRNP-Elkhorn Ranch	0.374	0.160	0.214
Lostwood NWR	0.750	0.322	0.428

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

2 - SO_2 emissions reduction by 90% over protocol baseline case. This scenario assumes protocol emission rates for NO_X and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 3.1-2. Similarly, the same information for the post-control SO_2 emission rates is summarized and shown in Table 3.1-2. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control SO_2 emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 1. The impact in terms of days exceeding 0.50 dV varies from an approximately 17% reduction for TRNP – Elkhorn in 2001 to an approximately 74% reduction for TRNP – South in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 27% for TRNP – South in 2001 to approximately 89% for Lostwood NWR in 2000.

Table 3.1-2 – Visibility Impairment Improvements – MRYS Unit 1 SO_2 Scenarios

Class 1 Area	SO_2 Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	Dry FGD	10	20	24	4	11	12	1	3	3
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	Dry FGD	13	31	25	7	13	12	1	4	4
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	Dry FGD	9	20	18	4	8	9	2	3	2
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	Dry FGD	17	36	17	3	19	4	2	3	3

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels.

2 - Number of days for predicted visibility impairment impacts provided in Appendix B.

3.2 SO_2 EVALUATION BASIS – UNIT 2

Milton R. Young Station Unit 2 is a Babcock and Wilcox steam generator including a lignite-fired boiler with multiple cyclone-furnaces. Installed in 1977, the original unit design has a fuel heat input of 4,696 mmBtu/hr. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site. The lignite significantly influences the resulting SO_2 concentration of the flue gases emitted from the boilers. Unit 2 has a Combustion Equipment Associates wet flue gas desulfurization (FGD) system (modified by Combustion Engineering) that treats the majority of the flue gas with the remaining flue gas by-passed for stack gas reheat.

The modeling for Unit 2 uses two SO_2 emission rates as a basis for the visibility impairment impacts. One emission rate was based upon the NDDH Modeling Protocol value of 6,879.0 lb SO_2/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The second emission rate of 1,574.4 lb SO_2/hr was based upon application of wet Flue Gas Desulfurization (FGD) process at a more representative maximum heat input of 5,158 mmBtu/hr. The Consent Decree requires MRYS to modify the existing wet FGD on Unit 2 to achieve a removal efficiency of at least 90%. The modified wet FGD process that achieves at least 90% removal, considered to be BACT-level control technology by the CD, was selected and evaluated as BART for Unit 2.

3.2.1 SO_2 VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the BART SO_2 analysis was to conduct a visibility improvement determination for Unit 2. Due to the association of the Consent Decree, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the CD specified the applicable BACT-level control technology, one technology (i.e., the modified wet FGD process) and related emission rate was selected for modeling to determine the visibility impairment impacts. The NDDH BART protocol[8] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then compared with the result predicted from a modeled post-control SO_2 emission rate based upon the BACT-level control technology specified in the CD.

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[8] Ibid, NDDH Modeling Protocol.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 2. The post-control CALPUFF model scenario for MRYS Unit 2 was conducted with the protocol NO_X and PM emission rates and the post-control SO_2 emission rate as discussed in Section 3.2 and Table 1.3-1.

The results of the visibility impairment modeling at the protocol baseline SO_2 emission rate for MRYS Unit 2 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control SO_2 emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for all Class 1 areas at the post-control SO_2 emission rate was below the 0.50 dV threshold level. The modeling results are presented in Table 3.2-1.

Table 3.2-1 – SO_2 Visibility Impairment Impacts and Reductions, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.580	0.390	0.190
TRNP-North Unit	0.619	0.370	0.249
TRNP-Elkhorn Ranch	0.360	0.225	0.135
Lostwood NWR	0.775	0.493	0.282

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

2 - SO_2 emissions corresponding to improvement of FGD SO_2 removal performance to 90%. This scenario assumes protocol emission rates for NO_X and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 3.2-2. Similarly, the same information for the post-control SO_2 emission rates is summarized and shown in Table 3.2-2. The visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control SO_2 emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 2. The impact in terms of days exceeding 0.50 dV varies from an approximately 9% reduction for TRNP – Elkhorn in 2001 to an approximately 61% reduction for TRNP – Elkhorn in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 14% for TRNP – North in 2002 to approximately 56% for TRNP – South in 2000.

Table 3.2-2 – Visibility Impairment Improvements – MRYS Unit 2 SO_2 Scenarios

Class 1 Area	SO_2 Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	Wet FGD Upgraded to 90% Control	24	20	36	8	11	23	2	3	3
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	Wet FGD Upgraded to 90% Control	22	32	35	11	13	25	2	4	4
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	Wet FGD Upgraded to 90% Control	12	21	24	8	10	16	2	3	2
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	Wet FGD Upgraded to 90% Control	36	39	30	14	22	16	3	3	5

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels.

2 - Number of days for predicted visibility impairment impacts provided in Appendix B.

4.0 PARTICULATE MATTER BART EVALUATION

The BART analyses for PM emissions from MRYS Unit 1 and Unit 2 are described in this section. A brief description of MRYS Unit 1 and Unit 2 existing PM air pollution control equipment is provided. As discussed in the introduction, Minnkota has entered into a Consent Decree (CD). The CD requires MRYS to maintain or upgrade the existing PM controls on both units to achieve specified emission rates. Because the CD specified the PM controls and associated emission rate, the analysis was shortened to use the CD specified PM emission rates for meeting BART. The remaining portion of the analysis assesses potential visibility impairment impact reduction capability for the CD specified emission rates via visibility modeling results.

4.1 PM EVALUATION BASIS – UNIT 1

MRYS Unit 1 is a B&W cyclone-type coal-fired boiler. The quantity of uncontrolled PM emissions is a strong function of the type of boiler utilized. Different boiler types generate different splits between bottom ash, which is collected in the bottom of the boiler, and fly ash, which is entrained in the flue gas and becomes boiler particulate matter emissions. Unit 1 is a cyclone-type boiler that has an inherently lower percentage of fly ash due to the method of combustion. Particulate control is currently provided by a Research-Cottrell Electrostatic Precipitator rated at approximately 99% control.

The modeling for Unit 1 uses two PM emission rates that distinguish between coarse and fine particulate as a basis for the visibility impairment impacts. One emission rate scenario was based upon the NDDH Modeling Protocol values of 36.7 lb PM_{Coarse}/hr and 5.5 lb PM_{Fine}/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. However, as discussed in Section 1.3.2, the protocol emission rates are based upon actual maximum historical 24-hour emissions that are not representative of future maximum 24-hour emissions. After obtaining approval from NDDH to use alternative emission rates based upon representative stack conditions, Minnkota based the post-control emission rates of 38.5 lb PM_{Coarse}/hr and 5.8 lb PM_{Fine}/hr upon application of CD specified rates applied to a more representative maximum heat input of 2,955 mmBtu/hr. The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 1 to achieve an emission rate of 0.015 lb PM/mmBtu if a dry FGD process is selected for SO_2 control or 0.030 lb PM/mmBtu if a wet FGD process is selected. Because a dry FGD process is considered the worst case for SO_2 control, the associated emission rate of 0.015 lb PM/mmBtu is being used for PM.

The post-control emission rate on a lb/hr basis is slightly higher because the existing ESP performance used to derive the protocol emission rate was very good and due to the use of a higher yet more representative heat input.

4.1.1 PM VISIBLITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the BART PM analysis was to conduct a visibility improvement determination for Unit 1. Due to the association of the Consent Decree, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the CD specified the PM control technology and associated emission rate, one emission rate (the 0.015 lb/mmBtu specified in the CD) was selected for modeling to determine the visibility impairment impacts. The NDDH BART protocol[9] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then compared with the result predicted from a modeled post-control PM emission rate based upon the emission rate specified in the CD.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 1. The post-control CALPUFF model scenario for MRYS Unit 1 was conducted with the protocol NO_X and SO_2 emission rates and the post-control PM emission rate as discussed in Section 4.1 and Table 1.3-1.

The results of the visibility impairment modeling at the protocol baseline PM emission rate for MRYS Unit 1 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control PM emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for two of the Class 1 areas at the post-control PM emission rate was below the 0.50 dV threshold level. The TRNP – North Class 1 area had a modeled visibility impairment impact of 0.500 dV and Lostwood NWR Class 1 area had a modeled visibility impairment impact of 0.587 dV. The modeling results are presented in Table 4.1-1.

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[9] Ibid, NDDH Modeling Protocol.

Table 4.1-1 – PM Visibility Impairment Impacts and Reductions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.549	0.465	0.084
TRNP-North Unit	0.628	0.500	0.128
TRNP-Elkhorn Ranch	0.374	0.328	0.046
Lostwood NWR	0.750	0.587	0.163

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

2 - PM emissions corresponding to the 0.015 lb/mmBtu specified in the CD. This scenario assumes protocol emission rates for NO_X and SO_2.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 4.1-2. Similarly, the same information for the post-control PM emission rates is summarized and shown in Table 4.1-2. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control PM emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 1. The impact in terms of days exceeding 0.50 dV varies from an approximately 3% reduction for TRNP – Elkhorn in 2002 to an approximately 27% reduction for TRNP – South in 2001. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 3% for TRNP – North in 2002 to approximately 33% for TRNP – Elkhorn in 2000.

Table 4.1-2 – Visibility Impairment Improvements – MRYS Unit 1 PM Scenarios

Class 1 Area	**PM Control Technique**	**Days[2] Exceeding 0.5 dV in 2000**	**Days[2] Exceeding 0.5 dV in 2001**	**Days[2] Exceeding 0.5 dV in 2002**	**Days[2] Exceeding 1.0 dV in 2000**	**Days[2] Exceeding 1.0 dV in 2001**	**Days[2] Exceeding 1.0 dV in 2002**	**Consecutive Days[2] Exceeding 0.5 dV 2000**	**Consecutive Days[2] Exceeding 0.5 dV 2001**	**Consecutive Days[2] Exceeding 0.5 dV 2002**
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	Fabric Filter Baghouse	31	22	43	13	11	21	3	3	4
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	Fabric Filter Baghouse	27	35	42	11	16	28	2	4	4
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	Fabric Filter Baghouse	22	21	34	8	12	18	2	3	4
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	Fabric Filter Baghouse	44	45	38	21	25	23	3	3	4

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control PM emission levels.

2 - Number of days for predicted visibility impairment impacts provided in Appendix B.

4.2 PM EVALUATION BASIS – UNIT 2

MRYS Unit 2 is a B&W cyclone-type coal-fired boiler. The quantity of uncontrolled PM emissions is a strong function of the type of boiler utilized. Different boiler types generate different splits between bottom ash, which is collected in the bottom of the boiler, and fly ash, which is entrained in the flue gas and becomes boiler particulate matter emissions. Unit 2 is a cyclone-type boiler that has an inherently lower percentage of fly ash due to the method of combustion. Particulate control for Unit 2 is provided by a Wheelabrator-Lurgi electrostatic precipitator rated at approximately 99% control.

The modeling for Unit 2 uses two PM emission rates that distinguish between coarse and fine particulate as a basis for the visibility impairment impacts. One emission rate scenario was based upon the NDDH Modeling Protocol values of 178.7 lb PM_{Coarse}/hr and 28.1 lb PM_{Fine}/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. However, as discussed in Section 1.3.2, the protocol emission rates are based upon actual maximum historical 24-hour emissions that are not representative of future maximum 24-hour emissions. After obtaining approval from NDDH to use alternative emission rates based upon representative stack conditions, Minnkota based the post-control emission rates of 133.7 lb PM_{Coarse}/hr and 21.0 lb PM_{Fine}/hr upon application of CD specified rates applied to a more representative maximum heat input of 5,158 mmBtu/hr. The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 2 to achieve an emission rate of 0.030 lb PM/mmBtu.

4.2.1 PM VISIBLITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the BART PM analysis was to conduct a visibility improvement determination for Unit 2. Due to the association of the Consent Decree, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the CD specified the PM control technology and associated emission rate, one technology (i.e., the existing ESP) and related emission rate was selected for modeling to determine the visibility impairment impacts. The NDDH BART protocol[10] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then compared with the result predicted from a modeled post-control PM emission rate based upon the emission rate specified in the CD.

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[10] Ibid, NDDH Modeling Protocol.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 2. The post-control CALPUFF model scenario for MRYS Unit 2 was conducted with the protocol NO_X and SO_2 emission rates and the post-control PM emission rate as discussed in Section 4.2 and Table 1.3-1.

The results of the visibility impairment modeling at the protocol baseline PM emission rate for MRYS Unit 2 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control PM emission rate showed a reduction in visibility impairment impact for all Class 1 areas. The modeling results are presented in Table 4.2-1.

Table 4.2-1 – PM Visibility Impairment Impacts and Reductions, MRYS Unit 2

Federal Class 1 Area	**Visibility Impairment Impacts[1] (deciView)**		**Visibility Impairment Reduction (deciView)**
	Protocol Emissions	**Post-Control Emissions[2]**	
TRNP-South Unit	0.580	0.563	0.017
TRNP-North Unit	0.619	0.570	0.049
TRNP-Elkhorn Ranch	0.360	0.345	0.015
Lostwood NWR	0.775	0.739	0.036

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

2 - PM emissions corresponding to the 0.030 lb/mmBtu specified in the CD. This scenario assumes protocol emission rates for NO_X and SO_2.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results were summarized and presented in Table 4.2-2. Similarly, the same information for the post-control PM emission rates was summarized and is shown in Table 4.2-2. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control PM emission rates were reduced in the majority of cases. The TRNP – South Class 1 area in 2001 and 2002 each had one additional day with a visibility impairment impact exceeding 0.50 dV. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 2. The TRNP – South Class 1 area in 2001 and 2002 each had a impact increase of one day in terms of days exceeding 0.50 dV. The approximate visibility impact increase for 2001 was 4% and for 2002 was 2%. The impact reduction in terms of days exceeding 0.50 dV varies from approximately 0% in multiple areas and years to approximately 14% for TRNP – North in 2001. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 0% in multiple areas and years to approximately 13% for Lostwood NWR in 2000.

There are several plausible explanations for an increase in the number of days with a visibility impairment impact exceeding 0.50 dV for TRNP – South in 2001 and 2002. One possible cause could be the reduced exit velocity that was due to an increase in stack diameter and an increased flow rate caused by scrubbing of all of the flue gas. Because the modeling results presented in Table 4.2-1 showed a reduction in visibility impairment impacts for all Class 1 areas, additional research was not conducted to determine the cause of the increase.

Table 4.2-2 – Visibility Impairment Improvements – MRYS Unit 2 PM Scenarios

Class 1 Area	PM Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	Maintain ESP	37	29	52	16	13	27	3	3	4
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	Maintain ESP	29	37	45	18	21	29	2	4	4
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	Maintain ESP	29	23	36	11	13	19	2	3	4
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	Maintain ESP	50	48	45	27	27	25	3	3	4

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control PM emission levels.

2 - Number of days for predicted visibility impairment impacts provided in Appendix B.

5.0 BART RECOMMENDATIONS

This report presents the analysis of control technologies for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Minnkota Power Cooperative Inc.'s (Minnkota's) Milton R. Young Station (MRYS) Units 1 and 2. The final result of this analysis is a recommendation of the Best Achievable Retrofit Technology (BART) for each unit based upon "improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). The presented emission rates in this section are the BART recommendation.

As stated previously, this report uses the determinations made in the Consent Decree (CD) and associated NO_X BACT analysis as part of the analysis. BACT is considered to be more stringent than BART because it usually is not limited by the design of existing equipment or current operating conditions as is required for a retrofit application. Because BACT is similar to BART and BACT-level controls are required by CD, the visibility impacts evaluation was the only step in the determination performed to satisfy BART. This analysis evaluated the visibility impairment impacts of the BACT-level control technologies specified in the CD and results in a BART recommendation based upon an acceptable amount of visibility improvement in Class 1 areas. This section summarizes the visibility analysis performed for each Unit and its associated pollutants.

5.1 UNIT 1 BART RECOMMENDATIONS

The remaining step for the BART analysis was to conduct a visibility improvement determination for MRYS Unit 1. Due to the association of the Consent Decree, which required a NO_X BACT analysis, along with the specification of SO_2 and PM control technologies or emission rates for each pollutant, the visibility impairment impact analysis was the only impact evaluation necessary to establish BART. To conduct a visibility impairment impact analysis, the baseline visibility impairment impact was compared with the predicted impact from a post-control emission rate modeled separately for each pollutant. A control technology and associated emission rate are considered to meet BART requirements when the 90th percentile modeling results show a reduction in visibility impairment impact. The MRYS Unit 1 modeling results for all pollutants showed a reduction in visibility impairment impact for all Class 1 areas. Thus, the control technologies recommeded as BACT for NO_X emissions and those specified by the CD for SO_2 and PM emissions along with the modeled emission rates are recommended as BART. Table 5.1-1 summarizes the control technologies and associated emission rates that are recommended as BART for each pollutant. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

Table 5.1-1 – Recommended BART 30-Day Rolling Average, MRYS Unit 1

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.36*
SO_2	Dry Flue Gas Desulfurization (FGD) Process	0.24
PM	Fabric Filter Baghouse	0.015**

* Excludes startups. See Appendix A for a detailed discussion.

** Emission rate is associated with SO_2 control technology and applies to dry FGD process only.

The pollutant specific modeling results for MRYS Unit 1 described previously in the analysis represent the visibility impairment impact reduction attributable to a technology used to control an individual pollutant of concern. While this result supports an individual technology in terms of visibility impact reduction, the result is not representative of actual plant-wide operations. Application of the BART-recommended technologies will result in simultaneous control of all pollutants. Thus, a comparison of the visibility impairment reduction due to reducing the protocol emission rates to post-control emission rates for all pollutants simultaneously is more representative of actual expected results. A modeling scenario was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies and the results are presented in Table 5.1-2.

Table 5.1-2 – Visibility Impairment Impacts for Control of all Pollutants, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction
	Protocol Emissions	Post-Control Emissions	
TRNP-South Unit	0.549	0.091	0.458
TRNP-North Unit	0.628	0.093	0.535
TRNP-Elkhorn Ranch	0.374	0.057	0.290
Lostwood NWR	0.750	0.127	0.623

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

The simultaneous control of all pollutants for MRYS Unit 1 results in visibility impairment impacts that are approximately one fourth of the threshold the EPA designates as contributing to visibility impairment. These modeling results provide additional support for recommending the control technologies recommended as BACT for NO_X emissions and those specified by the CD for SO_2 and PM emissions as BART.

The BART analysis for MRYS was conducted before determining the SO_2 control technology for Unit 1. The Consent Decree provides the acceptable BACT-level SO_2 emission control technologies for Unit 1. SO_2 emissions were modeled using a dry FGD process at 90% control. A 90% reduction is the minimum reduction allowed by the CD and results in the worst case SO_2 post-control emission rate. Because a dry FGD process was evaluated as worst case, this analysis will still be applicable if Minnkota chose to utilize an equivalent or more efficient SO_2 emission control technology. However, if the final selection of SO_2 control technology and the corresponding post-control emission rate required by the CD changes, the post-control PM emission rate required by the CD may also change.

As discussed previously in this report, the Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 1 to achieve an emission rate of 0.015 lb PM/mmBtu if a dry FGD process is selected for SO_2 control or 0.030 lb PM/mmBtu if a wet FGD process is selected. Because a dry FGD process is considered the worst case for SO_2 control, the associated emission rate of 0.015 lb PM/mmBtu is being used for PM (only applies with utilization of dry FGD for SO_2 control). If Minnkota determines that a wet FGD process with 95% SO_2 control should be used for Unit 1, the PM emission rate dictated by the Consent Decree will increase to 0.030 lb PM/mmBtu (only applies with utilization of wet FGD for SO_2 control). Although the PM emission rate would change as a result of the SO_2 control scenario, when considering the effect of all pollutants on visibility impacts, reducing SO_2 emissions would have a greater effect. The modeling results in Appendix B provide the percent contribution of each pollutant to the visibility impact. For Unit 1, the PM contribution to the visibility impact ranges from 0.13% to 2.22%. The SO_2 contribution to the visibility impact ranges from 7.64% to 67.12%. Because the contribution of SO_2 is more than double the PM contribution in all cases, reducing SO_2 emissions by an additional 50% by going from 90% to 95% control would have a greater effect than doubling PM emissions. Thus, this analysis will still be applicable if Minnkota chooses to utilize a wet FGD process for SO_2 control and incorporate the corresponding increase in the PM emission rate as dictated by the Consent Decree.

5.2 UNIT 2 BART RECOMMENDATIONS

The remaining step for the MRYS Unit 2 BART analysis was to conduct a visibility improvement determination. Due to the association of the Consent Decree which required a NO_X BACT analysis along with the specification of SO_2 and PM control technologies or emission rates for each pollutant, the visibility impairment impact analysis was the only subsequent impact evaluation necessary to establish BART. To conduct a visibility impairment impact analysis, the baseline visibility impairment impact was compared with the predicted impact from a post-control emission rate modeled separately for each pollutant. A control technology and associated emission rate are considered to meet BART requirements when the 90th percentile modeling results show a reduction in visibility impairment impact. The MRYS Unit 2 modeling results for all pollutants showed a reduction in visibility impairment impact for all Class 1 areas. Thus, the control technologies recommended as BACT for NO_X emissions and those specified by the CD for SO_2 and PM emissions along with the modeled emission rates are recommended as BART. Table 5.2-1 summarizes the control technologies and associated emission rates that are recommended as BART for each pollutant. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

As discussed previously in this report, the CD required that a complete BACT analysis be performed to determine the applicable NO_X control technology for Unit 2. Due to amount of time necessary to complete a BACT analysis and a BART analysis, both reports were assembled concurrently. A preliminary BACT analysis based on historical emissions records and estimated control technology capabilities resulted in an emission rate of 0.39 lb NO_X/mmBtu to be assumed for the post-control 24-hour average emission rate for the visibility impairment impact modeling. However, further analysis conducted after the completion of the CALPUFF modeling resulted in a 30-day rolling average NO_X emission rate of 0.35 lb NO_X/mmBtu. Because the final recommended BART 30-day rolling average emission rate is lower than the modeled rate and the associated visibility impact would be reduced, dispersion modeling was not redone.

Table 5.2-1 – Recommended BART 30-Day Rolling Average, MRYS Unit 2

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.35*
SO_2	Upgrade of Existing Wet Flue Gas Desulfurization (FGD) Process	0.31
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See Appendix A for a detailed discussion.

The pollutant specific modeling results for MRYS Unit 2 described previously in this analysis represent the visibility impairment impact reduction attributable to a technology used to control an individual pollutant of concern. While this result supports an individual technology in terms of visibility impact reduction, the result is not representative of actual plant-wide operations. Application of the BART recommended technologies will result in simultaneous control of all pollutants. Thus, a comparison of the visibility impairment reduction due to reducing the protocol emission rates to post-control emission rates for all pollutants simultaneously is more representative of actual expected results. A modeling scenario was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies and the results are presented in Table 5.2-2.

Table 5.2-2 – Visibility Impairment Impacts for Control of all Pollutants, MRYS Unit 2

Federal Class 1 Area	**Visibility Impairment Impacts[1] (deciView)**		**Visibility Impairment Reduction**
	Protocol Emissions	**Post-Control Emissions**	
TRNP-South Unit	0.580	0.173	0.407
TRNP-North Unit	0.619	0.169	0.450
TRNP-Elkhorn Ranch	0.360	0.104	0.256
Lostwood NWR	0.775	0.243	0.532

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

The simultaneous control of all pollutants for MRYS Unit 2 results in visibility impairment impacts that are approximately one half of the threshold the EPA designates as contributing to visibility impairment. These modeling results provide additional support for recommending the control technologies recommended as BACT for NO_X emissions and those specified by the CD for SO_2 and PM emissions as BART.

In addition to the visibility impairment impact modeling scenario conducted to determine the effects of simultaneous control of all pollutants for the individual units, another modeling scenario was conducted to combine the effects of both units. The modeling showed that the visibility impairment impact for all Class 1 areas was reduced to below the threshold the EPA designates as contributing to visibility impairment. Results of this scenario (labeled Run 5) are provided in Appendix B.

Appendix A

NO_X BACT Analysis Unit 1

NO_X BACT Analysis Unit 2

NOx BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS STUDY

for

Milton R. Young Station Unit 1
Minnkota Power Cooperative, Inc.

Final Report

October 2006

31777

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NOx Best Available
Control Technology
Analysis Study
for
Milton R. Young Station Unit 1

prepared for

Minnkota Power Cooperative, Inc.

October 2006

Project No. 31777

Final Report

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

INDEX AND CERTIFICATION

Minnkota Power Cooperative, Inc.
Milton R. Young Station Unit 1
NO_X Best Available Control Technology Analysis Study

Project 31777

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Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the laws and rules of the North Dakota State Board of Registration under Title 28 Administrative Code.

STEPHEN W. VOSS
4945

10-4-06

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EXECUTIVE SUMMARY

The Milton R. Young Station of Minnkota Power Cooperative, Inc. (Minnkota) and Square Butte Electric Cooperative (Square Butte) includes two cyclone-furnace, lignite-fired steam-electric generating units (SEGUs). The units both fire North Dakota lignite supplied from the adjacent mine, near Center, North Dakota. Unit 1 has a nominal 235 MW net design output capacity rating, is typically capable of sustained output of approximately 250 MW_g (gross), and has a gross design output capacity rating of 257 MW_g. Unit 1 is owned and operated entirely by Minnkota. Unit 2 has a nominal 439 MW net design output capacity rating, is capable of sustained output of approximately 460 MW_g (gross), and has a gross design output capacity rating of 477 MW_g. Unit 2 is owned by Square Butte Electric Cooperative (Square Butte), and operated by Minnkota.

A Notice of Violation (NOV) from the United States Environmental Protection Agency (US EPA or EPA) was issued to Minnkota Power Cooperative on June 21, 2002. The NOV alleged that modifications had been made at the Milton R. Young Station that would have required a construction permit under New Source Review (Code of Federal Regulations 40 CFR 52.21, and North Dakota Administrative Code NDAC 33-15). As a result of this allegation, a civil complaint was filed by the United States of America and the State of North Dakota against Minnkota Power Cooperative Inc. ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") in the United States District Court for the District of North Dakota. A Consent Decree (CD) has been approved that represents a final negotiated settlement of the United States' and North Dakota's claims against Minnkota and Square Butte. The Consent Decree requires Minnkota and Square Butte to perform a "NO_X Top-Down Best Available Control Technology (BACT) Analysis" to describe the emission limits for NO_X that will be required at Units 1 and 2, expressed as a 30-Day Rolling Average NO_X Emission Rate [Consent Decree paragraph 24, page 7, and paragraph 5, page 4].

Burns & McDonnell was retained to conduct a Top-Down BACT Analysis for nitrogen oxides (NO_X) at the Milton R. Young Station. The results of the BACT analysis are presented in this study report.

The procedures mandated by the Consent Decree for performing a Top-Down BACT Analysis are outlined in Chapter B of the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990 ("EPA's NSR Manual"). The MRY Station BACT analysis was performed in accordance with this procedure. The

EPA's NSR Manual outlines five basic steps that are to be followed in this BACT analysis. These basic steps for such a BACT analysis are summarized as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

A Best Available Control Technology (BACT) analysis was performed for Milton R. Young Unit 2 for NO_X using the EPA's "top-down" approach. Best Available Control Technology is defined as "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant" (40 CFR 52.21, NSR Manual B.1).

Unit 1 at Milton R. Young Station is a cyclone-fired boiler that burns North Dakota lignite. The method of firing is very significant in analyzing control options for NO_X emissions. A cyclone boiler produces inherently higher uncontrolled NO_X levels than pulverized-coal and circulating fluidized bed boilers. There have been no new coal-burning cyclone-fired boilers built and installed in the United States since the early 1980's. Consequently, there are no examples of BACT control options listed in the RACT/BACT/LAER Clearinghouse database for consideration and direct application of published NO_X emission permit limits on the Milton R. Young cyclone-fired boilers.

Step 1 – Identify All Control Technologies

The Consent Decree requires that the NO_X Top-Down BACT Analysis for the Milton R. Young Station "include an evaluation of Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Overfire Air (OFA), Rich Reagent Injection (RRI), as well as other NO_X control technologies" potentially applicable for lignite-fired cyclone boilers [Consent Decree paragraph 65, page 19]. Other identified control techniques, such as fuel switching and fuel cleaning, and combustion-related emission control technologies, such as fuel reburn and oxygen-enhanced combustion, were also considered.

Step 2 – Eliminate Technically Infeasible Options

The BACT evaluation determined that not all the technologies identified were considered available and applicable. The technically infeasible alternatives were eliminated from further evaluation, along with feasible technologies with economic impacts that were unreasonable compared to other cost-efficient alternatives to control NO_X emissions for MRY Station Unit 1.

The technical feasibility of applying NO_X emission reduction techniques and technologies at Milton R. Young Station is dominated by the composition and combustion characteristics of the North Dakota lignite supplied solely from a surface mine adjacent to the plant. This mine is the only supplier of solid fuel for this station, as there are no railroad facilities provided to service the Milton R. Young plant. North Dakota lignite has high moisture and high sodium content, moderate higher heating values, and can have a widely variable and high ash content compared to other coals. These characteristics create difficulties in promoting consistent, steady combustion and slag formation in the cyclone burners. It also results in producing a flyash that has severe deposition characteristics.

Both boilers include a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boilers.

Ash deposition in each boiler and air preheater is a significant operational challenge for the facility. Significant equipment and manpower resources are devoted to on-going removal of fireside ash accumulations. Unit outages must be conducted at regular intervals to clean each boiler (approximately every 80-120 days). There are a number of issues that make selective catalytic reduction (SCR) technically infeasible for NO_X emission control for Milton R. Young Unit 1. The consistent long-term operation of SCR technology on lignite-fired cyclone boilers will be drastically inhibited by the susceptibility of the SCR catalyst to severe fouling, deactivation, and erosion resulting from the actions of the emitted flue gases and flyash, and ash deposit removal operations. SCR technology is considered technically infeasible for application on the cyclone boilers at the Milton R. Young Station.

Rich Reagent Injection has been demonstrated on boilers burning bituminous and subbituminous coal. However, it has not been commercially installed and placed in continuous operation on a cyclone-fired boiler burning lignite coal with high fouling and slag temperature sensitivities associated and a highly variable heat content. RRI adds urea reagent to the hot furnace gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea, and thus creating NO_X. While RRI is specifically intended for NO_X emissions control on cyclone boilers, RRI is considered technically infeasible for application on the lignite fired cyclone boilers at the Milton R. Young Station due to the variable heat content of the lignite fuel which allows the creation of oxygen-rich conditions in the boiler.

The application of separated overfire air (SOFA) for NOx emissions control on Milton R. Young Unit 1's boiler was evaluated as part of the BACT analysis. A version of separated overfire air specifically designed for increased NO_X emission reduction performance for lignite-fired cyclone boilers, referred to as "Advanced SOFA" in this analysis, can be installed on both units at M.R. Young Station. This highest-performing form of SOFA can be applied alone and in combination with other technologies. Key aspects of successfully applying and operating a separated overfire air system on a cyclone-fired boiler are the ability to:

- Accurately measure the fuel heat input rate (BTUs) and combustion air inputs on a real-time, individual cyclone by cyclone basis, to allow the ability to determine and control the desired air/fuel ratio, especially when "starved air" (i.e. substoichiometric) combustion conditions are required.
- Maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps.

The degree to which the individual cyclone furnaces can be operated with less-than-theoretical (substoichiometric) combustion air, which corresponds to operation of a SOFA system, directly contributes to less combustion-related NO_X formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. This places great emphasis on achieving tight control over the air/fuel ratios on each cyclone during air-staged combustion operation with SOFA in order for air-staged combustion to be successful in producing significant additional NOx emissions reduction on lignite-fired cyclone boilers.

In the case of MRY Station Unit 1's boiler, air-staged combustion must be sufficient to reduce NO_X emissions while releasing enough heat to continue to melt the fuel ash so that it flows effectively within and from the cyclone burners. Due to the short-term variability of the combustible and ash components of North Dakota lignite supplied from the current mine near Center, ND, and the complex behavior of lignite ash when exposed to high temperatures, the extent of air-staging and thus the level of NO_X control while operating the highest-performing version of SOFA system is expected to be modest.

Selective Non-Catalytic Reduction (SNCR) technology has been used to reduce NO_X emissions on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used on fuel oil and natural gas-fired units. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without air-staged combustion with overfire air in full operation.

There are significant concerns associated with effective long-term SOFA operation for Milton R. Young Station Unit1‘s boiler. The ability of basic combustion equipment and improvements to precisely measure the boiler’s heat input rate in real-time on an individual cyclone by cyclone basis with compensation for the short-term variability of the combustible content of the Center lignite to consistently maintain substoichiometric operation of every cyclone during air-staged combustion is unproven.

Several other techniques and technologies were considered technically feasible for NOx emissions control at MRY Station: Fuel Blending/Switching; Basic Combustion Control Improvements; and various forms of Fuel Reburn. Fuel switching/blending was not evaluated further because of expected unreasonably high capital and operating costs and no additional emission reduction compared to continued lignite firing.

Other NOx emissions control techniques and technologies for MRY Station that were evaluated and determined to be technically infeasible were: Fuel Cleaning; Low NOx Burners (LNB); Flue Gas Recirculation; Oxygen-enhanced Combustion (OEC); Water/steam injection (combustion tempering); and Electro-Catalytic Oxidation (ECO®).

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The third step in the “top-down” BACT evaluation ranked the remaining control technologies by effectiveness. The purpose of ranking the control technologies was to establish a hierarchy that places at the “top” the control technology that achieves the lowest emission level. The technologies in order of their effectiveness, from highest to lowest, are: SNCR with ASOFA; Gas Reburn with ASOFA; Lignite Reburn with ASOFA; Fuel Lean Gas Reburn with ASOFA; and Advanced Separated Overfire Air (ASOFA). None of these control options has been installed on a cyclone-fired boiler burning North Dakota lignite. As such, the expressed control percentages reflect the use of engineering judgment, based on the listed technique or technology application.

Step 4 – Evaluate Most Effective Controls and Document Results

Additional criteria besides technical feasibility were utilized for technology selection in this BACT analysis. These included estimates of control effectiveness (i.e. percent pollutant removed), capital plus operating and maintenance costs, annual emission reduction (tons per year), energy impacts, average and incremental cost effectiveness ($/ton), and environmental impacts (other media and emissions of toxic and hazardous air pollutants).

The economic analysis examined the capital cost of each feasible BACT alternative evaluated and any other powerplant upgrade costs necessary to implement the alternative. In addition, the economic analysis examined the operating and maintenance cost associated with the highest-performing forms of each feasible BACT alternative evaluated. These costs were then combined into a levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each alternative was evaluated.

Two alternatives were on the dominant controls cost curve and thus were identified as the more cost effective alternatives. The two BACT NO_X control alternatives evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 1 were:

- Selective Non-Catalytic Reduction (SNCR) combined with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA); and
- ASOFA alone.

The two most cost-effective feasible control alternatives for reduction of NO_X emissions were reviewed to determine if the use of the technique or technology would result in any significant or unusual energy penalties or benefits. Potential increase in power plant energy consumption or net generation reductions, for ASOFA alone, or ASOFA with SNCR were relatively small.

The predicted environmental impacts from implementation of the two most cost-effective feasible NO_X emissions control alternatives from slightly higher unburned carbon in the emitted fly ash, carbon monoxide, and excess ammonia (“slip”) emissions was expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO_X emission reduction.

Step 5 – Select BACT

Taking into account technical feasibility, energy, environmental, and economic impacts and other costs, the recommended Best Available Control Technologies and associated emission rates for nitrogen oxides emissions produced by Milton R. Young Station Unit 1 boiler are provided in the table below.

NO_X Emission Control Technology and Rate Recommended as BACT

Control Technology and Emission Rate Recommended as BACT			
Unit	**Pollutant**	**Control Method**	**12-Month Rolling Average NOx Emission Rate (lb/ million Btu)**
1	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.355

This recommended BACT 12-month NO_X emission rate is based upon a historic pre-control 12-month baseline average annual NO_X emission rate used in the control and cost-effectiveness analysis of 0.849 lb/mmBtu for Unit 1. The baseline emission was determined from the 12 consecutive month period with the highest historic summation of NO_X mass emissions (pounds) reported for actual operation between January 1,2001 and December 31, 2005.

To complete the BACT determination process, the Consent Decree (CD) requires that “specific control technologies to be installed and a specific Phase II 30-day Rolling Average NO_X Emission Rate limitation (lbs/MMBtu)” must be established for each subject emission Unit [CD Paragraph 66, pg 20]. Because there are expected to be minor short term variations in operating conditions where Minnkota has not, in fact, materially changed any of their normal daily operating practices, a margin between the 12-month average operating conditions and the 30-day permit limit is proposed. This recommended emission rate should be suitably higher such that operation consistent with the technological limitations, manufacturer’s specifications, and good engineering and maintenance practices to the extent practicable for the recommended NOx BACT alternative would not result in an exceedance (violation) of an enforceable emission permit limit.

The Consent Decree also requires that the North Dakota Department of Health's (NDDH) NO_X BACT Determination address specific emission limitations during Unit startups at Milton R. Young Station [CD Paragraph 66, pg 20]. The type and duration of firing during startups, and the limited ability of available and feasible technologies to control startup NO_X emissions, both significantly influence the 30-day rolling average BACT NO_X emission rate limit recommended for Milton R. Young Station boilers. A 24-hour rolling average NO_X emission rate limit applied to startup periods is also recommended for Milton R. Young Station boilers.

The SEGU startup operating period is usually not defined in emission permits. However, for the purpose of this NO_X BACT analysis, Unit startup was defined as the period from initial fuel combustion to the point in time when:

- the measured Heat Input to the boiler on a 6-hour rolling average basis is greater than or equal to 2500 million BTU/hr for Unit 1; or
- the amount of time reported for the longest individual Unit 1 startup period during actual operation between January 1, 2001 and December 31, 2005 elapses, whichever occurs first; or
- fuel firing is discontinued prior to satisfying either previous criteria.

For MRYS Unit 1, the recommended 30-day rolling average NO_X emission permit limit rate that includes the impact of startups is based upon recognized operational factors and equipment designs that influence whether the startup emissions result in higher 30-day emissions compared to normal continuous operation excluding such startup periods:

- The uncontrolled emission rate (i.e. without separated OFA or SNCR in operation) and its variability during operation from a cold startup up to and including maximum continuous rated output;
- The operating conditions that are required to exist for the selected NO_X BACT control techniques to be initiated and be effective; and
- The effectiveness of these two particular control techniques if invoked at less-than-MCR steady-state operating conditions.
- The number of startups and their range of typical durations per 30-day period time frame.

The Consent Decree and the EPA's NSR Manual do not describe the method for determining a 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT applied to Milton R. Young Station Unit 1. The approach taken in this analysis was to establish a historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) from the 30-consecutive day period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation between January 1,2001 and December 31, 2005. This reflects unit NO_X emissions that were generated during periods of high unit operations, not affected by unit shutdowns, startups, or malfunctions. This was then compared to the 12-month historic pre-control baseline average NO_X emission rate (lb/mmBtu) from the 12-consecutive month period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation during the same 5-year look-back period. An estimate of NO_X emission reduction for the proposed BACT NO_X alternative operating at the historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) was made. This rate considered recognized operational factors and equipment designs applied to "steady state" conditions with sustained output close to maximum continuous capacity ratings. The potential impact of startups, recognizing operational and technical limitations on NO_X emission control performance, was then applied to the steady-state rate, to establish a recommended 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT for Milton R. Young Station Unit 1. This is summarized below.

Recommended NO_X BACT Control Method and 30-Day Rolling Average NO_X Emission Rate Limit Without Startups

Unit	Pollutant	Control Method	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)
1	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.360

This recommended BACT 30-day NO_X emission rate limit is based upon a historic pre-control 30-day baseline average NO_X emission rate of 0.884 lb/mmBtu for Unit 1. The baseline emission was determined from the 30-consecutive day period with the highest historic unit NO_X emissions rate reported for actual operation between January 1,2001 and December 31, 2005.

An incremental adjustment to the proposed 30-day rolling average steady-state unit NO_X BACT emission rate without startups of 0.36 lb/mmBtu for Unit 1 is recommended for the 30-day rolling average NO_X emission permit limit periods as defined and applied to Milton R. Young Station. This is summarized in the table below.

Recommended BACT 30-Day Rolling Average NO_X Emission Rate Limit and Startup Impact

Unit	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)	Impact on 30-day Rolling Average NOx Emission Rate Limit Due to Startups (lb/million Btu)
1	0.36	+0.041 per startup

This recommended adjustment to the proposed 30-day rolling average steady-state NO_X BACT emission rate limit without startups is based upon average historic pre-control NO_X emission rates of 0.766 lb/mmBtu for Unit 1 reported for the longest individual Unit 1 startup period during actual operation between January 1, 2001 and December 31, 2005. These emissions occurred during the 61-hour June 27-29, 2005 startup for Unit 1.

A 24-hour rolling average BACT NO_X emission rate limit applied to startup periods is also recommended for each of the Milton R. Young Station boilers.

This is summarized in the table below.

Recommended 24-Hour Rolling Average NO_X Emission Rate Limit During Startups

Unit	24-hour Rolling Average NOx Emission Rate Limit During Startups (lb/million Btu)
1	0.980

These emissions occurred during the 61-hour June 27-29, 2005 startup for Unit 1.

Compliance with these emission rate would be measured at the stack of the Unit, verified with Continuous Emission Monitoring (CEM) systems in accordance with the reference methods specified in 40 C.F.R. Part 75, and would be determined on a 30 consecutive Operating Day and 24-consecutive hour rolling average basis, respectively.

A trial demonstration period of 18 months after the completion of Consent Decree Phase II NO_X emission reduction system installation commissioning at Milton R. Young Station is recommended. It is proposed to allow Minnkota to demonstrate the actual control system capabilities of the combined NO_X BACT emissions reduction system. Operating experience during the trial period will:

- confirm steady-state control performance of the combined NO_X BACT emissions reduction system;
- allow determination of the ability to further control Unit start-up emissions;
- allow the determination of the permitted 30-day rolling average NO_X emission limit including startups, shutdowns, and malfunctions; and
- address the specific emission limitations during Unit startups at Milton R. Young Station and their impact on the proposed 30-day rolling average emission rate limit (without startups).

Based upon the information obtained during the trial period, final emission limits can then be determined.

The means that will be employed to minimize emissions during startup will primarily be based on operating procedures, both before and after the level of upper furnace gas temperatures and/or heat input rate are considered sufficient to start the NO_X controls and operating conditions are conducive for effective emissions reduction. These could be similar to Minnkota's current MRYS practices, or could be different, depending upon the capabilities of the NO_X controls and their impacts on Unit operations.

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1.0 INTRODUCTION

The Milton R. Young Station of Minnkota Power Cooperative, Inc. (Minnkota) and Square Butte Electric Cooperative (Square Butte) includes two cyclone-furnace, lignite-fired boilers producing steam for electric generation. Both units fire North Dakota lignite supplied from an adjacent mine, near Center, North Dakota.

A Notice of Violation (NOV) from the United States Environmental Protection Agency (US EPA or EPA) was issued to Minnkota on June 21, 2002. The NOV alleged that modifications have been made at the Milton R. Young Station that would require a construction permit under New Source Review (Code of Federal Regulations 40CFR52.21, and North Dakota Administrative Code NDAC 33-15). As a result of this allegation, a civil complaint was filed by the United States of America and the State of North Dakota against Minnkota Power Cooperative Inc. ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") in the United States District Court for the District of North Dakota. A Consent Decree[1] has been entered that represents a final negotiated settlement of the United States and North Dakota's claims against Minnkota and Square Butte. The Consent Decree requires Minnkota and Square Butte to perform a NO_X "Top-Down" Best Available Control Technology (BACT) Analysis to describe the emission limits for NO_X that will be required at Units 1 and 2, expressed as a 30-Day Rolling Average Emission Rate (lbs/million Btu)[2].

Burns & McDonnell was retained by Minnkota to conduct a "Top-Down" Best Available Control Technology (BACT) Analysis for nitrogen oxides (NO_X) at the Milton R. Young Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services since the 1970s. As part of those services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies and control technology analysis. The results of the BACT analysis are presented in this report.

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[1] In the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No. 1:06-CV-034

[2] Ibid – footnote number 1, CD paragraph 65, page 19.

The primary guidance utilized in preparation of this BACT analysis is the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990[3] ("NSR Manual").

In the next section of the report, the approach to the BACT Analysis is described. Following that, a quick summary of the plant conditions and report basis is given and then the BACT Analysis begins. The impact portion of the report is broken down into separate subsections. Within the last section, the results of all of the BACT Analysis steps are summarized for NO_X control options for Unit 1's boiler at the Milton R. Young Station.

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[3] Chapter B of the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990.

2.0 "TOP-DOWN" NO_X BACT ANALYSIS APPROACH

Best Available Control Technology (BACT) is an emissions limitation for each pollutant from a source determined to be achievable using control technologies(s) that provide the "maximum degree of emission reduction…taking into account energy, environmental, and economic impacts"[4]. A BACT review does not result in an emissions removal efficiency requirement. The generally accepted procedures for performing a BACT analysis are outlined in the EPA's draft NSR Manual. The BACT analysis for Milton R. Young Station Unit 1's boiler NO_X emissions was performed in accordance with this procedure. The EPA's draft NSR Manual outlines five basic steps that are to be followed in the "top-down" BACT evaluation. These steps are as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

The predefined steps of a BACT analysis are described in this section, and results presented. Available NO_X control techniques and technologies are defined, identified, and a technical description of the emission reduction process and capabilities are reviewed in the following section. Subsequently, those techniques and technologies deemed feasible for retrofit application are ranked according to nominal NO_X control capability. An engineering analysis reviews the estimated capital and operations and maintenance (O&M) costs for each feasible alternative, including taking a look at Balance of Plant (BOP) requirements. Following the cost impact determination, the energy and environmental impacts are reviewed for each feasible technology. Finally, the results of the engineering analyses are tabulated and a NO_X BACT selection is recommended for each unit.

2.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

The first step in a "top-down" NO_X BACT analysis is to identify, for the emissions unit in question, a comprehensive list of all "available" control options. In the EPA's draft NSR Manual,

> "available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of

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[4] Ibid footnote number 2, NSR Manual B.1

production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant"[5].

According to the EPA's draft NSR Manual, "a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term"[6]. Also, "a control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development"[7].

In order to identify available NO_X emission control technologies and techniques appropriate for potential application to MRY Station units, the following information sources were reviewed for coal-fired electric generating unit powerplants:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) database and Control Technology Center (website).
- Federal (EPA) and State, including North Dakota Department of Health internet websites for air emission permits and recently-submitted applications, including BACT Evaluations following New Source Review procedures.
- Federal (EPA and Department of Justice) and State, including North Dakota Department of Health internet websites for Consent Decrees issued as a result of legal actions taken by the United States government for alleged violations of the Prevention of Significant Deterioration (PSD) provisions and New Source Review provisions of the Clean Air Act, and/or federally-approved and enforceable State Implementation Plans.
- Control technology vendor information.
- Published and available information from technical, engineering, and environmental consultants.
- Technical literature found in journals, reports, internet websites, newsletters, proceedings of technical seminars and conferences pertaining to studies, engineering, designs, and testing of air pollution controls.

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[5] Ibid, NSR Manual B.5
[6] Ibid, NSR Manual B.17
[7] Ibid, NSR Manual B.18

2.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The second step of the "top-down" BACT process is to evaluate the available NO_X control technologies and techniques identified in Step 1 in terms of the specific factors that apply to the emissions unit in question. In accordance with EPA's draft NSR Manual, "an available technology is "applicable" if it can be reasonably installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible[8]".

The EPA's NSR Manual states a technology may be determined to be not applicable if "a technical assessment considering physical, chemical and engineering principles and/or empirical data showing the technology would not work on the emissions unit under review or that unsolvable technical difficulties would preclude the successful deployment of the technique"[9]. Also, a "showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g., size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source)"[10]. After a determination is made that any of the processes are technically infeasible, options are eliminated if technical challenges would preclude or prevent the successful long-term use of the control option or technique on the emission unit under consideration. This is performed prior to any economic analysis.

However, the EPA's NSR Manual also states "…control options incapable of meeting an applicable New Source Performance Standard (NSPS) or State Implementation Plan (SIP) limit would not meet the definition of BACT under any circumstances. The applicant does not need to consider them in the BACT analysis"[11]. Also, it states "An NSPS simply defines the minimum level of control to be considered in the BACT analysis"[12]. The NSR Manual further states "When developing a list of possible BACT alternatives, the only reason for comparing control options to an NSPS is to determine whether the control option would result in an emission level less stringent than the NSPS. If so, the option is unacceptable"[13]. New Source Performance Standards (NSPS) for NO_X emissions from EGUs firing North Dakota lignite are 0.8 lb/mmBtu. The EPA Acid Rain Program's Title IV NO_X emission limit for Group 2, cyclone-fired coal boilers with outputs greater than 155 MWe is 0.86 lb/mmBtu.

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[8] Ibid, NSR Manual B.17
[9] Ibid, NSR Manual B.20
[10] Ibid, NSR Manual B.19
[11] Ibid, NSR Manual B.12
[12] Ibid, NSR Manual B.12
[13] Ibid, NSR Manual B.12

EPA’s draft NSR Manual also states ”A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review”[14].

Also in the EPA’s draft NSR Manual is a qualification for technical feasibility, as described by the statement “Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or “applicable” to the source type under consideration”[15].

2.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

The third step in the “top-down” BACT evaluation is to rank the control technologies remaining after the feasibility analysis by control effectiveness. The purpose of ranking the control technologies is to establish a hierarchy that “places at the “top”, the control technology that achieves the lowest emission level”[16].

Selecting common units in order to compare emissions performance levels amongst options is one of the two key issues that must be addressed in a BACT analysis. EPA’s draft NSR Manual states “it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed”[17]. For fossil fuel-fired boilers, pounds of nitrogen oxides per unit of fuel heat input (i.e. lb/mmBtu), is a common means of comparing and calculating NO_X emissions.

Many control techniques, including both add-on controls and inherently lower polluting processes can perform at a wide range of levels. The EPA’s draft NSR Manual states “It is not the EPA’s intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would

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[14] Ibid, NSR Manual B.18
[15] Ibid, NSR Manual B.18
[16] Ibid, NSR Manual B.25
[17] Ibid, NSR Manual B.22

result in a large number of options"[18]. Also, "manufacturer's data, engineering estimates, and the experience of other sources provide the basis for determining achievable limits"[19].

2.4 STEP 4 – EVALUATE THE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

The fourth step of a "top-down" BACT review is to evaluate the technically-feasible emission controls, beginning with the most effective. Economic, energy, and environmental impacts are to be assessed and quantified, where possible, in the control technology analysis. The purpose of the evaluation is to determine if there are any identified impacts that would eliminate the top control technology from consideration. In the case where the most effective control alternative is determined to incur or produce adverse energy, economic or environmental impacts, the basis of the determination is documented, and the next most stringent control alternative is evaluated. This analysis process continues until the control technology under consideration cannot be eliminated by identification of any source-specific adverse energy, economic or environmental impacts.

The economic impacts are based on estimates of capital equipment pricing, procurement, installation and estimated operating and maintenance costs. The total installed capital costs along with the operating costs for each control technology are summarized in the economics of each respective section. The Levelized Total Annual Cost (LTAC) represents the levelized cost of procurement, construction, operation and maintenance over an assumed service life. Cost effectiveness ($/ton) of a control technique or technology is calculated by dividing the LTAC ($/yr) by the annual amount of NO_X removed (tons/yr). Baseline pre-control emissions are calculated using realistic upper boundary operating assumptions, considering inherent physical or operational constraints on the source. Plotting of the annual amount of NO_X removed (tons/yr) versus the levelized total annual control cost ($/yr) for the various control options on an x-y graph allows visualization of the cost-effectiveness. A "least-cost envelope" can be readily identified to indicate the inferior control options which should not be considered in the subsequent analyses. The incremental cost-effectiveness (difference in $/ton) between control techniques or technologies can also be calculated and compared. This allows evaluation of the dominant controls included on the least-cost envelope (curve).

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[18] Ibid, NSR Manual B.23
[19] Ibid, NSR Manual B.24

2.5 STEP 5 – SELECT BACT

The final step in the "top-down" evaluation process is to select BACT for the applicable pollutant and emission unit. Per the EPA guidance document, BACT is "the most effective control technology not eliminated in Step 4"[20]. The methodology described above was applied to the Milton R. Young Station Unit 1's boiler for emissions of nitrogen oxides.

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[20] Ibid, NSR Manual B.53

3.0 BACT ANALYSIS for MRY STATION UNIT 1 NO_X EMISSIONS

The approach taken in this BACT analysis for Milton R. Young Station included a technical analysis of demonstrated control alternatives for NO_X emissions. This approach followed the predefined steps of a BACT analysis process as generally described in Section 2. Potential NO_X control techniques and technologies were identified, and a technical description of the emission reduction process and capabilities were provided. Subsequently, those techniques and technologies deemed available and feasible for retrofit application were ranked according to nominal NO_X control capability. The engineering analysis then developed the estimated capital and O&M costs for each alternative, including taking a look at Balance of Plant (BOP) requirements. Finally, the cost effectiveness points for each feasible technology were plotted, and those that comprise the dominant controls curve were identified.

For the feasible techniques and technologies considered for determining NO_X control cost-effectiveness for the two steam electric generating units at the MRY Station, estimates were produced for predicted NOx reductions that represent achievable long-term expectations of the alternative reduction techniques and technologies being presented in the technical analysis. Each were tabulated and graphed.

3.0.1 EMISSION UNIT DESCRIPTION

Milton R. Young Station Unit 1 is owned and operated entirely by Minnkota. MRY Station Unit 1 includes a Babcock and Wilcox steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. Original unit design steam generating capacity is 1.714 million lbs/hr at 1,920 psi with a fuel heat input of 2,510 mmBtu/hr. The boiler is fired by seven ten-foot diameter cyclone burners, arranged “three over four” across the front wall of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the electrostatic precipitator (ESP). Exhaust gases leave the air heater and pass through an ESP for particulate collection and removal prior to the two induced draft fans (installed in parallel) which discharge to the stack. Unit 1 has a nominal 235 MW net design output capacity rating, is typically capable of sustained output of approximately 253 MW gross, and has an ultimate short-term maximum gross output (URGE) rating of 278 MW.

The EPA's Technical Support Document[21] published in the Edocket (EPA's internet website) for the Final BART Guidelines lists nameplate steam turbine-generator capacity of MRY Station Unit 1 as 257 MW (gross), which was assumed for calculating capital cost estimates for control alternatives.

The Unit 1 boiler at M.R. Young Station includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boilers.

Milton R. Young Station Unit 1's boiler design, combustion performance, and NO_X emissions are dominated by the composition and combustion characteristics of the North Dakota lignite supplied solely from a surface mine adjacent to the plant. This mine is the only supplier of solid fuel for this station, as there are no railroad facilities provided to service the Milton R. Young plant. North Dakota lignite has high moisture and high sodium content, moderate higher heating values, and can have a widely variable and high ash content compared to other coals. These characteristics create difficulties in promoting consistent, steady combustion and slag formation in the cyclone burners. It also results in producing a flyash that has severe deposition characteristics.

The design unit operating conditions for this study are presented in Table 3-1. The historical average lignite coal analysis is shown in Table 3-2.

Table 3-1 – Unit Design Parameters

Design Unit Operating Characteristics	**Unit 1 Design**
Boiler Type	Subcritical(1)
Combustion System	Cyclone
Number of Cyclones; arrangement, location	7; 3 over 4, front
Unit Design Capacity Electrical Output(2), MW (net/gross)	235 / 257

(1) – Balanced draft, single drum, superheated steam with single stage of steam reheat.
(2) – These values were established by the original equipment manufacturers, prior to construction.

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[21] EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: from EDOCKET at http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b; this is associated with EPA Acid Rain Program Clean Air Markets Division, Technical Support Document – Methodology For Developing BART NO_x Presumptive Limits, June 15, 2005, OAR-2002-0076-0445

[23] Ibid, footnote number 2, NSR Manual page B.11

Table 3-2 – Historical Average Lignite Coal Analysis

Lignite - Center Mine Ultimate Coal Analysis: (as received)	**Average % by mass**
Moisture	37.29
Carbon	38.69
Hydrogen	2.50
Nitrogen	0.57
Sulfur	0.81
Ash	8.74
Oxygen	11.40
Total	100.00
Higher Heating Value, Btu/lb	6,662

3.0.2 NITROGEN OXIDES EMISSION FORMATION

Nitrogen oxides (NO_X) are produced when nitrogen in the fuel and combustion air are exposed to high temperatures. There are two primary sources of NO_X emissions, referred to as "thermal" NO_X and "fuel" NO_X. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is admitted to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of the fuel containing nitrogen compounds. For most coal-fired units, thermal NO_X emission typically represents approximately 20% and fuel NO_X about 80% of the total NO_X formed. Nitrogen oxide (NO) is typically the most predominant form of NO_X emissions from fossil fuel combustion, along with nitrogen dioxide (NO_2). The formation of these compounds in utility powerplant boilers is sensitive to the method of firing and combustion controls utilized. The techniques employed for mixing the combustion air and fuel, which creates flames and high temperature combustion products, results from the rapid oxidization of carbon, hydrogen, and other exothermic reactions. Cyclone-fired boilers, by design, create intense heat release rates to melt and fluidize the coal ash introduced into the barrel-shaped furnaces. This produces high temperature flue gases and results in very high uncontrolled NO_X emissions. The amount of thermal NO_X emissions produced by cyclone boilers can be considerably higher than fuel NO_X emissions.

3.1 IDENTIFICATION OF NO_X CONTROL OPTIONS FOR MILTON R. YOUNG STATION

The first step in the BACT evaluation is to identify all "demonstrated and potentially applicable control technology alternatives"[23] according to the EPA's draft NSR Manual. In identifying control technologies, "the applicant needs to survey the range of potentially available control options"[24].

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[24] Ibid, NSR Manual page B.11

3.1.1 REVIEW OF RETROFIT INSTALLATIONS

The BACT determinations listed in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database are for new facilities. The Milton R. Young Station is an existing powerplant facility with two coal-fired EGUs. A BACT evaluation for retrofitting control equipment to coal-fired EGUs in an existing facility will be substantially different than an analysis for installing control equipment on coal-fired EGUs in a new facility. Consequently, in performing the BACT analysis for existing boilers at Milton R. Young Station, it is important to review powerplant facilities, especially cyclone-fired coal boilers, which have retrofitted NO_X control equipment in recent years.

In 1998, EPA issued a NO_X SIP (State Implementation Plan) call. Under the SIP call, utility boilers in the eastern United States were required to substantially reduce NO_X emissions during the "ozone season". The compliance date for the NO_X SIP call is May 31, 2004. A high percentage of the fired electric generation facilities in the eastern United States have or are in the process of retrofitting NO_X controls to comply with the NO_X SIP call. The EPA's NO_X SIP call was not applicable to North Dakota utility boilers.

There are a number of fossil fuel-fired EGU powerplants around the United States that have implemented or are planning to implement modifications to reduce NO_X emissions. The NO_X emission control system installations are in response to Acid Rain requirements, EPA's NO_X SIP call, the Clean Air Interstate Rule (CAIR), the Regional Haze Rule (RHR), and local regulations.

In addition to the facilities that have had to retrofit emissions controls as a result of the Title IV Part 76 Acid Rain requirements and/or EPA's NO_X SIP call, a few installations have had to retrofit controls in recent years as the result of court decisions resulting from litigation and regulatory action. None of the boilers associated with identified consent decrees are cyclone-fired. They are also located in a region requiring compliance with an EPA-approved State Implementation Plan for nitrogen oxides emissions controls (i.e. NO_X SIP call). As mentioned above, North Dakota utility boilers were not subject to the EPA's NO_X SIP call.

3.1.2 POTENTIALLY FEASIBLE NOx CONTROL OPTIONS FOR MILTON R. YOUNG STATION

A review of available information on retrofit installations performed at utility and industrial coal-fired powerplants during the past fifteen years was undertaken. NO_X emission control technologies and techniques with potential application to Milton R. Young Station boilers were identified, and are listed in Table 3-3.

TABLE 3-3 – Potentially Available NO_X Control Technologies Identified for BACT Analysis

NOx Control Technology
Pre-Combustion Controls
Fuel Cleaning/Blending/Switching
Combustion Controls
Basic Combustion Control Improvements
Low NOx Burners (LNB)
Separated Overfire Air (SOFA)(1)
Flue Gas Recirculation
Fuel Reburn
Oxygen-enhanced combustion (OEC)
Water/steam injection (combustion tempering)
Post-Combustion Controls
Selective Non-Catalytic Reduction (SNCR)(2)
Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO®)(3)

Notes: these are basic forms of the identified techniques.
Not all variations or combinations are included.
(1) – SOFA technologies include Boosted SOFA and Rotating Opposed Fired Air (ROFA)
(2) – SNCR technologies include Rich Reagent Injection, and Hydrocarbon-enhanced SNCR, commercially available as "NOxStar™".
(3) – Multi-pollutant control technology currently under commercial development by Powerspan Corp.

A comprehensive literature search, with sources including technical papers and presentations made at conferences by nationally-recognized technical organizations, utilities and other parties involved with design, construction, and testing of NO_X control techniques, plus hardware supplier experience lists, was performed. The results of this search are presented in Appendix A2, which includes a summary of various selected U.S. NO_X emission reduction retrofit projects.

3.2 FEASIBILITY ANALYSIS

The second step of the "top-down" BACT process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible.

An available technology is "applicable" if it can be reasonably be installed and operated on the source type under consideration. Also, a control technique is considered available if it has reached the stage of licensing and commercial availability. For the purposes of this analysis, the term "commercial" is further defined to mean "capable of establishing a full contractual agreement with commercial and performance guarantees supported by appropriate financial backing" for the implementation of full-scale, full-time systems of the technique or technology application. A technology that is available and applicable is technically feasible.

There are three basic categories of NO_X emission control techniques and technologies:

- Pre-combustion controls;
- Combustion controls; and
- Post-combustion controls

Uncontrolled NO_X emissions from a coal-fired electric generating unit are highly dependent on type of firing method, amount of solid fuel fired per unit time and furnace volume, and the fuel's basic combustion properties and elemental composition. The basic methods for reduction of such emissions:

- either prevent pollution, i.e. use inherently lower-emitting processes/practices which produce fewer NO_X emissions during the power generation process; or
- involve improvements to, or provide new add-on controls that, reduce emissions after they are produced before they are emitted from the facility; or
- are combinations of inherently lower-emitting processes and add-on controls.

Most of the identified control options have been commercially-available, installed, and operating in many full-scale, permanent coal-fired utility boiler installations in the United States for five years or more.

Pre-combustion controls, such as fuel switching, fuel blending, and fuel cleaning have been practiced and performed at numerous utility power plants, typically for operational and sulfur emissions control reasons.

Combustion controls, such as low-NO_X burners (LNBs) and overfire air systems, are very commonly applied to reduce NO_X emissions from fossil fuel-fired powerplants. Low-NO_X Burners are typically applied to pulverized coal, gaseous and liquid fuel-fired boilers. They are not applicable to cyclone-fired boilers. Flue gas recirculation (FGR) has been practiced and performed at numerous natural gas and fuel oil-fired utility and industrial powerplants for NO_X emissions control reasons. On large coal-fired utility boilers, FGR has primarily been applied for steam temperature control purposes, not for emissions control. Conventional Gas Reburn (CGR) with overfire air has been installed and placed in commercial operation on several cyclone-fired boilers, primarily in the eastern region of the United States. Coal Reburn (CR) with overfire air has been successfully demonstrated on two cyclone-fired boilers and commercially installed on three pulverized coal-fired boilers in the United States. Combustion tempering (water/steam injection) has been tested but has not been continuously practiced on cyclone-fired coal boilers. Oxygen-enhanced combustion has only been demonstrated and/or installed on a limited number of pulverized coal-fired powerplants, not on any coal-fired cyclone boilers.

Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) are post-combustion technologies that have been applied predominantly on eastern or midwestern bituminous coal-fired boilers. Others, mostly comprised of a combination of available emission reduction technologies, are often referred to as “hybrid” or “layered” controls. Variations of SNCR, such as Rich Reagent Injection (RRI) with and without SNCR, have only been installed or demonstrated on a limited number of cyclone-fired boilers. Other technologies, such as Fuel Lean Gas Reburn™ with SNCR, hydrocarbon-enhanced SNCR (commercially available as NO_XStar^{TM}), and Conventional Gas Reburn with SNCR have only been demonstrated and/or installed on a limited number of pulverized coal-fired power plants.

Emerging post-combustion multi-pollutant control technologies, such as Powerspan’s Electro-Catalytic Oxidation (ECO$^{®}$), which include NO_X control, were also identified. These are typically in the large pilot-scale commercial development phase, and have not been successfully demonstrated on a full scale basis on any pulverized coal, cyclone, or circulating fluid bed boilers.

In most of the combination or “layered” and emerging control cases, the NO_X control technology has been demonstrated to be capable of controlling the targeted pollutant(s) on either:

- a full-scale basis, but only with temporary equipment; or
- a full-scale basis, with permanent equipment but in a limited number of installations; or

- with less than full-scale and full-time application.

3.2.1 SUMMARY OF RETROFIT INSTALLATIONS OF NO_X CONTROL TECHNOLOGIES

There are a number of facilities around the country that have implemented or are planning to implement modifications to reduce NO_X emissions. Table 3-4 summarizes the various NO_X emission control system installations currently installed, or that have been demonstrated on a full-scale, short-term basis, in response to Acid Rain requirements, EPA's NO_X SIP call and local regulations, or a utility investigating the technology.

TABLE 3-4 – Identified NO_X Control System Retrofits on Cyclone Coal-fired Boilers

No. of Units(1)	Cyclone NO_X Control Technology Description
1	Fuel Switching/Blending
39(2)	Separated Overfire Air (SOFA)
2	Selective Non-Catalytic Reduction, with or without SOFA
2(3)	Rich Reagent Injection, with SOFA
7(4)	Conventional fuel reburn (pulverized or micronized coal, gas), w/ SOFA
1(5)	Fuel lean gas reburn, with or without SOFA
22(6)	High-dust or low-dust SCR, with or without other technologies
1(6)	Tail-gas SCR, with or without other technologies

(1) – This list of known NOx control retrofit installations is primarily focused on units in the United States. There may be other installations that are similar but were not identified.

(2) – Installed for NOx control (without fuel reburn). A list of known cyclone boiler SOFA installations is included in Appendix A2.

(3) – RRI has only been demonstrated with temporary equipment for testing. See technical literature references in Appendix A1 and A2 for details.

(4) – Several conventional coal and gas reburn retrofits have discontinued reburn demonstration or routine operation. See Technical Literature Reference list and Appendix A3 for further details.

(5) – Only one example of fuel lean gas reburn retrofit (without OFA) on a cyclone-fired boiler has been demonstrated. This system was installed for short-term reburn testing and has been removed.

(6) – High-dust SCR technology has been retrofitted on sixteen U.S. cyclone-fired boilers, all believed to have SOFA. Low-dust SCRs in U.S. have only been installed only on pulverized coal-fired boilers, none on cyclones. One tail-gas SCR installation on a coal-fired cyclone boiler found in Germany; none in the U.S. See technical literature references in Appendix A1 and A2 for details.

A more detailed description of the various control technology retrofits and their claimed effectiveness is included in the technical descriptions and reference literature in the technical feasibility assessment of

Appendix A1, and Appendix A2, which includes a summary of various selected U.S. NO_X emission reduction retrofit projects.

3.2.2 SUMMARY OF FEASIBLE NO_X CONTROL TECHNOLOGIES FOR MRY STATION

One example of fuel switching applied to a cyclone-fired boiler was identified. Ottertail's Big Stone Unit 1 was originally designed to burn North Dakota lignite and was switched to western subbituminous (PRB) coal for reasons unrelated to NO_X emissions reduction. Big Stone Unit 1 and M.R. Young Station Unit 2 have similar boiler designs, and MRYS Unit 1's boiler is approximately 60% as large as MRYS Unit 2's boiler. Thus, conversion of Milton R. Young Station Unit 1's boiler to fire PRB coal or a lignite/PRB blend is technically possible. There are no railroad facilities provided to service the Milton R. Young plant. Additional operational and capital costs to bring in large quantities of PRB coal will be significant. Based on a comparison of available emission data between Ottertail's Big Stone Unit 1 and M.R. Station Young Unit 1, there is no expected reduction in baseline (i.e. uncontrolled) NO_X emissions from switching to PRB from lignite at Milton R. Young Station. Although fuel switching at Milton R. Young Station is technically feasible, this alternative will not be economically competitive with other NO_X control technologies that offer better results for a much lower combination of capital and operational costs. For these reasons, it has not been considered further as an effective NO_X emissions control option for MRY Station Unit 1 boiler.

Separated Overfire Air (SOFA) is the most commonly-applied, combustion-related NO_X emission reduction technology that has been proven effective on cyclone-fired boilers. A version of separated overfire air specifically designed for increased NO_X emission reduction performance for lignite-fired cyclone boilers, referred to as "Advanced SOFA" in this analysis, can be installed on both units at M.R. Young Station. The potential operational limitations mentioned in the detailed feasibility discussions included in Appendix A1 for deeply air-staged cyclones associated with separated overfire air are expected to limit the control effectiveness of this technique, alone and in combination with other feasible NO_X control options.

Selective Non-Catalytic Reduction (SNCR) technology is a form of post-combustion NO_X emission control that has been successfully applied on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal to reduce NO_X emissions. SNCR has also been used on fuel oil and natural gas-fired units. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without air-staged combustion with overfire air in full operation. This control technology adds urea (or ammonia) reagent to the hot furnace gases in the upper furnace to chemically reduce nitrogen oxides. SNCR was considered technically feasible for application on both units at M.R. Young Station. SNCR can be operated with and without SOFA. Variations of SNCR technologies such as Hydrocarbon-enhanced SNCR (HE-SNCR) and "Rotamix" have been installed on pulverized coal-fired boilers but are not proven on cyclone boilers. This is described in detail in Appendix A1.

Rich Reagent Injection (RRI) is a form of SNCR under development specifically intended for NOx emissions control on cyclone boilers. As of October 2006, RRI has been demonstrated but has not been commercially installed and placed in continuous operation on a cyclone-fired boiler, especially one burning coal with high fouling and slag temperature sensitivities associated with lignite supplied from the Center mine. RRI adds aqueous urea reagent to the hot furnace gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea which will increase NOx emissions. RRI is considered technically infeasible for application on the cyclone boilers at the Milton R. Young Station at the present time. This is described in detail in Appendix A1.

Various forms of fuel reburn with and without overfire air are types of combustion-related technologies that have been demonstrated and commercially installed on pulverized coal, fuel oil-fired, and cyclone utility and industrial boilers. Natural gas-consuming variations such as Conventional Gas Reburn (CGR) and Fuel-Lean Gas Reburn (FLGR™) have been applied to cyclone boilers burning bituminous and subbituminous coals. High capital costs expected for installing a natural gas pipeline and high operating costs from consumption of large volumes of such fuel make these alternatives economically unfavorable for both units at M.R. Young Station. Pulverized or micronized coal reburn, in combination with SOFA, are technically feasible but will require extensive capital, operating and maintenance costs for fuel grinding equipment and facilities when installed and operated for both units at M.R. Young Station. This is described in detail in Appendix A1.

Fuel cleaning is a technique normally applied to reduce the sulfur or ash content of a fossil fuel prior to combustion. No examples of fuel cleaning of North Dakota lignite or western subbituminous coal strictly for NO_X emissions reduction were found in available technical literature. This technique is considered infeasible for NO_X emissions control of M.R. Young Station boilers at the present time.

High-dust, low-dust, and tail-gas variations of selective catalytic reduction (SCR) technology have been applied on pulverized coal and cyclone boilers as a post-combustion type of NO_X emission control throughout the world and in the United States, except on units firing North Dakota lignite. The severity of catalyst blinding and pluggage from particulate matter and flue gases emitted from cyclone-fired boilers burning North Dakota lignite precludes the technical feasibility for successful application of such SCR technology on the EGUs at the Milton R. Young Station. This is described in detail in Appendix A1 with supporting documentation in Appendix B.

The results of Step 2 of the NO_X BACT Analysis for determining the technical feasibility of potential control technologies, including various "layered" combinations, are listed in Tables 3-5 and 3-6.

TABLE 3-5 – Technically-Feasible Potential NO_X Control Technologies for M.R. Young Station Cyclone Boilers

Control Technology(1)	In Permanent, Full-Scale Service on Existing Coal-Fired Cyclone Utility Boilers?	Technically Feasible on M.R. Young Station Unit 1 boiler?
Selective Non-Catalytic Reduction (SNCR)	Yes(2)	Yes
Conventional Gas Reburn	Yes(3)	Yes(3); Requires SOFA or ASOFA
Coal Reburn	Yes(4)	Yes(4); Requires SOFA or ASOFA
Fuel Lean Gas Reburn	No(5)	Yes(5) (w/ or w/out SOFA or ASOFA)
Advanced SOFA	No(6)	Yes(6). Includes relocated lignite drying vent ports
Separated OFA (basic SOFA)	Yes(6)	Yes(6)
Combustion Improvements	Yes	Yes(7); typically included with separated OFA
Flue Gas Recirculation	Not for NOx control	Yes(8) (not expected to reduce NOx further)
Fuel Switching / Blending	Yes	Yes(9) (not expected to reduce NOx further)

See technical feasibility details and literature References in Appendix A for details.

(1) – All potential combinations of technologies not listed. See discussion of "layered" technologies.

(2) – Assumes use of urea for reagent. Limited number of active installations on cyclone-fired boilers burning western subbituminous (i.e. Powder River Basin or PRB coal).

(3) – Limited number of active conventional gas reburn (CGR) installations on cyclone-fired boilers burning PRB coal.

(4) – Limited number of demonstrations or active installations of pulverized or micronized coal reburn on cyclone-fired boilers. One demonstration of pulverized coal reburning with PRB coal has been performed on a cyclone-fired boiler, no longer active. Only one active permanent coal reburn installation on cyclone-fired boiler burning eastern bituminous coal, none burning western subbituminous coal or lignite.

(5) – Only one short-term test demonstration of FLGR™ on a cyclone-fired boiler burning coal with separated overfire air.

(6) – No cyclone boilers firing North Dakota lignite have installed basic or advanced SOFA. See Appendix A.

(7) – Considered part of SOFA installation for coal boilers without combustion controls for NOx reduction.

(8) – No examples of using recirculated flue gas on coal-fired boilers for NOx emissions control were found in available technical literature. Zero additional NO_X reduction potential expected from this technique alone for MRY Station Unit 1 / 2. Potential NO_X reduction improvement on MRY Unit 1 / 2 considered part of "advanced" SOFA.

(9) – Zero additional NO_X reduction potential expected from this technique (switching from lignite to lignite/PRB blends or 100% PRB) alone for MRY Station Unit 1 / 2.

TABLE 3-6 – Technically Infeasible Potential NO_X Control Technologies for M.R. Young Station Cyclone Boilers

Control Technology(1)	In Permanent, Full-Scale Service on Existing Coal-Fired Cyclone Utility Boilers?	Technically Feasible on M.R. Young Station Unit 1 boiler?
Selective Catalytic Reduction (SCR): conventional (high dust); Low-dust; Tail-gas	Yes(2) / No / Yes(3)	No(4) - Unresolvable fouling and catalyst deactivation problems expected. See discussion of SCR feasibility for ND lignite.
Electro-Catalytic Oxidation (ECO®)	No	No, has not been demonstrated full-scale nor reached commercial availability
HE-SNCR (using ammonia)	No(5)	No(5). Has not been demonstrated on cyclone.
Rotamix (ROFA + SNCR)	No(6)	No(6). Has not been demonstrated on cyclone.
Rich Reagent Injection (RRI) with ASOFA	No(7)	No(7). Requires oxygen-free furnace environment, varying air/fuel would increase NOx emissions.
RRI + SNCR with ASOFA	No(7)	No(7). See footnote and feasibility discussion.
Advanced Conventional Gas Reburn (ACGR) + SNCR	No(8)	No. Has not been demonstrated on cyclone.
Coal Reburn + SNCR	No(8)	No. Has not been demonstrated on cyclone.
Fuel Lean Gas Reburn + SNCR	No(8)	No. Has not been demonstrated on cyclone.
Rotating Opposed-Fired Air	No(6)	No. Has not been demonstrated on cyclone.
Oxygen Enhanced Combustion	No(9)	No. Has not been demonstrated on cyclone.
Water Injection	No(10)	No(10)
Fuel Cleaning	Not for NOx control	No(11) (not expected to reduce NOx further)

See technical feasibility details and literature References in Appendix A for details.

(1) – All potential combinations of technologies not listed. See discussion of "layered" technologies.

(2) – Limited number of active installations on cyclone-fired boilers burning western subbituminous coal.

(3) – No identified installations on coal-fired boilers in the United States. One tail-end SCR on cyclone boiler in Germany.

(4) – See discussion of SCR feasibility for ND lignite in Appendix A1 and Appendix B.

(5) – Hydrocarbon-enhanced SNCR has not been demonstrated on a cyclone-fired boiler, nor any boiler firing western subbituminous coal or lignite.

(6) – Rotating Opposed-Fired Air with or without SNCR has not been demonstrated on a cyclone-fired boiler. No apparent significant advantages over SOFA on cyclone-fired boilers.

(7) – Rich Reagent Injection has been successfully demonstrated for brief periods with SOFA with and without SNCR at two cyclone powerplants. There are no permanent RRI installations completed and operational as of May 2006. Difficulties in maintaining an oxygen-free furnace environment in MRY Station boilers where the urea reagent would be injected due to cyclone air/fuel imbalances during air-starved combustion would increase NOx emissions.

(8) – No known demonstrations or permanent installations of Advanced conventional gas reburn (CGR) or FLGR™ or pulverized/micronized coal reburn (PCR/mCR) in combination with SNCR on cyclone-fired boilers. CGR and PCR/mCR require separated overfire air. FLGR™ has been applied to pulverized coal firing with and without SOFA, with and without SNCR; FLGR™ with SNCR is also called amine-enhanced fuel lean gas reburn (AEFLGR™).

(9) – No known demonstrations or permanent installations of oxygen-enhanced combustion (OEC) on cyclone-fired boilers.

(10) – No permanently installed examples of using this technique continuously on coal-fired boilers were found in available technical literature. Not suitable for high-moisture lignite fuels.

(11) – No known demonstrations or permanent installations of using this technique continuously on coal-fired boilers for NOx emissions control were found in available technical literature.

Additional criteria besides technical feasibility are utilized for technology selection in a BACT analysis have been included in the following sections summarizing control effectiveness estimates, capital plus operating and maintenance cost estimates, energy impacts, and environmental impacts:

- Control effectiveness (i.e. percent pollutant removed)
- Expected emission rate (see Tables 3-7, 3-8) and emission reduction (tons per year)
- Economic impacts (total cost and incremental cost effectiveness)
- Energy impacts
- Environmental impacts (other media and emissions of toxic and hazardous air pollutants)

3.3 RANK OF TECHNICALLY FEASIBLE NO$_X$ CONTROL OPTIONS BY EFFECTIVENESS

The third step in the "top-down" BACT evaluation is to rank the remaining control technologies by effectiveness. The purpose of ranking the control technologies is to establish a hierarchy that "places at the "top" the control technology that achieves the lowest emission level."

The emission reduction (control effectiveness) percentages developed for ranking the available NO$_X$ emission control options considered feasible for Milton R. Young Station Unit 1 are shown in Table 3-7. These are estimates based upon engineering judgments with considerations of:

- Boiler heat input rates associated with realistic upper boundary operating assumptions;
- baseline emission rates corresponding to the realistic upper boundary operating assumptions;
- the general combustion properties of North Dakota lignite;
- published and available emission reduction performance achieved at other similar utility powerplants (cyclone-fired boilers);
- computer-derived predictions; and
- inclusion of performance margins to allow for variations in fuel, weather, equipment condition, and other factors that prevent the ultimate peak short-term performance from being reliably sustained over the course of long-term operation.

These NO$_X$ emission level and reduction percentage estimates include adjustments of previously demonstrated or predicted performance that reflect differences between North Dakota lignite and eastern or midwestern bituminous and western subbituminous coals.

The numbers assume the estimated capability of the employed technique is achievable and sustainable (long-term) and that potential operational limitations mentioned in the feasibility discussions allow the successful practice of the technique or technology. None of the remaining control options has been installed on a cyclone-fired boiler burning North Dakota lignite. As such, the expressed control percentages reflect the use of engineering judgment, based on the listed technique or technology application. This is particularly pertinent to all control options that involve air-staged combustion associated with various forms of separated overfire air. SOFA-based controls for cyclone-fired coal-burning boilers have typically reduced NO_X emission levels significantly from the precontrol baseline, and which allow or enhance further reductions when combined with other control techniques and technologies.

3.3.1 ESTABLISHING BASELINE NO_X EMISSIONS FOR RANKING CONTROL OPTIONS

Before the various feasible NO_X emission control alternatives can be estimated and ranked in order of effectiveness, the precontrol baseline level of emissions and its basis must be determined. The EPA's NSR Manual provides general guidance for establishing estimated baseline emissions to be used for the purpose of calculating and comparing the control and cost-effectiveness of a control option:

> "The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions from the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of added post-process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for the use of inherently lower polluting processes"[25].

Also stated in the EPA's NSR Manual:

> "Estimating realistic upper bound case scenario does not mean that the source operates in an absolute worst-case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true

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[25] Ibid, NSR Manual B.37

> upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints"[26].

Establishing estimated baseline NO_X emissions for a new or existing source involves determining the design or operational basis of the emission rate. A useful means of comparing such emission rates is to establish the unit emission rate, expressed in pounds of pollutant per unit of process output. For processes such as steam-electric generating powerplants utilizing combustion in boilers, the desired process output (kilowatts or megawatts) can be related to the pollutant-bearing flue gas created by the combustion of fuel. Units of fuel heat input (millions of BTUs) required to create a unit of desired electrical output (kW) and thus the efficiency of converting the fuel heat to such electrical output (unit heat rate, Btu/kW-hr) are important.

A review of reported hourly NO_X emissions for MRY Station Unit 1 boiler, including unit mass rates (lb/mmBtu and lb/hr), boiler heat input (mmBtu/hr), and gross electrical output in megawatts (MW_g), was performed for the operating periods in years 2001-2005 inclusive. A realistic upper bound emission case scenario for each boiler's baseline emissions at Milton R. Young Station determined the highest summation of any rolling 12-month period NO_X mass emissions (pounds), along with the summation of the gross heat input (mmBtus) and the boiler operating hours for the same rolling 12-month period corresponding to the highest NO_X pounds. Dividing the summation of the rolling 12-month NO_X pounds by heat input results in a average unit emission rates (lb/mmBtu). Likewise, the summation of the rolling 12-month gross heat input (mmBtus) divided by the boiler operating hours yields an average gross heat input rate (mmBtu/hr). This emission evaluation revealed that:

- Unit 1 at Milton R. Young Station is typically operated in a base-loaded manner;
- MRYS Unit 1's highest 12-month NO_X mass emissions summation divided by the summation of the same 12-month period's heat input averaged 0.849 lb/mmBtu at a corresponding average unit heat input rate of 2,744 mmBtu/hr and unit gross electrical output of 244.5 MW_g.

3.3.2 ESTIMATING CONTROL-EFFECTIVENESS OF NO_X EMISSIONS CONTROL OPTIONS

The degree of success in operation of separated overfire air alone and in combination with the other selected feasible alternatives is important to the amount of NO_X emission reduction achieved. The emission control performance from the advanced version of separated overfire air (ASOFA) is highly

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[26] Ibid, NSR Manual B.37

dependent on the degree of success in admitting combustion air insufficient for complete combustion in the cyclones without causing related negative impacts. The control percentages estimated for firing North Dakota lignite in the MRY Station boilers reflect the belief that operating the existing cyclones much below an average cyclone stoichiometric ratio of approximately 0.95 (95% of the theoretical amount of combustion air required for complete combustion) will not be successful. This is due primarily to the expected "starved air" combustion causing a reduction in cyclone furnace gas temperatures, thus creating a strong potential for molten slag solidifying in the cyclone barrels, slag taps, and lower furnace floor openings. This would impose a great interruption to steam production since forced outages would be required to remove this physical obstruction before full load boiler operation could be reestablished. The EPA's draft NSR Manual states "It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options"[27].

The potential operational limitations for deeply air-staged cyclones associated with separated overfire air and coal reburn alternatives are expected to limit the amount of NO_X control potential possible from successful practice of the particular technique or technology. This is described in the detailed feasibility discussions included in Appendix A1.

The advanced form of separated overfire air is expected to be effective in NO_X emission reduction and can be combined with other feasible combustion-related and post-combustion control alternatives for these lignite-fired cyclone boilers. The basic form of SOFA in combination with coal reburn, gas reburn options, and SNCR, was not included in the detailed control effectiveness analysis in order to limit the number of options that were evaluated.

Using an advanced form of SOFA system, M.R. Young Station's Unit 1's boiler operating at MCR is expected to achieve a NO_X emission level of 0.51 lb/mmBtu when operating modestly air-staged cyclone furnaces with suitable combustion controls. This level of NO_X reduction from ASOFA operation, approximately forty percent, is based on the expected ability to reduce emissions without incurring potential significant negative impacts of this technique. This reduction estimate includes the additional amounts of control potential available from operating with relocated lignite drying system vent ports associated with ASOFA operation with modestly air-staged cyclone furnaces.

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[27] Ibid, NSR Manual B.37

Coal reburn with ASOFA is estimated to reduce NO_X emissions for M.R. Young Station's Unit 1's boiler operating at MCR slightly less than 55 percent from the pre-control baseline NO_X emission rate, considering similar control levels demonstrated by previous coal-reburn retrofits on cyclone-fired boilers and limitations previously discussed with ASOFA.

Conventional Gas Reburn and Fuel Lean Gas Reburn options were both assumed to be installed with ASOFA. NO_X reduction from CGR with ASOFA operation is expected to be approximately fifty six percent. FLGR with ASOFA is expected to reduce NO_X emissions approximately forty six percent. Estimates for NO_X emissions for M.R. Young Station's Unit 1's boiler considered similar control levels demonstrated by previous gas-reburn retrofits on cyclone-fired boilers with modestly air-staged cyclone furnaces and limitations previously discussed with ASOFA.

The NO_X emission rate for Selective Non-Catalytic Reduction (SNCR) (using urea) with ASOFA is expected to be approximately 0.355 / 0.33, resulting from a reduction in NO_X emissions of approximately 58 percent from the 12-month average pre-control baseline NO_X emission rate.

Included in the feasible control option ranking of Table 3-7 are layered alternatives that were shown in Table 3-5. The highest-performing NO_X control alternatives remaining in consideration are ranked in declining order of expected emission reduction. These combined control options refer to "advanced" SOFA, which is expected to have significantly lower NO_X emissions than a typical SOFA system as applied to the Milton R. Young cyclone boilers.

TABLE 3-7 – Ranked NO_X Control Options Feasible for MRY Station Unit 1 Boiler with Expected Control Performance

Alt. Label[(1)]	NO_X Control Technique	Emission Rate (lb/mmBtu)	Control Percentage[(2)]
E	SNCR (using urea) w/ ASOFA	0.355	58.1
D	Gas Reburn with ASOFA	0.374	56.0
C	Lignite Reburn w/ ASOFA	0.385	54.6
B	Fuel Lean Gas Reburn with ASOFA	0.460	45.9
A	Advanced Separated Overfire Air (ASOFA)	0.513	39.5
-	Baseline	0.849	-

(1) - Alternative designation assigned from highest to lowest unit NOx emission rate.

(2) - Control percentages are relative to an average pre-control emission baseline of 0.849 lb/mmBtu based on annual operation at highest pre-control 12-month rolling NOx summation mass emissions divided by the 12-month heat input summation.

The annual emission levels developed for Table 3-7's ranking the feasible alternatives assume that the highest 12-month average pre-retrofit level of unit NO_X emissions for M.R. Young Station's Unit 1's boiler is a baseline of 0.849 lb/mmBtu. This was determined from the highest reported rolling 12 consecutive month period's summation of hourly NO_X emissions (lbs).

The hourly gross fuel heat input (mmBtu) was summed over that same 12-month time period, and divided by the number of boiler operating hours to yield an annual average gross fuel heat input rate (mmBtu/hr). Multiplying the 12-month average heat input rate (mmBtu/hr) by the baseline or control alternative's 12-month average unit emission rate (lb/mmBtu) equals a 12-month average hourly NO_X emissions rate (lb/hr). Annual NO_X emissions (tons) for the baseline pre-control condition were calculated by multiplying the 12-month summation for boiler operating hours during the same period as the highest NO_X emissions by the 12-month average emission rate (lb/hr). The annual tons for the control options were calculated by multiplying the alternative's average annual emission rate (lb/yr) by a reduction factor (if applicable) for heat input or running plant capacity and adjusting boiler operating hours by an annual uptime (availability) factor. Details for these adjustments are included in Appendix C3. Based on these calculations, the annual emissions for M.R. Young Station's Unit 1's boiler are shown in Table 3-8.

TABLE 3-8 – Expected Annual NO_X Control Performance for MRY Station Unit 1 Alternatives

		EMISSIONS				
Alt. Label[1]	**NOx Control Alternative**	**Emission Rate lb/mmBtu**	**Hourly Emission[2] lbs/hr**	**Annual Emission[3] tons/yr**	**Emission Reduction[4] tons/yr**	**NOx Removal Efficiency[5] %**
E	SNCR (using urea) w/ ASOFA	0.355	975	4,025	5,909	58.1
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6
B	Fuel Lean Gas Reburn w/ ASOFA	0.460	1,261	5,260	4,674	45.9
A	Advanced Separated Overfire Air (ASOFA)	0.513	1,409	5,874	4,060	39.5
-	Baseline	0.849	2,330	9,934	0	-

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Hourly NO_X emission estimates (lb/hr) were calculated based upon average annual unit emission rate (lb/mmBtu) x 2,744 mmBtu/hr heat input.
(3) - Estimated annual emission tons assume an annual capacity factor specific to each alternative; 94.1% was assumed for the baseline case.
(4) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).
(5) - Estimated NO_X control level percentage reductions relative to 0.849 lb/mmBtu emission baseline at 2,744 mmBtu/hr MCR heat input.

3.4 NO$_X$ CONTROLS ANALYSIS AND IMPACTS EVALUATION

The fourth step of a "top-down" BACT review is to evaluate the most effective emission controls. Energy, economic, and environmental impacts are to be considered in the control technology evaluation. The purpose of the evaluation is to determine if there are any energy, economic or environmental impacts that would eliminate the top control technologies from consideration.

3.4.1 NO$_X$ CONTROL ECONOMIC IMPACTS FOR MRY STATION UNIT 1

An evaluation was performed to determine the various cost impacts of installing feasible NO$_X$ control alternatives on Milton R. Young Unit 1. This evaluation includes estimated:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 3-9 through 3-13.

3.4.1.1 CAPITAL COST ESTIMATES FOR NO$_X$ CONTROL ALTERNATIVES

The capital costs to implement the various NO$_X$ control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. In the cases of SNCR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

The unit nameplate output capacity (gross electrical output in megawatts) assumed for the NO$_X$ control technologies capital cost estimate basis was 257 MW$_g$ for MRY Station Unit 1[28].

A review of the unit capital cost factor range and single point factors applicable to MRY Station Unit 1 NO$_X$ control technologies are presented in Table 3-9. The estimated installed and levelized capital costs for the highest-performing form of the various feasible NO$_X$ emission reduction technologies evaluated for cost-effectiveness are shown in Table 3.10. These are listed in order of control effectiveness, with the highest ranked option at the top.

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[28] Ibid footnote number 23.

TABLE 3-9 – Unit Capital Cost Factors of Feasible NO_X Control Options for MRY Station Unit 1

Alt. Label(1)	NO_X Control Technique	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3), ($/kW) MRYS Unit 1
E	SNCR (using urea) w/ ASOFA	20-35(4)	31.6(4),(5)
D	Gas Reburn w/ ASOFA	15-30(6)	70.1(5),(6),(7)
C	Lignite Reburn w/ ASOFA	30-60(6)	181.5(5),(8)
B	Fuel Lean Gas Reburn w/ ASOFA	--(9)	41.4(4),(5),(9)
A	Advanced Separated Overfire Air (ASOFA)	5-10(6)	16.6(5)

(1) – Alternative designation has been assigned from highest to lowest unit NOx emission rate.

(2) – Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ this due to positive or negative synergistic effects. Range based on published values or vendor proposals.

(3) – Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on EPA’s nameplate rating. Single point cost figures in 2006 dollars.

(4) – Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. See Appendix C2 for details.

(5) – The single point unit capital cost factor shown for the “advanced” version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(6) – NESCAUM 2005 Technical Paper, posted at their website. See technical references in Appendix A1 for details.

(7) – The single point unit capital cost factor shown for a conventional gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW), and that both boilers share the capital cost in proportion to their respective rated MW gross output capacities.

(8) – The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report, posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 91.7 $/kW. See technical references in Appendix A1 for details.

(9) – The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. The single point unit capital cost factor shown for a fuel lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (15.7 $/kW), and that both boilers share the capital cost in proportion to their respective rated MW gross output capacities.

TABLE 3-10 – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 1

Alt. Label(1)	NOx Control Alternative	Installed Capital Cost(2) $1,000	Annualized Capital Cost(3) $1,000
E	SNCR w/ ASOFA	8,113	707
D	Gas Reburn w/ ASOFA(4)	18,006	1,570
C	Lignite Reburn w/ ASOFA(5)	46,656	4,068
B	Fuel Lean Gas Reburn w/ ASOFA(4)	10,639	928
A	Advanced SOFA (ASOFA)	4,277	373
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars.

(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.

(4) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR; and annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnotes #8 and 10 under Table 3-9.

(5) - Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost, and $2,054,000/yr annualized capital cost.

3.4.1.2 Operating and Maintenance Cost Estimates for MRY Station NO_X Controls

The operational and maintenance costs to implement the various NO_X control technologies were largely estimated from cost factors (percentages of installed capital costs) established in the EPA's Air Pollution Control Cost Manual (OAQPS) for SNCR[29], and from published in technical papers discussing those control technologies. In the cases including various forms of SNCR, preliminary vendor quotes were obtained and used in place of, or to adjust the OAQPS cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's annual O&M costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR alternatives; and
- Reagent dilution water consumption and unit cost for SNCR alternatives.

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[29] EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NO_X Controls – NO_X Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.
- Reductions in revenue expected to result from loss of unit availability, i.e. outages attributable to the control option, which reduce annual net electrical generation available for sale (revenue).

For economic evaluation purposes, an annual average running plant capacity factor of 96.6 percent compared to a nominal unit output capacity of 253 MW_g combined with an average annual availability (uptime) of 8,528 operating hours (97.3 percent of 8760 hours per year) resulting in an annual unit capacity factor of 94.1% were assumed for Unit 1's pre-control baseline annual operation. A heat input rate of 2,744 mmBtu/hr and a NO_X emission rate of 0.849 lb/mmBtu were assumed for calculating control and cost-effectiveness from pre-control maximum rolling 12 month summation of nitrogen oxides' mass emissions for MRY Station Unit 1.

Table 3-11 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the highest-performing form of the various feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Appendix C3 provides more details for the levelized annual O&M cost calculations and cost factors.

TABLE 3-11 – Estimated O&M Costs for
NO_X Control Alternatives - MRY Station Unit 1

Alt. Label(1)	NOx Control Alternative	Annual O&M Cost(2) $1,000	Levelized Annual O&M Cost(3) $1,000
E	SNCR w/ ASOFA	5,417	6,764
D	Gas Reburn w/ ASOFA	28,641	35,765
C	Lignite Reburn w/ ASOFA	5,862	7,320
B	FLGR w/ ASOFA	12,863	16,062
A	Advanced SOFA (ASOFA)	1,695	2,117
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at an average unit output (244.5 MWg) and assumes a 97.3% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(4) - Costs for increased PM collection capacity included in lignite reburn option are $2,024,000/yr for annual O&M cost, and $2,527,000/yr annualized O&M cost.

3.4.1.3 LEVELIZED TOTAL ANNUAL COST ESTIMATES FOR MRY STATION NO_X CONTROLS

In order to compare a particular NO_X emission reduction alternative during the initial engineering analysis portion of the BACT selection process, the sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which is referred to as "Levelized Total Annual Cost" (LTAC) of expected pollutant removal by implementing that alternative was calculated. The LTAC for all NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Appendix C1 for methodology). The unit control cost was then determined as the LTAC divided by annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. The control alternatives were also compared by calculating the change in unit cost (incremental cost) per incremental ton removed for the next most stringent alternative. This identified which alternatives produced the highest increment of expected pollutant reduction for the estimated lowest average annual cost increment compared with the baseline emission rate. The expected annual number of tons of pollutant removed versus estimated LTAC for each remaining control alternative was then plotted.

The comparison of the cost-effectiveness of the remaining NO_X emission reduction technologies was made and is shown in Table 3-12 and Figures 3-1 and 3-2 for MRY Station Unit 1. These figures plot estimated annual amount of NO_X removal (emission reduction) in tons per year on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis), for each of the remaining NO_X control technologies. Points on the graph that are farthest to the right and closest to the horizontal axis are deemed more cost-effective, since they represent controls that achieve more NO_X removal per dollar required for total annual costs of operation, maintenance, and capital recovery (depreciation).

Although the NSR Manual repeatedly prescribes following a "top down" analysis approach for BACT determination, the development of a least cost envelope with dominant controls (as seen in NSR Manual Figure B-1, page B.42) clearly labels points with lower emissions reductions and total annual costs first, i.e. "A", "B", etc. then proceeding with labeling and connecting points plotted further away from the zero emission reduction point. This "bottom-up" approach is for plotting the least-cost (dominant) control curve. The labeling of each unit's NOx control technique alternative has followed this approach.

TABLE 3-12 – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 1

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) \$1,000	Average Control Cost(5) \$/ton
E	SNCR w/ ASOFA	4,025	5,909	7,472	1,265
D	Gas Reburn w/ ASOFA	4,275	5,659	37,334(6)	6,597
C	Lignite Reburn w/ ASOFA	4,343	5,591	11,388(7)	2,037
B	FLGR w/ ASOFA	5,260	4,674	16,990(6)	3,635
A	Advanced SOFA (ASOFA)	5,874	4,060	2,489	613
	Baseline	9,934	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated annual emission tons assume an annual capacity factor specific to each alternative; 94.1% was assumed for the baseline case.

(3) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

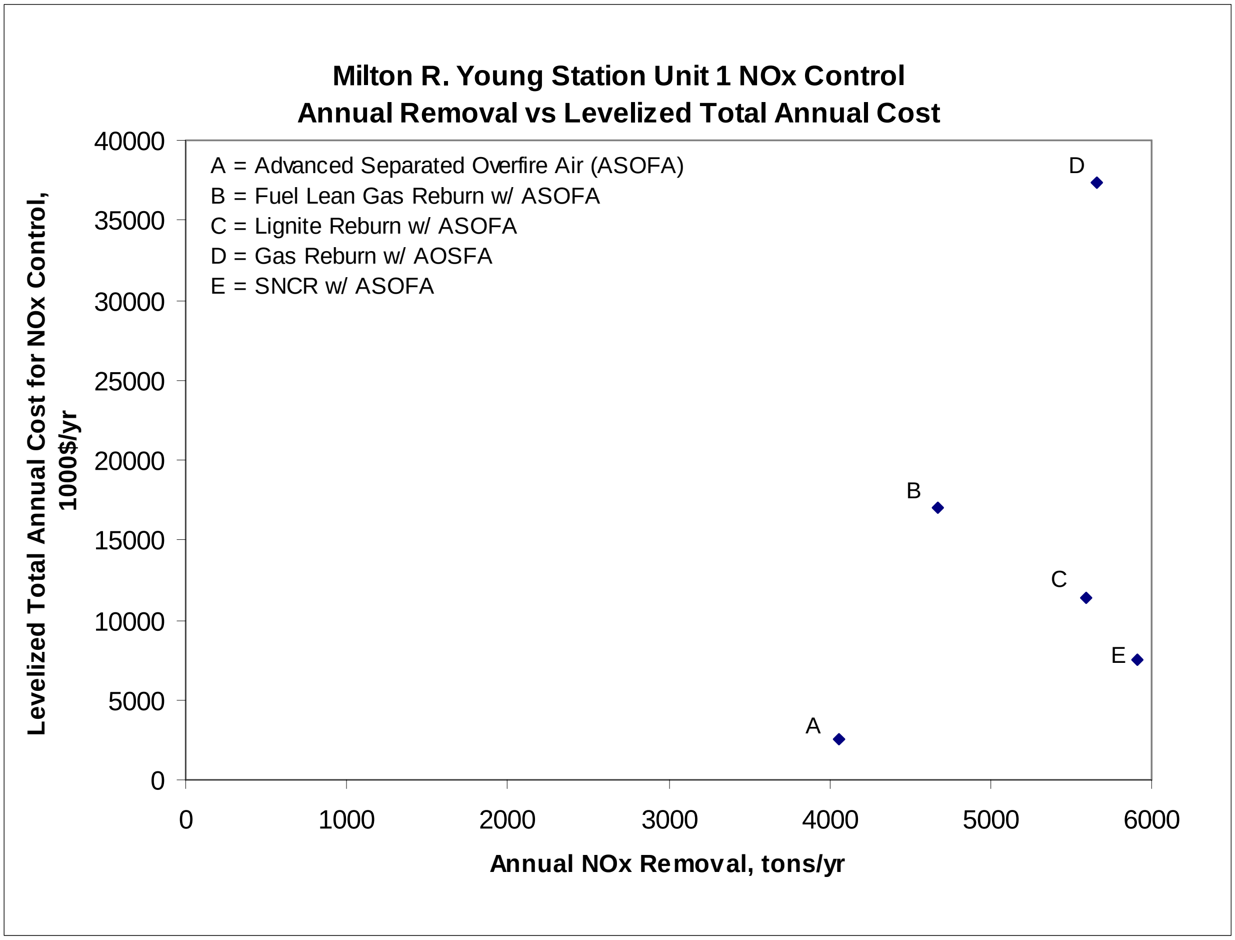
(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note #3 for Tables 3-10 and 3-11 for annualized cost factors. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at highest allowable pre-control NOx emission rate.

(5) - Average Control Cost Effectiveness (\$/ton) is the Levelized Total Annual Cost (1000\$/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(6) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of \$704,000/yr for CGR and \$352,000 for FLGR. See footnotes #8 and 10 under Table 3-9.1

(7) - LTAC for increased PM collection capacity included in lignite reburn option are approximately \$2,054,000 for annualized capital cost plus \$2,527,000/yr for annualized O&M cost, for a LTAC subtotal of \$4,581,000/yr.

Figure 3-1 – NO_X Control Cost Effectiveness - MRY Station Unit 1(1)



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 3-12.

The purpose of Figure 3-1 is to show the range of control and cost for all feasible NO_X reduction alternatives evaluated. A dominant set of control alternatives were determined by generating what is called the “envelope of least-cost alternatives”. The dominant controls cost curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the annual NO_X removal tonnage versus LTAC for the various remaining BACT alternatives. Following a “bottom-up” graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope are inferior control alternatives per the NSR Manual and should be excluded from further analysis on a cost efficiency basis.

Of the technically feasible NO_X control alternatives considered for MRY Station Unit 1, data points for conventional gas reburn (Point D) and fuel-lean gas reburn (Point B) with advanced separated overfire air, and lignite reburn with ASOFA (Point C), lay distinctly left and above the other points of the control cost points' scatter plot of Figure 3-1. These control options are inferior and therefore were eliminated from further control cost-effectiveness analysis.

Average and incremental annual costs and NO_X emission reductions for the dominant least-cost control alternatives remaining after the elimination of the obviously inferior options are listed in Table 3-13. The annual NO_X control tons per year, divided by the total levelized annual cost, yields an average unit cost ($/ton). Incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. The additional tons per year of NO_X control relative to the previous apparent least-cost curve point, divided by the increase in levelized annual cost, yields an incremental unit cost ($/ton). Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the envelope of least-cost control alternatives, also called the dominant controls cost curve or DCCC) between successively more effective alternatives which are considered technically feasible for Milton R. Young Station boilers.

TABLE 3-13 – Dominant Controls Cost Curve Points for Feasible BACT NO_X Alternatives - MRY Station Unit 1

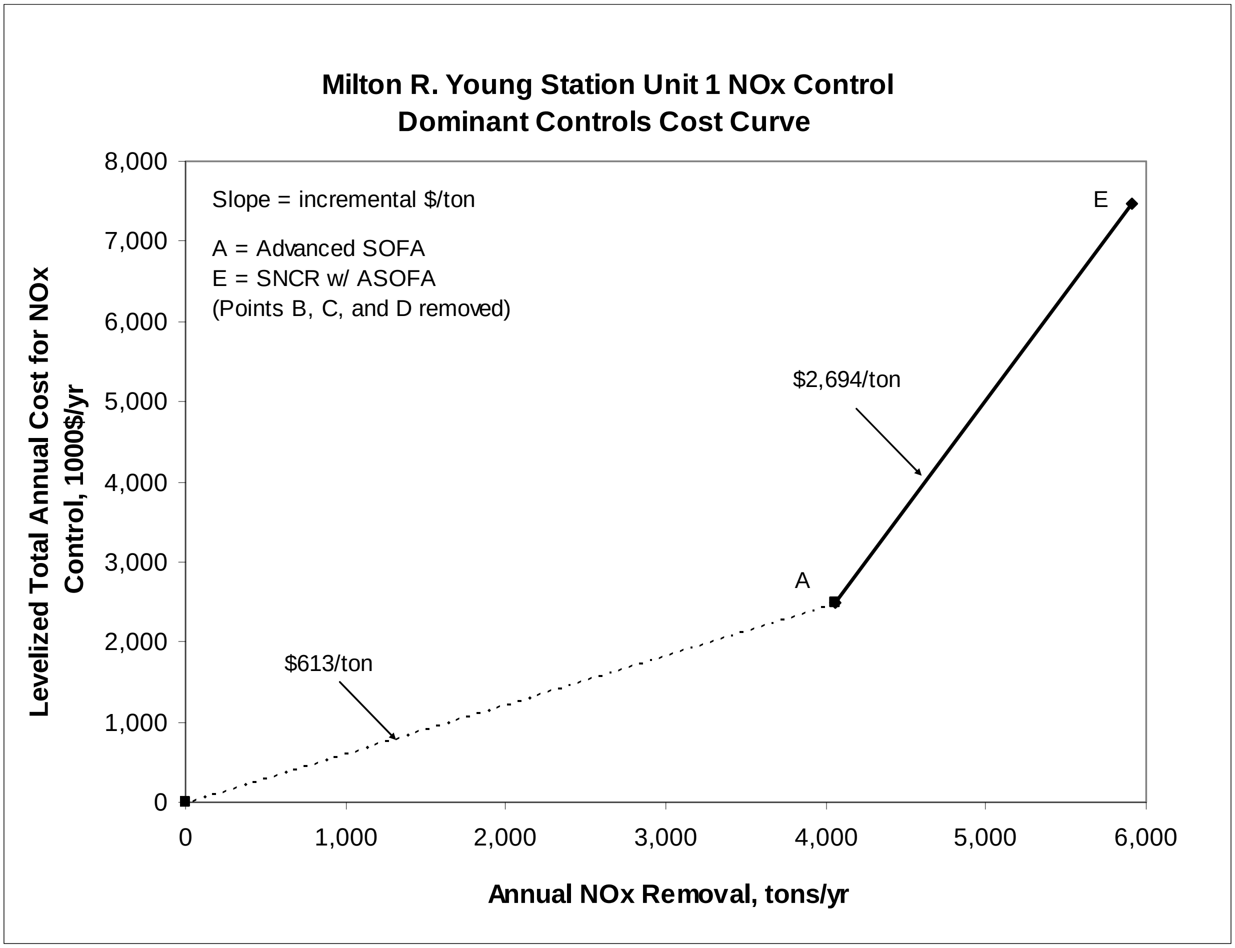
Alt. Label(1)	NOx Control Technique	Levelized Total Annual Cost(2),(3) ($1,000/yr)	Annual Emission Reduction(3) (tpy)	Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)	Incremental Annual Emission Reduction(4) (tpy)	Incremental Control Cost Effectiveness ($/ton)(2),(4)
E	SNCR w/ ASOFA	7,472	5,909	4,982	1,849	2,694
A	Advanced SOFA (ASOFA)	2,489	4,060	2,489	4,060	613

(1) – Dominant controls cost curve points from lowest (ASOFA) to highest (SNCR w/ ASOFA) are labeled the same as in Table 3-12, and on the graphs that accompany this table (Points B, C, and D were eliminated).
(2) – All cost figures in 2006 dollars.
(3) – Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate.
(4) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest, except as noted.

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control technique (slope from zero baseline to ASOFA, Point A was $613/ton for MRYS Unit 1; the incremental cost (slope) from ASOFA, Point A to SNCR with ASOFA, Point E was $2,694/ton for MRYS Unit 1.

Figure 3-2 contains a repetition of the levelized total annual cost and NO_X control information from Figure 3-1 for MRY Station Unit 1, with Point B (FLGR™ with ASOFA) , Point C (Lignite Reburn with ASOFA) and Point D (conventional gas reburn with ASOFA) removed. This is the dominant controls cost curve for MRY Station Unit 1 NO_X emissions alternatives.

Figure 3-2 – MRY Station Unit 1 NO_X Control Alternatives BACT Dominant Controls Cost Curve(1)



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 3-13.

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. As can be seen from a review of Table 3-14, the average levelized control cost effectiveness (called the unit control cost in this report) ranges from approximately $613/ton to $6,597/ton of MRYS Unit 1's NO_X emissions removed. It should be noted, however, that the highest estimated average control costs involve gas reburn technologies that were shown to be inferior options (not on the dominant controls cost curve) and thus were eliminated from further impacts analysis.

The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the least-cost envelope of dominant control alternatives or dominant controls cost curve) between successively more effective alternatives. The economic impact analysis indicates that from a cost effectiveness viewpoint, the highest performing alternative is SNCR with ASOFA (Point E). This control option is considered technically feasible for Milton R. Young Station Unit 1 boiler but incurs a significant annual (levelized) incremental cost relative to the next highest feasible NO_X control technique, ASOFA (Point A) when ASOFA is compared against the pre-control baseline. The Advanced Separated Overfire Air alternative has an average unit control cost ($613/ton) approximately 48% of the highest performing feasible alternative on the dominant controls cost curve (SNCR with ASOFA, $1,265/ton). ASOFA also has a much lower incremental cost per ton relative to the pre-control baseline (slope from zero to Point A, $613/ton) compared to SNCR with ASOFA (Point E) versus ASOFA (Point A); the slope from Point A to Point E was $2,694/ton.

The other elements of the fourth step of a BACT analysis following economic impacts are to evaluate the following impacts of feasible emission controls:

- The energy impacts.
- The environmental impacts.

TABLE 3-14 – Estimated Emissions and Economic Impacts Summary for NO$_X$ Control Alternatives - MRY Station Unit 1

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 1

		EMISSIONS(2)					ECONOMIC IMPACTS			
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	NOx Removal Efficiency(2) %	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	58.1	8,113	5,417	7,472	1,265
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0	18,006	28,641	37,334(7)	6,597
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6	46,656	5,862	11,388(7)	2,037
B	FLGR w/ ASOFA	0.460	1,261	5,260	4,674	45.9	10,639	12,863	16,990(7)	3,635
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	39.5	4,277	1,695	2,489	613
	Baseline	0.849	2,330	9,934	0	0.0	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO$_X$ control level reductions relative to average annual unit emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.5 MWg and assumes a 96.6% average running plant capacity factor compared to nominal unit gross electrical output capacity of 253 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $1,909,000/yr for annual O&M cost.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars.

(7) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $2,054,000 for annualized capital cost plus $2,384,000/yr for annualized O&M cost, for a total of $4,438,000/yr.

3.4.2 ENERGY IMPACTS OF MRY STATION NO_X CONTROLS

Operation of the most cost-effective NO_X control technologies considered feasible for potential application at the Milton R. Young Station impose direct impacts on the consumption of energy required for the production of electrical power at the facility. The details of estimated energy usage and costs for the various NO_X control alternatives are summarized in Appendix C3.

Control alternatives for reduction of NO_X emissions were reviewed to determine if the use of the technique or technology will result in any significant or unusual energy penalties or benefits. There are several basic kinds of energy impacts for NO_X emissions controls:

- Potential increase or decrease in power plant energy consumption resulting from a change in thermal (heat) energy to net electrical output conversion efficiency of the unit, usually expressed as an hourly unit heat rate (Btu/kW-hr) or the inverse of pounds of pollutant per unit electrical power output (MW-hr). This may or may not change the net electrical output (MW) capacity of the EGU, depending on if there are physical or imposed limits on the total heat input to the boiler or electrical power output.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in physical operational limitations imposed on the ability to sustain a fuel heat input rate (mmBtu/hr) which results in a potentially lower or higher unit net electrical output (MW) capacity. This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in auxiliary electrical power demand and usage (kW, kW-hrs). This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in reliability and availability to generate electrical power. This results in a change to the number of hours of annual operation, not necessarily a change in net electrical output (MW) capacity of the EGU.

3.4.2.1 ENERGY IMPACTS OF SOFA TECHNOLOGY

There should not be a major impact on energy consumption resulting from the operation of the advanced variation of a separated overfire air system. SOFA does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. Damper resistance and supply pressure impacts of the SOFA system on fan power consumption should be insignificant. The amount of flyash emitted from the boiler is expected to be reduced (less than five percent) from the baseline level when the SOFA system is in full operation. Slightly higher levels of unburned carbon in the flyash may occur with the operation of a SOFA system. This could have a small negative impact on the plant heat rate (higher Btu/kw-hr). These changes are expected to be within the typical range of current operation.

There is a potential reduction in reliability and availability of a lignite-fired cyclone boiler to generate steam for production of electrical power as a result of installing and operating a separated overfire air system. Typical SOFA operation on bituminous or western subbituminous coal-fired cyclone boilers does not carry a significant additional risk of causing insufficient or excessive accumulation of slag within the cyclone barrels or furnace bottom compared with non air-staged combustion. Reliable boiler operation depends on avoiding such adverse conditions in the cyclones and lower furnace, which could require a forced outage to remove the solidified slag prior to returning the boiler to generation production service.

The challenges of maintaining adequate slag layer development and flow while firing lignite in MRY Unit 1's cyclones under excess air conditions have been significant during the operating history of the powerplant. Minimizing forced outages resulting from cyclone slag issues have largely been successful through operational practices that do not affect day-to-day boiler reliability and availability. Due to the variability of combustion characteristics of lignite supplied from the Center mine, and the dependency of the slag flow on the temperature within the cyclone barrels or furnace bottom, conditions may occur during ASOFA operation that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the solidified slag.

The potential impact on annual unit operating time due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation was estimated to be approximately 2% reduction from the assumed pre-control baseline availability, i.e. 0.97-0.02=0.95. The estimated electrical generation production lost due to the reduction in MRY Unit 1's annual availability is shown in Table 3-16.

3.4.2.2 ENERGY IMPACTS OF SNCR TECHNOLOGY

For SNCR, the injection of a diluted urea solution will require some additional auxiliary power for heating and pumping the liquid and using compressed air for atomization and cooling the reagent injection nozzles/lances, on the order of 70 to 200 kW. The injection of water (used for urea dilution) into the boiler flue gas also will have a small negative impact on the plant heat rate (higher Btu/kw-hr), although the vendor of SNCR systems advises that the heat released from the oxidation of a portion of the injected urea compensates for this impact. The impact of additional flue gas created by operation of an SNCR-related system on fan power consumption should be small.

There is a potential reduction in reliability and availability of a lignite-fired cyclone boiler to generate steam for production of electrical power as a result of installing and operating a SNCR-related system. Typical SNCR operation with low ammonia slip when firing low-sulfur western subbituminous coal in cyclone-fired boilers does not carry a significant additional risk of causing excessive fouling of the tubular air preheater compared with non-SNCR operation. Reliable boiler operation depends on avoiding adverse fouling conditions in the air preheater, which could require a forced outage to remove the ash deposits prior to returning the boiler to generation production service.

The challenges of maintaining open passages through the air preheater tubes while firing lignite in MRY Unit 1's cyclones under typical conditions have been minor during the operating history of the powerplant. Minimizing forced outages resulting from ash deposits within the air preheater have largely been successful through operational practices that do not affect day-to-day boiler reliability and availability. Due to the variability of fouling characteristics of lignite supplied from the Center mine, and the dependency of the fouling within the air preheater on sodium, sulfur, and ammonia slip emission levels, conditions may occur during SNCR operation that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the air preheater deposits.

The potential impact on annual unit operating time due to air preheater fouling and other potential issues associated with SNCR system operation was estimated to be an incremental 1% reduction from the assumed pre-control baseline or ASOFA availability. The estimated electrical generation production lost due to the reduction in MRY Unit 1's annual availability is shown in Table 3-16.

TABLE 3-15 – Expected Auxiliary Electrical Power Impacts for NO_X Controls - MRY Station Unit 1

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Auxiliary Electrical Power Demand and Consumption for NOx Control Equipment	
		Gross Demand(2) kW	Power Usage(3) kW-hrs/yr
E	SNCR w/ ASOFA	73	582,411
A	Advanced SOFA (ASOFA)	1	8,058

(1) – Alternative number has been previously assigned from highest to lowest unit NOx emission rate.

(2) – The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects.

(3) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.

TABLE 3-16 – Expected Electrical Power Generation Availability and Capacity Impacts for NO_X Controls - MRY Station Unit 1

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Availability(2)	Estimated Annual Average Operating Time Reduction, hrs/yr(3)	Estimated Annual Average Running Plant Capacity Factor(4)	Estimated Annual Average Electricity Generation Reduction kW-hrs/yr(5)
E	SNCR w/ ASOFA	0.956	273	0.965	67,660,606
A	Advanced SOFA (ASOFA)	0.952	188	0.966	46,586.546

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.

(2) – Baseline availability is assumed at 97.3 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.

(3) – Annual lost operating time resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.

(4) – Baseline running plant capacity factor is assumed at 96.6 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.

(5) – Annual electricity generation reduction is annual reduction of operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the MCR capacity rating of 253 MW (MCR gross unit electrical output capacity).

TABLE 3-17 – Expected Total Electrical Power Generation Impacts for NO_X Controls - MRY Station Unit 1

Alt. Label(1)	NOx Control Technique	Power Usage(2) kW-hrs/yr	Estimated Annual Average Electricity Generation Reduction(3) kW-hrs/yr	Est. Total Annual Change in Net Electrical Power Generation Available for Sale(4) kW-hrs/yr
E	SNCR w/ ASOFA	582,411	67,660.606	68,243,017
A	Advanced SOFA (ASOFA)	8,058	46,586.546	46,594,605

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.

(2) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.

(3) – Annual electricity generation reduction is annual reduction of operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the MCR capacity rating of 253 MW (MCR gross unit electrical output capacity).

(4) – Annual change in net electrical power generation available for sale is arithmetic sum of annual power generation reduction due to a change in the auxiliary electrical power consumed plus the annual generation reduction from a decrease in annual operating time and average annual running plant capacity factor resulting from the implementation of the individual NOx control technique, compared with baseline.

3.4.3 ENVIRONMENTAL IMPACTS OF NOx CONTROLS - MRY STATION

Nitrogen oxides react with oxygen in the atmosphere to produce elemental nitrogen and ozone (O_3). This is one of the common causes of visible pollution in the atmosphere referred to as “smog”. Operation of the various NO_X control technologies considered for potential application at the Milton R. Young Station impose direct and indirect impacts on the environment. The most pronounced direct environmental impact expected from operation of any of the NO_X control options considered is the reduction of ozone and improvement in atmospheric visibility (i.e. reduced visibility impairment) downwind of the facility.

3.4.3.1 ENVIRONMENTAL IMPACTS OF SOFA TECHNOLOGY

The operation of a separated overfire air system is expected to slightly increase carbon monoxide concentrations in the stack flue gas. The advanced form of SOFA alternative is expected to slightly lower the amount of particulate matter emitted from the boiler and may raise the amount of unburned carbon in the flyash collected for land disposal and emitted to the atmosphere by small increments. Alternatives involving forms of gas reburn should experience lower particulate emissions, and a reduction in the amount of boiler bottom and flyash requiring disposal.

The environmental impact from potential reduction of annual unit operating time by approximately two percent due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation will be to reduce the annual amount (tons) of nitrogen oxides emitted, and therefore the annual number of NO_X tons removed will increase, by approximately two percent.

3.4.3.2 ENVIRONMENTAL IMPACTS OF SNCR TECHNOLOGY

Operation of a conventional SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs).

Operation of an SNCR system will normally create a small amount of unreacted urea or ammonia to be emitted. The amount of ammonia slip produced by SNCR depends on the amount of reagent utilization and location of the injection points. Higher SNCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 10 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate $[(NH_4)_2SO_4]$ and ammonium bisulfate $[NH_4HSO_4]$ will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates.

Some of the unreacted ammonia from SNCR operation will be collected with the flyash in the electrostatic precipitator. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be emitted from the stack as an aerosol or condensable particulate. This has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition. Although the predicted amount of such potential impact from ammonia slip emissions has not been determined, it is expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NOx emission reduction.

Delivery of the urea reagent to the powerplant facility and storage of aqueous urea reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Urea is much less volatile than anhydrous or aqueous ammonia, and these risks are expected to be manageable. Emergency planning and community communications are part of the management plan requirements for such reagent usage.

The environmental impact from potential reduction of annual unit operating time by approximately one percent due to air preheater fouling issues associated with SNCR system operation will be to reduce the annual amount (tons) of nitrogen oxides emitted, and therefore the annual number of NO_X tons eliminated relative to the constant pre-control emission baseline will increase by approximately one percent.

3.4.4 SUMMARY OF ECONOMIC, ENERGY AND ENVIRONMENTAL IMPACTS OF MRY STATION NO_X CONTROLS

The economic, energy, and environmental impacts of each feasible BACT alternative evaluated for this study is summarized in this Section. Table 3-18 summarizes the various impacts discussed in Sections 3.4.1 through 3.4.3. The economic analysis examined the capital cost of each feasible BACT alternative evaluated and any other powerplant upgrade costs necessary to implement the alternative. In addition, the economic analysis examined the operating and maintenance cost associated with the highest-performing forms of each feasible BACT alternative evaluated. These costs were then combined into the levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each alternative was evaluated. Two alternatives were on the dominant controls cost curve and thus were identified as the more cost effective alternatives. The two BACT NO_X control alternatives evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 1 were:

- Selective Non-Catalytic Reduction (SNCR) combined with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA); and
- ASOFA alone.

TABLE 3-18 – Summary of Top-Down BACT Impact Analysis Results for Dominant NO_X Control Alternatives - MRY Station Unit 1

		EMISSIONS(2)				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS	
Alt. Label(1)	**NOx Control Alternative**	**Emission Rate lb/mmBtu**	**Hourly Emission lbs/hr**	**Annual Emission tons/yr**	**Emission Reduction tons/yr**	**Installed Capital Cost(3) $1,000**	**Annual O & M Cost(4) $1,000**	**Levelized Total Annualized Cost(5) $1,000**	**Average Control Cost(6) $/ton**	**Incremental Control Cost(7) $/ton**	**Incremental Aux. Power Demand(8), kW**	**Incremental Annual Aux. Power Usage + Generation Reduction(8), kW-hrs/yr**	**Non-Air Increase**	**Toxic Air Increase**
E	SNCR w/ ASOFA	0.355	975	4,275	5,659	8,113	5,417	7,472	1,265	2,694	73	68,243,017	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	4,277	1,695	2,489	613	613	1	46,594,605	Flyash UBC	CO
	Baseline	0.849	2,330	9,934	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars.

(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit reliability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr).

(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations likely will increase with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology.

3.5 BACT RECOMMENDATIONS AND CONTROL LEVELS – MRY STATION UNIT 1

This report presents the analysis of control technologies for nitrogen oxides (NO_X) for Minnkota Power Cooperative's (MPC's) Milton R. Young Station Unit 1 using the EPA's "top-down" BACT approach. BACT is an emissions limitation for each pollutant from a source determined to be achievable using control technologies(s) that provide the "maximum degree of emission reduction…taking into account energy, environmental, and economic impacts"[30]. A BACT review does not result in a percent removal efficiency requirement. The generally accepted procedures for performing a BACT analysis are outlined in the EPA's draft NSR Manual. The BACT analysis for Milton R. Young Station NO_X emissions was performed in accordance with this procedure. The EPA's draft NSR Manual outlines five basic steps that are to be followed in the "top-down" BACT evaluation. These steps were as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

The final result of this analysis is a recommendation of the BACT alternative and the associated NO_X emission rate for Minnkota Power Cooperative's Milton R. Young Station Unit 1. The emission limitations for a generation facility are expressed in a pounds per million British Thermal Units (lb/mmBtu) basis.

3.5.1 UNIT 1 NO_X BACT

In step one of the technology evaluation, three basic categories of NO_X controls for EGUs were-identified: pre-combustion, combustion, and post-combustion. Eleven basic types of NO_X control processes were identified within these three categories. Twenty four variations of these eleven processes were reviewed for availability and applicability to cyclone-fired EGUs burning North Dakota lignite. An "advanced" form of Separated Overfire Air, alone and in various combinations with Lignite Reburn, Selective Non-Catalytic Reduction (SNCR), Conventional Gas Reburn and

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[30] Ibid, NSR Manual B.1

Fuel Lean Gas Reburn™, was evaluated for cost-effectiveness. The cost-effectiveness analysis indicated that ASOFA alone, and ASOFA with SNCR were cost effective alternatives for MRY Station Unit 1 NO_X control. The energy and environmental impacts analysis for MRY Station Unit 1's cost-effective NO_X control alternatives were generally insignificant.

Based upon the definition of BACT and the results of the BACT analysis, Selective Non-Catalytic Reduction (SNCR) in combination with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA) is recommended as the Best Available Control Technology for nitrogen oxides emissions from Minnkota Power Cooperative's Milton R. Young Station Unit 1. The unit BACT NO_X emissions rate for MRYS Unit 1 is 0.355 lb/mmBtu , determined as a rolling 12-month average. This is shown in Table 3-19.

TABLE 3-19 – NO_X Emission Control Technology and Rate Recommended as BACT for Milton R. Young Station Unit 1

Control Technology and Emission Rate Recommended as BACT			
Unit	**Pollutant**	**BACT Control Method**	**12-Month Rolling Average BACT NOx Emission Rate (lb/mmBtu)**
1	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.355

3.5.2 EMISSION RATE LIMITATION RECOMMENDATION

To complete the BACT determination process, the Consent Decree (CD) requires that "specific control technologies to be installed and a specific Phase II 30-day Rolling Average NO_X Emission Rate limitation (lbs/MMBtu)"[31] (pounds per million Btu) must be established for each subject emission Unit. The CD also states that "a "30-day Rolling Average Emission Rate" shall be determined by calculating an arithmetic average of all hourly emission rates in lbs/MMBtu for the current Operating Day and the previous 29 Operating Days. A new 30-day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-day Rolling Average Emission Rate shall include startup, shutdown, and Malfunction periods within each Operating Day"[32].

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[31] Ibid footnote number 1, Paragraph 66, page 20.
[32] Ibid footnote number 1, Paragraph 5, page 4.

The Consent Decree also states that the North Dakota Department of Health's (NDDH) NO_X "BACT Determination shall address specific emission limitations during Unit startups"[33] at Milton R. Young Station. The type and duration of firing during startups, and the limited ability of available and feasible technologies to control startup NO_X emissions, both significantly influence the 30-day rolling average BACT NO_X emission rate limit recommended for Milton R. Young Station boilers. A 24-hour rolling average NO_X emission rate limit applied to startup periods is also recommended for Milton R. Young Station boilers.

The Consent Decree and the EPA's NSR Manual do not describe the method for determining a 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT applied to Milton R. Young Station Unit 1.

In keeping with the establishment of a specific CD Phase II 30-day Rolling Average NO_X Emission Rate limitation, a relevant precontrol baseline level of emissions and its basis must be determined. The EPA's NSR Manual states:

> "The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions from the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions"[34].

Also stated in the EPA's NSR Manual:

> "Estimating realistic upper bound case scenario does not mean that the source operates in an absolute worst-case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints"[35].

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[33] Ibid footnote number 1, Paragraph 66, page 20.
[34] Ibid footnote number 2, NSR Manual page B.37
[35] Ibid footnote number 2, NSR Manual page B.37.

The BACT Analysis was conducted based upon the highest historical 12-month rolling NO_X emission summation operating conditions for Milton R. Young Station boilers during years 2001-2005. However, a baseline reflecting a realistic upper bound case scenario based upon the highest historical 30-day rolling NO_X emission operating conditions during years 2001-2005 was established prior to recommending enforceable permit conditions for BACT to be applied to each Milton R. Young Station boiler.

The approach taken in this analysis was to identify pre-control 30-day baseline operating conditions from the 30-consecutive day period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation between January 1, 2001 and December 31, 2005. This reflects unit NO_X emissions that were generated during periods of high unit operations, not affected by unit shutdowns, startups, or malfunctions. MRYS Unit 1's highest reported 30-day rolling average NO_X unit emission rate during years 2001-2005 was 0.884 lb/mmBtu for the period ending January 15, 2004. The corresponding MRYS Unit 1 30-day average hourly NO_X mass emission rate was 2,642 lb/hr. The average unit heat input rate for MRYS Unit 1 was 2,990 mmBtu/hr, and the average gross unit electrical power output was 246.7 MW_g for the same 30-day period.

The operating conditions during the highest historical 30-day rolling NO_X emission for years 2001-2005 were then compared to the highest 12-month historic pre-control baseline conditions. The average unit NO_X emission rate (lb/mmBtu) from the highest historic pre-control 30-day baseline period was compared with the average NO_X emission rate (lb/mmBtu) from the 12-consecutive month period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation during the same 5-year look-back period. An estimate of NO_X emission reduction for the proposed BACT NO_X alternative operating at the historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) was made. This rate considered recognized operational factors and equipment designs applied to "steady state" conditions with sustained output close to maximum continuous capacity ratings. The potential impact of startups, recognizing operational and technical limitations on NO_X emission control performance, was then applied to the steady-state rate, to establish a recommended 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT for Milton R. Young Station Unit 1. This is explained below.

NO_X emissions for cyclone-fired boilers are typically higher in pounds per million BTUs during start up events than during steady-state operation at maximum continuous rating (MCR) conditions. This is because hourly heat and combustion air input rates required to establish adequate molten slag formation within the cyclone barrels and promote slag tapping are typically produced from firing conditions that create high flame temperatures. NO_X emissions are sensitive to peak furnace gas temperatures, thus uncontrolled NO_X emissions can be high during cyclone boiler startups. Furnace exit flue gas temperatures (FEGTs) during cyclone boiler startups are less than those occurring during conditions of steady state MCR firing rates due to the high heat absorption of the boiler metal and water being raised from ambient or near-ambient temperatures. Until sufficient FEGT exists for a feasible and available post-combustion technology, such as SNCR, to be effective, NO_X emissions will be basically uncontrolled. There is a practical lower limit of boiler heat input for conventional combustion-based NO_X emission control techniques, such as the advanced version of separated overfire air, to be operated beyond the amount required for cooling the SOFA injection nozzles when it can be diverted from the cyclone burners and significantly control NO_X emissions. These limitations of the effectiveness of BACT controls on Milton R. Young Station boilers during startups and other reduced-load operating periods influence the recommended 24-hour and 30-day rolling average NO_X emission rate limits.

Startup procedures for steam electric generating units (SEGUs) comprising a fossil fuel-fired boiler and steam turbine-generator are specified by the original equipment manufacturers to follow guidelines for heat and pressure increases to provide protection of boiler and turbine equipment. Initial start up duration after an outage may be dictated by the need to gradually warm up burner port/cyclone refractory materials, steam drum shell, steam headers, and other boiler metal surfaces exposed directly or indirectly to furnace gases, and the steam turbine’s multiple casings and rotor shafts. This is normally accomplished with easy-to-ignite fossil fuel firing (such as natural gas, distillate fuel oil, or propane) of the boiler combined with coal to gradually increase firing until recommended boiler steam outlet temperature and pressure are reached. This is followed by supplying the steam turbine with sufficient inlet steam flow to reach conditions that allow the coupled generator to be synchronized and electricity to be generated above zero megawatts. From this point, boiler fuel firing is increased within prescribed rates until the desired operating load is achieved.

The SEGU startup operating period is usually not defined in emission permits. Startup is the period beginning with initiation of fuel ignition, and continuing until the powerplant equipment has reached operating conditions that include continuous fuel firing and sustained operating steam pressure and temperature levels within the guidelines of the designs for the boiler and turbine and their auxiliary systems for minimum sustainable levels without causing damage to the equipment.

A recent SEGU proposed PSD permit has included a definition of startup as “the period beginning with ignition and lasting until the equipment has reached a continuous operating level and operating permit limits”[36]. Similarly, a shutdown is defined as “the period beginning with the lowering of equipment from base load and lasting until fuel is no longer added to the boiler and combustion has ceased”[37]. Based on the referenced definitions of a startup period and a shutdown period, the amount of time required for a SEGU’s load (boiler steam output or generator electrical output) to increase beyond such minimum sustainable operating levels can be considered part of startup events if the SEGU is typically base-loaded at full load or MCR output. This is the case with both MRY Station SEGUs.

Startups of SEGUs may be labeled as cold, warm, and hot to account for the amount of residual heat remaining in the boiler and steam turbine equipment. The various types of starts are dependent upon the amount of time the SEGU has been out-of-service (i.e. without boiler fuel firing or generator megawatt output). Cold starts have been defined as starts after the boiler has been without fuel firing for more than 72 hours, warm starts are more than 8 hours and less than 72 hours, and hot starts are less than 8 hours[38].

Although the definition of a startup event and the corresponding startup period is not required by the Consent Decree, defining start-ups is recommended. This helps to address the specific emission limitations during Unit startups at Milton R. Young Station and determine the impact of such operations on 30-day rolling average NO_X emissions. For the purpose of this NO_X BACT analysis, a Unit startup was defined as the period from initial fuel combustion to the point in time when:

- the measured Heat Input to the boiler on a 6-hour rolling average basis is greater than or equal to 2500 million BTU/hr for Unit 1; or
- the amount of time reported for the longest individual Unit 1 startup period during actual operation between January 1, 2001 and December 31, 2005 elapses, whichever occurs first; or
- fuel firing is discontinued prior to satisfying either previous criteria.

This startup definition for MRY Station Unit 1 accounts for conditions where cyclone refractory materials replaced during boiler overhauls must be cured by extended low-firing heating cycles,

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[36] Desert Rock Energy Center (AZP04-01) Proposed PSD Permit Conditions, page 7. (http://www.epa.gov/region09/air/permit/desertrock/#permit)
[37] Ibid, page 7.
[38] Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility, Document Number 09417-360-250R1, May 2004, page 5-1.

unit controls are upgraded and must be adjusted during low-load operation, or for boiler feedwater quality to improve after boiler maintenance has been performed that affects the insides of the waterwall and superheated steam tubes. It also allows for a failed or interrupted start sequence which can require considerably less or more time to elapse than an average startup duration.

Analysis of MRY Station Unit 1 operations data from 2001 through 2005 revealed:

- There were 60 total startups in the five year period;
- Minimum startup was 10 hours for a "hot" start following a boiler master fuel interruption (Unit "trip");
- Maximum startup with an extended ramp-up period until full load was reached was 61 hours.

Unit 1 had a start-up that began on June 27, 2005 that lasted for 61 hours. This startup included initial firing in the 5th hour of 6/27 (0500 hours being the beginning of the startup period), and which ended at the end of the 17th hour (i.e. at 1800 hours) on June 29th, 2005 upon reaching a generator output of 245 MW (gross) rather than a 6-hour average heat input rate of more than 2500 million Btu per hour.

There are certain boiler operating conditions that need to exist before the BACT NOx control techniques and technologies can be effectively operated:

1. The furnace gas temperature in the region where a urea reagent solution is injected for SNCR-based NO_X control must be between 1700°F and 2100°F. This region is expected to be in the vicinity of the furnace exit, which is commonly defined as either the horizontal plane extending from the furnace rear wall arch ("nose") to the front wall of the boiler, or the vertical plane from the nose up to the furnace roof, upstream of the gas inlet to the superheater tube banks. The gas temperature (FEGT) range in this furnace region is dependent on boiler heat input rate and cleanliness of the firesides of the furnace walls, which affects the amount of radiant energy absorbed by the wall tubes and transferred to the water within.
2. The numbers of active cyclones and continuous coal firing rates must be enough to establish sufficient:
   a. coverage of molten slag on the actively-fired cyclone barrel surfaces and drainage of the slag from the bottom of the boiler; and

b. combustion airflow through the actively-fired cyclones to allow a portion to be diverted to the separated overfire air system above the amount required for idle cyclone cooling and SOFA nozzle cooling.

As previously discussed, furnace exit flue gas temperatures (FEGTs) will need to be measured or determined empirically during operation of the MRY Station boilers in order to be able to effectively control NO_X emissions using SNCR technology. The design and operation of the SNCR systems at MRYS for CD Phase II emissions control should include features that accommodate cyclone boiler startups and low-load operation with "clean" or "dirty" boiler heat transfer surfaces as soon as conditions occur that are technically practicable, i.e. within the SNCR system vendor's recommended operating guidelines, as well as full-load conditions in order to minimize NO_X emissions.

The amount and duration of sustained boiler heat input required to establish the operating conditions described in item 2 above is more difficult to precisely determine. Lignite heat content variability and inability to accurately determine the actual air/fuel ratio on a cyclone-by-cyclone basis in real-time, and the slagging and fouling characteristics of the lignite ash, cause (and are expected to continue to cause) difficulties with stable combustion performance. The minimum firing rates of the MRY Station boilers required to successfully initiate the effective operation of the SOFA system are specific to each individual boiler, and are not currently known. Due to such operating problems and emission control limitations, the ability to effectively limit NO_X emissions during startup periods and low-load operation following implementation of advanced SOFA (CD Phase I control) and/or an SNCR system (CD Phase II control) is uncertain.

Because there are expected to be minor short term variations in operating conditions during startups where Minnkota has not, in fact, materially changed any of their normal startup operating practices and criteria, a margin between the 30-day rolling average steady-state NO_X emission rate (which does not include the impacts of startups) and the proposed 30-day rolling average NO_X emission permit limit that includes startup emissions is recommended. This rate considered recognized operational factors and equipment designs applied to steady state conditions with sustained output close to maximum continuous capacity ratings. The recommended 30-day Rolling Average NO_X Emission Rate permit limitation excluding the impact of startups that reflects BACT for Milton R. Young Station Unit 1 is shown in the table below.

TABLE 3-20 – Recommended NO_X BACT Control Method and 30-Day Rolling Average NO_X Emission Rate Limit Without Startups

Unit	Pollutant	Control Method	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)
1	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.360

This recommended BACT 30-day NO_X emission rate limit is based upon a historic pre-control 30-day baseline average NO_X emission rate of 0.884 lb/mmBtu for Unit 1. The baseline emission was determined from the 30-consecutive day period with the highest historic unit NO_X emissions rate reported for actual operation between January 1,2001 and December 31, 2005.

A recommended BACT 30-day NO_X emission rate limit that includes the impact of startup emissions should be suitably higher such that operation consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices to the extent practicable for the MRY Station boilers would not result in an exceedance (violation) of an enforceable 30-day rolling average NO_X emission permit limit.

For MRYS Unit 1, the recommended 30-day rolling average NO_X emission permit limit rate that includes the impact of startups is based upon recognized operational factors and equipment designs that influence whether the startup emissions result in higher 30-day emissions compared to normal continuous operation without or excluding such startup periods:

1. The uncontrolled emission rate (i.e. without separated OFA or SNCR in operation) and its variability during operation from a cold, warm, or hot startup up to and including maximum continuous rated output;
2. The operating conditions that are required to exist for the selected NO_X BACT control techniques to be initiated and be effective; and
3. The effectiveness of these two particular control techniques if invoked at less-than-MCR steady-state operating conditions.
4. The number of startups and their range of typical durations per 30-day period time frame.

The June 27-29, 2005 startup was chosen for additional evaluation as the start-up for MRY Station Unit 1.

An incremental adjustment to the proposed 30-day rolling average steady-state unit NO_X BACT emission rate without startups of 0.36 lb/mmBtu for Unit 1 is recommended for the 30-day rolling average NO_X emission permit limit periods as defined and applied to Milton R. Young Station. This is summarized in the table below.

TABLE 3-21 – Recommended BACT 30-Day Rolling Average NO_X Emission Rate Limit and Startup Impact

Unit	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)	Impact on 30-day Rolling Average NOx Emission Rate Limit Due to Startups (lb/million Btu)
1	0.36	+0.041 per startup

This recommended adjustment to the proposed 30-day rolling average steady-state NO_X BACT emission rate limit without startups is based upon average historic pre-control NO_X emission rates of 0.766 lb/mmBtu for Unit 1 reported for the longest individual Unit 1 startup period during actual operation between January 1, 2001 and December 31, 2005. These emissions occurred during the 61-hour June 27-29, 2005 startup for Unit 1.

A 24-hour rolling average BACT NO_X emission rate limit applied to startup periods is also recommended for each of the Milton R. Young Station boilers.

This is summarized in the table below.

TABLE 3-22 – Recommended 24-Hour Rolling Average NO_X Emission Rate Limit During Startups

Unit	24-hour Rolling Average NOx Emission Rate Limit During Startups (lb/million Btu)
1	0.980

These emissions occurred during the 61-hour June 27-29, 2005 startup for Unit 1.

Compliance with these emission rates would be measured at the stack of the Unit, verified with Continuous Emission Monitoring (CEM) systems in accordance with the reference methods specified in 40 C.F.R. Part 75, and would be determined on a 30 consecutive Operating Day and 24-consecutive hour rolling average basis, respectively.

A trial demonstration operating period of 18 months after the completion of Consent Decree Phase II NO_X emission reduction system installation commissioning at Milton R. Young Station is recommended. It is proposed to allow Minnkota to demonstrate the actual control system capabilities of the combined NO_X BACT emissions reduction system. Operating experience during the trial period will:

- confirm steady-state control performance of the combined NO_X BACT emissions reduction system;
- allow determination of the ability to further control Unit start-up emissions;
- allow the determination of the permitted 30-day rolling average NO_X emission limit including startups, shutdowns, and malfunctions; and
- address the specific emission limitations during Unit startups at Milton R. Young Station and their impact on the proposed 30-day rolling average emission rate limit (without startups).

Based upon the information obtained during the trail period, final emission limits can then be determined.

The means that will be employed to minimize emissions during startup will primarily be based on operating procedures, both before and after the level of upper furnace gas temperatures and/or heat input rate are considered sufficient to start the NO_X controls and operating conditions are conducive for effective emissions reduction. These could be similar to Minnkota's current MRYS practices, or could be different, depending upon the capabilities of the NO_X controls and their impacts on Unit operations.

References:

1. In the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034.

2. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The “NSR Manual”).

3. EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: from EDOCKET at http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b; this is associated with EPA Acid Rain Program Clean Air Markets Division, Technical Support Document – Methodology For Developing BART NO_x Presumptive Limits, June 15, 2005, OAR-2002-0076-0445.

4. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NO_X Controls – NO_X Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

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APPENDIX A

Technical Feasibility Assessment Details for NO_X Control Technologies (A1)

U.S. Coal Cyclone NO_X Reduction Projects Summary

With Retrofit NO_X Control Projects’ Technical Literature Summary (A2)

A.1 Technical Feasibility Assessment of NO_X Control Alternatives

A.1.1 Pre-Combustion Fuel Treatment/Switching

Fuel switching can be a viable method of NO_X emission reduction in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. In the case of MRY Station, the Unit 1 and 2 boilers were designed and constructed specifically for firing North Dakota lignite, which has a fuel higher heating value (Btu/lb) approximately 20% lower than typical Powder River Basin (PRB) coal. A cyclone–fired boiler (Ottertail's Big Stone Unit 1) that is similar in geometry and steam generation design to MRY Station Unit 2 fires PRB coal. Based on a comparison of available emission data between Big Stone Unit 1 and MR Young Unit 2, there is no expected reduction in baseline (i.e. uncontrolled) NO_X emissions from switching to PRB from lignite at Milton R. Young Station.

Conversion of Milton R. Young Station Unit 1 boiler to fire PRB coal is technically possible. It is expected that major plant modifications will be required. Rail service is not presently installed at this site, so the additional operational and capital costs to bring in large quantities of PRB coal will be significant. Investigation of the specific source, distance, and costs for supplying necessary quantities of PRB coal via rail or trucks to M.R. Young station has not been performed. With zero baseline NO_X emissions reduction expected from application of fuel switching, this alternative will not be economically competitive with other NO_X control technologies that offer better results for a much lower combination of capital and operational costs. Although fuel switching is technically feasible, it has not been considered further as an effective NO_X emissions control option for MRY Station Unit 1 boiler.

A.1.2 Combustion Controls

Combustion controls comprise the most numerous category of NO_X emission reduction technologies. These techniques employ methods that reduce the amount of NO_X emissions created in the combustion zone of the boiler prior to exhausting the flue gases from the furnace (upstream of the convective heat transfer zones). These controls result in fewer emissions to atmosphere or that may require subsequent reduction from additional applicable combustion and/or post-combustion techniques.

As the boilers in question were designed for firing North Dakota lignite fuel, they were furnished with suitably-sized furnaces and limited back-end economizer heat transfer surfaces upstream of the air preheaters. This provides high temperature air to aid the evaporation of excess moisture from the crushed coal particles in the pre-combustion drying systems, and long residence times for solid and gaseous fuel particles to burn essentially to completion prior to leaving the furnaces. The latter feature is especially advantageous for applying various forms of combustion modifications which are conducive in reducing NO_X emissions.

A.1.2.1 Basic Combustion Improvements

Combustion improvements are commonly-applied techniques which may produce modest incremental NO_X emissions reductions. In their most basic form, these typically provide improvements to combustion air flow distribution, measurement, and pressure, together with fuel flow measurement and metering, to promote consistent combustion performance by burning fuel with more accuracy in maintaining a desired fuel/air ratio.

These improvements may allow, or be combined with, the practice of several other NO_X control techniques. Separated overfire air (discussed below), with or without “low excess air” (LEA), burners out-of-service (BOOS) and biased firing (BF) operation of the cyclones, cause a decrease in the ratio of combustion air to fuel supplied to the cyclones (burners), thus reducing the amount of thermal NO_X emissions produced during combustion. The amount of potential NO_X emission reduction achievable from these basic techniques is highly-dependent on the specific type of firing, fuel, and conditions which apply to the boiler(s) being reviewed.

Making lignite drying system air adjustments and adding improvements to the boiler combustion controls and reducing combustion air inputs have already reduced uncontrolled NO_X emissions at Milton R. Young Station boilers approximately 10%. Further incremental improvements from additional combustion controls that allow operation with modest amounts of cyclone air staging, similar to the effect of a separated overfire air system, are possible. Incremental NO_X emissions reductions are expected from such improvements being incorporated into another feasible alternative, such as separated overfire air. This alternative was not considered as a stand-alone option for additional NO_X reduction at Milton R. Young Station for the Unit 1 boiler.

A.1.2.2 Low NO_X Burners (LNB)

Low NO_X burners (LNBs) of various designs have been commonly applied to pulverized coal-fired utility and industrial boilers for more than ten years. However, they are not installed on cyclone-fired boilers. This technology is infeasible on cyclone boilers[1], and was eliminated from consideration for additional NO_X reduction at Milton R. Young Station Unit 1’s boiler.

A.1.2.3 Separated Overfire Air (SOFA)

Separated overfire air (SOFA) is a combustion-related NO_X emission reduction technology frequently-applied with and without low NO_X burners to utility and industrial boilers for more than twenty five years. Separated Overfire Air (SOFA) is an air-staging NO_X emission reduction combustion technique that is typically based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the firing zone. The diverted combustion air is then injected in the upper furnace, where combustion is completed. For typical cyclone coal-fired boilers, this involves diverting approximately 20 percent of the secondary combustion air, forcing the cyclones to operate fuel-rich. Starved-air combustion causes fewer NO_X emissions to be produced.

At least thirty nine existing cyclone-fired boilers, firing eastern bituminous, midwestern bituminous, and western subbituminous (“Powder River Basin”) coals in units ranging in size from 50 to 1150 MW, have been retrofitted with commercial SOFA since 1998. A summary of several of the first SOFA (and reburn) retrofits to cyclone-fired boilers is described in published technical papers[1,2]. Cyclone boiler retrofit SOFA installations are included in the EPA’s BART technical support document[3] and listed later in Appendix A2.

A basic form of separated overfire air (SOFA) can be applied and installed on MRY Station Units 1. There are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application.

Key aspects of successfully applying and operating a separated overfire air system on a cyclone-fired boiler are the ability to:

- Accurately measure the fuel heat input rate (BTUs) and combustion air inputs on a real-time, individual cyclone by cyclone basis, to allow the ability to determine and control the desired air/fuel ratio, especially when “starved air“ (i.e. substoichiometric) combustion conditions are required.
- Maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps.

The degree to which the cyclone furnaces can be operated with less than theoretical (substoichiometric) combustion air directly contributes to less NO_X formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. In the case of MRY Station Unit 1 boiler, cyclone combustion must be sufficiently air-staged to reduce NO_X emissions while releasing enough heat to continue to melt the fuel ash so that it flows effectively within and from the cyclone burners.

In the case of MRY Station boilers, there is a significant amount of variability in the combustible and ash components of North Dakota lignite supplied from the current mine near Center, ND. Analysis of several hundred coal feed samples taken simultaneously from multiple cyclones of MRY Station Unit 2's boiler revealed that the maximum differential of the lignite heating values from cyclone-to-cyclone was just over 12% of the average heating value of all the samples. Assuming an operating case occurred where the maximum cyclone-to-cyclone differential heating value was for two cyclones at the opposite ends of the fuel heat content range, there would be a plus or minus 6% variation in fuel heat content for either of the individual cyclones from the overall average. If the desired average cyclone air/fuel (stoichiometric) ratio was 0.95 when operating with air-staged cyclones associated with separated overfire air, and the amount of secondary combustion air to each cyclone was equal, there would be a stoichiometric ratio of approximately 1.01 in one cyclone and a stoichiometric ratio around 0.89 in another cyclone at the same time. The modestly air-staged cyclone would produce higher than average NOx emissions. The deeply staged cyclone would produce less than average NOx emissions and potentially insufficient amounts of heat release, and raise the risk of solidifying the fuel ash so that it accumulates within the cyclone barrel. This could result in firing auxiliary fuel oil in the deeply-staged cyclone or taking the boiler out-of-service to remove the pluggage. Neither of these conditions is desirable because they result in lower emissions removal performance and higher operating costs. Thus, due to the variability of the fuel heat content and the complex behavior of lignite ash when exposed to high temperatures, the extent of air-staging and thus the level of NO_X control in MRY Station boilers is expected to be modest while firing lignite coals.

In order to potentially achieve lower NO_X emission rates with modestly air-staged combustion for MRY Station boilers, additional combustion improvements can be installed. One potential improvement is to implement a unique form of SOFA for North Dakota-lignite–fired cyclone boilers. This includes relocated lignite drying system vent ports. This will be referred to as "Advanced SOFA" (ASOFA). There are several design challenges anticipated for implementing the advanced version (with the described port relocations) of separated OFA. These are believed to be solvable.

Both forms of separated overfire air as a combustion-related NO_X control technique are considered feasible for application to Milton R. Young Station cyclone boilers. Since the advanced SOFA is the highest-performing form of this technology, only this ASOFA version of the alternative was considered for additional NO_X reduction at Milton R. Young Station boilers.

Another form of separated overfire air being marketed commercially is “Rotating Opposed Fire Air” (ROFA). For utility applications in the United States, this has only been applied to pulverized coal-fired boilers, primarily tangentially-fired units[4]. It is different than basic SOFA in that it includes a hot air booster fan, and injects the overfire air in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. The vendor (Mobotec USA) claims ROFA maximizes air-staged in-furnace combustion NOx reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon.

While this variation of separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Because cyclone boilers do not require the addition of hot air booster fans for SOFA, this technique is not distinct enough from basic SOFA from functional and air-staged cyclone NO_X reduction performance standpoints to warrant individual consideration. ROFA technology lacks demonstrated cyclone-fired boiler experience, and thus was considered infeasible and not included in the control effectiveness and cost-effectiveness sections of the main report.

A.1.2.4 Oxygen-Enhanced Combustion

A supplier of liquid oxygen (Praxair) has developed a method of replacing some of the combustion air supplied to the burners with pure oxygen. Combustion air, which is normally input through the secondary air system ductwork downstream of the forced draft (FD) fan and air heater, is supplemented with pure oxygen directly injected into the burners. Oxygen-enhanced combustion (OEC) can reduce boiler NO_X emissions resulting from “ thermal NO_X“, a reaction of the nitrogen in the combustion air admitted to the burners with the available oxygen in the air in the flame or peak temperature regions of the fuel combustion process. The use of pure oxygen instead of air reduces the availability of nitrogen from the air to be oxidized in the high temperature regions, thus reducing formation of thermal NO_X. This technique has only been demonstrated in a boiler with pulverized fuel burners firing bituminous coal[5].

The lack of adequate experience on any cyclone-fired coal-burning boiler, on a temporary demonstration or permanent full-scale basis, and for a coal-fired facility of this size, precludes consideration of oxygen-enhanced combustion at MRY Station Unit 1’s boiler. This is deemed to be infeasible technology at this location at the present time.

A.1.2.5 Flue Gas Recirculation

Flue gas recirculation (FGR) has been commonly applied to coal-fired boilers, primarily to inject into the lower furnace, just above the burners, supplied from the boiler’s economizer flue gas outlet via a hot gas booster fan. This modifies the amount and temperature of hot furnace gas either in the lower-middle or upper furnace and convection heat transfer zones. As this flue gas typically has an oxygen content around 2-5%, it limits the availability of oxygen in a high temperature, possibly fuel-rich lower furnace zone. Flue gas recirculation for NO_X control is most commonly applied with gaseous or liquid fossil fuels to reduce the high temperatures which convert nitrogen in the combustion air to nitrogen oxides. No examples of using or installing FGR on cyclone-fired boilers strictly for NO_X emissions control were found in available technical literature.

For MRY Station Unit 1’s boiler, FGR was originally supplied from the outlet of the induced draft fans, but has since been discontinued and removed. Since it is not operational on Unit 1, and therefore does not affect the potential performance of separated overfire air (in an “advanced” form), it would not be expected to reduce NO_X emissions if reinstalled alone or in combination with SOFA. Although FGR is technically feasible, it has not been considered further as an effective NO_X emissions control option for MRY Station Unit 1’s boiler.

A.1.2.6 Water/Steam Injection (Combustion Tempering)

When applied to older gas-fired and oil-fired utility and industrial boilers, water and/or steam injection adds moisture into the lower furnace, concurrent with or near (to the side or slightly above) the burners, supplied from the boiler’s treated feedwater or auxiliary steam systems via a metering pump or valve. There has been some limited testing of water injection for NO_X emissions control on natural gas-fired and coal-fired cyclone boilers[6,1]. For coal-fired cyclones, this technique is most effective on boilers burning bituminous coal; however, it has not been permanently installed and continuously operated in such applications. Successful long-term operation of water injection would be difficult for lignite-fired cyclone boilers, due to the high moisture levels in the coal and the need to readily ignite and sustain stable combustion and molten slag formation in the cyclone furnaces. For these reasons, water/steam injection is considered technically infeasible for NO_X control application at Milton R. Young Station.

A.1.2.7 Fuel Reburn

Another combustion technology that may be applicable to control NO_X emissions from the Milton R. Young Station units is fuel reburn. In a similar manner that overfire air diverts a portion of the combustion air input to the main firing zone, the reburning process involves supplying a portion of the fuel heat input to the boiler at a higher elevation in the furnace. This creates an upper furnace atmosphere where the reburn fuel's combustion products causes some of the NO_X formed in the main burner combustion zone and reburn zone to be converted into molecular nitrogen. Depending on the amount of reburn fuel added and the amount of oxygen available in the furnace gases to combine with the reburn fuel introduced, additional combustion air may be supplied as supplemental or overfire air. Downstream of the air injection elevation, the intention is to complete the reaction of any remaining carbon monoxide (CO) to carbon dioxide (CO_2), plus reduce the amount of combustible matter remaining in the entrained flyash.

The most common forms of reburn technology applied to utility powerplant boilers are:

- Pulverized or micronized coal reburn (PCR or MiCR); and
- Gas reburn (GR).

Pulverized coal reburning and micronized coal reburning have been applied to pulverized coal and cyclone-fired boilers. NO_X reduction efficiencies of 50 to 60 percent have been demonstrated on eastern bituminous coal and midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone[7,8].

For utility powerplant boiler applications, natural gas has been utilized as reburn fuel most often, demonstrated in two basic approaches:

- Conventional gas reburn (CGR); and
- Fuel-lean gas reburn (FLGR™).

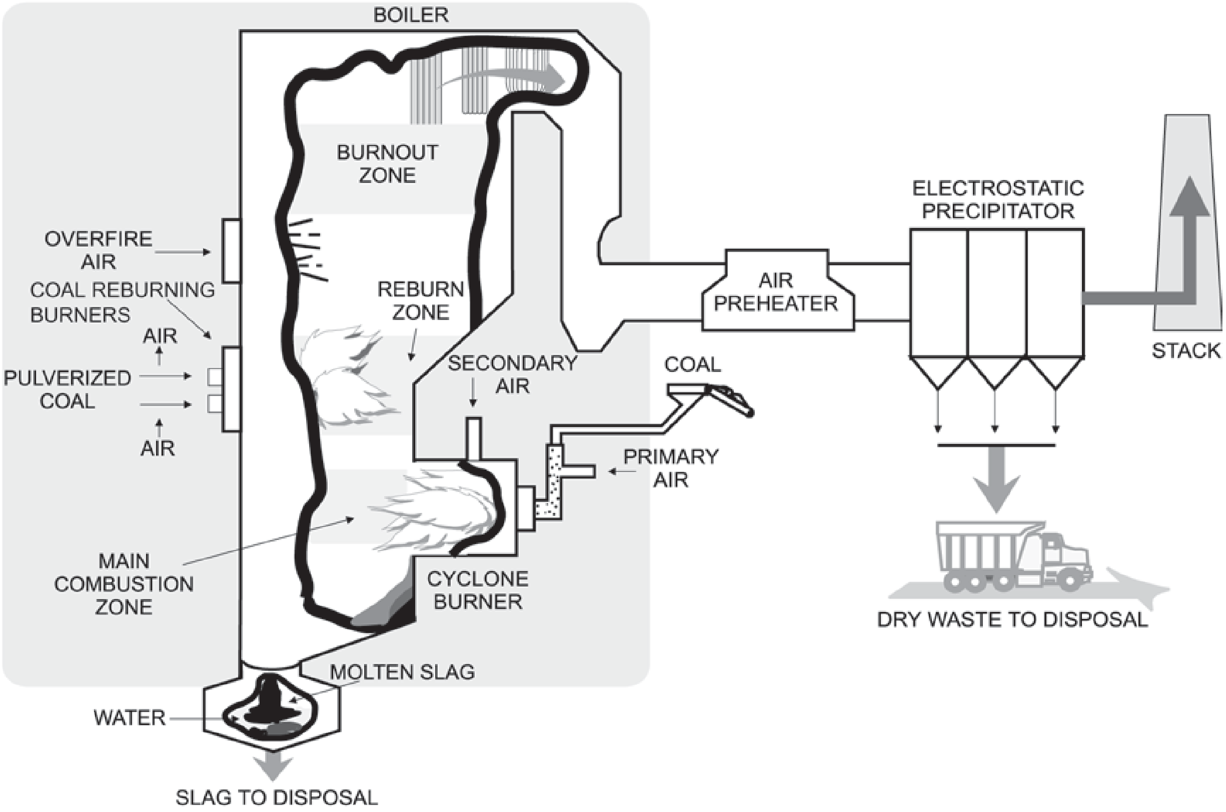
Either natural gas or pulverized coal (lignite) can be used as the reburn fuel. A sufficient quantity of natural gas is not currently available at the Milton R. Young Station plant site. Supplying enough natural gas to provide 6 to 25% of the total heat input to either or both boilers at MRY Station is expected to be technically feasible, although transport pipeline installation capital costs, and current and predicted unit natural gas costs and operating economics, are likely to be unfavorable.

Various forms of fuel reburning have been demonstrated and operated routinely on cyclone boilers for NO_X emission controls. This has been applied to units firing eastern bituminous coal, and western subbituminous or PRB/bituminous coal blends, using pulverized or micronized coal or natural gas as the most common reburn fuel. Reburning for NO_X emissions reduction has not been demonstrated on a unit firing high moisture, low heat content North Dakota lignite. Pulverized/micronized coal, along with conventional and fuel lean gas reburn technologies, are discussed below.

A.1.2.7.1 Coal Reburn

In the case of applying conventional coal reburn to cyclone boilers, the existing cyclones are supplied with the majority of the fuel, with either natural gas or pulverized coal (lignite) used as the reburn fuel such that the total heat input to the boiler is essentially the same as without fuel reburn. Separated OFA ports are located above the reburn fuel injection section of the furnace. These SOFA ports provide sufficient oxygen in a conventional fuel reburn installation to complete the combustion process that begins in the main combustion zone and is supplemented in the reburn and burnout zones. This is shown schematically for a pulverized coal reburn application on a cyclone-fired boiler with SOFA in Figure A.1-1.

Figure A.1-1 Pulverized Coal Reburn Application on Cyclone Boiler With Overfire Air[8]



In the United States, pulverized coal reburning and micronized coal reburning techniques for utility powerplant NO_X emissions reduction have been applied on a very limited full-scale, full-time basis to cyclone-fired boilers in field demonstration tests and longer-term demonstration operation, respectively. There have been only two known pulverized or micronized coal reburn installations in the United States on cyclone boilers, one on a utility boiler in Wisconsin, and one on a small industrial-size cyclone boiler in New York state[7,8,9,10,11,12,13,14]. NO_X emissions reduction efficiencies of 57 percent have been demonstrated on cyclone boilers firing eastern bituminous coal, or midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone. With the exception of the U.S. Department of Energy's (DOE) Clean Coal Technology Program demonstration projects[7,8,9], no known commercially-available coal reburn systems have been installed and are routinely operated on cyclone boilers in the United States to date. The DOE-CCTP projects for coal reburn applied to cyclone boilers are described below.

Pulverized coal reburning for NO_X emissions reduction in a cyclone-fired boiler was demonstrated on the 110 MW Nelson Dewey Unit 2 for Wisconsin Power & Light in 1991-1992. Reburn fuel preparation and handling, reburn burners with flue gas recirculation, and a separated overfire air system were added. Coal reburn tests were conducted on this unit while firing bituminous and PRB coals. NO_X emission control efficiencies of 50 to 60 percent, with reductions from 0.75-0.83 lb/mmBtu baselines to around 0.38 lb/mmBtu, but as low as 0.29 to 0.32 lb/mmBtu, with PRB coal at full load with approximately 25-30% of the total fuel heat input from reburn fuel were demonstrated[9,11,12]. The reburn system is no longer operated on Nelson Dewey Unit 2.

Micronized coal reburning has been demonstrated in 1997-1998, and continues to operate year-round on a small industrial cyclone boiler (400,000 lb/hr steam output, 50 MW gross equivalent) for Eastman Kodak Company at their Kodak Park facility in Rochester, NY. This unit (Boiler #15) achieves a NO_X reduction efficiency of approximately 57 percent on eastern bituminous coal, involving limited cyclone air-staging (cyclones believed to be slightly above 0% excess air) and a modest amount of overfire air injection downstream of the micronized reburn fuel input nozzles. Approximately 17% of the boiler's total fuel heat input is typically supplied to the reburn zone. This coal reburn system continues to operate routinely at this facility. This installation is reported to use a Fuller MicroMill to produce micronized coal with 80% passing through a 325 mesh screen[7,9,13].

If a coal reburn system was applied to MRY Station boilers, the existing cyclones would be supplied with the majority of the fuel in the form of crushed coal, and the balance of fuel would be supplied to a pair of dedicated pulverizers to feed the reburn injection ports, such that the total heat input to the boiler is essentially the same as without fuel reburn. In a conventional fuel reburn installation, OFA ports located above the reburn section of the furnace provide sufficient oxygen to complete the combustion process that begins in the main combustion zone and is supplemented in the reburn and burnout zones.

Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. As a reburn fuel, lignite is expected to behave appropriately upon introduction in the lower middle furnace to help reduce NO_X emissions. The concerns are that the diversion of a significant amount of heat input from the cyclone barrels to use as a source of reburn fuel in the form of pulverized or micronized lignite may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction as part of this reburn technique will further risk slag “freezing” in the barrels and lower furnace. Reducing the number of active cyclones which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with reburn and separated overfire air is the typical approach to avoid slag tapping problems.

Potential NO_X emissions reduction performance is expected to be limited on lignite-fired cyclone boilers with a basic form of separated overfire air system, since the reburn fuel injection location is expected to coincide with the existing lignite pre-drying system vent ports. The amount of oxygen introduced by the vent ports will be disruptive to any conventional reburn process in that it would require much higher reburn fuel injection rates to create a substoichiometric atmosphere in the lower secondary furnace that is conducive to promoting in-furnace NO_X reduction.

Significant additions to the fuel preparation equipment in the existing plant facilities will be required. The coal reburn system expected to be applied to MRY Station boilers may use two new fine-grind pulverizers and dynamic classifiers to achieve the level of coal particle size distribution required.

Higher unburned carbon levels in the flyash exhausted from the boiler may occur, especially when the reburn fuel is coal, and the regular burners are fired with less than theoretical amounts or combustion air commonly practiced with the use of overfire air. Lowering the reburn fuel injection elevation, decreasing the amount of reburn fuel, and grinding the reburn coal to a greater degree of fineness can help to offset some of the increase in flyash unburned carbon content. Flue gas opacity from the stack may increase if the particulate removal equipment is an electrostatic precipitator, due primarily to reduced resistivity and smaller particle sizes of the flyash.

An issue that affects the feasibility of lignite reburning is the uptime required for the lignite reburn fuel pulverizing system, and impact of the reburn system on effectiveness in reducing NO_X emissions during load changes and lower loads. Typically, one new pulverizer is dedicated to prepare reburn fuel in existing pulverized fuel-fired boiler applications. Cyclones may be fired with less fuel or deactivated during boiler operation in order to accommodate changes in fuel combustion characteristics, boiler load, and for scheduled or unscheduled individual crusher maintenance. Milton R. Young Station Unit 1 has seven crushers for cyclone coal grinding, each dedicated to one of the seven cyclone furnaces. Diverting as much as 30% of the total heat input as reburn fuel could require two of the existing cyclones to be deactivated, and two new MPS-89 pulverizers to be dedicated to reburn fuel preparation. As each of these mills requires periodic maintenance, boiler emissions and/or load could be negatively impacted during individual reburn mill outage periods while the boiler remained in service. A high level of fineness of coal particles from the reburn mills is important to achieve and maintain in order to limit increases in flyash combustibles. A minimum of 60 percent passing through 200 mesh fineness is recommended by one of the reburn technology vendors (B&W) for pulverized lignite reburn. Micronized coal reburn requires even greater fineness: 70-80 percent passing through a 325 mesh screen.

Pulverized or micronized coal reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on MRY Station Unit 1's boiler. These combined techniques are expected to reduce NO_X emissions approximately 54% from current pre-control baseline levels (down to 0.385 lb/mmBtu) for the MRY Station Unit 1 boiler. These levels of NO_X reduction depend on the advanced form of separated overfire air technique to achieve the expected NO_X reduction percentages when applied to lignite-fired cyclone boilers, which may not be successful given the concerns expressed about the potential impacts of this technique. Using finely pulverized lignite for reburn fuel is considered technically feasible for NO_X emissions control under evaluation for application to MRY Station Unit 1's boiler.

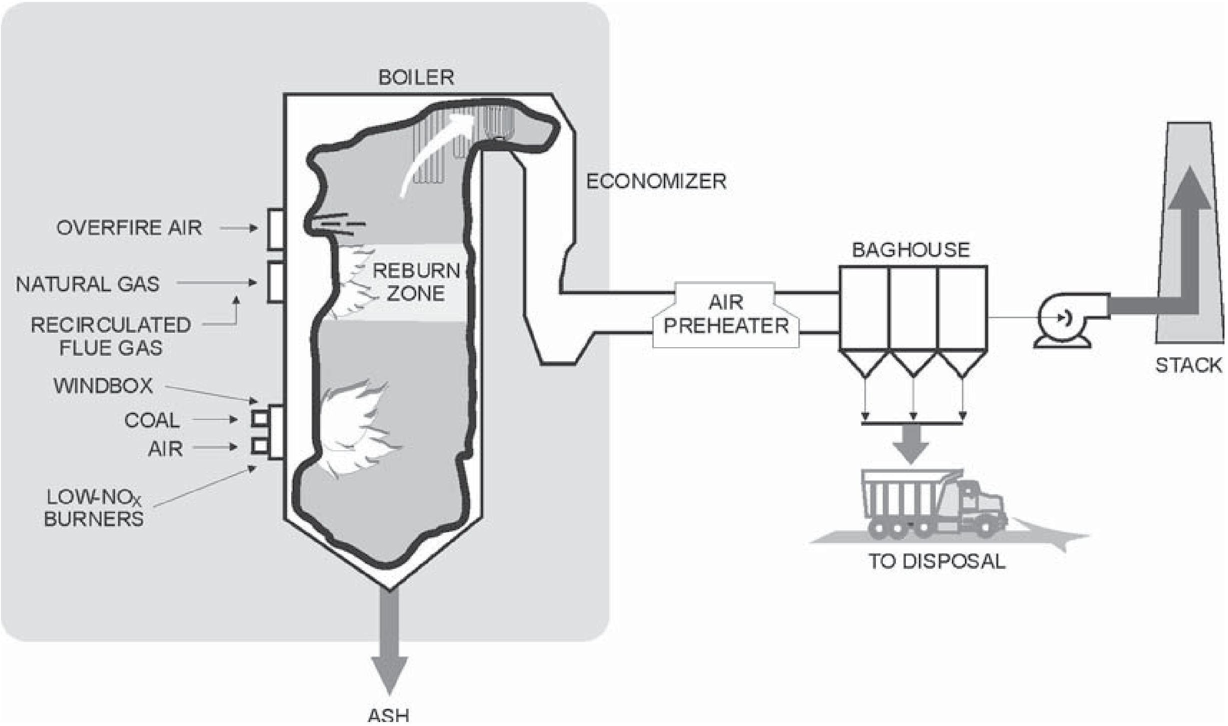
A.1.2.7.2 Conventional Gas Reburn

Natural gas has been preferred as the reburn fuel of choice. Natural gas has been utilized for reburn fuel in two basic approaches: conventional reburn and fuel-lean gas reburn. In the conventional approach, up to 30% of the boiler's total fuel heat input is supplied to the reburn zone, followed by a significant amount of overfire air for completion of combustion prior to flue gases exiting the boiler.

Conventional gas reburning in a cyclone-fired boiler has been available at Tennessee Valley Authority's Allen Station Boiler #1 (300 MW) since 1998. The reburn technology provider (vendor) claims NO_X emissions were reduced 67% from a full-load baseline of 1.29 (down to 0.42) lb/mmBtu when firing a blend of western bituminous and PRB coals[14]. Conventional gas reburn fuel input rates were not available from the technology vendor's literature. Another reference source of information stated NO_X emissions were reduced 65% from a full-load baseline of 0.86 (down to 0.30) lb/mmBtu with 7 percent of the total fuel heat input supplied as reburn fuel[9].

A schematic graphic of conventional gas reburn on a pulverized coal-fired boiler is shown in Figure A.1-2.

Figure A.1-2 Natural Gas Reburn Application on
Wall-Fired Pulverized Coal Boiler with Overfire Air[8]



Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. For the most effective NO_X reduction by applying the various available forms of fuel reburn, the injection of fuel is usually performed using recirculated flue gas as a diluent and carrier media to aid dispersion and avoid completely oxidizing the carbon and nitrogen components in the fuel and furnace gases from staged burners/cyclones. Improved gas reburn designs have reduced or eliminated FGR with higher gas injection pressures. For lignite-fired cyclone boilers, reburn fuel firing with a basic form of separated overfire air is expected to be much less effective in reducing NO_X emissions than previously demonstrated elsewhere. This is related to the likelihood that the injection of reburn fuel will be near the elevation of the existing lignite drying system vent ports, and that the oxygen introduced with the lignite drying system's vented moisture will disrupt the desired in-furnace nitrogen oxides reduction process.

It should be recognized that application of air-staged cyclones with basic or advanced forms of SOFA with reburn techniques will require the overfire air injection ports to be located at a somewhat lower elevation of the furnace compared with air-staged cyclones without reburning. This means that less air-staging of the cyclones may be practiced, or that less residence time will be available for the in-furnace NO_X reduction process to occur.

Similar to coal reburning, there are concerns that withholding a significant amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones for use of separated overfire air to further complement combustion NO_X reduction as part of this reburn technique will further risk slag "freezing" in the barrels and lower furnace. Reducing the number of active cyclones which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with conventional reburn and separated overfire air systems is the typical approach to avoid slag tapping problems. Natural gas reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on Milton R. Young Station's Unit 1 boiler.

Although the unit operating and capital costs to supply large quantities of gaseous fuel not currently available at this site are economic disadvantages, using high-pressure natural gas for reburn fuel is considered technically feasible for NO_X emissions control under evaluation for application to MRY Station Unit 1's boiler.

A.1.2.7.3 Fuel Lean Gas Reburn

Another approach to gas reburning is “fuel-lean gas reburn” (FLGR™) technology, which injects limited amounts of natural gas (approximately 3-10 percent of the total fuel heat input) above the burners (or cyclones) with or without significant air-staging of the burners (cyclones) or the addition of overfire air upstream of the fuel injection elevation. FLGR’s first field-test on a cyclone-fired boiler was at Commonwealth Edison’s Joliet Unit 6 (327 MW), a 9-cyclone-furnace boiler[15]. NO_X emissions reduction with FLGR (without SOFA) was believed to be approximately 35-40% with 7% of the boiler’s total fuel heat input supplied in the reburn zone. This test yielded 0.59 lb/mmBtu NO_X emissions from a baseline of 0.98[16]. One other cyclone boiler has been modeled using computational fluid dynamics (CFD) as part of a study looking at applying FLGR at Owensboro Municipal Utilities’ Elmer Smith Station Unit 1 (150 MW single-wall, eastern bituminous coal-fired boiler). This model predicted that NO_X emissions could be reduced by 25-30% over that achievable from overfire air and SNCR[17].

More commonly, FLGR™ has been applied on medium to large pulverized coal wall-fired boilers burning eastern bituminous or western subbituminous coals. On Wisconsin Electric Power Company’s (WEPCO’s) Pleasant Prairie Unit 1, a 620 MWg Riley turbo-fired wet-bottom (slagging) boiler, FLGR™ alone was predicted to reduce NO_X emissions by 35-39 percent at a gas reburn rate of 7-8 percent but only achieved 20% from a baseline of 0.45 lb/mmBtu[16,18]. This is presumably without burner air-staging or SOFA. It has also been applied in combination with SNCR at this WEPCO site.

A potential advantage of FLGR™ over conventional gas reburn is that the former is generally compatible with, but does not require, the installation and operation of SOFA. The staged reburn fuel is introduced into an oxygen-rich atmosphere downstream of the burners and any OFA injection points. The amount of reburn fuel injected is typically limited by acceptable carbon monoxide levels in the boiler exit flue gas.

There are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. This is significant, especially for alternatives with FLGR™ technology when combined with basic or advanced SOFA to allow the natural gas introduced above the SOFA ports to burn completely prior to the furnace exit plane. In either case, the amount of additional potential NOx reduction possible with FLGR™ is limited, since the reburn fuel injection location is expected to coincide with the existing lignite pre-drying system vent ports. The amount of oxygen introduced by the vent ports will be disruptive to the fuel-lean reburn process in that it would require much higher reburn fuel injection rates in the lower secondary furnace to promote in-furnace NO_X reduction. There are reduced concerns that the withholding of a modest amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction is an optional part of this reburn technique which will further risk slag "freezing" in the barrels and lower furnace.

Fuel lean gas reburn can be applied and installed on MRY Station Unit 1's boiler with or without SOFA/ASOFA. This technique is considered technically feasible for application to MRY Station Unit 1's boiler. Expected NO_X reduction will be modest for FLGR™ without SOFA and FLGR™ with a basic form of SOFA. Unit operating and capital costs to supply large quantities of gaseous fuel not currently available at this site are economic disadvantages. Because of these factors, these variations of this technology will not be cost-effective compared to other alternatives with similar control effectiveness. FLGR™ without SOFA and FLGR™ with a basic form of SOFA were not included in the control effectiveness and cost-effectiveness sections of the main report.

Other demonstrated forms of fuel lean gas reburning in combination with post-combustion technologies, such as amine-enhanced fuel lean gas reburn (FLGR™ with SNCR), are discussed under the layered technologies section.

A.1.2.7.4 Fuel Oil Reburn

Fuel oil has been substituted for natural gas in a conventional reburn application. This is much less common in the United States than using natural gas as a reburn fuel, due to the general lack of demand and difficulties in supplying the volume of fuel oil which would be required. It has been installed commercially on three 350 MW oil-fired boilers in New Brunswick (Canada) at the Coleson Cove plant. NO_X emissions reduction with reburn and SOFA was 78% with 25% of the boiler's total fuel heat input supplied in the reburn zone. This yielded 0.22 lb/mmBtu NO_X emissions from a baseline of 1.0 lb/mmBtu[9]. No examples of conventional fuel oil reburn applied to a coal-fired cyclone boiler were found in available literature.

Fuel oil reburn could potentially be considered for application to MRY Station Unit 1 and Unit 2 boilers. Investigation of the specific source, distance, and costs for supplying significantly increased quantities of fuel oil via transport trucks hauling tanker trailers or underground pipeline to M.R. Young station has not been performed. The unit operating and capital costs to supply large quantities of high-volume liquid fossil fuel at this site are economic disadvantages. The concerns regarding potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application are similar to those expressed for conventional gas reburn. It is believed that potential NO_X control with oil reburn would be slightly less than comparable conventional gas reburn systems.

Although fuel oil reburn could potentially be considered for application to MRY Station Unit 1's boiler, the lack of any distinct potential NO_X reduction advantages and demonstration on cyclone-fired boilers does not appear to support its consideration. This alternative was not included in the NO_X control and cost-effectiveness analysis.

A.1.3 Post-Combustion Controls

Post-combustion controls deal with techniques that thermally or chemically-treat the flue gases to reduce NO_X emissions after they have exited the boiler's lower furnace. In the case of Milton R. Young Station Unit 1, this primarily involves forms of selective catalytic reduction (SCR) and selective non-catalytic reduction (SCR) technologies. Another emerging technology that has recently entered the commercial market is Powerspan's Electro Catalytic Oxidation®, which treats utility boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury. Another emerging technology that has recently entered the commercial utility air pollution control market is Powerspan's Electro Catalytic Oxidation®, which treats boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury.

A.1.3.1 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR), and variations such as hydrocarbon-enhanced SNCR (sold under the trade name of NOxStar™), and Rich Reagent Injection (RRI), are all post-combustion types of boiler NO_X emission controls. While these technologies are insensitive to the specific fuel types whose combustion products are being treated, the large majority of boiler applications to date have been on pulverized coal-fired units burning eastern bituminous fuels. SNCR has been used to reduce NO_X emissions on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used with fuel oil and natural gas-fired units. SNCR (and hydrocarbon-enhanced SNCR) technologies can each be applied to cyclone boilers with or without the use of a SOFA system. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without overfire air in full operation. Operation at these plants has demonstrated that SNCR can decrease NO_X emissions as much as 15-40% at full load, most typically between 25-35 percent[19].

In the conventional SNCR process, urea or ammonia is injected into the boiler in a region where the combustion gas temperature is in the 1700 to 2100 degrees F range. Under these temperature conditions, the urea reagent [$CO(NH_2)_2$] or ammonia [NH_3] reacts with the NO_X, forming N_2 and water, reducing NO_X emissions.

Long-term examples where SNCR has been used to reduce NO_X emissions on two cyclone-fired boilers are on a 138 MW unit and 160 MW unit burning eastern bituminous coal at Conectiv's B.L England Station (Units 1 and 2) since 1995 and 1996, respectively. Tests at these plants demonstrated that SNCR can decrease NO_X emissions as much as 30-36% at full load, from around 1.3-1.4 lb/mmBtu respectively to as low as 0.85 lb/mmBtu (without overfire air)[18,19,20]. These boilers, located near Atlantic City, New Jersey, continue to operate SNCR (with OFA) for annual NOx emissions around 0.55 and 0.45 lb/mmBtu, respectively.

SNCR can be applied and installed on MRY Station boilers. Estimated NO_X emission rates for using SNCR with North Dakota lignite considered published levels achieved by cyclone-fired units firing western subbituminous coal, and vendor predictions. SNCR alone is expected to reduce NO_X emissions approximately 37% from MCR baseline levels (down to around 0.5 lb/mmBtu) for the MRY Station Unit 1 boiler with ammonia slip limited to approximately 5 ppmvd. Because of the operating costs of the consumed reagent, this technology will not be cost-effective compared to other alternatives with similar control effectiveness (i.e. SOFA), SNCR alone was not included in the control effectiveness and cost-effectiveness sections of the main report.

Other demonstrated forms of SNCR-related technologies, such as Rich Reagent Injection with SNCR, and amine-enhanced fuel lean gas reburn (FLGR™ with SNCR), are discussed under the layered technologies section.

A.1.3.2 Hydrocarbon-enhanced SNCR (NOxStar™)

Hydrocarbon-enhanced SNCR technology, commercially marketed as NO_XStar™, is offered by a single vendor (Mitsui Babcock) as a post-combustion type of enhanced SNCR technology, whereby an ammonia-based reagent is continuously injected into the superheater/reheater pass of an operating boiler with small amounts of gaseous hydrocarbon (typically either natural gas or propane) and air or steam to provide lance cooling and aid reagent dispersion. The targeted combustion gas temperature range is between 1500°F and 2000°F. The amount of gaseous hydrocarbon introduced is small enough (0.1 to 0.2% of total fuel heat input) that this is not intended to act as a form of reburn or staged fuel combustion. An array of permanently-installed injection lances are located within the boiler convection pass, divided into numerous discrete zones across the full width and height of the duct. The hydrocarbon auto-ignites, forming hydroxyl (OH) radicals which react with the NO_X and ammonia to produce elemental nitrogen (N_2) and water vapor (H_2O).

NO_XStar™ was demonstrated at Tennessee Valley Authority's Kingston Power Station Unit 9 (tangentially-fired 200 MW twin-furnace boiler firing eastern bituminous coal) in 2002[21]. This technology was subsequently permanently-installed at TVA's Colbert Station Unit 4 in late 2003 on a 192 MW wall-fired boiler burning eastern bituminous coal[22]. NO_X reduction was stated as 68-80% for these applications, which included the impact of overfire air and air-staged combustion upstream of the ammonia and propane injection locations.

An example of a hydrocarbon-enhanced SNCR installation on a wall-fired pulverized fuel boiler is shown as a sectional side elevation view of the upper furnace in Figure A.1-3.

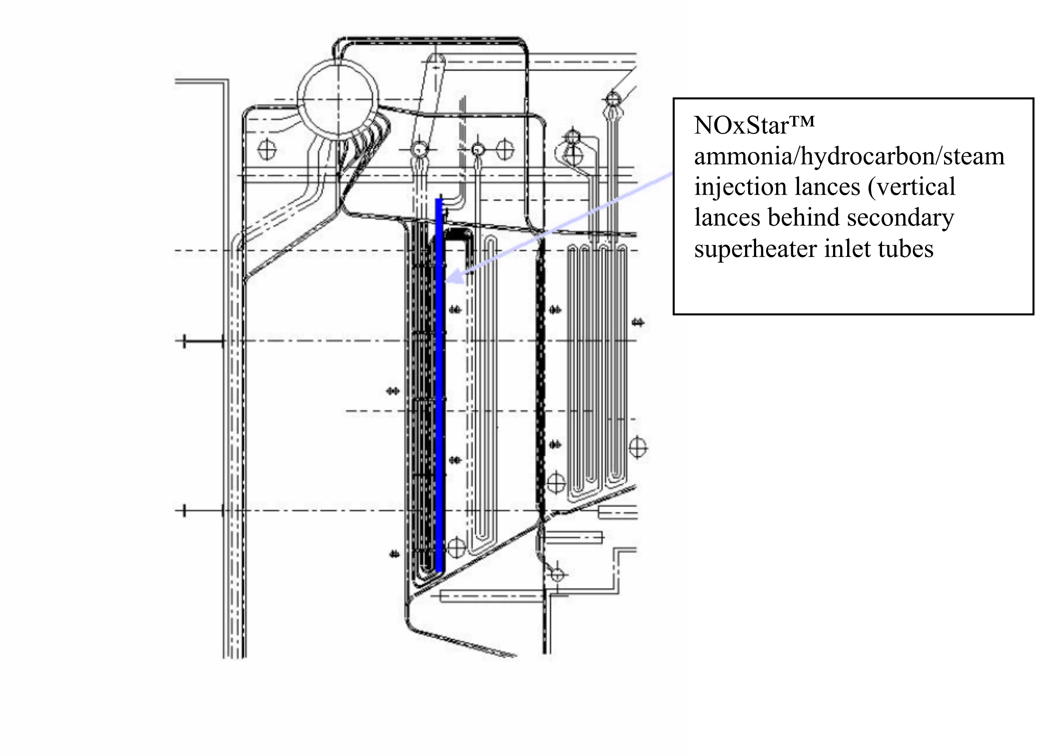


Figure A.1-3 Hydrocarbon-enhanced SNCR Application on PC-fired Boiler[22]

The supplier (Mitsui Babcock) of hydrocarbon-enhanced SNCR technology claims there is little sensitivity to the type fuel (coal) or burners this technique can be potentially applied to in order to reduce NO_X emissions. The chemical reagent injection for hydrocarbon-enhanced SNCR (NO_XStar™) NO_X control technology must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) model simulations are needed to determine the optimum injection points and spray patterns. Boiler operating conditions change with unit load and varying fuel characteristics. The NO_XStar™ process control system must be able to adjust for these changing conditions in order to be effective throughout the intended load range and firing conditions encountered. Non-retractable ammonia injection lances arranged in a parallel-series manner are permanently mounted inside the upper furnace zone, attached to convective tube elements. Different sections of the injection "grid" can be turned off or on, depending on load and firing conditions and amount of NO_X reduction required. Injection nozzles are continuously purged and cooled by extracted superheated steam from the boiler's main steam outlet, whether ammonia reagent is being introduced into the flue gas stream or not. Ammonia slip can be minimized by injecting less reagent, although NO_X control performance will be reduced.

There are a number of issues with firing North Dakota lignite that make the applicability of hydrocarbon-enhanced SNCR infeasible compared to previous experience in other coal-fired powerplants. These issues include:

- Hydrocarbon-enhanced SNCR (NOxStar™) technology has not been applied to cyclone boilers (with or without the use of a SOFA system). It has been only applied to date on pulverized coal-fired boilers burning eastern bituminous fuels.
- There is no successful demonstrated full-scale experience in continuous service of hydrocarbon-enhanced SNCR (NO_XStar™) technology on units firing high-slagging coals such as western subbituminous (PRB) and lignite. The heat transfer surfaces in the convective heat transfer zone where the reagent mixture is injected are prone to severe fouling from flyash constituents common in North Dakota lignite coals. Flyash deposit accumulation on the outside of the NO_XStar™ lances in Milton R. Young Station Unit 1 boiler's upper furnace is expected to be significant, potentially occurring within a matter of a few weeks from startup and nearly impossible to prevent or remove effectively during boiler operation. Such buildup is expected to cause maldistribution of the NO_X reduction chemical reagent from the injection nozzles. Effective on-line removal of these deposits from the injection nozzles is anticipated to be insufficient to maintain effective injection distribution and volume control. It is anticipated that this would significantly reduce the NO_X emission reduction performance consistently achieved on a sustainable basis.

The lack of experience with cyclone boilers, especially those firing coal with severe deposition characteristics such as North Dakota lignite, makes this technology technically infeasible for application on the Milton R. Young Station Unit 1 boiler.

A.1.3.3 Rich Reagent Injection (RRI)

Rich Reagent Injection (RRI) is a NO_X control process that has been developed and demonstrated specifically for use on cyclone boilers. Rich Reagent Injection is an SNCR process that involves the injection of aqueous urea into the lower furnace between the cyclones and the SOFA ports. RRI targets a high temperature, fuel-rich zone within the boiler-furnace environment immediately adjacent to the cyclone burners, and requires temperatures in the range of 2400 to 3100 degrees F.

The three zones of a Rich Reagent Injection SNCR application on a boiler with separated overfire air are shown as a sectional side elevation view of the furnace in Figure A.1-4.

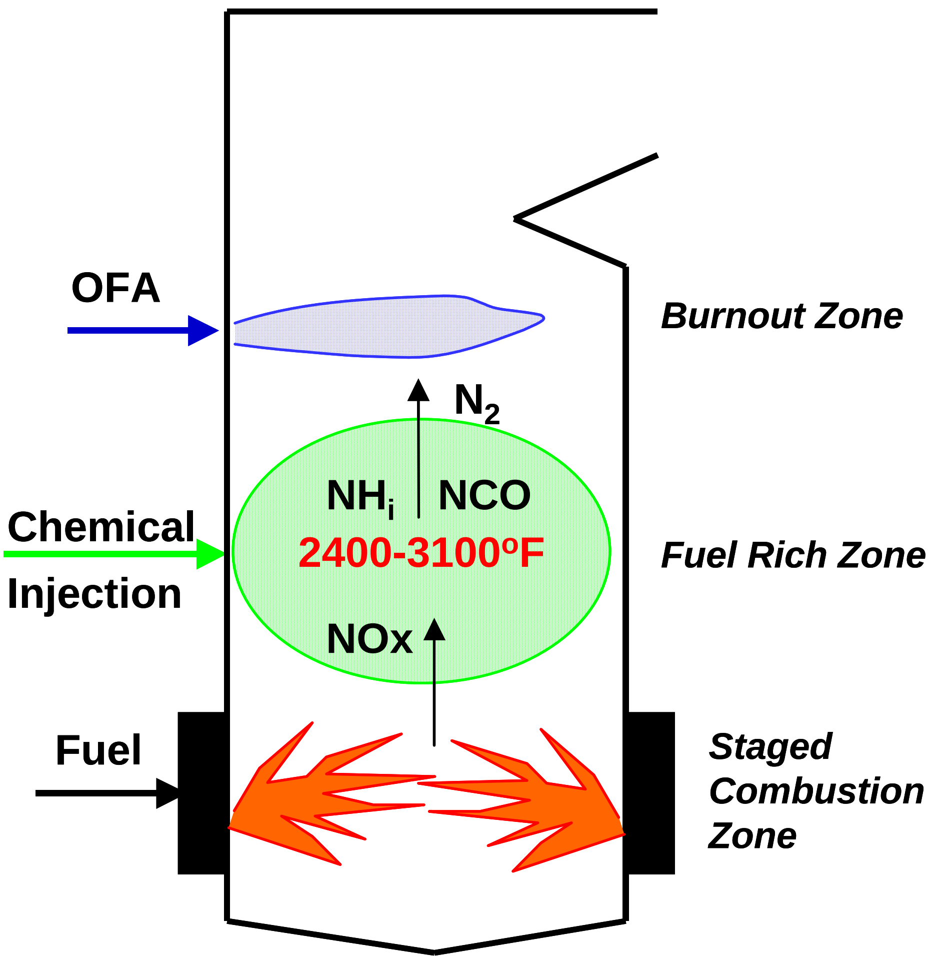


Figure A.1-4 Rich Reagent Injection Application on Boiler With Overfire Air[23]

The Rich Reagent Injection (RRI) process has been successfully demonstrated on at least two cyclone-fired boilers, with the most recent installation at Ameren's Sioux Unit 1, a 500 MW boiler firing a blend of PRB and midwestern bituminous coals. Generally, the heat content of these coals typically varies very little. Short-term testing of the RRI process has been performed alone and in combination with SNCR on B.L. England Unit 1 in 1999[24,25], and more recently at Ameren's Sioux Unit 1 in 2002[23,25], in 2004[26] (alone), and in the first half of 2005[27] (alone, and with SNCR).

The RRI process is intended to be used only with air-starved (substoichiometric staged-air) cyclone combustion, in conjunction with the installation and operation of an OFA system. The RRI process has not been demonstrated on any unit that fires North Dakota lignite. As of May 2006, no commercial installation of a permanent Rich Reagent Injection system has been made at any cyclone-fired boiler.

There is only one holder of a commercial license for modeling and conceptually designing RRI (Reaction Engineering International), with two vendors sub-licensed to design and sell RRI equipment (Fuel Tech and Combustion Components Associates). Since these license agreements are in place, and considering that successful demonstration testing has been performed at two cyclone-fired boiler powerplants, this technology is considered to be applicable and commercially available for potential application on cyclone boilers which burn coals with heat contents that are relatively constant. However, due to the variable heat content of lignite coal, RRI is considered to be technically-infeasible for application on North Dakota lignite-fired boilers. Technical feasibility and expected NO_X emissions from RRI for application on the Milton R. Young Station Unit 1 boiler are included in the "Layered NO_X Reduction Technologies" section.

A.1.3.4 Selective Catalytic Reduction (SCR)

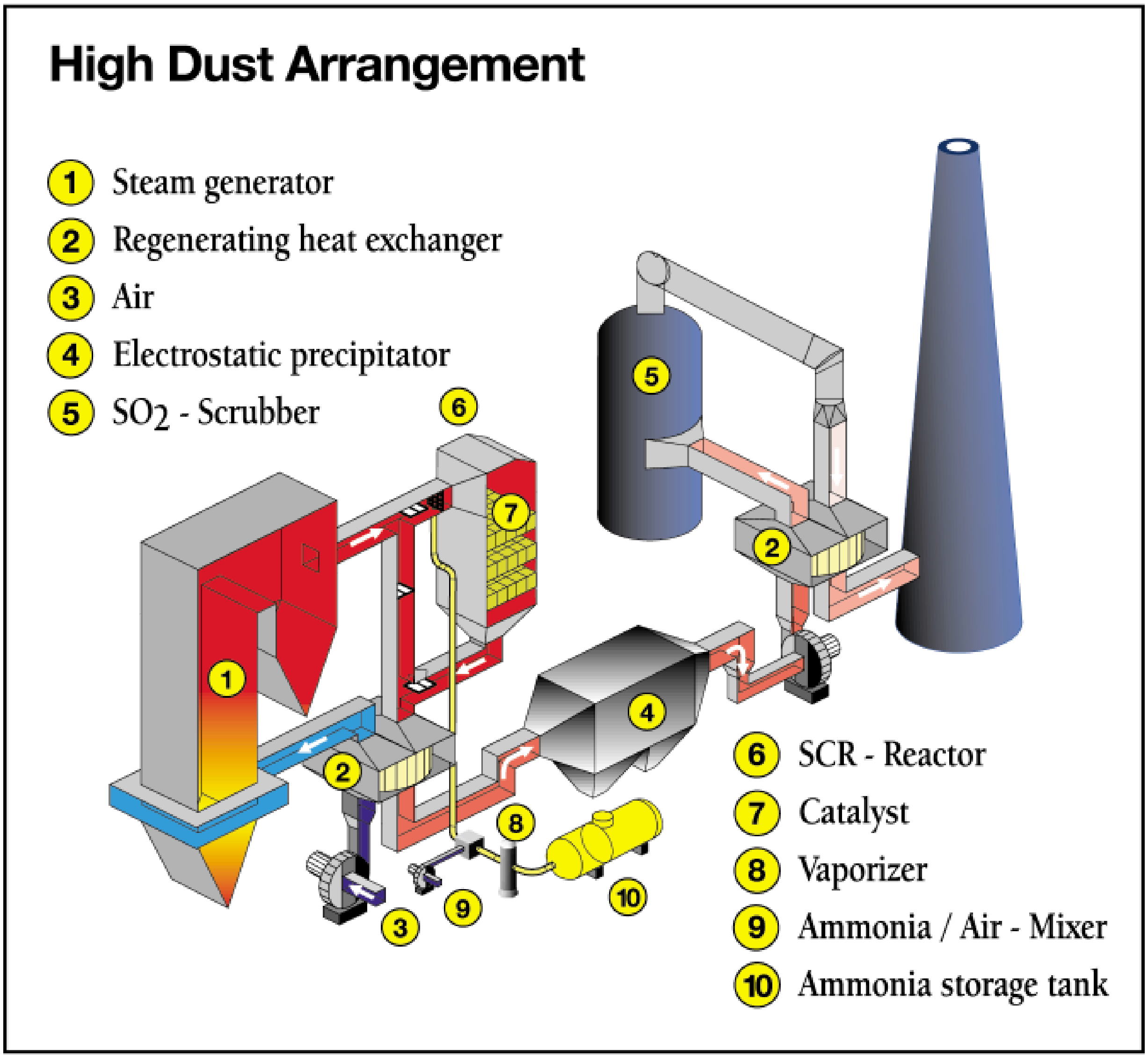
The lowest NOx emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NO_X to molecular nitrogen and water. The process is termed "selective" because the ammonia preferentially reacts with the NO_X rather than with the oxygen in the flue gas. A catalyst is used to enhance NO_X reduction and ammonia utilization at appropriate flue gas temperatures. SCR is usually applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO_X emission reduction effect. These are described below.

A.1.3.4.1 High-Dust Selective Catalytic Reduction (HD-SCR)

For coal-fired boilers, a conventional SCR reactor utilizes readily-available catalyst materials and reagent in the form of ammonia. A conventional SCR reactor is commonly installed in a high-dust, hot-side arrangement, located between the economizer outlet and air heater inlet, where the flue gas temperature is within the desired operating range for the SCR catalyst. The conventional SCR reactor arrangement is preferred for most coal-fired applications in utility boilers because it avoids the added expense of reheating the flue gas if placed after the air heaters which cool the flue gas, and downstream of any flue gas treatment to remove acid gases. Conventional SCR technology uses an ammonia injection grid (AIG), which consists of multiple nozzles, for distributing the reagent into the flue gas at the boiler's economizer flue gas outlet.

A schematic graphic diagram for a conventional high-dust, hot-side SCR system on a boiler with a flue gas desulfurization system and stack gas reheat is provided in Figure A.1-5.

Figure A.1-5 Conventional High-Dust SCR Arrangement with FGD Scrubber Outlet Reheat



(figure copied from Wheelabrator Air Pollution Control literature)

Conventional high-dust, hot-side SCR technology has been installed on several pulverized coal and cyclone boilers firing bituminous and subbituminous coal in the United States. There are also a limited number of European SCR installations on steam electric generating units (SEGUs) firing lower grade (brown) coal. There are, however, no existing full-scale SCR installations on units that fire North Dakota lignite. There are approximately 50 cyclone-fired units located in the states affected by EPA's NO_X SIP call. Over half of these units are planning to install conventional high-dust, hot-side SCR systems in response to the SIP call. The installation of conventional high-dust, hot-side SCR systems has been completed on approximately 22 of these units. Appendix A2 lists several conventional high-dust hot-side U.S. SCR installations on pulverized coal and cyclone-fired utility boilers, along with measured NO_X emissions. Initial data from these units indicate that conventional high-dust, hot-side SCR systems operated on suitable cyclone-fired units may be able to reduce NO_X emissions to as low as 0.07 lbs/mmBtu. Several SCR installations have been retrofit on existing cyclone-fired boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). For cyclone coal-fired utility boilers retrofitted with SCR technology, all were originally designed to burn bituminous coal.

The EPA NO_X SIP call only applies to units in the eastern United States. There are no facilities firing North Dakota lignite in the EPA NO_X SIP call region. SCR system operation is currently only needed during the ozone season (June – September) for units installing control equipment solely to meet the EPA NO_X SIP call requirements. Limited annual operation is a significant factor with respect to SCR equipment reliability, maintenance, operational costs, and catalyst life. The demands on the SCR system are much more severe if the equipment is required to operate on a full-time, annual basis.

Two byproducts from the high-dust, hot-side SCR process are ammonia slip and SO_3:

- Ammonia Slip: Slip is ammonia that is unreacted in the NO_x emission reduction process. Maximum ammonia slip for a gas fired unit is usually 10 ppmvd whereas, on a coal fired unit, ammonia slip below 5 ppm is desired. For certain applications, this concentration can be problematic, therefore requiring more catalyst to reduce slip. Most new SCR applications have ammonia slip guaranteed at a 2 ppmvd maximum for an initial operating period.
- SO_3: Due to the composition of typical SCR catalysts, a small percentage of inherent SO_2 will be oxidized to SO_3. This oxidation can be controlled by catalyst selection and can be less than one percent. SO_2 to SO_3 oxidation must be carefully controlled to avoid creating SO_3 levels sufficiently high to raise the possibility of air heater fouling. A unit firing high-sulfur coal with SCR technology is especially vulnerable to SO_3 oxidation and ammonia slip-related fouling problems. The deposition and fouling is due to formation of solid ammonium sulfate ($(NH_4)_2SO_4$) and liquid ammonium bisulfate (NH_4HSO_4). The most important design variable is optimizing the catalyst selection and amount of catalyst that will reduce NO_X emissions, control ammonia slip, and minimize SO_2 oxidation.

Recent technology has allowed catalyst suppliers to make more rigorous and lengthy guarantees. A reasonable initial operating period for conventional catalysts in high-dust reactor arrangements on boilers firing eastern or midwestern bituminous coal is around 24,000 active operating hours (i.e. when ammonia reagent is being injected). Factors that need to be taken into account in design of a high-dust, hot-side SCR application that affect the need for catalyst replacement are:

- Pressure drop: The amount of restriction to flue gas flow through the SCR inlet, ammonia injection grid, SCR reactor, and downstream ductwork directly increases induced draft fan horsepower required to maintain adequate boiler draft. This is an important parameter to consider and minimize during the design stage. Pressure drop is a function of the average and maximum SCR reactor duct velocities, the amount of restriction caused by flow distribution correction devices (baffles or vanes), and the number and geometrical aspects of the catalyst layers. Many retrofit SCR installations require a booster fan or upgraded induced draft fan to overcome the added flow resistance. This increases operating cost for the increase in auxiliary power consumption and loss of saleable electric power. The type and pitch of the catalyst are factors most influential in determining the amount of pressure drop.
    - Catalyst type: The most common types or forms of catalyst material are honeycomb or plate. The former offers more surface area per volume, but can be more restrictive and prone to pluggage from ash deposits. The latter is usually less restrictive but requires more catalyst per layer or more layers to achieve the active surface needed to achieve the intended NO_X emission reduction.
    - Catalyst pitch: The pitch of the catalyst, a term used to describe the size of the gas path openings through the catalyst, varies depending on the manufacturer and design dust loading. Pitch is generally on the order of 5 to 7 millimeters. Potential pluggage of flow channels within the catalysts layers is therefore an issue that must be dealt with during design.
- Catalyst performance: The amount of NO_X emission reduction expected is a function of the specific activity level of the catalyst material and the amount of catalyst installed, over a given period of time. Catalyst formulation selection and features of construction have a significant impact on long-term NO_X emission reduction and subsequent costs for reagent and catalysts replacement. The frequency of catalyst replacement is influenced strongly by:
    - Catalyst erosion: Erosion of the catalyst material in coal fired units from entrained flyash or sootblowing action reduces the amount of active surface available for reacting with the reagent and flue gas, and can cause distortions in gas distribution (“channeling”) through the

SCR reactor. Catalyst material is fragile and can be easily damaged. Some catalyst is provided with erosion-resistant top edges to mitigate this tendency.

- Moisture absorption: Many types of catalyst are damaged by absorption of moisture. The reactor must be kept above ambient dewpoint temperatures or protected from freezing during outages in order to protect the catalyst from moisture damage. Spare catalyst must be carefully packaged to keep it dry and must be handled delicately to prevent damage.
- Thermal degradation: The specific active elements of the catalyst surface, or the matrix structure itself upon which the catalyst material is applied, can degrade when exposed to flue gas temperatures greater than the intended design of the formulation. High flue gas temperatures within the reactor causes sintering, leading to a permanent loss of catalyst activity due to a change in the pore structure of the catalyst. Proper selection and manufacturing control of the catalyst structure and formulation can minimize thermal degradation.
- Catalyst poisoning: The loss of performance or activity of the catalyst over time can be due to chemical damage or poisoning. Two elements especially detrimental to the life of common titanium-supported vanadium pentoxide SCR catalyst are arsenic and zinc. Vanadia/tungsten-based catalysts are particularly susceptible to rapid deactivation due to gaseous arsenic poisoning. In some German SCR installations, a 50% loss of activity has been reported within 10,000-15,000 operating hours. Addition of molybdenum to a vanadia-titanium SCR catalyst on similar applications shows relative activity reductions of 20-25%. Progressive loss of SCR NO_X reduction performance from catalyst deactivation due to poisoning is not possible to restore without effective cleaning to remove the deposits, or eventual replacement.
- Catalyst fouling: The surface area potentially exposed to the reagent (ammonia) and nitrogen oxides in the flue gas can become fouled with flyash or sulfur-related compounds. The presence of excess calcium oxide in the presence of sulfur in the flue gas can form a calcium sulfate surface coating that can be extremely dense, masking the pores of the catalyst. Progressive loss of SCR NO_X reduction performance from catalyst deactivation due to fouling is difficult to restore without effective cleaning to remove the deposits, or eventual replacement.

SCR technology has been installed on numerous coal-fired utility boiler facilities around the world and there are a large number of manufacturers that market the catalysts. The question is whether SCR is a feasible technology for a unit firing North Dakota lignite. There are serious concerns whether installation of SCR technology on a North Dakota lignite-fired unit can be successful, especially in a conventional "hot-side, high-dust" configuration. The effectiveness of the SCR process is highly dependent upon the ability of the nitrogen oxides in the flue gas being able to contact the active sites within microscopic pores of the catalyst in the presence of ammonia reagent with minimal interference from contaminants.

A recent technical paper "Ash and Mercury Behavior in SCR Catalysts When Firing Subbituminous and Lignite Coals" by the Energy & Environmental Research Center (EERC) of the University of North Dakota was published in the February 2005 issue of Fuel Processing Technology magazine[28]. This paper summarized the results of SCR slipstream testing at two PRB-fired plants and one North Dakota lignite-fired powerplant. The evaluation included determination of impacts of ash on SCR plugging and blinding. Flue gas was isokinetically extracted from the convective pass of the boiler upstream of the air heater. Pressure drop across the catalyst was measured during the initial two-month test period, and the two consecutive two-month test periods following the initial trial, while holding flue gas flow and temperatures constant. Ammonia was injected downstream of a screen, upstream of a flow straightener and air pulse section. Compressed air was injected ahead of the reactor, and was periodically pulsed to simulate sootblowing to minimize ash deposit accumulation.

This slipstream SCR testing examined the significance of ash accumulations on SCR catalyst on both the macroscopic and microscopic levels. Very small flyash particles were found bonded together by a matrix of sodium-, calcium-, and sulfur-rich materials, likely in the form of calcium sulfate. North Dakota lignite coal contains many alkali and alkaline-earth elements, and sulfur. The firing of lignite coal which produces fine (less than 5-µm diameter) flyash particles creates conditions that enter the pores of the catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into the matrix.

As posted on Electric Power Research Institute Inc.'s (EPRI's) website regarding the impact of coal type on SCR catalyst life and performance, a recent EPRI study[29] produced field data analyzed from an "In-Situ Mini SCR Reactor" system installed in a typical "high-dust" location at seven different test sites, including four firing PRB coal, one firing Texas lignite, one firing high-sulfur eastern bituminous coal, and one firing a PRB/eastern bituminous coal blend. The PRB/bituminous coal blend test was performed at AmerenUE's Sioux Station, on one of the two 500 MW cyclone-fired boilers. This study found that the cyclone unit firing the PRB/bituminous coal blend exhibited the fastest rate of catalyst activity degradation. Also, the higher deactivation rates seen at this site were due to economizer exit flue gas temperatures being significantly higher than at the other sites. A comparison of the Texas lignite and one of the PRB-fired sites with two different catalysts, deactivation was more a function of trace elements in the flue gas and flyash than the specific catalyst type or formulation.

North Dakota lignite produces an ash that is very sticky and creates severe ash deposition problems. There have been no installations of SCR systems (full-scale) on units that fire North Dakota lignite. A technical assessment was conducted for the installation of SCR technology on a North Dakota lignite unit. In order to further evaluate the feasibility of installing a conventional SCR system on a North Dakota lignite fired unit, the Energy & Environmental Research Center (EERC) at the University of North Dakota was consulted. EERC has extensive experience investigating the deposition characteristics of North Dakota lignite ash.

Technical difficulties and anticipated operating problems that are unresolved with respect to installing conventional SCR technology at Milton R. Young Station include the impacts of erosion, severe ash deposition, and "popcorn ash" on the catalyst. According the EERC's study (see Appendix B), "the most significant problems that prohibit the successful operation of SCR catalysts to lignite coal is the formation of low-temperature sodium-calcium-magnesium sulfates and phosphates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency". For these reasons, application of available conventional high-dust SCR technology is considered technically infeasible for Milton R. Young Station Unit 1 and Unit 2 boilers. These concerns can be divided into four categories. Each category is addressed below. An explanation of the factors that make conventional SCR technology infeasible for these boilers follows:

1. Ash Deposition: North Dakota lignite contains a variable and complex variety of inorganic compounds that contribute to ash deposition. This fuel produces ash with severe deposition characteristics that are not typical with other coals. When exposed to the heat of the combustion process inside the cyclone burners, the majority of the fuel ash becomes molten and flows into the bottom of the furnace. A significant portion of the fuel ash is entrained into the flue gas exiting the cyclone barrels at high velocity, where it comes into contact with the lower furnace waterwalls. The portion that is carried with the rising flue gas cools and some is deposited on heat transfer surfaces in the upper furnace and boiler convection pass. Ash deposition on heat transfer surfaces is a substantial problem for units that fire North Dakota lignite. The problem is so severe at Milton R. Young that the Unit 1 boiler must be shut down at 120-day intervals to

allow for cleaning of ash deposits from the boiler heat transfer surfaces in order to restore reasonable furnace exit gas velocities and temperatures.

Sodium is a significant contributor to the "stickiness" of the ash produced from firing North Dakota lignite. Sodium content of the lignite ash averages approximately 4.4%, and can nearly double this value for some of the lignite produced from the Center mine. PRB coal typically averages around 1.5% sodium content. Boilers firing North Dakota lignite typically have a 2.5% higher heat rate (million Btu per kilowatt of electric generation) than a typical boiler firing PRB coal, thus requiring more heat input and firing more fuel per megawatt of electricity output. A cyclone boiler firing North Dakota lignite also converts approximately 50% of the fuel ash to flyash, compared with a 35% conversion rate for PRB coal-fired cyclone boilers. Overall, this results in an amount of sodium emitted from a cyclone boiler firing North Dakota lignite of approximately 7.3 lbs/MW-hr compared with 0.9 lbs/MW-hr for a PRB-fired cyclone boiler.

The catalysts in coal-fired boiler SCR reactors are highly susceptible to ash deposition. In a typical conventional high-dust SCR reactor, the flue gas typically passes through two to four layers of catalyst modules. The catalyst modules have numerous narrow passages to provide intimate contact between the flue gas, ammonia and catalyst. The clearance (pitch) in these passages is typically 6-10 millimeters. A typical catalyst layer is approximately 1 to 1.5 meters deep. The catalysts in coal-fired boiler SCR reactors must be cleaned frequently using soot blowers and/or sonic horns. This is true even on units firing fuels that do not produce a sticky ash that contributes to ash deposition. Ash deposition on the catalyst in a high-dust SCR application would be severe for a unit firing North Dakota lignite.

Sulfur in the coal is oxidized during excess air combustion to form sulfur dioxide (SO_2), and a small amount of sulfur trioxide (SO_3). Some of the ammonia-based reagent injected upstream of the SCR reactor will combine with SO_3 to form ammonium bisulfate. The catalyst in the SCR reactor will also oxidize a portion of the SO_2 to SO_3. Excess unreacted ammonia reagent carryover ("ammonia slip") from the SCR reactor will also react with these sulfuric acid compounds in a similar fashion. The deposition characteristics for a unit burning North Dakota lignite will create difficult-to-remove ash deposits and pluggage of a conventional high-dust catalyst, and increase the probability that the air preheater downstream and flue gas ductwork will be prone to accumulations which could be severe. High-dust SCR performance and catalyst life will be severely impacted. It is anticipated that a high-dust SCR's catalyst life will be shortened from 3-6 years (typical) to as little as 2-12 months, requiring extended, frequent outages for replacement.

Hot-side air preheaters are susceptible to fouling. Tubular air pre heaters originally supplied with all cyclone boilers also tolerate moderate dust loadings, since their height and size make them difficult to maintain cleanliness. Leak tightness of the air preheater is important on cyclone-fired boilers with relatively high forced draft fan discharge (combustion air supply) pressures. A high-dust SCR installation will be prone to air preheater tube fouling and pluggage, requiring extended, frequent outages for cleaning.

2. "Popcorn Ash": A second consideration in the application of conventional high-dust SCR technology on a lignite-fired unit is the potential of the SCR reactor catalyst pluggage resulting from carry over of "popcorn ash" from the boiler. Boilers firing North Dakota lignite have severe problems with ash deposition on boiler surfaces. North Dakota lignite has a high propensity to form deposits on the boiler's furnace and convection pass fireside surfaces. For lignite-fired units, the boiler's heat transfer surfaces must be cleaned by sootblowing and other methods (e.g. water lances) frequently to maintain satisfactory boiler operation. Some of the removed deposits released by the cleaning action within the boiler and convection passes form "popcorn ash", which will be entrained in the flue gas. Carry over of boiler ash deposits will contribute to pluggage of the "popcorn ash" screen ahead of the top layer of SCR reactor catalyst. This can cause distortions in gas distribution ("channeling") through the SCR reactor, which will aggravate erosion in the high velocity areas and ineffective performance of the catalyst.

3. Temperature: A third issue that impacts the feasibility of installing high-dust SCR technology on the North Dakota lignite-fired units is catalyst operating temperature. The performance of any SCR catalyst is highly dependent on the temperature of the flue gas passing through the reactor. Typically, a temperature of 600 – 750 degrees F is required to obtain satisfactory operation of an SCR reactor. Operation of commonly supplied catalyst suitable for a high-dust SCR reactor at temperatures above 750 degrees results in severe and rapid deterioration of the catalyst and SCR reactor's NO_X emission reduction performance. For bituminous and sub-bituminous coal-fired units, boiler flue gas passing between the economizer outlet and air heater inlet is generally

within a temperature range acceptable for conventional SCR catalysts without additional heating or cooling of the flow stream.

North Dakota lignite-fired cyclone boilers, including those at Milton R. Young Station, have high temperatures at the economizer's flue gas outlet by design. The highest gas temperatures downstream of the convection pass economizer sections and upstream of the air heater inlets in Milton R. Young Unit 1's boiler are much higher than 750 degrees.

High gas temperatures at the air heater inlet are required to produce the high air temperatures (700°F) needed for the pre-combustion lignite drying system, along with primary and secondary combustion air supplied to the cyclones. Such air preheater arrangements and capabilities have been taken into account in the design of the North Dakota lignite-fired cyclone boilers. Reducing this high gas temperature to accommodate conventional catalysts for a conventional high-dust SCR reactor would result in pre-combustion air temperatures that are too low to provide satisfactory drying and rapid ignition of the high-moisture fuel. This will seriously impact reliable combustion, slag formation and tapping in the cyclone burners. Consequently, it is not feasible to modify the Milton R. Young Unit 1's boiler to operate with the lower economizer outlet flue gas temperature.

Catalysts for a conventional high-dust, hot-side SCR system have not been installed nor successfully demonstrated in a full-scale installation of an operating solid fuel-fired unit that are designed to continuously operate at the high temperatures (above 750 degrees F) that exist between the convection pass economizer and air heater on the Milton R. Young Unit 1's boiler.

4. Erosion: A final consideration on whether hot-side, high-dust SCR technology can be successful on a North Dakota lignite-fired unit is the potential for erosion of the SCR catalyst. North Dakota lignite supplied from the Center mine has an average fuel ash content of 10.5%, and can have an ash content up to 25.5 percent. PRB coal fuel ash content typically averages approximately 5 percent. As previously stated, a cyclone boiler firing North Dakota lignite converts a significantly greater amount of flyash than a PRB-fired cyclone boiler. Overall, this results in a flyash output rate from a cyclone boiler firing North Dakota lignite of approximately 83 lbs/MW-hr compared with 21 lbs/MW-hr for a PRB-fired cyclone boiler. High ash contents in the flue gas stream can result in physical erosion of the catalyst. In addition, effective on-line cleaning of the

high-dust catalyst will likely require steam or compressed air sootblowing. Cleaning cycles of the catalyst will be required much more frequently than a typical conventional SCR installation due to the ash deposition characteristics of the North Dakota lignite and the expected buildup and pluggage resulting from the carry over of "popcorn ash". Frequent sootblowing of the catalyst to remove fouling deposits and ash accumulations will contribute to erosion and decreased catalyst life. There is some European experience with high ash brown coals that catalyst manufacturers will be able to draw upon. This experience, however, will not be directly applicable to these United States units because of the severe deposition characteristics of the North Dakota lignite ash compared to brown coal.

The EPA's NSR Manual states that for a technology to be feasible it must "available and applicable". SCR technology is an available technology which has been installed on numerous powerplant facilities around the world and there are a large number of manufacturers that market the technology. The question is whether SCR technology is "applicable" for a unit firing North Dakota lignite.

In accordance with EPA's NSR Manual, a technology is "applicable" if it has been installed on a "similar unit". Hot-side, high-dust SCR technology has been retrofit on coal-fired units featuring cyclone boilers. However, there are no SCR installations in operation or planned on units that include cyclone burners firing North Dakota lignite with severe slagging and fouling tendencies combined with such high boiler economizer outlet gas temperatures (over 750°F) required for high-moisture fuel pre-drying systems and tubular air preheaters.

The EPA's NSR Manual also states a technology may be determined to be not applicable if "a technical assessment considering physical, chemical and engineering principles and/or empirical data showing the technology would not work on the emissions unit under review or that unsolvable technical difficulties would preclude the successful deployment of the technique." In this SCR technology application, it appears that a facility utility powerplant firing North Dakota lignite would experience extended time delays or be required to devote significant internal resources and engage outside research, followed by extended field trials to learn how to apply a conventional high-dust, hot-side SCR technology on a such a fuel source.

Based upon this technical assessment that looked at the various design and operational issues associated with the installation of hot-side, high-dust SCR technology on a North Dakota lignite-fired steam-electric generating unit, this control option is considered technically infeasible for Unit 1's boiler at Milton R. Young Station.

A.1.3.4.2 Low-Dust Selective Catalytic Reduction (LD-SCR)

Low-dust SCR (LD SCR) technology could potentially be applicable to North Dakota lignite-fired boilers for NOx emission control. Low-dust SCR refers to the location of the SCR system downstream of a particulate collection system, such as an electrostatic precipitator or a fabric filter. If the low-dust SCR is downstream of a hot-side electrostatic precipitator and prior to the air preheater, flue gas reheating is unnecessary. This has been the prevalent form of alternative retrofit SCRs in the United States for coal-fired utility boilers. There are ten known hot-side low-dust SCR installations (without flue gas reheat) operating in the United States as of July 2005. These are listed in Appendix A2. If applied to MRY Station Unit 1's boiler, the low-dust SCR equipment would be downstream of a cold-side electrostatic precipitator; flue gas reheat prior to the LD SCR reactor inlet would be required for proper NO_X emission reduction performance.

For a cold-side LD SCR, the ESP outlet flue gas passes through a low-dust gas-to-gas heat exchanger (LD GTG-HE), prior to passing to the low-dust SCR reactor. After the LD GTG-HE, the flue gas will travel through the new duct, receiving hot flue gases from a direct-fired gas burner or set of high-pressure steam coils, leading to an ammonia injection grid, turning vanes and then into the LD SCR reactor. The flue gas entering the inlet to the LD GTG HE is expected to be near the air heater outlet temperature (330-340°F) in a cold-side LD SCR application. The supplemental heat added downstream of the LD GTG-HE can be supplied from high temperature steam coils (indirect heat exchange) or directly from natural gas-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the LD SCR NO_X–ammonia reaction to be effective. The LD gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the FGD system (if applicable) and stack. The use of rotary regenerative-type heat exchangers has been applied in European LD SCRs. With this design, there will be leakage between the untreated and treated gas streams such that the exit flue gas has higher NO_X concentrations than the LD SCR outlet gas. The direct-fired flue gas reheat duct burners will also create NO_X emissions, which will add to the amount emitted from the boiler and input into the LD SCR reactor. The LD SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This normally requires an induced draft fan upgrade or a booster fan addition.

The factors that make low-dust SCR technology infeasible for the Milton R. Young Station Unit 1's boiler with existing particulate collection via electrostatic precipitators are as follows:

- Catalyst Fouling and Deactivation: An existing electrostatic precipitator upstream of a low dust SCR reactor will still expose the catalyst to the acid gas content and fine particulate containing trace metals and the high alkali mineral content of the entrained lignite flyash not removed by the ESP upstream. Although the total amount of flyash carryover into the LD-SCR reactor is greatly reduced compared with a high-dust design, it is anticipated that the low-dust SCR catalyst life will still be unacceptably short. The small particle flyash passing into the reactor will be sufficient to cause pluggage of the catalyst pores, resulting in deactivation of the catalyst. The firing of lignite coal produces fine (less than 5-µm diameter) flyash particles, which are also least likely to be removed by the existing particulate collection equipment (e.g. ESP) upstream of a low-dust SCR. This creates conditions that allow these small flyash particles to enter the pores of the catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into a matrix of sodium-, calcium-, and sulfur-rich materials (likely in a form of calcium sulfate). Once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. One catalyst vendor's has stated it is their "experience that low-dust catalyst is more difficult to clean than that from high-dust"[30]. Low-dust SCR performance and catalyst life could be severely negatively impacted. Shortened lifespans of the LD SCR catalyst will require premature, extended, frequent outages for replacement.
- Site Space Constraints: The installation of a low-dust SCR system with flue gas reheat requires a substantial amount of space for installation and operation. A low-dust SCR system will likely use a regenerative gas-to-gas heat exchanger (reheater) to raise the temperature of the flue gas at the SCR inlet. A GTG HE will transfer heat from the flue gas at the SCR reactor outlet to the flue gas entering the SCR reactor in order to minimize the supplemental SCR energy usage. The gas-to-gas heat exchanger dictates the footprint of the cold-side low-dust SCR system. Space is required for the GTG HE and for ductwork in and out of the reheater. Sufficient free space around the reheater and SCR is also required for maintenance.

  The area around Units 1 and 2 at the M.R. Young station is extremely congested in the areas where low-dust SCR systems must be located. The situation is particularly severe for Unit No. 2. Equipment that impacts the feasibility of installing a low-dust SCR system on Units 1 and 2 includes the Unit 2 absorbers, Unit 2 flue gas desulfurization (FGD) dewatering equipment, fly ash handling equipment, fuel storage and transfer equipment, stacks, fans and ductwork. It would be extremely disruptive to the continued economic operation of both boilers to relocate all the mentioned equipment to create space for the low-dust SCR systems at the M.R. Young Station. Stacks, fans and ductwork and the Unit 2 FGD system cannot be readily relocated due to adjacent structures and the need to continue operation while constructing the retrofit installations. The fuel handling equipment includes a coal storage barn and the main conveyors supplying lignite to the units. Relocating the coal handling equipment currently occupying space needed for the low dust SCR systems would be quite difficult given the site configuration. It is conceivable that the fly ash equipment located west of Unit 1 could be relocated to provide some of the space needed for the low-dust SCR. However, the availability of this space is doubtful, since avoiding the likelihood of severe SCR catalyst sulfate fouling will require a new Unit 1 FGD system to be installed. If a new FGD system is installed for Unit 1, the FGD system would need to occupy the space that can be made available by relocating ash handling equipment. This space subsequently would not be available for a low-dust SCR system.

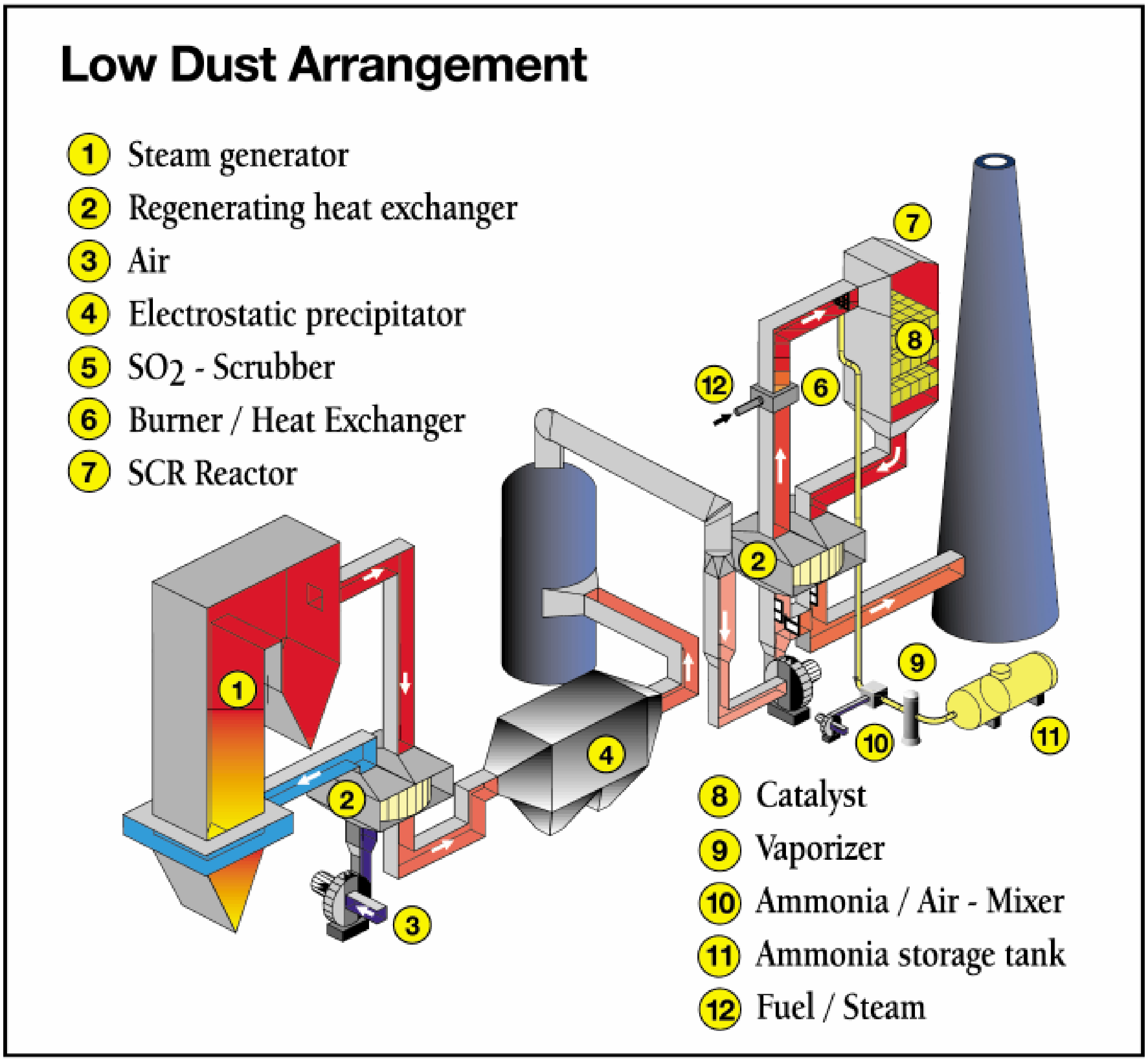
Based upon a technical assessment that looked at the various design and operational issues associated with the installation of low-dust SCR technology on a North Dakota lignite-fired steam-electric generating unit, this control option is considered technically infeasible for the Milton R. Young Station Unit 1’s boiler.

A.1.3.4.3 Tail-Gas Selective Catalytic Reduction (LD-SCR)

A tail-gas (TG) SCR is a low-dust SCR system where the LD SCR reactor is installed downstream of a FGD scrubber. The FGD outlet flue gas passes through a gas-to-gas heat exchanger (GTG-HE), prior to passing to the tail-gas SCR reactor. The flue gas will travel through new or modified ductwork leading to an ammonia injection grid, turning vanes and then into the TG SCR reactor. The TG SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This normally requires an induced draft fan upgrade or a booster fan addition.

A schematic graphic diagram for a low dust arrangement is shown in Figure A.1-6.

Figure A.1-6 Tail-Gas SCR Arrangement



(figure copied from Wheelabrator Air Pollution Control literature)

The flue gas from a wet FGD scrubber outlet entering the inlet to the gas-to-gas heat exchanger is expected to be near the saturation temperature (140°F) in a cold-side TG SCR application. The supplemental heat added downstream of the TG GTG-HE can be supplied from high temperature steam coils (indirect heat exchange) or directly from natural gas-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the TG SCR NO_X– ammonia reaction to be effective. The TG gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the stack. With a rotary regenerative-type gas-to-gas heat exchanger, there will be internal leakage between the untreated and treated gas streams such that the stack exit flue gas has higher NO_X concentrations than the

TG SCR reactor outlet gas. Using direct-fired flue gas reheat duct burners will also create NO_X emissions, which will add to the amount emitted from the boiler and input into the TG SCR reactor.

There is limited technical information published in English for coal-fired steam-electric generating units (SEGU) with low-dust/tail-gas SCR technology in applications requiring full flue gas reheat prior to the reactor inlet. There is no experience with TG SCR on eastern bituminous, western subbituminous coal or lignite-fired SEGUs in the United States. As of 1997, there was one low-dust/tail-gas SCR on a 220 MWe German cyclone-fired boiler with a 1988 retrofit installation. This boiler was reported to be operating without combustion controls or FGD, burning low sulfur, low ash, moderate moisture bituminous coal with an average pre-SCR NO_X emission rate of approximately 1.07 lb/mmBtu, and was meeting a 30-day rolling average emission limit of approximately 0.16 lb/mmBtu (85% reduction)[31].

Milton R. Young Station Unit 1 does not currently incorporate any flue gas desulfurization equipment, which would place the reactor catalyst in a low-dust SCR configuration, which is considered infeasible when burning North Dakota lignite. A new FGD system for Unit 1 would be required in order to avoid or significantly reduce expected sulfate formation within the catalyst and gas-to-gas heat exchanger when combined with ammonia required for the TG SCR. Unit 2 currently employs a wet scrubber which currently treats approximately 83% of the total flue gas flow from the boiler. Flue gas reheat is currently provided by the FGD bypass (i.e. warm, untreated flue gas is mixed with the cool scrubbed gas).

The factors that make tail-gas SCR technology infeasible for both Milton R. Young Station boilers with existing particulate collection via electrostatic precipitators are as follows:

- Catalyst Fouling and Deactivation: The TG SCR reactor downstream of a flue gas desulfurization (FGD) scrubber will still be susceptible to fouling, contamination, pluggage, and catalyst deactivation.
    - An existing electrostatic precipitator (ESP) upstream of a tail-gas SCR reactor will still expose the catalyst to fine particulate containing trace metals and the high alkali mineral content of the entrained lignite flyash not removed by the ESP upstream. Although the total amount of flyash carryover into the TG-SCR reactor is greatly reduced compared with a high-dust design, it is anticipated that the tail-gas SCR catalyst life will still be unacceptably short.
    - The firing of lignite coal produces fine (less than 5-µm diameter) flyash particles, which are also least likely to be removed by the existing particulate collection equipment (e.g. ESP) upstream of

a TG-SCR. Flue gas with entrained fine particulate matter, including some involving sodium and sulfur-containing compounds, will pass through and be carried-over from a wet FGD scrubber. This treated gas stream will carry sodium sulfate particles, formed by homogenous condensation after exiting the boiler and not removed by the FGD system, into the catalyst layers of the TG-SCR reactor. A dry FGD system followed by a fabric filter upstream of the TG-SCR will still allow sulfur-bearing flue gas and fine particles to enter the catalyst. There is serious concern that fine particles passing into the reactor will accumulate within the catalyst, and be resistant to removal by conventional sootblowers and other cleaning technologies. This creates conditions that allow these small flyash particles to enter the pores of the catalyst, react with SO_2 and/or SO_3 in the flue gas, and form sulfates which bind other ash particles into a matrix of sodium-, calcium-, and sulfur-rich materials (likely in a form of calcium sulfate). Once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. Catalyst that is exposed to such conditions will be ineffective at maintaining adequate activity upon which the performance of the TG-SCR's NO_X removal is based.

  - These entrained particles will also deposit on the gas-to-gas heat exchanger ahead of the tail gas SCR reactor. This deposition will decrease heat transfer between the incoming (cool) flue gas and the outgoing (warm) flue gas. Sootblowers could be used to remove the accumulated deposits from the GTG HE, but the SCR reactor could still suffer catalyst fouling from the deposits dislodged from the GTG HE cleaning cycle becoming reentrained in the reheated flue gas. Tail-gas SCR performance and catalyst life could be severely negatively impacted. Shortened lifespans of the TG SCR catalyst will require premature, extended, frequent outages for replacement.

- Site Space Constraints: The installation of a tail-gas SCR system with flue gas reheat requires a substantial amount of space for installation and operation. A tail-gas SCR system will likely use a regenerative gas-to-gas heat exchanger (reheater) to raise the temperature of the flue gas at the SCR inlet. A GTG HE will transfer heat from the flue gas at the TG SCR reactor outlet to the scrubbed flue gas entering the SCR reactor in order to minimize the supplemental SCR energy usage. The gas-to-gas heat exchanger dictates the footprint of the TG SCR system. Space is required for the GTG HE and for ductwork in and out of the reheater. Sufficient free space around the reheater and SCR system is also required for maintenance.

  The area around Units 1 and 2 at the M.R. Young station is extremely congested in the areas where TG SCR systems must be located. A flue gas desulfurization system will be needed for Unit 1 in the near future to comply with the Consent Decree. When a new FGD system is installed for Unit 1, the FGD system would need to occupy the space that can be made available by relocating ash handling equipment. This space subsequently would not be available for a tail-gas SCR system. Thus, the availability of adequate space for all the new FGD and TG-SCR system equipment and structures while accommodating existing coal storage and handling needs for both existing boilers at Milton R. Young Station is doubtful.

The challenges for installation of new ductwork, SCR reactors, and flue gas reheating equipment and the lack of pertinent experience with all aspects of design, construction, operation and maintenance of tail-gas SCRs on such high-fouling coals as North Dakota lignite are significant. The flue gas conditions that the TG-SCR catalyst will be exposed to will create unresolvable fouling and blinding that makes successful application of this technology difficult, expensive, and uncertain.

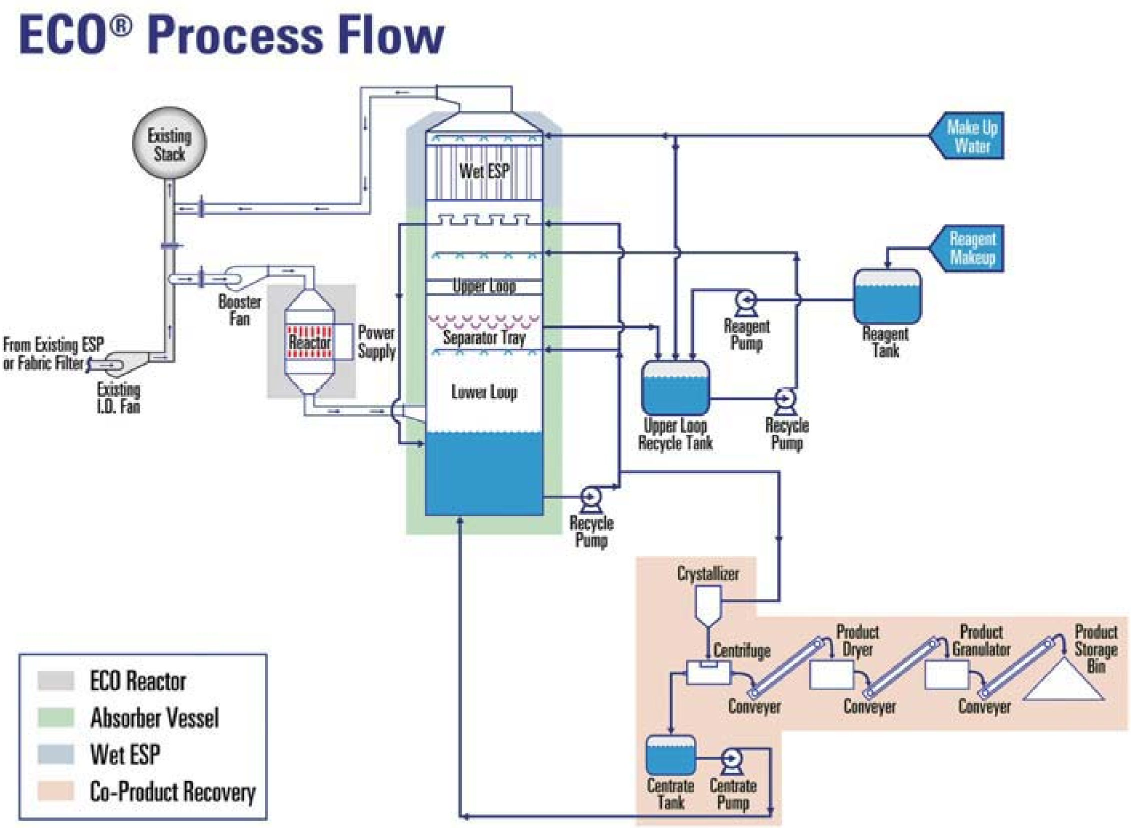
The risk of failure and uncertainty of successfully applying low-dust, tail-gas SCR technology to a cyclone-fired utility powerplant firing North Dakota lignite appear substantial.

Based upon a technical assessment that looked at the various design and operational issues associated with the installation of tail-gas SCR technology on a North Dakota lignite-fired steam-electric generating unit including a cyclone boiler, this control option is considered technically infeasible for the Milton R. Young Station Unit 1's boiler.

A.1.3.5 Electro-Catalytic Oxidation (ECO®)

Powerspan's Electro-Catalytic Oxidation (ECO®) system is a multi-pollutant technology designed to control emissions of NO_X, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO® process has two main process vessels, a barrier discharge reactor, and a multi-level wet scrubber. The barrier discharge reactor utilizes an electrical discharge to create oxygen and hydroxide radicals which then react with NO_X, and other constituents in the flue gas stream. The flue gas stream then enters the bottom of the ECO® scrubber where the lower loop cools the flue gas and removes a portion of the acid gasses [sulfur trioxide (SO_3), sulfuric acid (H_2SO_4), nitric acid (HNO_3)] produced in the barrier reactor and oxidized metals such as mercury, with a low pH aqueous ammonia reagent. A second scrubbing loop is then entered where additional SO_2, NO_2, acid gases and oxidized metals are removed with an aqueous ammonia reagent, though at a higher pH. Above the second scrubber loop is an absorber section for absorbing fugitive ammonia from the first and second scrubbing loops. The final step in the ECO® process is a wet electrostatic precipitator (WESP) which collects fine particulate matter, aerosols generated in the scrubber and additional mercury. An updated schematic process flow diagram for the basic ECO® process is shown in Figure A.1-7.

Figure A.1-7 – Electro-Catalytic Oxidation (ECO®) Process Flow Diagram
(copied from http://www.epa.gov/appcdwww/aptb/EPA600R03110.pdf)



Powerspan has been involved in an extended ECO® process demonstration using a 28 MW Commercial Demonstration Unit (CDU) at R.E. Burger Station Units 4&5. The ECO® CDU project treated a slipstream and demonstrated performance, reliability and economics for approximately one year. The demonstration program started in January, 2004. NO_X removal is stated to be up to 90% with a claimed 0.05 lb NO_X/mmBtu outlet condition achievable for the front-end of the ECO® process. Further sustained operational tests of the ECO® CDU are underway during the second and third quarters of 2005.

As this is a post-combustion multi-pollutant control technology, it is claimed that there is little sensitivity to the type boiler or burners that Powerspan's Electro-Catalytic Oxidation (ECO®) process can be potentially applied to in order to reduce NO_X emissions. The effectiveness of this ECO® process for NO_X control has been demonstrated on a slip-stream commercial demonstration unit (CDU) associated with pulverized fuel boilers firing midwestern or eastern bituminous coal.

Powerspan's published data from the commercial demonstration unit's performance of up to 90% when treating flue gas with an inlet NO_X concentration around 0.5 lb/mmBtu. This would result in a stack NO_X emission around 0.05 lb/mmBtu.

The ECO® process has not been demonstrated in a full-scale configuration on any unit, nor tested in a slipstream configuration on any boiler that fires western subbituminous coals or North Dakota lignite. It has also not been applied to emissions from a cyclone-fired boiler. According the EPA's Draft NSR Manual, "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available: an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice".

There are a number of issues with firing North Dakota lignite that make the applicability of the ECO® process technically infeasible for MRY Station boilers. These issues include:

- Deposits and Pluggage: The flyash deposition characteristics of the North Dakota lignite are extremely severe. Anything that contributes to flyash deposition and pluggage within the barrier reactor is expected to have a detrimental impact on the multi-pollutant control performance of the ECO® process, and thus could have a serious impact on MRY Station operations. The lack of demonstrated operation on treating the emissions from a boiler firing coal with a high slagging index precludes the use of the ECO® process as technically feasible for BACT as applied to a boiler firing North Dakota lignite.
- Reliability and Availability: Milton R. Young Station's major planned outages for each unit are scheduled to occur once every three years. Any NO_X control technology selected as BACT will need to operate year-round, year in and year out, on a routine basis, while performing at high levels of pollutant reduction. The Powerspan ECO® system is a new technology and is not as highly developed as other more common NO_X and SO_2 control technologies such as SCR or SNCR plus wet or semi-dry flue gas desulfurization (FGD). It is expected to require a full-time, full-scale application with sustained continuous operation to confirm levels of currently demonstrated reliability and availability from the ECO® CDU are acceptable to meet the

expectation of infrequent major outages over long time periods while maintaining high levels of control.

There are additional factors that make the application of the ECO® process potentially more difficult than other established emission control technologies available for coal-fired powerplants:

- There is a lack of experience with the ECO® downstream ammonia scrubber's coproduct crystallization and granulization equipment design, operation, and maintenance, which was not included with the initial commercial demonstration unit. The coproduct stream that would normally feed into the crystallization and granulation processes was collected and transported offsite for this process step during CDU operation. Because crystallization and granulation of ammonium sulfate from an ammonia scrubber solution is not a new technological process, this was not considered a technical feasibility deficiency. For instance, the Dakota Gasification Company (DGC) in Beulah, ND currently operates an SO_2 scrubber utilizing ammonia as a reagent. Following the generation of ammonium sulfate, DGC crystallizes and granulates a fertilizer product on site. However, at MRY Station, considerable costs would be incurred for interim storage and shipment of the ECO® process scrubber's liquid bleedstream until sufficient experience has identified and eliminated potential failures and repairs for the crystallization and granulation equipment should it prove to be unreliable.

- Size of the barrier reactor: Powerspan recently indicated that they would scale the reactor for optimum cost and space arrangement based upon lessons learned from the CDU plant operation. The number of individual passages within a barrier reactor sized for either of MRY Station boilers' maximum flue gas flow and gas stream constituents is expected to require a cross-sectional area comparable to half of a large electrostatic precipitator. Although this has not been closely examined for all aspects of design, construction, operation and maintenance, the amount of physical space required to hold the barrier reactor and inlet and outlet ductwork is believed to not be available for potential retrofit to MRY Station units. Site space constraints are considered to be a barrier to technical feasibility for potential application of the ECO® process at Milton R. Young Station for Unit 1 and Unit 2's boilers.

- Additional station auxiliary power consumption: The barrier reactor, plus the ammonia scrubber and wet electrostatic precipitator additions by an ECO™ system, require an increase in station auxiliary power consumption. For NO_X control, this includes more horsepower required by the booster fan needed to compensate for the flue gas pressure drop created across the barrier reactor. It also includes the power consumed by the electrodes of the barrier reactor itself.

Because of the technical feasibility issues and lack of commercial availability and full-scale experience, especially on such high fouling coals, the ECO® system was considered technically infeasible as a BACT alternative for Milton R. Young Station for Unit 1's boiler.

A.1.4 "Layered" NOx Reduction Technologies

Many of the NO_X emission reduction technologies which involve furnace or convection pass areas for their introduction into the flue gas stream have been, or can potentially be, applied in combinations so as to result in an overall higher level of removal. Separated overfire air, various types of fuel reburn, and various forms of SNCR could potentially be combined in series to reduce NO_X emissions prior to boiler's flue gas exit. However, all the possible NO_X control technology combinations have not been installed on coal-fired powerplants, so actual feasibility of some combinations have not been demonstrated as viable, particularly in consideration of the special challenges posed by cyclone boilers firing lignite coal.

A.1.4.1 SOFA Combined With Other NO_X Reduction Technologies

Separated Overfire Air can be favorably combined with every other method in order to reduce the amount of reagent or reburn fuel required to achieve the resulting level of NO_X emission reduction. Some control technologies, especially conventional fuel reburn systems, require overfire air to complete the combustion of the staged fuel admitted to the upper furnace. Fuel lean gas reburn can be applied with or without SOFA, as this limited amount of staged fuel is introduced into an oxygen-rich atmosphere downstream of the cyclone burners and any overfire air injection points.

A.1.4.1.1 SOFA with SNCR

Selective non catalytic reduction technologies are post-combustion, in-furnace NO_X control alternatives that have been installed in numerous boilers of various designs, fuel types, with and without overfire air. It is usually advantageous to apply overfire air so that the amount of chemical reagent consumption can be minimized in order to achieve the targeted NO_X emission rate from the boiler outlet.

Tests at Conectiv's B.L England Station (Units 1 and 2) demonstrated that SNCR can decrease NO_X emissions as much as 31% at full load, from 0.55 to 0.38 lb/mmBtu, over and above the reduction possible from overfire air alone (approximately 60% drop, from 1.3 to 1.4 down to 0.55) in full operation. This is an overall NO_X emission reduction of 72% from pre-retrofit baseline[24].

SNCR can be applied alone or combined with either the basic or the advanced forms of separated overfire air (ASOFA) on MRY Station boilers. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction is an optional part of this technique. However, as previously explained in the discussion of SOFA alternatives, this will risk slag "freezing" in the barrels and lower furnace. Estimated NO_X emission rates for using SNCR techniques with North Dakota lignite considered published levels achieved by cyclone-fired units firing western subbituminous coal, and vendor estimates. SNCR with ASOFA is expected to reduce NO_X emissions approximately 31% below NO_X levels predicted for ASOFA operation, and potentially 58% overall from current baseline level for the MRY Station Unit 1 boiler with ammonia slip limited to approximately 5 ppmvd. This highest performing basic SNCR system is potentially able to achieve a NO_X emission rate of 0.355 lb/mmBtu, when combined with the advanced form of SOFA on MRY Station Units 1 boiler during operation at the pre-control baseline (near MCR load). These levels of NO_X reduction depend on the advanced form of separated overfire air technique to achieve the expected NO_X reduction percentages when applied to lignite-fired cyclone boilers.

Another form of SNCR is combined with separated overfire air. This is currently being marketed commercially as "Rotating Mixing" (Rotamix). In the United States' utilities industry, this has only been applied to pulverized coal-fired boilers. It is different than basic SNCR in that it includes a hot air booster fan and a small ambient air fan, and injects the ammonia (or urea) reagent into the high-pressure overfire air flow stream ahead of the ROFA nozzles' outlets. This mixture is imparted into the boiler in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. This vendor (Mobotec USA) claims that Rotamix (rotating opposed fire air or ROFA + SNCR) helps to distribute the reagent across the furnace cross section, which maximizes in-furnace NOx reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon. Three tangentially-fired utility boilers burning eastern bituminous coal or Illinois bituminous coal were retrofitted with Rotamix, each achieving a NO_X reduction of approximately zero to 55 percent beyond the levels produced by ROFA alone, from pre-SNCR baselines of 0.22 to 0.28 lb/mmBtu down to 0.10 to 0.23 lb/mmBtu without low-NO_X burners[4,32,33,34].

While this variation of SNCR combined with separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Since cyclone boilers do not require the addition of hot air booster fans for SOFA, and optimum injection locations for both SOFA and SNCR reagent may not coincide, Rotamix may not perform as well as, or significantly better than, a well-designed combination of conventional SOFA and SNCR. This technique is not distinct enough from basic SNCR from functional and air-staged cyclone NO_X reduction performance standpoints to warrant individual consideration for Milton R. Young Station boilers. Because of a lack of cyclone-fired boiler experience with ROFA and Rotamix, the latter was considered infeasible and thus was not included in the control effectiveness and cost-effectiveness sections of the main report.

A.1.4.1.2 SOFA with RRI

Rich Reagent Injection must be used in an oxygen-deprived atmosphere in order to effectively reduce nitrogen oxide emissions. This requires air-staged cyclones and separated overfire air operation.
The NO_X emission reduction reagent injection for RRI processes must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) simulations are needed to determine the optimum injection points. Boiler operating conditions will change with unit load and varying fuel characteristics. The RRI process control systems must be able to adjust for these changing conditions.

RRI has the potential to provide a moderate degree of NO_X reduction on coal-fired boilers. Data from B.L. England and Sioux plants show this technology can reduce NO_X emissions between zero and 39 percent beyond the amount attributable to overfire air system operation[23,24,25,26,27]. During initial demonstration testing of RRI at Ameren's Sioux Unit 1 boiler, a 500 MW unit firing a blend of PRB and midwestern bituminous coals (without SNCR), with SOFA in August 2001 at a lower furnace SR of approximately 0.99, NO_X emissions were reduced approximately 55% to 0.55 lb/mmBtu w/ SOFA only, with zero to 15% additional NO_X reduction from RRI (down to 0.47 lb/mmBtu) with zero ammonia slip[25]. Results of this initial RRI testing at Sioux plant were poor at cyclone stoichiometric ratios close to 0.99 because inconsistent, sporadic, and non-repeatable NO_X emissions reductions between zero and 15% were measured. Subsequent RRI testing at Sioux Unit 1 in March 2002 with SOFA at an average cyclone stoichiometric ratio around 0.95 showed NO_X emissions reduction of 29 percent (down to 0.27 lb/mmBtu) beyond those achieved with a modest amount of cyclone air-staging with SOFA (68% drop down to 0.38 lb/mmBtu from SOFA alone), for an 80% overall decrease from uncontrolled baseline; RRI CFD model predictions for these conditions were NO_X emissions reduction of 31% with FGR and 37% without FGR operation. Tested NO_X emissions with RRI+SOFA in 2002 were with a reagent normalized stoichiometric ratio (NSR) of 3 (lbs NH_3 per lb NO_X)[25].

Parametric testing at Sioux Unit 1 in May 2005 reduced NO_X emissions between 15-38% with RRI, down to 0.15 to 0.20 lb/mmBtu. Reagent NSR between 1.0 and 4.0 and low ammonia slip levels less than 2 ppm from an established baseline condition of 0.20 to 0.285 lb/mmBtu level achieved NO_X emissions as low as 0.12 lb/mmBtu with deep cyclone air-staging and SOFA operation firing an 80:20 PRB/Illinois coal blend at 480 MWg unit output[27].

The intent of the RRI process for NO_X reduction is that it must be used in conjunction with air-starved (substoichiometric staged-air) cyclone combustion resulting from the installation and operation of an OFA system, with or without SNCR. The cyclones' air/fuel stoichiometry must be carefully controlled to maintain fuel-rich conditions for the RRI process to be effective. The combustion gases in the vicinity of the RRI urea injection ports must be essentially devoid of free oxygen, in order to avoid oxidizing the nitrogen contained in the injected reagent, which will increase NO_X emissions. For lignite-fired cyclone boilers, the basic form of separated overfire air (without relocated lignite drying system vent ports) is incompatible with RRI. Reagent injection will be near the elevation of the existing lignite drying system vent ports in the lower front and rear walls of a lignite-fired cyclone boiler located immediately above the top rows of cyclones. The oxygen introduced with the lignite drying system's vented moisture-laden airstreams will cause the urea to be oxidized, creating NO_X emissions.

The advanced form of SOFA relocates these lignite drying system vent ports from the lower to the middle furnace, enhancing the desired in-furnace nitrogen oxides reduction process. Therefore, in order for RRI to be even moderately effective in reducing NO_X emissions from a lignite-fired cyclone boiler, this technology must be combined with an advanced form of separated overfire air, whether installed with or without SNCR.

As mentioned in the feasibility discussion of applying separated overfire air to lignite-fired cyclone boilers, the degree to which each and every individual cyclone furnace can be successfully operated with less than theoretical (substoichiometric) combustion air directly impacts potential NO_X formation and further in-furnace emission reduction. Because the heat content of lignite from the Center mine is not consistent from hour to hour, there can be substantial deviations in air/fuel ratios for individual cyclones from the overall average.

In the case of MRY Station boilers, Minnkota has simultaneously sampled the unprepared lignite feed to several cyclones' lignite drying systems in order to determine the variability in the combustible and ash components of North Dakota lignite. This investigation found that fuel quality variations can result in individual samples' heating values to have a maximum differential of over 12% of the lignite samples' average.

TABLE A1-1 – Lignite Heating Values and Variations for Milton R. Young Station (Unit 2)

M.R. Young Station Individual Cyclone Lignite Samples		Differences Between Individual Cyclone Lignite Samples	
Higher Heating Values, Btu/lb	Percentage of Average HHV	HHV Differential, Btu/lb	Percentage of Average HHV
Minimum HHV: 5,852	88.9%	Minimum : 4	0.06%
Maximum HHV: 7,101	1.08%	Maximum : 797	12.1%
Average HHV: 6,584	100%	Average: 165	2.51%

When operating with air-staged conditions associated with separated overfire air, any individual cyclone with lignite heat input lower than average can allow significant amounts of oxygen to oxidize the urea reagent at high temperatures, thus increasing NOx emissions in that zone at that time. Cyclones with lignite heat inputs higher than average would produce lower stoichiometric air/fuel ratios and less NOx emissions. Less complete combustion in the deeply staged cyclones may release insufficient amounts of heat, thus raising the risk of solidifying the fuel ash so that it accumulates within the cyclone barrel. This could result in firing auxiliary fuel oil or taking the boiler out-of-service to remove the pluggage. Neither of these conditions is desirable because they result in increased emissions, lower performance, and higher operating costs.

The MRY Station Unit 1 boiler's cyclone air/fuel ratios vary in real-time based on significant changes in combustible content on an individual cyclone by cyclone basis. Adjustment of individual cyclone combustion air inputs to compensate for the variability in individual cyclone lignite heat input rates for Unit 1's boiler would be necessary to maintain consistent substoichiometric operation of every cyclone during air-staged combustion. This places great emphasis on achieving tight control over the air/fuel ratios on each cyclone during air-staged combustion operation in order for ASOFA to be successful in producing significant additional NOx emissions reduction on lignite-fired cyclone boilers.

There is no equipment available for coal-fired boilers that can measure the fuel heat input at the prepared feed injection point on such a variable fuel to allow the determination of reasonably accurate air/fuel ratios on individual cyclones in real time. Without being able to measure the cyclone air and heat inputs to allow for control of air/fuel proportions and emissions, the stoichiometric ratios of individual cyclones can not be established accurately to produce combustion products essentially devoid of free oxygen. This requirement is especially necessary when employing RRI to avoid increasing, rather than reducing, NO_X emissions on the Milton R. Young Station Unit 1 boiler.

Because of the significant insurmountable problems discussed above which would increase NOx emission rates, RRI is considered technically infeasible for application on the Unit 1 cyclone boiler at the Milton R. Young Station.

A.1.4.1.3 SOFA with RRI and SNCR

When RRI is combined with separated overfire air and SNCR, it has demonstrated very high NO_X emissions reduction at Conectiv's B.L. England Unit 1 boiler during short-term testing firing eastern bituminous coal, on the order of 80% from an uncontrolled baseline around 1.2 lb/mmBtu[24]. In May 2005, testing RRI+SNCR+SOFA at Ameren's Sioux Unit 1 boiler firing a high PRB-blend coal demonstrated NO_X emissions as low as 0.12 lb/mmBtu. This was from an established baseline condition of 0.20 lb/mmBtu level achieved with deep cyclone air-staging and SOFA operation. These testing results when firing an 80%:20% PRB/Illinois coal blend at 480 MWg unit output with a reagent NSR of 4 and ammonia slip limited to less than 5 ppmvd, showed an overall 90% reduction with no apparent adverse short-term impacts of deeper air-staged combustion together with overfire air, RRI and SNCR applications[27].

Because of the significant insurmountable problems regarding RRI as mentioned above, RRI with SNCR and ASOFA is considered technically infeasible for application on the Unit 1 cyclone boiler at the Milton R. Young Station due to the variable heat content of the lignite fuel which allows the creation of oxygen-rich conditions in the boiler.

A.1.4.2 SNCR and Reburn

Various forms of SNCR could potentially be installed downstream of separated overfire air and various types of fuel reburn, to reduce NO_X emissions prior to a boiler's flue gas exit. Several of these examples were already described[7,8,9,10,11,1213,14]. Conventional gas (CGR) or coal reburn systems, by and large, have not been combined with forms of SNCR, although at least one vendor (GE Energy) has promoted a combination of conventional gas reburn with SNCR and overfire air systems as "advanced" gas reburn. Only one example of permanent installation of SNCR with conventional gas reburn (and overfire air) on a tangentially-fired boiler was found in available technical literature[10] and vendor experience lists[14]. The vendor (GE Energy) that provided the advanced gas reburn system at 120 MW NRG Somerset Station claimed NO_X emissions were reduced by 44% from a baseline of 0.45 down to 0.25 lb/mmBtu with overfire air alone; an additional reduction of 20% resulting from conventional gas reburn with overfire air, down to 0.20 lb/mmBtu; and further decrease of 45% down to 0.11 lb/mmBtu using gas reburn with SNCR with an unstated amount of ammonia slip, for an overall reduction of 75% from uncontrolled baseline[14].

No examples of actual demonstration or permanent installation of SNCR with conventional gas or coal reburn (and overfire air) on cyclone-fired boilers were found in a search of published and proprietary technical literature. The lack of experience with these combinations on a cyclone-fired boiler, especially for lignite-firing, makes the application for MRY Station's boilers infeasible.

FLGR™ has been installed with SNCR for NO_X emission reduction on several pulverized coal boilers, as discussed in the following subsection. A potential advantage of FLGR™ over conventional coal or gas reburn techniques is that the former is generally compatible with, but does not require, the installation and operation of SOFA.

Rich Reagent Injection would appear to be less capable of being combined with fuel reburn, especially conventional fuel reburn alternatives with high amounts of reburn fuel injection. This is due to the expected need to idle (e.g. not fire) up to two of the seven cyclones when operating the reburn system at full boiler load. In this case, the cooling air introduced into the idle cyclones, and any conveying air injected with pulverized reburn coal (or if natural gas is injected with recirculated flue gas), are expected to counteract the fuel-rich conditions of the air-and fuel-staged cyclones operating substoichiometrically. This will cause a portion of the amine reagent to be oxidized in the lower furnace, creating NO_X emissions instead of converting them to nitrogen and water. No example of actual demonstration or permanent installation of RRI with reburn (and overfire air) on cyclone-fired boilers was found in available technical literature or vendor experience lists. This combination is considered infeasible at the present time.

Hydrocarbon-enhanced SNCR (e.g. NO_XStar™) may potentially be combined with all types and forms of reburn previously discussed, since the location of the enhanced ammonia injection nozzles will be above (beyond) the elevation in the middle furnace where any reburn fuel should be reacted. No example of actual demonstration or permanent installation of HE-SNCR with reburn (and overfire air) on any coal-fired utility boilers, especially cyclone-fired units, was found in available technical literature or vendor experience lists. The advantage that HE-SNCR presents is the potential for greater-than-SNCR-levels of NOx reduction without significant amounts of gaseous hydrocarbon being required. Because of a lack of experience with HE SNCR applied to cyclone boilers, and none with significant amounts of fuel reburn, this combination has not been investigated further, and was not included in the control and cost-effectiveness analysis for NO_X controls.

A.1.4.2.1 Amine-Enhanced FLGR™ (AEFLGR™) or FLGR™ + SNCR

Fuel-lean gas reburn has been combined with SNCR as a hybrid form of amine reagent technologies on at least five pulverized coal-fired utility powerplants retrofit installations within the United States. This combination of technologies allows the boiler to be operated with FLGR™ alone, FLGR™ and SNCR simultaneously, or SNCR only (without SOFA) for the specific level of control desired or required.

No examples of actual demonstration or permanent installation of FLGR™ + SNCR (with or without overfire air) applied to a cyclone-fired boiler were found in available technical literature or vendor experience lists. The vendor (Fuel Tech) that provided the AEFLGR™ system at Mercer Station claimed NO_X emissions were reduced by 60% (from a baseline of 1.4 down to 0.56 lb/mmBtu) with 5 ppm ammonia slip without overfire air. A technical paper provides more details[18]. Another technical paper stated that FLGR™ alone only reduced NO_X emissions approximately 27% from the 1.4 lb/mmBtu baseline, down to 1.03 lb/mmBtu[35].

An AEFLGR™ system (with or without SOFA or ASOFA) may be potentially applied to a cyclone-fired boiler. The high capital and operating costs associated with applying fuel lean gas reburn is expected to make this economically unattractive, and the existing lignite pre-drying vent ports will likely limit the NO_X emission reduction potential of the FLGR™ component if installed without the advanced form of

SOFA. The lack of experience with this combination on any cyclone-fired boiler, especially for lignite-firing, makes this combination infeasible for MRY Station Unit 1 boiler.

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A.2.1 - U.S. Cyclone NOx Reduction Projects Summary

SELECTIVE NON-CATALYTIC REDUCTION/ RICH REAGENT INJECTION
Cyclone-Fired Boilers

Conectiv (formerly Atlantic Electric)
BL England Unit 1 Crushed Coal, single-wall cyclone-fired 1962 vintage
138 MW B&W boiler aqueous urea SNCR, 1995 startup eastern bituminous coal
Boiler has only 3 cyclone burners, arranged “1 over 2” style.
RJM implemented commercial Fuel Tech urea-based SNCR system installation in 1995 after short-term (3-month demonstration test) in 1993-1994. 31 % NOx reduction claimed, from 1.31 lb/mmBtu NOx baseline(1) for SNCR only; RJM claimed 35% reduction from 1.31 lb/mmBtu down to 0.85 lb/mmBtu (without overfire air) with urea-to-NOx NSR = 0.85 (RJM experience list).

Added eight temporary RRI ports (three nozzles on each lower sidewall, and two nozzles on the upper rear wall, and performed one month demonstration parametric testing of overfire air only (without SNCR or RRI), at 120 MW nominal boiler load and cyclone S.R. = 0.90 in 1999. REI claimed 55% NOx reduction from a 1.2 lb/mmBtu uncontrolled NOx baseline to 0.55 lb/mmBtu with OFA only, with stack CO emissions below 50 ppm. For Rich Reagent Injection; REI claimed 25-30% NOx reduction for RRI down to 0.38 lb/mmBtu from controlled baseline w/ OFA alone of 0.55 lb/mmBtu NOx and a RRI urea-to-NOx NSR = 2; also showed RRI+SNCR w/ OFA reduced NOx 55% to 0.25 lb/mmBtu (34% beyond RRI w/ OFA), for an overall 79% NOx reduction with a SNCR urea-to-NOx NSR = 1. Measured less than 1 ppm ammonia slip during RRI testing, < 5 ppm slip for RRI + SNCR. No significant increase in CO emissions during RRI testing(2).
Source: (1) ICAC White Paper; RJM experience list; (2) REI 2001 Technical Paper.

Conectiv (formerly Atlantic Electric)
BL England Unit 2 Crushed Coal, cyclone-fired, single-wall-fired 1964 vintage
160 MW B&W boiler SNCR, 1996 startup eastern bituminous coal
RJM implemented commercial Fuel Tech urea-based SNCR system in 1996, claimed 36% reduction from 1.36 lb/mmBtu down to 0.85 lb/mmBtu, urea-to-NOx NSR = 0.85 (without overfire air) (1).
An OFA system was added in 1998, resulting in NOx emissions of 0.33 lb/mmBtu, for an overall NOx reduction of 76%.
Source: RJM experience list. (Also listed in (1) ICAC White Paper).

AmerenUE (formerly Union Electric Co.)
Sioux Unit 1 Crushed Coal, opposed-wall cyclone-fired 1969 vintage
500 MW B&W boiler Rich Reagent Injection demonstration testing in 2001
Boiler has 10 cyclone burners, arranged “2 over 3” style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel.

Installed twenty temporary RRI ports (six nozzles on each lower sidewall, and four nozzles on each front and rear wall), and performed one month demonstration parametric testing of overfire air only and initial testing with RRI in August 2001, followed by additional testing in March 2002, and the second quarter of 2004. Added 8 RRI ports (1 in each sidewall, 4 in each front and rear wall) and 14 SNCR ports (5 on upper front wall, 9 on upper rear wall) to the furnace in early 2005, followed by three weeks of parametric testing and 3 days of continuous testing of RRI with SNCR and deeper-staged OFA.
Tested in August 2001 at lower furnace SR approx.=1.0, 0.55 lb/mmBtu w/ OFA only, only 15% NOx reduction w/ RRI, zero ammonia slip.

Tested in March 2002 at lower furnace SR approx.=0.95, from 0.38 lb/mmBtu baseline w/ OFA only, achieved 29% NOx reduction w/ RRI down to 0.27 lb/mmBtu, NSR=3, zero ammonia slip(3).
(assume blend of PRB and Illinois bituminous coal w/ tire-derived fuel and petroleum coke)(3).
Operation in the second quarter 2004 showed actual stack NOx averaged around of 0.30 lb/mmBtu with OFA only and lower furnace at a cyclone SR around 0.88 burning a 85% PRB, 15% Illinois #6 bituminous coal blend, presumably at 440 MW. This is a 75% NOx reduction from a 1.19 lb/mmBtu pre-control baseline. REI using CFD modeling predicted NOx down to 0.18 lb/mmBtu with RRI+OFA, and below 0.15 with RRI+SNCR under similar deep cyclone air-staging (1.19 to 0.28 lb/mmBtu is 76% reduction, 0.18 vs 0.28 is an additional 36% reduction w/ RRI, and 0.14 vs 0.28 is a 50% reduction w/ RRI+SNCR, for an overall reduction of 88%)(4).
Tested in May 2005 at 480 MWg with lower furnace SR approx. = 0.85-0.88, 76-83% reduction from 1.2 lb/mmBtu baseline down to as low as 0.20 lb/mmBtu w/ SOFA only firing 80% PRB, 20% Illinois #6 bituminous coal blend; additional 15-39% NOx reduction w/ RRI, to as low as 0.15 lb/mmBtu from 0.20-0.28 lb/mmBtu baseline w/ SOFA only at urea NSR varied between 1 and 4, with one ppm ammonia slip; achieved additional NOx reduction w/ RRI +SNCR down to 0.12 lb/mmBtu, NSR=4, ammonia slip10 ppm or less. RRI+SNCR w/ SOFA NOx reduction percentage varied from 15% to 50% below SOFA-only levels, with NSRs between 1 and 4.5. SNCR alone had 13% (NSR=1) to 32% (NSR=1) NOx reduction with ammonia slip around 1-2 ppm*.
Source: (3) REI 2002 and 2003 Technical Papers; (4) REI 2004 Technical paper;* REI 2005 Technical paper.

REBURN – GAS, CONVENTIONAL

Cyclone-Fired Boilers

Constellation Energy (formerly Baltimore Gas & Electric)
C.P. Crane Station, Units 1 & 2 (MD)   Crushed Coal, cyclone-fired, eastern bituminous coal
2 x 200 MW B&W boilers   (four cyclones each)   1961, 1963 vintage
GE-EER Conventional Gas Reburn, 1999 startup
Added gas supply piping, metering, hangers, supports; reburn injectors and cooling air ductwork, OFA ductwork, injection nozzles and wall ports, field (assume eastern bituminous coal)
GE-EER claimed Gas Reburn with OFA lowered NOx between 60% and 65% from baselines of 1.50 lb/mmBtu to between 0.60 and 0.52 lb/mmBtu, at full load with reburn operation. No claims of percent reburn fuel or percent OFA included in GE-EER's experience list.
Another technical paper showed this installation of CGR operated with 25 percent reburn fuel(5).
Source: Sept. 2005 GE-EER experience list; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

City Water, Light & Power
Lakeside Unit 7   Crushed Coal, front-wall cyclone-fired, midwestern bituminous coal
300,000 lb/hr steam B&W boiler (approx. 33 MWe equivalent, two cyclones)   1961 vintage
Springfield, IL   DOE Clean Coal demonstration project (included sorbent injection)
GE-EER conventional gas reburn w/ OFA   1992 startup (CGR not currently operating)
Vendor claimed to lower NOx by 66% from 0.95 lb/mmBtu baseline to 0.32 lb/mmBtu. A GE-EER 2004 technical paper showed 25% reburn fuel yielded minimum NOx emissions(6).
A DOE NETL technical paper showed this demonstration of CGR from 5/93-10/94 (assume with OFA) with 23 percent reburn fuel reduced NOx 60% from 0.97 to 0.39 lb/mmBtu (5).
Source: Sept. 2005 GE-EER experience list; (6) GE-EER 2004 Technical paper; (5) DOE-NETL 2004 Reburn Conference Technical paper.

Eastman Kodak Company
Kodak Park Boilers 41 & 42   Crushed Coal, front-wall cyclone-fired, 1964 & 1966 vintage

400,000 lb/hr steam B&W boilers (approx. 50 MWe equivalent, two 8-ft dia. cyclones)
Rochester, NY eastern bituminous coal
B&W conventional gas reburn w/ OFA December 1998, July 1998 startups (still operating)
Commercial installation of CGR, with (1) gas burner added to each sidewall + (2) large and (2) small OFA ports added to front wall above cyclones, utilizing higher reburn gas pressure (vs. Boiler #43) requires no flue gas recirculation; {Very small furnace w/ cyclone SR not <1.0}.
B&W claimed reburn with OFA lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. B&W graph shows 10-12% percent reburn fuel to achieve 0.6 lb/mmBtu and 23-24% reburn gas input to reach 0.33 lb/mmBtu NOx (73% reduction) (7).
Another technical paper showed NOx lowered by 52% from 1.25 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel(5).
Source: (7) B&W Technical Paper; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL
Cyclone-Fired Boilers, continued
Eastman Kodak Company
Kodak Park Boiler 43 Crushed Coal, front-wall cyclone-fired 1968 vintage
600,000 lb/hr steam B&W boiler (approx. 60 MWe equivalent, two cyclones)
Rochester, NY eastern bituminous coal
B&W conventional gas reburn 1995 startup (still operating)
Commercial installation of CGR, with flue gas recirculation (FGR) for injection mass momentum w/ (1) FGR fan; (1) gas burner added to each sidewall + (2) OFA ports added front wall above cyclones. {Very small furnace/low residence time w/ cyclone SR not <1.0}
B&W claimed reburn with OFA & FGR lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. B&W graph shows 18% percent reburn fuel to achieve 0.6 lb/mmBtu and 29% reburn gas input to reach 0.36 lb/mmBtu NOx (70% reduction) (7).
Another technical paper showed NOx lowered by 56% from 1.35 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel(5).
Source: (7) B&W Technical Paper; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Tennessee Valley Authority (TVA)
Allen Station Unit 1 (TN) Crushed Coal, cyclone-fired (seven cyclones) 1959 vintage
300 MW B&W boiler PRB &western bituminous coal blend fired
GE-EER Conventional Gas Reburn, 1998 startup
Commercial installation added gas supply piping, metering, hangers, supports; reburn injectors and cooling air piping, OFA ductwork, injection nozzles and wall ports, field I&C devices.
Reburn with OFA claimed to lower NOx 65% from baseline 1.20 lb/mmBtu to 0.42 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included. (TVA also installed duplicate OFA systems on Allen Units 2 & 3 boilers).
Another technical paper showed NOx lowered by 65% from 0.86 lb/mmBtu baseline (to 0.30 lb/mmBtu) with 7 percent reburn fuel(5).
Source: Sept. 2005 GE-EER experience list; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, CONVENTIONAL
Cyclone-Fired Boilers
Alliant Energy (formerly Wisconsin Power & Light)
Nelson Dewey Station Unit 2 Crushed Coal, cyclone-fired, PRB coal 1962 vintage

110 MW B&W boiler 3-cyclones across front wall, 4 reburn burners +
4 OFA ports across rear wall, aligned vertically in columns.
US DOE Clean Coal Demonstration project of B&W's Conventional Coal Reburn, 1991 startup (since discontinued) added coal supply piping, reburn burners with flue gas recirculation, OFA ductwork + dual zone ports; coal feeder, pulverizer & PA fan, tested with PRB and bituminous coals. (western subbituminous coal)
B&W claimed reburn operation lowered NOx by 57% from baseline of 0.83 mmBtu to 0.38 lb/mmBtu at full load(7). Approx. 30% percent of total fuel input supplied as reburn fuel. Increased unit output by 10 MW, increased flyash unburned carbon by 4% (13-22% vs 9-18%), decreased furnace exit gas temperature (FEGT). OFA ports listed in B&W experience list.
B&W shows full load NOx w/o reburn was 0.75 lb/mmBtu, and 0.29-0.32 lb/mmBtu w/ PRB fuel during reburn operation (57% decrease). At 75% load, 0.64 vs 0.29-0.32 lb/mmBtu. At 55% load, 0.62 vs 0.29-0.31 lb/mmBtu without and with reburn activated(8).
Another technical paper showed NOx lowered by 52-55% from 0.82 lb/mmBtu baseline (to 0.39-0.34 lb/mmBtu) with 25-30 percent reburn fuel(5).
Source: (7) 2004 B&W Technical Paper; (5) DOE-NETL 2004 Reburn Conference Technical paper;
(8) B&W case history (from website, dated 1997).

REBURN – COAL, MICRONIZED, CONVENTIONAL

Cyclone-Fired Boilers

Eastman Kodak Company
Kodak Park #15 Boiler Crushed Coal, front-wall cyclone-fired, 1956 vintage
400,000 lb/hr steam B&W boiler (approx. 50 MWe equivalent, two cyclones)
Rochester, NY eastern bituminous coal
GE-EER micronized coal reburn1996 initial startup (operating since 1997)
Demonstration project performed with Dept. of Energy's US Clean Coal Technology Program. Project added flue gas recirculation for injection mass momentum, FGR fan and two micronized coal pulverizers; (6) reburn coal injectors added to rear wall + (1) reburn coal injector on each of the sidewalls, with (4) OFA ports added across front wall above cyclones(9). GE-EER designed and fabricated the coal injectors and OFA ports. {Extremely small furnace and low residence time}.
GE-EER claimed reburn + OFA w/ FGR reduced NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. No claims of percent reburn fuel included.
Another technical paper showed this demonstration of micronized coal reburn from 4/97-10/98 lowered NOx by 57% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 17 percent reburn fuel(5).
Source: (9) DOE Topical Report Number 14 (May 1999); GE-EER experience list;(5) DOE-NETL 2004 Reburn Conference Technical paper.

REBURN – FUEL LEAN GAS REBURN

Cyclone-Fired Boilers

Midwest Generation (formerly Commonwealth Edison)
Joliet Station 9, Unit 6 Crushed Coal, opposed-wall cyclone-fired (nine cyclones)
340 MW B&W boiler 1959 vintage, 1997 startup (FLGR has since been decommissioned)
Energy Systems Associates demonstrated 25-30% NOx reduction using 5-10% of total heat input as reburn natural gas injected (without OFA)(5).
Another technical paper showed this demonstration in collaboration with Gas Research Institute of FLGR lowered NOx by 28-43% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 7 percent reburn fuel(10).
Source: (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference);
(10) NGB Technologies Technical Paper.

REBURN – FUEL LEAN GAS REBURN w/ SNCR continued

Cyclone-Fired Boilers

Owensboro Municipal Utilities (KY) Crushed Coal, front-wall cyclone-fired
Elmer Smith Unit 1 (three cyclones) 1965 vintage
150 MW B&W boiler

CFD model study only predicted NOx reductions from 1.59 to 0.39 lb/mmBtu with OFA only (75% reduction, 0.90 SR); 25-30% NOx reduction using 6% of total heat input as reburn natural gas injected above OFA; 40-45% NOx reduction from SNCR with <5 ppm ammonia slip$^{(11)}$.
Source: $^{(11)}$ REI Technical paper.

Separated OVERFIRE AIR

Cyclone-Fired Boilers

Tennessee Valley Authority (TVA) Crushed Coal, cyclone-fired, 1959 vintage
Allen Station Units 2 & 3 (TN) (seven cyclones)
300 MW B&W boilers PRB &western bituminous coal blend
GE-EER Overfire air (duplicate of Allen 1), 1999 startup
GE-EER claimed to lower NOx with OFA alone up to 29% from baseline 1.20 lb/mmBtu to 0.85 lb/mmBtu on Units #2 and 3 at full load.
Source: Sept. 2005 GE-EER experience list.

AmerenUE (formerly Union Electric Co.)
Sioux Unit 1 Crushed Coal, opposed-wall cyclone-fired 1969 vintage
500 MW B&W boiler PRB/Illinois Coal blend
Boiler has 10 cyclone burners, arranged “2 over 3” style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel.
A ten-port OFA system (five ports on each front and rear wall) began operation in mid-2001, which reduced NOx emissions approx. 40-50% reduction from 1.1-1.3 (assume average of 1.19) down to 0.7 lb/mmBtu with moderate cyclone air-staging (cyclone SR from 1.19 to 1.0). $^{(3)}$ Subsequent testing and full load operation at deeper cyclone air-staging (SRs ≤ 0.90) has dropped NO_X with SOFA alone to around 0.3 lb/mmBtu in 2004$^{(4)}$.
Source: $^{(3)}$ REI 2002 and 2003 Technical Papers; $^{(4)}$ REI 2004 Technical paper;* REI 2005 Technical paper

Coal burning cyclone-fired utility boilers in the United States that have been retrofitted with Separated Overfire Air CR technology are listed in Table A.2-1. A large majority of the cyclone-fired boilers listed burn western subbituminous coal (or PRB blended with midwestern bituminous coal).

TABLE A.2-1 – Cyclone-Fired Boiler Overfire Air Retrofit Installations(12)

Facility Name	Installation Date	Comments
Allen Station Units 1	Installed 1998*	OFA w/ CGR retrofit; has SCR
Allen Station Unit 2	Installed 1999*	(Similar to Unit 1, w/o CGR) have SCR
Allen Station Unit 3	Installed 1999*	(Similar to Unit 1, w/o CGR) have SCR
Asbury Unit 1	Installed 5/10/1999	Empire District, BART-eligible
Bailly Unit 7	Installed 2003(13)	SCR to be installed in 2006-7
Bailly Unit 8	Installed 5/31/2000	SCR retrofit 5/11/2004
Baldwin Unit 1	Installed 12/31/1999	SCR retrofit 4/28/2003
Baldwin Unit 2	Installed 5/8/2000	SCR retrofit 4/12/2002
Big Stone Unit 1	Installed 10/22/1997	part of conversion to PRB
BL England Unit 2	Installed 1998*	previous SNCR retrofit in 1996
CP Crane Unit 2	Installed 2/1/1999	OFA w/ CGR retrofit
Coffeen Unit 1	Installed 2/1/2001	SCR retrofit 4/21/2003
Coffeen Unit 2	Installed 2/9/2000	SCR retrofit 4/09/2002
Edgewater Unit 3	Installed 11/2001(13)	
Edgewater Unit 4	Installed 6/19/2001	
Joliet 9 Unit 6	Installed 2000(13)	
Kincaid Unit 1	Installed 4/28/2000	SCR retrofit 12/17/2002
Kincaid Unit 2	Installed 5/24/2000	SCR retrofit 6/07/2002
Allen S. King Unit 1	Installed 11/30/1999	
LaCygne Unit 1	Installed 2/28/2000	
Lake Road Unit 6	Installed 6/01/2002	
Michigan City Unit 12	Installed 4/1998(13)	SCR retrofit 5/01/2003
Nelson Dewey Unit 1	Installed 2002(13)	
Nelson Dewey Unit 2	Installed 2002(13)	
Paradise Unit 1	Installed 11/14/1998	SCR retrofit 5/01/2001
Paradise Unit 2	Installed 12/8/1999	SCR retrofit 5/01/2000
Paradise Unit 3	Installed 5/4/2000	SCR retrofit 3/10/2004
Powerton Unit 5-1	Installed 6/1/2003	
Powerton Unit 5-2	Installed 6/1/2003	
Powerton Unit 6-1	Installed 6/1/2002	
Powerton Unit 6-2	Installed 5/4/1999	
Schahfer Unit 14	Installed early 2000(13)	SCR retrofit 5/11/2004
Sibley Unit 2	Installed 5/24/2002	
Sibley Unit 3	Installed 5/4/1999	
Sioux Unit 1	Installed 4/30/2001	SNCR demo May 2005
Sioux Unit 2	Installed 4/30/1997	
State Line Unit 4	Installed 11/2001(13)	Similar to Joliet 9 Unit 6
Tanners Creek Unit 4	Installed 5/12/2002	
Thomas Hill Unit 1	Installed June 2004(13)	
Thomas Hill Unit 2	Installed November 2000(13)	

Note: This table does not include every installed U.S. coal-fired cyclone boiler OFA retrofit project.
Source: (12) US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005 (except as noted below)
* Vendor experience list (GE Energy for Allen Station Units 1-3; RJM for BL England Unit 2)
(13) Burns & McDonnell internal database.

Coal burning cyclone-fired utility boilers in the United States that have been retrofitted with SCR technology are listed in Table A.2-2. This list includes at least eighteen cyclone-fired boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). The highest emission reductions listed in Table A.2-2 for SCR systems are for clean reactor catalyst and ideal operating conditions.

TABLE A.2-2 – Cyclone-Fired Boiler High-Dust SCR Installations

Facility[1]	**Unit Size[2],MW**	**Tested Control Efficiency[3]**	**Tested Outlet NO_X Emission Rate (lb/mmBtu)[3]**	**2003 Ozone Season Average NO_X Emission Rate[4] (lb/mmBtu)**
Allen 1, 2, & 3[5,6]	330 ea.	91.1/NAD[7]/88.7	0.070/NAD[7]/0.088	0.088/0.077/0.086
Baldwin 1[5,6]	600[3]	82.9	0.072	0.238
Baldwin 2[5,6]	605[3]	83.5	0.067	0.286
Bailly 8[5,6]	422	NAD[7]	NAD[7]	0.84
Coffeen 1[5,6]	389	NAD[7]	NAD[7]	0.114
Coffeen 2[5,6]	617	NAD[7]	NAD[7]	0.120
Dallman 31 & 32	207	NAD[6]	NAD[6]	0.149/0.146
Kincaid 1 & 2[5,6]	660[3] ea.	89/89	0.079/0.079	0.181/1.198
Marion 4	173	94.3	0.067	0.252
Merrimack 1[5,8]	114	50.5[9]	0.148	0.158
Merrimack 2	346	51.3[9]	0.155	0.171
Michigan City 12[5,10]	540	84.2	0.109	0.418
New Madrid 1 & 2[8,10]	600 ea.	87.4/88.1	0.149/0.147	0.319/1.172
Paradise 1 & 2[5,6]	704 ea.	87.7/87.7	0.102/0.101	0.124/0.113
Paradise 3[5,6]	1150	89.1	0.088	0.658
Schahfer 14[5,10]	540	83.5	0.106	0.478

[1] – original design fuel for all listed cyclone boilers was bituminous coal
[2] – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.
[3] – Burns & McDonnell internal database.
[4] – as reported to US EPA, available from their website at http://cfpub.epa.gov/gdm/index.cfm
[5] – includes application of separated overfire air for combustion NO_X control
[6] – current fuel believed to be a blend of subbituminous and bituminous coals
[7] – NAD = no published data from SCR emission testing found on these units.
[8] – original air preheaters were tubular-type; changed to rotary-type during SCR retrofit
[9] – Design NO_X removal efficiency is higher, approx. 90%.
[10] – current fuel believed to be subbituminous coal

For Merrimack Unit 1's SCR, inlet (i.e. uncontrolled) NO_X was 1.34 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. The catalyst was designed for 88.9% NO_X removal efficiency and 5 ppm ammonia slip. SCR commercial service date July 20, 1999. [(14) Babcock Borsig Power 2000 technical paper on SCRs].

For Merrimack Unit 2's SCR, inlet (i.e. uncontrolled) NO_X was 2.66 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. Initial testing demonstrated 70% removal(15), which exceeded the 65% requirement to achieve a 0.92 lb/mmBtu permit limit. The catalyst was designed for 85-95% NO_X removal efficiency and 5 ppm ammonia slip(16).

(15)NETL-DOE Clean Coal Technology 1997 technical paper on SCRs; (16) 1997 ICAC White Paper on SCRs.

Northern Indiana Public Service Company (NIPSCO)
Bailly Unit 8 Crushed Coal, cyclone-fired, opposed-wall-fired 1968 vintage
360 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2004 startup
Boiler fires a blend of 85% western subbituminous (PRB) coal, with Illinois bituminous coal.
Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 2000(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

Northern Indiana Public Service Company (NIPSCO)
Michigan City Unit 12 Crushed Coal, cyclone-fired, opposed-wall-fired 1974 vintage
520 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2003 startup
Boiler fires western subbituminous (PRB) coal.
Commercial Fuel Tech urea-based system installed in 2003 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 1998(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

Northern Indiana Public Service Company (NIPSCO)
Schahfer Unit 14 Crushed Coal, cyclone-fired, opposed-wall-fired 1975 vintage
520 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2004 startup
Boiler fires western subbituminous (PRB) coal.
Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 2000(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

TABLE A-3 – Low-Dust Pulverized Coal-Fired Boiler SCR Installations

Operator/Facility[1,2]	SCR Startup Date[3]	Average NO_X Emission Rates[4] (lb/mmBtu)	Unit Size[5], MW
AEP/Cardinal Unit 3[6]	5/01/03	0.74 / 0.34 / 0.135	650
Carolina P&L/Mayo Unit 1[7]		- / (0.36) / N/A	368 x 2
Carolina P&L/Roxboro Unit 4[7,8]	5/07/01	0.57 / 0.26 / 0.081	372 x 2
Cinergy/East Bend Unit 1	4/01/02	- / (0.28) / 0.067	648
Constellation/Brandon Shores Unit 1[8]	(2001)	0.47 /0.33 / 0.126	685
Constellation/Brandon Shores Unit 2[8]	(2000)	0.45 / 0.31 / 0.094	685
Dayton P&L/Killen Station Unit 2	11/01/03	- / (0.48) / 0.06[9]	666
Dynegy Midwest Gen/Havana Unit 6[10]	(2000)	0.46 /0.20 / 0.102[9]	488
PSEG Power LLC / Mercer Unit 1[11]	(2005)	- / (0.63) / N/A	320
PSEG Power LLC / Mercer Unit 2[11]	(2004)	- / (0.76) / N/A	320

[1] – Burns & McDonnell internal database.

[2] – Current fuel is eastern or midwestern bituminous coal, except Havana

[3] – US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, except where noted. Dates in () are believed to be accurate but have not been confirmed.

[4] – The three values are "Pre-control average", "2004 annual average", and "2003 ozone season average" NO_X emission rates, as reported to US EPA. Pre-control and year 2004 annual average data as shown in US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b. Values shown in parentheses are year 2003 annual average where 2004 data is not available. Year 2003 and 2003 ozone season data is available from the EPA's website at http://cfpub.epa.gov/gdm/index.cfm, includes application of separated overfire air for combustion NO_X control where applicable.

[5] – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.

[6] – This boiler has low-NOx burners for combustion controls.

[7] – Carolina Power & Light plants listed here have two boilers per unit, total nameplate for Mayo is 736 MW, Roxboro is 745 MW; emission numbers are the average of both boilers.

[8] – This boiler has low-NOx burners and overfire air for combustion controls.

[9] – This is preliminary data reported to the US EPA for 2004 ozone season average emission rate.

[10] – This boiler's current fuel is believed to be subbituminous coal.

[11] – Mercer boilers listed have low-dust SCR with flue gas reheat. Unit size is approximate, not nameplate.

N/A = complete 2004 ozone season data is not available, and 2003 ozone season data is not representative of the post-SCR installation emission rate.

SELECTIVE NON-CATALYTIC REDUCTION

Pulverized coal-fired boilers

American Electric Power (AEP)   Pulverized Coal, cell-burner, opposed wall-fired B&W boiler
Cardinal Unit 1   1967 vintage; Low NO_x burners installed in October 1998
600 MW (nominal)   Brilliant, Ohio
Fuel Tech urea-based SNCR installed in October 1998.
Fuel Tech, DOE, EPRI-member utilities SNCR demonstration project. Tested in March-April 1999, claimed 65% reduction with LNBs + SNCR w/ 5 ppm NH_3 slip, (from pre-LNB retrofit baseline of 1.20 lb/mmBtu*) down to 0.52 lb/mmBtu at 620 MW (100% MCR). SNCR reduced NO_X 31% below LNBs alone (0.75 lb/mmBtu baseline), at 620 MWg (100% MCR), 34% reduction at 75% MCR (450 MWg), and 42% reduction at minimum load (340 MWg, 55% MCR) ≤ 5% ammonia slip(17), burning eastern bituminous coal. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005; (1)ICAC White Paper, (17) 2000 Fuel Tech technical paper, *Riley Power (Babcock Power Inc.) experience list 8/16/04.

Carolina Power & Light (Progress Energy)
Asheville Unit 1   Pulverized Coal, front wall fired
200 MWe DB Riley boiler   1964 vintage, eastern bituminous coal, June 2000 SNCR startup
Fuel Tech commercial SNCR installation claimed 25% NOx reduction from low-NO_X burner w/o OFA baseline of 0.58 lb/mmBtu (down to 0.44 lb/mmBtu on SNCR alone). Urea-to-NOx NSR not stated. (Also see FLGR + SNCR installation summaries for pulverized coal boilers).
Source: Fuel Tech experience list dated 1/28/2005.

Carolina Power & Light (Progress Energy)   Pulverized Coal, Tangentially-fired
Cape Fear Unit 5   1956 vintage; eastern bituminous coal
154 MW CE boiler   SNCR startup in 2002
Mobotec USA “Rotamix” ammonia-based SNCR system injects aqueous ammonia liquid into a high velocity boosted separated overfire air (ROFA) system at the boiler.
CP&L technical paper claimed to lower NO_X from 0.28 lb/mmBtu baseline by 43% to 0.16 lb/mmBtu in 2002 with 5 ppm NH_3 slip following the installation of ROFA in 2000.
Overall reduction 73% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.16 lb/mmBtu(18).
Mobotec claimed further NO_X reduction was possible by injecting urea in place of ammonia, achieving 0.13 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 54% decrease from 0.28 lb/mmBtu with ROFA alone, or 78% overall decrease(19). Ammonia-to-NOx NSR not stated.
Source: (18) CP&L 2002 Technical paper; (19) Mobotec 2003 technical paper.

Carolina Power & Light (Progress Energy)   Pulverized Coal, Tangentially-fired
Cape Fear Unit 6   twin-furnace (eight corner), 1958 vintage; eastern bituminous coal
175 MW CE boiler   SNCR startup in 2001
Mobotec USA “Rotamix” ammonia-based SNCR system, injects aqueous ammonia liquid into a high velocity boosted separated overfire air (“ROFA”) system at the boiler.
CP&L technical paper claimed to lower NO_X from 0.23 lb/mmBtu baseline by 22% to 0.18 lb/mmBtu with 5 ppm NH_3 slip following the installation of ROFA+SNCR in 2001(18). Presentation slide graph shows no reduction for Rotamix beyond ROFA alone at full load NO_X emission rate of 0.23 lb/mmBtu. Ammonia-to-NOx NSR not stated.
Overall reduction 67% from full-load pre-ROFA baseline 0.54 lb/mmBtu to 0.18 lb/mmBtu.
Mobotec claimed further NO_X reduction was possible by injecting urea in place of ammonia, achieving 0.10 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 56% decrease from 0.23 lb/mmBtu with ROFA alone, or 81% overall decrease(19). Urea-to-NOx NSR not stated.
Source: (18) CP&L 2002 Technical paper; (19) Mobotec 2003 technical paper.

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Cinergy (formerly Cincinnati G&E) Pulverized Coal, Tangentially-fired,
Miami Fort Unit 6 (Ohio) 1960 vintage; startup prior to 2000
163 MW CE boiler
Fuel Tech urea-based SNCR system, claimed to lower NOx by 35% from 0.55 lb/mmBtu baseline(1).(assume eastern bituminous coal). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, (1) ICAC White Paper.

Conectiv (formerly Delmarva Power & Light)
Edgemoor Unit 3 Pulverized Coal, Tangentially-fired, 1954 vintage
84 MW CE boiler mid-March 1996 startup; (assume eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR system. HRC claimed 35% NOx reduction with less than 10 ppm ammonia slip. Urea-to-NOx NSR not stated.
Another source shows a 30% reduction from 0.54 lb/mmBtu baseline(1).
Source: Hamon experience list (not listed by Fuel Tech); (1) ICAC White Paper.

Conectiv (formerly Delmarva Power & Light) Pulverized Coal
Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage
B&W, DB Riley boilers Spring 2000 startup (eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR system (not listed by Fuel Tech) on both units. HRC claimed 35% NO_X reduction with less than 5 ppm ammonia slip. Urea-to-NOx NSR not stated.
An REI 1999 technical paper shows a pre-SNCR baseline of 0.37 and 0.44 lb/mmBtu, respectively. (20)
Another source listed these units as having a pre-control NO_X baseline of 0.97 and 0.57 lb/mmBtu, and 2004 post-SNCR startup average of 0.32 and 0.33 lb/mmBtu, respectively. (12)
Source: Hamon experience list (not listed by Fuel Tech); (20) REI 1999 technical paper;
(12) US EPA Docket OAR-2002-0076-0446 Excel Spreadsheet 6/15/2005.

Dominion Generation (Virginia E&P Co.) Pulverized Coal, Tangentially-fired
Clover Station, Units 1 & 2 (VA) ABB/CE boilers, 1995, 1996 vintage
2 x 465 MW (eastern bituminous coal)
Urea-based SNCR (Fuel Tech system) 1995, 1996 startup (initial commercial)
Fuel Tech claimed NOx reduced by 25% from 0.32 lb/mmBtu baseline (to 0.24 lb/mmBtu).
Source: Fuel Tech experience list dated 1/28/2005. Urea-to-NOx NSR not stated.

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Vermillion Station, Unit 1 1955 vintage
82 MW CE boiler, bituminous Illinois coal
Mobotec USA "Rotamix" urea-based SNCR system with rotating opposed fired air (ROFA).
Mobotec 2004 technical paper claimed to lower NO_X by 55% from 0.22 lb/mmBtu baseline to 0.10 lb/mmBtu in April 2004 with urea-based Rotamix SNCR and < 5 ppm CO. NH_3 slip not mentioned. Overall reduction 83% from full-load pre-ROFA baseline 0.58 lb/mmBtu to 0.10 lb/mmBtu (21). Urea-to-NOx NSR not stated.
Source: (21) Mobotec 2004 technical paper.

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Eastern Utilities Associates,
Montaup Electric Company
Somerset Unit 8 (Massachusetts)
112 MW CE boiler

Pulverized Coal, Tangentially-fired
1959 vintage
Summer 1995 startup
(eastern bituminous coal)

Hamon Research-Cottrell supplied a urea-based SNCR (Fuel Tech system), claimed to lower NOx below 0.38 lb/mmBtu (Mass. RACT). Urea-to-NOx NSR not stated.
Another source listed 28-60% NOx reduction from a 0.49-0.89 lb/mmBtu baseline(1).
Source: Hamon experience list, Fuel Tech experience list dated 1/28/2005, (1)ICAC White Paper.

First Energy
Eastlake Unit 3 (Ohio)
130 MW CE boiler (w/ division wall)
Urea-based SNCR (Fuel Tech system)

Pulverized Coal, Tangentially-fired,
1954 vintage
(eastern bituminous coal)
SNCR startup prior to 2000

Fuel Tech claimed to lower NOx from 20-32.5% from 0.34-0.40 lb/mmBtu baseline(1). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, (1) ICAC White Paper.

First Energy
Sammis Unit 2 (Ohio)
180 MW Foster Wheeler boiler SNCR startup Fall 1999
Urea-based SNCR (Fuel Tech system)

Pulverized Coal, wall-fired,
1960 vintage
(eastern bituminous coal)

Fuel Tech claimed to lower NOx from 25-30% from 0.45 lb/mmBtu baseline (1). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, (1) ICAC White Paper.

First Energy
Sammis Units 6 & 7 (Ohio)
680 MW B&W Universal Pressure boilers
Urea-based SNCR (Fuel Tech system)

Pulverized Coal, wall-fired,
1969 & 1971 vintage
(eastern bituminous coal)
SNCR startup after 1999

Fuel Tech claimed to lower NOx from 25% from 0.38 lb/mmBtu baseline. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005.

New England Power Company (NEPCO)
Salem Harbor Station
Units 1, 2 & 3
84 MWe x 2, & 156 MWe B&W boilers
Urea-based SNCR (Fuel Tech system)

Pulverized Coal, front wall-fired,
1952, 1952, 1958 vintage (eastern bit. coal)
SNCR startup prior to 2000

Fuel Tech claimed 66% (50-75%) NOx reduction from baseline of 1.0 ± 0.1 (range 0.85-1.12) lb/mmBtu, (which would lower NOx to around 0.34±0.07 lb/mmBtu). Urea-to-NOx NSR not stated. {These NOx reduction percentages may include impact of low-NOx burners}.
Source: Fuel Tech experience list dated 1/28/2005, (1)ICAC White Paper.
(Also see LNB installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)
Schiller Units 4, 5, & 6
50 MWe x 3Foster Wheeler boilers
Urea-based SNCR (Fuel Tech system)
August 1999 startup

Pulverized Coal/#6 Fuel oil, front-wall-fired
1952, 1955, 1957 vintage
Colombian bituminous coal

RJM implemented Fuel Tech urea-based commercial SNCR installation on all three boilers.

RJM claimed 50% reduction from 0.50 lb/mmBtu pre-SNCR baseline to 0.25 lb/mmBtu for SNCR coal-firing operation; NO_X baseline 0.82 lb/mmBtu prior to RJM's LNB modifications installed in 1994, 1992, & 1994 (39% reduction); Urea-to-NOx NSR not stated.
Fuel Tech claimed 30% NO_X reduction for SNCR from baseline of 153 ppm firing #6 fuel oil on Units 4 & 6 only.
Source: RJM experience list, Fuel Tech experience list dated 1/28/2005.

SELECTIVE NON-CATALYTIC REDUCTION continued
Pulverized coal-fired boilers
Owensboro Municipal Utilities (KY) Pulverized Coal, Tangentially-fired,
Elmer Smith Unit 2 1974 vintage
300 MW CE boiler eastern bituminous coal
Hamon Research-Cottrell supplied an ammonia-based SNCR system but stated no claims for NOx reduction; (this project is not listed in ICAC White Paper(1)). Ammonia-to-NOx NSR not stated.
Source: Hamon experience list.

PECO Energy (formerly Philadelphia Electric Company)
Cromby Unit 1 Pulverized Coal, front wall-fired divided furnace
160 MWe B&W boiler 1954 vintage eastern bituminous coal
RJM installed Fuel Tech urea-based SNCR with low NO_X burner modifications & OFA in 1999, June 1999 startup.
RJM claimed 29% SNCR NO_X reduction from baseline of 0.35 lb/mmBtu, down to 0.25 lb/mmBtu with urea NSR = 0.8; RJM provided burner modifications of B&W XCL low-NOx burners installed in 1994 + OFA; this reduced NO_X from 0.50 to 0.35 lb/mmBtu (30% reduction) without SNCR. Urea-to-NOx NSR not stated.
Source: RJM experience list; (1)ICAC White Paper.

Exelon (formerly PECO Energy/ Pennsylvania Electric Company)
Eddystone Units 1 & 2 Pulverized Coal Tangentially-fired, 1954 vintage
318, 333 MW each CE boilers 1999 SNCR startup, eastern bituminous coal
Fuel Tech claimed 30% NOx reduction from baseline of 0.26 lb/mmBtu.
Source: Fuel Tech experience list dated 1/28/2005.

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage
660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup
Fuel Tech urea-based commercial SNCR installation claimed 25% (initial) NOx reduction for SNCR alone from baseline of 0.65 lb/mmBtu (down to 0.49 lb/mmBtu). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, also listed in (1)ICAC White Paper. (Also see FLGR+SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Mercer Station (2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired
Unit 1 and Unit 2 front wall PC, wet-bottom (slagging ash) eastern bituminous coal
Furnace #11 & #12 1960 vintage April 1999 startup
Furnace #21 & 22 1961 vintage May 1999 startup
Fuel Tech urea-based commercial SNCR installation claimed 30-35% NOx reduction from baseline of 2.0 lb/mmBtu on SNCR alone, down to 1.4 lb/mmBtu. Urea-to-NOx NSR not stated.

Source: Fuel Tech experience list dated 1/28/2005; also listed in (1)ICAC White Paper. (Also see FLGR+SNCR installation summaries for pulverized coal boilers)

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Reliant Energy (formerly GPU Genco) Pulverized Coal
(formerly Sithe, formerly Penelec) Tangentially-fired
Seward # 15 (PA) mid-1990's SNCR startup
Units 4 & 5 eastern bituminous coal
62 & 156 MW CE boilers 1950 & 1957 vintage
Urea-based SNCR (Fuel Tech system), later installed an in-duct SCR to reduce NH_3 slip.
Fuel Tech claimed to lower NOx 35% for SNCR only (55% for combined SNCR/SCR from 0.78 lb/mmBtu baseline). Boilers have since been demolished and replaced with CFBs. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, (1)ICAC White Paper.

Rochester Gas & Electric Pulverized Coal, Tangentially-fired
Russell Station, Units 1-4 (NY) 1948, 1950, 1953, 1957 vintage
1 x 50 MW, 2 x 65 MW, 1 x 85 MW CE boilers eastern bituminous coal
Urea-based SNCR (Fuel Tech system) SNCR startup prior to 2000
Vendor claimed to lower NOx by 15-27.5% from 0.28 – 0.42 lb/mmBtu baselines. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005.

HYDROCARBON-ENHANCED AMMONIA SNCR (NOxStar™)

Pulverized coal-fired boilers

Tennessee Valley Authority (TVA) Pulverized Coal twin-furnace, tangentially-fired,
Kingston Power Station (TN) 1955 vintage eastern bituminous coal
Unit 9, 200 MWe CE boiler NOxStar™ startup January 2002
Demonstration of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR installation.
Mitsui Babcock claimed 68% NOx reduction from baseline of 0.55 lb/mmBtu down to 0.17 lb/mmBtu with boosted OFA and NOxStar™ with < 5 ppm ammonia slip; NOxStar™ alone reduced NOx by 53%(22); boosted OFA only reduced NOx from 0.55 to 0.45 lb/mmBtu (18% reduction). Ammonia-to-NOx NSR not stated.
TVA's website reported that "an earlier version of NOxStar was installed at Kingston Fossil Plant Unit 9 in 2002 with mixed results. NOx reductions were achieved, but the boiler was damaged" (http://www.tva.gov/environment/repotrs/envreports/aer/2003/env_compliance.htm)
Source: (22) Mitsui Babcock Technical paper, October 2003.

Tennessee Valley Authority (TVA) Pulverized Coal, wall-fired
Colbert Station (AL) 1955 vintage
Unit 4, 192 MWe twin-furnace B&W boiler w/ FGR eastern bituminous coal
First commercial installation of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR technology.
Mitsui Babcock showed 80% NOx reduction from baseline of 0.50 to 0.10 lb/mmBtu; using < 0.1% of total boiler heat input for propane input and 1% of total steam flow generated in the boiler for lance cooling(23); 2004 SNCR system startup. Ammonia-to-NOx NSR not stated.
Source: (23) Mitsui Babcock 2004 Technical paper.

REBURN – GAS, CONVENTIONAL

Pulverized coal-fired boilers

Allegheny Power (formerly West Pennsylvania Power)
Hatfield's Ferry Station
Units 2 & 3, 600 MW (nominal) each (B&W boilers)

Pulverized Coal, opposed wall-fired
cell-burner, 1969 & 1972 vintage
eastern bituminous coal

GE-EER Gas Reburn; 1999 startup (Unit 2) & 2003 (Unit 3)
GE-EER Low NOx burners, boosted OFA, gas reburn system.
GE-EER claimed to lower NOx up to 67% from baseline of 0.60 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation on Unit 2, 68% from 0.62 lb/mmBtu to 0.20 lb/mmBtu on Unit 3. No claims of percent reburn fuel included.
GE-EER technical paper shows approx. 35% NOx reduction at 600 MW load with LNB + OFA w/o reburn fuel, and an additional 50% reduction to 0.20 lb/mmBtu with reburn fuel(24).
B&W added 20 OFA ports in 1994 per B&W's experience list. No NOx reduction claims. Source: Sept. 2005 GE-EER experience list; (24) GE-EER 2004 Technical paper. Unit 2 and Unit 3 listed in (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL continued

Pulverized coal-fired boilers)

Conectiv (formerly Delmarva Power & Light)
Edgemoor Unit 4
160 MW CE boiler

Pulverized Coal, Tangentially-fired
1966 vintage, eastern bituminous coal
1999 startup

GE-EER Gas Reburn project added gas supply piping, metering, hangers, supports, reburn injectors and cooling air piping; OFA ductwork, injection nozzles and wall ports, field instrumentation. No FGR or OFA booster fans.
Vendor claimed to lower NOx up to 48% from baseline of 0.32 lb/mmBtu to 0.16 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included.
GE-EER technical paper shows approx. 32% NOx reduction for gas reburn with 4-mill operation at 160 MW load from 0.31 lb/mmBtu LNB + OFA baseline w/o reburn fuel (down to 0.21 lb/mmBtu), and 48% NOx reduction for gas reburn with 3-mill operation, to 0.16 lb/mmBtu (24).
Source: Sept. 2005 GE-EER experience list; (24) GE-EER 2004 Technical paper. Listed in (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)

Dynegy (formerly Illinois Power)
Hennepin Unit 1
71 MW CE boiler

Pulverized Coal, Tangentially-fired
1966 vintage
eastern bituminous coal

GE-EER Gas Reburn, 1990 startup (not currently operating); GE-EER Orimulsion Reburn, 1997.
DOE Clean Coal demonstration project (included sorbent injection).
Vendor claimed gas reburn w/ OFA lowered NOx up to 67% from baseline of 0.75 lb/mmBtu to 0.25 lb/mmBtu) at full load; 65% reduction from baseline of 0.75 lb/mmBtu down to 0.26 lb/mmBtu with subsequent Orimulsion reburn operation.
GE-EER 2004 technical paper shows 18% gas reburn fuel yielded minimum NOx emissions(6).
Another technical paper showed this 80 MW US DOE Clean Coal demonstration project in January 1991-January 1993 lowered NOx by 67% from 0.75 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 18 percent reburn fuel(5).
Source: Sept. 2005 GE-EER experience list; (6) GE-EER 2004 Technical paper; (5) DOE-NETL 2004 Reburn Conference technical paper, and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see Conventional Oil reburn installation summaries for pulverized coal boilers).

REBURN – GAS, CONVENTIONAL continued

Pulverized coal-fired boilers)

AES (formerly New York State Gas & Electric (NYSEG)

Greenidge #6 (NY)	Pulverized Coal, Tangentially-fired,	1953 vintage
100 MW CE boiler	GE-EER Conventional Gas Reburn, 1996 startup	

Vendor claimed to lower NOx 55% from 0.63 lb/mmBtu baseline to 0.28 lb/mmBtu at full load with reburn operation burning eastern bituminous coal. Gas Research Institute predicted would achieve 76% (down to 0.15 lb/mmBtu) w/ advanced gas reburn.

GE-EER 2004 technical paper shows 23% reburn fuel yielded minimum NOx emissions around 0.23 lb/mmBtu(6).

EPA's "Scorecard on Reburning 6/1/2004" shows a 109 MW t-fired boiler (listed as Greenidge Unit 4) lowered NOx by 50% from 0.50 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 10 percent reburn fuel (no longer operating) (5).

Source: Sept. 2005 GE-EER experience list; (6) GE-EER 2004 Technical paper; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station	Pulverized Coal	opposed wall-fired B&W boilers
Units 1 & 2	1964, 1965 vintage	eastern bituminous coal
360 MW (nominal)	GE-EER Gas Reburn, 2000 startup	

Vendor claimed to lower NOx up to 43% and 45% from 0.60 lb/mmBtu baseline to 0.34 and 0.33 lb/mmBtu) at full load with reburn operation, respectively. No claims of percent reburn fuel included.

Source: 2002 GE-EER experience list. Listed in (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3	Pulverized coal, wall-fired, 1962 vintage
175 MW B&W boiler	western bituminous coal
DOE Clean Coal demonstration project	November 1992-January 1995

Gas reburn demonstration performed with Dept. of Energy and Gas Research Institute 1992-1995. Existing boiler with 16 burners was retrofitted with low NO_X burners and GE-EER gas reburn OFA, FGR, and reburn injectors. Added OFA booster fan, 800 hp flue gas recirculation fan for injection mass momentum, for increased gas injection mass momentum (which was subsequently removed). The CGR installation portion has since been decommissioned.

Vendor claimed to lower NOx up to 64% from baseline of 0.73 lb/mmBtu to 0.26 lb/mmBtu) at full load with reburn operation.

GE-EER 2004 technical paper shows 15-20% reburn fuel yielded minimum NOx emissions(6).

A 2004 DOE-NETL technical paper showed this project achieved 0.46 lb/mmBtu NO_X emissions with low NO_X burners alone (37% reduction), further reduced NO_X by 44% with 12.5 percent reburn fuel(5).

A 2001 DOE-NETL technical paper claimed a NOx reduction of 65% at an average reburn gas heat input of 18% of total boiler fuel input, with and without FGR. Demonstrated 70% NOx reduction at higher reburn input rates. Referred to technology as GR-LNB. FGR was added for gas injection momentum but was subsequently removed to reduce fuel input. (25)

Source: Sept. 2005 GE-EER experience list; (6) GE-EER 2004 Technical paper; (5) DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference); (25) DOE-NETL 2001 Technical paper; also in (9) DOE 1999 Topical Report Number 14.

REBURN – OIL, CONVENTIONAL

Pulverized coal-fired boilers

Dynegy (formerly Illinois Power)	Pulverized Coal, Tangentially-fired	
Hennepin Unit 1	1966 vintage, eastern bituminous coal	
71 MW	CE boiler	1997 startup

GE-EER Orimulsion Reburn system w/ OFA, claimed orimulsion reburn lowered NOx up to 65% from baseline of 0.75 lb/mmBtu to 0.26 lb/mmBtu at full load with Orimulsion reburn operation (installed after gas reburn was demonstrated in early 1990's). No claims for percent reburn fuel included.
GE-EER 2004 technical paper shows 60% reduction with subsequent Orimulsion reburn (6).
Source: GE-EER experience list; (6) GE-EER 2004 Technical paper. Orimulsion not mentioned in (5) DOE-NETL 2004 Reburn Conference technical paper or DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

New Brunswick Power	
Coleson Cove,	Bunker C/Orimulsion–fired, opposed-wall
St. John, New Brunswick, Canada	
3x 350 MW B&W Boilers	

Sixteen new low-NO$_X$ oil/Orimulsion burners, eight reburn burners, nine SOFA ports, two combustion air booster fans, reburn and OFA wall penetration openings, OFA windboxes, ductwork, dampers, and accessories were added(7).
Another technical paper showed this reburn system lowered NOx by 78% from 1.0 lb/mmBtu baseline to 0.22 lb/mmBtu at 25 percent reburn fuel input(5).
Source: (7) B&W 2004 Technical Paper;(5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Georgia Power	Pulverized Coal, Tangentially-fired
Scherer Unit 1	1982 vintage
887 MW CE boiler	2000 oil reburn startup

GE-EER Oil Reburn system, claimed to lower NOx from baseline of 0.36 lb/mmBtu.
GE-EER 2004 Technical paper shows reduction up to 48% (to 0.19 lb/mmBtu) at 800 MW load with oil reburn operation. No claims of percent reburn fuel included(24).
Source: Sept. 2005 GE-EER experience list shows this as a coal reburn project with eastern bituminous coal, reducing NO$_X$ emissions 33% from 0.36 to 0.24 lb/mmBtu;
(24) GE-EER 2004 Technical paper. Not listed in (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, MICRONIZED, CONVENTIONAL

Pulverized coal-fired boilers

AES (formerly New York State Electric and Gas Milliken Station Unit 1)

Cayuga	tangentially-fired, pulverized coal, 1956 vintage	
148 MWe, CE boiler	eastern bituminous coal	
GE-EER micronized coal reburn system		1996 startup (still operating)

US DOE Clean Coal demonstration project from March 1997-April 1999 lowered NOx with this reburn system by 29% from 0.35 lb/mmBtu baseline to 0.25 lb/mmBtu at 14 percent reburn fuel input(5). Not listed in GE-EER's experience list nor in their 2004 technical paper.
Source: (5) DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, MICRONIZED, CONVENTIONAL continued

Pulverized coal-fired boilers

E. ON US Holdings (formerly Louisville Gas and Electric)
R.D. Green Station Units 1 & 2 (KY) wall-fired, pulverized coal, vintage unknown
293 MWe, 2 boilers eastern bituminous coal
GE-EER coal reburn system Startup dates: 2003 & 2002, respectively
Vendor claimed to lower NOx up to 57% from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation.
Reburn system listed on EPA's "Scorecard on Reburning 6/1/2004" shows NOx lowered by 44% from baseline of 0.45 lb/mmBtu down to 0.25 lb/mmBtu (with unknown reburn fuel input(5)).
Another technical paper showed baseline NOx with existing low-NOx burners was 0.45 lb/mmBtu, and reduced NOx emission 40% to 0.27 lb/mmBtu with OFA, and further reduced NOx emissions 22% down to 0.21 lb/mmBtu with the coal reburn system in operation[26].
Source: (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference);
(24) GE Energy 2004 Technical paper, and (26) March 2004 Modern Power Systems issue.

Cheng Loong (not in United States)
Unit #1, 250 MWe wall-fired, bituminous pulverized coal, vintage & mfr unknown
GE-EER coal reburn system 2000 Startup (still operating)
Source: GE-EER experience list
Vendor claimed to lower NOx 44% from baseline 0.45 lb/mmBtu to 0.25 lb/mmBtu) at full load with OFA alone; further reduced NOx 28% to 0.18 lb/mmBtu, for 60% overall reduction. Recent (2004) data shows NOx down to 0.14 lb/mmBtu (69% overall) with up to 30 percent reburn fuel(24).
Source: (24) GE Energy 2004 Technical paper; GE-EER experience list. Listed in (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL w SNCR

Pulverized coal-fired boilers)

NRG Somerset Pulverized Coal, Tangentially-fired, vintage
Unit 6 Boiler 8 (NY) GE-EER Conventional Gas Reburn,
120 MW CE boiler Fuel Tech SNCR, 2003 startup
Reburn vendor claimed to lower NOx 55% from 0.45 lb/mmBtu baseline to 0.20 lb/mmBtu at full load with reburn operation burning Venezuelan coal. The SNCR system further reduced NOx emissions 45% down to 0.11 lb/mmBtu, for an overall reduction of 77%.(26).
Source: Sept. 2005 GE Energy experience list; (26) March 2004 Modern Power Systems issue.

REBURN – FUEL LEAN GAS REBURN (FLGR)

Pulverized coal-fired boilers

Duke Power Company tangentially-fired, pulverized coal
Riverbend Unit 7 eastern bituminous coal 1954 vintage
140 MWe, CE boiler 1998 FLGR startup, gas reburn decommissioned since then
Previously installed ABB/CE's Low NOx Concentric Firing System (LNCFS-1) with Close-Coupled Overfire Air (CCOFA); (pre-mod NOx + combustion mods date not known).
Commercial FLGR installation claimed 34% NOx reduction from full-load baseline of 0.42 lb/mmBtu down to 0.29 lb/mmBtu w/ the combustion modifications and FLGR gas reburn fuel at 7% of total boiler heat input. CO emissions were above 1000 ppm corrected to 3% O_2.(27)
Vendor claimed to lower NOx 57% from 0.47 lb/mmBtu baseline to 0.20 lb/mmBtu) at full load with separated OFA alone; further reduced NOx 45% to 0.11 lb/mmBtu with low-NOx burners, OFA, gas reburn, and SNCR, for 77% overall reduction; no claims for amount of reburn fuel(24).

EPA's "Scorecard on Reburning 6/1/2004" showed this reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input(5).
Source: (27) ESA, GRI, NGB 1998 Technical paper; (24) GE Energy 2004 Technical paper; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – FUEL LEAN GAS REBURN (FLGR) continued
Pulverized coal-fired boilers
Wisconsin Electric Power Company (WEPCO)
Pleasant Prairie Unit 1 DB Riley, turbo-fired PC, Powder River Basin coal
620 MWg 1980 vintage 1999 startup
Fuel Tech listed FLGR installation and claimed 20% NOx reduction from baseline of 0.45 lb/mmBtu (to 0.36 lb/mmBtu). No claims of percent reburn fuel input included.
Source: Fuel Tech experience list dated 1/28/2005. (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see FLGR + SNCR installation summaries for pulverized coal boilers).

REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR)
Pulverized coal-fired boilers
Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 startup
Commercial urea-based Fuel Tech SNCR +FLGR installation claimed 50% NOx reduction from baseline of 0.58 lb/mmBtu (426 ppm) down to 0.29 lb./mmBtu w/ 5 ppm ammonia slip(1). Low NO_X burners were previously retrofitted in 1997 without separated overfire air(28). This is 33 % lower than 0.44 lb/mmBtu baseline for SNCR alone. (Also see SNCR installation summaries for pulverized coal boilers). Urea-to-NOx NSR not stated.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating(5).
Another technical paper showed 52% NOx reduction down to 0.28 lb/mmBtu at all loads, from 99 MWg to 207 MWg (48% to 100% MCR) with an average NH_3 slip of 3 ppm. FLGR alone achieved 23% NOx reduction with 6% reburn fuel and < 400 ppm CO at full load. (28)
Source: Fuel Tech experience list, (1)ICAC White Paper; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference); (28) CP&L and Fuel Tech 2001 Technical paper.
(Also see SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage
660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup
Commercial SNCR + FLGR urea-based Fuel Tech installation claimed 40% NOx reduction from baseline of 0.65 lb/mmBtu (down to 0.39 lb/mmBtu) w/ 10 ppm ammonia slip(1). This is 20 % lower than 0.49 lb/mmBtu baseline for SNCR alone. Urea-to-NOx NSR not stated.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating(5).
Source: Fuel Tech experience list, (1)ICAC White Paper;(5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).
(Also see SNCR installation summaries for pulverized coal boilers).

REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR) continued

Pulverized coal-fired boilers

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Mercer Station (2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired
Unit 1 and Unit 2 front wall PC, wet-bottom (slagging ash) eastern bituminous coal
Furnace #11 & #12 1960 vintage May 1999 startup
Furnace #21 & 22 1961 vintage May 1999 startup
Commercial urea-based Fuel Tech SNCR + FLGR installation claimed 60% NOx reduction from baseline of 1.4 lb/mmBtu (down to 0.56 lb/mmBtu) w/ 5 ppm ammonia slip (1). This is 72 % lower than 2.0 lb/mmBtu baseline without control. Initial demonstration of AEFLGR coinjected amine-enhanced natural gas into Furnace 22 in 1998. Subsequently installed AEFLGR on both units to reduce NOx starting in May 1999 using (2) levels of AEFLGR retractable gas injectors and (2) levels of SNCR injectors(29). Urea-to-NOx NSR not stated, goal was NSR < 1.25.
{Note both units have since been retrofitted with low-dust tail-end SCRs in 2004; SNCR systems are still capable and operated as needed, mostly for flyash conditioning to aid ESP performance}
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 1999, but not currently operating(5).
Source: Fuel Tech experience list, (1)ICAC White Paper; (29) PSE&G, FT and ESA 2000 Technical paper;(5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Wisconsin Electric Power Company (WEPCO)
Pleasant Prairie Unit 1 DB Riley, turbo-fired PC, Powder River Basin coal
620 MWg 1980 vintage 1999 startup
Fuel Tech urea-based SNCR +FLGR demonstration installation claimed 56% NOx reduction from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu w/ 5 ppm ammonia slip(1). This is 44 % lower than 0.36 lb/mmBtu baseline for FLGR alone.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating(5).
Source: Fuel Tech experience list, (1)ICAC White Paper and F.T. experience list 0207;
(5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR

Pulverized coal-fired boilers

AEP Cardinal Unit 1 Pulverized Coal cell-burner, opposed wall-fired B&W boiler
600 MW (nominal) 1967 vintage; Low NO_x burners installed in October 1998
Produced 0.75 lb/mmBtu NOx post-LNB install baseline at full load.
LNBs reduced NO_X 57% from 1.20 down to 0.52*, produce NO_X at approx. 0.57 lb/mmBtu at min. load w/o SNCR (range 0.51 to 0.65) and produce 0.75 lb/mmBtu NO_X at approx. 585 MW (top of load range tested, NO_X range 0.73 to 0.86 lb/mmBtu) (17).
(50) original B&W circular burners were recently replaced on Cardinal Units 2 & 3 by Buckeye Power with DB Riley (now Babcock Power) CCV type low NOx burners.
Source: *Riley Power (Babcock Power Inc.) 8/16/04 experience list; (17) 2000 Fuel Tech technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 startup
Low NO_X burners were previously retrofitted in 1997 without separated overfire air(22). NOx reduction was 46% from pre-LNB installation baseline of 1.08 lb/mmBtu (12) down to 0.58 lb./mmBtu (28).

(Also see SNCR, and FLGR with SNCR installation summaries for pulverized coal boilers).
Source: (12) 2005 US EPA Docket OAR-2002-0076-0446 Technical Support Document spreadsheet; (28) CP&L and Fuel Tech 2001 Technical paper.

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 5 1956 vintage; eastern bituminous coal
154 MW CE boiler ROFA startup in 2000
Mobotec USA's Rotating Opposed Fire Air (ROFA) is a high velocity boosted separated overfire air system claimed to lower NO_X without retrofitting low-NOx burners. This was the first U.S. installation of Mobotec USA's "Rotating Opposed Fire Air" (ROFA) on a utility boiler, which utilizes a booster fan.
CP&L technical paper claimed to lower NO_X 53% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.28 lb/mmBtu with ROFA alone following the installation of ROFA in 2000(18).
Source: (18) CP&L 2002 Technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 6 twin-furnace (eight corner), 1958 vintage; eastern bituminous coal
175 MW CE boiler ROFA startup in 2001
This unit's "ROFA" system was installed as part of a "Rotamix" SNCR + ROFA system.
CP&L technical paper shows ROFA alone reduced NOx 57% from full-load pre-ROFA baseline 0.54 lb/mmBtu to a NO_X emission rate of 0.23 lb/mmBtu. (18)
Source: (18) CP&L 2002 Technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Conectiv (formerly Delmarva Power & Light)
Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage
B&W, DB Riley boilers eastern bituminous coal
REI performed CFD modeling on both units for potential SNCR application.
Unit 3 has Riley Low NOx burners (16), (8) front wall and (8) rear wall OFA ports, (8) wall boundary air ports, (66) side wall OFA slots, claimed baseline NOx around 0.37 lb/mmBtu w/o SNCR (20).
Unit 4 has (24) front and rear wall down-fired burners, (28) front and rear wall SOFA ports, claimed NOx around 0.44 lb/mmBtu w/o SNCR (20) {furnace has "Mae West" belt}.
Riley provided 16 CCV low-NOx burners for Unit 3 in 1994, and claimed to reduce NOx emissions by 67% from pre-LNB baseline of 1.05 lb/mmBtu down to 0.34 lb/mmBtu.
Source: (20)REI 1999 Technical Paper; Riley Power (Babcock Power Inc.) 8/16/04 experience list. (Also see SNCR installation summaries for pulverized coal boilers).

Dayton Power & Light Pulverized Coal, Tangentially-fired
Killen Station, Unit 2 1955 vintage
632 MW CE boiler, bituminous Illinois coal
GE-EER provided low-NOx burners in 1999. Vendor claimed full load NO_X was reduced by 23% from a 0.57 lb/mmBtu baseline down to 0.44 lb/mmBtu.
Source: GE-EER Experience list 2/1/02. (Also see low-dust SCR installation list for pulverized coal boilers)

LOW NO$_x$ BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, wall-fired
Havana Station, Unit 6 1978 vintage
460 MW B&W boiler, bituminous Illinois coal
GE-EER provided modifications to the original B&W dual-register burners, and an OFA system in 2000. Vendor claimed full load NO$_X$ was unchanged from 0.38 lb/mmBtu baseline.
Source: GE-EER Experience list 2/1/02. (Also see low-dust SCR installation list for pulverized coal boilers)

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Vermillion Station, Unit 1 1955 vintage
82 MW CE boiler, bituminous Illinois coal
This rotating opposed fire air (Mobotec USA ROFA) system was installed in July 2002, as part of a "Rotamix" SNCR + ROFA system, without low-NOx burners.
Mobotec 2004 technical paper claimed to lower full load NO$_X$ by 62% from 0.58 lb/mmBtu baseline to 0.22 lb/mmBtu in July 2002 (without LNB or SNCR). (21)
Source: (21) Mobotec 2004 technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Georgia Power Pulverized coal, opposed wall-fired,
Harlee Branch Unit 1 250 MW B&W boiler, 1965 vintage 2003 startup
Harlee Branch Unit 2 359 MW Riley boiler, 1967 vintage 1998 startup
B&W provided 24 DRB-4Z low NOx burners for Unit 1 B&W boiler, 24 DRB-XCL low NOx burners for Unit 2 Riley boiler (believe southeast coast lignite is primary fuel).
Source: B&W's experience list. No NOx reduction claims.

Kansas City Power & Light Pulverized coal, opposed wall-fired, 600 MW B&W boiler
Hawthorn Unit 5 30 burners, 2001 vintage, (Powder River Basin coal)
B&W provided 30 DRB-4Z low NOx burners and 11 OFA ports with the new boiler.
Source: B&W's experience list. No NOx reduction claims.

New England Power Company (NEPCO)
Salem Harbor Station Pulverized Coal, front wall-fired,
Units 1, 2 & 3 1952, 1952, 1958 vintage (eastern bit. coal)
84 MWe x 2, & 156 MWe B&W boilers LNBs startup in 1995, 1995, and 1993
Riley claimed Unit 1 LNBs reduced NOx emissions by 57% from baseline of 1.10 lb/mmBtu down to 0.42 lb/mmBtu; Unit 2's LNBs achieved 42% NOx reduction from a baseline of 0.95 lb/mmBtu down to 0.55 lb/mmBtu; Unit 3's LNBs achieved 60% NOx reduction from a baseline of 1.05 lb/mmBtu down to 0.42 lb/mmBtu.
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list.
(Also see SNCR installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)
Shiller Station Pulverized Coal/#6 Fuel oil, front-wall-fired
Units 4, 5, & 6 1952, 1955, 1957 vintage
50 MWe x 3 Foster Wheeler boilers
RJM provided (6) Low NO$_x$ burner modifications per boiler in 1994, 1992, & 1994 respectively;
LNBs reduced NOx 43% from 0.85 to 0.48, 50% from 1.0 to 0.50, and 51% from 0.82 to 0.40 lb/mmBtu.
Source: RJM experience list

LOW NO$_x$ BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued
Pulverized coal-fired boilers

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station	Pulverized Coal	opposed wall-fired
Units 1 & 2	1964, 1965 vintage	eastern bituminous coal
360 MW (nominal)	B&W boilers	

DB Riley (now Babcock Power) CCV type low NOx burners retrofitted in 1993 and 1994, respectively. Vendor claimed to lower NOx up to 52% and 50% from 1.35 and 1.40 lb/mmBtu baselines (to 0.65 and 0.70 lb/mmBtu, assumed at full load).
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list. (Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3	Pulverized coal, wall-fired, B&W boiler, 16 burners, 1962 vintage
175 MW	October 1992 baseline testing started (western bituminous coal)

Installed (16) Foster Wheeler Controlled Flow/Split Flame low NO$_x$ replacement burners as part of a DOE Clean Coal Technology gas reburn demonstration performed with Gas Research Institute 1992-1995.
Uncontrolled NOx w/ original B&W flare-type burners was 0.73 lb/mmBtu. Replacement LNBs (assuming OFA included) reduced NO$_X$ 37% to 0.46 lb/mmBtu(25).
Source: (25) DOE NETL 2001 Technical paper.

A.2.2 Technical Literature References for U.S. NOx Control Retrofit Projects:

(1) SNCR White Paper, Institute of Clean Air Companies, Inc. (ICAC), SNCR Committee, May 2000, Fuel Tech website http://www.fueltechnv.com/pdf/TPP-534.pdf

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APPENDIX B

EERC REPORT

Ash Impacts on SCR Catalyst Performance

ASH IMPACTS ON SCR CATALYST PERFORMANCE

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ASH IMPACTS ON SCR CATALYST PERFORMANCE

EXECUTIVE SUMMARY

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be plagued with problems. The Center lignite fired at the Milton R. Young (MRY) Power Station is highly variable in abundance of various types of ash/slag-forming components. Ash-forming components consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. The alkali and alkaline-earth elements combine with minerals during combustion, resulting in low-melting-point phases that cause a wide range of fireside deposition problems. In addition, the alkali and alkaline-earth elements also form very small particles that are carried into the backpasses of the combustion system and react with flue gas to form sulfates that can cause deposition, blinding, and plugging problems in selective catalytic reduction (SCR) systems. This report analyzes these problems, and concludes that SCR is not a feasible option to control NOx emissions at MRY Power Station because of the high sodium levels present in the coal.

Following is a list of the key problems that are associated with Center lignite which have not been overcome and, in our opinion, make the installation of SCR at the MRY plant technically infeasible for NO_x control.

➢ Blinding of Catalyst Pores by High Sodium Compounds

  X High levels of alkali and alkaline-earth elements present in the coal fired at the MRY plant produce small particles that react to form sulfates that blind the catalyst pores. The high levels of sodium in the coals combined with calcium will produce low-melting-point eutectic sulfate compounds that will form and melt inside the pores of the catalyst.
  - Alkali and alkaline earth sulfates are enhanced by cyclone fired system. The cyclone firing results in partitioning of the ash between bottom slag and the body of the boiler. The sulfate forming materials are more concentrated in the ash as a a result of cyclone firing.

  - Sulfate formation is enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.

  - The sulfate reactions are more severe at MRY because of the high temperature where an SCR would be installed. The higher temperature increases the rate of formation of sulfates and rate of pore plugging.

  - The testing conducted by the Germans found catalyst deactivation and blinding occurs when firing coals with lignite or brown coals that have ashes that are rich in alkali and alkaline-earth elements. .

- The findings by the Germans were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-rich sulfate formation that fill and plug the catalyst at both lignite- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or "popcorn ash," plugging the top of the SCR catalyst is a significant problem because of the extremely high deposition rates of the Center coal. When firing Center coal, deposits form on various parts of the boiler requiring continuous sootblowing. The sootblowing of upstream heat-exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, resulting in plugging. In addition, during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

- Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

- Cold Side SCR Installation

  - High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces significant levels of homogeneously condensed sodium sulfate that pass through the ESP and wet scrubber.

  - These small particles have been shown to pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials require sootblowing to remove the particulate and will result in increased opacity.

  - Liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems are known to catalyze the formation of SO_3 from SO_2. The presence of SO_3 significantly enhances the formation of the pyrosulfates.

ASH IMPACTS ON SCR CATALYST PERFORMANCE

INTRODUCTION

Ash produced during combustion of coal in conventional power systems is a major problem that results in decreased efficiency, unscheduled outages, equipment failures, and increased cleaning. The many ways in which the detrimental effects of ash manifest themselves in a boiler system include fireside ash deposition on heat-transfer surfaces, corrosion and erosion of boiler parts, poor slag flow, and production of fine particulates that are difficult to collect. Decades of research have been conducted to develop a better understanding of the chemical and physical processes of ash formation and deposition in combustion systems. Overviews of ash-related issues and compilations of work by many investigators can be found by referring to the work of Mehta and Benson (1), Schobert (2), Baxter and DeSollar (3), Couch (4), Williamson and Wigley (5), Benson and others (6), Benson (7), Bryers and Vorres (8), Raask (9, 10), and Benson (11). This work has led to a detailed understanding of ash formation and behavior in combustion systems as well as the development of predictive methods (12, 13).

The chemical composition and physical characteristics of ash-forming or inorganic components (mineral and organically associated elements) of the fuel(s) fired have an influence on the following processes in the combustion systems:

- Firing conditions such as cyclone, pulverized coal, and low-NO_x burners
- Transformations of coal inorganic components to ash particulate and vapor-phase species
- Boiler design characteristics, including number of burners, radiant section area, tube bank spacing, access for cleaning, and number of sootblowers
- Ash transport to heat-transfer surfaces in utility boilers
- Erosion wear and sticking
- Ash deposit growth and impact on heat transfer
- Ash blinding and plugging of selective catalytic reduction (SCR) catalysts
- Ash deposit removability

The ash deposition in North Dakota lignite-fired power plants is a major problem that impacts all fireside surfaces of the power plant. The ash problems are due to the variable and complex nature of inorganic components associated with lignite coals (2). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. During the gas-cooling processes in the boiler, the gas-phase species condense and the liquid-phase materials solidify. The abundance of these gas-phase and liquid materials entrained in the bulk gas flow is highly dependent upon coal composition and system operating conditions. The inorganic materials are transported to heat-transfer and catalyst surfaces by diffusion, electrophoresis, thermophoresis,

and inertial impaction. The particle sticking and accumulation rates are dependent upon the quantity of ash and the abundance and viscosity of the liquid-phase components. In high-temperature regions of the boiler, high-temperature sodium–calcium–aluminosilicate liquid phases act as the sticky material, causing deposit initiation, growth, and development of deposit strength. As the temperature of the flue gases decreases, the condensation and reaction of flame-volatilized species play a more significant role in the formation of deposits from lignite coals. The formation of sodium and/or calcium magnesium sulfates dominates the deposit accumulation mechanisms at lower temperatures. The aluminosilicate phases are dominant above about 1800°F. Below about 1800°F, the sulfate phases become stable, with an optimum temperature of formation of about 1400°F, and can form at temperatures as low as 300°F.

The most significant problems that prohibit the successful operation of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates and phosphates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16).

INORGANIC COMPOSITION OF LOW-RANK COALS

Inorganic elements in coal occur as discrete minerals, organically associated cations, and cations dissolved in pore water. The fraction of inorganic components that are organically associated varies with coal rank. Lower-ranked subbituminous and lignitic coals have high levels of oxygen, which act as bonding sites for cations such as sodium, magnesium, calcium, potassium, strontium, and barium (other minor and trace elements may also be present in this form). In higher-ranked coals, bituminous and anthracite, inorganic components consist mainly of minerals. Mineral grains are usually the most abundant inorganic component in coal. The major mineral groups found in coals include silicates, aluminosilicates, carbonates, sulfides, sulfates, phosphates, and some oxides.

The behavior of ash produced during coal combustion is related to the abundance, size, and association of mineral grains in the coal. In addition, the association of the mineral grain with the coal matrix influences the temperature and gaseous environment the mineral is exposed to during combustion. A mineral associated with the organic part of a coal particle is said to be included. A mineral that is not associated with organic material is referred to as excluded. The behavior of the organically associated elements, those elements that are atomically dispersed in the coal matrix, must also be measured as to their abundance in the coal. The organically associated elements will react and interact with the other ash-forming constituents during combustion.

The Center lignite is highly variable in abundance of various types of ash/slag-forming constituents. Ash-forming components in the Center lignite are of two types. The first form may constitute up to 50% of the ash and is derived from inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix of the coal. The second type consists of mineral grains (sand, clay, limestone, and pyrite). The minerals are discrete particles of ash-forming species and the sources of silicon, aluminum, iron, titanium, and minor amounts of the calcium and potassium. The Center lignite fired at the Milton R. Young (MRY) plant has been examined extensively because of its problem with ash behavior. Analyses

of as-fired and drill core samples have been conducted. The mean and the range of selected components are shown in Figure 1. The results indicate that both the abundance of ash and the abundance of major oxides in the ash vary significantly. In addition, the abundance of alkali and alkaline-earth elements (Na and Ca) varied dramatically. Variations in Si were found to be the most significant. High levels of Ca and/or Na were found for lower-ash coals as compared to high levels of Al and Si associated with higher-ash coals (17, 18).

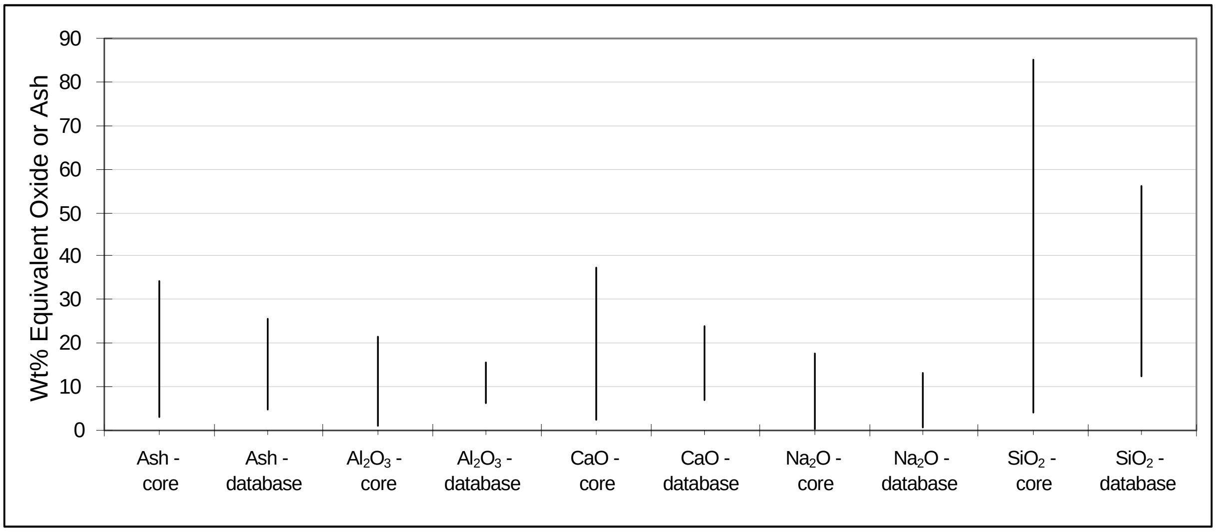

Figure 1. Variability of ash and selected constituents in core analysis database provided by BNI Coal, Ltd. and Minnkota as fired coal analysis database.

The variability of the ash-forming components has been examined for the approximately 5000 samples characterized to date. Wide variations in ash contents and the major ash-forming constituents are observed. During the mining processes, the inorganic components are mixed, and some of the extreme characteristics are diluted (17).

INORGANIC TRANSFORMATIONS AND ASH FORMATION

The inorganic coal components undergo complex chemical and physical transformations during combustion to produce intermediate ash species. The inorganic species consist of vapors, liquids, and solids. The partitioning of the inorganic components during combustion to form ash intermediates depends upon the association and chemical characteristics of the inorganic components, the physical characteristics of the coal particles, the physical characteristics of the coal minerals, and the combustion conditions.

The physical transformation of inorganic constituents depends on the inorganic composition of the coal and combustion conditions. The inorganic components can consist of organically associated cations, mineral grains that are included in coal particles, and excluded mineral grains. There is a wide range of combinations of mineral–mineral, mineral–coal,

mineral–cation–coal, and mineral–mineral–cation–coal associations in coal. These associations are unique to each coal sample.

The physical transformations involved in fly ash formation include 1) coalescence of individual mineral grains within a char particle, 2) shedding of the ash particles from the surface of the chars, 3) incomplete coalescence due to disintegration of the char, 4) convective transport of ash from the char surface during devolatilization, 5) fragmentation of the inorganic mineral particles, 6) formation of cenospheres, and 7) vaporization and subsequent condensation of the inorganic components upon gas cooling. As a result of these interactions, the ash has a bimodal size distribution. The submicron component is largely a result of the condensation of flame-volatilized inorganic components. The mass mean diameter of the larger particles is approximately 12 to 15 μm, depending upon the coal and combustion conditions. The larger-size particles have been called the residual ash by some investigators (19) because these ash particles resemble, to a limited degree, the original minerals in the coal. Processes such as ash mineral coalescence, partial coalescence, ash shedding, and char fragmentation during char combustion and mineral fragmentation, all play an important role in the size and composition of the final fly ash. Loehden and others (20) and Zygarlicke and others (21) indicate that three potential modes for fly ash generation can be used to describe fly ash particle-size and composition evolution. The first, “fine limit,” assumes that each mineral grain forms a fly ash particle and that the organically associated elements form fly ash particles of less than 2 μm. The second, “total coalescence,” assumes one fly ash particle forms per coal particle. The third, “partial coalescence,” suggests that the fly ash composition and particle size evolve because of partial coalescence.

The transformations of excluded minerals are dependent upon the physical characteristics of the mineral. Excluded minerals such as quartz (SiO_2) can be carried through the combustion system with its angular structure still intact. Excluded clay minerals can fragment during dehydration, melt, and form cenospheres. The behavior of excluded pyrite depends upon its morphology. Some of the pyrite may be present as framboids. Framboidal pyrite may fragment more easily than massive pyrite particles. In addition, the decomposition of pyrite is very exothermic, and it transforms to pyrrhotite and oxidizes to FeO, Fe_3O_4, and Fe_2O_3 during combustion.

ASH DEPOSITION ON HEAT-TRANSFER AND OTHER SURFACES EXPOSED TO ASH AND FLUE GAS

The characteristics of a deposit depend upon the chemical and physical characteristics of the intermediate ash species, geometry of the system (gas flow patterns), gas temperature, gas composition, and gas velocity. Figure 2 illustrates the ash deposition phenomena in utility boilers. Ash particle accumulations occur via transport of particles to the fireside surfaces (heat transfer, ceramic materials, support materials, SCR catalysts, baghouse materials, and ESP wires and plates) and sticking of the particles. The transport mechanisms important for ash deposition include small-particle mechanisms for particles less than 10 μm that involve thermophoresis, electrophoresis, and vapor-phase and small-particle diffusion; and large-particle mechanisms for particles greater than 10 μm that involve inertial impaction. The ability of larger particles to stick depends upon the quantity and viscosity of the liquid phase on the particle surface.

Thermophoresis is a phenomenon that involves the transport of very small particles as a result of a thermal gradient from hot gases to cooler surfaces. Electrophoresis is the transport of particles because of a difference in charge. Vapor-phase and small-particle diffusion occurs in the boundary layer next to the surface and results in transport of ash to the surface. Inertial impaction is a larger-particle phenomenon where the particles are of a sufficient size and density to leave airflow patterns around the tube and impinge upon the surface of a tube or deposit. Deposits that form in high-temperature regions of the boiler, such as the radiant section, are called slag deposits. Deposits that form in lower-temperature regions of the boiler, such as in the convective pass on steam tubes and lower-temperature surfaces such as SCR catalysts, are called fouling deposits. Slag deposits are usually associated with a high level of liquid-phase components and are exposed to radiation from the flame. This is a description that many researchers use to aid in classification of deposits since some engineers call any type of deposit "slag". Slag deposits are typically dominated by silicate liquid phases, but may also contain moderate to high levels of reduced iron phases such as FeO and FeS. The liquid characteristics of the silicates are highly dependent upon the quantities of Na, Mg, Ca, K, and Fe ash on the silicates. In addition, the initiating layers of slag deposits may consist of very fine particulate and can produce a reflective ash layer. This phenomenon is especially evident when high organically associated calcium subbituminous coal is fired. These coals produce small CaO particles that usually form the initiating layers.

Fouling deposits form in the lower-temperature regions of the boilers and, in most cases, do not contain the high levels of liquid phases that are usually associated with slagging-type deposits. Fouling deposits contain lower levels of liquid phases as compared to slag deposits. The fouling deposit liquid phases usually consist mainly of sulfates that bind the particles together. Fouling deposits typically form as a result of the reaction of gas-phase sulfur oxide species with particles rich in alkali and alkaline-earth elements.

ASH-RELATED EXPERIENCES AT MRY FACILITY

The MRY is a minemouth electrical generating plant located near Center, North Dakota. The station consists of two units: Unit 1, rated at 276 MWg, began production in 1970; Unit 2, rated at 506 MWg, began production in 1977. Both Units 1 and 2 are equipped with B&W cyclone-fired boilers; the Unit 1 boiler has seven cyclones, and the Unit 2 boiler has twelve cyclones. Annual station gross generation is approximately 5.5 million MWh.

BNI Coal Ltd. is the sole coal supplier for the MRY Station. Coal is mined from the nearby Center mine, which consists of three distinct seams varying from 2½–9 feet thick. Coal is strip-mined using two draglines and is loaded with front-end loaders and delivered to the plant with bottom-dump haul trucks. Annual coal production is 4.3 million tons per year.

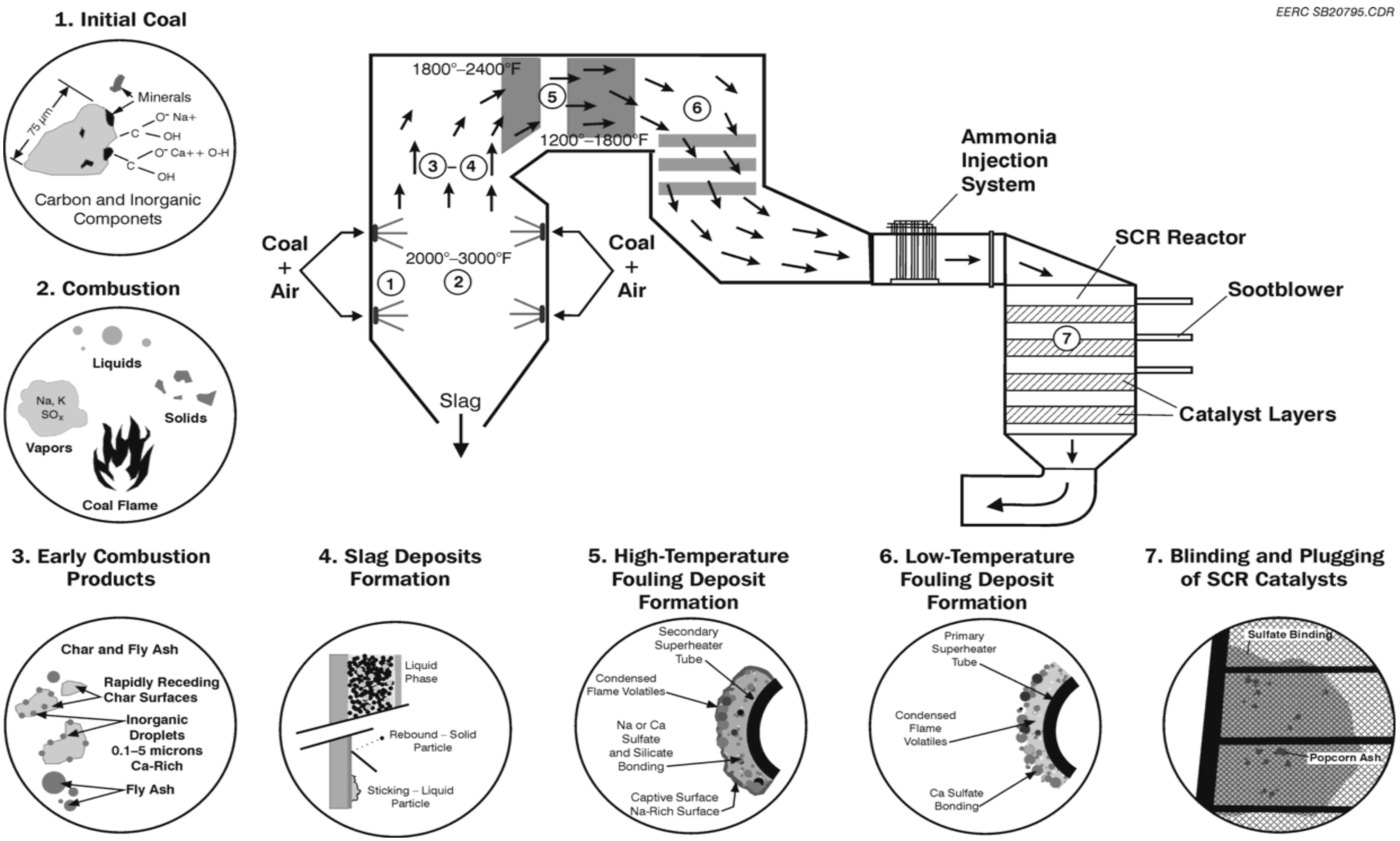

Figure 2. Overall processes of ash deposition typical of a lignite- or subbituminous-fired boiler.

History of Furnace Slagging/Fouling

Prior to 1991, besides annual maintenance outages, load reductions and forced outages due to furnace slagging/fouling were the largest cause of production loss. In 1985, operating guidelines were established that reduced furnace slagging/fouling, including deslagging outages scheduled every six months.

In 1991, a 3-month boiler cleaning cycle was proposed and initiated. The goal of this program was to increase annual generation by running the units at higher sustained loads and scheduling boiler-cleaning outages at 3-month intervals. However, furnace slagging/fouling continued to have a significant impact on plant operations. Success was measured in the number of production days between boiler-cleaning outages.

During the mid-1990s, a major outage every third year was scheduled for each unit. In addition, Unit 1 cleaning outages were scheduled for 80–90-day runs (four cleaning outages per year), and Unit 2 cleaning outages were scheduled for 65–75-day runs (five cleaning outages per year). The problem was that furnace and convection-pass surfaces gradually become coated with ash deposits, which, over time, sootblowers cannot remove. Some of the contributors to the ash deposits were as follows:

- Organically associated sodium is a primary contributor to deposition problems. Sodium is vaporized in the cyclones and condenses on other ash particles, causing them to become sticky and deposit at the furnace exit. The problem is associated with sulfate formation and occurs in the convective pass, including the economizer. Samples show that sodium in the ash varies from 0.6%–13.0%.

- Organically associated calcium is another component that causes deposition problems. Unlike sodium, calcium does not produce a vapor-phase component. Calcium does react with silicate (derived from clays) to cause low-melting-point phases that produce wall deposits and deposits in the high-temperature regions of the convective pass. Calcium also produces very small particles that will be transported to heat-transfer surfaces, resulting in the formation of thin, light-colored layers called reflective ash. These small particles of ash are carried through to the back passes where they are sulfated and can combine with sodium to cause the formation of strongly bonded sulfate-based deposits. Samples show that calcium in the ash varies from 6.8%–24.0%.

- Clay minerals and quartz – Center lignite can contain high levels of illite, which has a 1:3 Al:Si ratio and high levels of potassium, both of which cause wall slagging and high-temperature fouling. Quartz and other clays can significantly contribute to the mass of the deposits. Samples show that ash content varies from 5.0%–25.5%.

Advanced Boiler Performance Indices

Advanced indices are used to relate the coal characteristics as determined by computer-controlled scanning electron microscopy (CCSEM) and chemical fractionation to ash behavior in a coal-fired utility boiler (12). Fuel performance is estimated in terms of slag flow behavior,

abrasion and erosion wear, wall slagging, high-temperature silicate-based convective pass fouling, and low-temperature sulfate-based convective pass fouling. The following indices are used to assess the effects of ash behavior on utility boiler performance:

- Convective-Pass Fouling Indices

  Sulfation Index: Indicates the propensity of deposit to form in the convective pass of the utility boiler in the temperature range from 1000°–1750°F. This index is based on the availability of alkali (Na and K) and alkaline-earth (Ca and Mg) elements to react with SO_2 and SO_3 to form sulfates. The sulfates are the primary materials that cause particle-to-particle bonding in high-calcium coals. The sulfates are thermodynamically stable at temperatures below about 1650°F. Index values range from 1 (low) to 10 (severe).

  Silicate Index: Indicates the propensity of deposits to form from 1600°–2400°F. This index is related to the formation of deposits in which the silicate material is the primary component that bonds the deposits together. The information used to derive the index includes the size of the minerals such as quartz and clay minerals, availability of alkali and alkaline-earth elements, and viscosity of the silicate liquid phase. Index values range from 1 (low) to 200 (severe).

- Waterwall Slagging

  Slagging Index: Indicates the propensity of a deposit to form on the radiant walls from 2000°–3000°F. The basis of the slagging index is the size of the minerals (especially the illite, quartz, and pyrite), association of the calcium (calcite can contribute to slagging), and viscosity of the silicate-based liquid phase. Index values range from 1 (low) to 20 (severe).

- Wear Indices

  Abrasion Index: This index indicates the potential for wear of fuel preparation and handling equipment. The wear is related to the hardness of minerals in the coal. The primary minerals of concern include quartz and pyrite. The index values range from 0.1 (low) to 10 (severe).

  Erosion Index: This index indicates the potential for wear of boiler parts due to the impaction of fly ash particles. The erosion index is dependent upon the size of the ash/mineral particle, size of the particle, and velocity of the particle. The index values range from 0.1 (low) to 1.0 (severe).

- Cyclone Slagging Index: This index provides information on the slag flow behavior in cyclones. The factors that are included in this index include the partitioning of the ash in the cyclone based on size and association of the ash-forming components in the coal. The partitioning of the ash between the slag and entrained ash can significantly influence the flow behavior of the slag. Standard partitioning criteria have been developed to provide the composition of the slag. The composition is used to estimate the viscosity of the slag as a function of temperature. The index values have several ranges as follows: 1 (low viscosity), 1.5–2.5 (optimum viscosity), >3.0 (slag freezing).

- Strength Development Index: The strength index is based on the ability of the deposited material to develop strength. Strength development is primarily dependent upon the abundance and viscosity of the liquid-phase components in the deposits. Index values less than 0.25 indicate that the material will produce weak deposits; index values of 0.25–0.34 indicate weak-to-moderate-strength deposits; index values of 0.34–0.41 indicate high-strength deposits; and index values >0.41 indicate flowing slag.

Indices were calculated for a range of coals from the Center mine, and the propensity for ash deposition in various portions of the boiler indicates wide variations, as shown in Table 1. The BNI numbers indicate the location in the seams where the coal originated: Kinneman Creek seam (KC), Hagel A (HA), and Hagel (HB). Each seam has a different distribution of minerals and organically associated elements that can have a significant impact on the formation of deposits in the system. Comparison of Center lignite to subbituminous and bituminous coals from other regions of the United States, shown in Table 2, indicates significant differences in the potential to form deposits in the boilers. In all cases, the lignite (not the worst coal from Center mine) from the Center mine has a high propensity to produce deposits as compared to the other coals.

Another indication of the variability of lignites can be illustrated based on the calculation of the temperature where the slag flow would occur. This is defined as the T250 temperature, where the slag viscosity is 250 poise. Frequency distributions of the T250 values for all the data for coals analyzed are illustrated in Figure 3. Calculations of T250 values for 1212 samples obtained from the Center mine database (17) were made using empirical relations derived from CCSEM and chemical fractionation data and knowledge of how ash partitions in the cyclone. Figure 3 shows a bimodal distribution in the T250 based on the Urbain equation calculations. The primary mode was at a value of 2000°F. The secondary mode was at about 2700°F. The results indicate that many of the coals have a sufficiently low T250 for good slag flow. However, coals with T250 at 2700°F are not suitable for maintaining good slag flow.

Figures 4 through 6 illustrate the variations in T250 for the various seams of coals characterized. The HA and HB seam coals appear to have large numbers of samples, with T250 values at or near 2000°F. The KC seam coal, as illustrated in Figure 6, has extremely high T250 values. Based on these data, the KC coals are not favored relative to the slag flow behavior of the ash.

Frequency distributions of cyclone slagging index values indicated significant variations in slagging potentials of coals mined from the three seams, KC, HA, and HB. This information proved particularly useful in planning the mining and firing of coal from the KC seam.

During a July 1999 test burn, the composition of the cores was used to examine and illustrate the variability of the delivered coal quality based on base-to-acid ratio calculated from the ash composition. Figure 7 shows the variation in the base-to-acid-ratio and the seam where the coal was loaded. The base-to-acid ratios were calculated from core data that corresponded to the location in the seam where the coal was mined. There is a significant variation in the base-to-acid ratio for the coals. The coals that have the highest base-to-acid ratio are typically from the HA seam. HB seam coals generally have an intermediate base-to-acid ratio. KC or top-seam coal has the lowest base-to-acid ratio. Lower base-to-acid-ratio coals typically produce slag with high viscosities.

Table 1. Characteristics and Indices Calculated for Selected Center Lignite Samples

BNI No.	41-132HB	41-44KC	41-144HA	41-144HB	41-168KC	41-168HA	41-168HB	41-180KC	41-180HA	41-180HB	41-192KC	41-192HA
Mineral wt%, mineral basis												
Total Quartz Content			18.8	9.8	30.3	8.7	8.8	11.4	20.0	3.9	15.0	17.4
Quartz <10 microns		10.8		6.4	24.6	4.4	4.0	6.8	3.3	2.6	9.7	12.7
Total Kaolinite Content		10.6		10.8	7.7	6.4	1.7	9.5	4.4	2.4	14.3	28.0
Kaolinite Content <10 microns		5.1		6.3	4.5	2.6	0.9	4.8	1.1	0.9	10.2	20.8
Total Montmorillonite		10.7		2.7	6.5	1.7	6.1	7.0	2.3	2.4	7.6	5.1
Total Illite		14.1		9.3	6.6	0.2	28.0	19.1	10.2	1.6	6.8	1.9
Total Pyrite		8.0		26.7	18.9	67.1	19.7	9.1	10.9	57.2	22.6	32.3
Pyrite Content <10 microns		4.5		10.5	2.8	9.8	4.7	2.5	2.5	17.0	6.6	7.0
Gypsum Content		6.5		0.0	1.6	2.7	0.8	5.4	0.0	16.1	2.2	0.0
Proximate (wt% as received)												
Moisture		30.95		41.66	36.24	38.23	37.50	37.90	37.99	38.21	37.85	39.52
Volatile Matter		27.26		25.74	26.32	25.90	24.55	25.11	24.42	25.88	26.13	24.27
Fixed Carbon		26.56		27.97	28.18	29.65	30.37	27.94	29.53	31.54	29.15	30.30
Ash		10.30		4.63	9.26	6.22	7.58	9.05	8.1	4.37	6.88	5.91
Total Sulfur (% as received)		0.94		0.55	1.49	1.08	0.75	0.99	0.64	0.86	0.90	0.85
Btu/lb		6597		6593	6791	6957	6806	6584	6653	7194	6881	6835
% Ash (dry basis)	11.64	10.30		7.94	14.52	10.07	12.13	14.57	13.00	7.07	11.07	9.77
Ash Comp. (wt% equiv. Oxide)												
Na_2O		0.50		10.65	0.82	9.25	8.02	0.46	8.15	11.99	1.48	9.69
MgO		3.30		5.74	3.72	4.90	4.45	3.90	5.00	4.59	6.13	5.10
Al_2O_3		11.90		10.37	9.34	5.64	11.81	12.12	10.19	5.23	10.59	7.46
SiO_2		30.60		14.70	33.71	8.47	30.74	35.57	36.25	5.31	25.80	13.06
P_2O_5		0.20		0.06	0.15	0.42	0.25	0.07	0.26	0.23	0.25	0.24
SO_3		23.00		25.50	21.28	35.25	21.05	18.32	15.93	35.75	24.15	32.75
K_2O		1.20		0.96	0.47	0.62	1.52	1.03	1.22	0.47	0.55	0.60
CaO		16.80		21.00	15.31	18.94	12.10	17.15	14.87	15.43	20.01	18.98
TiO_2		1.30		0.39	0.72	0.29	0.40	0.51	0.29	0.16	0.48	0.28
MnO		0.20		0.03	0.07	0.05	0.04	0.10	0.07	0.04	0.07	0.12
Fe_2O_3		10.30		8.43	14.87	15.95	10.44	7.80	6.84	18.88	10.12	13.29
Cyclone Slagging Index		2.77		1.28	2.5	1.1	2.6	3.3	2.9	0.4	2.2	1.3
Silicate		10.71		102.43	29.47	108.33	109.93	16.29	176.22	137.49	14.19	149.54
Sulfate		9.43		3.57	2.2	5.01	3.46	1.75	3.98	4.4	2.21	3.24
Wall Slagging Index		1.18		11	2.67	10.68	9.27	1.79	8.83	12.63	2.2	10.53
Erosion Index		0.19		0.15	0.17	0.19	0.22	0.21	0.27	0.17	0.17	0.17
Abrasion Index		2.14		0.71	6.46	1.55	1.41	2.25	1.93	0.83	1.75	1.68
Strength Index		0.32		0.66	0.35	1.11	0.35	0.3	0.33	1.32	0.43	0.63

Continued . .

Table 2. Advanced Index Values for Other Coals (12)

Advanced Indices	Lignite North Dakota	Powder River Basin	Bituminous Illinois	Bituminous Appalachian
Cyclone Slagging Index	1.6	2.1	3.5	3.2
Convective Pass Fouling				
Silicate	61.8	23.99	10.36	14.21
Sulfate	4.09	2.88	0	0
Wall Slagging Index	9.28	1.85	1.53	1.66
Erosion Index	0.15	0.17	0.14	0.17
Abrasion Index	0.71	1.96	3.94	1.96

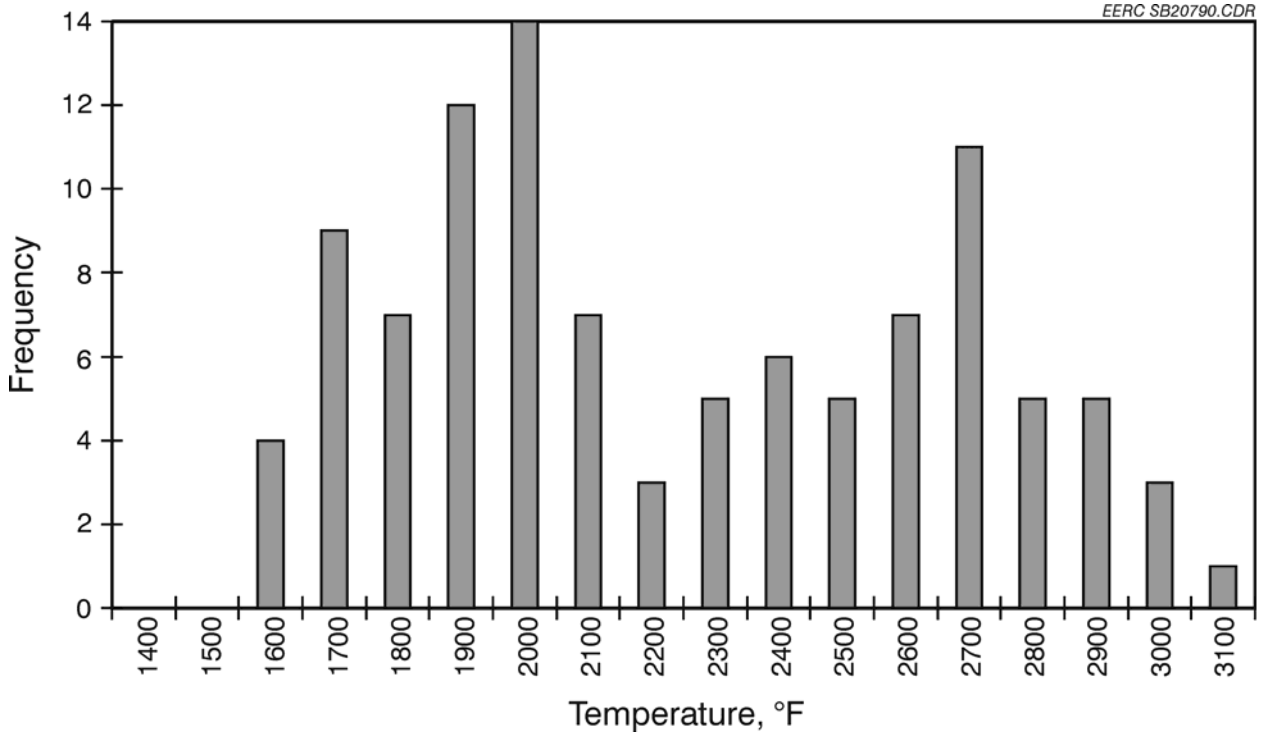

Figure 3. T_{250} frequency distribution for all Coal Quality Management System (CQMS) data, °F.

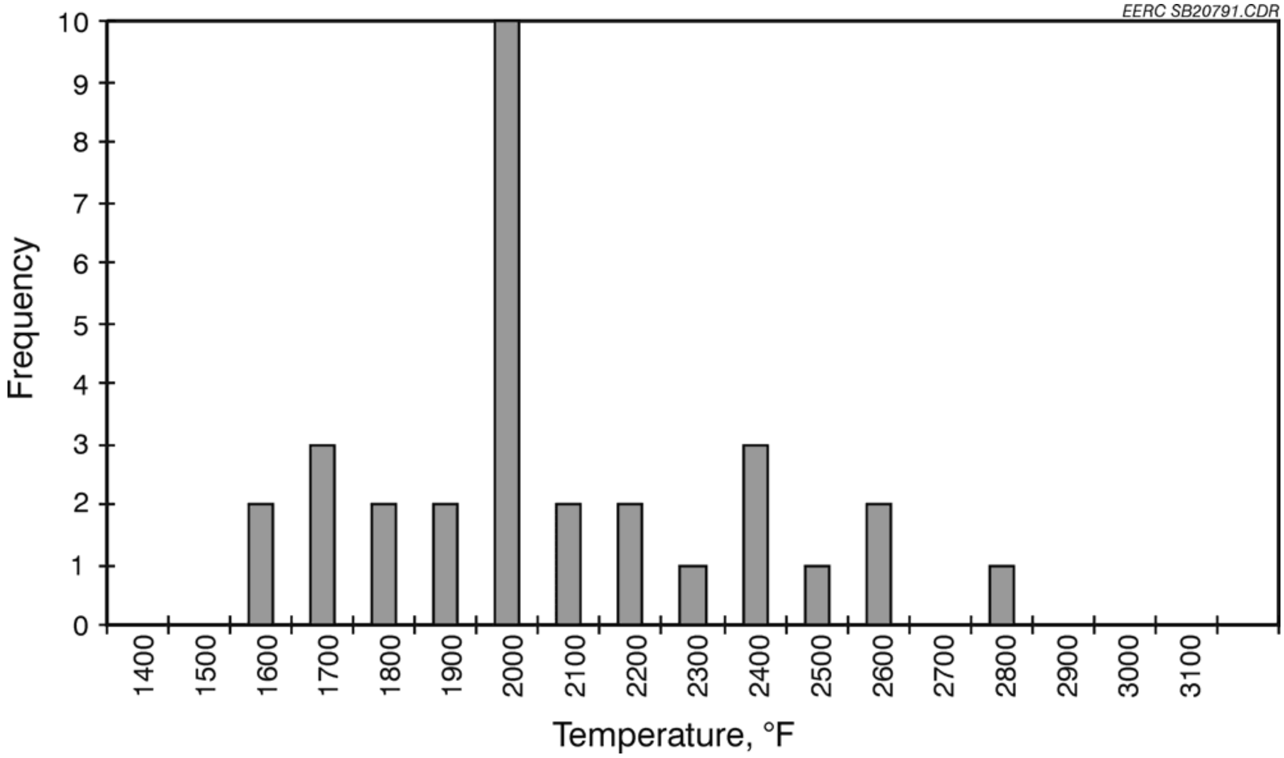

Figure 4. T_{250} distribution for HA seam coal.

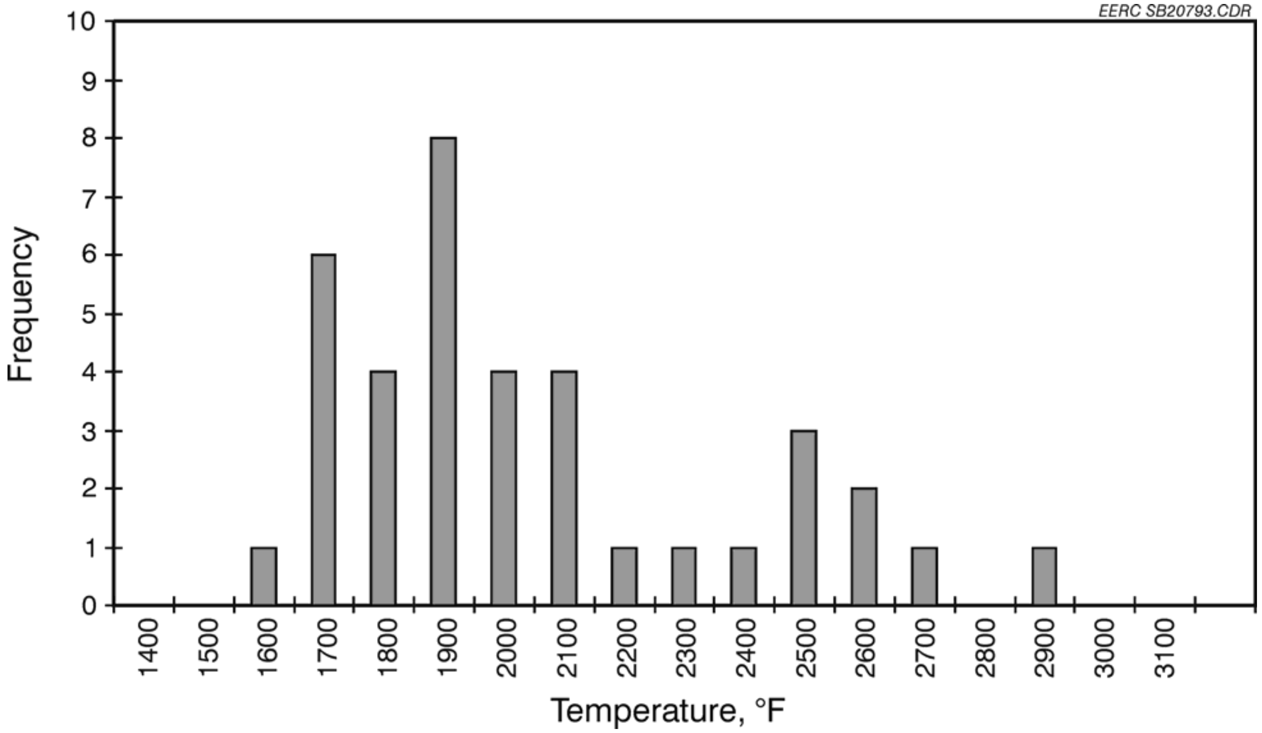

Figure 5. T_{250} distribution for HB seam coal.

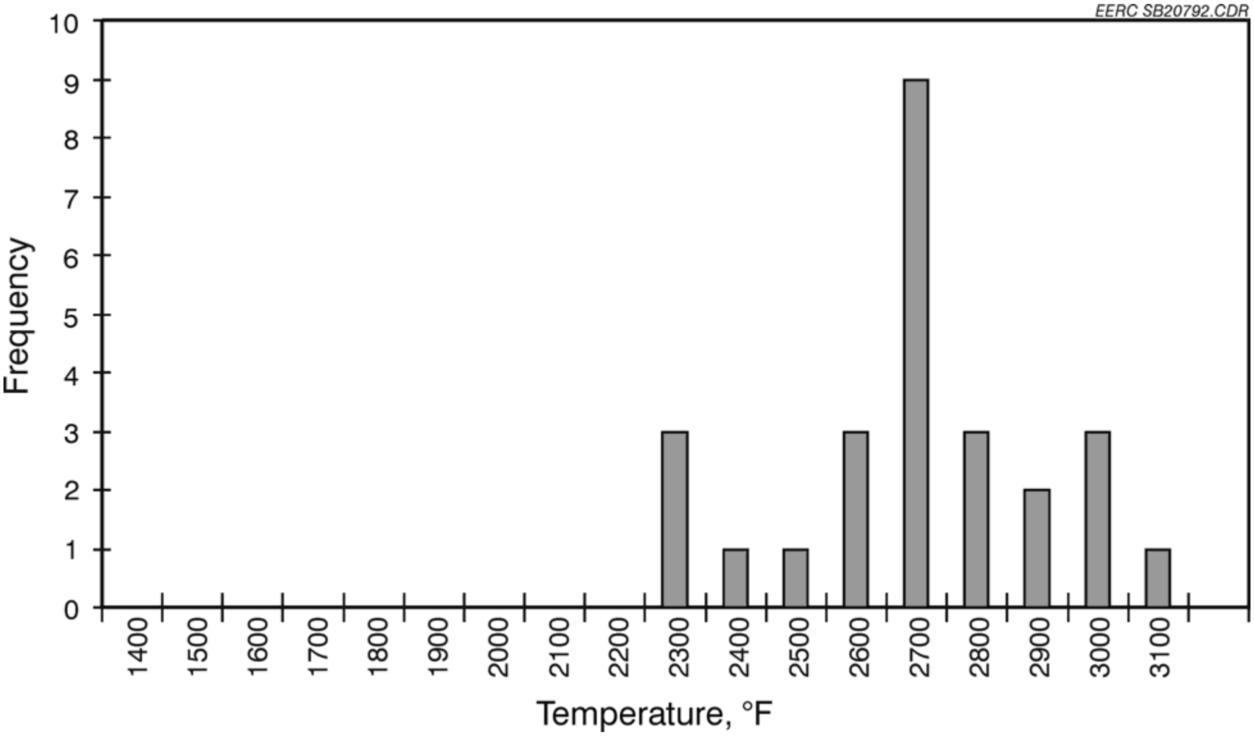

Figure 6. T_{250} distribution for KC seam coal.

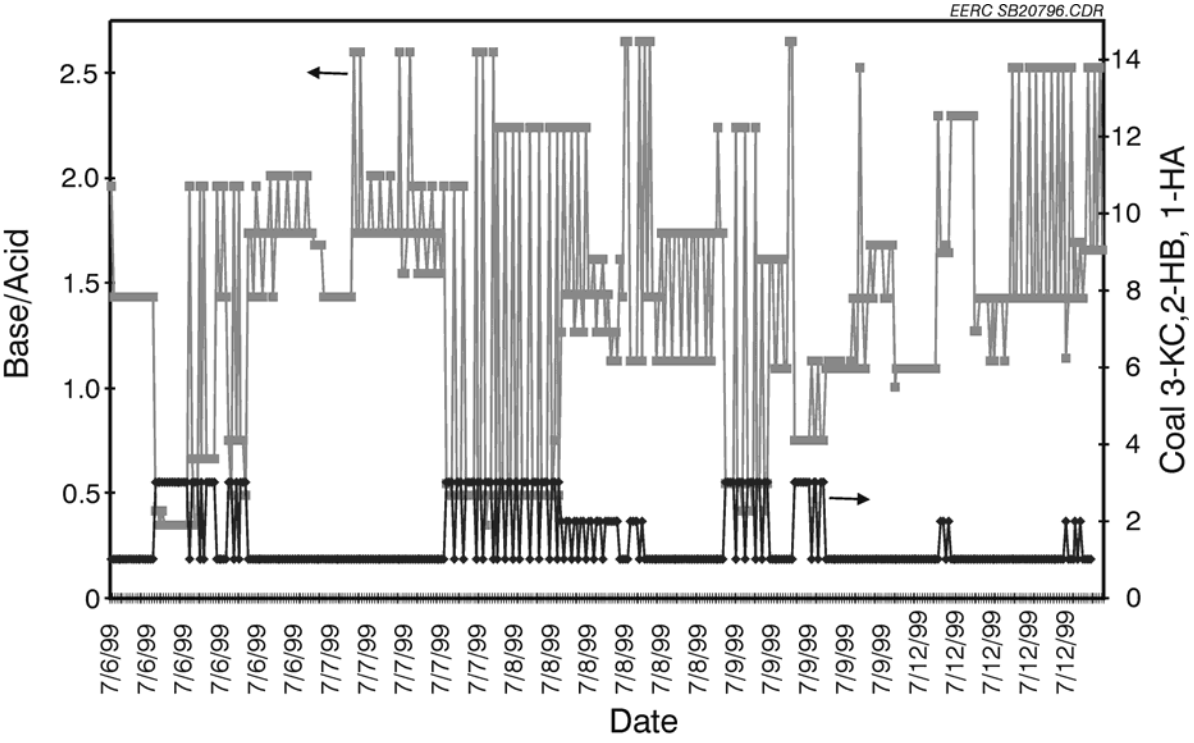

Figure 7. Variations in the delivered coal quality during a test burn period.

Figure 7 shows the sequence of deliveries beginning on July 6 and ending on July 12, 2004. During this period, the majority of the coal delivered was from the HA seam, followed by KC, and HB. Most of the deliveries alternated between KC and HA. Figure 6 shows several instances where significant quantities of KC coal were delivered, on July 6 through July 9. The quantity of KC coal delivered will have the potential to increase the viscosity of the slag and result in poor slag flow from the cyclones.

ASH-RELATED IMPACTS ON SCR CATALYST PERFORMANCE

Ash-related impacts on SCR catalyst performance will depend upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (14–16, 22). The problems currently being experienced on SCR catalysts include the following:

- Formation of sulfate- and phosphate-based blinding materials on the surface of catalysts.
- Carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing on top of the SCR catalysts.

Licata and others (14) conducted tests on a South African and German Ruhr coal and found that the German Ruhr coal significantly increased the pressure drop across the catalyst because of the accumulation of ash. They found that the German coal produced a highly adhesive ash consisting of alkali (K and Na) sulfates. In addition, they reported that the alkali elements are in a water-soluble form and highly mobile and will migrate throughout the catalyst material, reducing active sites. The water-soluble form is typical of organically associated alkali elements in coals. The German Ruhr Valley coal has about 9.5% ash and 0.9 % S on an as-received basis, and the ash consists mainly of Si (38.9%), Al (23.2%), Fe (11.6%), and Ca (9.7%), with lower levels of K (1.85%) and Na (0.85%) (15). Cichanosicz and Muzio (16) summarized the experience in Japan and Germany and indicated that the alkali elements (K and Na) reduced the acidity of the catalyst sites for total alkali content (K+Na+Ca+Mg) of 8%–15% of the ash in European power plants. They also found that alkaline-earth elements such as calcium react with SO_3 on the catalyst, resulting in plugging of pores and a decrease in the ability of NH_3 to bond to catalyst sites. The levels of calcium in the coals that caused blinding ranged from 3%–5% of the ash.

The mechanisms for this type of low-temperature deposition have been examined and modeled in detail at the Energy & Environmental Research Center (EERC) in work termed Project Sodium and Project Calcium in the early 1990s; however, the focus of those projects was specific to primary superheater and economizer regions of boilers and not SCR systems (22, 23). Deposit buildup of this type can effectively blind or mask the catalyst, diminishing its reactivity for converting NO_2 to N_2 and water and potentially creating increased ammonia slip (14). Arsenic and phosphates, which are not uncommon in low-rank coals, may also play a role in catalyst degeneration. Arsenic is a known catalyst poison (14) in applications such as catalytic oxidation for pollution control. Phosphates can occur in low-temperature ash deposits to create blinding effects, and they also occur with arsenic and can cause catalyst poisoning (23).

Lignite and subbituminous coals produce ash that plugs and blinds catalysts (25–28). The problems currently experienced with SCR catalysts include the formation of sulfate- and phosphate-based blinding materials on the surface of catalysts and the carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing them on top of the SCR catalysts (14). The most significant problem that limits the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates, phosphates, and possibly carbonates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16, 27–28). The degree of the ash-related impacts on SCR catalyst performance depends upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (15–16, 24, 27–28).

In studies (7) the impacts of temperature and the presence of catalyst on the ability of ash to sulfate were examined. The tests were conducted using a thermogravimetric analyzer (TGA). TGA testing was conducted using a <5-µm-size fraction of ash produced from Powder River Basin (PRB) coals and lignites and exposing them to vapor-phase sulfur dioxide with and without catalyst at several temperatures. The aim of the testing was to determine the potential of the formation of sulfates to cause particle-to-particle bonding that leads to the formation of deposits in the temperature range where SCR catalysts are used. The TGA testing is focused on determining the reactivity of the <5-µm ash produced from selected PRB and blends to sulfur dioxide and gas-phase phosphorus species as a function of temperature. Testing was conducted to determine the weight gain with flue gas containing ammonia. The impact temperature on the weight gain due to the formation of sulfates for a PRB blend is shown in Figure 8. The rates of sulfation were found to increase with increased temperature. The results show an increase in the weight gains when ammonia and phosphorus were added. Ground catalyst was mixed with PRB and placed in the TGA. Increases in weight gain were observed when catalyst was added as compared to baseline cases for 100% PRB, as shown in Figures 8 and 9, respectively. The presence of catalyst enhances the formation of sulfates.

Full-Scale Slipstream Testing

More recently (8), the behavior of ash and mercury in flue gas produced from the combustion of lignite and subbituminous coals from the United States of America in selective catalytic reduction (SCR) systems for nitrogen oxide removal has been examined. Typically, these coals contain ash-forming components that consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, these coals produce ash that has an abundance of alkali and alkaline-earth-rich oxide particles (<5 µm) that are carried into the backpasses of the combustion system and react with flue gas to form sulfates and possibly carbonates. The forms of mercury in the flue gas produced from the lignite and subbituminous coals are dominated by the elemental form. Slipstream testing was conducted at two subbituminous-fired power plants and one lignite-fired power plant to determine the impacts of ash on SCR plugging, blinding, and mercury oxidation.

The SCR slipstream system consists of two primary components: the control room and the SCR reactor. The reactor section consists of a catalyst section, an ammonia injection system, and sampling ports for NO_x at the inlet and exit of the catalyst section. The control room houses a computer system that logs data and controls the gas flow rates, temperatures, pressure drop across the catalyst, and sootblowing cycles. The computer is programmed to maintain constant temperature of the catalyst, gas flow rates, sootblowing cycles, and ammonia injection. The computer is equipped with a modem that allows for downloading of data and modification of the operation of the reactor from a remote computer located at the EERC.

Flue gas is isokinetically extracted from the convective pass of the boiler upstream of the air heater. The temperature is typically about 790°F. The flue gases pass through a 4-inch pipe equipped with sampling, thermocouple, and pressure ports. Ammonia is injected into the piping upstream of the reactor section. The reactor consists of a steel housing that is approximately 8.5 inches square and 8 feet long. The reactor section has three components, including a flow straightener, a pulse section or sootblower, and a catalyst test section. A metal honeycomb is used as a flow straightener upstream of the catalyst section and is about 6 inches long. A purge section was installed ahead of the catalyst test section to remove accumulated dust and deposits. The catalyst test section is located downstream of the purge section. The entire catalyst section is insulated and equipped with strip heaters for temperature control. The catalyst test section is 3.28 ft (1 m) in length and houses three catalyst sections. Thermocouple and pressure taps are located in the purge sections for measurements before and after each section.

The induced-draft fan is used to extract approximately 400 acfm (200 scfm) of flue gas from the convective pass of the utility boiler to achieve an approach velocity of 5.2 m/s (17.0 ft/s). The gas velocity is similar to that found in full-scale applications. The total gas flow through the reactor represents a thermal load of approximately 300 kW.

The range of operating conditions for the reactor is listed below:

X Gas temperature: ~700°–800°F
X Gas flow rate: 400–500 acfm
X Approach velocity range: 5.0–5.5 m/sec
X Ammonia injection rate: 0.5:1 with NO_x level
X Tempering air for fan: ~ 50–200 scfm
X Catalyst dP: 0.5–1.0 inches water column
X Fan sized for up to 30 inches water column

The catalyst installed at the Baldwin and Coyote Stations was the Haldor Topsoe catalyst. Topsoe's DNX-series of catalysts comprises SCR DENOX catalysts tailored to suit a comprehensive range of process requirements. DNX-series catalysts are based on a corrugated, fiber-reinforced titanium dioxide (TiO_2) carrier impregnated with the active components vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels. The unique catalyst design provides a highly porous structure with a large surface area and an ensuing large number of active sites. The pitch of the catalyst was approximately 6 mm.

The catalyst installed at the Columbia Station was a Babcock Hitachi plate-type catalyst. This catalyst is a TiO_2-based plate catalyst, developed and manufactured by Hitachi. The pitch of the catalyst was approximately 10 mm.

The coals produced ash that had significant accumulations of ash on the catalyst on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation.

The deposits on the surfaces and within the pores of the catalyst consisted of mainly alkali and alkaline-earth element-rich phases that have been sulfated. The results of this testing found that the <5-µm ash rich in alkali and alkaline-earth elements is captured on the surface and within the catalyst pores. These materials react with SO_2/SO_3 in the flue gas, resulting in the formation of a continuous phase that blinds the catalyst. The ability of elemental mercury to be oxidized across the SCR catalyst was investigated at a North Dakota lignite-fired plant. These results showed no oxidation of mercury across the SCR catalyst.

The reactor was installed at the Baldwin Station and operated for a 6-month time period on the Haldor Topsoe catalyst. The information obtained from testing included pressure drop, sootblowing cycles, and reactor temperatures. Figure 10 show the pressure drop across the catalyst test periods from 0 to 2 months. During the first two months of operation, the pressure was about 0.5 inches of water; at the end of two months, the pressure drop was about 0.8 inches of water, indicating plugging had occurred. The air was pulsed a minimum of every 8 hours in an attempt to maintain cleanliness. The reactor was monitored on a daily basis, and adjustments in pulsing cycles were made in order to minimize deposit accumulation. However, for the first two months, the pressure drop steadily increased. There are several periods where the unit was taken off-line; during those times, the temperature of the catalyst was maintained. At 2-month intervals, a section of catalyst was removed and replaced with a new one.

For Months 2 through 4, the pressure drop was highly variable initially but was about 0.8 inches of water. From Months 4 through 6, the pressure drop was maintained between 0.6 and 0.8 inches of water. This is due to the installation of a fresh catalyst section and leaving two thirds of the catalysts in place that were partially plugged. The gas velocity in the single section of new, clean catalyst was high because of channeling, and the result of the high gas flow was less deposition and accumulation. Gas velocity has a significant impact on the potential for deposits to form. However, at high gas velocity, low NO_x conversion is likely.

The reactor was installed at the Columbia Station and operated for a 6-month period of time with the Babcock Hitachi catalyst. The information obtained from the testing included pressure drop information, sootblowing cycles, and reactor temperature. Figure 11 shows the test periods from 0 to 2 months. The pressure drop across the SCR upon installation was about 0.4 inches of water and increased to an average of about 0.5 inches of water, but ranged from less than 0.4 to greater than 0.8 inches of water. The pressure drop for Months 2 to 4 increased from about 0.5 to 0.7 inches of water because of accumulation of ash. After cleaning the reactor and replacing one catalyst section, the pressure drop was about 0.3 but increased to over

0.6 inches of water up to about 4100 hours. There was an outage at the plant, and aggressive pulsing of the reactor was conducted; the pressure drop was brought back down to 0.3 but rapidly increased to over 0.5 inches of water within 500 hours.

The same reactor that was installed at the Baldwin Station was moved and installed at the Coyote Station. In addition, the same Haldor Topsoe catalyst type was used in the reactor. The reactor was operated for a 6-month period of time. Figure 12 shows the test periods from 0 to 2 months. As this paper is being prepared, the reactor is still operating on-site. The pressure drop across the catalyst upon installation was about 0.4 inches of water. After only 750 hours, the pressure drop was 1.5 inches of water, indicating significant plugging and blinding. Very aggressive air pulsing was conducted, with little success in removing the deposits. The pressure drop for the catalyst was over two times greater than the pressure drop observed for the Baldwin Station utilizing the same reactor and same catalyst. At about 1700 hours, the reactor was cleaned, and a section of catalyst was removed for characterization. The pressure drop after cleaning was about 0.8 to 1.0 inches of water. The pressure drop did not increase as rapidly because of the higher velocities through the clean section of the catalyst.

The tops of the catalysts were photographed during inspection and sampling of the catalyst sections. Figure 13 shows the ash materials that accumulated on the catalyst inlet after 2 months of operation. The most significant accumulation was noted for the Coyote Station, followed by Columbia and Baldwin. The Coyote Station had some larger pieces of ash deposit material on the surface as well as plugging of the catalyst passages. The Baldwin Station showed some obvious deposition along the walls of the reactor and some accumulation on the inlet sections. The Columbia Station showed more significant accumulation and plugging than the Baldwin Station.

After 4 months, the tops of the catalysts were photographed during inspection and sampling of the catalyst sections, as shown in Figure 14. The most significant accumulation was noted for the Coyote Station and some accumulation for the Baldwin Station.

SCR Ash Deposit Characterization

The characteristics of the ash materials that collected on the catalyst surfaces and pores were characterized by SEM and x-ray microanalysis and, in selected cases, XRD was used to determine the crystalline phases present. The catalysts were sampled after 2, 4, and 6 months. The sections were sampled, and approximately 2.5-cm squares were mounted for SEM analysis on double-stick tape and in epoxy resin. The double-stick tape samples allowed for characterization of the external morphology of the particles and catalyst surface. The samples mounted in resin were cross-sectioned and polished, which allowed for more detailed and quantitative analysis of the bonding materials and materials that accumulated in the pores of the catalyst. Detailed information on all the samples can be found elsewhere (add FPT reference). Examples of two deposit and catalyst analysis are presented here.

The 6-month sample from the Baldwin Station showed extensive sulfation of the alkaline-earth elements present in the deposits. Figures 15a and 15b show regions of the catalyst where all the pores were blocked and a minimal amount of deposit on the surface of the catalyst. Figure

15c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical compositions of selected points that indicate the presence of high levels of calcium and sulfur are listed in Table 3. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample. In addition, there are some regions of high levels of calcium, aluminum, and sulfur present. The calcium aluminum materials are likely derived from the calcium aluminum phosphate minerals found in the coal fired at this plant.

The 4-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst. Figure 16 shows the 4-month sample from the Coyote Station. The catalyst showed particles adhering to the surface and completely filling and masking the pores in the catalyst. The external morphology of the catalyst surface shows the masking of the catalyst surface. Chemical compositions of selected points are shown in Table 4. The 4-month sample shows more sulfation than the two months of exposure samples. Figures 16b and 16c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of sodium-, calcium-, and sulfur-rich material, likely in the form of calcium sulfate. Significant sodium was found in the deposits, as shown in Table 4. The sample shows significant evidence of sulfation after 4 months of exposure and was much more pronounced than the samples for the Baldwin and Columbia Stations that are fired on PRB coals. The presence of sodium enhances the bonding and sulfation of the particles to form a strongly bonded matrix (22).

SCR Deposit Formation Mechanisms

The mechanism for the formation of deposits that blind SCR catalysts involves the transport of very small particles rich in alkali and alkaline-earth elements, the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. The formation of SO_3 from SO_2 is catalyzed by the SCR; this, in turn, increases the reaction rate of SO_3 to form sulfates. In some cases, the alkali and alkaline-earth elements will also react with CO_2 to form carbonates. XRD analysis identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements including sodium, magnesium, calcium, and potassium, in addition to mineral phases. The primary minerals present in these coals include quartz, clay minerals, carbonates, sulfates, sulfides, and phosphorus-containing minerals (6).

During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component, their association in the coal, and combustion system design and operating conditions. Significant research has been conducted on ash formation mechanisms and relationships to impacts on power plant performance (1–6, 9–13, 19–21, 29). During combustion, the inorganic components associated with western subbituminous and lignite coal typically are distributed into various size fractions of ash. The smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. These ash particles are largely derived from the organically associated cations in the coal. The larger size fraction has higher levels of aluminum and silicon derived from the mineral fraction of the ash-forming component of the coal. Entrained ash was extracted from the Columbia Station at the point of the inlet to the SCR reactor and was aerodynamically classified and analyzed. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst, as shown in Figure 17. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-µm size fraction. The deposited material shows significantly more sulfation than the entrained-ash size fraction, indicating that the sulfation process occurs after the particles are deposited in the catalyst.

The mechanism of SCR catalyst blinding when firing lignite or subbituminous coals is shown in Figure 18 (30). The requirements for the formation of deposits that blind SCR catalyst include firing a coal that produces significant levels of <5-µm-sized particles. The particles are transported into the pores of the catalyst and subsequently react with SO_3 to form sulfates. The sulfate forms a matrix that bonds other ash particles. The SCR catalyzes the formation of SO_3 and thereby increases the rate of sulfation (24, 25). The sulfation of CaO increases the molar volume, resulting in the filling of the pore. For coals that have high sodium contents, formation of low-melting-point phases such as pyrosulfates is possible (31). Pyrosulfate materials can melt at temperatures as low as 535°F in coal-fired power systems.

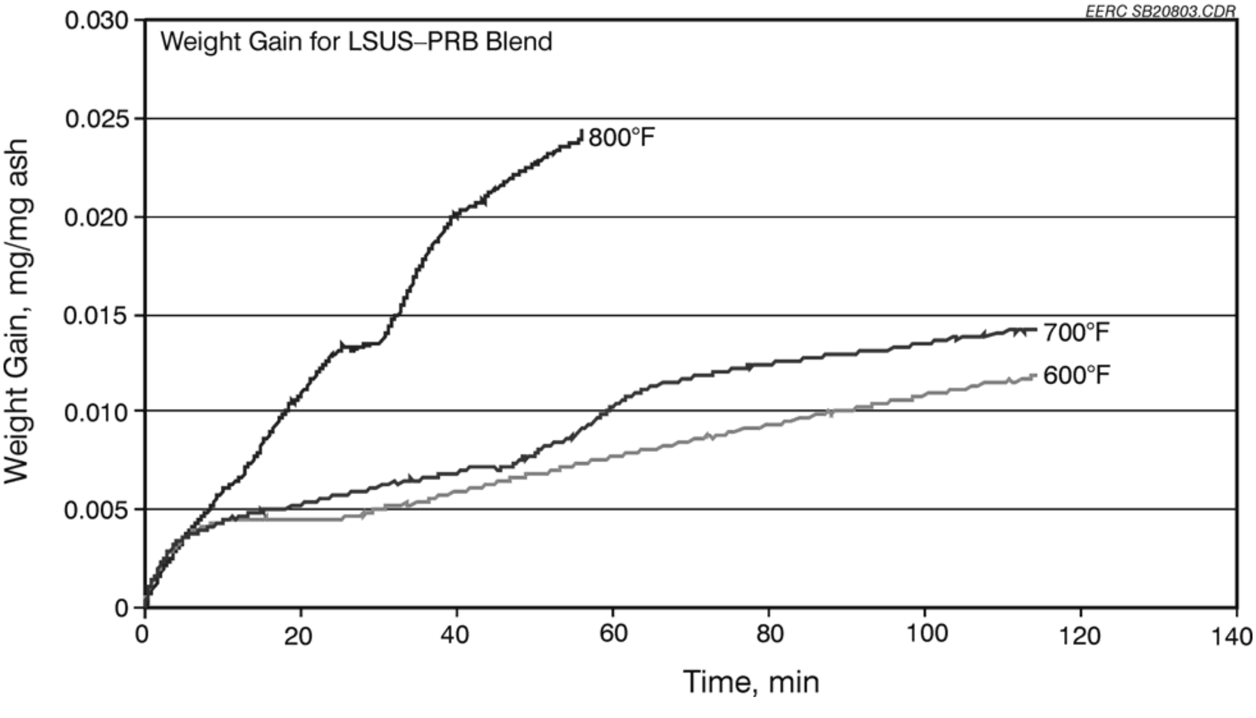

Figure 8. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia at three temperatures.

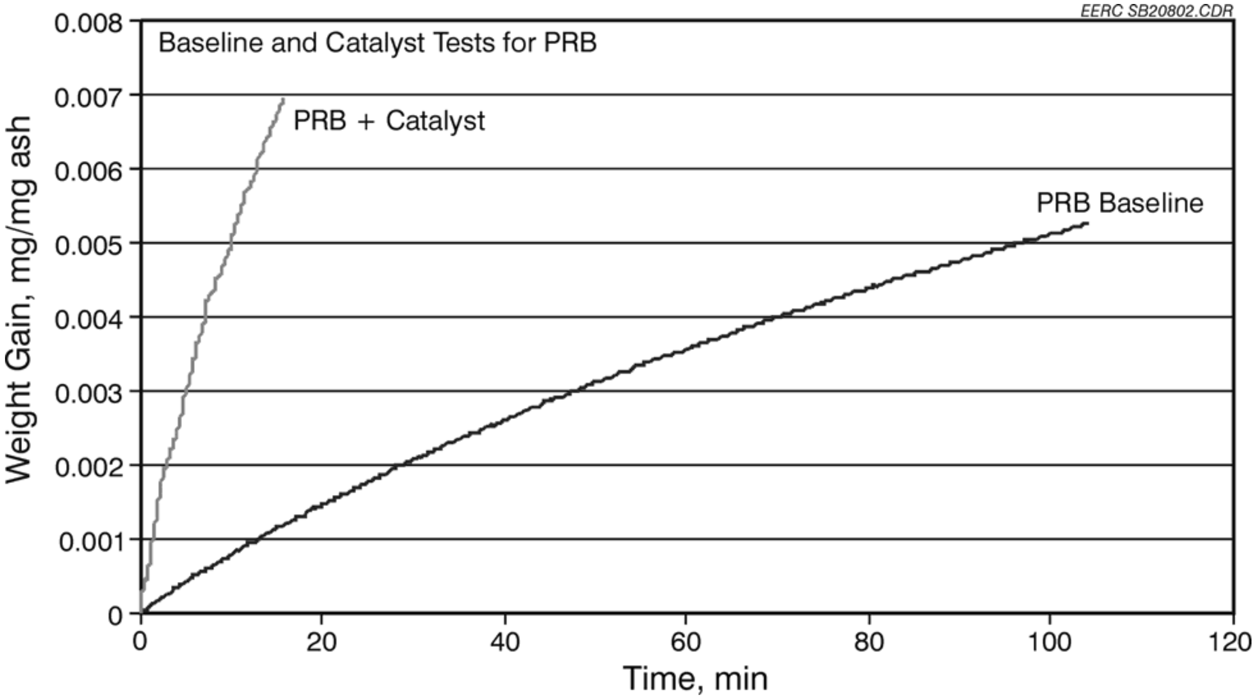

Figure 9. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia with and without SCR catalyst present.

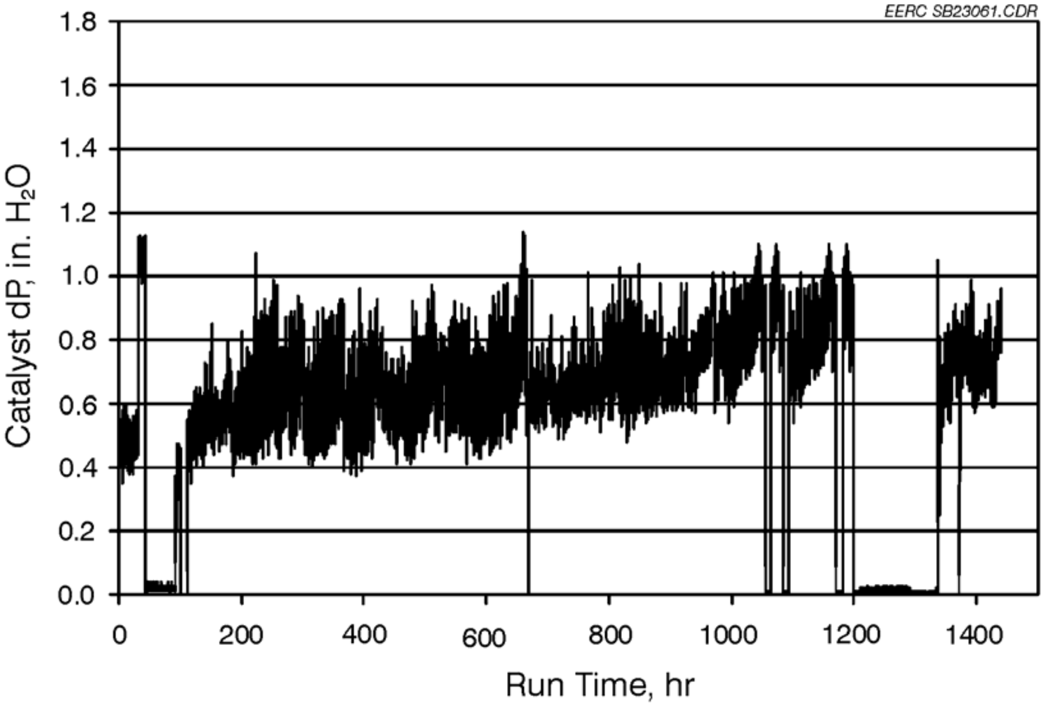

Figure 10. Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.

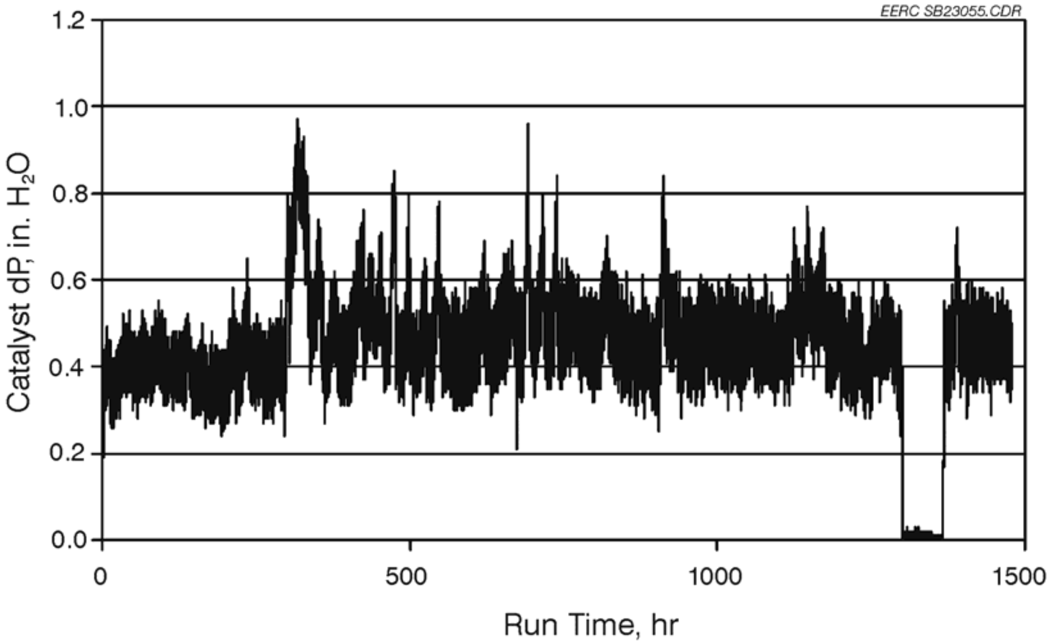

Figure 11. Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.

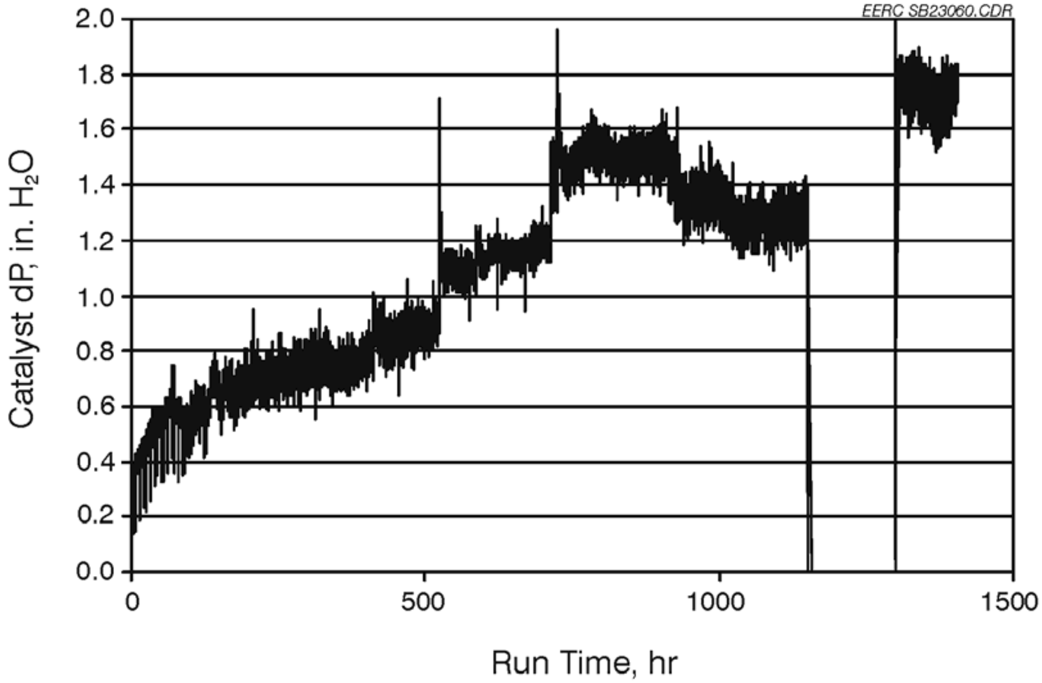

Figure 12. Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.

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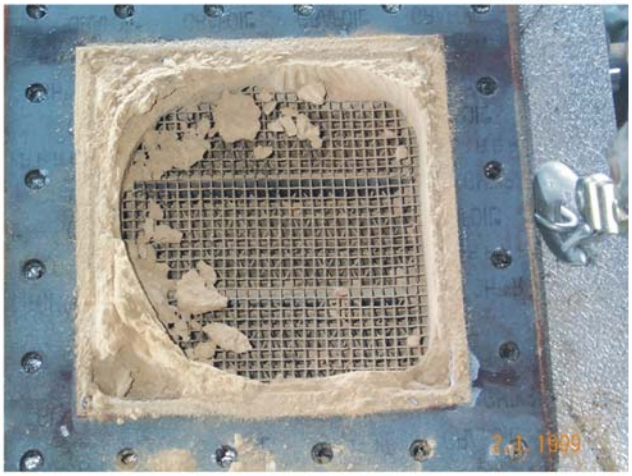
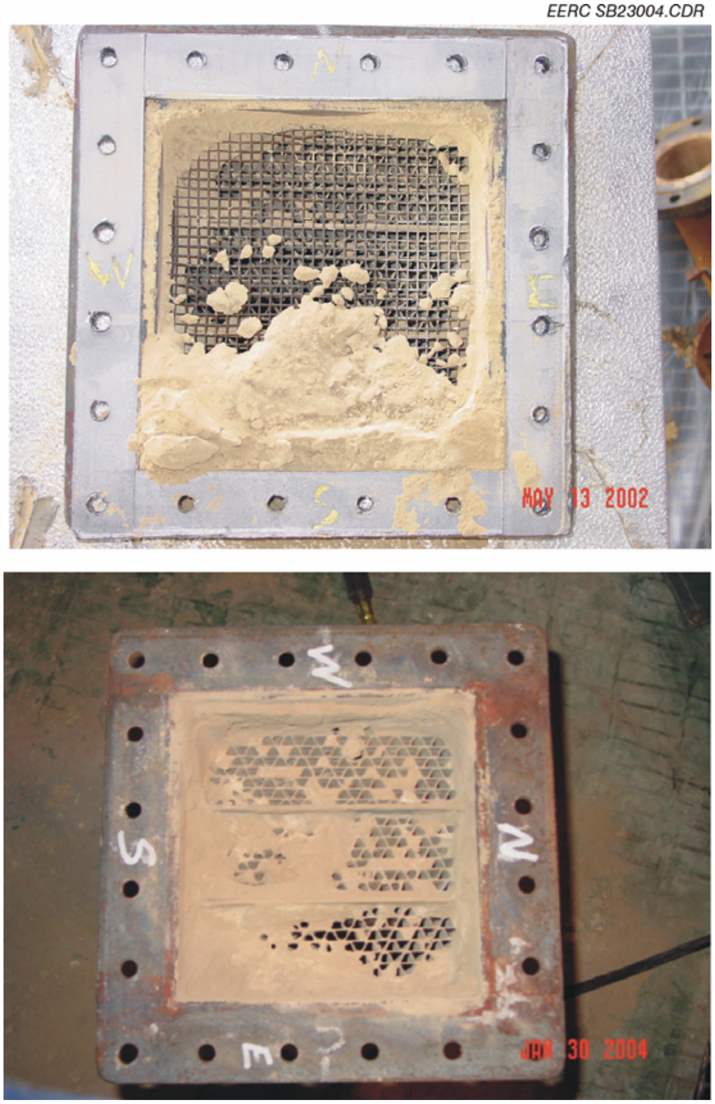


Baldwin Station after 2 months

Coyote Station after 2 months

Columbia Station after 2 months

Figure 13. Pictures of catalyst inlet after about 2 months of testing at each plant.



Baldwin Station after 4 months

Coyote Station after 4 months

Figure 14. Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.

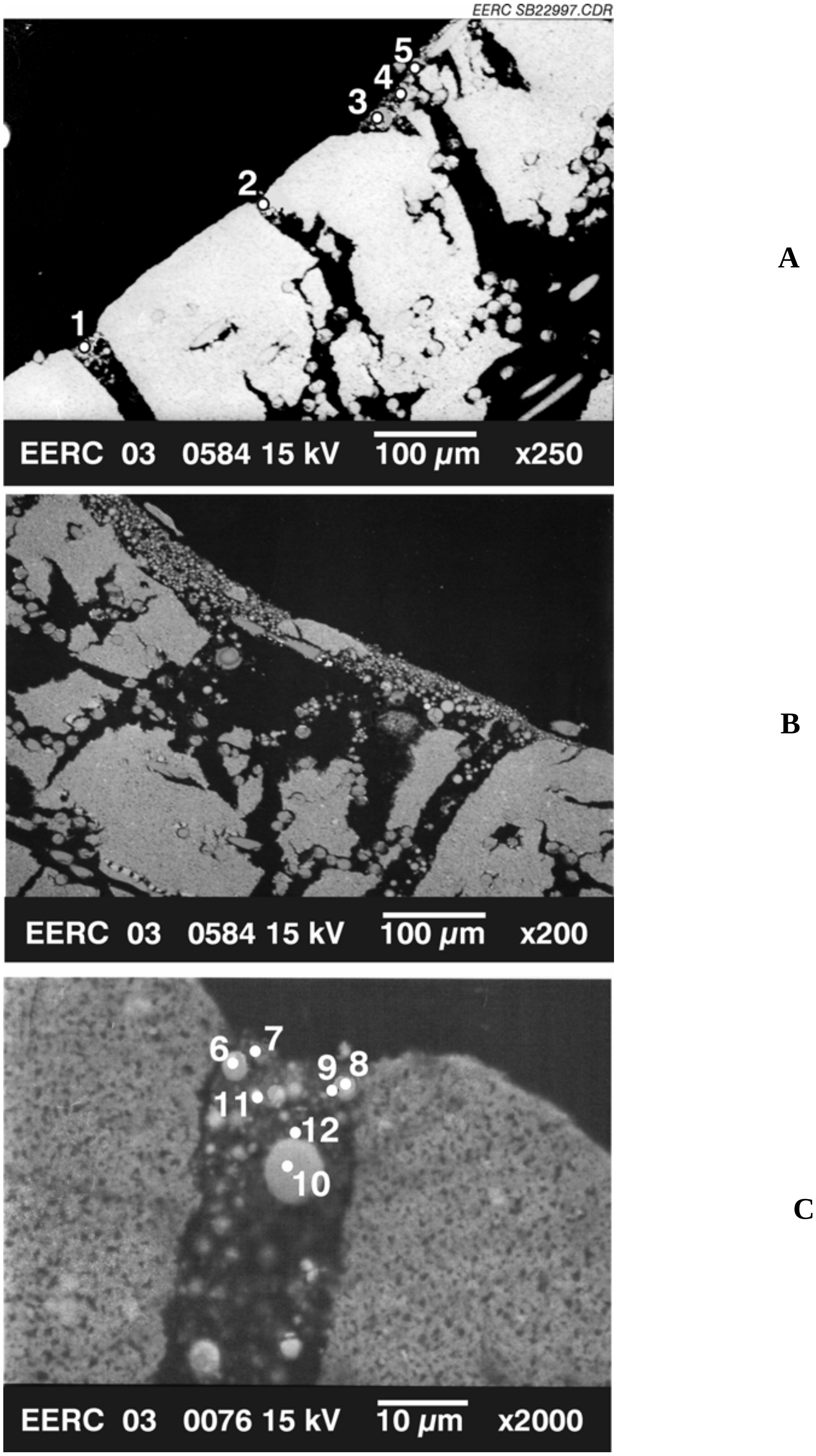


Figure 15. SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure. A) and B) low-magnification images of ash deposit on catalyst surface

and C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

Table 3. Chemical Composition of Selected Points and Areas in Figure 15

	Chemical composition (normalized wt% equivalent oxide)					
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6
1.1.1						
	0.6	1.0	2.1	0.3	0.5	2.7
Na_2O	4.3	2.5	6.3	0.7	1.6	7.6
MgO	14.8	16.0	15.6	15.5	14.7	0.9
Al_2O_3	3.3	7.8	18.8	57.7	7.7	47.3
SiO_2	2.3	2.1	0.5	0.6	1.8	0.0
P_2O_5	30.7	20.4	17.7	0.0	29.0	0.8
SO_3	0.7	0.0	1.0	0.4	0.9	0.9
K_2O	28.8	28.7	28.1	22.5	34.9	28.4
CaO	2.0	7.2	2.2	0.3	1.3	1.1
TiO_2	11.4	12.9	6.2	0.0	7.6	7.9
Fe_2O_3	1.1	1.4	1.4	2.0	0.0	2.5
BaO						
Total	100	100	100	100	100	100
Oxide	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
1.1.2						
	1.7	0.4	0.5	2.2	1.3	1.7
Na_2O	4.5	6.4	5.9	5.0	3.4	6.4
MgO	5.0	2.4	3.0	19.2	10.8	3.8
Al_2O_3	8.4	18.4	18.5	31.0	17.9	16.7
SiO_2	1.8	0.9	1.0	0.0	1.7	1.2
P_2O_5	37.9	1.7	5.3	0.0	22.5	13.9
SO_3	0.4	0.0	0.0	0.9	0.8	0.0
K_2O	31.4	52.6	49.0	28.9	30.6	45.4
CaO	1.9	6.9	7.4	2.4	2.0	1.1
TiO_2	7.1	5.7	6.0	6.3	6.1	6.5
Fe_2O_3	0.0	4.6	3.5	4.2	2.9	3.3
BaO						
Total	100	100	100	100	100	100

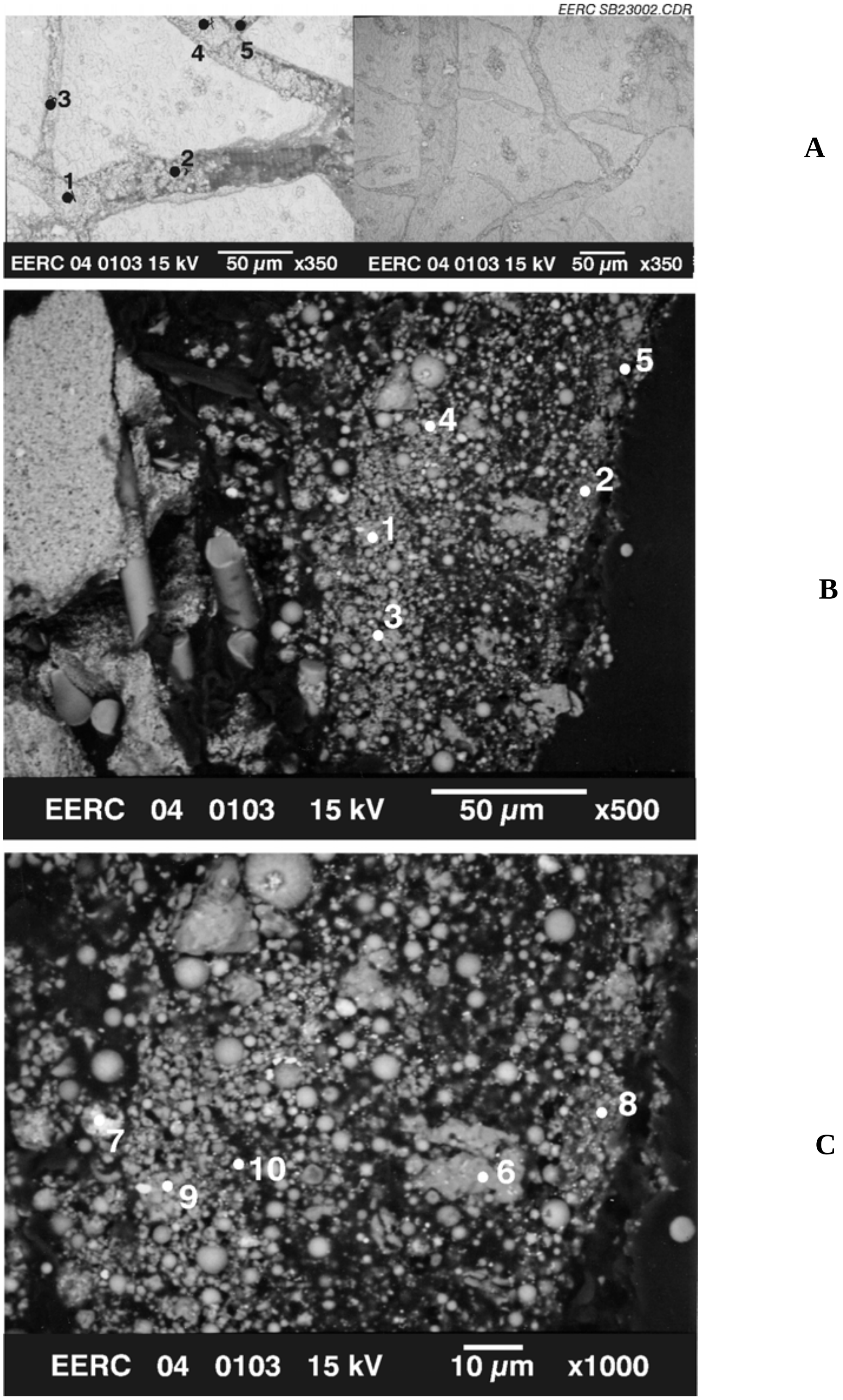


Figure 16. SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure. A) low-magnification image of ash deposit on catalyst surface, B) low-

magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

1.1.2.1 Table 4. Chemical Composition of Selected Points and Areas in Figure 16

	Chemical composition (normalized wt% equivalent oxide)				
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5
1.1.3					
	6.7	1.9	7.1	6.2	3.1
Na_2O	1.1	1.7	1.1	2.6	3.2
MgO	2.6	8.8	4.0	4.8	10.5
Al_2O_3	7.0	21.1	11.3	5.6	32.2
SiO_2	0.2	2.4	0.0	0.2	0.9
P_2O_5	54.7	38.5	56.4	57.5	30.4
SO_3	2.0	2.8	0.7	2.8	2.4
K_2O	18.0	3.4	15.8	9.3	2.3
CaO	0.6	0.8	1.1	1.3	1.5
TiO_2	5.8	5.1	2.1	6.5	9.8
Fe_2O_3	1.4	13.5	0.5	3.4	3.6
BaO					
Total	100	100	100	100	100

Oxide	Point 6	Point 7	Point 8	Point 9	Point 10
1.1.4					
	9.5	2.6	10.4	8.9	4.4
Na_2O	1.2	1.9	1.3	3.0	3.7
MgO	2.6	8.6	4.2	4.9	10.6
Al_2O_3	6.3	18.2	10.5	5.0	28.9
SiO_2	0.1	1.9	0.0	0.1	0.7
P_2O_5	41.8	28.4	44.9	44.5	23.4
SO_3	3.2	4.3	1.2	4.4	3.8
K_2O	24.5	4.4	22.5	12.8	3.1
CaO	0.6	0.8	1.3	1.5	1.8
TiO_2	7.7	6.6	2.9	8.9	13.2
Fe_2O_3	2.4	22.3	0.9	5.9	6.3
BaO					
Total	100	100	100	100	100

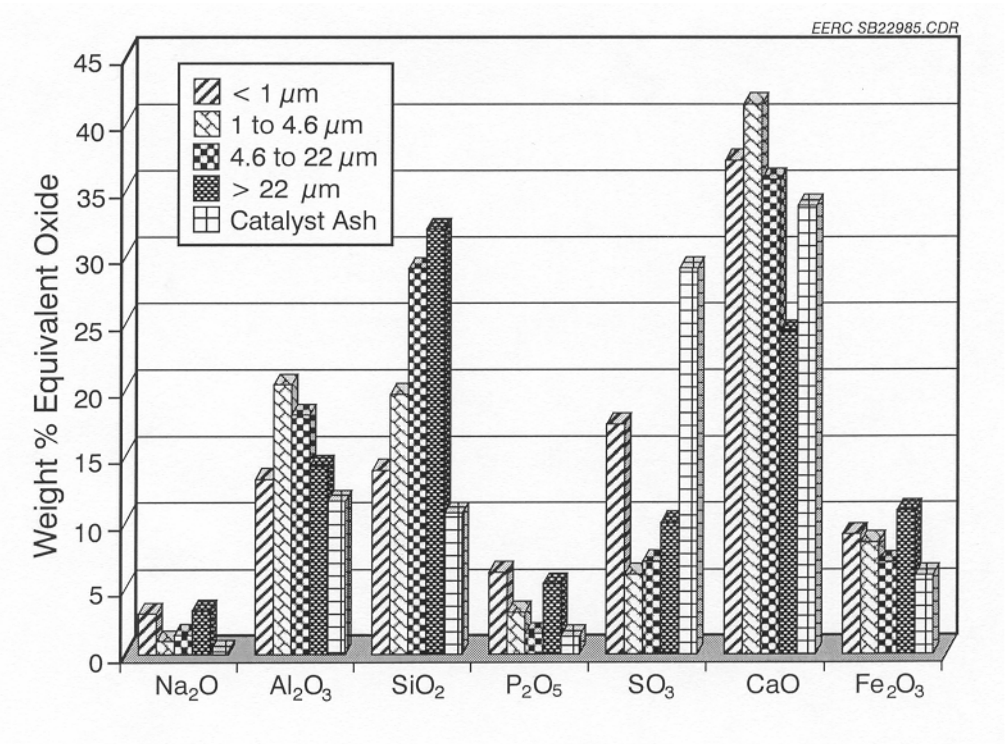


Figure 17. Comparison of entrained ash and deposited ash on catalyst for Columbia Station.

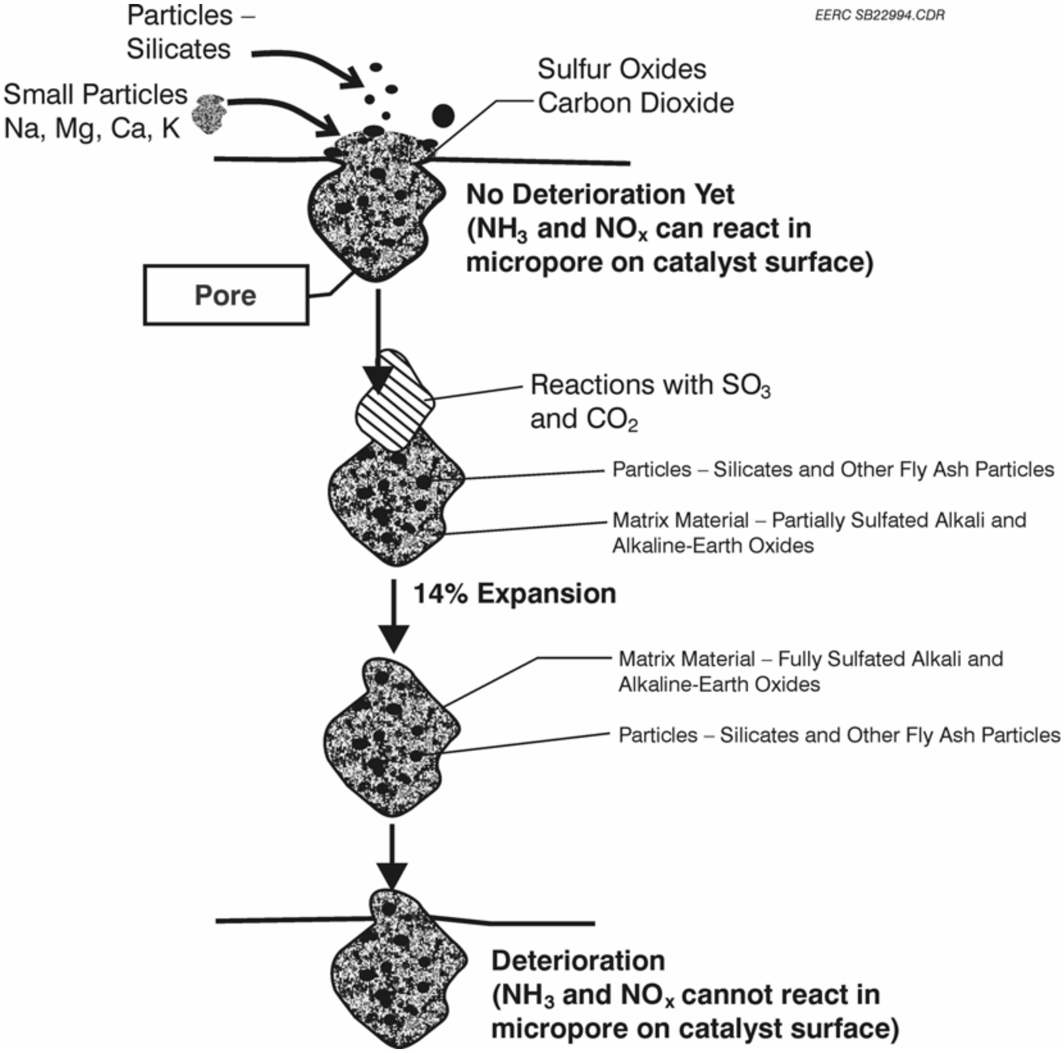


Figure 18. Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard and others [30]).

Low-Temperature Pyrosulfates

The presence of sodium sulfate in the flue gas exiting a scrubber will cause problems to low-dust and tail-end devices such as selective catalytic reduction (SCR) systems for NO_x reduction. There are two problems associated with the fine particulate rich in sodium sulfate on downstream devices. These include accumulation of fine particles on the SCR that, when sootblown, will cause opacity problems, and that the fine particles on the SCR will form pyrosulfates such as $(K_{1.5}Na_{0.5})S_2O_7$ that have melting points as low as 535°F (31) that will blind the catalyst. The presence of these compounds in low-temperature corrosion deposits is well known (32). In addition, the presence of SO_3 enhances the formation of the low-melting-point pyrosulfates (31). The sodium sulfate materials will cause opacity and SCR catalyst blinding problems that limit the feasibility of the low-dust or tail-end SCR technology for use with high-sodium lignite coals.

The sodium sulfate materials will be transported to the catalyst surfaces by diffusion, electrophoresis, and, possibly, inertial impaction. The particles are held in place by weak electrostatic and van der Waals forces. Once accumulation takes place, the sodium sulfate particles will react with flue gas components, resulting in the formation of pyrosulfates. The formation of pyrosulfates involves the following processes (31):

1. Formation of sulfates such as Na_2SO_4 and K_2SO_4
2. Conversion of SO_2 to SO_3 in the bulk gas phase – catalytically active surface such as an SCR catalyst – $SO_2 + \frac{1}{2} O_2 \rightarrow SO_3$
3. Pyrosulfate formation – $Na_2SO_4 + SO_3 \rightarrow Na_2S_2O_7$

The melting points of selected pyrosulfate phases are shown in Table 5.

Table 5. Melting Points of Selected Pyrosulfate Compounds

Compound	Temperature, °C	Temperature, °F
$K_3Fe(SO_4)_3$	618	1144
$K_3Al(SO_4)_3$	654	1209
$KFe(SO_4)_2$	694	1281
$Na_3Fe(SO_4)_3$	624	1155
$Na_3Al(SO_4)_3$	646	1195
$NaFe(SO_4)_2$	690	1274
$Na_2S_2O_7$	401	754
$K_2S_2O_7$	300	572
$(K_{1.5}Na_{0.5})S_2O_7$	279	535

Melting points for pyrosulfates between 535° and 770°F have been reported in the literature. Much of the past work has focused on the formation of these phases on tube surfaces. These species contribute to the corrosion of heat-transfer surfaces in coal-fired power plants. The exact melting point depends on the relative amounts of sodium and/or potassium.

There is significant evidence for the formation of sodium-rich fine particulate in full-scale power plants when firing high-sodium-containing coals. For example, Minnesota Power's Boswell Energy Station found that when it fired high-sodium, lower-ash subbituminous coal, it experienced increases in opacity. Hurley and Katrinak (33) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with an electrostatic precipitator and a wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using an impactor and multicyclone. The sized fractions were analyzed to determine the composition of the submicron-sized fraction.

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of one of the coals. Vapor-phase sodium condenses in the convective pass to form fine sodium sulfate particles or other Na species that later react with ash particles. Pure Na_2SO_4 particles are too small to be removed by scrubbing.

CONCLUSION: SCR IS NOT FEASIBLE FOR NO_X REDUCTION AT MILTON R. YOUNG

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be impossible because of the formation of sodium calcium sulfates in the pores of the catalyst. Following is a list of the key roadblocks associated with lignites which have not been overcome and, in our opinion, make the installation of SCR catalyst at the MRY plant technically infeasible for NO_x control.

- High alkali and alkaline-earth elements present in the coal fired at the MRY plant form sulfates that blind the catalyst.
    - Cyclone-firing partitions the ash during combustion. As a result the level of sodium and calcium in the fly ash is enhanced and will increase the SCR catalyst blinding.
    - Sulfate reactions increase with increasing temperature, and the suggested temperature of installation at the MRY facility is higher than typical installations; therefore, sulfation problems are enhanced.
    - Sulfate formation is also enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.
    - The high levels of sodium in the coals combined with calcium produces low-melting-point eutectic compounds that will melt on the surface.
    - Sulfates form on the surfaces of catalysts firing PRB coals. Lignites will be several orders of magnitude worse because of the higher levels of sodium.

- The ash components to impact SCR performance in Japan and Europe (14–16) include alkali and alkaline-earth elements that result in sulfate formation. The total calcium content and the sum of the calcium, magnesium, potassium, and sodium provide an indication of the problems that occur. For the coals fired at the MRY power plant, the CaO content ranges from 6.8%–19.99%, and the sum of the alkali and alkaline-earth elements range from 9.33%–29.87% of the ash. The levels of calcium in Center lignite are 2 to 4 times higher than the problematic coals in Japan and Europe.

- The finding or work conducted in Germany and Japan were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-rich sulfate formation that fill and plug the catalyst at both lignite (North Dakota)- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or popcorn ash, plugging the top of the SCR catalyst with deposit fragments, is a significant problem because of the extremely high deposition potential of the coal. The formation of deposits in various parts of the boiler requires continuous sootblowing. The deposit fragments are likely going to be carried with the bulk gas flow to the SCR catalyst, resulting in plugging.
- The variability of the lignite is a problem of unique concern at MRY. The deposition potential of the coal is always changing rapidly, resulting in rapid growth and formation of deposits in various sections of the boiler. Aggressive sootblowing of all fireside surfaces is already required to maintain full-load operation. The sootblowing of upstream heat exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, and during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

The ash-related impacts of the lignites from North Dakota are the most complex and severe of any coals in the world, and installation of tail-end SCR systems for NO_x reduction will not be possible. The key problems associated with lignites that have not been overcome and, in our opinion, make the installation of tail-end SCR systems at the MRY plant technically infeasible for NO_x control at MRY's Units 1 and 2 are listed below:

X High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces extreme levels of homogeneously condensed sodium sulfate that pass through the wet scrubber. In addition, the cyclone-firing system captures much of the ash as slag, resulting in a decrease in ash that is available for providing condensation sites for vapor-phase sodium compounds upon gas cooling. This results in an increased homogeneous condensation of sodium sulfate.

X These small particles pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials cannot feasibly be resolved through conventional sootblowing and cleaning technologies to remove the particulate.

X Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

The formation of liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems catalyze the formation of SO_3 from SO_2. The presence of SO_3 significantly enhances the formation of the pyrosulfates at MRY to an extreme level that cannot be dealt with effectively using cleaning technologies that exist today.

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APPENDIX C

COST METHODOLOGY

CAPITAL COST ESTIMATE DETAILS FOR NO_X CONTROLS

O&M COST ESTIMATE DETAILS FOR NO_X CONTROLS

C.1 METHODOLOGY FOR ESTIMATED COSTS

The summary economic evaluations of each alternative are presented in the cost impact sections of the main report. Capital and O&M cost estimates for each alternative are presented individually. The Levelized Total Annual Cost (LTAC) for all the alternatives for control of a single pollutant (i.e. NO_X) from a single unit is then presented together with Unit Control Costs. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 20 year design life, again in current (2006) dollars. As a minimum, the design life for any alternative was taken to be that recommended by “The EPA Air Pollution Control Cost Manual”, Sixth Edition, January 2002, EPA/452/B-02-001[i].

The LTAC is also used to calculate the average annual and incremental cost effectiveness of each alternative. The LTAC represents an annual payment in current day dollars sufficient to finance the project over its entire life.

In determining the LTAC a Capital Recovery Factor and an O&M Levelization Factor were calculated from the project economic conditions and then applied separately to the estimated capital and O&M costs. The equation used is shown below.

$$LACC / NPV = \left(\frac{i(1+i)^n}{(1+i)^n - 1} \right) = CRF$$

Where,
LACC = Levelized Annual Capital Cost
NPV = Net Present Value of the capital investments required.
i = discount rate
n = design life in years
CRF = Capital Recovery Factor

Therefore:

$$LACC = CRF \times NPV$$

For the economic conditions described in Table C.1-1 the Capital Recovery Factor was calculated to be 0.08718.

In determining the levelized annual O&M cost the estimated annual O&M cost, the inflation rate, the discount rate, and the equipment life are taken into account. The O&M Levelization Factor (OMLF) was calculated as follows.

$$LAOMC / A_1 = \left(\frac{1+i_d}{1+i_i} - 1 \right) \left(\frac{i_d (1+i_d)^n}{(1+i_d)^n - 1} \right) = OMLF$$

Where,
A = Levelized Annual O&M Cost (LAOMC)
A_1 = Total annual O&M cost in current dollars
i_d = discount rate
i_i = inflation rate
n = design life in years

Therefore:

$$LAOMC = OMLF \times A_1$$

For the economic conditions described in Table C.1-1 the Operating and Maintenance Levelization Factor was calculated to be 1.24873.

The Levelized Total Annual Cost, or LTAC is the sum of the levelized capital cost and the levelized O&M cost. Therefore:

$$LTAC = LACC + LAOMC = (CRF \times P) + (OMLF \times A_1) = 0.08718 \times P + 1.24873 \times A_1$$

The differences between alternatives are also presented graphically in the form of a plot of the annual emissions reduction (tpy) versus the LTAC for each alternative. This form of plot graphically depicts the cost effectiveness or Unit Control Cost (in $/ton of pollutant reduction) of each alternative relative to all of the others. The cost effectiveness is also referred to as the Unit Control Cost and defined as the LTAC divided by the annual emissions reduction (ton/yr). The area on the plot indicated by the various data points represents the cost effectiveness envelope for the alternatives under consideration. A smooth line is drawn on this plot connecting the rightmost points (those with the lowest cost for a given level of emissions reduction). This line is referred to as the Dominant Control Curve (DCC). The DCC defines the right hand boundary of the envelope encompassing all of the alternatives considered. The DCC is used as a screening tool between considered alternatives. Those alternatives whose plotted position is above and/or to the left of the DCC are not as cost effective as those forming the line and thus can be eliminated from further analysis if desired.

In order to compare various pollutant control alternatives, the Unit Control Cost and the incremental Unit Control Cost of each alternative were also calculated and tabulated for comparison purposes. The Unit

Control Cost compares control technologies on a basis of dollars expended per ton of pollutant reduced ($/ton). This relationship is graphically depicted in the DCC chart.

To more accurately compare between alternatives with different costs and control efficiencies, the incremental cost effectiveness is also determined for those alternatives on the DCC. The incremental cost effectiveness is defined as the LTAC of a given control option minus the LTAC of an alternative, divided by the difference between the annual emissions reduction (tpy) of the given control option and the alternative being evaluated. The combination of these two economic analyses can be used as an argument for the elimination of control technologies with significantly greater marginal control costs than the given case. The equation used for the incremental cost effectiveness is shown below.

$$ICF = \frac{(LTAC_1 - LTAC_2)}{(AE_1 - AE_2)}$$

Where,

ICF = Incremental cost effectiveness ($/incremental ton removed)
$LTAC_1$ = Levelized Total Annual Cost of control alternative No. 1 ($/yr)
$LTAC_2$ = Levelized Total Annual Cost of control alternative No. 2 ($/yr)
AE_1 = Control option No. 1 Annual Emissions Reduction (ton/yr)
AE_2 = Control option No. 2 Annual Emissions Reduction (ton/yr)
(The higher cost, more effective control option is subscript 1 in this equation.)

The economic analyses presented in this report not only include the estimated capital and O&M costs for each alternative, but also the LTAC for economic comparison of the various alternatives. In addition, the Unit Control Cost or cost effectiveness is presented for each alternative. Finally, a comparison between alternatives, in the form of the marginal cost effectiveness, is presented in both numerical and graphical form. Thus a comprehensive comparison of the economic impacts of each alternative, as well as the differences in economic impact between alternatives is clearly presented.

Table C.1-1 – Economic Factors(1),(2)

Total Possible Operating Hours per Year	8,760
Amortization Life, Years	20
Cost of Money	6%
Property Taxes, Insurance, %	NA
Conversion Tax (in lieu of property tax)	NA
Amortization Rate for APC Capital Costs	6%
Interest During Construction (IDC)	6%
Discount Rate (used to calculate NPV)	6%
Construction Cost Escalation	3%
Non-Fuel O&M Escalation	2.5%
Fuel (coal and natural gas) Escalation	2.5%
Auxiliary Electric Power Cost, $/MW-hr	$35.00
Urea Cost, ($/ton delivered, 50% aqueous solution)	$380.00
Natural Gas ($/mmBtu)	$7.98

(1) - All financial percentages and unit auxiliary electric power cost were provided by MPC.
(2) - All costs are in 2006 dollars unless noted otherwise.

C.2 NOx CONTROLS - CAPITAL COST ESTIMATES

The capital costs to implement the various NO_X control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. In the cases of SNCR and FLGR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy, or better.

The limitations of these capital cost estimates developed from unit capital cost factors multiplied by unit output are:

- Scope basis uncertainty – inability to precisely determine what scope of supply, including such things as balance-of-plant (BOP) systems and equipment improvements were required, assumed, or accounted for when developing the unit cost factors. Some alternatives may have higher indirect or BOP capital costs than others. Similarly, the inclusion of general facilities, preproduction and inventory costs, and other indirect costs is not known. It is likely that the utility owner's final total expenditure for the implementation of the alternatives, especially options that are most capital cost-intensive, will be greater than the calculated cost estimates.
- Location-specific influences – most NO_X control techniques have been applied primarily to eastern bituminous coal-fired plants located near large metropolitan areas, not in largely rural, upper midwestern United States locales. The amount of space available is dependent on the existing powerplant equipment and building layout and property plot area, versus what is expected to be required for implementing various control technologies. Transportation and local/regional labor costs are also variables.
- Size influences – some technologies' capital costs are more sensitive to "economies of scale" than others.
- Capacity margins – some technologies' may require higher capacity margins to allow sustained operation at high throughput rates over extended periods of time.
- Reliability concerns – some technologies' have been refined to a higher degree, and others may require more component redundancy than others in order to avoid performance reductions and potential outages for failures and repairs or replacements.
- Inflationary influences – the significant increases in 2004-2005 for raw material costs, especially steel and alloys for fabrication of structural and mechanical components, has occurred after many of these technologies were installed in projects upon which the referenced unit capital cost factors were based.

- Market conditions – as demand increases for emission controls, some alternatives become more cost-competitive, while others do not. This can be influenced by the relative supply and demand for the technology and number of suppliers who can furnish it. The demand for some alternatives can also be strongly influenced by the stringency of the local, state, and national regulatory requirements. Schedule for implementation and availability of local/regional labor for installation contractors are also market-driven factors.

The estimated NO_X control costs are in addition to capital costs to provide normal replacements of the existing Milton R. Young Station's major power generating equipment.

C.2.1 Separated Overfire Air Capital Cost Estimates

Installation of separated overfire air systems typically includes windbox and/or secondary combustion air supply duct modifications, boiler waterwall tube openings, airflow distribution devices (dampers/registers), airflow controls and measurement instrumentation, and related structural and electrical tie-ins to the existing plant facilities. A basic separated overfire air retrofit system installed on a lignite-fired cyclone boiler includes ports across the front and rear walls of the upper furnace. The unit capital cost factor is expected to be above the high end of the typical published cost range of \$5-10/kW[ii] (\$12.0/kW or \$3,080,000[iii] for MRYS Unit 1), due to the large ducts, relatively tall furnace (compared to typical bituminous coal-fired cyclone boilers), and the need to avoid existing obstructions within the boiler house.

An advanced form of SOFA unique to North Dakota lignite-fired boilers will include relocation of the existing lignite drying system vent port openings from the lower primary furnace to the upper furnace, to be placed at the same elevation as the new SOFA ports. This requires extension of the existing cyclones' lignite drying systems' vent piping to supply the new boiler furnace ports. This is expected to cost in the area of +\$4.7/kW or approximately \$1,200,000 for Unit 1's additional capital cost over and above the basic SOFA system. Overall, the advanced version of separated overfire air technology is estimated to have an installed capital cost of approximately \$16.6/kW (\$4.3Million) for MRYS Unit 1.

C.2.2 Reburn Capital Cost Estimates

C.2.2.1 Coal Reburn Capital Cost Estimates

There is one alternative that includes a new coal reburn system. Capital cost estimates for coal reburn systems are highly dependent on the requirements for reburn fuel preparation and feeding to the boiler. For the purposes of this analysis, the application of a pulverized coal reburn system assumed the need to make extensive additions to the existing fuel preparation equipment in the existing plant facilities and feeding to new furnace injectors. At least two new fine-grind pulverizers, or MPS-89 standard pulverizers followed by dynamic classifiers are expected to supply the amount of finely ground reburn coal for this method.

Addition of new electrical loads for the pulverized coal preparation equipment to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power will be available for powering the new pulverizers/micro-mills and related new coal reburn equipment, but this has not been confirmed.

The existing crusher bays do not have floor space available to allow the new milling equipment for reburn fuel preparation to be located adjacent to the existing coal crushers. This will require a separate building or addition to the existing powerhouse to be built to provide sufficient space to enclose the new milling and coal silo/handling equipment. Separate modified pulverized coal-style burners or coal injectors will be installed through new openings in the upper furnace front and rear waterwalls at or above the elevation of the existing lignite drying system vent ports, along with new overfire air ports located at a higher elevation, above the reburn fuel injectors. This would have the capacity to supply approximately up to thirty percent of the total full load fuel heat input to the boiler through the coal reburn injectors. This coal reburn system design was not expected to change the existing cyclone silo/feeder arrangement, such that all cyclones would remain operational. To achieve maximum NO_X emission control, only the advanced form of SOFA for pulverized coal reburn was included. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

The installed capital cost of pulverized coal reburn for the cyclone boilers at Milton R. Young Station used in this cost effectiveness analysis was estimated based upon a Clean Air Markets Division [CAMD] of the US EPA dollar per kilowatt unit capital cost factor for cyclones. The installed capital cost estimate of $21,900,000 for MRY Station Unit 1’s pulverized coal reburn alternative used in this cost effectiveness analysis was estimated based upon applying a 3.5% assumed inflation cost adjustment to the CAMD unit capital cost factor for cyclones of \$82.33/kW (x 1.035 = \$85.2/kW) included in a WRAP (Western Regional Air Partnership) draft report[iv] published on their website, dated April 26, 2005. The cost to relocate the lignite drying system vent ports (+\$4.7/kW) was added to the inflation-adjusted CAMD number (\$85.2 + \$4.7/kW = \$89.9/kW), since coal reburn is expected to include separated overfire air but not the extra costs for the special improvements identified for air-staged lignite-firing in cyclone boilers. This increased the installed capital cost by \$1,200,000 for MRY Station Unit 1's coal reburn system to a total of \$23,561,000. This does not include the additional particulate matter collection capacity considered necessary to limit the expected negative impact on opacity from this option.

To control particulate matter (PM) emissions that would be expected to increase from installation and operation of pulverized or micronized coal reburn, additional PM collection capacity will be required. A hybrid form of PM collection that supplements the existing electrostatic precipitator's performance, referred to as COHPAC (COmpact Hybrid PArticulate Collector). This was estimated in 2002 dollars at \$20,191,000 for MRY Station Unit 1's COHPAC[3]. Adjusted by an escalation factor of 1.2623, the installed capital cost of the COHPAC addition was estimated to be \$23,561,000 for MRY Station Unit 1 in 2006 dollars. When the COHPAC addition was combined with the Lignite Reburn and ASOFA alternatives, the resulting total estimated capital costs were \$46,656,000 for MRYS Unit 1 (\$89.9 + \$91.7 = \$181.5 /kW).

C.2.2.1 Gas Reburn Capital Cost Estimates

Conventional gas reburn options assume that seventeen percent of the total fuel heat input to the boiler is through the new gas reburn injectors to be located in the lower secondary furnace above the top rows of cyclones. Eight to twelve gas reburn injectors would be expected to be required in this case. Seven percent of the total fuel heat input to the boiler through the gas reburn injectors is assumed to be supplied for the fuel lean gas reburn alternatives. Four to eight gas reburn injectors could be assumed in FLGR™ cases. Gas reburn options assume that a new high-pressure gas pipeline would be brought from near Bismarck, ND approximately twenty six miles. The pipeline diameter is proportional to the amount of fuel required for the specific alternative, ranging from 24 inches for conventional gas reburn to 12 inches for fuel lean gas reburn cases. A station gas main, with new gas trains, consisting of valves, metering, and safety shutoff valves for the front and rear boiler for the gas injectors' supply, would be furnished and installed.

The capital costs for conventional gas reburn alternatives were estimated considering unit capital costs published in published technical literature. One vendor that has supplied numerous domestic utility boiler gas reburn systems (GE Energy, formerly GE-EER) published \$10/kW for gas reburn in a 2001 technical paper[v]. Another source published a 2005 technical paper[vi] that provided a unit capital cost range for gas reburn of \$15/kW to \$30/kW. Neither source included a detailed scope description nor cost breakdown for engineering, equipment, materials, and labor to install a gas reburn system.

Site-specific needs and challenges identified for applying conventional gas reburn to Milton R. Young Station, and lack of detailed gas reburn project scope and equipment descriptions available in published technical literature leads to a much greater degree of uncertainty with regards to an accurate capital cost estimate for this alternative. For the purposes of this study, the estimated installed capital cost for a conventional gas reburn system with advanced SOFA on MRYS Unit 1 is expected to be approximately \$9.9M (\$38.6/kW), which is above the top end of the previously stated range, before adding the new underground gas pipeline capital costs. This study assumed an average unit capacity capital cost factor of \$22/kW for conventional gas reburn, plus the additional costs for the advanced from of SOFA over basic SOFA (+\$1.2M or +\$4.6/kW) and the new high-pressure gas pipeline. This results in a an estimated installed capital cost for conventional gas reburn system with advanced SOFA on MRYS Unit 1 of \$11.1M (\$25.7/kW) plus the new high-pressure gas pipeline costs. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

Fuel lean gas reburn (without SOFA) capital cost estimates were based upon a late 2004 budgetary proposal[vii] by a vendor (Fuel Tech) with experience in supplying FLGR™ equipment, typically combined with an SNCR system. Estimated capital costs of \$3M include budgetary numbers for the equipment installation, including installation management, material and labor, with a –43% price adjustment assumed for 257 vs 450 MW for a fuel lean gas reburn system without SOFA on MRY Unit 1, not including the capital cost for the gas supply pipeline. Costs for work outside the vendor's scope, such as balance-of-plant additions plus other indirect costs were estimated to add approximately \$0.5M (25% plus 10% contingency) to the adjusted vendor's estimated installed cost of \$1.7M for their scope of supply. These adjustments result in a total installed capital cost for FLGR (without SOFA) estimated to be \$2.2M plus the capital cost for the gas supply pipeline. Adding the incremental costs for the advanced from of SOFA over no SOFA (+\$4.3M (+\$16.6/kW) results in an estimated installed capital cost for a fuel gas reburn system with advanced SOFA on MRYS Unit 1 of \$6.6M (\$25.7/kW) plus the new high-pressure gas pipeline costs.

The capital cost estimates for the new high-pressure underground gas supply pipeline assumed $7 per inch of diameter per foot of length. This was calculated to be approximately $23M for conventional gas reburning and $11.5M for FLGR™. The cost analysis for each NO_X control alternative involving a particular form of gas reburn assumed that both boilers at Milton R. Young Station select the same alternative that burns natural gas. Therefore, the estimated capital costs for gas reburn alternatives reflect a capacity-based proportional share of the gas pipeline capital costs, avoiding double-counting. This results in an estimated installed capital cost for MRYS Unit 1's share of the gas pipeline to be $8.1M / for the conventional gas reburn alternative and $4M for fuel-lean gas reburn alternatives.

The total installed capital costs for conventional gas reburn (with ASOFA) with MRYS Unit 1's share of the total capital cost for the gas supply pipeline estimated to be $18M ($70.6/kW). The total installed capital costs for FLGR™ (with ASOFA) with MRYS Unit 1's share of the total capital cost for the gas supply pipeline were estimated to be $10.6M ($41.4/kW). Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

C.2.3 SNCR Capital Cost Estimate

The alternatives that include selective non-catalytic reduction systems assume the use of urea unless noted otherwise. The SNCR systems' preliminary design and estimated capital costs were based upon a 450 MW lignite-fired cyclone boiler in a late 2004 budgetary proposal[7] by a vendor (Fuel Tech) with experience in supplying SNCR equipment. Circulation, metering, dilution, control, and injection equipment is included. A 180,000 gallon field-erected stainless steel storage tank will hold the 50% urea solution (as delivered by truck). Individual and multiple nozzle lances with multiple levels of urea reagent injection will be designed and located to optimize distribution and accommodate various boiler load conditions. Estimated capital costs of $4.9 Million include budgetary numbers for equipment installation, including installation management, material and labor assumed for a SNCR system applied to a 450 MW boiler. Costs for work outside the vendor's scope, such as outdoor reagent storage tank and building enclosure/equipment foundations and containment, and balance-of-plant additions plus other indirect costs were estimated to add approximately $1.9 Million (25% plus 10% contingency) to the vendor's estimated installed cost for their scope of supply. This results in an estimated total capital cost for SNCR (without SOFA) of $6.8M for a 450 MW lignite-fired cyclone boiler.

Applying these adjustments to a 257 MW boiler, estimated direct capital costs of $2.800,000, plus $1,000,000 for indirect costs yields a total installed capital cost for applying SNCR to MRY Station Unit 1 of approximately $3,836,000 ($14.9/kW).

C2.5 Layered Technology Capital Cost Estimates

Capital costs were generally estimated based upon simple arithmetic addition of individual unit output capital cost factors for combinations of available NO_X reduction technologies, such as SNCR with ASOFA. An advanced form of separated overfire air system included the lignite-fired cyclone boiler equipment changes within the estimated unit capital cost factors.

Adding the advanced SOFA capital cost of $4.3 Million to the previous estimated installed capital cost of $3.8 Million yields a total estimated installed capital cost of $8.113 Million ($31.6/kW) for the SNCR with ASOFA alternative for MRYS Unit 1.

As previously discussed, Lignite (coal) reburn (CR) was assumed to be combined with advanced SOFA and a COHPAC addition considered necessary to limit the expected negative impact on opacity from this option. The installed capital cost of the COHPAC addition was estimated to be $23,561,000 for MRY Station Unit 1. When the COHPAC addition was combined with the Lignite Reburn and ASOFA alternatives, the resulting total estimated capital costs were $46,656,000 for MRYS Unit 1 ($89.9 + $91.7 = $181.5 /kW).

C.3 Operating and Maintenance Cost Estimates for MRY Station NO_X Control

An evaluation was performed to determine the estimated operating and maintenance cost impacts of installing and continuously operating various feasible NO_X control technologies on Milton R. Young Station Unit 1. These were estimated to be in addition to existing O&M costs to operate and maintain the MRY Station equipment.

The expected loss of electrical power sales from the operation of the specific NO_X control alternative was included as an annualized cost, assuming $35 per megawatt-hour. This was determined to include estimates for:

- Reduction in annual unit output due to an expected negative reliability (i.e. uptime availability) impact for each alternative. This generation reduction was calculated by multiplying the estimated additional numbers of outage hours per year by the average running plant capacity factor for that specific alternative, multiplied by the historic 12-month average unit gross electrical power output (MW_g) determined during the same period as the highest 12-month rolling summation NO_X pounds.
- Net additional auxiliary electric power demand for the added control equipment for each specific alternative based on assumptions for gross horsepower, plus additional power demand for existing fans caused by flue gas pressure drop (COHPAC for additional PM collection capacity), with adjustment for expected reductions in power demand (such as a decrease in existing coal crusher and feeder electric demand for the pulverized coal reburn case).
- The average running plant capacity factor for each alternative, which may also include an expected negative impact on the unit capacity from operation of the technology. This assumes that the control technique limits the gross electrical power output of the Unit (such as causing an increase in flue gas flow) such that the firing rate of the boiler cannot be maintained or raised to compensate for the load impact. Examples are lower boiler thermal efficiency (higher unit heat rate) when firing natural gas (due to higher moisture content of the flue gas).

For the SNCR alternative that involves a chemical reagent injected for NOx control, such as urea, the annual reagent consumption based on an assumed actual stoichiometric ratio (ASR) of moles of equivalent NH_3 injected per mole of uncontrolled NO_X emission estimated at the point of injection, converted to a mass rate (lbs/hr) by multiplying by the estimated annual number of hours of operation and the estimated NOx reduction fraction, and then multiplied by unit reagent cost (for a specific inlet NO_X concentration, emission reduction percentage and ammonia slip level).

General annual maintenance costs were assumed to be 1.5 percent of the estimated installed capital cost for each alternative, except for the coal conveying and grinding equipment portion of the coal reburn alternative, which was assumed to be 3 percent. The periodic bag replacement costs and other COHPAC system maintenance costs were estimated to be approximately 5.3% of the installed capital cost of the additional particulate matter collection equipment.

Additional operating labor costs directly attributable to each alternative were assumed to be zero for all alternatives.

Other operating costs include:

- Reagent dilution water for those alternatives that involve a chemical reagent injected for NOx control, typically four times the amount of urea consumption (assumes urea is a 50% solution as delivered and is injected as a 10% solution); this follows EPA OAQPS convention[1].
- Heat required for urea reagent storage, for those alternatives that involve a chemical reagent injected for NOx control; the source of heat is assumed to be auxiliary electrical power, but could be auxiliary steam (depending on heat source availability and plant preference).
- Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water;
  This follows EPA OAQPS convention[1], but is not accepted practice by an experienced SNCR vendor (Fuel Tech) who claims that the heat produced from the exothermic reaction of urea and NO_X is approximately equal to the heat required to evaporate the dilution water. For the purposes of this study, this additional coal consumption has been included in the annual O&M costs.

The sum of the estimated annual O&M costs was multiplied by the O&M levelization factor (1.24873) for each alternative to yield levelized total annual O&M costs.

C.3.1 Separated Overfire Air O&M Cost Estimate

Operation of SOFA is expected to add a small amount of O&M cost, primarily electricity consumed by the conventional SOFA damper electric drive actuator and airflow measuring system transmitter on each port. Using the existing forced draft, induced draft, and flue gas recirculation fans is not expected to change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. Maintenance of the new overfire air ports and relocated lignite drying system vent ports is included, assumed to be 1.5 percent of the installed capital cost. This is included in every control alternative's estimated O&M cost.

SOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers can be routinely established. A Unit availability reduction of 2.2% (188 hours per year), for M.R. Young Station Unit 1 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic cyclone slag tapping operational conditions encountered during substoichiometric cyclone operation with SOFA. The expected loss of electrical power sales from the reduction in annual electrical power output due to a decrease in expected Unit availability from ASOFA operation is included in every control alternative's estimated O&M cost.

Boiler furnace waterwall tube maintenance may increase slightly as a result of more fireside corrosion due to substoichiometric cyclone operation with SOFA. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion from sulfur compounds in the furnace gases being created above the cyclones and below the SOFA injection ports. Due to the relatively moderate amounts of sulfur content in the lignite, modest amount of air-staging of the existing cyclones during SOFA operation, and the potential use of recirculated flue gas along the lower furnace walls, the expected change in corrosion rate of the boiler tubes should be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The additional costs associated with potential change in the frequency of furnace wall tube failures and changeouts are difficult to estimate, and have not been quantified.

C.3.2 Reburn O&M Cost Estimates

The alternatives that include a new coal reburn system assume the use of new equipment for preparing the reburn fuel to replace 25% of the MRY Station Unit 1 boiler's total fuel heat input. Two additional lignite silos, with coal feeders and fine-grind pulverizers followed by dynamic classifier(s), are assumed to be located in a new separate building or powerhouse enclosure. Booster fan(s) addition was included because the existing forced draft fans were assumed to be incapable supplying the additional amount of primary air to the fine-grind pulverizers and dynamic classifier(s) for processing and conveying the reburn fuel. Using the existing forced draft, induced draft, and flue gas recirculation fans is not expected to significantly change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. The expected loss of electrical power sales from the additional auxiliary electric power demand for the reburn milling equipment from an estimated 0.6% (1.5 MW) reduction in net output was included as a cost, assuming $35 per megawatt-hour for MRY Station Unit 1. Electrical power consumed by the increased load on boiler fans to overcome the higher flue gas system pressure drop, plus the COHPAC particulate collection system support equipment was estimated to be a 1.2% (3.2 MW) reduction in net output for Unit 1.

Maintenance of the separate reburn coal injectors, fuel and primary air piping, and reburn fuel milling equipment is expected to be similar to the expenses associated with typical pulverized coal burners. The estimated additional annual maintenance costs for a new micronized coal reburn system was assumed to be 3.0 percent of the installed capital cost, or roughly $693,000 per year, for MRY Station Unit 1. The estimated additional annual maintenance costs (inflation adjusted from 2002 to 2006 $) for the COHPAC system was approximately $1,223,000 for MRYS Unit 1. Boiler furnace waterwall tube and superheater/reheater tube maintenance may increase slightly as a result of more erosion due to increased particulate emissions or fouling by flyash deposits resulting from coal reburn operation with ASOFA. The additional costs associated with potential change in the frequency of boiler tube failures and changeouts are difficult to estimate, and have not been quantified.

The estimated impacts on operation and maintenance costs for the coal reburn alternative that include a new pulverized or micronized coal reburn system are approximate. The seven (Unit 1) existing coal crushers for preparing the main (cyclone) fuel fraction will have slightly lower electrical demand. This was estimated as -0.26 MW (-0.1%) for MRYS Unit 1. Addition of new electrical loads for the micronized coal preparation equipment to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power will be available for powering the new pulverizers/classifiers and related new coal reburn equipment, but this has not been confirmed.

Coal Reburn with ASOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers can be routinely established. A Unit availability reduction of 3.7% (316 hrs/yr), for M.R. Young Station Unit 1 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic operational conditions encountered during coal reburn operation with ASOFA. This reduction in annual electrical power output due to a decrease in expected Unit availability is included in the coal reburn control alternative's estimated O&M cost.

A Running Plant Capacity Factor reduction of 0.5% of annual gross electrical output was assumed for the coal reburn alternative. This would result in an estimated 1.2 MW average load decrease for M.R. Young Station Unit 1. This expected loss of electrical power sales from the reduction in net output due to this plant capacity impact was included in the estimated annual O&M costs.

Conventional and fuel-lean gas reburn options will involve higher operating costs compared with the existing operation of M.R. Young Station. Natural gas supply was assumed to be available near Bismarck, ND, but this has not been confirmed. The estimated unit cost of this natural gas was assumed to average $7.98/million Btu on a levelized annual cost basis, with a "credit" of $0.71 per mmBtu for avoided cost of consumption of lignite coal reduced by the natural gas heat input. The estimated annual cost of natural gas for the conventional gas reburning alternative applied to MRYS Unit 1 is approximately $29.7M per year. The estimated annual cost of natural gas for the FLGR™ alternative applied to MRYS Unit 1 is approximately $12.3M per year.

The new gas reburn injectors, station gas main and injector gas trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost. Maintenance of separated overfire air nozzles is expected to be similar to the expenses associated with Unit 2's existing flue gas recirculation ports.

C.3.3 SNCR O&M Cost Estimate

The alternatives that include selective non-catalytic reduction systems will involve higher operating costs compared with the existing operation of MRY Station Unit 1. Urea reagent supply was confirmed to be available regionally. The estimated unit cost of this 50% aqueous urea solution was assumed to average approximately $379/ton delivered (2006$). Consumption of urea reagent for SNCR with ASOFA was based upon preliminary numbers allowing for a boiler flue gas exit ammonia slip of 5 ppmvd. These were estimated as approximately 200 gph for SNCR when applied to MRY Station Unit 1 with ASOFA.

New electrical loads are required for high flow urea circulation, in-line and storage tank heating, water dilution, and reagent metering equipment. These auxiliary electrical demands and reagent dilution water usage were calculated based upon equations published in EPA Office of Air Quality Planning and

Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Oxidation[1]. Compressed air for reagent atomization and lance purging and cooling, as well as multiple nozzle lance water cooling are additional demands on the existing plant facilities. These powerhouse building service supplies were assumed to be available, but this has not been confirmed. The new urea reagent injection nozzle lances, reagent pumps, dilution water pumps, and distribution piping/valve trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost.

SNCR with ASOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming urea injection does not impact the ability to maintain consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers. A Unit availability reduction of 3.2% (273 hrs/yr), for M.R. Young Station Unit 1 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic operational conditions encountered during SNCR-related operation with ASOFA. This reduction in annual electrical power output due to a decrease in expected Unit availability is included in the these control alternatives' estimated O&M costs.

A Running Plant Capacity Factor reduction of 0.15% of annual gross electrical output was assumed for the SNCR with ASOFA alternative. This would result in an estimated 0.37 MW average load decrease for M.R. Young Station Unit 1. This expected loss of electrical power sales from the reduction in net output due to this plant capacity impact was included in the estimated annual O&M costs.

C.3.4 Layered Technology O&M Cost Estimates

Operating and maintenance costs for combinations of available NO_X reduction technologies were estimated based upon simple arithmetic addition of individual cost estimates. SNCR was combined with advanced SOFA, as previously shown. Pulverized coal reburn was assumed to be combined with advanced SOFA (and a COHPAC addition for PM control). The auxiliary electrical demands and reagent dilution water usage for SNCR with ASOFA were calculated based upon equations published in EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Oxidation[1].

C.3.5 Summary of O&M Costs Estimates for MRY Station NOx Control

The results of this evaluation for estimated variable operating and maintenance costs for the individual NOx control alternatives are summarized in this section. The expected reductions in Unit availability (uptime) and capacity are included in Tables C.3-1 through C.3-4 for MRYS Unit 1. Tables C.3-5 and C.3-6 for MRYS Unit 1 include the estimated urea reagent and dilution water usage rates and costs for the alternatives that involve SNCR with ASOFA NO_X control technologies.

TABLE C.3-1 – Expected Availability Reductions for MRY Unit 1 NO_X Controls

		Estimated Annual Average Unit Operating Time			
Alt.[1]	**NOx Control Technique**	**Unit Availability[2]**	**Unit Operating Time[3], hrs/yr**	**Unit Outage Time[4], hrs/yr**	**Unit Operating Time Reduction[5], hrs/yr**
E	SNCR w/ ASOFA	0.942	8255	505	273
D	Gas Reburn w/ ASOFA	0.952	8340	420	188
C	Coal Reburn w/ ASOFA	0.937	8212	548	316
B	FLGR w/ ASOFA	0.952	8340	420	188
A	Advanced SOFA (ASOFA)	0.952	8340	420	188
	Baseline	0.973	8528	232	0

1 – Alternative number has been previously assigned from least removal to highest removal percentage.
2 – 12-month baseline availability is assumed at 97.3 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
3 – Annual operating time is annual average availability multiplied by 8760 hrs/yr of possible uptime.
4 – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.
5 – Annual operating time reduction resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.

TABLE C.3-2 – Expected Capacity Reductions for MRY Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Unit Electrical Power Generation Reduction from Operating Time Reduction		
		Unit Running Plant Capacity Factor(2)	Unit Generation Reduction(3) kW-hrs/yr	Unit Generation Reduction Cost(4), 1000$/yr
E	SNCR w/ ASOFA	0.965	67,660,606	2,368
D	Gas Reburn w/ ASOFA	0.957	46,120,681	1,614
C	Coal Reburn w/ ASOFA	0.961	77,958,350	2,729
B	FLGR w/ ASOFA	0.962	46,400,200	1,624
A	Advanced SOFA (ASOFA)	0.966	46,586,546	1,631
	Baseline	0.966	0	0

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.

(2) – 12-month baseline running plant capacity factor is assumed at 96.6 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.

(3) – Annual electricity generation reduction is annual operating time reduction multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the 12-month average gross output of 244.4 MW.

(4) – Annual electricity generation reduction cost is the annual electricity generation reduction (kW-hrs/yr) resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-3 – Expected Auxiliary Electrical Power Demand Changes for MRY Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average APC NOx Equipment Auxiliary Electrical Power Demand and Usage				
		Gross Demand (2) kW	**Credit(3) kW**	**Total Net Demand(4) kW**	**Power Usage(5) kW-hrs/yr**	**Power Usage Cost(6), 1000$/yr**
E	SNCR w/ ASOFA	73.1	0	73.1	582,411	20
D	Gas Reburn w/ ASOFA	1	133	(132)	(1,054,343)	(37)
C	Coal Reburn w/ ASOFA	4,666	261	4,405	11,905,082	1,217
B	FLGR w/ ASOFA	1	73	(72)	(578,744)	(20)
A	Advanced SOFA (ASOFA)	1	0	1	8,058	0.3

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.

(2) – The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects. Coal reburn includes 1,507 kW for feed preparation and conveying equipment demand plus 3,158 kW for the COHPAC system addition for PM control.

(3) – The APC NOx equipment auxiliary electrical power demand credit of coal reburn alternatives is the estimated result of lower cyclone coal preparation and feeder power demand due to lower boiler cyclone coal equipment loading. Actual power demands may differ from this due to accuracy of estimates for assumed amount of operating horsepower reduction.

(4) – The total net auxiliary electrical power demand is the sum of the gross demand and credit.

(5) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.

(6) – The annual change in APC NOx equipment auxiliary electrical power demand electricity cost is the annual change in kW-hrs/yr for these alternatives resulting from the implementation of the individual NOx control technique multiplied by the incremental value of auxiliary electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-4 – Expected Auxiliary Electrical Power Demand and Generation Reduction Cost Changes for MRY Unit 1 NO_X Controls

Alt. Label[1]	NOx Control Technique	Estimated Annual Change in Unit Generation Due to APC NOx Equipment Auxiliary Power Electricity Demand and Generation Reduction			
		APC Electrical Power Usage[2] kW-hrs/yr	Unit Generation Reduction[3] kW-hrs/yr	Total Unit Electrical Power Generation Change[4] kW-hrs/yr	Total Unit Electrical Power Generation Change Cost[5] 1000$/yr
E	SNCR w/ ASOFA	582,411	67,660,606	68,243,017	2,389
D	Gas Reburn w/ ASOFA	(1,054,343)	46,120,681	45,066,338	1,577
C	Coal Reburn w/ ASOFA	11,905,082	77,958,350	89,863,432	3,946
B	FLGR w/ ASOFA	(578,744)	46,400,200	45,821,456	1,604
A	Advanced SOFA (ASOFA)	8,058	46,586,546	46,594,605	1,631

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.

(2) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.

(3) – Annual electricity generation reduction is annual operating time reduction multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the 12-month average gross output of 244.4 MW.

(4) – The total unit electrical power generation change is the sum of the annual change in APC NOx equipment auxiliary electrical power demand electricity usage plus the annual electricity generation reduction resulting from the implementation of the individual NOx control technique.

(5) – The total unit electrical power generation change cost is the total generation change (kw-hrs/yr) multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-5 – Expected NOx Reagent Usage and Cost Estimates for MRY Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Technique	NOx Reduction Reagent Urea Usage(2)			NOx Reduction Reagent Dilution Water Usage(3)	
		lbs/hr	tons/yr	1000$/yr	1000 gal/yr	1000$/yr
E	SNCR w/ ASOFA	1,894	7,544	2,861	7,232	7

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – All cost figures in 2006 dollars.
(3) – Reagent dilution water usage assumes potable water is added to create a 10% urea concentration (4 parts water to 1 part urea solution at 50% concentration) prior to injection. Dilution water unit cost assumed to be $1.00 per thousand gallons.

TABLE C.3-6 – Expected Heat Input and Equivalent Coal Cost to Evaporate Aqueous Urea for MRY Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Unit Equivalent Coal Consumption Cost for Aqueous Urea Evaporation		
		Heat Required to Evaporate Aqueous Urea(2), mmBtu/yr	Equivalent Coal Consumption for Heat Input(2), Tons/yr	Coal Consumption Cost(2), 1000$/yr
E	SNCR w/ ASOFA	54,315	4,077	38

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – Heat required to evaporate urea reagent dilution water assumes 900 Btu/lb required based on a 10% urea concentration (4 parts water to 1 part urea solution at 50% concentration) injected for the estimated amount of urea usage. Coal heat content of 6,662 Btu/lb, unit cost of $0.71/mmBtu.

Appendix C References:

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[i] EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf, Chapter 2 - Selective Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch2.pdf.

[ii] "Stationary Source NOx and PM Emissions in the WRAP Region: An Initial Assessment of Emissions, Controls, and Air Quality Impacts", October 1, 2003 Western Regional Air Partnership Final Report of the WRAP Market Trading Forum, Section VI: Summary of Emission Controls Available for Large Stationary Sources of NOx and PM (by Reaction Engineering International), available at http://www.wrapair.org/forums/mtf/nox-pm.html

[iii] Burns & McDonnell internal database.

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NOx BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS STUDY

for

Milton R. Young Station Unit 2

Minnkota Power Cooperative, Inc.

Operating Agent for

Square Butte Electric Cooperative

Owner

Final Report

October 2006

31777

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NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 2

prepared for

Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative

October 2006

Project No. 31777

Final Report

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

INDEX AND CERTIFICATION

Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative
Milton R. Young Station Unit 2
NO_X Best Available Control Technology Analysis Study

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Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the laws and rules of the North Dakota State Board of Registration under Title 28 Administrative Code.

STEPHEN W. VOSS
4945

10-4-06

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EXECUTIVE SUMMARY

The Milton R. Young Station of Minnkota Power Cooperative, Inc. (Minnkota) and Square Butte Electric Cooperative (Square Butte) includes two cyclone-furnace, lignite-fired steam-electric generating units (SEGUs). The units both fire North Dakota lignite supplied from the adjacent mine, near Center, North Dakota. Unit 1 has a nominal 235 MW net design output capacity rating, is typically capable of sustained output of approximately 250 MW_g (gross), and has a gross design output capacity rating of 257 MW_g. Unit 1 is owned and operated entirely by Minnkota. Unit 2 has a nominal 439 MW net design output capacity rating, is capable of sustained output of approximately 460 MW_g (gross), and has a gross design output capacity rating of 477 MW_g. Unit 2 is owned by Square Butte Electric Cooperative (Square Butte), and operated by Minnkota.

A Notice of Violation (NOV) from the United States Environmental Protection Agency (US EPA or EPA) was issued to Minnkota Power Cooperative on June 21, 2002. The NOV alleged that modifications had been made at the Milton R. Young Station that would have required a construction permit under New Source Review (Code of Federal Regulations 40 CFR 52.21, and North Dakota Administrative Code NDAC 33-15). As a result of this allegation, a civil complaint was filed by the United States of America and the State of North Dakota against Minnkota Power Cooperative Inc. ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") in the United States District Court for the District of North Dakota. A Consent Decree (CD) has been approved that represents a final negotiated settlement of the United States' and North Dakota's claims against Minnkota and Square Butte. The Consent Decree requires Minnkota and Square Butte to perform a "NO_X Top-Down Best Available Control Technology (BACT) Analysis" to describe the emission limits for NO_X that will be required at Units 1 and 2, expressed as a 30-Day Rolling Average NO_X Emission Rate [Consent Decree paragraph 24, page 7, and paragraph 5, page 4].

Burns & McDonnell was retained to conduct a Top-Down BACT Analysis for nitrogen oxides (NO_X) at the Milton R. Young Station. The results of the BACT analysis are presented in this study report.

The procedures mandated by the Consent Decree for performing a Top-Down BACT Analysis are outlined in Chapter B of the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990 ("EPA's NSR Manual"). The MRY Station BACT analysis was performed in accordance with this procedure. The

EPA's NSR Manual outlines five basic steps that are to be followed in this BACT analysis. These basic steps for such a BACT analysis are summarized as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

A Best Available Control Technology (BACT) analysis was performed for Milton R. Young Unit 2 for NO_X using the EPA's "top-down" approach. Best Available Control Technology is defined as "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant" (40 CFR 52.21, NSR Manual B.1).

Unit 2 at Milton R. Young Station is a cyclone-fired boiler that burns North Dakota lignite. The method of firing is very significant in analyzing control options for NO_X emissions. A cyclone boiler produces inherently higher uncontrolled NO_X levels than pulverized-coal and circulating fluidized bed boilers. There have been no new coal-burning cyclone-fired boilers built and installed in the United States since the early 1980's. Consequently, there are no examples of BACT control options listed in the RACT/BACT/LAER Clearinghouse database for consideration and direct application of published NO_X emission permit limits on the Milton R. Young cyclone-fired boilers.

Step 1 – Identify All Control Technologies

The Consent Decree requires that the NO_X Top-Down BACT Analysis for the Milton R. Young Station "include an evaluation of Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Overfire Air (OFA), Rich Reagent Injection (RRI), as well as other NO_X control technologies" potentially applicable for lignite-fired cyclone boilers [Consent Decree paragraph 65, page 19]. Other identified control techniques, such as fuel switching and fuel cleaning, and combustion-related emission control technologies, such as fuel reburn and oxygen-enhanced combustion, were also considered.

Step 2 – Eliminate Technically Infeasible Options

The BACT evaluation determined that not all the technologies identified were considered available and applicable. The technically infeasible alternatives were eliminated from further evaluation, along with feasible technologies with economic impacts that were unreasonable compared to other cost-efficient alternatives to control NO_X emissions for MRY Station Unit 2.

The technical feasibility of applying NO_X emission reduction techniques and technologies at Milton R. Young Station is dominated by the composition and combustion characteristics of the North Dakota lignite supplied solely from a surface mine adjacent to the plant. This mine is the only supplier of solid fuel for this station, as there are no railroad facilities provided to service the Milton R. Young plant. North Dakota lignite has high moisture and high sodium content, moderate higher heating values, and can have a widely variable and high ash content compared to other coals. These characteristics create difficulties in promoting consistent, steady combustion and slag formation in the cyclone burners. It also results in producing a flyash that has severe deposition characteristics.

Both boilers include a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boilers.

Ash deposition in each boiler and air preheater is a significant operational challenge for the facility. Significant equipment and manpower resources are devoted to on-going removal of fireside ash accumulations. Unit outages must be conducted at regular intervals to clean each boiler (approximately every 80-120 days). There are a number of issues that make selective catalytic reduction (SCR) technically infeasible for NO_X emission control for Milton R. Young Unit 2. The consistent long-term operation of SCR technology on lignite-fired cyclone boilers will be drastically inhibited by the susceptibility of the SCR catalyst to severe fouling, deactivation, and erosion resulting from the actions of the emitted flue gases and flyash, and ash deposit removal operations. SCR technology is considered technically infeasible for application on the cyclone boilers at the Milton R. Young Station.

Rich Reagent Injection has been demonstrated on boilers burning bituminous and subbituminous coal. However, it has not been commercially installed and placed in continuous operation on a cyclone-fired boiler burning lignite coal with high fouling and slag temperature sensitivities associated and a highly variable heat content. RRI adds urea reagent to the hot furnace gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea, and thus creating NO_X. While RRI is specifically intended for NO_X emissions control on cyclone boilers, RRI is considered technically infeasible for application on the lignite fired cyclone boilers at the Milton R. Young Station due to the variable heat content of the lignite fuel which allows the creation of oxygen-rich conditions in the boiler.

The application of separated overfire air (SOFA) for NOx emissions control on Milton R. Young Unit 2’s boiler was evaluated as part of the BACT analysis. A version of separated overfire air specifically designed for increased NO_X emission reduction performance for lignite-fired cyclone boilers, referred to as “Advanced SOFA” in this analysis, can be installed on both units at M.R. Young Station. This highest-performing form of SOFA can be applied alone and in combination with other technologies. Key aspects of successfully applying and operating a separated overfire air system on a cyclone-fired boiler are the ability to:

- Accurately measure the fuel heat input rate (BTUs) and combustion air inputs on a real-time, individual cyclone by cyclone basis, to allow the ability to determine and control the desired air/fuel ratio, especially when “starved air“ (i.e. substoichiometric) combustion conditions are required.
- Maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps.

The degree to which the individual cyclone furnaces can be operated with less-than-theoretical (substoichiometric) combustion air, which corresponds to operation of a SOFA system, directly contributes to less combustion-related NO_X formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. This places great emphasis on achieving tight control over the air/fuel ratios on each cyclone during air-staged combustion operation with SOFA in order for air-staged combustion to be successful in producing significant additional NOx emissions reduction on lignite-fired cyclone boilers.

In the case of MRY Station Unit 2’s boiler, air-staged combustion must be sufficient to reduce NO_X emissions while releasing enough heat to continue to melt the fuel ash so that it flows effectively within and from the cyclone burners. Due to the short-term variability of the combustible and ash components of North Dakota lignite supplied from the current mine near Center, ND, and the complex behavior of lignite ash when exposed to high temperatures, the extent of air-staging and thus the level of NO_X control while operating the highest-performing version of SOFA system is expected to be modest.

Selective Non-Catalytic Reduction (SNCR) technology has been used to reduce NO_X emissions on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used on fuel oil and natural gas-fired units. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without air-staged combustion with overfire air in full operation.

There are significant concerns associated with effective long-term SOFA operation for Milton R. Young Station Unit 2‘s boiler. The ability of basic combustion equipment and improvements to precisely measure the boiler’s heat input rate in real-time on an individual cyclone by cyclone basis with compensation for the short-term variability of the combustible content of the Center lignite to consistently maintain substoichiometric operation of every cyclone during air-staged combustion is unproven.

Several other techniques and technologies were considered technically feasible for NOx emissions control at MRY Station: Fuel Blending/Switching; Basic Combustion Control Improvements; and various forms of Fuel Reburn. Fuel switching/blending was not evaluated further because of expected unreasonably high capital and operating costs and no additional emission reduction compared to continued lignite firing.

Other NOx emissions control techniques and technologies for MRY Station evaluated and determined to be technically infeasible were: Fuel Cleaning; Low NOx Burners (LNB); Flue Gas Recirculation; Oxygen-enhanced Combustion (OEC); Water/steam injection (combustion tempering); and Electro-Catalytic Oxidation (ECO®).

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The third step in the “top-down” BACT evaluation ranked the remaining control technologies by effectiveness. The purpose of ranking the control technologies was to establish a hierarchy that places at the “top” the control technology that achieves the lowest emission level. The technologies in order of their effectiveness, from highest to lowest, are: SNCR with ASOFA; Gas Reburn with ASOFA; Lignite Reburn with ASOFA; Fuel Lean Gas Reburn with ASOFA; and Advanced Separated Overfire Air (ASOFA). None of these control options has been installed on a cyclone-fired boiler burning North Dakota lignite. As such, the expressed control percentages reflect the use of engineering judgment, based on the listed technique or technology application.

Step 4 – Evaluate Most Effective Controls and Document Results

Additional criteria besides technical feasibility were utilized for technology selection in this BACT analysis. These included estimates of control effectiveness (i.e. percent pollutant removed), capital plus operating and maintenance costs, annual emission reduction (tons per year), energy impacts, average and incremental cost effectiveness ($/ton), and environmental impacts (other media and emissions of toxic and hazardous air pollutants).

The economic analysis examined the capital cost of each feasible BACT alternative evaluated and any other powerplant upgrade costs necessary to implement the alternative. In addition, the economic analysis examined the operating and maintenance cost associated with the highest-performing forms of each feasible BACT alternative evaluated. These costs were then combined into a levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each alternative was evaluated.

Two alternatives were on the dominant controls cost curve and thus were identified as the more cost effective alternatives. The two BACT NO_X control alternatives evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 2were:

- Selective Non-Catalytic Reduction (SNCR) combined with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA); and
- ASOFA alone.

The two most cost-effective feasible control alternatives for reduction of NO_X emissions were reviewed to determine if the use of the technique or technology would result in any significant or unusual energy penalties or benefits. Potential increase in power plant energy consumption or net generation reductions, for ASOFA alone, or ASOFA with SNCR were relatively small.

The predicted environmental impacts from implementation of the two most cost-effective feasible NO_X emissions control alternatives from slightly higher unburned carbon in the emitted fly ash, carbon monoxide, and excess ammonia ("slip") emissions was expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO_X emission reduction.

Step 5 – Select BACT

Taking into account technical feasibility, energy, environmental, and economic impacts and other costs, the recommended Best Available Control Technologies and associated emission rates for nitrogen oxides emissions produced by Milton R. Young Station Unit 2 boiler are provided in the table below.

NO_X Emission Control Technology and Rate Recommended as BACT

Control Technology and Emission Rate Recommended as BACT			
Unit	**Pollutant**	**Control Method**	**12-Month Rolling Average NOx Emission Rate (lb/ million Btu)**
2	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.330

This recommended BACT 12-month NO_X emission rate is based upon a historic pre-control 12-month baseline average annual NO_X emission rate used in the control and cost-effectiveness analysis of 0.786 lb/mmBtu for Unit 2. The baseline emission was determined from the 12 consecutive month period with the highest historic summation of NO_X mass emissions (pounds) reported for actual operation between January 1,2001 and December 31, 2005.

To complete the BACT determination process, the Consent Decree (CD) requires that “specific control technologies to be installed and a specific Phase II 30-day Rolling Average NO_X Emission Rate limitation (lbs/MMBtu)” must be established for each subject emission Unit [CD Paragraph 66, pg 20]. Because there are expected to be minor short term variations in operating conditions where Minnkota has not, in fact, materially changed any of their normal daily operating practices, a margin between the 12-month average operating conditions and the 30-day permit limit is proposed. This recommended emission rate should be suitably higher such that operation consistent with the technological limitations, manufacturer’s specifications, and good engineering and maintenance practices to the extent practicable for the recommended NOx BACT alternative would not result in an exceedance (violation) of an enforceable emission permit limit.

The Consent Decree also requires that the North Dakota Department of Health's (NDDH) NO_X BACT Determination address specific emission limitations during Unit startups at Milton R. Young Station [CD Paragraph 66, pg 20]. The type and duration of firing during startups, and the limited ability of available and feasible technologies to control startup NO_X emissions, both significantly influence the 30-day rolling average BACT NO_X emission rate limit recommended for Milton R. Young Station boilers. A 24-hour rolling average NO_X emission rate limit applied to startup periods is also recommended for Milton R. Young Station boilers.

The SEGU startup operating period is usually not defined in emission permits. However, for the purpose of this NO_X BACT analysis, Unit startup was defined as the period from initial fuel combustion to the point in time when:

- the measured Heat Input to the boiler on a 6-hour rolling average basis is greater than or equal to 4800 million BTU/hr for Unit 2; or
- the amount of time reported for the longest individual Unit 2 startup period during actual operation between January 1, 2001 and December 31, 2005 elapses, whichever occurs first; or
- fuel firing is discontinued prior to satisfying either previous criteria.

For MRYS Unit 2, the recommended 30-day rolling average NO_X emission permit limit rate that includes the impact of startups is based upon recognized operational factors and equipment designs that influence whether the startup emissions result in higher 30-day emissions compared to normal continuous operation excluding such startup periods:

- The uncontrolled emission rate (i.e. without separated OFA or SNCR in operation) and its variability during operation from a cold startup up to and including maximum continuous rated output;
- The operating conditions that are required to exist for the selected NO_X BACT control techniques to be initiated and be effective; and
- The effectiveness of these two particular control techniques if invoked at less-than-MCR steady-state operating conditions.
- The number of startups and their range of typical durations per 30-day period time frame.

The Consent Decree and the EPA's NSR Manual do not describe the method for determining a 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT applied to Milton R. Young Station Unit 2. The approach taken in this analysis was to establish a historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) from the 30-consecutive day period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation between January 1,2001 and December 31, 2005. This reflects unit NO_X emissions that were generated during periods of high unit operations, not affected by unit shutdowns, startups, or malfunctions. This was then compared to the 12-month historic pre-control baseline average NO_X emission rate (lb/mmBtu) from the 12-consecutive month period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation during the same 5-year look-back period. An estimate of NO_X emission reduction for the proposed BACT NO_X alternative operating at the historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) was made. This rate considered recognized operational factors and equipment designs applied to “steady state” conditions with sustained output close to maximum continuous capacity ratings. The potential impact of startups, recognizing operational and technical limitations on NO_X emission control performance, was then applied to the steady-state rate, to establish a recommended 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT for Milton R. Young Station Unit 2. This is summarized below.

Recommended NO_X BACT Control Method and 30-Day Rolling Average NO_X Emission Rate Limit Without Startups

Unit	Pollutant	Control Method	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)
2	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.350

This recommended BACT 30-day NO_X emission rate limit is based upon a historic pre-control 30-day baseline average NO_X emission rate of 0.874 lb/mmBtu for Unit 2. The baseline emission was determined from the 30-consecutive day period with the highest historic unit NO_X emissions rate reported for actual operation between January 1,2001 and December 31, 2005.

An incremental adjustment to the proposed 30-day rolling average steady-state unit NO_X BACT emission rate without startups of 0.35 lb/mmBtu for Unit 2 is recommended for the 30-day rolling average NO_X emission permit limit periods as defined and applied to Milton R. Young Station. This is summarized in the table below.

Recommended BACT 30-Day Rolling Average NO_X Emission Rate Limit and Startup Impact

Unit	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)	Impact on 30-day Rolling Average NOx Emission Rate Limit Due to Startups (lb/million Btu)
2	0.35	+0.102 per startup

This recommended adjustment to the proposed 30-day rolling average steady-state NO_X BACT emission rate limit without startups is based upon average historic pre-control NO_X emission rates of 0.959 lb/mmBtu for Unit 2 reported for the longest individual Unit 2 startup period during actual operation between January 1, 2001 and December 31, 2005. These emissions occurred during the 115-hour October 25-30, 2001 startup for Unit 2.

A 24-hour rolling average BACT NO_X emission rate limit applied to startup periods is also recommended for each of the Milton R. Young Station boilers.

This is summarized in the table below.

Recommended 24-Hour Rolling Average NO_X Emission Rate Limit During Startups

Unit	24-hour Rolling Average NOx Emission Rate Limit During Startups (lb/million Btu)
2	1.064

These emissions occurred during the 115-hour October 25-30, 2001 startup for Unit 2.

Compliance with these emission rate would be measured at the stack of the Unit, verified with Continuous Emission Monitoring (CEM) systems in accordance with the reference methods specified in 40 C.F.R. Part 75, and would be determined on a 30 consecutive Operating Day and 24-consecutive hour rolling average basis, respectively.

A trial demonstration period of 18 months after the completion of Consent Decree Phase II NO_X emission reduction system installation commissioning at Milton R. Young Station is recommended. It is proposed to allow Minnkota (for Square Butte) to demonstrate the actual control system capabilities of the combined NO_X BACT emissions reduction system. Operating experience during the trial period will:

- confirm steady-state control performance of the combined NO_X BACT emissions reduction system;
- allow determination of the ability to further control Unit start-up emissions;
- allow the determination of the permitted 30-day rolling average NO_X emission limit including startups, shutdowns, and malfunctions; and
- address the specific emission limitations during Unit startups at Milton R. Young Station and their impact on the proposed 30-day rolling average emission rate limit (without startups).

Based upon the information obtained during the trial period, final emission limits can then be determined.

The means that will be employed to minimize emissions during startup will primarily be based on operating procedures, both before and after the level of upper furnace gas temperatures and/or heat input rate are considered sufficient to start the NO_X controls and operating conditions are conducive for effective emissions reduction. These could be similar to Minnkota's current MRYS practices, or could be different, depending upon the capabilities of the NO_X controls and their impacts on Unit operations.

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1.0 INTRODUCTION

The Milton R. Young Station of Minnkota Power Cooperative, Inc. (Minnkota) and Square Butte Electric Cooperative (Square Butte) includes two cyclone-furnace, lignite-fired boilers producing steam for electric generation. Both units fire North Dakota lignite supplied from an adjacent mine, near Center, North Dakota.

A Notice of Violation (NOV) from the United States Environmental Protection Agency (US EPA or EPA) was issued to Minnkota on June 21, 2002. The NOV alleged that modifications have been made at the Milton R. Young Station that would require a construction permit under New Source Review (Code of Federal Regulations 40CFR52.21, and North Dakota Administrative Code NDAC 33-15). As a result of this allegation, a civil complaint was filed by the United States of America and the State of North Dakota against Minnkota Power Cooperative Inc. ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") in the United States District Court for the District of North Dakota. A Consent Decree[1] has been entered that represents a final negotiated settlement of the United States and North Dakota's claims against Minnkota and Square Butte. The Consent Decree requires Minnkota and Square Butte to perform a NO_X "Top-Down" Best Available Control Technology (BACT) Analysis to describe the emission limits for NO_X that will be required at Units 1 and 2, expressed as a 30-Day Rolling Average Emission Rate (lbs/million Btu)[2].

Burns & McDonnell was retained by Minnkota to conduct a "Top-Down" Best Available Control Technology (BACT) Analysis for nitrogen oxides (NO_X) at the Milton R. Young Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services since the 1970s. As part of those services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies and control technology analysis. The results of the BACT analysis are presented in this report.

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[1] In the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No. 1:06-CV-034

[2] Ibid – footnote number 1, CD paragraph 65, page 19.

The primary guidance utilized in preparation of this BACT analysis is the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990[3] ("NSR Manual").

In the next section of the report, the approach to the BACT Analysis is described. Following that, a quick summary of the plant conditions and report basis is given and then the BACT Analysis begins. The impact portion of the report is broken down into separate subsections. Within the last section, the results of all of the BACT Analysis steps are summarized for NO_X control options for Unit 2's boiler at the Milton R. Young Station.

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[3] Chapter B of the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990.

2.0 "TOP-DOWN" NO_X BACT ANALYSIS APPROACH

Best Available Control Technology (BACT) is an emissions limitation for each pollutant from a source determined to be achievable using control technologies(s) that provide the "maximum degree of emission reduction…taking into account energy, environmental, and economic impacts"[4]. A BACT review does not result in an emissions removal efficiency requirement. The generally accepted procedures for performing a BACT analysis are outlined in the EPA's draft NSR Manual. The BACT analysis for Milton R. Young Station Unit 2's boiler NO_X emissions was performed in accordance with this procedure. The EPA's draft NSR Manual outlines five basic steps that are to be followed in the "top-down" BACT evaluation. These steps are as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

The predefined steps of a BACT analysis are described in this section, and results presented. Available NO_X control techniques and technologies are defined, identified, and a technical description of the emission reduction process and capabilities are reviewed in the following section. Subsequently, those techniques and technologies deemed feasible for retrofit application are ranked according to nominal NO_X control capability. An engineering analysis reviews the estimated capital and operations and maintenance (O&M) costs for each feasible alternative, including taking a look at Balance of Plant (BOP) requirements. Following the cost impact determination, the energy and environmental impacts are reviewed for each feasible technology. Finally, the results of the engineering analyses are tabulated and a NO_X BACT selection is recommended for each unit.

2.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

The first step in a "top-down" NO_X BACT analysis is to identify, for the emissions unit in question, a comprehensive list of all "available" control options. In the EPA's draft NSR Manual,

> "available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of

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[4] Ibid footnote number 2, NSR Manual B.1

> production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant"[5].

According to the EPA's draft NSR Manual, "a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term"[6]. Also, "a control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development"[7].

In order to identify available NO_X emission control technologies and techniques appropriate for potential application to MRY Station units, the following information sources were reviewed for coal-fired electric generating unit powerplants:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) database and Control Technology Center (website).
- Federal (EPA) and State, including North Dakota Department of Health internet websites for air emission permits and recently-submitted applications, including BACT Evaluations following New Source Review procedures.
- Federal (EPA and Department of Justice) and State, including North Dakota Department of Health internet websites for Consent Decrees issued as a result of legal actions taken by the United States government for alleged violations of the Prevention of Significant Deterioration (PSD) provisions and New Source Review provisions of the Clean Air Act, and/or federally-approved and enforceable State Implementation Plans.
- Control technology vendor information.
- Published and available information from technical, engineering, and environmental consultants.
- Technical literature found in journals, reports, internet websites, newsletters, proceedings of technical seminars and conferences pertaining to studies, engineering, designs, and testing of air pollution controls.

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[5] Ibid, NSR Manual B.5
[6] Ibid, NSR Manual B.17
[7] Ibid, NSR Manual B.18

2.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The second step of the "top-down" BACT process is to evaluate the available NO_X control technologies and techniques identified in Step 1 in terms of the specific factors that apply to the emissions unit in question. In accordance with EPA's draft NSR Manual, "an available technology is "applicable" if it can be reasonably installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible[8]".

The EPA's NSR Manual states a technology may be determined to be not applicable if "a technical assessment considering physical, chemical and engineering principles and/or empirical data showing the technology would not work on the emissions unit under review or that unsolvable technical difficulties would preclude the successful deployment of the technique"[9]. Also, a "showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g., size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source)"[10]. After a determination is made that any of the processes are technically infeasible, options are eliminated if technical challenges would preclude or prevent the successful long-term use of the control option or technique on the emission unit under consideration. This is performed prior to any economic analysis.

However, the EPA's NSR Manual also states "…control options incapable of meeting an applicable New Source Performance Standard (NSPS) or State Implementation Plan (SIP) limit would not meet the definition of BACT under any circumstances. The applicant does not need to consider them in the BACT analysis"[11]. Also, it states "An NSPS simply defines the minimum level of control to be considered in the BACT analysis"[12]. The NSR Manual further states "When developing a list of possible BACT alternatives, the only reason for comparing control options to an NSPS is to determine whether the control option would result in an emission level less stringent than the NSPS. If so, the option is unacceptable"[13]. New Source Performance Standards (NSPS) for NO_X emissions from EGUs firing North Dakota lignite are 0.8 lb/mmBtu. The EPA Acid Rain Program's Title IV NO_X emission limit for Group 2, cyclone-fired coal boilers with outputs greater than 155 MWe is 0.86 lb/mmBtu.

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[8] Ibid, NSR Manual B.17
[9] Ibid, NSR Manual B.20
[10] Ibid, NSR Manual B.19
[11] Ibid, NSR Manual B.12
[12] Ibid, NSR Manual B.12
[13] Ibid, NSR Manual B.12

EPA's draft NSR Manual also states "A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review"[14].

Also in the EPA's draft NSR Manual is a qualification for technical feasibility, as described by the statement "Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration"[15].

2.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

The third step in the "top-down" BACT evaluation is to rank the control technologies remaining after the feasibility analysis by control effectiveness. The purpose of ranking the control technologies is to establish a hierarchy that "places at the "top", the control technology that achieves the lowest emission level"[16].

Selecting common units in order to compare emissions performance levels amongst options is one of the two key issues that must be addressed in a BACT analysis. EPA's draft NSR Manual states "it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed"[17]. For fossil fuel-fired boilers, pounds of nitrogen oxides per unit of fuel heat input (i.e. lb/mmBtu), is a common means of comparing and calculating NO_X emissions.

Many control techniques, including both add-on controls and inherently lower polluting processes can perform at a wide range of levels. The EPA's draft NSR Manual states "It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would

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[14] Ibid, NSR Manual B.18
[15] Ibid, NSR Manual B.18
[16] Ibid, NSR Manual B.25
[17] Ibid, NSR Manual B.22

result in a large number of options"[18]. Also, "manufacturer's data, engineering estimates, and the experience of other sources provide the basis for determining achievable limits"[19].

2.4 STEP 4 – EVALUATE THE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

The fourth step of a "top-down" BACT review is to evaluate the technically-feasible emission controls, beginning with the most effective. Economic, energy, and environmental impacts are to be assessed and quantified, where possible, in the control technology analysis. The purpose of the evaluation is to determine if there are any identified impacts that would eliminate the top control technology from consideration. In the case where the most effective control alternative is determined to incur or produce adverse energy, economic or environmental impacts, the basis of the determination is documented, and the next most stringent control alternative is evaluated. This analysis process continues until the control technology under consideration cannot be eliminated by identification of any source-specific adverse energy, economic or environmental impacts.

The economic impacts are based on estimates of capital equipment pricing, procurement, installation and estimated operating and maintenance costs. The total installed capital costs along with the operating costs for each control technology are summarized in the economics of each respective section. The Levelized Total Annual Cost (LTAC) represents the levelized cost of procurement, construction, operation and maintenance over an assumed service life. Cost effectiveness ($/ton) of a control technique or technology is calculated by dividing the LTAC ($/yr) by the annual amount of NO_X removed (tons/yr). Baseline pre-control emissions are calculated using realistic upper boundary operating assumptions, considering inherent physical or operational constraints on the source. Plotting of the annual amount of NO_X removed (tons/yr) versus the levelized total annual control cost ($/yr) for the various control options on an x-y graph allows visualization of the cost-effectiveness. A "least-cost envelope" can be readily identified to indicate the inferior control options which should not be considered in the subsequent analyses. The incremental cost-effectiveness (difference in $/ton) between control techniques or technologies can also be calculated and compared. This allows evaluation of the dominant controls included on the least-cost envelope (curve).

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[18] Ibid, NSR Manual B.23
[19] Ibid, NSR Manual B.24

2.5 STEP 5 – SELECT BACT

The final step in the “top-down” evaluation process is to select BACT for the applicable pollutant and emission unit. Per the EPA guidance document, BACT is “the most effective control technology not eliminated in Step 4”[20]. The methodology described above was applied to the Milton R. Young Station Unit 2‘s boiler for emissions of nitrogen oxides.

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[20] Ibid, NSR Manual B.53

3.0 BACT ANALYSIS for MRY STATION UNIT 2 NO_X EMISSIONS

The approach taken in this BACT analysis for Milton R. Young Station included a technical analysis of demonstrated control alternatives for NO_X emissions. This approach followed the predefined steps of a BACT analysis process as generally described in Section 2. Potential NO_X control techniques and technologies were identified, and a technical description of the emission reduction process and capabilities were provided. Subsequently, those techniques and technologies deemed available and feasible for retrofit application were ranked according to nominal NO_X control capability. The engineering analysis then developed the estimated capital and O&M costs for each alternative, including taking a look at Balance of Plant (BOP) requirements. Finally, the cost effectiveness points for each feasible technology were plotted, and those that comprise the dominant controls curve were identified.

For the feasible techniques and technologies considered for determining NO_X control cost-effectiveness for the two steam electric generating units at the MRY Station, estimates were produced for predicted NOx reductions that represent achievable long-term expectations of the alternative reduction techniques and technologies being presented in the technical analysis. Each were tabulated and graphed.

3.0.1 EMISSION UNIT DESCRIPTION

Milton R. Young Unit 2 is a Babcock and Wilcox steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. Original unit design steam generating capacity is 3.20 million lbs/hr at 2,620 psi with a fuel heat input of 4,696 mmBtu/hr. The boiler is fired by twelve ten-foot diameter cyclone burners, arranged “three over three” across the front and rear walls of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Exhaust gases leave the air heater and pass through an ESP for particulate collection and removal followed by the two induced draft fans (installed in parallel) prior to a wet flue gas desulfurization (FGD) system which discharges to the stack. The current air pollution control system’s configuration allows a portion of the low dust flue gas to reheat the stack gas, thus bypassing the FGD system. Unit 2 has a nominal 439 MW net design output capacity rating, is capable of sustained output of approximately 462 MW gross, and has an ultimate short-term maximum gross output (URGE) of 512 MW.

The EPA's Technical Support Document[22] lists nameplate steam turbine-generator capacity of MRY Station Unit 2 as 477 MW (gross), which was assumed for calculating capital cost estimates for control alternatives.

The Unit 2 boiler at M.R. Young Station includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boilers.

Milton R. Young Station Unit 2's boiler design, combustion performance, and NO_X emissions are dominated by the composition and combustion characteristics of the North Dakota lignite supplied solely from a surface mine adjacent to the plant. This mine is the only supplier of solid fuel for this station, as there are no railroad facilities provided to service the Milton R. Young plant. North Dakota lignite has high moisture and high sodium content, moderate higher heating values, and can have a widely variable and high ash content compared to other coals. These characteristics create difficulties in promoting consistent, steady combustion and slag formation in the cyclone burners. It also results in producing a flyash that has severe deposition characteristics.

The design unit operating conditions for this study are presented in Table 3-1. The historical average lignite coal analysis is shown in Table 3-2.

Table 3-1 – Unit Design Parameters

Design Unit Operating Characteristics	**Unit 2 Design**
Boiler Type	Subcritical(1)
Combustion System	Cyclone
Number of Cyclones; arrangement, location	12; 3 over 3, opposed
Unit Design Capacity Electrical Output(2), MW (net/gross)	439 / 477

(1) – Balanced draft, single drum, superheated steam with single stage of steam reheat.
(2) – These values were established by the original equipment manufacturers, prior to construction.

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[22] Ibid

Table 3-2 – Historical Average Lignite Coal Analysis

Lignite - Center Mine Ultimate Coal Analysis: (as received)	**Average % by mass**
Moisture	37.29
Carbon	38.69
Hydrogen	2.50
Nitrogen	0.57
Sulfur	0.81
Ash	8.74
Oxygen	11.40
Total	100.00
Higher Heating Value, Btu/lb	6,662

3.0.2 NITROGEN OXIDES EMISSION FORMATION

Nitrogen oxides (NO_X) are produced when nitrogen in the fuel and combustion air are exposed to high temperatures. There are two primary sources of NO_X emissions, referred to as "thermal" NO_X and "fuel" NO_X. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is admitted to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of the fuel containing nitrogen compounds. For most coal-fired units, thermal NO_X emission typically represents approximately 20% and fuel NO_X about 80% of the total NO_X formed. Nitrogen oxide (NO) is typically the most predominant form of NO_X emissions from fossil fuel combustion, along with nitrogen dioxide (NO_2). The formation of these compounds in utility powerplant boilers is sensitive to the method of firing and combustion controls utilized. The techniques employed for mixing the combustion air and fuel, which creates flames and high temperature combustion products, results from the rapid oxidization of carbon, hydrogen, and other exothermic reactions. Cyclone-fired boilers, by design, create intense heat release rates to melt and fluidize the coal ash introduced into the barrel-shaped furnaces. This produces high temperature flue gases and results in very high uncontrolled NO_X emissions. The amount of thermal NO_X emissions produced by cyclone boilers can be considerably higher than fuel NO_X emissions.

3.1 IDENTIFICATION OF NO_X CONTROL OPTIONS FOR MILTON R. YOUNG STATION

The first step in the BACT evaluation is to identify all "demonstrated and potentially applicable control technology alternatives"[23] according to the EPA's draft NSR Manual. In identifying control technologies, "the applicant needs to survey the range of potentially available control options"[24].

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[23] Ibid, footnote number 2, NSR Manual page B.11

3.1.1 REVIEW OF RETROFIT INSTALLATIONS

The BACT determinations listed in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database are for new facilities. The Milton R. Young Station is an existing powerplant facility with two coal-fired EGUs. A BACT evaluation for retrofitting control equipment to coal-fired EGUs in an existing facility will be substantially different than an analysis for installing control equipment on coal-fired EGUs in a new facility. Consequently, in performing the BACT analysis for existing boilers at Milton R. Young Station, it is important to review powerplant facilities, especially cyclone-fired coal boilers, which have retrofitted NO_X control equipment in recent years.

In 1998, EPA issued a NO_X SIP (State Implementation Plan) call. Under the SIP call, utility boilers in the eastern United States were required to substantially reduce NO_X emissions during the "ozone season". The compliance date for the NO_X SIP call is May 31, 2004. A high percentage of the fired electric generation facilities in the eastern United States have or are in the process of retrofitting NO_X controls to comply with the NO_X SIP call. The EPA's NO_X SIP call was not applicable to North Dakota utility boilers.

There are a number of fossil fuel-fired EGU powerplants around the United States that have implemented or are planning to implement modifications to reduce NO_X emissions. The NO_X emission control system installations are in response to Acid Rain requirements, EPA's NO_X SIP call, the Clean Air Interstate Rule (CAIR), the Regional Haze Rule (RHR), and local regulations.

In addition to the facilities that have had to retrofit emissions controls as a result of the Title IV Part 76 Acid Rain requirements and/or EPA's NO_X SIP call, a few installations have had to retrofit controls in recent years as the result of court decisions resulting from litigation and regulatory action. None of the boilers associated with identified consent decrees are cyclone-fired. They are also located in a region requiring compliance with an EPA-approved State Implementation Plan for nitrogen oxides emissions controls (i.e. NO_X SIP call). As mentioned above, North Dakota utility boilers were not subject to the EPA's NO_X SIP call.

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[24] Ibid, NSR Manual page B.11

3.1.2 POTENTIALLY FEASIBLE NOx CONTROL OPTIONS FOR MILTON R. YOUNG STATION

A review of available information on retrofit installations performed at utility and industrial coal-fired powerplants during the past fifteen years was undertaken. NO_X emission control technologies and techniques with potential application to Milton R. Young Station boilers were identified, and are listed in Table 3-3.

TABLE 3-3 – Potentially Available NO_X Control Technologies Identified for BACT Analysis

NOx Control Technology
Pre-Combustion Controls
Fuel Cleaning/Blending/Switching
Combustion Controls
Basic Combustion Control Improvements
Low NOx Burners (LNB)
Separated Overfire Air (SOFA)(1)
Flue Gas Recirculation
Fuel Reburn
Oxygen-enhanced combustion (OEC)
Water/steam injection (combustion tempering)
Post-Combustion Controls
Selective Non-Catalytic Reduction (SNCR)(2)
Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO®)(3)

Notes: these are basic forms of the identified techniques.
Not all variations or combinations are included.
(1) – SOFA technologies include Boosted SOFA and Rotating Opposed Fired Air (ROFA)
(2) – SNCR technologies include Rich Reagent Injection, and Hydrocarbon-enhanced SNCR, commercially available as “NOxStar™”.
(3) – Multi-pollutant control technology currently under commercial development by Powerspan Corp.

A comprehensive literature search, with sources including technical papers and presentations made at conferences by nationally-recognized technical organizations, utilities and other parties involved with design, construction, and testing of NO_X control techniques, plus hardware supplier experience lists, was performed. The results of this search are presented in Appendix A2, which includes a summary of various selected U.S. NO_X emission reduction retrofit projects.

3.2 FEASIBILITY ANALYSIS

The second step of the "top-down" BACT process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible.

An available technology is "applicable" if it can be reasonably be installed and operated on the source type under consideration. Also, a control technique is considered available if it has reached the stage of licensing and commercial availability. For the purposes of this analysis, the term "commercial" is further defined to mean "capable of establishing a full contractual agreement with commercial and performance guarantees supported by appropriate financial backing" for the implementation of full-scale, full-time systems of the technique or technology application. A technology that is available and applicable is technically feasible.

There are three basic categories of NO_X emission control techniques and technologies:

- Pre-combustion controls;
- Combustion controls; and
- Post-combustion controls

Uncontrolled NO_X emissions from a coal-fired electric generating unit are highly dependent on type of firing method, amount of solid fuel fired per unit time and furnace volume, and the fuel's basic combustion properties and elemental composition. The basic methods for reduction of such emissions:

- either prevent pollution, i.e. use inherently lower-emitting processes/practices which produce fewer NO_X emissions during the power generation process; or
- involve improvements to, or provide new add-on controls that, reduce emissions after they are produced before they are emitted from the facility; or
- are combinations of inherently lower-emitting processes and add-on controls.

Most of the identified control options have been commercially-available, installed, and operating in many full-scale, permanent coal-fired utility boiler installations in the United States for five years or more.

Pre-combustion controls, such as fuel switching, fuel blending, and fuel cleaning have been practiced and performed at numerous utility power plants, typically for operational and sulfur emissions control reasons.

Combustion controls, such as low-NO_X burners (LNBs) and overfire air systems, are very commonly applied to reduce NO_X emissions from fossil fuel-fired powerplants. Low-NO_X Burners are typically applied to pulverized coal, gaseous and liquid fuel-fired boilers. They are not applicable to cyclone-fired boilers. Flue gas recirculation (FGR) has been practiced and performed at numerous natural gas and fuel oil-fired utility and industrial powerplants for NO_X emissions control reasons. On large coal-fired utility boilers, FGR has primarily been applied for steam temperature control purposes, not for emissions control. Conventional Gas Reburn (CGR) with overfire air has been installed and placed in commercial operation on several cyclone-fired boilers, primarily in the eastern region of the United States. Coal Reburn (CR) with overfire air has been successfully demonstrated on two cyclone-fired boilers and commercially installed on three pulverized coal-fired boilers in the United States. Combustion tempering (water/steam injection) has been tested but has not been continuously practiced on cyclone-fired coal boilers. Oxygen-enhanced combustion has only been demonstrated and/or installed on a limited number of pulverized coal-fired powerplants, not on any coal-fired cyclone boilers.

Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) are post-combustion technologies that have been applied predominantly on eastern or midwestern bituminous coal-fired boilers. Others, mostly comprised of a combination of available emission reduction technologies, are often referred to as “hybrid” or “layered” controls. Variations of SNCR, such as Rich Reagent Injection (RRI) with and without SNCR, have only been installed or demonstrated on a limited number of cyclone-fired boilers. Other technologies, such as Fuel Lean Gas Reburn™ with SNCR, hydrocarbon-enhanced SNCR (commercially available as NO_XStar^{TM}), and Conventional Gas Reburn with SNCR have only been demonstrated and/or installed on a limited number of pulverized coal-fired power plants.

Emerging post-combustion multi-pollutant control technologies, such as Powerspan’s Electro-Catalytic Oxidation (ECO®), which include NO_X control, were also identified. These are typically in the large pilot-scale commercial development phase, and have not been successfully demonstrated on a full scale basis on any pulverized coal, cyclone, or circulating fluid bed boilers.

In most of the combination or “layered” and emerging control cases, the NO_X control technology has been demonstrated to be capable of controlling the targeted pollutant(s) on either:

- a full-scale basis, but only with temporary equipment; or
- a full-scale basis, with permanent equipment but in a limited number of installations; or

- with less than full-scale and full-time application.

3.2.1 SUMMARY OF RETROFIT INSTALLATIONS OF NO_X CONTROL TECHNOLOGIES

There are a number of facilities around the country that have implemented or are planning to implement modifications to reduce NO_X emissions. Table 3-4 summarizes the various NO_X emission control system installations currently installed, or that have been demonstrated on a full-scale, short-term basis, in response to Acid Rain requirements, EPA's NO_X SIP call and local regulations, or a utility investigating the technology.

TABLE 3-4 – Identified NO_X Control System Retrofits on Cyclone Coal-fired Boilers

No. of Units(1)	Cyclone NO_X Control Technology Description
1	Fuel Switching/Blending
39(2)	Separated Overfire Air (SOFA)
2	Selective Non-Catalytic Reduction, with or without SOFA
2(3)	Rich Reagent Injection, with SOFA
7(4)	Conventional fuel reburn (pulverized or micronized coal, gas), w/ SOFA
1(5)	Fuel lean gas reburn, with or without SOFA
22(6)	High-dust or low-dust SCR, with or without other technologies
1(6)	Tail-gas SCR, with or without other technologies

(1) – This list of known NOx control retrofit installations is primarily focused on units in the United States. There may be other installations that are similar but were not identified.
(2) – Installed for NOx control (without fuel reburn). A list of known cyclone boiler SOFA installations is included in Appendix A2.
(3) – RRI has only been demonstrated with temporary equipment for testing. See technical literature references in Appendix A1 and A2 for details.
(4) – Several conventional coal and gas reburn retrofits have discontinued reburn demonstration or routine operation. See Technical Literature Reference list and Appendix A3 for further details.
(5) – Only one example of fuel lean gas reburn retrofit (without OFA) on a cyclone-fired boiler has been demonstrated. This system was installed for short-term reburn testing and has been removed.
(6) – High-dust SCR technology has been retrofitted on sixteen U.S. cyclone-fired boilers, all believed to have SOFA. Low-dust SCRs in U.S. have only been installed only on pulverized coal-fired boilers, none on cyclones. One tail-gas SCR installation on a coal-fired cyclone boiler found in Germany; none in the U.S. See technical literature references in Appendix A1 and A2 for details.

A more detailed description of the various control technology retrofits and their claimed effectiveness is included in the technical descriptions and reference literature in the technical feasibility assessment of

Appendix A1, and Appendix A2, which includes a summary of various selected U.S. NO_X emission reduction retrofit projects.

3.2.2 SUMMARY OF FEASIBLE NO_X CONTROL TECHNOLOGIES FOR MRY STATION

One example of fuel switching applied to a cyclone-fired boiler was identified. Ottertail's Big Stone Unit 1 was originally designed to burn North Dakota lignite and was switched to western subbituminous (PRB) coal for reasons unrelated to NO_X emissions reduction. Big Stone Unit 1 and M.R. Young Station Unit 2 have similar boiler designs. Thus, conversion of Milton R. Young Station Unit 2's boiler to fire PRB coal or a lignite/PRB blend is technically possible. There are no railroad facilities provided to service the Milton R. Young plant. Additional operational and capital costs to bring in large quantities of PRB coal will be significant. Based on a comparison of available emission data between Ottertail's Big Stone Unit 1 and M.R. Station Young Unit 2, there is no expected reduction in baseline (i.e. uncontrolled) NO_X emissions from switching to PRB from lignite at Milton R. Young Station. Although fuel switching at Milton R. Young Station is technically feasible, this alternative will not be economically competitive with other NO_X control technologies that offer better results for a much lower combination of capital and operational costs. For these reasons, it has not been considered further as an effective NO_X emissions control option for MRY Station Unit 2 boiler.

Separated Overfire Air (SOFA) is the most commonly-applied, combustion-related NO_X emission reduction technology that has been proven effective on cyclone-fired boilers. A version of separated overfire air specifically designed for increased NO_X emission reduction performance for lignite-fired cyclone boilers, referred to as "Advanced SOFA" in this analysis, can be installed on both units at M.R. Young Station. The potential operational limitations mentioned in the detailed feasibility discussions included in Appendix A1 for deeply air-staged cyclones associated with separated overfire air are expected to limit the control effectiveness of this technique, alone and in combination with other feasible NO_X control options.

Selective Non-Catalytic Reduction (SNCR) technology is a form of post-combustion NO_X emission control that has been successfully applied on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal to reduce NO_X emissions. SNCR has also been used on fuel oil and natural gas-fired units. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without air-staged combustion with overfire air in full operation. This control technology adds urea (or ammonia) reagent to the hot furnace gases in the upper furnace to chemically reduce nitrogen oxides. SNCR was considered technically feasible for application on both units at M.R. Young Station. SNCR can be operated with and without SOFA. Variations of SNCR technologies such as Hydrocarbon-enhanced SNCR (HE-SNCR) and “Rotamix” have been installed on pulverized coal-fired boilers but are not proven on cyclone boilers. This is described in detail in Appendix A1.

Rich Reagent Injection (RRI) is a form of SNCR under development specifically intended for NOx emissions control on cyclone boilers. As of October 2006, RRI has been demonstrated but has not been commercially installed and placed in continuous operation on a cyclone-fired boiler, especially one burning coal with high fouling and slag temperature sensitivities associated with lignite supplied from the Center mine. RRI adds aqueous urea reagent to the hot furnace gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea which will increase NOx emissions. RRI is considered technically infeasible for application on the cyclone boilers at the Milton R. Young Station at the present time. This is described in detail in Appendix A1.

Various forms of fuel reburn with and without overfire air are types of combustion-related technologies that have been demonstrated and commercially installed on pulverized coal, fuel oil-fired, and cyclone utility and industrial boilers. Natural gas-consuming variations such as Conventional Gas Reburn (CGR) and Fuel-Lean Gas Reburn (FLGR™) have been applied to cyclone boilers burning bituminous and subbituminous coals. High capital costs expected for installing a natural gas pipeline and high operating costs from consumption of large volumes of such fuel make these alternatives economically unfavorable for both units at M.R. Young Station. Pulverized or micronized coal reburn, in combination with SOFA, are technically feasible but will require extensive capital, operating and maintenance costs for fuel grinding equipment and facilities when installed and operated for both units at M.R. Young Station. This is described in detail in Appendix A1.

Fuel cleaning is a technique normally applied to reduce the sulfur or ash content of a fossil fuel prior to combustion. No examples of fuel cleaning of North Dakota lignite or western subbituminous coal strictly for NO_X emissions reduction were found in available technical literature. This technique is considered infeasible for NO_X emissions control of M.R. Young Station boilers at the present time.

High-dust, low-dust, and tail-gas variations of selective catalytic reduction (SCR) technology have been applied on pulverized coal and cyclone boilers as a post-combustion type of NO_X emission control throughout the world and in the United States, except on units firing North Dakota lignite. The severity of catalyst blinding and pluggage from particulate matter and flue gases emitted from cyclone-fired boilers burning North Dakota lignite precludes the technical feasibility for successful application of such SCR technology on the EGUs at the Milton R. Young Station. This is described in detail in Appendix A1 with supporting documentation in Appendix B.

The results of Step 2 of the NO_X BACT Analysis for determining the technical feasibility of potential control technologies, including various "layered" combinations, are listed in Tables 3-5 and 3-6.

TABLE 3-5 – Technically-Feasible Potential NO_X Control Technologies for M.R. Young Station Unit 2 Cyclone Boiler

Control Technology(1)	**In Permanent, Full-Scale Service on Existing Coal-Fired Cyclone Utility Boilers?**	**Technically Feasible on M.R. Young Station Unit 2 boiler?**
Selective Non-Catalytic Reduction (SNCR)	Yes(2)	Yes
Conventional Gas Reburn	Yes(3)	Yes(3); Requires SOFA or ASOFA
Coal Reburn	Yes(4)	Yes(4); Requires SOFA or ASOFA
Fuel Lean Gas Reburn	No(5)	Yes(5) (w/ or w/out SOFA or ASOFA)
Advanced SOFA	No(6)	Yes(6). Includes relocated lignite drying vent ports
Separated OFA (basic SOFA)	Yes(6)	Yes(6)
Combustion Improvements	Yes	Yes(7); typically included with separated OFA
Flue Gas Recirculation	Not for NOx control	Yes(8) (not expected to reduce NOx further)
Fuel Switching / Blending	Yes	Yes(9) (not expected to reduce NOx further)

See technical feasibility details and literature References in Appendix A for details.

(1) – All potential combinations of technologies not listed. See discussion of "layered" technologies.

(2) – Assumes use of urea for reagent. Limited number of active installations on cyclone-fired boilers burning western subbituminous (i.e. Powder River Basin or PRB) coal.

(3) – Limited number of active conventional gas reburn (CGR) installations on cyclone-fired boilers burning PRB coal.

(4) – Limited number of demonstrations or active installations of pulverized or micronized coal reburn on cyclone-fired boilers. One demonstration of pulverized coal reburning with PRB coal has been performed on a cyclone-fired boiler, no longer active. Only one active permanent coal reburn installation on cyclone-fired boiler burning eastern bituminous coal, none burning PRB coal or lignite.

(5) – Only one short-term test demonstration of FLGR™ on a cyclone-fired boiler burning coal with separated overfire air.

(6) – No cyclone boilers firing North Dakota lignite have installed basic or advanced SOFA. See Appendix A.

(7) – Considered part of SOFA installation for coal boilers without combustion controls for NOx reduction.

(8) – No examples of using recirculated flue gas on coal-fired boilers for NOx emissions control were found in available technical literature. Zero additional NO_X reduction potential expected from this technique alone for MRY Station Unit 2. Potential NO_X reduction improvement on MRY Unit 2 considered part of "advanced" SOFA.

(9) – Zero additional NO_X reduction potential expected from this technique (switching from lignite to lignite/PRB blends or 100% PRB) alone for MRY Station Unit 2.

TABLE 3-6 – Technically Infeasible Potential NO_X Control Technologies for M.R. Young Station Unit 2 Cyclone Boiler

Control Technology[(1)]	**In Permanent, Full-Scale Service on Existing Coal-Fired Cyclone Utility Boilers?**	**Technically Feasible on M.R. Young Station Unit 2 boiler?**
Selective Catalytic Reduction (SCR): conventional (high dust); Low-dust; Tail-gas	Yes(2) / No / Yes(3)	No(4) - Unresolvable fouling and catalyst deactivation problems expected. See discussion of SCR feasibility for ND lignite.
Electro-Catalytic Oxidation (ECO®)	No	No, has not been demonstrated full-scale nor reached commercial availability
HE-SNCR (using ammonia)	No(5)	No(5). Has not been demonstrated on cyclone.
Rotamix (ROFA + SNCR)	No(6)	No(6). Has not been demonstrated on cyclone.
Rich Reagent Injection (RRI) with ASOFA	No(7)	No(7). Requires oxygen-free furnace environment, varying air/fuel would increase NOx emissions.
RRI + SNCR with ASOFA	No(7)	No(7). See footnote and feasibility discussion.
Advanced Conventional Gas Reburn (ACGR) + SNCR	No(8)	No. Has not been demonstrated on cyclone.
Coal Reburn + SNCR	No(8)	No. Has not been demonstrated on cyclone.
Fuel Lean Gas Reburn + SNCR	No(8)	No. Has not been demonstrated on cyclone.
Rotating Opposed-Fired Air	No(6)	No. Has not been demonstrated on cyclone.
Oxygen Enhanced Combustion	No(9)	No. Has not been demonstrated on cyclone.
Water Injection	No(10)	No(10)
Fuel Cleaning	Not for NOx control	No(11) (not expected to reduce NOx further)

See technical feasibility details and literature References in Appendix A for details.

(1) – All potential combinations of technologies not listed. See discussion of "layered" technologies.

(2) – Limited number of active installations on cyclone-fired boilers burning western subbituminous coal.

(3) – No identified installations on coal-fired boilers in the United States. One tail-end SCR on cyclone boiler in Germany.

(4) – See discussion of SCR feasibility for ND lignite in Appendix A1 and Appendix B.

(5) – Hydrocarbon-enhanced SNCR has not been demonstrated on a cyclone-fired boiler, nor any boiler firing western subbituminous coal or lignite.

(6) – Rotating Opposed-Fired Air with or without SNCR has not been demonstrated on a cyclone-fired boiler. No apparent significant advantages over SOFA on cyclone-fired boilers.

(7) – Rich Reagent Injection has been successfully demonstrated for brief periods with SOFA with and without SNCR at two cyclone powerplants. There are no permanent RRI installations completed and operational as of May 2006. Difficulties in maintaining an oxygen-free furnace environment in MRY Station boilers where the urea reagent would be injected due to cyclone air/fuel imbalances during air-starved combustion would increase NOx emissions.

(8) – No known demonstrations or permanent installations of Advanced conventional gas reburn (CGR) or FLGR™ or pulverized/micronized coal reburn (PCR/mCR) in combination with SNCR on cyclone-fired boilers. CGR and PCR/mCR require separated overfire air. FLGR™ has been applied to pulverized coal firing with and without SOFA, with and without SNCR; FLGR™ with SNCR is also called amine-enhanced fuel lean gas reburn (AEFLGR™).

(9) – No known demonstrations or permanent installations of oxygen-enhanced combustion (OEC) on cyclone-fired boilers.

(10) – No permanently installed examples of using this technique continuously on coal-fired boilers were found in available technical literature. Not suitable for high-moisture lignite fuels.

(11) – No known demonstrations or permanent installations of using this technique continuously on coal-fired boilers for NOx emissions control were found in available technical literature.

Additional criteria besides technical feasibility are utilized for technology selection in a BACT analysis have been included in the following sections summarizing control effectiveness estimates, capital plus operating and maintenance cost estimates, energy impacts, and environmental impacts:

- Control effectiveness (i.e. percent pollutant removed)
- Expected emission rate (see Tables 3-7, 3-8) and emission reduction (tons per year)
- Economic impacts (total cost and incremental cost effectiveness)
- Energy impacts
- Environmental impacts (other media and emissions of toxic and hazardous air pollutants)

3.3 RANK OF TECHNICALLY FEASIBLE NO$_X$ CONTROL OPTIONS BY EFFECTIVENESS

The third step in the “top-down” BACT evaluation is to rank the remaining control technologies by effectiveness. The purpose of ranking the control technologies is to establish a hierarchy that “places at the “top” the control technology that achieves the lowest emission level.”

The emission reduction (control effectiveness) percentages developed for ranking the available NO$_X$ emission control options considered feasible for Milton R. Young Station Unit 2 are shown in Table 3-7. These are estimates based upon engineering judgments with considerations of:

- Boiler heat input rates associated with realistic upper boundary operating assumptions;
- baseline emission rates corresponding to the realistic upper boundary operating assumptions;
- the general combustion properties of North Dakota lignite;
- published and available emission reduction performance achieved at other similar utility powerplants (cyclone-fired boilers);
- computer-derived predictions; and
- inclusion of performance margins to allow for variations in fuel, weather, equipment condition, and other factors that prevent the ultimate peak short-term performance from being reliably sustained over the course of long-term operation.

These NO$_X$ emission level and reduction percentage estimates include adjustments of previously demonstrated or predicted performance that reflect differences between North Dakota lignite and eastern or midwestern bituminous and western subbituminous coals.

The numbers assume the estimated capability of the employed technique is achievable and sustainable (long-term) and that potential operational limitations mentioned in the feasibility discussions allow the successful practice of the technique or technology. None of the remaining control options has been installed on a cyclone-fired boiler burning North Dakota lignite. As such, the expressed control percentages reflect the use of engineering judgment, based on the listed technique or technology application. This is particularly pertinent to all control options that involve air-staged combustion associated with various forms of separated overfire air. SOFA-based controls for cyclone-fired coal-burning boilers have typically reduced NO_X emission levels significantly from the precontrol baseline, and which allow or enhance further reductions when combined with other control techniques and technologies.

3.3.1 ESTABLISHING BASELINE NO_X EMISSIONS FOR RANKING CONTROL OPTIONS

Before the various feasible NO_X emission control alternatives can be estimated and ranked in order of effectiveness, the precontrol baseline level of emissions and its basis must be determined. The EPA's NSR Manual provides general guidance for establishing estimated baseline emissions to be used for the purpose of calculating and comparing the control and cost-effectiveness of a control option:

> "The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions from the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of added post-process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for the use of inherently lower polluting processes"[25].

Also stated in the EPA's NSR Manual:

> "Estimating realistic upper bound case scenario does not mean that the source operates in an absolute worst-case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true

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[25] Ibid, NSR Manual B.37

> upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints"[26].

Establishing estimated baseline NO_X emissions for a new or existing source involves determining the design or operational basis of the emission rate. A useful means of comparing such emission rates is to establish the unit emission rate, expressed in pounds of pollutant per unit of process output. For processes such as steam-electric generating powerplants utilizing combustion in boilers, the desired process output (kilowatts or megawatts) can be related to the pollutant-bearing flue gas created by the combustion of fuel. Units of fuel heat input (millions of BTUs) required to create a unit of desired electrical output (kW) and thus the efficiency of converting the fuel heat to such electrical output (unit heat rate, Btu/kW-hr) are important.

A review of reported hourly NO_X emissions for MRY Station Unit 2 boiler, including unit mass rates (lb/mmBtu and lb/hr), boiler heat input (mmBtu/hr), and gross electrical output in megawatts (MW_g), was performed for the operating periods in years 2001-2005 inclusive. A realistic upper bound emission case scenario for each boiler's baseline emissions at Milton R. Young Station determined the highest summation of any rolling 12-month period NO_X mass emissions (pounds), along with the summation of the gross heat input (mmBtus) and the boiler operating hours for the same rolling 12-month period corresponding to the highest NO_X pounds. Dividing the summation of the rolling 12-month NO_X pounds by heat input results in a average unit emission rates (lb/mmBtu). Likewise, the summation of the rolling 12-month gross heat input (mmBtus) divided by the boiler operating hours yields an average gross heat input rate (mmBtu/hr). This emission evaluation revealed that:

- Unit 2 at Milton R. Young Station is typically operated in a base-loaded manner;
- MRYS Unit 2's highest 12-consecutive month NO_X mass emissions summation divided by the summation of the same 12-month period's heat input averaged 0.786 lb/mmBtu at a corresponding average unit heat input rate of 4,885 mmBtu/hr and unit gross electrical output of 440 MW_g.

3.3.2 ESTIMATING CONTROL-EFFECTIVENESS OF NO_X EMISSIONS CONTROL OPTIONS

The degree of success in operation of separated overfire air alone and in combination with the other selected feasible alternatives is important to the amount of NO_X emission reduction achieved. The

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[26] Ibid, NSR Manual B.37

emission control performance from the advanced version of separated overfire air (ASOFA) is highly dependent on the degree of success in admitting combustion air insufficient for complete combustion in the cyclones without causing related negative impacts. The control percentages estimated for firing North Dakota lignite in the MRY Station boilers reflect the belief that operating the existing cyclones much below an average cyclone stoichiometric ratio of approximately 0.95 (95% of the theoretical amount of combustion air required for complete combustion) will not be successful. This is due primarily to the expected "starved air" combustion causing a reduction in cyclone furnace gas temperatures, thus creating a strong potential for molten slag solidifying in the cyclone barrels, slag taps, and lower furnace floor openings. This would impose a great interruption to steam production since forced outages would be required to remove this physical obstruction before full load boiler operation could be reestablished. The EPA's draft NSR Manual states "It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options"[27].

The potential operational limitations for deeply air-staged cyclones associated with separated overfire air and coal reburn alternatives are expected to limit the amount of NO_X control potential possible from successful practice of the particular technique or technology. This is described in the detailed feasibility discussions included in Appendix A1.

The advanced form of separated overfire air is expected to be effective in NO_X emission reduction and can be combined with other feasible combustion-related and post-combustion control alternatives for these lignite-fired cyclone boilers. The basic form of SOFA in combination with coal reburn, gas reburn options, and SNCR, was not included in the detailed control effectiveness analysis in order to limit the number of options that were evaluated.

Using an advanced form of SOFA system, M.R. Young Station's Unit 2's boiler operating at MCR is expected to achieve a NO_X emission level of 0.49 lb/mmBtu when operating modestly air-staged cyclone furnaces with suitable combustion controls. This level of NO_X reduction from ASOFA operation, approximately thirty eight percent, is based on the expected ability to reduce emissions without incurring potential significant negative impacts of this technique. This reduction estimate includes the additional amounts of control potential available from operating with relocated lignite drying system vent ports (and FGR ports for Unit 2) associated with ASOFA operation with modestly air-staged cyclone furnaces.

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[27] Ibid, NSR Manual B.37

Coal reburn with ASOFA is estimated to reduce NO_X emissions for M.R. Young Station's Unit 2's boiler operating at MCR slightly more than 54 percent from the pre-control baseline NO_X emission rate, considering similar control levels demonstrated by previous coal-reburn retrofits on cyclone-fired boilers and limitations previously discussed with ASOFA.

Conventional Gas Reburn and Fuel Lean Gas Reburn options were both assumed to be installed with ASOFA. NO_X reduction from CGR with ASOFA operation is expected to be approximately 55.4 percent. FLGR with ASOFA is expected to reduce NO_X emissions approximately forty five percent. Estimates for NO_X emissions for M.R. Young Station's Unit 2's boiler considered similar control levels demonstrated by previous gas-reburn retrofits on cyclone-fired boilers with modestly air-staged cyclone furnaces and limitations previously discussed with ASOFA.

The NO_X emission rate for Selective Non-Catalytic Reduction (SNCR) (using urea) with ASOFA is expected to be approximately 0.355 / 0.33, resulting from a reduction in NO_X emissions of approximately 58 percent from the 12-month average pre-control baseline NO_X emission rate.

Included in the feasible control option ranking of Table 3-7 are layered alternatives that were shown in Table 3-5. The highest-performing NO_X control alternatives remaining in consideration are ranked in declining order of expected emission reduction. These combined control options refer to "advanced" SOFA, which is expected to have significantly lower NO_X emissions than a typical SOFA system as applied to the Milton R. Young cyclone boilers.

TABLE 3-7 – Ranked NO_X Control Options Feasible for MRY Station Unit 2 Boiler with Expected Control Performance

Alt. Label[1]	NO_X Control Technique	Emission Rate (lb/mmBtu)	Control Percentage[2]
E	SNCR (using urea) w/ ASOFA	0.330	58.0
D	Gas Reburn with ASOFA	0.350	55.4
C	Lignite Reburn w/ ASOFA	0.360	54.2
B	Fuel Lean Gas Reburn with ASOFA	0.432	45.0
A	Advanced Separated Overfire Air (ASOFA)	0.489	37.7
-	Baseline	0.786	-

(1) - Alternative designation assigned from highest to lowest unit NOx emission rate.
(2) - Control percentages are relative to an average pre-control emission baseline of 0.786 lb/mmBtu based on annual operation at highest pre-control 12-month rolling NOx summation mass emissions divided by the 12-month heat input summation.

The annual emission levels developed for Table 3-7's ranking the feasible alternatives assume that the highest 12-month average pre-retrofit level of unit NO_X emissions for M.R. Young Station's Unit 2's boiler is a baseline of 0.786 lb/mmBtu. This was determined from the highest reported rolling 12 consecutive month period's summation of hourly NO_X emissions (lbs).

The hourly gross fuel heat input (mmBtu) was summed over that same 12-month time period, and divided by the number of boiler operating hours to yield an annual average gross fuel heat input rate (mmBtu/hr). Multiplying the 12-month average heat input rate (mmBtu/hr) by the baseline or control alternative's 12-month average unit emission rate (lb/mmBtu) equals a 12-month average hourly NO_X emissions rate (lb/hr). Annual NO_X emissions (tons) for the baseline pre-control condition were calculated by multiplying the 12-month summation for boiler operating hours during the same period as the highest NO_X emissions by the 12-month average emission rate (lb/hr). The annual tons for the control options were calculated by multiplying the alternative's average annual emission rate (lb/yr) by a reduction factor (if applicable) for heat input or running plant capacity and adjusting boiler operating hours by an annual uptime (availability) factor. Details for these adjustments are included in Appendix C3. Based on these calculations, the annual emissions for M.R. Young Station's Unit 2's boiler are shown in Table 3-8.

TABLE 3-8 – Expected Annual NO_X Control Performance for MRY Station Unit 2 Alternatives

		EMISSIONS				
Alt. Label[1]	**NOx Control Alternative**	**Emission Rate lb/mmBtu**	**Hourly Emission[2] lbs/hr**	**Annual Emission[3] tons/yr**	**Emission Reduction[4] tons/yr**	**NOx Removal Efficiency[5] %**
E	SNCR (using urea) w/ ASOFA	0.330	1,663	6,298	9,216	58.0
D	Gas Reburn w/ ASOFA	0.350	1,764	6,693	8,820	55.4
C	Lignite Reburn w/ ASOFA	0.360	1,815	6,806	8,707	54.2
B	Fuel Lean Gas Reburn w/ ASOFA	0.432	2,176	8,306	7,207	45.0
A	Advanced Separated Overfire Air (ASOFA)	0.489	2,466	9,451	6,063	37.7
-	Baseline	0.786	3,959	15,513	0	-

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Hourly NO_X emission estimates (lb/hr) were calculated based upon average annual unit emission rate (lb/mmBtu) x 4,885 mmBtu/hr MCR heat input.
(3) - Estimated annual emission tons assume an annual capacity factor specific to each alternative; 89.5% was assumed for the baseline case.
(4) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative’s annual emissions (tons).
(5) - Estimated NO_X control level percentage reductions relative to 0.786 lb/mmBtu emission baseline at 4,885 mmBtu/hr MCR heat input.

3.4 NO$_X$ CONTROLS ANALYSIS AND IMPACTS EVALUATION

The fourth step of a "top-down" BACT review is to evaluate the most effective emission controls. Energy, economic, and environmental impacts are to be considered in the control technology evaluation. The purpose of the evaluation is to determine if there are any energy, economic or environmental impacts that would eliminate the top control technologies from consideration.

3.4.1 NO$_X$ CONTROL ECONOMIC IMPACTS FOR MRY STATION UNIT 2

An evaluation was performed to determine the various cost impacts of installing feasible NO$_X$ control alternatives on Milton R. Young Unit 2. This evaluation includes estimated:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 3-9 through 3-13.

3.4.1.1 CAPITAL COST ESTIMATES FOR NO$_X$ CONTROL ALTERNATIVES

The capital costs to implement the various NO$_X$ control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. In the cases of SNCR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

The unit nameplate output capacity (gross electrical output in megawatts) assumed for the NO$_X$ control technologies capital cost estimate basis was 477 MW$_g$ for MRY Station Unit 2[28].

A review of the unit capital cost factor range and single point factors applicable to MRY Station Unit 2 NO$_X$ control technologies are presented in Table 3-9. The estimated installed and levelized capital costs for the highest-performing form of the various feasible NO$_X$ emission reduction technologies evaluated for cost-effectiveness are shown in Table 3.10. These are listed in order of control effectiveness, with the highest ranked option at the top.

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[28] Ibid footnote number 23.

TABLE 3-9 – Unit Capital Cost Factors of Feasible NO_X Control Options for MRY Station Unit 2

Alt. Label(1)	NO_X Control Technique	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3), ($/kW) MRYS Unit 2
E	SNCR (using urea) w/ ASOFA	20-35)6)	35.9(4),(5)
D	Gas Reburn w/ ASOFA	15-30(6)	74.4(5),(6),(7)
C	Lignite Reburn w/ ASOFA	30-60(6)	170.2(5),(8)
B	Fuel Lean Gas Reburn w/ ASOFA	--(9)	45.7(4),(5),(9)
A	Advanced Separated Overfire Air (ASOFA)	5-10(6)	21(5)

(1) – Alternative designation has been assigned from highest to lowest unit NOx emission rate.

(2) – Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ this due to positive or negative synergistic effects. Range based on published values or vendor proposals.

(3) – Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on existing nameplate rating. Single point cost figures in 2006 dollars.

(4) – Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. See Appendix C2 for details.

(5) – The single point unit capital cost factor shown for the “advanced” version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(6) – NESCAUM 2005 Technical Paper, posted at their website. See technical references in Appendix A1 for details.

(7) – The single point unit capital cost factor shown for a conventional gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW), and that both boilers share the capital cost in proportion to their respective rated MW gross output capacities.

(8) – The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report, posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 75.5 $/kW. See technical references in Appendix A1 for details.

(9) – The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. The single point unit capital cost factor shown for a fuel lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (15.7 $/kW), and that both boilers share the capital cost in proportion to their respective rated MW gross output capacities.

TABLE 3-10 – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 2

Alt. Label(1)	**NOx Control Alternative**	**Installed Capital Cost(2) $1,000**	**Annualized Capital Cost(3) $1,000**
E	SNCR w/ ASOFA	17,128	1,493
D	Gas Reburn w/ ASOFA[4]	35,490	3,094
C	Lignite Reburn w/ ASOFA[5]	81,167	7,077
B	Fuel Lean Gas Reburn w/ ASOFA[4]	21,817	1,902
A	Advanced SOFA (ASOFA)	10,008	873
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars.

(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.

(4) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $14,988,000 for CGR and $7,494,000 for FLGR; and annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR. See footnotes #8 and 10 under Table 3-9.

(5) - Costs for increased PM collection capacity included in lignite reburn option are $36,013,000 for installed capital cost, and $3,140,000/yr annualized capital cost.

3.4.1.2 Operating and Maintenance Cost Estimates for MRY Station NO_X Controls

The operational and maintenance costs to implement the various NO_X control technologies were largely estimated from cost factors (percentages of installed capital costs) established in the EPA's Air Pollution Control Cost Manual (OAQPS) for SNCR[29], and from published in technical papers discussing those control technologies. In the cases including various forms of SNCR, preliminary vendor quotes were obtained and used in place of, or to adjust the OAQPS cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's annual O&M costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR alternatives; and
- Reagent dilution water consumption and unit cost for SNCR alternatives.

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[29] EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NO_X Controls – NO_X Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.
- Reductions in revenue expected to result from loss of unit availability, i.e. outages attributable to the control option, which reduce annual net electrical generation available for sale (revenue).

For economic evaluation purposes, an annual average running plant capacity factor of 95.2 percent compared to a nominal unit output capacity of 462 MWg combined with an average annual availability (uptime) of 8,229 operating hours (94.7 percent of 8760 hours per year) resulting in an annual unit capacity factor of 89.5% were assumed for Unit 2's pre-control baseline annual operation. A heat input rate of 4,885 mmBtu/hr and a NO_X emission rate of 0.786 lb/mmBtu were assumed for calculating control and cost-effectiveness from pre-control maximum rolling 12 month summation of nitrogen oxides' mass emissions for MRY Station Unit 2.

Table 3-11 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the highest-performing form of the various feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Appendix C3 provides more details for the levelized annual O&M cost calculations and cost factors.

TABLE 3-11 – Estimated O&M Costs for
NO_X Control Alternatives - MRY Station Unit 2

Alt. Label(1)	**NOx Control Alternative**	**Annual O&M Cost**(2) **$1,000**	**Levelized Annual O&M Cost**(3) **$1,000**
E	SNCR w/ ASOFA	7,937	9,911
D	Gas Reburn w/ ASOFA	48,680	60,789
C	Lignite Reburn w/ ASOFA	9,929	12,398
B	FLGR w/ ASOFA	21,951	27,411
A	Advanced SOFA (ASOFA)	2,805	3,503
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at nominal unit capacity (462 MWg) and assumes a 94.7% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(4) - Costs for increased PM collection capacity included in lignite reburn option are $3,358,000/yr for annual O&M cost, and $4,194,000/yr annualized O&M cost.

3.4.1.3 LEVELIZED TOTAL ANNUAL COST ESTIMATES FOR MRY STATION NO_X CONTROLS

In order to compare a particular NO_X emission reduction alternative during the initial engineering analysis portion of the BACT selection process, the sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which is referred to as "Levelized Total Annual Cost" (LTAC) of expected pollutant removal by implementing that alternative was calculated. The LTAC for all NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Appendix C1 for methodology). The unit control cost was then determined as the LTAC divided by annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. The control alternatives were also compared by calculating the change in unit cost (incremental cost) per incremental ton removed for the next most stringent alternative. This identified which alternatives produced the highest increment of expected pollutant reduction for the estimated lowest average annual cost increment compared with the baseline emission rate. The expected annual number of tons of pollutant removed versus estimated LTAC for each remaining control alternative was then plotted.

The comparison of the cost-effectiveness of the remaining NO_X emission reduction technologies was made and is shown in Table 3-12 and Figures 3-1 and 3-2 for MRY Station Unit 2. These figures plot estimated annual amount of NO_X removal (emission reduction) in tons per year on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis), for each of the remaining NO_X control technologies. Points on the graph that are farthest to the right and closest to the horizontal axis are deemed more cost-effective, since they represent controls that achieve more NO_X removal per dollar required for total annual costs of operation, maintenance, and capital recovery (depreciation).

Although the NSR Manual repeatedly prescribes following a "top down" analysis approach for BACT determination, the development of a least cost envelope with dominant controls (as seen in NSR Manual Figure B-1, page B.42) clearly labels points with lower emissions reductions and total annual costs first, i.e. "A", "B", etc. then proceeding with labeling and connecting points plotted further away from the zero emission reduction point. This "bottom-up" approach is for plotting the least-cost (dominant) control curve. The labeling of each unit's NOx control technique alternative has followed this approach.

TABLE 3-12 – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 2

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) $1,000	Average Control Cost(5) $/ton
E	SNCR w/ ASOFA	6,298	9,216	11,405	1,238
D	Gas Reburn w/ ASOFA	6,693	8,820	63,883(6)	7,243
C	Lignite Reburn w/ ASOFA	6,806	8,707	19,475(7)	2,237
B	FLGR w/ ASOFA	8,306	7,207	29,313(6)	4,067
A	Advanced SOFA (ASOFA)	9,451	6,063	4,376	722
	Baseline	15,513	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated annual emission tons assume an annual capacity factor specific to each alternative; 89.5% was assumed for the baseline case.

(3) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

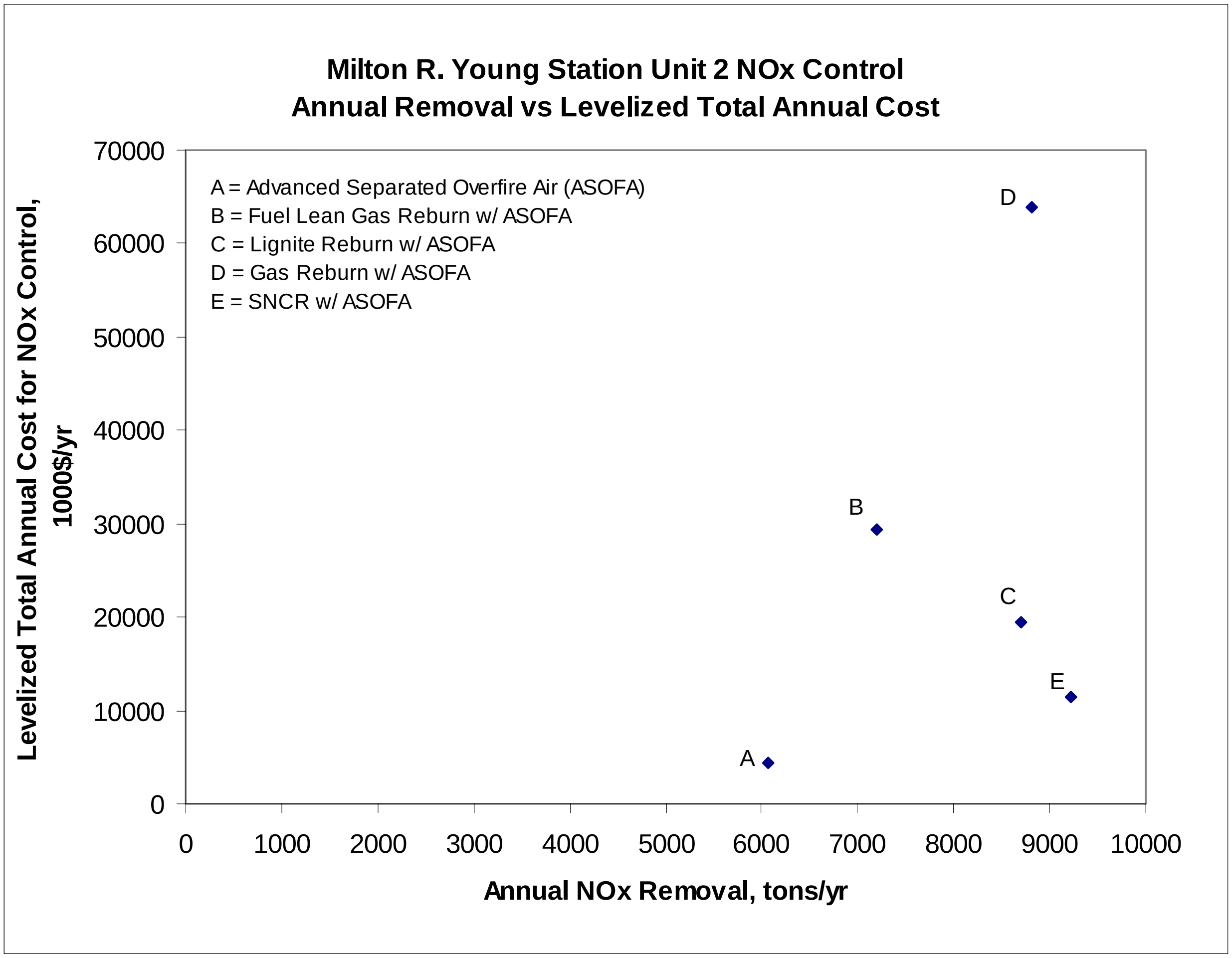
(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note #3 for Tables 3-10 and 3-11 for annualized cost factors. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at highest allowable pre-control NOx emission rate.

(5) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(6) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $1,307,000/yr for CGR and $653,000 plus for FLGR. See footnotes #8 and 10 under Table 3-9

(7) - LTAC for increased PM collection capacity included in lignite reburn option are approximately $3,140,000 for annualized capital cost plus $4,194,000/yr for annualized O&M cost, for a LTAC subtotal of $7,333,000/yr.

Figure 3-1 – NO_X Control Cost Effectiveness - MRY Station Unit 2[(1)]



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 3-12.

The purpose of Figure 3-1 is to show the range of control and cost for all feasible NO_X reduction alternatives evaluated. A dominant set of control alternatives were determined by generating what is called the “envelope of least-cost alternatives”. The dominant controls cost curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the annual NO_X removal tonnage versus LTAC for the various remaining BACT alternatives. Following a “bottom-up” graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope are inferior control alternatives per the NSR Manual and should be excluded from further analysis on a cost efficiency basis.

Of the technically feasible NO_X control alternatives considered for MRY Station Unit 2, data points for conventional gas reburn (Point D) and fuel-lean gas reburn (Point B) with advanced separated overfire air, and lignite reburn with ASOFA (Point C), lay distinctly left and above the other points of the control cost points' scatter plot of Figure 3-1. These control options are inferior and therefore were eliminated from further control cost-effectiveness analysis.

Average and incremental annual costs and NO_X emission reductions for the dominant least-cost control alternatives remaining after the elimination of the obviously inferior options are listed in Table 3-13. The annual NO_X control tons per year, divided by the total levelized annual cost, yields an average unit cost ($/ton). Incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. The additional tons per year of NO_X control relative to the previous apparent least-cost curve point, divided by the increase in levelized annual cost, yields an incremental unit cost ($/ton). Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the envelope of least-cost control alternatives, also called the dominant controls cost curve or DCCC) between successively more effective alternatives which are considered technically feasible for Milton R. Young Station boilers.

TABLE 3-13 – Dominant Controls Cost Curve Points for Feasible BACT NO_X Alternatives - MRY Station Unit 2

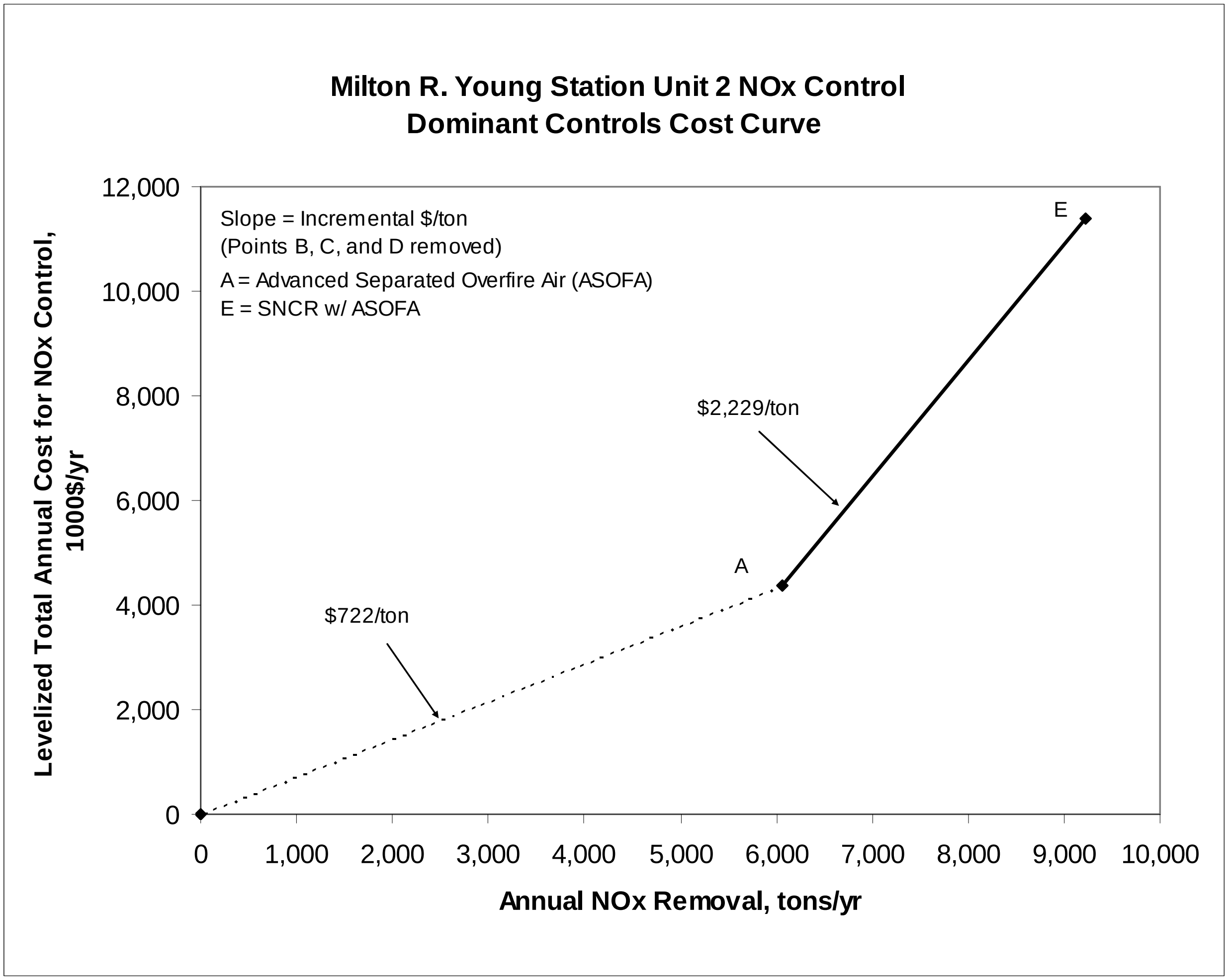
Alt. Label(1)	NOx Control Technique	Levelized Total Annual Cost(2),(3) ($1,000/yr)	Annual Emission Reduction(3) (tpy)	Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)	Incremental Annual Emission Reduction(4) (tpy)	Incremental Control Cost Effectiveness ($/ton)(2),(4)
E	SNCR w/ ASOFA	11,405	9,216	7,029	3,153	2,229
A	Advanced SOFA (ASOFA)	4,376	6,063	4,376	6,063	722

(1) – Dominant controls cost curve points from lowest (ASOFA) to highest (SNCR w/ ASOFA) are labeled the same as in Table 3-12, and on the graphs that accompany this table (Points B, C, and D were eliminated).
(2) – All cost figures in 2006 dollars.
(3) – Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate.
(4) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest, except as noted.

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control technique (slope from zero baseline to ASOFA, Point A was $722/ton for MRYS Unit 2; the incremental cost (slope) from ASOFA, Point A to SNCR with ASOFA, Point E was $2,229/ton for MRYS Unit 2.

Figure 3-2 contains a repetition of the levelized total annual cost and NO_X control information from Figure 3-1 for MRY Station Unit 2, with Point B (FLGR™ with ASOFA) , Point C (Lignite Reburn with ASOFA) and Point D (conventional gas reburn with ASOFA) removed. This is the dominant controls cost curve for MRY Station Unit 2 NO_X emissions alternatives.

Figure 3-2 – MRY Station Unit 2 NO_X Control Alternatives BACT Dominant Controls Cost Curve(1)



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 3-13

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. As can be seen from a review of Table 3-14, the average levelized control cost effectiveness (called the unit control cost in this report) ranges from approximately \$722/ton to \$7,243/ton of MRYS Unit 2's NO_X emissions removed. It should be noted, however, that the highest estimated average control costs involve gas reburn technologies that were shown to be inferior options (not on the dominant controls cost curve) and thus were eliminated from further impacts analysis.

The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the least-cost envelope of dominant control alternatives or dominant controls cost curve) between successively more effective alternatives. The economic impact analysis indicates that from a cost effectiveness viewpoint, the highest performing alternative is SNCR with ASOFA (Point E). This control option is considered technically feasible for Milton R. Young Station Unit 2 boiler but incurs a significant annual (levelized) incremental cost relative to the next highest feasible NO_X control technique, ASOFA (Point A) when ASOFA is compared against the pre-control baseline. The Advanced Separated Overfire Air alternative has an average unit control cost (\$722/ton) approximately 58% of the highest performing feasible alternative on the dominant controls cost curve (SNCR with ASOFA, \$1,238/ton). ASOFA also has a much lower incremental cost per ton relative to the pre-control baseline (slope from zero to Point A, \$722/ton) compared to SNCR with ASOFA (Point E) versus ASOFA (Point A); the slope from Point A to Point E was \$2,229/ton.

The other elements of the fourth step of a BACT analysis following economic impacts are to evaluate the following impacts of feasible emission controls:

- The energy impacts.
- The environmental impacts.

TABLE 3-14 – Estimated Emissions and Economic Impacts Summary for NO$_X$ Control Alternatives - MRY Station Unit 2

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 2

Alt. Label(1)	NOx Control Alternative	EMISSIONS(2)				NOx Removal Efficiency(2) %	ECONOMIC IMPACTS			
		Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr		Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton
E	SNCR w/ ASOFA	0.330	1,663	6,298	9,216	58.0	17,128	7,937	11,405	1,238
D	Gas Reburn w/ ASOFA	0.350	1,764	6,693	8,820	55.4	35,490	48,680	63,883(7)	7,243
C	Lignite Reburn w/ ASOFA	0.360	1,815	6,806	8,707	54.2	81,167	9,929	19,475(7)	2,237
B	FLGR w/ ASOFA	0.432	2,176	8,306	7,207	45.0	21,817	21,951	29,313(7)	4,067
A	Advanced SOFA (ASOFA)	0.489	2,466	9,451	6,063	37.7	10,008	2,805	4,376	722
	Baseline	0.786	3,959	15,513	0	0.0	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO$_X$ control level reductions relative to average annual emission baseline of 0.786 lb/mmBtu at 4,885 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 440 MWg and assumes a 93.9% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $14,988,000 for CGR and $7,494,000 for FLGR; and annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $36,013,000 for installed capital cost.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 440 MWg and assumes a 95.2% average running plant capacity factor compared to nominal unit gross electrical output capacity of 462 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $3,155,000/yr for annual O&M cost.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars.

(7) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $3,140,000 for annualized capital cost plus $3,940,000/yr for annualized O&M cost, for a total of $7,080,000/yr.

3.4.2 ENERGY IMPACTS OF MRY STATION NO_X CONTROLS

Operation of the most cost-effective NO_X control technologies considered feasible for potential application at the Milton R. Young Station impose direct impacts on the consumption of energy required for the production of electrical power at the facility. The details of estimated energy usage and costs for the various NO_X control alternatives are summarized in Appendix C3.

Control alternatives for reduction of NO_X emissions were reviewed to determine if the use of the technique or technology will result in any significant or unusual energy penalties or benefits. There are several basic kinds of energy impacts for NO_X emissions controls:

- Potential increase or decrease in power plant energy consumption resulting from a change in thermal (heat) energy to net electrical output conversion efficiency of the unit, usually expressed as an hourly unit heat rate (Btu/kW-hr) or the inverse of pounds of pollutant per unit electrical power output (MW-hr). This may or may not change the net electrical output (MW) capacity of the EGU, depending on if there are physical or imposed limits on the total heat input to the boiler or electrical power output.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in physical operational limitations imposed on the ability to sustain a fuel heat input rate (mmBtu/hr) which results in a potentially lower or higher unit net electrical output (MW) capacity. This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in auxiliary electrical power demand and usage (kW, kW-hrs). This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in reliability and availability to generate electrical power. This results in a change to the number of hours of annual operation, not necessarily a change in net electrical output (MW) capacity of the EGU.

3.4.2.1 ENERGY IMPACTS OF SOFA TECHNOLOGY

There should not be a major impact on energy consumption resulting from the operation of the advanced variation of a separated overfire air system. SOFA does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. Damper resistance and supply pressure impacts of the SOFA system on fan power consumption should be insignificant. The amount of flyash emitted from the boiler is expected to be reduced (less than five percent) from the baseline level when the SOFA system is in full operation. Slightly higher levels of unburned carbon in the flyash may occur with the operation of a SOFA system. This could have a small negative impact on the plant heat rate (higher Btu/kw-hr). These changes are expected to be within the typical range of current operation.

There is a potential reduction in reliability and availability of a lignite-fired cyclone boiler to generate steam for production of electrical power as a result of installing and operating a separated overfire air system. Typical SOFA operation on bituminous or western subbituminous coal-fired cyclone boilers does not carry a significant additional risk of causing insufficient or excessive accumulation of slag within the cyclone barrels or furnace bottom compared with non air-staged combustion. Reliable boiler operation depends on avoiding such adverse conditions in the cyclones and lower furnace, which could require a forced outage to remove the solidified slag prior to returning the boiler to generation production service.

The challenges of maintaining adequate slag layer development and flow while firing lignite in MRY Unit 2’s cyclones under excess air conditions have been significant during the operating history of the powerplant. Minimizing forced outages resulting from cyclone slag issues have largely been successful through operational practices that do not affect day-to-day boiler reliability and availability. Due to the variability of combustion characteristics of lignite supplied from the Center mine, and the dependency of the slag flow on the temperature within the cyclone barrels or furnace bottom, conditions may occur during ASOFA operation that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the solidified slag.

The potential impact on annual unit operating time due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation was estimated to be approximately 2% reduction from the assumed pre-control baseline availability, i.e. 0.94-0.02=0.92. The estimated electrical generation production lost due to the reduction in MRY Unit 2’s annual availability is shown in Table 3-16.

3.4.2.2 ENERGY IMPACTS OF SNCR TECHNOLOGY

For SNCR, the injection of a diluted urea solution will require some additional auxiliary power for heating and pumping the liquid and using compressed air for atomization and cooling the reagent injection nozzles/lances, on the order of 100 to 300 kW. The injection of water (used for urea dilution) into the boiler flue gas also will have a small negative impact on the plant heat rate (higher Btu/kw-hr), although the vendor of SNCR systems advises that the heat released from the oxidation of a portion of the injected urea compensates for this impact. The impact of additional flue gas created by operation of an SNCR-related system on fan power consumption should be small.

There is a potential reduction in reliability and availability of a lignite-fired cyclone boiler to generate steam for production of electrical power as a result of installing and operating a SNCR-related system. Typical SNCR operation with low ammonia slip when firing low-sulfur western subbituminous coal in cyclone-fired boilers does not carry a significant additional risk of causing excessive fouling of the tubular air preheater compared with non-SNCR operation. Reliable boiler operation depends on avoiding adverse fouling conditions in the air preheater, which could require a forced outage to remove the ash deposits prior to returning the boiler to generation production service.

The challenges of maintaining open passages through the air preheater tubes while firing lignite in MRY Unit 2's cyclones under typical conditions have been minor during the operating history of the powerplant. Minimizing forced outages resulting from ash deposits within the air preheater have largely been successful through operational practices that do not affect day-to-day boiler reliability and availability. Due to the variability of fouling characteristics of lignite supplied from the Center mine, and the dependency of the fouling within the air preheater on sodium, sulfur, and ammonia slip emission levels, conditions may occur during SNCR operation that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the air preheater deposits.

The potential impact on annual unit operating time due to air preheater fouling and other potential issues associated with SNCR system operation was estimated to be an incremental 1% reduction from the assumed pre-control baseline or ASOFA availability. The estimated electrical generation production lost due to the reduction in MRY Unit 2's annual availability is shown in Table 3-16.

TABLE 3-15 – Expected Auxiliary Electrical Power Impacts for NO_X Controls - MRY Station Unit 2

		Estimated Annual Average Auxiliary Electrical Power Demand and Consumption of NOx Control Equipment	
Alt. Label(1)	**NOx Control Technique**	**Gross Demand(2) kW**	**Power Usage(3) kW-hrs/yr**
E	SNCR w/ ASOFA	133	1,008,704
A	Advanced SOFA (ASOFA)	1	7,664

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.

(2) – The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects.

(3) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.

TABLE 3-16 – Expected Electrical Power Generation Availability and Capacity Impacts for NO_X Controls - MRY Station Unit 2

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Availability(2)	Estimated Annual Average Operating Time Reduction, hrs/yr(3)	Estimated Annual Average Running Plant Capacity Factor(4)	Estimated Annual Average Electricity Generation Reduction kW-hrs/yr(5)
E	SNCR w/ ASOFA	0.909	263	0.951	110,176,095
A	Advanced SOFA (ASOFA)	0.919	181	0.952	75,859.855

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.

(2) – Baseline availability is assumed at 93.9 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.

(3) – Annual lost operating time resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.

(4) – Baseline running plant capacity factor is assumed at 95.2 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.

(5) – Annual electricity generation reduction is annual reduction of operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the MCR capacity rating of 462 MW (MCR gross unit electrical output capacity).

TABLE 3-17 – Expected Total Electrical Power Generation Impacts for NO_X Controls - MRY Station Unit 2

Alt. Label(1)	NOx Control Technique	Power Usage(2) kW-hrs/yr	Estimated Annual Average Electricity Generation Reduction(3) kW-hrs/yr	Est. Annual Change in Net Electrical Power Generation Available for Sale(4) kW-hrs/yr
E	SNCR w/ ASOFA	1,008,704	110,176,095	111,184,799
A	Advanced SOFA (ASOFA)	7,664	75,859.855	75,867,520

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.

(2) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.

(3) – Annual electricity generation reduction is annual reduction of operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the MCR capacity rating of 462 MW (MCR gross unit electrical output capacity).

(4) – Annual change in net electrical power generation available for sale is arithmetic sum of annual power generation reduction due to a change in the auxiliary electrical power consumed plus the annual generation reduction from a decrease in annual operating time and average annual running plant capacity factor resulting from the implementation of the individual NOx control technique, compared with baseline.

3.4.3 ENVIRONMENTAL IMPACTS OF NOx CONTROLS - MRY STATION

Nitrogen oxides react with oxygen in the atmosphere to produce elemental nitrogen and ozone (O_3). This is one of the common causes of visible pollution in the atmosphere referred to as “smog”. Operation of the various NO_X control technologies considered for potential application at the Milton R. Young Station impose direct and indirect impacts on the environment. The most pronounced direct environmental impact expected from operation of any of the NO_X control options considered is the reduction of ozone and improvement in atmospheric visibility (i.e. reduced visibility impairment) downwind of the facility.

3.4.3.1 ENVIRONMENTAL IMPACTS OF SOFA TECHNOLOGY

The operation of a separated overfire air system is expected to slightly increase carbon monoxide concentrations in the stack flue gas. The advanced form of SOFA alternative is expected to slightly lower the amount of particulate matter emitted from the boiler and may raise the amount of unburned carbon in the flyash collected for land disposal and emitted to the atmosphere by small increments. Alternatives involving forms of gas reburn should experience lower particulate emissions, and a reduction in the amount of boiler bottom and flyash requiring disposal.

The environmental impact from potential reduction of annual unit operating time by approximately two percent due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation will be to reduce the annual amount (tons) of nitrogen oxides emitted, and therefore the annual number of NO_X tons removed will increase, by approximately two percent.

3.4.3.2 ENVIRONMENTAL IMPACTS OF SNCR TECHNOLOGY

Operation of a conventional SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs).

Operation of an SNCR system will normally create a small amount of unreacted urea or ammonia to be emitted. The amount of ammonia slip produced by SNCR depends on the amount of reagent utilization and location of the injection points. Higher SNCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 10 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate $[(NH_4)_2SO_4]$ and ammonium bisulfate $[NH_4HSO_4]$ will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates.

Some of the unreacted ammonia from SNCR operation will be collected with the flyash in the electrostatic precipitator. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be emitted from the stack as an aerosol or condensable particulate. This has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition. Although the predicted amount of such potential impact from ammonia slip emissions has not been determined, it is expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NOx emission reduction.

Delivery of the urea reagent to the powerplant facility and storage of aqueous urea reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Urea is much less volatile than anhydrous or aqueous ammonia, and these risks are expected to be manageable. Emergency planning and community communications are part of the management plan requirements for such reagent usage.

The environmental impact from potential reduction of annual unit operating time by approximately one percent due to air preheater fouling issues associated with SNCR system operation will be to reduce the annual amount (tons) of nitrogen oxides emitted, and therefore the annual number of NO_X tons eliminated relative to the constant pre-control emission baseline will increase by approximately one percent.

3.4.4 SUMMARY OF ECONOMIC, ENERGY AND ENVIRONMENTAL IMPACTS OF MRY STATION NO_X CONTROLS

The economic, energy, and environmental impacts of each feasible BACT alternative evaluated for this study is summarized in this Section. Table 3-18 summarizes the various impacts discussed in Sections 3.4.1 through 3.4.3. The economic analysis examined the capital cost of each feasible BACT alternative evaluated and any other powerplant upgrade costs necessary to implement the alternative. In addition, the economic analysis examined the operating and maintenance cost associated with the highest-performing forms of each feasible BACT alternative evaluated. These costs were then combined into the levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each alternative was evaluated. Two alternatives were on the dominant controls cost curve and thus were identified as the more cost effective alternatives. The two BACT NO_X control alternatives evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 2 were:

- Selective Non-Catalytic Reduction (SNCR) combined with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA); and
- ASOFA alone.

TABLE 3-18 – Summary of Top-Down BACT Impact Analysis Results for Dominant NO_X Control Alternatives - MRY Station Unit 2

		EMISSIONS[2]				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS	
Alt. Label[1]	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	Installed Capital Cost[3] $1,000	Annual O & M Cost[4] $1,000	Levelized Total Annualized Cost[5] $1,000	Average Control Cost[6] $/ton	Incremental Control Cost[7] $/ton	Incremental Aux. Power Demand[8], kW	Incremental Annual Aux. Power Usage + Generation Reduction[8], kW-hrs/yr	Non-Air Increase	Toxic Air Increase
E	SNCR w/ ASOFA	0.330	1,663	6,298	9,216	17,128	7,937	11,405	1,238	2,229	133	111,184,799	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.489	2,466	9,451	6,063	10,008	2,805	4,376	722	722	1	75,867,520	Flyash UBC	CO
	Baseline	0.786	3,959	15,513	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.786 lb/mmBtu at 4,885 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at gross unit electrical output of 440 MWg and assumes a 93.9% average annual availability.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $36,013,000 for installed capital cost

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at gross unit electrical output of 440 MWg and assumes a 95.2% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars.

(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit reliability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr).

(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations likely will increase with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology.

3.5 BACT RECOMMENDATIONS AND CONTROL LEVELS – MRY STATION UNIT 2

This report presents the analysis of control technologies for nitrogen oxides (NO_X) for Minnkota Power Cooperative's (MPC's) Milton R. Young Station Unit 2 using the EPA's "top-down" BACT approach. BACT is an emissions limitation for each pollutant from a source determined to be achievable using control technologies(s) that provide the "maximum degree of emission reduction…taking into account energy, environmental, and economic impacts"[30]. A BACT review does not result in a percent removal efficiency requirement. The generally accepted procedures for performing a BACT analysis are outlined in the EPA's draft NSR Manual. The BACT analysis for Milton R. Young Station NO_X emissions was performed in accordance with this procedure. The EPA's draft NSR Manual outlines five basic steps that are to be followed in the "top-down" BACT evaluation. These steps were as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

The final result of this analysis is a recommendation of the BACT alternative and the associated NO_X emission rate for Square Butte Electric Cooperative's Milton R. Young Station Unit 2. The emission limitations for a generation facility are expressed in a pounds per million British Thermal Units (lb/mmBtu) basis.

3.5.1 UNIT 2 NO_X BACT

In step one of the technology evaluation, three basic categories of NO_X controls for EGUs were-identified: pre-combustion, combustion, and post-combustion. Eleven basic types of NO_X control processes were identified within these three categories. Twenty four variations of these eleven processes were reviewed for availability and applicability to cyclone-fired EGUs burning North Dakota lignite. An "advanced" form of Separated Overfire Air, alone and in various combinations with Lignite Reburn, Selective Non-Catalytic Reduction (SNCR), Conventional Gas Reburn and

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[30] Ibid, NSR Manual B.1

Fuel Lean Gas Reburn™, was evaluated for cost-effectiveness. The cost-effectiveness analysis indicated that ASOFA alone, and ASOFA with SNCR were cost effective alternatives for MRY Station Unit 2 NO_X control. The energy and environmental impacts analysis for MRY Station Unit 2's cost-effective NO_X control alternatives were generally insignificant.

Based upon the definition of BACT and the results of the BACT analysis, Selective Non-Catalytic Reduction (SNCR) in combination with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA) is recommended as the Best Available Control Technology for nitrogen oxides emissions from Square Butte Electric Cooperative's Milton R. Young Station Unit 2. The unit BACT NO_X emissions rate for MRYS Unit 2 is 0.330 lb/mmBtu , determined as a rolling 12-month average. This is shown in Table 3-19.

TABLE 3-19 – NO_X Emission Control Technology and Rate Recommended as BACT for Milton R. Young Station Unit 2

Control Technology and Emission Rate Recommended as BACT			
Unit	**Pollutant**	**BACT Control Method**	**12-Month Rolling Average BACT NOx Emission Rate (lb/mmBtu)**
2	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.330

3.5.2 EMISSION RATE LIMITATION RECOMMENDATION

To complete the BACT determination process, the Consent Decree (CD) requires that "specific control technologies to be installed and a specific Phase II 30-day Rolling Average NO_X Emission Rate limitation (lbs/MMBtu)"[31] (pounds per million Btu) must be established for each subject emission Unit. The CD also states that "a "30-day Rolling Average Emission Rate" shall be determined by calculating an arithmetic average of all hourly emission rates in lbs/MMBtu for the current Operating Day and the previous 29 Operating Days. A new 30-day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-day Rolling Average Emission Rate shall include startup, shutdown, and Malfunction periods within each Operating Day"[32].

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[31] Ibid footnote number 1, Paragraph 66, page 20.

[32] Ibid footnote number 1, Paragraph 5, page 4.

The Consent Decree also states that the North Dakota Department of Health's (NDDH) NO_X "BACT Determination shall address specific emission limitations during Unit startups"[33] at Milton R. Young Station. The type and duration of firing during startups, and the limited ability of available and feasible technologies to control startup NO_X emissions, both significantly influence the 30-day rolling average BACT NO_X emission rate limit recommended for Milton R. Young Station boilers. A 24-hour rolling average NO_X emission rate limit applied to startup periods is also recommended for Milton R. Young Station boilers.

The Consent Decree and the EPA's NSR Manual do not describe the method for determining a 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT applied to Milton R. Young Station Unit 2.

In keeping with the establishment of a specific CD Phase II 30-day Rolling Average NO_X Emission Rate limitation, a relevant precontrol baseline level of emissions and its basis must be determined. The EPA's NSR Manual states:

> "The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions from the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions"[34].

Also stated in the EPA's NSR Manual:

> "Estimating realistic upper bound case scenario does not mean that the source operates in an absolute worst-case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints"[35].

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[33] Ibid footnote number 1, Paragraph 66, page 20.

[34] Ibid footnote number 2, NSR Manual page B.37

[35] Ibid footnote number 2, NSR Manual page B.37.

The BACT Analysis was conducted based upon the highest historical 12-month rolling NO_X emission summation operating conditions for Milton R. Young Station boilers during years 2001-2005. However, a baseline reflecting a realistic upper bound case scenario based upon the highest historical 30-day rolling NO_X emission operating conditions during years 2001-2005 was established prior to recommending enforceable permit conditions for BACT to be applied to each Milton R. Young Station boiler.

The approach taken in this analysis was to identify pre-control 30-day baseline operating conditions from the 30-consecutive day period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation between January 1, 2001 and December 31, 2005. This reflects unit NO_X emissions that were generated during periods of high unit operations, not affected by unit shutdowns, startups, or malfunctions. MRYS Unit 2's highest reported 30-day rolling average NO_X unit emission rate during years 2001-2005 was 0.874 lb/mmBtu for the period ending April 5, 2002. The corresponding MRYS Unit 2 30-day average hourly NO_X mass emission rate was 3,726 lb/hr. The average unit heat input rate for MRYS Unit 2 was 4,264 mmBtu/hr, and the average gross unit electrical power output was 450.2 MW_g for the same 30-day period.

The operating conditions during the highest historical 30-day rolling NO_X emission for years 2001-2005 were then compared to the highest 12-month historic pre-control baseline conditions. The average unit NO_X emission rate (lb/mmBtu) from the highest historic pre-control 30-day baseline period was compared with the average NO_X emission rate (lb/mmBtu) from the 12-consecutive month period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation during the same 5-year look-back period. An estimate of NO_X emission reduction for the proposed BACT NO_X alternative operating at the historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) was made. This rate considered recognized operational factors and equipment designs applied to "steady state" conditions with sustained output close to maximum continuous capacity ratings. The potential impact of startups, recognizing operational and technical limitations on NO_X emission control performance, was then applied to the steady-state rate, to establish a recommended 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT for Milton R. Young Station Unit 2. This is explained below.

NO_X emissions for cyclone-fired boilers are typically higher in pounds per million BTUs during start up events than during steady-state operation at maximum continuous rating (MCR) conditions. This is because hourly heat and combustion air input rates required to establish adequate molten slag formation within the cyclone barrels and promote slag tapping are typically produced from firing conditions that create high flame temperatures. NO_X emissions are sensitive to peak furnace gas temperatures, thus uncontrolled NO_X emissions can be high during cyclone boiler startups. Furnace exit flue gas temperatures (FEGTs) during cyclone boiler startups are less than those occurring during conditions of steady state MCR firing rates due to the high heat absorption of the boiler metal and water being raised from ambient or near-ambient temperatures. Until sufficient FEGT exists for a feasible and available post-combustion technology, such as SNCR, to be effective, NO_X emissions will be basically uncontrolled. There is a practical lower limit of boiler heat input for conventional combustion-based NO_X emission control techniques, such as the advanced version of separated overfire air, to be operated beyond the amount required for cooling the SOFA injection nozzles when it can be diverted from the cyclone burners and significantly control NO_X emissions. These limitations of the effectiveness of BACT controls on Milton R. Young Station boilers during startups and other reduced-load operating periods influence the recommended 24-hour and 30-day rolling average NO_X emission rate limits.

Startup procedures for steam electric generating units (SEGUs) comprising a fossil fuel-fired boiler and steam turbine-generator are specified by the original equipment manufacturers to follow guidelines for heat and pressure increases to provide protection of boiler and turbine equipment. Initial start up duration after an outage may be dictated by the need to gradually warm up burner port/cyclone refractory materials, steam drum shell, steam headers, and other boiler metal surfaces exposed directly or indirectly to furnace gases, and the steam turbine’s multiple casings and rotor shafts. This is normally accomplished with easy-to-ignite fossil fuel firing (such as natural gas, distillate fuel oil, or propane) of the boiler combined with coal to gradually increase firing until recommended boiler steam outlet temperature and pressure are reached. This is followed by supplying the steam turbine with sufficient inlet steam flow to reach conditions that allow the coupled generator to be synchronized and electricity to be generated above zero megawatts. From this point, boiler fuel firing is increased within prescribed rates until the desired operating load is achieved.

The SEGU startup operating period is usually not defined in emission permits. Startup is the period beginning with initiation of fuel ignition, and continuing until the powerplant equipment has reached operating conditions that include continuous fuel firing and sustained operating steam pressure and temperature levels within the guidelines of the designs for the boiler and turbine and their auxiliary systems for minimum sustainable levels without causing damage to the equipment.

A recent SEGU proposed PSD permit has included a definition of startup as "the period beginning with ignition and lasting until the equipment has reached a continuous operating level and operating permit limits"[36]. Similarly, a shutdown is defined as "the period beginning with the lowering of equipment from base load and lasting until fuel is no longer added to the boiler and combustion has ceased"[37]. Based on the referenced definitions of a startup period and a shutdown period, the amount of time required for a SEGU's load (boiler steam output or generator electrical output) to increase beyond such minimum sustainable operating levels can be considered part of startup events if the SEGU is typically base-loaded at full load or MCR output. This is the case with both MRY Station SEGUs.

Startups of SEGUs may be labeled as cold, warm, and hot to account for the amount of residual heat remaining in the boiler and steam turbine equipment. The various types of starts are dependent upon the amount of time the SEGU has been out-of-service (i.e. without boiler fuel firing or generator megawatt output). Cold starts have been defined as starts after the boiler has been without fuel firing for more than 72 hours, warm starts are more than 8 hours and less than 72 hours, and hot starts are less than 8 hours[38].

Although the definition of a startup event and the corresponding startup period is not required by the Consent Decree, defining start-ups is recommended. This helps to address the specific emission limitations during Unit startups at Milton R. Young Station and determine the impact of such operations on 30-day rolling average NO_X emissions. For the purpose of this NO_X BACT analysis, a Unit startup was defined as the period from initial fuel combustion to the point in time when:

- the measured Heat Input to the boiler on a 6-hour rolling average basis is greater than or equal to 4800 million BTU/hr for Unit 2; or
- the amount of time reported for the longest individual Unit 2 startup period during actual operation between January 1, 2001 and December 31, 2005 elapses, whichever occurs first; or
- fuel firing is discontinued prior to satisfying either previous criteria.

This startup definition for MRY Station Unit 2 accounts for conditions where cyclone refractory materials replaced during boiler overhauls must be cured by extended low-firing heating cycles,

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[36] Desert Rock Energy Center (AZP04-01) Proposed PSD Permit Conditions, page 7. (http://www.epa.gov/region09/air/permit/desertrock/#permit)

[37] Ibid, page 7.

[38] Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility, Document Number 09417-360-250R1, May 2004, page 5-1.

unit controls are upgraded and must be adjusted during low-load operation, or for boiler feedwater quality to improve after boiler maintenance has been performed that affects the insides of the waterwall and superheated steam tubes. It also allows for a failed or interrupted start sequence which can require considerably less or more time to elapse than an average startup duration.

Analysis of MRY Station Unit 2 operations data from 2001 through 2005 revealed:

- There were 62 total startups in the five year period;
- Minimum startup was 14 hours for a "hot" start following a boiler master fuel interruption (Unit "trip");
- Maximum startup with an extended ramp-up period until full load was reached was 115 hours.

Unit 2 had a start-up that began on October 25, 2001 that lasted for 115 hours. This startup included initial firing in the 20th hour of 10/25 (2000 hours being the beginning of the startup period), and which ended at the end of the 14th hour (i.e. at 1500 hours) on October 30, 2001, upon reaching 451 MW (gross) output. The criteria of a 6-hour average heat input rate of more than 4800 million Btu per hour was not reached during this startup.

There are certain boiler operating conditions that need to exist before the BACT NOx control techniques and technologies can be effectively operated:

1. The furnace gas temperature in the region where a urea reagent solution is injected for SNCR-based NO_X control must be between 1700°F and 2100°F. This region is expected to be in the vicinity of the furnace exit, which is commonly defined as either the horizontal plane extending from the furnace rear wall arch ("nose") to the front wall of the boiler, or the vertical plane from the nose up to the furnace roof, upstream of the gas inlet to the superheater tube banks. The gas temperature (FEGT) range in this furnace region is dependent on boiler heat input rate and cleanliness of the firesides of the furnace walls, which affects the amount of radiant energy absorbed by the wall tubes and transferred to the water within.
2. The numbers of active cyclones and continuous coal firing rates must be enough to establish sufficient:
    a. coverage of molten slag on the actively-fired cyclone barrel surfaces and drainage of the slag from the bottom of the boiler; and

b. combustion airflow through the actively-fired cyclones to allow a portion to be diverted to the separated overfire air system above the amount required for idle cyclone cooling and SOFA nozzle cooling.

As previously discussed, furnace exit flue gas temperatures (FEGTs) will need to be measured or determined empirically during operation of the MRY Station boilers in order to be able to effectively control NO_X emissions using SNCR technology. The design and operation of the SNCR systems at MRYS for CD Phase II emissions control should include features that accommodate cyclone boiler startups and low-load operation with “clean” or “dirty” boiler heat transfer surfaces as soon as conditions occur that are technically practicable, i.e. within the SNCR system vendor’s recommended operating guidelines, as well as full-load conditions in order to minimize NO_X emissions.

The amount and duration of sustained boiler heat input required to establish the operating conditions described in item 2 above is more difficult to precisely determine. Lignite heat content variability and inability to accurately determine the actual air/fuel ratio on a cyclone-by-cyclone basis in real-time, and the slagging and fouling characteristics of the lignite ash, cause (and are expected to continue to cause) difficulties with stable combustion performance. The minimum firing rates of the MRY Station boilers required to successfully initiate the effective operation of the SOFA system are specific to each individual boiler, and are not currently known. Due to such operating problems and emission control limitations, the ability to effectively limit NO_X emissions during startup periods and low-load operation following implementation of advanced SOFA (CD Phase I control) and/or an SNCR system (CD Phase II control) is uncertain.

Because there are expected to be minor short term variations in operating conditions during startups where Minnkota has not, in fact, materially changed any of their normal startup operating practices and criteria, a margin between the 30-day rolling average steady-state NO_X emission rate (which does not include the impacts of startups) and the proposed 30-day rolling average NO_X emission permit limit that includes startup emissions is recommended. This rate considered recognized operational factors and equipment designs applied to steady state conditions with sustained output close to maximum continuous capacity ratings. The recommended 30-day Rolling Average NO_X Emission Rate permit limitation excluding the impact of startups that reflects BACT for Milton R. Young Station Unit 2 is shown in the table below.

TABLE 3-20 – Recommended NO_X BACT Control Method and 30-Day Rolling Average NO_X Emission Rate Limit Without Startups

Unit	Pollutant	Control Method	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)
2	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.350

This recommended BACT 30-day NO_X emission rate limit is based upon a historic pre-control 30-day baseline average NO_X emission rate of 0.874 lb/mmBtu for Unit 2. The baseline emission was determined from the 30-consecutive day period with the highest historic unit NO_X emissions rate reported for actual operation between January 1,2001 and December 31, 2005.

A recommended BACT 30-day NO_X emission rate limit that includes the impact of startup emissions should be suitably higher such that operation consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices to the extent practicable for the MRY Station boilers would not result in an exceedance (violation) of an enforceable 30-day rolling average NO_X emission permit limit.

For MRYS Unit 2, the recommended 30-day rolling average NO_X emission permit limit rate that includes the impact of startups is based upon recognized operational factors and equipment designs that influence whether the startup emissions result in higher 30-day emissions compared to normal continuous operation without or excluding such startup periods:

1. The uncontrolled emission rate (i.e. without separated OFA or SNCR in operation) and its variability during operation from a cold, warm, or hot startup up to and including maximum continuous rated output;
2. The operating conditions that are required to exist for the selected NO_X BACT control techniques to be initiated and be effective; and
3. The effectiveness of these two particular control techniques if invoked at less-than-MCR steady-state operating conditions.
4. The number of startups and their range of typical durations per 30-day period time frame.

The October 25-30, 2001 startup was chosen for additional evaluation as the start-up for MRY Station Unit 2.

An incremental adjustment to the proposed 30-day rolling average steady-state unit NO_X BACT emission rate without startups of 0.35 lb/mmBtu for Unit 2 is recommended for the 30-day rolling average NO_X emission permit limit periods as defined and applied to Milton R. Young Station. This is summarized in the table below.

TABLE 3-21 – Recommended BACT 30-Day Rolling Average NO_X Emission Rate Limit and Startup Impact

Unit	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)	Impact on 30-day Rolling Average NOx Emission Rate Limit Due to Startups (lb/million Btu)
2	0.35	+0.102 per startup

This recommended adjustment to the proposed 30-day rolling average steady-state NO_X BACT emission rate limit without startups is based upon average historic pre-control NO_X emission rates of 0.959 lb/mmBtu for Unit 2 reported for the longest individual Unit 2 startup period during actual operation between January 1, 2001 and December 31, 2005. These emissions occurred during the 115-hour October 25-30, 2001 startup for Unit 2.

A 24-hour rolling average BACT NO_X emission rate limit applied to startup periods is also recommended for each of the Milton R. Young Station boilers.

This is summarized in the table below.

TABLE 3-22 – Recommended 24-Hour Rolling Average NO_X Emission Rate Limit During Startups

Unit	24-hour Rolling Average NOx Emission Rate Limit During Startups (lb/million Btu)
2	1.064

These emissions occurred during the 115-hour October 25-30, 2001 startup for Unit 2.

Compliance with these emission rates would be measured at the stack of the Unit, verified with Continuous Emission Monitoring (CEM) systems in accordance with the reference methods specified in 40 C.F.R. Part 75, and would be determined on a 30 consecutive Operating Day and 24-consecutive hour rolling average basis, respectively.

A trial demonstration operating period of 18 months after the completion of Consent Decree Phase II NO_X emission reduction system installation commissioning at Milton R. Young Station is recommended. It is proposed to allow Minnkota (for Square Butte) to demonstrate the actual control system capabilities of the combined NO_X BACT emissions reduction system. Operating experience during the trial period will:

- confirm steady-state control performance of the combined NO_X BACT emissions reduction system;
- allow determination of the ability to further control Unit start-up emissions;
- allow the determination of the permitted 30-day rolling average NO_X emission limit including startups, shutdowns, and malfunctions; and
- address the specific emission limitations during Unit startups at Milton R. Young Station and their impact on the proposed 30-day rolling average emission rate limit (without startups).

Based upon the information obtained during the trail period, final emission limits can then be determined.

The means that will be employed to minimize emissions during startup will primarily be based on operating procedures, both before and after the level of upper furnace gas temperatures and/or heat input rate are considered sufficient to start the NO_X controls and operating conditions are conducive for effective emissions reduction. These could be similar to Minnkota's current MRYS practices, or could be different, depending upon the capabilities of the NO_X controls and their impacts on Unit operations.

References:

1. In the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034.

2. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The “NSR Manual”).

3. EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: from EDOCKET at http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b; this is associated with EPA Acid Rain Program Clean Air Markets Division, Technical Support Document – Methodology For Developing BART NO_x Presumptive Limits, June 15, 2005, OAR-2002-0076-0445.

4. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NO_X Controls – NO_X Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

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APPENDIX A

Technical Feasibility Assessment Details for NO_X Control Technologies (A1)

U.S. Coal Cyclone NO_X Reduction Projects Summary

With Retrofit NO_X Control Projects’ Technical Literature Summary (A2)

A.1 Technical Feasibility Assessment of NO_X Control Alternatives

A.1.1 Pre-Combustion Fuel Treatment/Switching

Fuel switching can be a viable method of NO_X emission reduction in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. In the case of MRY Station, the Unit 1 and 2 boilers were designed and constructed specifically for firing North Dakota lignite, which has a fuel higher heating value (Btu/lb) approximately 20% lower than typical Powder River Basin (PRB) coal. A cyclone–fired boiler (Ottertail's Big Stone Unit 1) that is similar in geometry and steam generation design to MRY Station Unit 2 fires PRB coal. Based on a comparison of available emission data between Big Stone Unit 1 and MR Young Unit 2, there is no expected reduction in baseline (i.e. uncontrolled) NO_X emissions from switching to PRB from lignite at Milton R. Young Station.

Conversion of Milton R. Young Station Unit 2 boiler to fire PRB coal is technically possible. It is expected that major plant modifications will be required. Rail service is not presently installed at this site, so the additional operational and capital costs to bring in large quantities of PRB coal will be significant. Investigation of the specific source, distance, and costs for supplying necessary quantities of PRB coal via rail or trucks to M.R. Young station has not been performed. With zero baseline NO_X emissions reduction expected from application of fuel switching, this alternative will not be economically competitive with other NO_X control technologies that offer better results for a much lower combination of capital and operational costs. Although fuel switching is technically feasible, it has not been considered further as an effective NO_X emissions control option for MRY Station Unit 2 boiler.

A.1.2 Combustion Controls

Combustion controls comprise the most numerous category of NO_X emission reduction technologies. These techniques employ methods that reduce the amount of NO_X emissions created in the combustion zone of the boiler prior to exhausting the flue gases from the furnace (upstream of the convective heat transfer zones). These controls result in fewer emissions to atmosphere or that may require subsequent reduction from additional applicable combustion and/or post-combustion techniques.

As the boilers in question were designed for firing North Dakota lignite fuel, they were furnished with suitably-sized furnaces and limited back-end economizer heat transfer surfaces upstream of the air preheaters. This provides high temperature air to aid the evaporation of excess moisture from the crushed coal particles in the pre-combustion drying systems, and long residence times for solid and gaseous fuel particles to burn essentially to completion prior to leaving the furnaces. The latter feature is especially advantageous for applying various forms of combustion modifications which are conducive in reducing NO_X emissions.

A.1.2.1 Basic Combustion Improvements

Combustion improvements are commonly-applied techniques which may produce modest incremental NO_X emissions reductions. In their most basic form, these typically provide improvements to combustion air flow distribution, measurement, and pressure, together with fuel flow measurement and metering, to promote consistent combustion performance by burning fuel with more accuracy in maintaining a desired fuel/air ratio.

These improvements may allow, or be combined with, the practice of several other NO_X control techniques. Separated overfire air (discussed below), with or without “low excess air” (LEA), burners out-of-service (BOOS) and biased firing (BF) operation of the cyclones, cause a decrease in the ratio of combustion air to fuel supplied to the cyclones (burners), thus reducing the amount of thermal NO_X emissions produced during combustion. The amount of potential NO_X emission reduction achievable from these basic techniques is highly-dependent on the specific type of firing, fuel, and conditions which apply to the boiler(s) being reviewed.

Making lignite drying system air adjustments and adding improvements to the boiler combustion controls and reducing combustion air inputs have already reduced uncontrolled NO_X emissions at Milton R. Young Station Unit 2 boiler approximately 27%. Further incremental improvements from additional combustion controls that allow operation with modest amounts of cyclone air staging, similar to the effect of a separated overfire air system, are possible. Incremental NO_X emissions reductions are expected from such improvements being incorporated into another feasible alternative, such as separated overfire air. This alternative was not considered as a stand-alone option for additional NO_X reduction at Milton R. Young Station for the Unit 2 boiler.

A.1.2.2 Low NO_X Burners (LNB)

Low NO_X burners (LNBs) of various designs have been commonly applied to pulverized coal-fired utility and industrial boilers for more than ten years. However, they are not installed on cyclone-fired boilers. This technology is infeasible on cyclone boilers[1], and was eliminated from consideration for additional NO_X reduction at Milton R. Young Station Unit 2’s boiler.

A.1.2.3 Separated Overfire Air (SOFA)

Separated overfire air (SOFA) is a combustion-related NO_X emission reduction technology frequently-applied with and without low NO_X burners to utility and industrial boilers for more than twenty five years. Separated Overfire Air (SOFA) is an air-staging NO_X emission reduction combustion technique that is typically based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the firing zone. The diverted combustion air is then injected in the upper furnace, where combustion is completed. For typical cyclone coal-fired boilers, this involves diverting approximately 20 percent of the secondary combustion air, forcing the cyclones to operate fuel-rich. Starved-air combustion causes fewer NO_X emissions to be produced.

At least thirty nine existing cyclone-fired boilers, firing eastern bituminous, midwestern bituminous, and western subbituminous ("Powder River Basin") coals in units ranging in size from 50 to 1150 MW, have been retrofitted with commercial SOFA since 1998. A summary of several of the first SOFA (and reburn) retrofits to cyclone-fired boilers is described in published technical papers[1,2]. Cyclone boiler retrofit SOFA installations are included in the EPA's BART technical support document[3] and listed later in Appendix A2.

A basic form of separated overfire air (SOFA) can be applied and installed on MRY Station Units 2. There are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application.

Key aspects of successfully applying and operating a separated overfire air system on a cyclone-fired boiler are the ability to:

- Accurately measure the fuel heat input rate (BTUs) and combustion air inputs on a real-time, individual cyclone by cyclone basis, to allow the ability to determine and control the desired air/fuel ratio, especially when "starved air" (i.e. substoichiometric) combustion conditions are required.
- Maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps.

The degree to which the cyclone furnaces can be operated with less than theoretical (substoichiometric) combustion air directly contributes to less NO_X formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. In the case of MRY Station Unit 2 boiler, cyclone combustion must be sufficiently air-staged to reduce NO_X emissions while releasing enough heat to continue to melt the fuel ash so that it flows effectively within and from the cyclone burners.

In the case of MRY Station boilers, there is a significant amount of variability in the combustible and ash components of North Dakota lignite supplied from the current mine near Center, ND. Analysis of several hundred coal feed samples taken simultaneously from multiple cyclones of MRY Station Unit 2's boiler revealed that the maximum differential of the lignite heating values from cyclone-to-cyclone was just over 12% of the average heating value of all the samples. Assuming an operating case occurred where the maximum cyclone-to-cyclone differential heating value was for two cyclones at the opposite ends of the fuel heat content range, there would be a plus or minus 6% variation in fuel heat content for either of the individual cyclones from the overall average. If the desired average cyclone air/fuel (stoichiometric) ratio was 0.95 when operating with air-staged cyclones associated with separated overfire air, and the amount of secondary combustion air to each cyclone was equal, there would be a stoichiometric ratio of approximately 1.01 in one cyclone and a stoichiometric ratio around 0.89 in another cyclone at the same time. The modestly air-staged cyclone would produce higher than average NOx emissions. The deeply staged cyclone would produce less than average NOx emissions and potentially insufficient amounts of heat release, and raise the risk of solidifying the fuel ash so that it accumulates within the cyclone barrel. This could result in firing auxiliary fuel oil in the deeply-staged cyclone or taking the boiler out-of-service to remove the pluggage. Neither of these conditions is desirable because they result in lower emissions removal performance and higher operating costs. Thus, due to the variability of the fuel heat content and the complex behavior of lignite ash when exposed to high temperatures, the extent of air-staging and thus the level of NO_X control in MRY Station boilers is expected to be modest while firing lignite coals.

In order to potentially achieve lower NO_X emission rates with modestly air-staged combustion for MRY Station boilers, additional combustion improvements can be installed. One potential improvement is to implement a unique form of SOFA for North Dakota-lignite–fired cyclone boilers. This includes relocated lignite drying system vent ports, and in Unit 2's case, also involves blocked or relocated lower furnace flue gas recirculation ports. This will be referred to as "Advanced SOFA" (ASOFA). There are several design challenges anticipated for implementing the advanced version (with the described port relocations) of separated OFA. These are believed to be solvable.

Both forms of separated overfire air as a combustion-related NO_X control technique are considered feasible for application to Milton R. Young Station cyclone boilers. Since the advanced SOFA is the highest-performing form of this technology, only this ASOFA version of the alternative was considered for additional NO_X reduction at Milton R. Young Station boilers.

Another form of separated overfire air being marketed commercially is “Rotating Opposed Fire Air” (ROFA). For utility applications in the United States, this has only been applied to pulverized coal-fired boilers, primarily tangentially-fired units[4]. It is different than basic SOFA in that it includes a hot air booster fan, and injects the overfire air in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. The vendor (Mobotec USA) claims ROFA maximizes air-staged in-furnace combustion NOx reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon.

While this variation of separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Because cyclone boilers do not require the addition of hot air booster fans for SOFA, this technique is not distinct enough from basic SOFA from functional and air-staged cyclone NO_X reduction performance standpoints to warrant individual consideration. ROFA technology lacks demonstrated cyclone-fired boiler experience, and thus was considered infeasible and not included in the control effectiveness and cost-effectiveness sections of the main report.

A.1.2.4 Oxygen-Enhanced Combustion

A supplier of liquid oxygen (Praxair) has developed a method of replacing some of the combustion air supplied to the burners with pure oxygen. Combustion air, which is normally input through the secondary air system ductwork downstream of the forced draft (FD) fan and air heater, is supplemented with pure oxygen directly injected into the burners. Oxygen-enhanced combustion (OEC) can reduce boiler NO_X emissions resulting from “ thermal NO_X“, a reaction of the nitrogen in the combustion air admitted to the burners with the available oxygen in the air in the flame or peak temperature regions of the fuel combustion process. The use of pure oxygen instead of air reduces the availability of nitrogen from the air to be oxidized in the high temperature regions, thus reducing formation of thermal NO_X. This technique has only been demonstrated in a boiler with pulverized fuel burners firing bituminous coal[5].

The lack of adequate experience on any cyclone-fired coal-burning boiler, on a temporary demonstration or permanent full-scale basis, and for a coal-fired facility of this size, precludes consideration of oxygen-enhanced combustion at MRY Station Unit 2’s boiler. This is deemed to be infeasible technology at this location at the present time.

A.1.2.5 Flue Gas Recirculation

Flue gas recirculation (FGR) has been commonly applied to coal-fired boilers, primarily to inject into the lower furnace, just above the burners, supplied from the boiler's economizer flue gas outlet via a hot gas booster fan. This modifies the amount and temperature of hot furnace gas either in the lower-middle or upper furnace and convection heat transfer zones. As this flue gas typically has an oxygen content around 2-5%, it limits the availability of oxygen in a high temperature, possibly fuel-rich lower furnace zone. Flue gas recirculation for NO_X control is most commonly applied with gaseous or liquid fossil fuels to reduce the high temperatures which convert nitrogen in the combustion air to nitrogen oxides. No examples of using or installing FGR on cyclone-fired boilers strictly for NO_X emissions control were found in available technical literature.

FGR is already practiced at MRY Station in the Unit 2 boiler, primarily for furnace gas temperature and lower wall slagging reduction reasons. For this boiler, FGR could aid in potentially providing some small additional NO_X emissions control if it were modified from its current configuration, as part of an advanced form of separated overfire air. Complete elimination of the use of FGR could also slightly reduce NO_X emissions from Unit 2's boiler during air-staged cyclone combustion with separated overfire air system operation. There is uncertainty whether elimination of the use of FGR in the lower furnace of MRY Station's Unit 2 boiler could be successful in controlling lower furnace wall fireside ash deposition.

A.1.2.6 Water/Steam Injection (Combustion Tempering)

When applied to older gas-fired and oil-fired utility and industrial boilers, water and/or steam injection adds moisture into the lower furnace, concurrent with or near (to the side or slightly above) the burners, supplied from the boiler's treated feedwater or auxiliary steam systems via a metering pump or valve. There has been some limited testing of water injection for NO_X emissions control on natural gas-fired and coal-fired cyclone boilers[6,1]. For coal-fired cyclones, this technique is most effective on boilers burning bituminous coal; however, it has not been permanently installed and continuously operated in such applications. Successful long-term operation of water injection would be difficult for lignite-fired cyclone boilers, due to the high moisture levels in the coal and the need to readily ignite and sustain stable combustion and molten slag formation in the cyclone furnaces. For these reasons, water/steam injection is considered technically infeasible for NO_X control application at Milton R. Young Station.

A.1.2.7 Fuel Reburn

Another combustion technology that may be applicable to control NO_X emissions from the Milton R. Young Station units is fuel reburn. In a similar manner that overfire air diverts a portion of the combustion air input to the main firing zone, the reburning process involves supplying a portion of the fuel heat input to the boiler at a higher elevation in the furnace. This creates an upper furnace atmosphere where the reburn fuel's combustion products causes some of the NO_X formed in the main burner combustion zone and reburn zone to be converted into molecular nitrogen. Depending on the amount of reburn fuel added and the amount of oxygen available in the furnace gases to combine with the reburn fuel introduced, additional combustion air may be supplied as supplemental or overfire air. Downstream of the air injection elevation, the intention is to complete the reaction of any remaining carbon monoxide (CO) to carbon dioxide (CO_2), plus reduce the amount of combustible matter remaining in the entrained flyash.

The most common forms of reburn technology applied to utility powerplant boilers are:

- Pulverized or micronized coal reburn (PCR or MiCR); and
- Gas reburn (GR).

Pulverized coal reburning and micronized coal reburning have been applied to pulverized coal and cyclone-fired boilers. NO_X reduction efficiencies of 50 to 60 percent have been demonstrated on eastern bituminous coal and midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone[7,8].

For utility powerplant boiler applications, natural gas has been utilized as reburn fuel most often, demonstrated in two basic approaches:

- Conventional gas reburn (CGR); and
- Fuel-lean gas reburn (FLGR™).

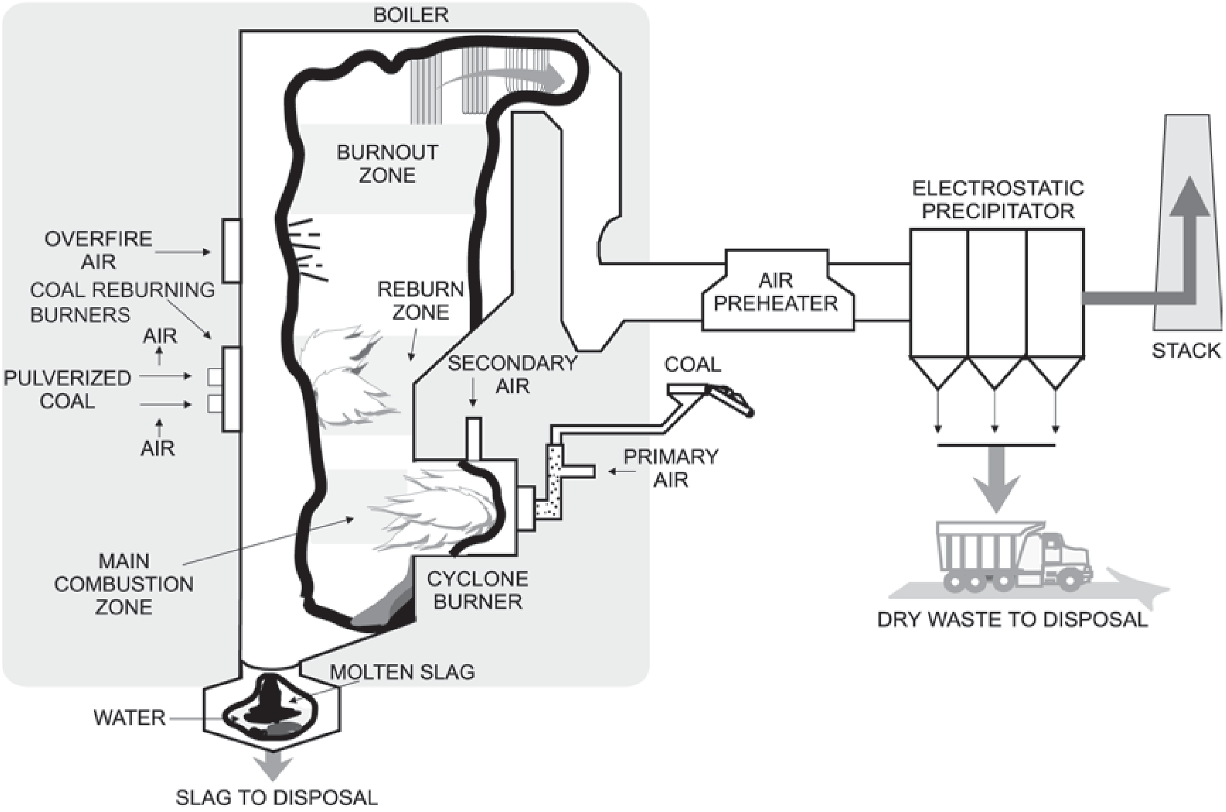
Either natural gas or pulverized coal (lignite) can be used as the reburn fuel. A sufficient quantity of natural gas is not currently available at the Milton R. Young Station plant site. Supplying enough natural gas to provide 6 to 25% of the total heat input to either or both boilers at MRY Station is expected to be technically feasible, although transport pipeline installation capital costs, and current and predicted unit natural gas costs and operating economics, are likely to be unfavorable.

Various forms of fuel reburning have been demonstrated and operated routinely on cyclone boilers for NO_X emission controls. This has been applied to units firing eastern bituminous coal, and western subbituminous or PRB/bituminous coal blends, using pulverized or micronized coal or natural gas as the most common reburn fuel. Reburning for NO_X emissions reduction has not been demonstrated on a unit firing high moisture, low heat content North Dakota lignite. Pulverized/micronized coal, along with conventional and fuel lean gas reburn technologies, are discussed below.

A.1.2.7.1 Coal Reburn

In the case of applying conventional coal reburn to cyclone boilers, the existing cyclones are supplied with the majority of the fuel, with either natural gas or pulverized coal (lignite) used as the reburn fuel such that the total heat input to the boiler is essentially the same as without fuel reburn. Separated OFA ports are located above the reburn fuel injection section of the furnace. These SOFA ports provide sufficient oxygen in a conventional fuel reburn installation to complete the combustion process that begins in the main combustion zone and is supplemented in the reburn and burnout zones. This is shown schematically for a pulverized coal reburn application on a cyclone-fired boiler with SOFA in Figure A.1-1.

Figure A.1-1 Pulverized Coal Reburn Application on Cyclone Boiler With Overfire Air[8]



In the United States, pulverized coal reburning and micronized coal reburning techniques for utility powerplant NO_X emissions reduction have been applied on a very limited full-scale, full-time basis to cyclone-fired boilers in field demonstration tests and longer-term demonstration operation, respectively. There have been only two known pulverized or micronized coal reburn installations in the United States on cyclone boilers, one on a utility boiler in Wisconsin, and one on a small industrial-size cyclone boiler in New York state[7,8,9,10,11,12,13,14]. NO_X emissions reduction efficiencies of 57 percent have been demonstrated on cyclone boilers firing eastern bituminous coal, or midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone. With the exception of the U.S. Department of Energy's (DOE) Clean Coal Technology Program demonstration projects[7,8,9], no known commercially-available coal reburn systems have been installed and are routinely operated on cyclone boilers in the United States to date. The DOE-CCTP projects for coal reburn applied to cyclone boilers are described below.

Pulverized coal reburning for NO_X emissions reduction in a cyclone-fired boiler was demonstrated on the 110 MW Nelson Dewey Unit 2 for Wisconsin Power & Light in 1991-1992. Reburn fuel preparation and handling, reburn burners with flue gas recirculation, and a separated overfire air system were added. Coal reburn tests were conducted on this unit while firing bituminous and PRB coals. NO_X emission control efficiencies of 50 to 60 percent, with reductions from 0.75-0.83 lb/mmBtu baselines to around 0.38 lb/mmBtu, but as low as 0.29 to 0.32 lb/mmBtu, with PRB coal at full load with approximately 25-30% of the total fuel heat input from reburn fuel were demonstrated[9,11,12]. The reburn system is no longer operated on Nelson Dewey Unit 2.

Micronized coal reburning has been demonstrated in 1997-1998, and continues to operate year-round on a small industrial cyclone boiler (400,000 lb/hr steam output, 50 MW gross equivalent) for Eastman Kodak Company at their Kodak Park facility in Rochester, NY. This unit (Boiler #15) achieves a NO_X reduction efficiency of approximately 57 percent on eastern bituminous coal, involving limited cyclone air-staging (cyclones believed to be slightly above 0% excess air) and a modest amount of overfire air injection downstream of the micronized reburn fuel input nozzles. Approximately 17% of the boiler's total fuel heat input is typically supplied to the reburn zone. This coal reburn system continues to operate routinely at this facility. This installation is reported to use a Fuller MicroMill to produce micronized coal with 80% passing through a 325 mesh screen[7,9,13].

If a coal reburn system was applied to MRY Station boilers, the existing cyclones would be supplied with the majority of the fuel in the form of crushed coal, and the balance of fuel would be supplied to a pair of dedicated pulverizers to feed the reburn injection ports, such that the total heat input to the boiler is essentially the same as without fuel reburn. In a conventional fuel reburn installation, OFA ports located above the reburn section of the furnace provide sufficient oxygen to complete the combustion process that begins in the main combustion zone and is supplemented in the reburn and burnout zones.

Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. As a reburn fuel, lignite is expected to behave appropriately upon introduction in the lower middle furnace to help reduce NO_X emissions. The concerns are that the diversion of a significant amount of heat input from the cyclone barrels to use as a source of reburn fuel in the form of pulverized or micronized lignite may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction as part of this reburn technique will further risk slag “freezing” in the barrels and lower furnace. Reducing the number of active cyclones which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with reburn and separated overfire air is the typical approach to avoid slag tapping problems.

Potential NO_X emissions reduction performance is expected to be limited on lignite-fired cyclone boilers with a basic form of separated overfire air system, since the reburn fuel injection location is expected to coincide with the existing lignite pre-drying system vent ports. The amount of oxygen introduced by the vent ports will be disruptive to any conventional reburn process in that it would require much higher reburn fuel injection rates to create a substoichiometric atmosphere in the lower secondary furnace that is conducive to promoting in-furnace NO_X reduction.

Significant additions to the fuel preparation equipment in the existing plant facilities will be required. The coal reburn system expected to be applied to MRY Station boilers may use two new fine-grind pulverizers and dynamic classifiers to achieve the level of coal particle size distribution required.

Higher unburned carbon levels in the flyash exhausted from the boiler may occur, especially when the reburn fuel is coal, and the regular burners are fired with less than theoretical amounts or combustion air commonly practiced with the use of overfire air. Lowering the reburn fuel injection elevation, decreasing the amount of reburn fuel, and grinding the reburn coal to a greater degree of fineness can help to offset some of the increase in flyash unburned carbon content. Flue gas opacity from the stack may increase if the particulate removal equipment is an electrostatic precipitator, due primarily to reduced resistivity and smaller particle sizes of the flyash.

An issue that affects the feasibility of lignite reburning is the uptime required for the lignite reburn fuel pulverizing system, and impact of the reburn system on effectiveness in reducing NO_X emissions during load changes and lower loads. Typically, one new pulverizer is dedicated to prepare reburn fuel in existing pulverized fuel-fired boiler applications. Cyclones may be fired with less fuel or deactivated during boiler operation in order to accommodate changes in fuel combustion characteristics, boiler load, and for scheduled or unscheduled individual crusher maintenance. Milton R. Young Station Unit 2 has twelve crushers for cyclone coal grinding, each dedicated to one of the twelve cyclone furnaces. Diverting as much as 30% of the total heat input as reburn fuel could require four existing cyclones to be deactivated, and two new MPS-89 pulverizers to be dedicated to reburn fuel preparation. As each of these mills requires periodic maintenance, boiler emissions and/or load could be negatively impacted during individual reburn mill outage periods while the boiler remained in service. A high level of fineness of coal particles from the reburn mills is important to achieve and maintain in order to limit increases in flyash combustibles. A minimum of 60 percent passing through 200 mesh fineness is recommended by one of the reburn technology vendors (B&W) for pulverized lignite reburn. Micronized coal reburn requires even greater fineness: 70-80 percent passing through a 325 mesh screen.

Pulverized or micronized coal reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on MRY Station Unit 2's boiler. These combined techniques are expected to reduce NO_X emissions approximately 54% from current pre-control baseline levels (down to 0.36 lb/mmBtu) for the MRY Station Unit 2 boiler. These levels of NO_X reduction depend on the advanced form of separated overfire air technique to achieve the expected NO_X reduction percentages when applied to lignite-fired cyclone boilers, which may not be successful given the concerns expressed about the potential impacts of this technique. Using finely pulverized lignite for reburn fuel is considered technically feasible for NO_X emissions control under evaluation for application to MRY Station Unit 2's boiler.

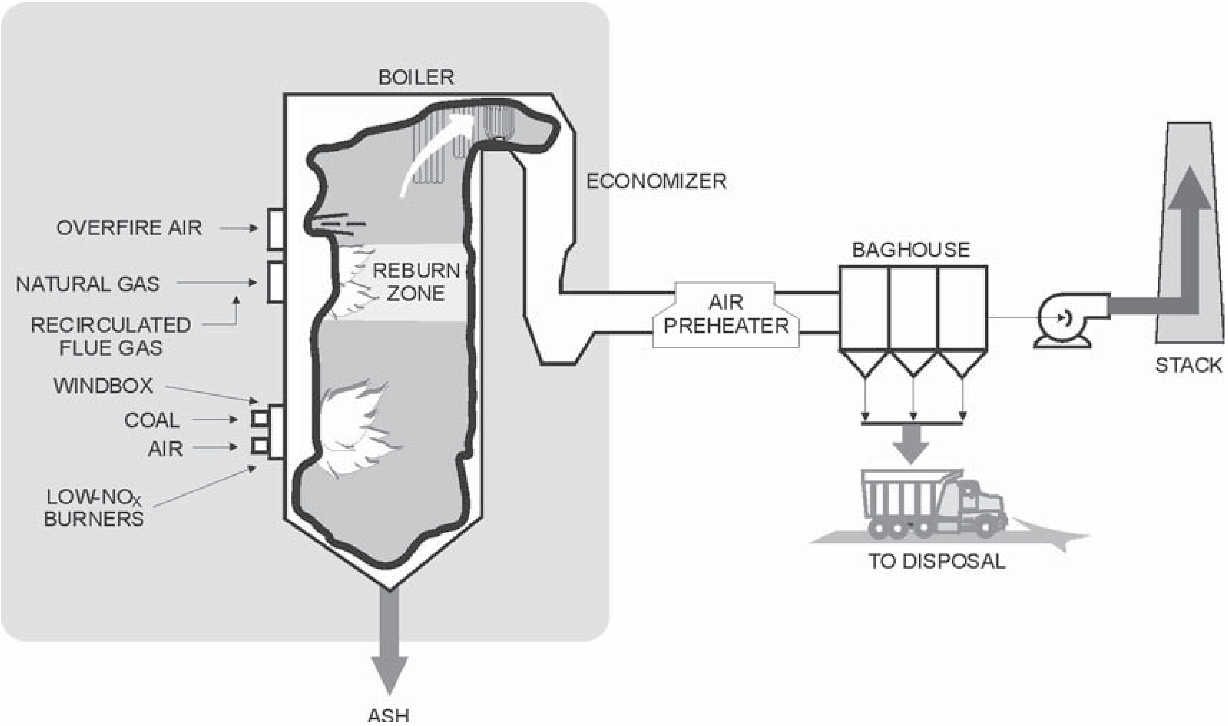
A.1.2.7.2 Conventional Gas Reburn

Natural gas has been preferred as the reburn fuel of choice. Natural gas has been utilized for reburn fuel in two basic approaches: conventional reburn and fuel-lean gas reburn. In the conventional approach, up to 30% of the boiler's total fuel heat input is supplied to the reburn zone, followed by a significant amount of overfire air for completion of combustion prior to flue gases exiting the boiler.

Conventional gas reburning in a cyclone-fired boiler has been available at Tennessee Valley Authority's Allen Station Boiler #1 (300 MW) since 1998. The reburn technology provider (vendor) claims NO_X emissions were reduced 67% from a full-load baseline of 1.29 (down to 0.42) lb/mmBtu when firing a blend of western bituminous and PRB coals[14]. Conventional gas reburn fuel input rates were not available from the technology vendor's literature. Another reference source of information stated NO_X emissions were reduced 65% from a full-load baseline of 0.86 (down to 0.30) lb/mmBtu with 7 percent of the total fuel heat input supplied as reburn fuel[9].

A schematic graphic of conventional gas reburn on a pulverized coal-fired boiler is shown in Figure A.1-2.

Figure A.1-2 Natural Gas Reburn Application on Wall-Fired Pulverized Coal Boiler with Overfire Air[8]



Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. For the most effective NO_X reduction by applying the various available forms of fuel reburn, the injection of fuel is usually performed using recirculated flue gas as a diluent and carrier media to aid dispersion and avoid completely oxidizing the carbon and nitrogen components in the fuel and furnace gases from staged burners/cyclones. Improved gas reburn designs have reduced or eliminated FGR with higher gas injection pressures. For lignite-fired cyclone boilers, reburn fuel firing with a basic form of separated overfire air is expected to be much less effective in reducing NO_X emissions than previously demonstrated elsewhere. This is related to the likelihood that the injection of reburn fuel will be near the elevation of the existing lignite drying system vent ports, and that the oxygen introduced with the lignite drying system's vented moisture will disrupt the desired in-furnace nitrogen oxides reduction process.

It should be recognized that application of air-staged cyclones with basic or advanced forms of SOFA with reburn techniques will require the overfire air injection ports to be located at a somewhat lower elevation of the furnace compared with air-staged cyclones without reburning. This means that less air-staging of the cyclones may be practiced, or that less residence time will be available for the in-furnace NO_X reduction process to occur.

Similar to coal reburning, there are concerns that withholding a significant amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones for use of separated overfire air to further complement combustion NO_X reduction as part of this reburn technique will further risk slag "freezing" in the barrels and lower furnace. Reducing the number of active cyclones which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with conventional reburn and separated overfire air systems is the typical approach to avoid slag tapping problems. Natural gas reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on Milton R. Young Station's Unit 2 boiler.

Although the unit operating and capital costs to supply large quantities of gaseous fuel not currently available at this site are economic disadvantages, using high-pressure natural gas for reburn fuel is considered technically feasible for NO_X emissions control under evaluation for application to MRY Station Unit 2's boiler.

A.1.2.7.3 Fuel Lean Gas Reburn

Another approach to gas reburning is “fuel-lean gas reburn” (FLGR™) technology, which injects limited amounts of natural gas (approximately 3-10 percent of the total fuel heat input) above the burners (or cyclones) with or without significant air-staging of the burners (cyclones) or the addition of overfire air upstream of the fuel injection elevation. FLGR’s first field-test on a cyclone-fired boiler was at Commonwealth Edison’s Joliet Unit 6 (327 MW), a 9-cyclone-furnace boiler[15]. NO_X emissions reduction with FLGR (without SOFA) was believed to be approximately 35-40% with 7% of the boiler’s total fuel heat input supplied in the reburn zone. This test yielded 0.59 lb/mmBtu NO_X emissions from a baseline of 0.98[16]. One other cyclone boiler has been modeled using computational fluid dynamics (CFD) as part of a study looking at applying FLGR at Owensboro Municipal Utilities’ Elmer Smith Station Unit 1 (150 MW single-wall, eastern bituminous coal-fired boiler). This model predicted that NO_X emissions could be reduced by 25-30% over that achievable from overfire air and SNCR[17].

More commonly, FLGR™ has been applied on medium to large pulverized coal wall-fired boilers burning eastern bituminous or western subbituminous coals. On Wisconsin Electric Power Company’s (WEPCO’s) Pleasant Prairie Unit 1, a 620 MWg Riley turbo-fired wet-bottom (slagging) boiler, FLGR™ alone was predicted to reduce NO_X emissions by 35-39 percent at a gas reburn rate of 7-8 percent but only achieved 20% from a baseline of 0.45 lb/mmBtu[16,18]. This is presumably without burner air-staging or SOFA. It has also been applied in combination with SNCR at this WEPCO site.

A potential advantage of FLGR™ over conventional gas reburn is that the former is generally compatible with, but does not require, the installation and operation of SOFA. The staged reburn fuel is introduced into an oxygen-rich atmosphere downstream of the burners and any OFA injection points. The amount of reburn fuel injected is typically limited by acceptable carbon monoxide levels in the boiler exit flue gas.

There are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. This is significant, especially for alternatives with FLGR™ technology when combined with basic or advanced SOFA to allow the natural gas introduced above the SOFA ports to burn completely prior to the furnace exit plane. In either case, the amount of additional potential NOx reduction possible with FLGR™ is limited, since the reburn fuel injection location is expected to coincide with the existing lignite pre-drying system vent ports. The amount of oxygen introduced by the vent ports will be disruptive to the fuel-lean reburn process in that it would require much higher reburn fuel injection rates in the lower secondary furnace to promote in-furnace NO_X reduction. There are reduced concerns that the withholding of a modest amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction is an optional part of this reburn technique which will further risk slag "freezing" in the barrels and lower furnace.

Fuel lean gas reburn can be applied and installed on MRY Station Unit 2's boiler with or without SOFA/ASOFA. This technique is considered technically feasible for application to MRY Station Unit 2's boiler. Expected NO_X reduction will be modest for FLGR™ without SOFA and FLGR™ with a basic form of SOFA. Unit operating and capital costs to supply large quantities of gaseous fuel not currently available at this site are economic disadvantages. Because of these factors, these variations of this technology will not be cost-effective compared to other alternatives with similar control effectiveness. FLGR™ without SOFA and FLGR™ with a basic form of SOFA were not included in the control effectiveness and cost-effectiveness sections of the main report.

Other demonstrated forms of fuel lean gas reburning in combination with post-combustion technologies, such as amine-enhanced fuel lean gas reburn (FLGR™ with SNCR), are discussed under the layered technologies section.

A.1.2.7.4 Fuel Oil Reburn

Fuel oil has been substituted for natural gas in a conventional reburn application. This is much less common in the United States than using natural gas as a reburn fuel, due to the general lack of demand and difficulties in supplying the volume of fuel oil which would be required. It has been installed commercially on three 350 MW oil-fired boilers in New Brunswick (Canada) at the Coleson Cove plant. NO_X emissions reduction with reburn and SOFA was 78% with 25% of the boiler's total fuel heat input supplied in the reburn zone. This yielded 0.22 lb/mmBtu NO_X emissions from a baseline of 1.0 lb/mmBtu[9]. No examples of conventional fuel oil reburn applied to a coal-fired cyclone boiler were found in available literature.

Fuel oil reburn could potentially be considered for application to MRY Station Unit 1 and Unit 2 boilers. Investigation of the specific source, distance, and costs for supplying significantly increased quantities of fuel oil via transport trucks hauling tanker trailers or underground pipeline to M.R. Young station has not been performed. The unit operating and capital costs to supply large quantities of high-volume liquid fossil fuel at this site are economic disadvantages. The concerns regarding potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application are similar to those expressed for conventional gas reburn. It is believed that potential NO_X control with oil reburn would be slightly less than comparable conventional gas reburn systems.

Although fuel oil reburn could potentially be considered for application to MRY Station Unit 2's boiler, the lack of any distinct potential NO_X reduction advantages and demonstration on cyclone-fired boilers does not appear to support its consideration. This alternative was not included in the NO_X control and cost-effectiveness analysis.

A.1.3 Post-Combustion Controls

Post-combustion controls deal with techniques that thermally or chemically-treat the flue gases to reduce NO_X emissions after they have exited the boiler's lower furnace. In the case of Milton R. Young Station Unit 2, this primarily involves forms of selective catalytic reduction (SCR) and selective non-catalytic reduction (SCR) technologies. Another emerging technology that has recently entered the commercial market is Powerspan's Electro Catalytic Oxidation®, which treats utility boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury. Another emerging technology that has recently entered the commercial utility air pollution control market is Powerspan's Electro Catalytic Oxidation®, which treats boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury.

A.1.3.1 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR), and variations such as hydrocarbon-enhanced SNCR (sold under the trade name of NOxStar™), and Rich Reagent Injection (RRI), are all post-combustion types of boiler NO_X emission controls. While these technologies are insensitive to the specific fuel types whose combustion products are being treated, the large majority of boiler applications to date have been on pulverized coal-fired units burning eastern bituminous fuels. SNCR has been used to reduce NO_X emissions on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used with fuel oil and natural gas-fired units. SNCR (and hydrocarbon-enhanced SNCR) technologies can each be applied to cyclone boilers with or without the use of a SOFA system. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without overfire air in full operation. Operation at these plants has demonstrated that SNCR can decrease NO_X emissions as much as 15-40% at full load, most typically between 25-35 percent[19].

In the conventional SNCR process, urea or ammonia is injected into the boiler in a region where the combustion gas temperature is in the 1700 to 2100 degrees F range. Under these temperature conditions, the urea reagent [$CO(NH_2)_2$] or ammonia [NH_3] reacts with the NO_X, forming N_2 and water, reducing NO_X emissions.

Long-term examples where SNCR has been used to reduce NO_X emissions on two cyclone-fired boilers are on a 138 MW unit and 160 MW unit burning eastern bituminous coal at Conectiv's B.L England Station (Units 1 and 2) since 1995 and 1996, respectively. Tests at these plants demonstrated that SNCR can decrease NO_X emissions as much as 30-36% at full load, from around 1.3-1.4 lb/mmBtu respectively to as low as 0.85 lb/mmBtu (without overfire air)[18,19,20]. These boilers, located near Atlantic City, New Jersey, continue to operate SNCR (with OFA) for annual NOx emissions around 0.55 and 0.45 lb/mmBtu, respectively.

SNCR can be applied and installed on MRY Station boilers. Estimated NO_X emission rates for using SNCR with North Dakota lignite considered published levels achieved by cyclone-fired units firing western subbituminous coal, and vendor predictions. SNCR alone is expected to reduce NO_X emissions approximately 37% from MCR baseline levels (down to around 0.5 lb/mmBtu) for the MRY Station Unit 2 boiler with ammonia slip limited to approximately 5 ppmvd. Because of the operating costs of the consumed reagent, this technology will not be cost-effective compared to other alternatives with similar control effectiveness (i.e. SOFA), SNCR alone was not included in the control effectiveness and cost-effectiveness sections of the main report.

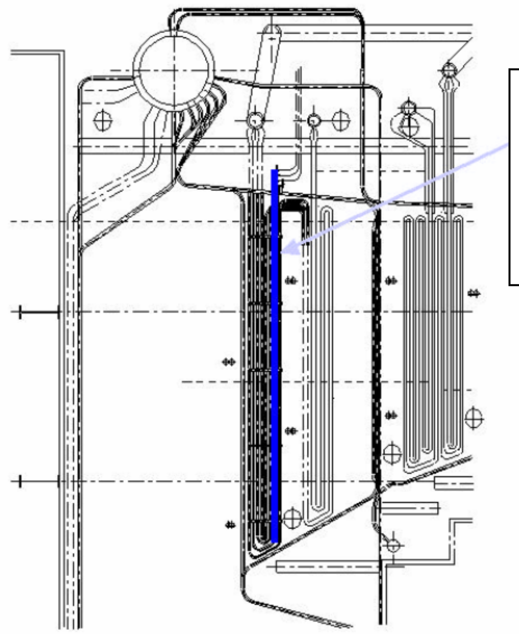
Other demonstrated forms of SNCR-related technologies, such as Rich Reagent Injection with SNCR, and amine-enhanced fuel lean gas reburn (FLGR™ with SNCR), are discussed under the layered technologies section.

A.1.3.2 Hydrocarbon-enhanced SNCR (NOxStar™)

Hydrocarbon-enhanced SNCR technology, commercially marketed as NO_XStar™, is offered by a single vendor (Mitsui Babcock) as a post-combustion type of enhanced SNCR technology, whereby an ammonia-based reagent is continuously injected into the superheater/reheater pass of an operating boiler with small amounts of gaseous hydrocarbon (typically either natural gas or propane) and air or steam to provide lance cooling and aid reagent dispersion. The targeted combustion gas temperature range is between 1500°F and 2000°F. The amount of gaseous hydrocarbon introduced is small enough (0.1 to 0.2% of total fuel heat input) that this is not intended to act as a form of reburn or staged fuel combustion. An array of permanently-installed injection lances are located within the boiler convection pass, divided into numerous discrete zones across the full width and height of the duct. The hydrocarbon auto-ignites, forming hydroxyl (OH) radicals which react with the NO_X and ammonia to produce elemental nitrogen (N_2) and water vapor (H_2O).

NO_XStar™ was demonstrated at Tennessee Valley Authority's Kingston Power Station Unit 9 (tangentially-fired 200 MW twin-furnace boiler firing eastern bituminous coal) in 2002[21]. This technology was subsequently permanently-installed at TVA's Colbert Station Unit 4 in late 2003 on a 192 MW wall-fired boiler burning eastern bituminous coal[22]. NO_X reduction was stated as 68-80% for these applications, which included the impact of overfire air and air-staged combustion upstream of the ammonia and propane injection locations.

An example of a hydrocarbon-enhanced SNCR installation on a wall-fired pulverized fuel boiler is shown as a sectional side elevation view of the upper furnace in Figure A.1-3.



NOxStar™ ammonia/hydrocarbon/steam injection lances (vertical lances behind secondary superheater inlet tubes

Figure A.1-3 Hydrocarbon-enhanced SNCR Application on PC-fired Boiler[22]

The supplier (Mitsui Babcock) of hydrocarbon-enhanced SNCR technology claims there is little sensitivity to the type fuel (coal) or burners this technique can be potentially applied to in order to reduce NO_X emissions. The chemical reagent injection for hydrocarbon-enhanced SNCR (NO_XStar™) NO_X control technology must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) model simulations are needed to determine the optimum injection points and spray patterns. Boiler operating conditions change with unit load and varying fuel characteristics. The NO_XStar™ process control system must be able to adjust for these changing conditions in order to be effective throughout the intended load range and firing conditions encountered. Non-retractable ammonia injection lances arranged in a parallel-series manner are permanently mounted inside the upper furnace zone, attached to convective tube elements. Different sections of the injection "grid" can be turned off or on, depending on load and firing conditions and amount of NO_X reduction required. Injection nozzles are continuously purged and cooled by extracted superheated steam from the boiler's main steam outlet, whether ammonia reagent is being introduced into the flue gas stream or not. Ammonia slip can be minimized by injecting less reagent, although NO_X control performance will be reduced.

There are a number of issues with firing North Dakota lignite that make the applicability of hydrocarbon-enhanced SNCR infeasible compared to previous experience in other coal-fired powerplants. These issues include:

- Hydrocarbon-enhanced SNCR (NOxStar™) technology has not been applied to cyclone boilers (with or without the use of a SOFA system). It has been only applied to date on pulverized coal-fired boilers burning eastern bituminous fuels.
- There is no successful demonstrated full-scale experience in continuous service of hydrocarbon-enhanced SNCR (NO_XStar™) technology on units firing high-slagging coals such as western subbituminous (PRB) and lignite. The heat transfer surfaces in the convective heat transfer zone where the reagent mixture is injected are prone to severe fouling from flyash constituents common in North Dakota lignite coals. Flyash deposit accumulation on the outside of the NO_XStar™ lances in Milton R. Young Station Unit 2 boiler's upper furnace is expected to be significant, potentially occurring within a matter of a few weeks from startup and nearly impossible to prevent or remove effectively during boiler operation. Such buildup is expected to cause maldistribution of the NO_X reduction chemical reagent from the injection nozzles. Effective on-line removal of these deposits from the injection nozzles is anticipated to be insufficient to maintain effective injection distribution and volume control. It is anticipated that this would significantly reduce the NO_X emission reduction performance consistently achieved on a sustainable basis.

The lack of experience with cyclone boilers, especially those firing coal with severe deposition characteristics such as North Dakota lignite, makes this technology technically infeasible for application on the Milton R. Young Station Unit 2 boiler.

A.1.3.3 Rich Reagent Injection (RRI)

Rich Reagent Injection (RRI) is a NO_X control process that has been developed and demonstrated specifically for use on cyclone boilers. Rich Reagent Injection is an SNCR process that involves the injection of aqueous urea into the lower furnace between the cyclones and the SOFA ports. RRI targets a high temperature, fuel-rich zone within the boiler-furnace environment immediately adjacent to the cyclone burners, and requires temperatures in the range of 2400 to 3100 degrees F.

The three zones of a Rich Reagent Injection SNCR application on a boiler with separated overfire air are shown as a sectional side elevation view of the furnace in Figure A.1-4.

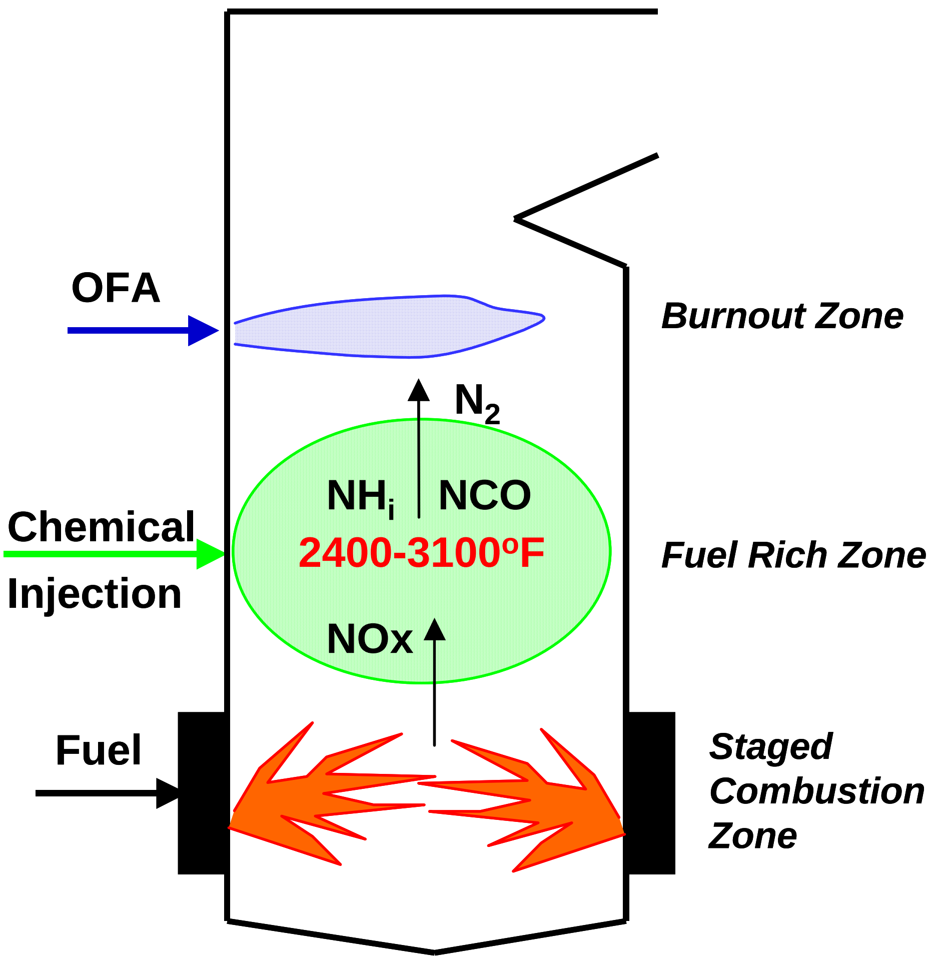


Figure A.1-4 Rich Reagent Injection Application on Boiler With Overfire Air[23]

The Rich Reagent Injection (RRI) process has been successfully demonstrated on at least two cyclone-fired boilers, with the most recent installation at Ameren's Sioux Unit 1, a 500 MW boiler firing a blend of PRB and midwestern bituminous coals. Generally, the heat content of these coals typically varies very little. Short-term testing of the RRI process has been performed alone and in combination with SNCR on B.L. England Unit 1 in 1999[24,25], and more recently at Ameren's Sioux Unit 1 in 2002[23,25], in 2004[26] (alone), and in the first half of 2005[27] (alone, and with SNCR).

The RRI process is intended to be used only with air-starved (substoichiometric staged-air) cyclone combustion, in conjunction with the installation and operation of an OFA system. The RRI process has not been demonstrated on any unit that fires North Dakota lignite. As of October 2006, no commercial installation of a permanent Rich Reagent Injection system has been made at any cyclone-fired boiler.

There is only one holder of a commercial license for modeling and conceptually designing RRI (Reaction Engineering International), with two vendors sub-licensed to design and sell RRI equipment (Fuel Tech and Combustion Components Associates). Since these license agreements are in place, and considering that successful demonstration testing has been performed at two cyclone-fired boiler powerplants, this technology is considered to be applicable and commercially available for potential application on cyclone boilers which burn coals with heat contents that are relatively constant. However, due to the variable heat content of lignite coal, RRI is considered to be technically-infeasible for application on North Dakota lignite-fired boilers. Technical feasibility and expected NO_X emissions from RRI for application on the Milton R. Young Station Unit 2 boiler are included in the “Layered NO_X Reduction Technologies” section.

A.1.3.4 Selective Catalytic Reduction (SCR)

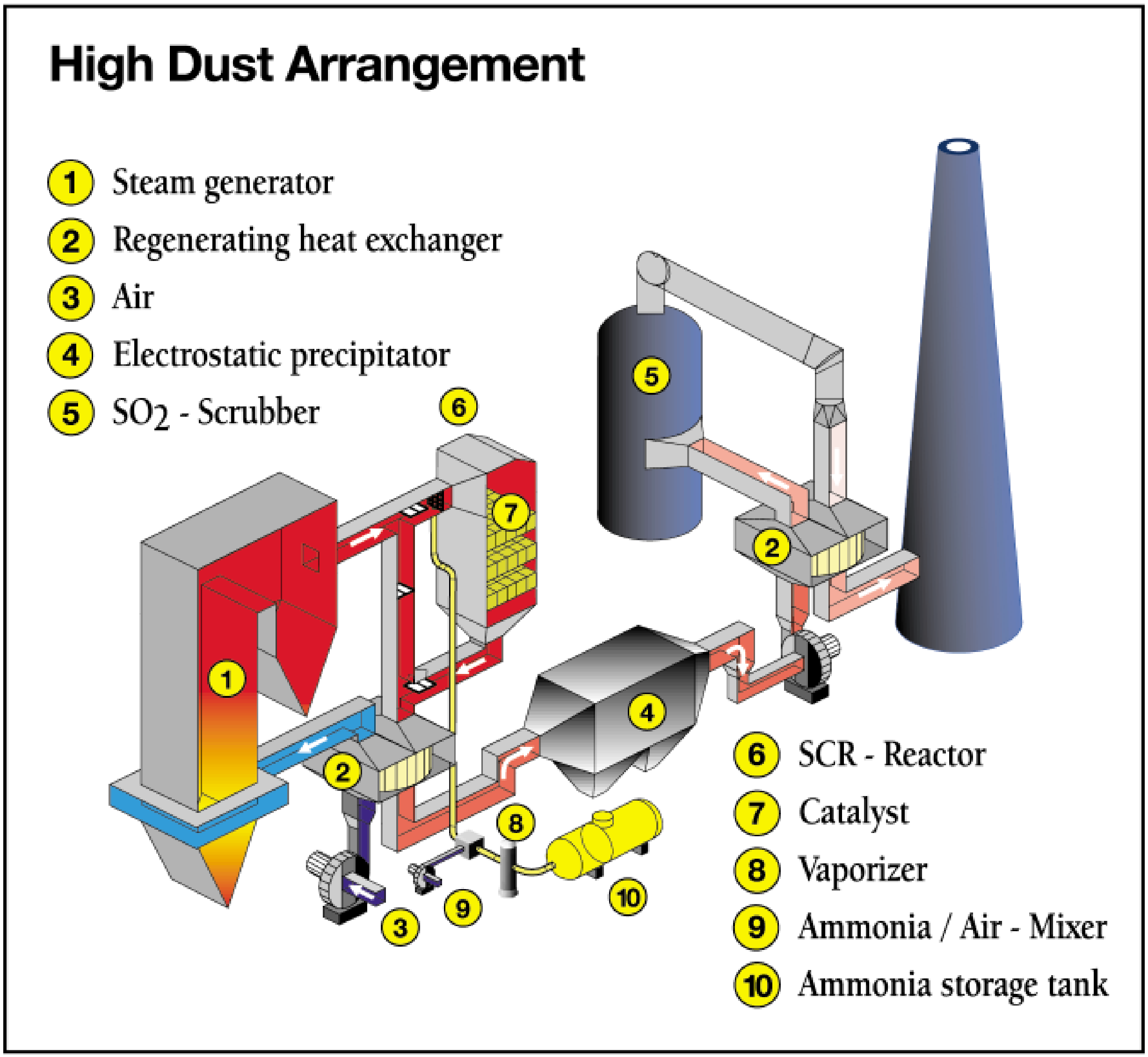
The lowest NOx emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NO_X to molecular nitrogen and water. The process is termed “selective” because the ammonia preferentially reacts with the NO_X rather than with the oxygen in the flue gas. A catalyst is used to enhance NO_X reduction and ammonia utilization at appropriate flue gas temperatures. SCR is usually applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO_X emission reduction effect. These are described below.

A.1.3.4.1 High-Dust Selective Catalytic Reduction (HD-SCR)

For coal-fired boilers, a conventional SCR reactor utilizes readily-available catalyst materials and reagent in the form of ammonia. A conventional SCR reactor is commonly installed in a high-dust, hot-side arrangement, located between the economizer outlet and air heater inlet, where the flue gas temperature is within the desired operating range for the SCR catalyst. The conventional SCR reactor arrangement is preferred for most coal-fired applications in utility boilers because it avoids the added expense of reheating the flue gas if placed after the air heaters which cool the flue gas, and downstream of any flue gas treatment to remove acid gases. Conventional SCR technology uses an ammonia injection grid (AIG), which consists of multiple nozzles, for distributing the reagent into the flue gas at the boiler’s economizer flue gas outlet.

A schematic graphic diagram for a conventional high-dust, hot-side SCR system on a boiler with a flue gas desulfurization system and stack gas reheat is provided in Figure A.1-5.

Figure A.1-5 Conventional High-Dust SCR Arrangement with FGD Scrubber Outlet Reheat



(figure copied from Wheelabrator Air Pollution Control literature)

Conventional high-dust, hot-side SCR technology has been installed on several pulverized coal and cyclone boilers firing bituminous and subbituminous coal in the United States. There are also a limited number of European SCR installations on steam electric generating units (SEGUs) firing lower grade (brown) coal. There are, however, no existing full-scale SCR installations on units that fire North Dakota lignite. There are approximately 50 cyclone-fired units located in the states affected by EPA's NO_X SIP call. Over half of these units are planning to install conventional high-dust, hot-side SCR systems in response to the SIP call. The installation of conventional high-dust, hot-side SCR systems has been completed on approximately 22 of these units. Appendix A2 lists several conventional high-dust hot-side U.S. SCR installations on pulverized coal and cyclone-fired utility boilers, along with measured NO_X emissions. Initial data from these units indicate that conventional high-dust, hot-side SCR systems operated on suitable cyclone-fired units may be able to reduce NO_X emissions to as low as 0.07 lbs/mmBtu. Several SCR installations have been retrofit on existing cyclone-fired boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). For cyclone coal-fired utility boilers retrofitted with SCR technology, all were originally designed to burn bituminous coal.

The EPA NO_X SIP call only applies to units in the eastern United States. There are no facilities firing North Dakota lignite in the EPA NO_X SIP call region. SCR system operation is currently only needed during the ozone season (June – September) for units installing control equipment solely to meet the EPA NO_X SIP call requirements. Limited annual operation is a significant factor with respect to SCR equipment reliability, maintenance, operational costs, and catalyst life. The demands on the SCR system are much more severe if the equipment is required to operate on a full-time, annual basis.

Two byproducts from the high-dust, hot-side SCR process are ammonia slip and SO_3:

- Ammonia Slip: Slip is ammonia that is unreacted in the NO_x emission reduction process. Maximum ammonia slip for a gas fired unit is usually 10 ppmvd whereas, on a coal fired unit, ammonia slip below 5 ppm is desired. For certain applications, this concentration can be problematic, therefore requiring more catalyst to reduce slip. Most new SCR applications have ammonia slip guaranteed at a 2 ppmvd maximum for an initial operating period.
- SO_3: Due to the composition of typical SCR catalysts, a small percentage of inherent SO_2 will be oxidized to SO_3. This oxidation can be controlled by catalyst selection and can be less than one percent. SO_2 to SO_3 oxidation must be carefully controlled to avoid creating SO_3 levels sufficiently high to raise the possibility of air heater fouling. A unit firing high-sulfur coal with SCR technology is especially vulnerable to SO_3 oxidation and ammonia slip-related fouling problems. The deposition and fouling is due to formation of solid ammonium sulfate ($(NH_4)_2SO_4$) and liquid ammonium bisulfate (NH_4HSO_4). The most important design variable is optimizing the catalyst selection and amount of catalyst that will reduce NO_X emissions, control ammonia slip, and minimize SO_2 oxidation.

Recent technology has allowed catalyst suppliers to make more rigorous and lengthy guarantees. A reasonable initial operating period for conventional catalysts in high-dust reactor arrangements on boilers firing eastern or midwestern bituminous coal is around 24,000 active operating hours (i.e. when ammonia reagent is being injected). Factors that need to be taken into account in design of a high-dust, hot-side SCR application that affect the need for catalyst replacement are:

- Pressure drop: The amount of restriction to flue gas flow through the SCR inlet, ammonia injection grid, SCR reactor, and downstream ductwork directly increases induced draft fan horsepower required to maintain adequate boiler draft. This is an important parameter to consider and minimize during the design stage. Pressure drop is a function of the average and maximum SCR reactor duct velocities, the amount of restriction caused by flow distribution correction devices (baffles or vanes), and the number and geometrical aspects of the catalyst layers. Many retrofit SCR installations require a booster fan or upgraded induced draft fan to overcome the added flow resistance. This increases operating cost for the increase in auxiliary power consumption and loss of saleable electric power. The type and pitch of the catalyst are factors most influential in determining the amount of pressure drop.
    - Catalyst type: The most common types or forms of catalyst material are honeycomb or plate. The former offers more surface area per volume, but can be more restrictive and prone to pluggage from ash deposits. The latter is usually less restrictive but requires more catalyst per layer or more layers to achieve the active surface needed to achieve the intended NO_X emission reduction.
    - Catalyst pitch: The pitch of the catalyst, a term used to describe the size of the gas path openings through the catalyst, varies depending on the manufacturer and design dust loading. Pitch is generally on the order of 5 to 7 millimeters. Potential pluggage of flow channels within the catalysts layers is therefore an issue that must be dealt with during design.
- Catalyst performance: The amount of NO_X emission reduction expected is a function of the specific activity level of the catalyst material and the amount of catalyst installed, over a given period of time. Catalyst formulation selection and features of construction have a significant impact on long-term NO_X emission reduction and subsequent costs for reagent and catalysts replacement. The frequency of catalyst replacement is influenced strongly by:
    - Catalyst erosion: Erosion of the catalyst material in coal fired units from entrained flyash or sootblowing action reduces the amount of active surface available for reacting with the reagent and flue gas, and can cause distortions in gas distribution (“channeling”) through the

SCR reactor. Catalyst material is fragile and can be easily damaged. Some catalyst is provided with erosion-resistant top edges to mitigate this tendency.

- Moisture absorption: Many types of catalyst are damaged by absorption of moisture. The reactor must be kept above ambient dewpoint temperatures or protected from freezing during outages in order to protect the catalyst from moisture damage. Spare catalyst must be carefully packaged to keep it dry and must be handled delicately to prevent damage.
- Thermal degradation: The specific active elements of the catalyst surface, or the matrix structure itself upon which the catalyst material is applied, can degrade when exposed to flue gas temperatures greater than the intended design of the formulation. High flue gas temperatures within the reactor causes sintering, leading to a permanent loss of catalyst activity due to a change in the pore structure of the catalyst. Proper selection and manufacturing control of the catalyst structure and formulation can minimize thermal degradation.
- Catalyst poisoning: The loss of performance or activity of the catalyst over time can be due to chemical damage or poisoning. Two elements especially detrimental to the life of common titanium-supported vanadium pentoxide SCR catalyst are arsenic and zinc. Vanadia/tungsten-based catalysts are particularly susceptible to rapid deactivation due to gaseous arsenic poisoning. In some German SCR installations, a 50% loss of activity has been reported within 10,000-15,000 operating hours. Addition of molybdenum to a vanadia-titanium SCR catalyst on similar applications shows relative activity reductions of 20-25%. Progressive loss of SCR NO_X reduction performance from catalyst deactivation due to poisoning is not possible to restore without effective cleaning to remove the deposits, or eventual replacement.
- Catalyst fouling: The surface area potentially exposed to the reagent (ammonia) and nitrogen oxides in the flue gas can become fouled with flyash or sulfur-related compounds. The presence of excess calcium oxide in the presence of sulfur in the flue gas can form a calcium sulfate surface coating that can be extremely dense, masking the pores of the catalyst. Progressive loss of SCR NO_X reduction performance from catalyst deactivation due to fouling is difficult to restore without effective cleaning to remove the deposits, or eventual replacement.

SCR technology has been installed on numerous coal-fired utility boiler facilities around the world and there are a large number of manufacturers that market the catalysts. The question is whether SCR is a feasible technology for a unit firing North Dakota lignite. There are serious concerns whether installation of SCR technology on a North Dakota lignite-fired unit can be successful, especially in a conventional "hot-side, high-dust" configuration. The effectiveness of the SCR process is highly dependent upon the ability of the nitrogen oxides in the flue gas being able to contact the active sites within microscopic pores of the catalyst in the presence of ammonia reagent with minimal interference from contaminants.

A recent technical paper "Ash and Mercury Behavior in SCR Catalysts When Firing Subbituminous and Lignite Coals" by the Energy & Environmental Research Center (EERC) of the University of North Dakota was published in the February 2005 issue of Fuel Processing Technology magazine[28]. This paper summarized the results of SCR slipstream testing at two PRB-fired plants and one North Dakota lignite-fired powerplant. The evaluation included determination of impacts of ash on SCR plugging and blinding. Flue gas was isokinetically extracted from the convective pass of the boiler upstream of the air heater. Pressure drop across the catalyst was measured during the initial two-month test period, and the two consecutive two-month test periods following the initial trial, while holding flue gas flow and temperatures constant. Ammonia was injected downstream of a screen, upstream of a flow straightener and air pulse section. Compressed air was injected ahead of the reactor, and was periodically pulsed to simulate sootblowing to minimize ash deposit accumulation.

This slipstream SCR testing examined the significance of ash accumulations on SCR catalyst on both the macroscopic and microscopic levels. Very small flyash particles were found bonded together by a matrix of sodium-, calcium-, and sulfur-rich materials, likely in the form of calcium sulfate. North Dakota lignite coal contains many alkali and alkaline-earth elements, and sulfur. The firing of lignite coal which produces fine (less than 5-µm diameter) flyash particles creates conditions that enter the pores of the catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into the matrix.

As posted on Electric Power Research Institute Inc.'s (EPRI's) website regarding the impact of coal type on SCR catalyst life and performance, a recent EPRI study[29] produced field data analyzed from an "In-Situ Mini SCR Reactor" system installed in a typical "high-dust" location at seven different test sites, including four firing PRB coal, one firing Texas lignite, one firing high-sulfur eastern bituminous coal, and one firing a PRB/eastern bituminous coal blend. The PRB/bituminous coal blend test was performed at AmerenUE's Sioux Station, on one of the two 500 MW cyclone-fired boilers. This study found that the cyclone unit firing the PRB/bituminous coal blend exhibited the fastest rate of catalyst activity degradation. Also, the higher deactivation rates seen at this site were due to economizer exit flue gas temperatures being significantly higher than at the other sites. A comparison of the Texas lignite and one of the PRB-fired sites with two different catalysts, deactivation was more a function of trace elements in the flue gas and flyash than the specific catalyst type or formulation.

North Dakota lignite produces an ash that is very sticky and creates severe ash deposition problems. There have been no installations of SCR systems (full-scale) on units that fire North Dakota lignite. A technical assessment was conducted for the installation of SCR technology on a North Dakota lignite unit. In order to further evaluate the feasibility of installing a conventional SCR system on a North Dakota lignite fired unit, the Energy & Environmental Research Center (EERC) at the University of North Dakota was consulted. EERC has extensive experience investigating the deposition characteristics of North Dakota lignite ash.

Technical difficulties and anticipated operating problems that are unresolved with respect to installing conventional SCR technology at Milton R. Young Station include the impacts of erosion, severe ash deposition, and "popcorn ash" on the catalyst. According the EERC's study (see Appendix B), "the most significant problems that prohibit the successful operation of SCR catalysts to lignite coal is the formation of low-temperature sodium-calcium-magnesium sulfates and phosphates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency". For these reasons, application of available conventional high-dust SCR technology is considered technically infeasible for Milton R. Young Station Unit 1 and Unit 2 boilers. These concerns can be divided into four categories. Each category is addressed below. An explanation of the factors that make conventional SCR technology infeasible for these boilers follows:

1. Ash Deposition: North Dakota lignite contains a variable and complex variety of inorganic compounds that contribute to ash deposition. This fuel produces ash with severe deposition characteristics that are not typical with other coals. When exposed to the heat of the combustion process inside the cyclone burners, the majority of the fuel ash becomes molten and flows into the bottom of the furnace. A significant portion of the fuel ash is entrained into the flue gas exiting the cyclone barrels at high velocity, where it comes into contact with the lower furnace waterwalls. The portion that is carried with the rising flue gas cools and some is deposited on heat transfer surfaces in the upper furnace and boiler convection pass. Ash deposition on heat transfer surfaces is a substantial problem for units that fire North Dakota lignite. The problem is so severe at Milton R. Young that the Unit 2 boiler must be shut down at 80 to 90-day intervals to

allow for cleaning of ash deposits from the boiler heat transfer surfaces in order to restore reasonable furnace exit gas velocities and temperatures.

Sodium is a significant contributor to the "stickiness" of the ash produced from firing North Dakota lignite. Sodium content of the lignite ash averages approximately 4.4%, and can nearly double this value for some of the lignite produced from the Center mine. PRB coal typically averages around 1.5% sodium content. Boilers firing North Dakota lignite typically have a 2.5% higher heat rate (million Btu per kilowatt of electric generation) than a typical boiler firing PRB coal, thus requiring more heat input and firing more fuel per megawatt of electricity output. A cyclone boiler firing North Dakota lignite also converts approximately 50% of the fuel ash to flyash, compared with a 35% conversion rate for PRB coal-fired cyclone boilers. Overall, this results in an amount of sodium emitted from a cyclone boiler firing North Dakota lignite of approximately 7.3 lbs/MW-hr compared with 0.9 lbs/MW-hr for a PRB-fired cyclone boiler.

The catalysts in coal-fired boiler SCR reactors are highly susceptible to ash deposition. In a typical conventional high-dust SCR reactor, the flue gas typically passes through two to four layers of catalyst modules. The catalyst modules have numerous narrow passages to provide intimate contact between the flue gas, ammonia and catalyst. The clearance (pitch) in these passages is typically 6-10 millimeters. A typical catalyst layer is approximately 1 to 1.5 meters deep. The catalysts in coal-fired boiler SCR reactors must be cleaned frequently using soot blowers and/or sonic horns. This is true even on units firing fuels that do not produce a sticky ash that contributes to ash deposition. Ash deposition on the catalyst in a high-dust SCR application would be severe for a unit firing North Dakota lignite.

Sulfur in the coal is oxidized during excess air combustion to form sulfur dioxide (SO_2), and a small amount of sulfur trioxide (SO_3). Some of the ammonia-based reagent injected upstream of the SCR reactor will combine with SO_3 to form ammonium bisulfate. The catalyst in the SCR reactor will also oxidize a portion of the SO_2 to SO_3. Excess unreacted ammonia reagent carryover ("ammonia slip") from the SCR reactor will also react with these sulfuric acid compounds in a similar fashion. The deposition characteristics for a unit burning North Dakota lignite will create difficult-to-remove ash deposits and pluggage of a conventional high-dust catalyst, and increase the probability that the air preheater downstream and flue gas ductwork will be prone to accumulations which could be severe. High-dust SCR performance and catalyst life will be severely impacted. It is anticipated that a high-dust SCR's catalyst life will be shortened from 3-6 years (typical) to as little as 2-12 months, requiring extended, frequent outages for replacement.

Hot-side air preheaters are susceptible to fouling. Tubular air pre heaters originally supplied with all cyclone boilers also tolerate moderate dust loadings, since their height and size make them difficult to maintain cleanliness. Leak tightness of the air preheater is important on cyclone-fired boilers with relatively high forced draft fan discharge (combustion air supply) pressures. A high-dust SCR installation will be prone to air preheater tube fouling and pluggage, requiring extended, frequent outages for cleaning.

2. "Popcorn Ash": A second consideration in the application of conventional high-dust SCR technology on a lignite-fired unit is the potential of the SCR reactor catalyst pluggage resulting from carry over of "popcorn ash" from the boiler. Boilers firing North Dakota lignite have severe problems with ash deposition on boiler surfaces. North Dakota lignite has a high propensity to form deposits on the boiler's furnace and convection pass fireside surfaces. For lignite-fired units, the boiler's heat transfer surfaces must be cleaned by sootblowing and other methods (e.g. water lances) frequently to maintain satisfactory boiler operation. Some of the removed deposits released by the cleaning action within the boiler and convection passes form "popcorn ash", which will be entrained in the flue gas. Carry over of boiler ash deposits will contribute to pluggage of the "popcorn ash" screen ahead of the top layer of SCR reactor catalyst. This can cause distortions in gas distribution ("channeling") through the SCR reactor, which will aggravate erosion in the high velocity areas and ineffective performance of the catalyst.

3. Temperature: A third issue that impacts the feasibility of installing high-dust SCR technology on the North Dakota lignite-fired units is catalyst operating temperature. The performance of any SCR catalyst is highly dependent on the temperature of the flue gas passing through the reactor. Typically, a temperature of 600 – 750 degrees F is required to obtain satisfactory operation of an SCR reactor. Operation of commonly supplied catalyst suitable for a high-dust SCR reactor at temperatures above 750 degrees results in severe and rapid deterioration of the catalyst and SCR reactor's NO_X emission reduction performance. For bituminous and sub-bituminous coal-fired units, boiler flue gas passing between the economizer outlet and air heater inlet is generally

within a temperature range acceptable for conventional SCR catalysts without additional heating or cooling of the flow stream.

North Dakota lignite-fired cyclone boilers, including those at Milton R. Young Station, have high temperatures at the economizer's flue gas outlet by design. The highest gas temperatures downstream of the convection pass economizer sections and upstream of the air heater inlets in Milton R. Young Unit 2's boiler are much higher than 750 degrees.

High gas temperatures at the air heater inlet are required to produce the high air temperatures (700°F) needed for the pre-combustion lignite drying system, along with primary and secondary combustion air supplied to the cyclones. Such air preheater arrangements and capabilities have been taken into account in the design of the North Dakota lignite-fired cyclone boilers. Reducing this high gas temperature to accommodate conventional catalysts for a conventional high-dust SCR reactor would result in pre-combustion air temperatures that are too low to provide satisfactory drying and rapid ignition of the high-moisture fuel. This will seriously impact reliable combustion, slag formation and tapping in the cyclone burners. Consequently, it is not feasible to modify the Milton R. Young Unit 2's boiler to operate with the lower economizer outlet flue gas temperature.

Catalysts for a conventional high-dust, hot-side SCR system have not been installed nor successfully demonstrated in a full-scale installation of an operating solid fuel-fired unit that are designed to continuously operate at the high temperatures (above 750 degrees F) that exist between the convection pass economizer and air heater on the Milton R. Young Unit 2's boiler.

4. Erosion: A final consideration on whether hot-side, high-dust SCR technology can be successful on a North Dakota lignite-fired unit is the potential for erosion of the SCR catalyst. North Dakota lignite supplied from the Center mine has an average fuel ash content of 10.5%, and can have an ash content up to 25.5 percent. PRB coal fuel ash content typically averages approximately 5 percent. As previously stated, a cyclone boiler firing North Dakota lignite converts a significantly greater amount of flyash than a PRB-fired cyclone boiler. Overall, this results in a flyash output rate from a cyclone boiler firing North Dakota lignite of approximately 83 lbs/MW-hr compared with 21 lbs/MW-hr for a PRB-fired cyclone boiler. High ash contents in the flue gas stream can result in physical erosion of the catalyst. In addition, effective on-line cleaning of the

high-dust catalyst will likely require steam or compressed air sootblowing. Cleaning cycles of the catalyst will be required much more frequently than a typical conventional SCR installation due to the ash deposition characteristics of the North Dakota lignite and the expected buildup and pluggage resulting from the carry over of “popcorn ash”. Frequent sootblowing of the catalyst to remove fouling deposits and ash accumulations will contribute to erosion and decreased catalyst life. There is some European experience with high ash brown coals that catalyst manufacturers will be able to draw upon. This experience, however, will not be directly applicable to these United States units because of the severe deposition characteristics of the North Dakota lignite ash compared to brown coal.

The EPA’s NSR Manual states that for a technology to be feasible it must “available and applicable”. SCR technology is an available technology which has been installed on numerous powerplant facilities around the world and there are a large number of manufacturers that market the technology. The question is whether SCR technology is “applicable” for a unit firing North Dakota lignite.

In accordance with EPA’s NSR Manual, a technology is “applicable” if it has been installed on a “similar unit”. Hot-side, high-dust SCR technology has been retrofit on coal-fired units featuring cyclone boilers. However, there are no SCR installations in operation or planned on units that include cyclone burners firing North Dakota lignite with severe slagging and fouling tendencies combined with such high boiler economizer outlet gas temperatures (over 750°F) required for high-moisture fuel pre-drying systems and tubular air preheaters.

The EPA’s NSR Manual also states a technology may be determined to be not applicable if “a technical assessment considering physical, chemical and engineering principles and/or empirical data showing the technology would not work on the emissions unit under review or that unsolvable technical difficulties would preclude the successful deployment of the technique.” In this SCR technology application, it appears that a facility utility powerplant firing North Dakota lignite would experience extended time delays or be required to devote significant internal resources and engage outside research, followed by extended field trials to learn how to apply a conventional high-dust, hot-side SCR technology on a such a fuel source.

Based upon this technical assessment that looked at the various design and operational issues associated with the installation of hot-side, high-dust SCR technology on a North Dakota lignite-fired steam-electric generating unit, this control option is considered technically infeasible for Unit 2's boiler at Milton R. Young Station.

A.1.3.4.2 Low-Dust Selective Catalytic Reduction (LD-SCR)

Low-dust SCR (LD SCR) technology could potentially be applicable to North Dakota lignite-fired boilers for NOx emission control. Low-dust SCR refers to the location of the SCR system downstream of a particulate collection system, such as an electrostatic precipitator or a fabric filter. If the low-dust SCR is downstream of a hot-side electrostatic precipitator and prior to the air preheater, flue gas reheating is unnecessary. This has been the prevalent form of alternative retrofit SCRs in the United States for coal-fired utility boilers. There are ten known hot-side low-dust SCR installations (without flue gas reheat) operating in the United States as of July 2005. These are listed in Appendix A2. If applied to MRY Station Unit 2's boiler, the low-dust SCR equipment would be downstream of a cold-side electrostatic precipitator; flue gas reheat prior to the LD SCR reactor inlet would be required for proper NO_X emission reduction performance.

For a cold-side LD SCR, the ESP outlet flue gas passes through a low-dust gas-to-gas heat exchanger (LD GTG-HE), prior to passing to the low-dust SCR reactor. After the LD GTG-HE, the flue gas will travel through the new duct, receiving hot flue gases from a direct-fired gas burner or set of high-pressure steam coils, leading to an ammonia injection grid, turning vanes and then into the LD SCR reactor. The flue gas entering the inlet to the LD GTG HE is expected to be near the air heater outlet temperature (330-340°F) in a cold-side LD SCR application. The supplemental heat added downstream of the LD GTG-HE can be supplied from high temperature steam coils (indirect heat exchange) or directly from natural gas-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the LD SCR NO_X–ammonia reaction to be effective. The LD gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the FGD system (if applicable) and stack. The use of rotary regenerative-type heat exchangers has been applied in European LD SCRs. With this design, there will be leakage between the untreated and treated gas streams such that the exit flue gas has higher NO_X concentrations than the LD SCR outlet gas. The direct-fired flue gas reheat duct burners will also create NO_X emissions, which will add to the amount emitted from the boiler and input into the LD SCR reactor. The LD SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This normally requires an induced draft fan upgrade or a booster fan addition.

The factors that make low-dust SCR technology infeasible for the Milton R. Young Station Unit 2's boiler with existing particulate collection via electrostatic precipitators are as follows:

- Catalyst Fouling and Deactivation: An existing electrostatic precipitator upstream of a low dust SCR reactor will still expose the catalyst to the acid gas content and fine particulate containing trace metals and the high alkali mineral content of the entrained lignite flyash not removed by the ESP upstream. Although the total amount of flyash carryover into the LD-SCR reactor is greatly reduced compared with a high-dust design, it is anticipated that the low-dust SCR catalyst life will still be unacceptably short. The small particle flyash passing into the reactor will be sufficient to cause pluggage of the catalyst pores, resulting in deactivation of the catalyst. The firing of lignite coal produces fine (less than 5-µm diameter) flyash particles, which are also least likely to be removed by the existing particulate collection equipment (e.g. ESP) upstream of a low-dust SCR. This creates conditions that allow these small flyash particles to enter the pores of the catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into a matrix of sodium-, calcium-, and sulfur-rich materials (likely in a form of calcium sulfate). Once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. One catalyst vendor's has stated it is their "experience that low-dust catalyst is more difficult to clean than that from high-dust"[30]. Low-dust SCR performance and catalyst life could be severely negatively impacted. Shortened lifespans of the LD SCR catalyst will require premature, extended, frequent outages for replacement.
- Site Space Constraints: The installation of a low-dust SCR system with flue gas reheat requires a substantial amount of space for installation and operation. A low-dust SCR system will likely use a regenerative gas-to-gas heat exchanger (reheater) to raise the temperature of the flue gas at the SCR inlet. A GTG HE will transfer heat from the flue gas at the SCR reactor outlet to the flue gas entering the SCR reactor in order to minimize the supplemental SCR energy usage. The gas-to-gas heat exchanger dictates the footprint of the cold-side low-dust SCR system. Space is required for the GTG HE and for ductwork in and out of the reheater. Sufficient free space around the reheater and SCR is also required for maintenance.

  The area around Units 1 and 2 at the M.R. Young station is extremely congested in the areas where low-dust SCR systems must be located. The situation is particularly severe for Unit No. 2. Equipment that impacts the feasibility of installing a low-dust SCR system on Units 1 and 2 includes the Unit 2 absorbers, Unit 2 flue gas desulfurization (FGD) dewatering equipment, fly ash handling equipment, fuel storage and transfer equipment, stacks, fans and ductwork. It would be extremely disruptive to the continued economic operation of both boilers to relocate all the mentioned equipment to create space for the low-dust SCR systems at the M.R. Young Station. Stacks, fans and ductwork and the Unit 2 FGD system cannot be readily relocated due to adjacent structures and the need to continue operation while constructing the retrofit installations. The fuel handling equipment includes a coal storage barn and the main conveyors supplying lignite to the units. Relocating the coal handling equipment currently occupying space needed for the low dust SCR systems would be quite difficult given the site configuration. It is conceivable that the fly ash equipment located west of Unit 1 could be relocated to provide some of the space needed for the low-dust SCR. However, the availability of this space is doubtful, since avoiding the likelihood of severe SCR catalyst sulfate fouling will require a new Unit 1 FGD system to be installed. If a new FGD system is installed for Unit 1, the FGD system would need to occupy the space that can be made available by relocating ash handling equipment. This space subsequently would not be available for a low-dust SCR system.

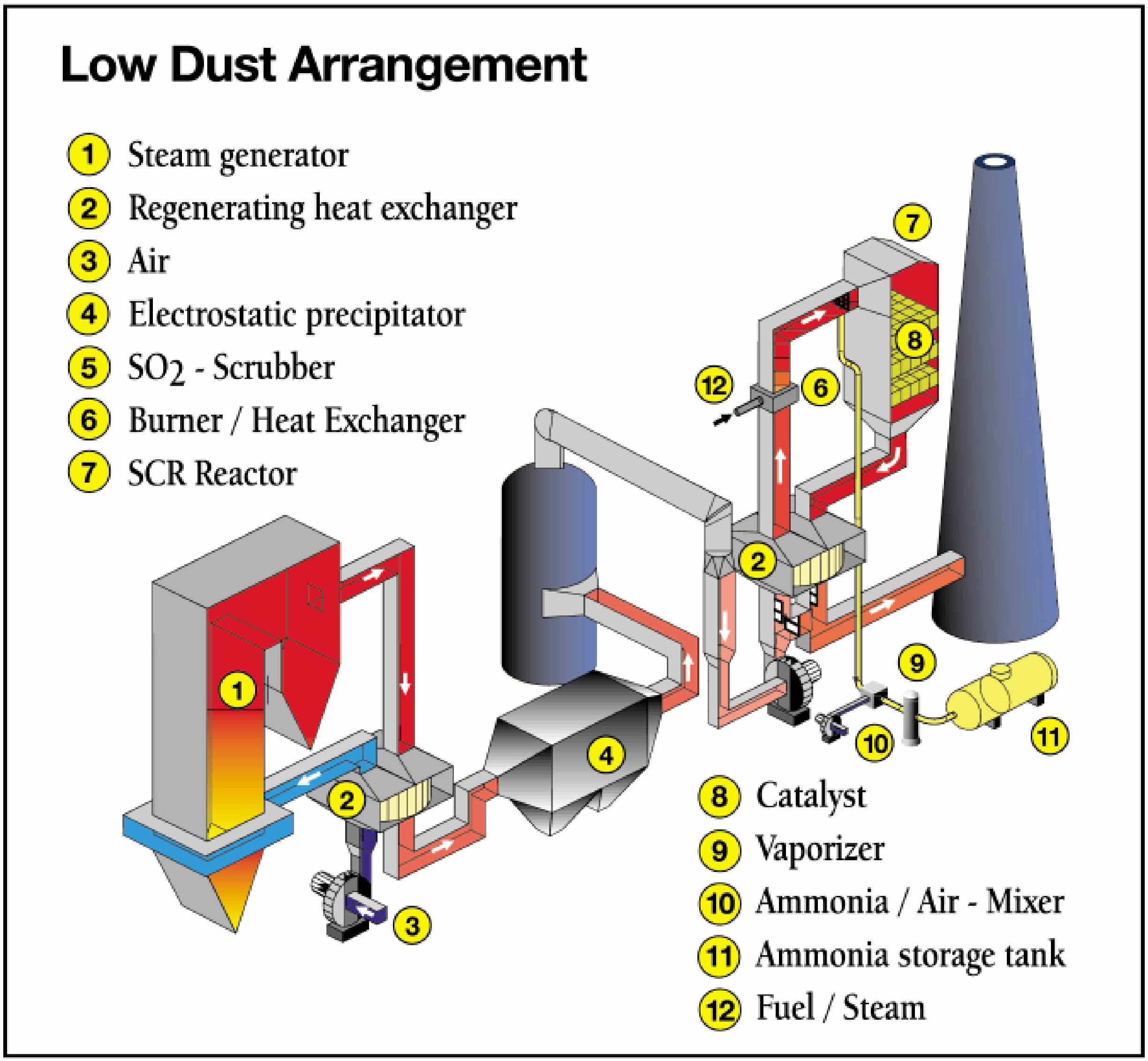
Based upon a technical assessment that looked at the various design and operational issues associated with the installation of low-dust SCR technology on a North Dakota lignite-fired steam-electric generating unit, this control option is considered technically infeasible for the Milton R. Young Station Unit 2's boiler.

A.1.3.4.3 Tail-Gas Selective Catalytic Reduction (LD-SCR)

A tail-gas (TG) SCR is a low-dust SCR system where the LD SCR reactor is installed downstream of a FGD scrubber. The FGD outlet flue gas passes through a gas-to-gas heat exchanger (GTG-HE), prior to passing to the tail-gas SCR reactor. The flue gas will travel through new or modified ductwork leading to an ammonia injection grid, turning vanes and then into the TG SCR reactor. The TG SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This normally requires an induced draft fan upgrade or a booster fan addition.

A schematic graphic diagram for a low dust arrangement is shown in Figure A.1-6.

Figure A.1-6 Tail-Gas SCR Arrangement



(figure copied from Wheelabrator Air Pollution Control literature)

The flue gas from a wet FGD scrubber outlet entering the inlet to the gas-to-gas heat exchanger is expected to be near the saturation temperature (140°F) in a cold-side TG SCR application. The supplemental heat added downstream of the TG GTG-HE can be supplied from high temperature steam coils (indirect heat exchange) or directly from natural gas-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the TG SCR NO_X– ammonia reaction to be effective. The TG gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the stack. With a rotary regenerative-type gas-to-gas heat exchanger, there will be internal leakage between the untreated and treated gas streams such that the stack exit flue gas has higher NO_X concentrations than the

TG SCR reactor outlet gas. Using direct-fired flue gas reheat duct burners will also create NO_X emissions, which will add to the amount emitted from the boiler and input into the TG SCR reactor.

There is limited technical information published in English for coal-fired steam-electric generating units (SEGU) with low-dust/tail-gas SCR technology in applications requiring full flue gas reheat prior to the reactor inlet. There is no experience with TG SCR on eastern bituminous, western subbituminous coal or lignite-fired SEGUs in the United States. As of 1997, there was one low-dust/tail-gas SCR on a 220 MWe German cyclone-fired boiler with a 1988 retrofit installation. This boiler was reported to be operating without combustion controls or FGD, burning low sulfur, low ash, moderate moisture bituminous coal with an average pre-SCR NO_X emission rate of approximately 1.07 lb/mmBtu, and was meeting a 30-day rolling average emission limit of approximately 0.16 lb/mmBtu (85% reduction)[31].

Milton R. Young Station Unit 1 does not currently incorporate any flue gas desulfurization equipment, which would place the reactor catalyst in a low-dust SCR configuration, which is considered infeasible when burning North Dakota lignite. A new FGD system for Unit 1 would be required in order to avoid or significantly reduce expected sulfate formation within the catalyst and gas-to-gas heat exchanger when combined with ammonia required for the TG SCR. Unit 2 currently employs a wet scrubber which currently treats approximately 83% of the total flue gas flow from the boiler. Flue gas reheat is currently provided by the FGD bypass (i.e. warm, untreated flue gas is mixed with the cool scrubbed gas).

The factors that make tail-gas SCR technology infeasible for both Milton R. Young Station boilers with existing particulate collection via electrostatic precipitators are as follows:

- Catalyst Fouling and Deactivation: The TG SCR reactor downstream of a flue gas desulfurization (FGD) scrubber will still be susceptible to fouling, contamination, pluggage, and catalyst deactivation.
    - An existing electrostatic precipitator (ESP) upstream of a tail-gas SCR reactor will still expose the catalyst to fine particulate containing trace metals and the high alkali mineral content of the entrained lignite flyash not removed by the ESP upstream. Although the total amount of flyash carryover into the TG-SCR reactor is greatly reduced compared with a high-dust design, it is anticipated that the tail-gas SCR catalyst life will still be unacceptably short.
    - The firing of lignite coal produces fine (less than 5-µm diameter) flyash particles, which are also least likely to be removed by the existing particulate collection equipment (e.g. ESP) upstream of

a TG-SCR. Flue gas with entrained fine particulate matter, including some involving sodium and sulfur-containing compounds, will pass through and be carried-over from a wet FGD scrubber. This treated gas stream will carry sodium sulfate particles, formed by homogenous condensation after exiting the boiler and not removed by the FGD system, into the catalyst layers of the TG-SCR reactor. A dry FGD system followed by a fabric filter upstream of the TG-SCR will still allow sulfur-bearing flue gas and fine particles to enter the catalyst. There is serious concern that fine particles passing into the reactor will accumulate within the catalyst, and be resistant to removal by conventional sootblowers and other cleaning technologies. This creates conditions that allow these small flyash particles to enter the pores of the catalyst, react with SO_2 and/or SO_3 in the flue gas, and form sulfates which bind other ash particles into a matrix of sodium-, calcium-, and sulfur-rich materials (likely in a form of calcium sulfate). Once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. Catalyst that is exposed to such conditions will be ineffective at maintaining adequate activity upon which the performance of the TG-SCR's NO_X removal is based.

  - These entrained particles will also deposit on the gas-to-gas heat exchanger ahead of the tail gas SCR reactor. This deposition will decrease heat transfer between the incoming (cool) flue gas and the outgoing (warm) flue gas. Sootblowers could be used to remove the accumulated deposits from the GTG HE, but the SCR reactor could still suffer catalyst fouling from the deposits dislodged from the GTG HE cleaning cycle becoming reentrained in the reheated flue gas. Tail-gas SCR performance and catalyst life could be severely negatively impacted. Shortened lifespans of the TG SCR catalyst will require premature, extended, frequent outages for replacement.

- Site Space Constraints: The installation of a tail-gas SCR system with flue gas reheat requires a substantial amount of space for installation and operation. A tail-gas SCR system will likely use a regenerative gas-to-gas heat exchanger (reheater) to raise the temperature of the flue gas at the SCR inlet. A GTG HE will transfer heat from the flue gas at the TG SCR reactor outlet to the scrubbed flue gas entering the SCR reactor in order to minimize the supplemental SCR energy usage. The gas-to-gas heat exchanger dictates the footprint of the TG SCR system. Space is required for the GTG HE and for ductwork in and out of the reheater. Sufficient free space around the reheater and SCR system is also required for maintenance.

  The area around Units 1 and 2 at the M.R. Young station is extremely congested in the areas where TG SCR systems must be located. A flue gas desulfurization system will be needed for Unit 1 in the near future to comply with the Consent Decree. When a new FGD system is installed for Unit 1, the FGD system would need to occupy the space that can be made available by relocating ash handling equipment. This space subsequently would not be available for a tail-gas SCR system. Thus, the availability of adequate space for all the new FGD and TG-SCR system equipment and structures while accommodating existing coal storage and handling needs for both existing boilers at Milton R. Young Station is doubtful.

The challenges for installation of new ductwork, SCR reactors, and flue gas reheating equipment and the lack of pertinent experience with all aspects of design, construction, operation and maintenance of tail-gas SCRs on such high-fouling coals as North Dakota lignite are significant. The flue gas conditions that the TG-SCR catalyst will be exposed to will create unresolvable fouling and blinding that makes successful application of this technology difficult, expensive, and uncertain.

The risk of failure and uncertainty of successfully applying low-dust, tail-gas SCR technology to a cyclone-fired utility powerplant firing North Dakota lignite appear substantial.

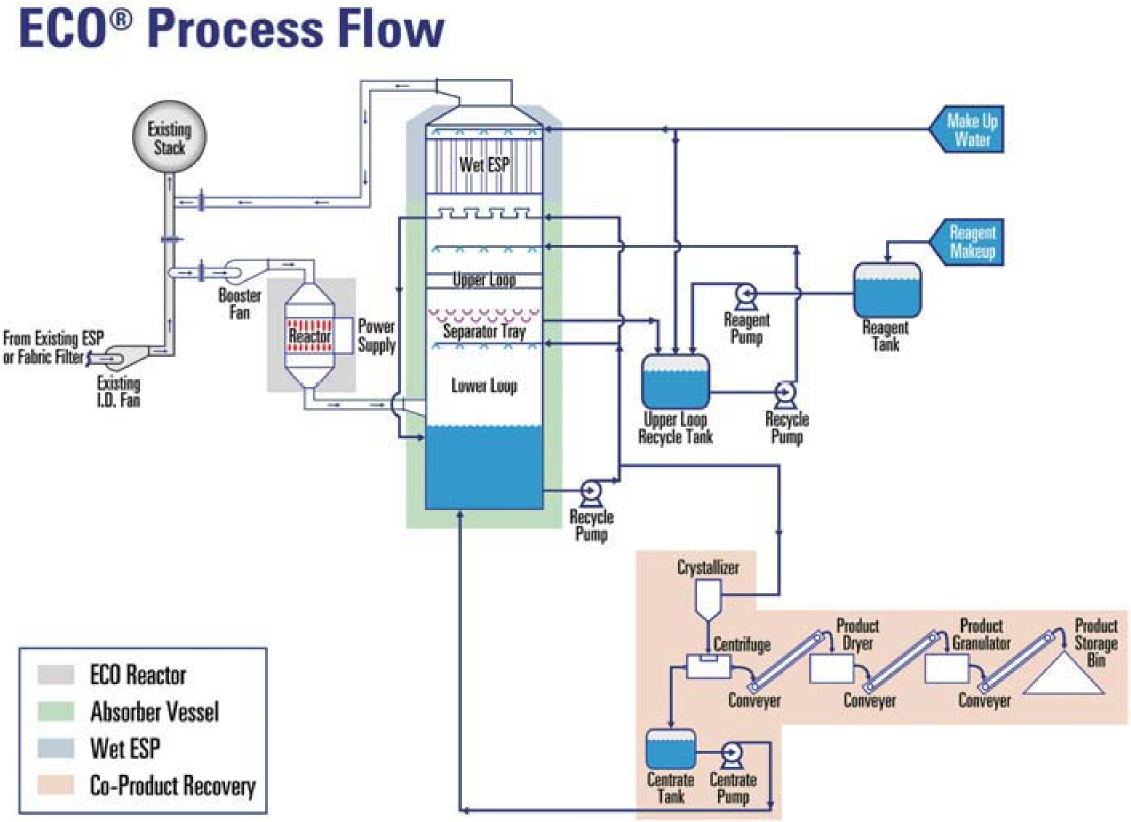
Based upon a technical assessment that looked at the various design and operational issues associated with the installation of tail-gas SCR technology on a North Dakota lignite-fired steam-electric generating unit including a cyclone boiler, this control option is considered technically infeasible for the Milton R. Young Station Unit 2's boiler.

A.1.3.5 Electro-Catalytic Oxidation (ECO®)

Powerspan's Electro-Catalytic Oxidation (ECO®) system is a multi-pollutant technology designed to control emissions of NO_X, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO® process has two main process vessels, a barrier discharge reactor, and a multi-level wet scrubber. The barrier discharge reactor utilizes an electrical discharge to create oxygen and hydroxide radicals which then react with NO_X, and other constituents in the flue gas stream. The flue gas stream then enters the bottom of the ECO® scrubber where the lower loop cools the flue gas and removes a portion of the acid gasses [sulfur trioxide (SO_3), sulfuric acid (H_2SO_4), nitric acid (HNO_3)] produced in the barrier reactor and oxidized metals such as mercury, with a low pH aqueous ammonia reagent. A second scrubbing loop is then entered where additional SO_2, NO_2, acid gases and oxidized metals are removed with an aqueous ammonia reagent, though at a higher pH. Above the second scrubber loop is an absorber section for absorbing fugitive ammonia from the first and second scrubbing loops. The final step in the ECO® process is a wet electrostatic precipitator (WESP) which collects fine particulate matter, aerosols generated in the scrubber and additional mercury. An updated schematic process flow diagram for the basic ECO® process is shown in Figure A.1-7.

Figure A.1-7 – Electro-Catalytic Oxidation (ECO®) Process Flow Diagram

(copied from http://www.epa.gov/appcdwww/aptb/EPA600R03110.pdf)



Powerspan has been involved in an extended ECO® process demonstration using a 28 MW Commercial Demonstration Unit (CDU) at R.E. Burger Station Units 4&5. The ECO® CDU project treated a slipstream and demonstrated performance, reliability and economics for approximately one year. The demonstration program started in January, 2004. NO_X removal is stated to be up to 90% with a claimed 0.05 lb NO_X/mmBtu outlet condition achievable for the front-end of the ECO® process. Further sustained operational tests of the ECO® CDU are underway during the second and third quarters of 2005.

As this is a post-combustion multi-pollutant control technology, it is claimed that there is little sensitivity to the type boiler or burners that Powerspan's Electro-Catalytic Oxidation (ECO®) process can be potentially applied to in order to reduce NO_X emissions. The effectiveness of this ECO® process for NO_X control has been demonstrated on a slip-stream commercial demonstration unit (CDU) associated with pulverized fuel boilers firing midwestern or eastern bituminous coal.

Powerspan's published data from the commercial demonstration unit's performance of up to 90% when treating flue gas with an inlet NO_X concentration around 0.5 lb/mmBtu. This would result in a stack NO_X emission around 0.05 lb/mmBtu.

The ECO® process has not been demonstrated in a full-scale configuration on any unit, nor tested in a slipstream configuration on any boiler that fires western subbituminous coals or North Dakota lignite. It has also not been applied to emissions from a cyclone-fired boiler. According the EPA's Draft NSR Manual, "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available: an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice".

There are a number of issues with firing North Dakota lignite that make the applicability of the ECO® process technically infeasible for MRY Station boilers. These issues include:

- Deposits and Pluggage: The flyash deposition characteristics of the North Dakota lignite are extremely severe. Anything that contributes to flyash deposition and pluggage within the barrier reactor is expected to have a detrimental impact on the multi-pollutant control performance of the ECO® process, and thus could have a serious impact on MRY Station operations. The lack of demonstrated operation on treating the emissions from a boiler firing coal with a high slagging index precludes the use of the ECO® process as technically feasible for BACT as applied to a boiler firing North Dakota lignite.
- Reliability and Availability: Milton R. Young Station's major planned outages for each unit are scheduled to occur once every three years. Any NO_X control technology selected as BACT will need to operate year-round, year in and year out, on a routine basis, while performing at high levels of pollutant reduction. The Powerspan ECO® system is a new technology and is not as highly developed as other more common NO_X and SO_2 control technologies such as SCR or SNCR plus wet or semi-dry flue gas desulfurization (FGD). It is expected to require a full-time, full-scale application with sustained continuous operation to confirm levels of currently demonstrated reliability and availability from the ECO® CDU are acceptable to meet the

expectation of infrequent major outages over long time periods while maintaining high levels of control.

There are additional factors that make the application of the ECO® process potentially more difficult than other established emission control technologies available for coal-fired powerplants:

- There is a lack of experience with the ECO® downstream ammonia scrubber's coproduct crystallization and granulization equipment design, operation, and maintenance, which was not included with the initial commercial demonstration unit. The coproduct stream that would normally feed into the crystallization and granulation processes was collected and transported offsite for this process step during CDU operation. Because crystallization and granulation of ammonium sulfate from an ammonia scrubber solution is not a new technological process, this was not considered a technical feasibility deficiency. For instance, the Dakota Gasification Company (DGC) in Beulah, ND currently operates an SO_2 scrubber utilizing ammonia as a reagent. Following the generation of ammonium sulfate, DGC crystallizes and granulates a fertilizer product on site. However, at MRY Station, considerable costs would be incurred for interim storage and shipment of the ECO® process scrubber's liquid bleedstream until sufficient experience has identified and eliminated potential failures and repairs for the crystallization and granulation equipment should it prove to be unreliable.

- Size of the barrier reactor: Powerspan recently indicated that they would scale the reactor for optimum cost and space arrangement based upon lessons learned from the CDU plant operation. The number of individual passages within a barrier reactor sized for either of MRY Station boilers' maximum flue gas flow and gas stream constituents is expected to require a cross-sectional area comparable to half of a large electrostatic precipitator. Although this has not been closely examined for all aspects of design, construction, operation and maintenance, the amount of physical space required to hold the barrier reactor and inlet and outlet ductwork is believed to not be available for potential retrofit to MRY Station units. Site space constraints are considered to be a barrier to technical feasibility for potential application of the ECO® process at Milton R. Young Station for Unit 1 and Unit 2's boilers.

- Additional station auxiliary power consumption: The barrier reactor, plus the ammonia scrubber and wet electrostatic precipitator additions by an ECO™ system, require an increase in station auxiliary power consumption. For NO_X control, this includes more horsepower required by the booster fan needed to compensate for the flue gas pressure drop created across the barrier reactor. It also includes the power consumed by the electrodes of the barrier reactor itself.

Because of the technical feasibility issues and lack of commercial availability and full-scale experience, especially on such high fouling coals, the ECO® system was considered technically infeasible as a BACT alternative for Milton R. Young Station for Unit 2's boiler.

A.1.4 "Layered" NOx Reduction Technologies

Many of the NO_X emission reduction technologies which involve furnace or convection pass areas for their introduction into the flue gas stream have been, or can potentially be, applied in combinations so as to result in an overall higher level of removal. Separated overfire air, various types of fuel reburn, and various forms of SNCR could potentially be combined in series to reduce NO_X emissions prior to boiler's flue gas exit. However, all the possible NO_X control technology combinations have not been installed on coal-fired powerplants, so actual feasibility of some combinations have not been demonstrated as viable, particularly in consideration of the special challenges posed by cyclone boilers firing lignite coal.

A.1.4.1 SOFA Combined With Other NO_X Reduction Technologies

Separated Overfire Air can be favorably combined with every other method in order to reduce the amount of reagent or reburn fuel required to achieve the resulting level of NO_X emission reduction. Some control technologies, especially conventional fuel reburn systems, require overfire air to complete the combustion of the staged fuel admitted to the upper furnace. Fuel lean gas reburn can be applied with or without SOFA, as this limited amount of staged fuel is introduced into an oxygen-rich atmosphere downstream of the cyclone burners and any overfire air injection points.

A.1.4.1.1 SOFA with SNCR

Selective non catalytic reduction technologies are post-combustion, in-furnace NO_X control alternatives that have been installed in numerous boilers of various designs, fuel types, with and without overfire air. It is usually advantageous to apply overfire air so that the amount of chemical reagent consumption can be minimized in order to achieve the targeted NO_X emission rate from the boiler outlet.

Tests at Conectiv's B.L England Station (Units 1 and 2) demonstrated that SNCR can decrease NO_X emissions as much as 31% at full load, from 0.55 to 0.38 lb/mmBtu, over and above the reduction possible from overfire air alone (approximately 60% drop, from 1.3 to 1.4 down to 0.55) in full operation. This is an overall NO_X emission reduction of 72% from pre-retrofit baseline[24].

SNCR can be applied alone or combined with either the basic or the advanced forms of separated overfire air (ASOFA) on MRY Station boilers. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction is an optional part of this technique. However, as previously explained in the discussion of SOFA alternatives, this will risk slag "freezing" in the barrels and lower furnace. Estimated NO_X emission rates for using SNCR techniques with North Dakota lignite considered published levels achieved by cyclone-fired units firing western subbituminous coal, and vendor estimates. SNCR with ASOFA is expected to reduce NO_X emissions approximately 32.6% below NO_X levels predicted for ASOFA operation, and potentially 58% overall from current baseline level for the MRY Station Unit 2 boiler with ammonia slip limited to approximately 5 ppmvd. This highest performing basic SNCR system is potentially able to achieve a NO_X emission rate of 0.330 lb/mmBtu, when combined with the advanced form of SOFA on MRY Station Units 2 boiler during operation at the pre-control baseline (near MCR load). These levels of NO_X reduction depend on the advanced form of separated overfire air technique to achieve the expected NO_X reduction percentages when applied to lignite-fired cyclone boilers.

Another form of SNCR is combined with separated overfire air. This is currently being marketed commercially as "Rotating Mixing" (Rotamix). In the United States' utilities industry, this has only been applied to pulverized coal-fired boilers. It is different than basic SNCR in that it includes a hot air booster fan and a small ambient air fan, and injects the ammonia (or urea) reagent into the high-pressure overfire air flow stream ahead of the ROFA nozzles' outlets. This mixture is imparted into the boiler in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. This vendor (Mobotec USA) claims that Rotamix (rotating opposed fire air or ROFA + SNCR) helps to distribute the reagent across the furnace cross section, which maximizes in-furnace NOx reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon. Three tangentially-fired utility boilers burning eastern bituminous coal or Illinois bituminous coal were retrofitted with Rotamix, each achieving a NO_X reduction of approximately zero to 55 percent beyond the levels produced by ROFA alone, from pre-SNCR baselines of 0.22 to 0.28 lb/mmBtu down to 0.10 to 0.23 lb/mmBtu without low-NO_X burners[4,32,33,34].

While this variation of SNCR combined with separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Since cyclone boilers do not require the addition of hot air booster fans for SOFA, and optimum injection locations for both SOFA and SNCR reagent may not coincide, Rotamix may not perform as well as, or significantly better than, a well-designed combination of conventional SOFA and SNCR. This technique is not distinct enough from basic SNCR from functional and air-staged cyclone NO_X reduction performance standpoints to warrant individual consideration for Milton R. Young Station boilers. Because of a lack of cyclone-fired boiler experience with ROFA and Rotamix, the latter was considered infeasible and thus was not included in the control effectiveness and cost-effectiveness sections of the main report.

A.1.4.1.2 SOFA with RRI

Rich Reagent Injection must be used in an oxygen-deprived atmosphere in order to effectively reduce nitrogen oxide emissions. This requires air-staged cyclones and separated overfire air operation.
The NO_X emission reduction reagent injection for RRI processes must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) simulations are needed to determine the optimum injection points. Boiler operating conditions will change with unit load and varying fuel characteristics. The RRI process control systems must be able to adjust for these changing conditions.

RRI has the potential to provide a moderate degree of NO_X reduction on coal-fired boilers. Data from B.L. England and Sioux plants show this technology can reduce NO_X emissions between zero and 39 percent beyond the amount attributable to overfire air system operation[23,24,25,26,27]. During initial demonstration testing of RRI at Ameren's Sioux Unit 1 boiler, a 500 MW unit firing a blend of PRB and midwestern bituminous coals (without SNCR), with SOFA in August 2001 at a lower furnace SR of approximately 0.99, NO_X emissions were reduced approximately 55% to 0.55 lb/mmBtu w/ SOFA only, with zero to 15% additional NO_X reduction from RRI (down to 0.47 lb/mmBtu) with zero ammonia slip[25]. Results of this initial RRI testing at Sioux plant were poor at cyclone stoichiometric ratios close to 0.99 because inconsistent, sporadic, and non-repeatable NO_X emissions reductions between zero and 15% were measured. Subsequent RRI testing at Sioux Unit 1 in March 2002 with SOFA at an average cyclone stoichiometric ratio around 0.95 showed NO_X emissions reduction of 29 percent (down to 0.27 lb/mmBtu) beyond those achieved with a modest amount of cyclone air-staging with SOFA (68% drop down to 0.38 lb/mmBtu from SOFA alone), for an 80% overall decrease from uncontrolled baseline; RRI CFD model predictions for these conditions were NO_X emissions reduction of 31% with FGR and 37% without FGR operation. Tested NO_X emissions with RRI+SOFA in 2002 were with a reagent normalized stoichiometric ratio (NSR) of 3 (lbs NH_3 per lb NO_X)[25].

Parametric testing at Sioux Unit 1 in May 2005 reduced NO_X emissions between 15-38% with RRI, down to 0.15 to 0.20 lb/mmBtu. Reagent NSR between 1.0 and 4.0 and low ammonia slip levels less than 2 ppm from an established baseline condition of 0.20 to 0.285 lb/mmBtu level achieved NO_X emissions as low as 0.12 lb/mmBtu with deep cyclone air-staging and SOFA operation firing an 80:20 PRB/Illinois coal blend at 480 MWg unit output[27].

The intent of the RRI process for NO_X reduction is that it must be used in conjunction with air-starved (substoichiometric staged-air) cyclone combustion resulting from the installation and operation of an OFA system, with or without SNCR. The cyclones' air/fuel stoichiometry must be carefully controlled to maintain fuel-rich conditions for the RRI process to be effective. The combustion gases in the vicinity of the RRI urea injection ports must be essentially devoid of free oxygen, in order to avoid oxidizing the nitrogen contained in the injected reagent, which will increase NO_X emissions. For lignite-fired cyclone boilers, the basic form of separated overfire air (without relocated lignite drying system vent ports) is incompatible with RRI. Reagent injection will be near the elevation of the existing lignite drying system vent ports in the lower front and rear walls of a lignite-fired cyclone boiler located immediately above the top rows of cyclones. These vent ports are located concurrently with the existing flue gas recirculation (FGR) ports on Unit 2's boiler. The oxygen introduced with the lignite drying system's vented moisture-laden airstreams will cause the urea to be oxidized, creating NO_X emissions.

The advanced form of SOFA relocates these lignite drying system vent ports from the lower to the middle furnace, enhancing the desired in-furnace nitrogen oxides reduction process. Therefore, in order for RRI to be even moderately effective in reducing NO_X emissions from a lignite-fired cyclone boiler, this technology must be combined with an advanced form of separated overfire air, whether installed with or without SNCR.

As mentioned in the feasibility discussion of applying separated overfire air to lignite-fired cyclone boilers, the degree to which each and every individual cyclone furnace can be successfully operated with less than theoretical (substoichiometric) combustion air directly impacts potential NO_X formation and further in-furnace emission reduction. Because the heat content of lignite from the Center mine is not consistent from hour to hour, there can be substantial deviations in air/fuel ratios for individual cyclones from the overall average.

In the case of MRY Station boilers, Minnkota has simultaneously sampled the unprepared lignite feed to several cyclones' lignite drying systems in order to determine the variability in the combustible and ash components of North Dakota lignite. This investigation found that fuel quality variations can result in individual samples' heating values to have a maximum differential of over 12% of the lignite samples' average.

TABLE A1-1 – Lignite Heating Values and Variations for Milton R. Young Station Unit 2

M.R. Young Station Individual Cyclone Lignite Samples		Differences Between Individual Cyclone Lignite Samples	
Higher Heating Values, Btu/lb	Percentage of Average HHV	HHV Differential, Btu/lb	Percentage of Average HHV
Minimum HHV: 5,852	88.9%	Minimum : 4	0.06%
Maximum HHV: 7,101	1.08%	Maximum : 797	12.1%
Average HHV: 6,584	100%	Average: 165	2.51%

When operating with air-staged conditions associated with separated overfire air, any individual cyclone with lignite heat input lower than average can allow significant amounts of oxygen to oxidize the urea reagent at high temperatures, thus increasing NOx emissions in that zone at that time. Cyclones with lignite heat inputs higher than average would produce lower stoichiometric air/fuel ratios and less NOx emissions. Less complete combustion in the deeply staged cyclones may release insufficient amounts of heat, thus raising the risk of solidifying the fuel ash so that it accumulates within the cyclone barrel. This could result in firing auxiliary fuel oil or taking the boiler out-of-service to remove the pluggage. Neither of these conditions is desirable because they result in increased emissions, lower performance, and higher operating costs.

The MRY Station Unit 2 boiler's cyclone air/fuel ratios vary in real-time based on significant changes in combustible content on an individual cyclone by cyclone basis. Adjustment of individual cyclone combustion air inputs to compensate for the variability in individual cyclone lignite heat input rates for Unit 2's boiler would be necessary to maintain consistent substoichiometric operation of every cyclone during air-staged combustion. This places great emphasis on achieving tight control over the air/fuel ratios on each cyclone during air-staged combustion operation in order for ASOFA to be successful in producing significant additional NOx emissions reduction on lignite-fired cyclone boilers.

There is no equipment available for coal-fired boilers that can measure the fuel heat input at the prepared feed injection point on such a variable fuel to allow the determination of reasonably accurate air/fuel ratios on individual cyclones in real time. Without being able to measure the cyclone air and heat inputs to allow for control of air/fuel proportions and emissions, the stoichiometric ratios of individual cyclones can not be established accurately to produce combustion products essentially devoid of free oxygen. This requirement is especially necessary when employing RRI to avoid increasing, rather than reducing, NO_X emissions on the Milton R. Young Station Unit 2 boiler.

Flue gas recirculation in MRY Station Unit 2 boiler's lower furnace could increase NO_X emissions by admitting oxygen-bearing flue gas in the vicinity of the injected urea if RRI were applied with basic or advanced forms of SOFA. To avoid this negative impact, FGR in the lower furnace would need to be discontinued. There is uncertainty whether modification or elimination of the use of FGR in the lower furnace of MRY Station's Unit 2 boiler could be successful in controlling lower furnace wall fireside ash deposition and gas temperatures.

Because of the significant insurmountable problems discussed above which would increase NO_X emission rates, RRI is considered technically infeasible for application on the Unit 2 cyclone boiler at the Milton R. Young Station.

A.1.4.1.3 SOFA with RRI and SNCR

When RRI is combined with separated overfire air and SNCR, it has demonstrated very high NO_X emissions reduction at Conectiv's B.L. England Unit 1 boiler during short-term testing firing eastern bituminous coal, on the order of 80% from an uncontrolled baseline around 1.2 lb/mmBtu[24]. In May 2005, testing RRI+SNCR+SOFA at Ameren's Sioux Unit 1 boiler firing a high PRB-blend coal demonstrated NO_X emissions as low as 0.12 lb/mmBtu. This was from an established baseline condition of 0.20 lb/mmBtu level achieved with deep cyclone air-staging and SOFA operation. These testing results when firing an 80%:20% PRB/Illinois coal blend at 480 MWg unit output with a reagent NSR of 4 and ammonia slip limited to less than 5 ppmvd, showed an overall 90% reduction with no apparent adverse short-term impacts of deeper air-staged combustion together with overfire air, RRI and SNCR applications[27].

Because of the significant insurmountable problems regarding RRI as mentioned above, RRI with SNCR and ASOFA is considered technically infeasible for application on the Unit 2 cyclone boiler at the Milton R. Young Station due to the variable heat content of the lignite fuel which allows the creation of oxygen-rich conditions in the boiler.

A.1.4.2 SNCR and Reburn

SNCR could potentially be installed downstream of separated overfire air and various types of fuel reburn, to reduce NO_X emissions prior to a boiler's flue gas exit. Several of these examples were already described[7,8,9,10,11,1213,14]. Conventional gas (CGR) or coal reburn systems, by and large, have not been combined with forms of SNCR, although at least one vendor (GE Energy) has promoted a combination of conventional gas reburn with SNCR and overfire air systems as "advanced" gas reburn. Only one example of permanent installation of SNCR with conventional gas reburn (and overfire air) on a tangentially-fired boiler was found in available technical literature[10] and vendor experience lists[14]. The vendor (GE Energy) that provided the advanced gas reburn system at 120 MW NRG Somerset Station claimed NO_X emissions were reduced by 44% from a baseline of 0.45 down to 0.25 lb/mmBtu with overfire air alone; an additional reduction of 20% resulting from conventional gas reburn with overfire air, down to 0.20 lb/mmBtu; and further decrease of 45% down to 0.11 lb/mmBtu using gas reburn with SNCR with an unstated amount of ammonia slip, for an overall reduction of 75% from uncontrolled baseline[14].

No examples of actual demonstration or permanent installation of SNCR with conventional gas or coal reburn (and overfire air) on cyclone-fired boilers were found in a search of published and proprietary technical literature. The lack of experience with these combinations on a cyclone-fired boiler, especially for lignite-firing, makes the application for MRY Station's boilers infeasible.

FLGR™ has been installed with SNCR for NO_X emission reduction on several pulverized coal boilers, as discussed in the following subsection. A potential advantage of FLGR™ over conventional coal or gas reburn techniques is that the former is generally compatible with, but does not require, the installation and operation of SOFA.

Rich Reagent Injection would appear to be less capable of being combined with fuel reburn, especially conventional fuel reburn alternatives with high amounts of reburn fuel injection. This is due to the expected need to idle (e.g. not fire) up to four of the twelve cyclones when operating the reburn system at full boiler load. In this case, the cooling air introduced into the idle cyclones, and any conveying air injected with pulverized reburn coal (or if natural gas is injected with recirculated flue gas), are expected to counteract the fuel-rich conditions of the air-and fuel-staged cyclones operating substoichiometrically. This will cause a portion of the amine reagent to be oxidized in the lower furnace, creating NO_X emissions instead of converting them to nitrogen and water. No example of actual demonstration or permanent installation of RRI with reburn (and overfire air) on cyclone-fired boilers was found in available technical literature or vendor experience lists. This combination is considered infeasible due to the location of injection and variable heat content of the lignite reburn fuel which allows the creation of oxygen-rich conditions in vicinity of RRI injectors in the lower furnace of Unit 2's boiler.

Hydrocarbon-enhanced SNCR (e.g. NO_XStar™) may potentially be combined with all types and forms of reburn previously discussed, since the location of the enhanced ammonia injection nozzles will be above (beyond) the elevation in the middle furnace where any reburn fuel should be reacted. No example of actual demonstration or permanent installation of HE-SNCR with reburn (and overfire air) on any coal-fired utility boilers, especially cyclone-fired units, was found in available technical literature or vendor experience lists. The advantage that HE-SNCR presents is the potential for greater-than-SNCR-levels of NOx reduction without significant amounts of gaseous hydrocarbon being required. Because of a lack of experience with HE SNCR applied to cyclone boilers, and none with significant amounts of fuel reburn, this combination has not been investigated further, and was not included in the control and cost-effectiveness analysis for NO_X controls.

A.1.4.2.1 Amine-Enhanced FLGR™ (AEFLGR™) or FLGR™ + SNCR

Fuel-lean gas reburn has been combined with SNCR as a hybrid form of amine reagent technologies on at least five pulverized coal-fired utility powerplants retrofit installations within the United States. This combination of technologies allows the boiler to be operated with FLGR™ alone, FLGR™ and SNCR simultaneously, or SNCR only (without SOFA) for the specific level of control desired or required.

No examples of actual demonstration or permanent installation of FLGR™ + SNCR (with or without overfire air) applied to a cyclone-fired boiler were found in available technical literature or vendor experience lists. The vendor (Fuel Tech) that provided the AEFLGR™ system at Mercer Station claimed NO_X emissions were reduced by 60% (from a baseline of 1.4 down to 0.56 lb/mmBtu) with 5 ppm ammonia slip without overfire air. A technical paper provides more details[18]. Another technical paper stated that FLGR™ alone only reduced NO_X emissions approximately 27% from the 1.4 lb/mmBtu baseline, down to 1.03 lb/mmBtu[35].

An AEFLGR™ system (with or without SOFA or ASOFA) may be potentially applied to a cyclone-fired boiler. The high capital and operating costs associated with applying fuel lean gas reburn is expected to make this economically unattractive, and the existing lignite pre-drying vent ports will likely limit the NO_X emission reduction potential of the FLGR™ component if installed without the advanced form of SOFA. The lack of experience with this combination on any cyclone-fired boiler, especially for lignite-firing, makes this combination infeasible for MRY Station Unit 2 boiler.

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A.2.1 - U.S. Cyclone NOx Reduction Projects Summary

SELECTIVE NON-CATALYTIC REDUCTION/ RICH REAGENT INJECTION

Cyclone-Fired Boilers

Conectiv (formerly Atlantic Electric)
BL England Unit 1 Crushed Coal, single-wall cyclone-fired 1962 vintage
138 MW B&W boiler aqueous urea SNCR, 1995 startup eastern bituminous coal
Boiler has only 3 cyclone burners, arranged “1 over 2” style.
RJM implemented commercial Fuel Tech urea-based SNCR system installation in 1995 after short-term (3-month demonstration test) in 1993-1994. 31 % NOx reduction claimed, from 1.31 lb/mmBtu NOx baseline(1) for SNCR only; RJM claimed 35% reduction from 1.31 lb/mmBtu down to 0.85 lb/mmBtu (without overfire air) with urea-to-NOx NSR = 0.85 (RJM experience list).

Added eight temporary RRI ports (three nozzles on each lower sidewall, and two nozzles on the upper rear wall, and performed one month demonstration parametric testing of overfire air only (without SNCR or RRI), at 120 MW nominal boiler load and cyclone S.R. = 0.90 in 1999. REI claimed 55% NOx reduction from a 1.2 lb/mmBtu uncontrolled NOx baseline to 0.55 lb/mmBtu with OFA only, with stack CO emissions below 50 ppm. For Rich Reagent Injection; REI claimed 25-30% NOx reduction for RRI down to 0.38 lb/mmBtu from controlled baseline w/ OFA alone of 0.55 lb/mmBtu NOx and a RRI urea-to-NOx NSR = 2; also showed RRI+SNCR w/ OFA reduced NOx 55% to 0.25 lb/mmBtu (34% beyond RRI w/ OFA), for an overall 79% NOx reduction with a SNCR urea-to-NOx NSR = 1. Measured less than 1 ppm ammonia slip during RRI testing, < 5 ppm slip for RRI + SNCR. No significant increase in CO emissions during RRI testing(2).
Source: (1) ICAC White Paper; RJM experience list; (2) REI 2001 Technical Paper.

Conectiv (formerly Atlantic Electric)
BL England Unit 2 Crushed Coal, cyclone-fired, single-wall-fired 1964 vintage
160 MW B&W boiler SNCR, 1996 startup eastern bituminous coal
RJM implemented commercial Fuel Tech urea-based SNCR system in 1996, claimed 36% reduction from 1.36 lb/mmBtu down to 0.85 lb/mmBtu, urea-to-NOx NSR = 0.85 (without overfire air) (1).
An OFA system was added in 1998, resulting in NOx emissions of 0.33 lb/mmBtu, for an overall NOx reduction of 76%.
Source: RJM experience list. (Also listed in (1) ICAC White Paper).

AmerenUE (formerly Union Electric Co.)
Sioux Unit 1 Crushed Coal, opposed-wall cyclone-fired 1969 vintage
500 MW B&W boiler Rich Reagent Injection demonstration testing in 2001
Boiler has 10 cyclone burners, arranged “2 over 3” style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel.

Installed twenty temporary RRI ports (six nozzles on each lower sidewall, and four nozzles on each front and rear wall), and performed one month demonstration parametric testing of overfire air only and initial testing with RRI in August 2001, followed by additional testing in March 2002, and the second quarter of 2004. Added 8 RRI ports (1 in each sidewall, 4 in each front and rear wall) and 14 SNCR ports (5 on upper front wall, 9 on upper rear wall) to the furnace in early 2005, followed by three weeks of parametric testing and 3 days of continuous testing of RRI with SNCR and deeper-staged OFA.
Tested in August 2001 at lower furnace SR approx.=1.0, 0.55 lb/mmBtu w/ OFA only, only 15% NOx reduction w/ RRI, zero ammonia slip.

Tested in March 2002 at lower furnace SR approx.=0.95, from 0.38 lb/mmBtu baseline w/ OFA only, achieved 29% NOx reduction w/ RRI down to 0.27 lb/mmBtu, NSR=3, zero ammonia slip(3).
(assume blend of PRB and Illinois bituminous coal w/ tire-derived fuel and petroleum coke)(3).
Operation in the second quarter 2004 showed actual stack NOx averaged around of 0.30 lb/mmBtu with OFA only and lower furnace at a cyclone SR around 0.88 burning a 85% PRB, 15% Illinois #6 bituminous coal blend, presumably at 440 MW. This is a 75% NOx reduction from a 1.19 lb/mmBtu pre-control baseline. REI using CFD modeling predicted NOx down to 0.18 lb/mmBtu with RRI+OFA, and below 0.15 with RRI+SNCR under similar deep cyclone air-staging (1.19 to 0.28 lb/mmBtu is 76% reduction, 0.18 vs 0.28 is an additional 36% reduction w/ RRI, and 0.14 vs 0.28 is a 50% reduction w/ RRI+SNCR, for an overall reduction of 88%)(4).
Tested in May 2005 at 480 MWg with lower furnace SR approx. = 0.85-0.88, 76-83% reduction from 1.2 lb/mmBtu baseline down to as low as 0.20 lb/mmBtu w/ SOFA only firing 80% PRB, 20% Illinois #6 bituminous coal blend; additional 15-39% NOx reduction w/ RRI, to as low as 0.15 lb/mmBtu from 0.20-0.28 lb/mmBtu baseline w/ SOFA only at urea NSR varied between 1 and 4, with one ppm ammonia slip; achieved additional NOx reduction w/ RRI +SNCR down to 0.12 lb/mmBtu, NSR=4, ammonia slip10 ppm or less. RRI+SNCR w/ SOFA NOx reduction percentage varied from 15% to 50% below SOFA-only levels, with NSRs between 1 and 4.5. SNCR alone had 13% (NSR=1) to 32% (NSR=1) NOx reduction with ammonia slip around 1-2 ppm*.
Source: (3) REI 2002 and 2003 Technical Papers; (4) REI 2004 Technical paper;* REI 2005 Technical paper.

REBURN – GAS, CONVENTIONAL

Cyclone-Fired Boilers

Constellation Energy (formerly Baltimore Gas & Electric)
C.P. Crane Station, Units 1 & 2 (MD)   Crushed Coal, cyclone-fired, eastern bituminous coal
2 x 200 MW B&W boilers   (four cyclones each)   1961, 1963 vintage
GE-EER Conventional Gas Reburn, 1999 startup
Added gas supply piping, metering, hangers, supports; reburn injectors and cooling air ductwork, OFA ductwork, injection nozzles and wall ports, field (assume eastern bituminous coal)
GE-EER claimed Gas Reburn with OFA lowered NOx between 60% and 65% from baselines of 1.50 lb/mmBtu to between 0.60 and 0.52 lb/mmBtu, at full load with reburn operation. No claims of percent reburn fuel or percent OFA included in GE-EER's experience list.
Another technical paper showed this installation of CGR operated with 25 percent reburn fuel(5).
Source: Sept. 2005 GE-EER experience list; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

City Water, Light & Power
Lakeside Unit 7   Crushed Coal, front-wall cyclone-fired, midwestern bituminous coal
300,000 lb/hr steam B&W boiler (approx. 33 MWe equivalent, two cyclones)   1961 vintage
Springfield, IL   DOE Clean Coal demonstration project (included sorbent injection)
GE-EER conventional gas reburn w/ OFA   1992 startup (CGR not currently operating)
Vendor claimed to lower NOx by 66% from 0.95 lb/mmBtu baseline to 0.32 lb/mmBtu. A GE-EER 2004 technical paper showed 25% reburn fuel yielded minimum NOx emissions(6).
A DOE NETL technical paper showed this demonstration of CGR from 5/93-10/94 (assume with OFA) with 23 percent reburn fuel reduced NOx 60% from 0.97 to 0.39 lb/mmBtu (5).
Source: Sept. 2005 GE-EER experience list; (6) GE-EER 2004 Technical paper; (5) DOE-NETL 2004 Reburn Conference Technical paper.

Eastman Kodak Company
Kodak Park Boilers 41 & 42   Crushed Coal, front-wall cyclone-fired, 1964 & 1966 vintage

400,000 lb/hr steam B&W boilers (approx. 50 MWe equivalent, two 8-ft dia. cyclones)
Rochester, NY eastern bituminous coal
B&W conventional gas reburn w/ OFA December 1998, July 1998 startups (still operating)
Commercial installation of CGR, with (1) gas burner added to each sidewall + (2) large and (2) small OFA ports added to front wall above cyclones, utilizing higher reburn gas pressure (vs. Boiler #43) requires no flue gas recirculation; {Very small furnace w/ cyclone SR not <1.0}.
B&W claimed reburn with OFA lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. B&W graph shows 10-12% percent reburn fuel to achieve 0.6 lb/mmBtu and 23-24% reburn gas input to reach 0.33 lb/mmBtu NOx (73% reduction) (7).
Another technical paper showed NOx lowered by 52% from 1.25 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel(5).
Source: (7) B&W Technical Paper; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL

Cyclone-Fired Boilers, continued

Eastman Kodak Company
Kodak Park Boiler 43 Crushed Coal, front-wall cyclone-fired 1968 vintage
600,000 lb/hr steam B&W boiler (approx. 60 MWe equivalent, two cyclones)
Rochester, NY eastern bituminous coal
B&W conventional gas reburn 1995 startup (still operating)
Commercial installation of CGR, with flue gas recirculation (FGR) for injection mass momentum w/ (1) FGR fan; (1) gas burner added to each sidewall + (2) OFA ports added front wall above cyclones. {Very small furnace/low residence time w/ cyclone SR not <1.0}
B&W claimed reburn with OFA & FGR lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. B&W graph shows 18% percent reburn fuel to achieve 0.6 lb/mmBtu and 29% reburn gas input to reach 0.36 lb/mmBtu NOx (70% reduction) (7).
Another technical paper showed NOx lowered by 56% from 1.35 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel(5).
Source: (7) B&W Technical Paper; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Tennessee Valley Authority (TVA)
Allen Station Unit 1 (TN) Crushed Coal, cyclone-fired (seven cyclones) 1959 vintage
300 MW B&W boiler PRB &western bituminous coal blend fired
GE-EER Conventional Gas Reburn, 1998 startup
Commercial installation added gas supply piping, metering, hangers, supports; reburn injectors and cooling air piping, OFA ductwork, injection nozzles and wall ports, field I&C devices.
Reburn with OFA claimed to lower NOx 65% from baseline 1.20 lb/mmBtu to 0.42 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included. (TVA also installed duplicate OFA systems on Allen Units 2 & 3 boilers).
Another technical paper showed NOx lowered by 65% from 0.86 lb/mmBtu baseline (to 0.30 lb/mmBtu) with 7 percent reburn fuel(5).
Source: Sept. 2005 GE-EER experience list; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, CONVENTIONAL

Cyclone-Fired Boilers

Alliant Energy (formerly Wisconsin Power & Light)
Nelson Dewey Station Unit 2 Crushed Coal, cyclone-fired, PRB coal 1962 vintage

110 MW B&W boiler 3-cyclones across front wall, 4 reburn burners +
4 OFA ports across rear wall, aligned vertically in columns.

US DOE Clean Coal Demonstration project of B&W's Conventional Coal Reburn, 1991 startup (since discontinued) added coal supply piping, reburn burners with flue gas recirculation, OFA ductwork + dual zone ports; coal feeder, pulverizer & PA fan, tested with PRB and bituminous coals. (western subbituminous coal)

B&W claimed reburn operation lowered NOx by 57% from baseline of 0.83 mmBtu to 0.38 lb/mmBtu at full load(7). Approx. 30% percent of total fuel input supplied as reburn fuel. Increased unit output by 10 MW, increased flyash unburned carbon by 4% (13-22% vs 9-18%), decreased furnace exit gas temperature (FEGT). OFA ports listed in B&W experience list.

B&W shows full load NOx w/o reburn was 0.75 lb/mmBtu, and 0.29-0.32 lb/mmBtu w/ PRB fuel during reburn operation (57% decrease). At 75% load, 0.64 vs 0.29-0.32 lb/mmBtu. At 55% load, 0.62 vs 0.29-0.31 lb/mmBtu without and with reburn activated(8).

Another technical paper showed NOx lowered by 52-55% from 0.82 lb/mmBtu baseline (to 0.39-0.34 lb/mmBtu) with 25-30 percent reburn fuel(5).

Source: (7) 2004 B&W Technical Paper; (5) DOE-NETL 2004 Reburn Conference Technical paper;
(8) B&W case history (from website, dated 1997).

REBURN – COAL, MICRONIZED, CONVENTIONAL

Cyclone-Fired Boilers

Eastman Kodak Company
Kodak Park #15 Boiler Crushed Coal, front-wall cyclone-fired, 1956 vintage
400,000 lb/hr steam B&W boiler (approx. 50 MWe equivalent, two cyclones)
Rochester, NY eastern bituminous coal
GE-EER micronized coal reburn1996 initial startup (operating since 1997)

Demonstration project performed with Dept. of Energy's US Clean Coal Technology Program. Project added flue gas recirculation for injection mass momentum, FGR fan and two micronized coal pulverizers; (6) reburn coal injectors added to rear wall + (1) reburn coal injector on each of the sidewalls, with (4) OFA ports added across front wall above cyclones(9). GE-EER designed and fabricated the coal injectors and OFA ports. {Extremely small furnace and low residence time}.

GE-EER claimed reburn + OFA w/ FGR reduced NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. No claims of percent reburn fuel included.

Another technical paper showed this demonstration of micronized coal reburn from 4/97-10/98 lowered NOx by 57% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 17 percent reburn fuel(5).

Source: (9) DOE Topical Report Number 14 (May 1999); GE-EER experience list;(5) DOE-NETL 2004 Reburn Conference Technical paper.

REBURN – FUEL LEAN GAS REBURN

Cyclone-Fired Boilers

Midwest Generation (formerly Commonwealth Edison)
Joliet Station 9, Unit 6 Crushed Coal, opposed-wall cyclone-fired (nine cyclones)
340 MW B&W boiler 1959 vintage, 1997 startup (FLGR has since been decommissioned)

Energy Systems Associates demonstrated 25-30% NOx reduction using 5-10% of total heat input as reburn natural gas injected (without OFA)(5).

Another technical paper showed this demonstration in collaboration with Gas Research Institute of FLGR lowered NOx by 28-43% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 7 percent reburn fuel(10).

Source: (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference);
(10) NGB Technologies Technical Paper.

REBURN – FUEL LEAN GAS REBURN w/ SNCR continued

Cyclone-Fired Boilers

Owensboro Municipal Utilities (KY) Crushed Coal, front-wall cyclone-fired
Elmer Smith Unit 1 (three cyclones) 1965 vintage
150 MW B&W boiler

CFD model study only predicted NOx reductions from 1.59 to 0.39 lb/mmBtu with OFA only (75% reduction, 0.90 SR); 25-30% NOx reduction using 6% of total heat input as reburn natural gas injected above OFA; 40-45% NOx reduction from SNCR with <5 ppm ammonia slip(11).
Source: (11) REI Technical paper.

Separated OVERFIRE AIR

Cyclone-Fired Boilers

Tennessee Valley Authority (TVA) Crushed Coal, cyclone-fired, 1959 vintage
Allen Station Units 2 & 3 (TN) (seven cyclones)
300 MW B&W boilers PRB &western bituminous coal blend
GE-EER Overfire air (duplicate of Allen 1), 1999 startup
GE-EER claimed to lower NOx with OFA alone up to 29% from baseline 1.20 lb/mmBtu to 0.85 lb/mmBtu on Units #2 and 3 at full load.
Source: Sept. 2005 GE-EER experience list.

AmerenUE (formerly Union Electric Co.)
Sioux Unit 1 Crushed Coal, opposed-wall cyclone-fired 1969 vintage
500 MW B&W boiler PRB/Illinois Coal blend
Boiler has 10 cyclone burners, arranged "2 over 3" style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel.
A ten-port OFA system (five ports on each front and rear wall) began operation in mid-2001, which reduced NOx emissions approx. 40-50% reduction from 1.1-1.3 (assume average of 1.19) down to 0.7 lb/mmBtu with moderate cyclone air-staging (cyclone SR from 1.19 to 1.0). (3) Subsequent testing and full load operation at deeper cyclone air-staging (SRs ≤ 0.90) has dropped NO$_X$ with SOFA alone to around 0.3 lb/mmBtu in 2004(4).
Source: (3) REI 2002 and 2003 Technical Papers; (4) REI 2004 Technical paper;* REI 2005 Technical paper

Coal burning cyclone-fired utility boilers in the United States that have been retrofitted with Separated Overfire Air CR technology are listed in Table A.2-1. A large majority of the cyclone-fired boilers listed burn western subbituminous coal (or PRB blended with midwestern bituminous coal).

TABLE A.2-1 – Cyclone-Fired Boiler Overfire Air Retrofit Installations(12)

Facility Name	Installation Date	Comments
Allen Station Units 1	Installed 1998*	OFA w/ CGR retrofit; has SCR
Allen Station Unit 2	Installed 1999*	(Similar to Unit 1, w/o CGR) have SCR
Allen Station Unit 3	Installed 1999*	(Similar to Unit 1, w/o CGR) have SCR
Asbury Unit 1	Installed 5/10/1999	Empire District, BART-eligible
Bailly Unit 7	Installed 2003(13)	SCR to be installed in 2006-7
Bailly Unit 8	Installed 5/31/2000	SCR retrofit 5/11/2004
Baldwin Unit 1	Installed 12/31/1999	SCR retrofit 4/28/2003
Baldwin Unit 2	Installed 5/8/2000	SCR retrofit 4/12/2002
Big Stone Unit 1	Installed 10/22/1997	part of conversion to PRB
BL England Unit 2	Installed 1998*	previous SNCR retrofit in 1996
CP Crane Unit 2	Installed 2/1/1999	OFA w/ CGR retrofit
Coffeen Unit 1	Installed 2/1/2001	SCR retrofit 4/21/2003
Coffeen Unit 2	Installed 2/9/2000	SCR retrofit 4/09/2002
Edgewater Unit 3	Installed 11/2001(13)	
Edgewater Unit 4	Installed 6/19/2001	
Joliet 9 Unit 6	Installed 2000(13)	
Kincaid Unit 1	Installed 4/28/2000	SCR retrofit 12/17/2002
Kincaid Unit 2	Installed 5/24/2000	SCR retrofit 6/07/2002
Allen S. King Unit 1	Installed 11/30/1999	
LaCygne Unit 1	Installed 2/28/2000	
Lake Road Unit 6	Installed 6/01/2002	
Michigan City Unit 12	Installed 4/1998(13)	SCR retrofit 5/01/2003
Nelson Dewey Unit 1	Installed 2002(13)	
Nelson Dewey Unit 2	Installed 2002(13)	
Paradise Unit 1	Installed 11/14/1998	SCR retrofit 5/01/2001
Paradise Unit 2	Installed 12/8/1999	SCR retrofit 5/01/2000
Paradise Unit 3	Installed 5/4/2000	SCR retrofit 3/10/2004
Powerton Unit 5-1	Installed 6/1/2003	
Powerton Unit 5-2	Installed 6/1/2003	
Powerton Unit 6-1	Installed 6/1/2002	
Powerton Unit 6-2	Installed 5/4/1999	
Schahfer Unit 14	Installed early 2000(13)	SCR retrofit 5/11/2004
Sibley Unit 2	Installed 5/24/2002	
Sibley Unit 3	Installed 5/4/1999	
Sioux Unit 1	Installed 4/30/2001	SNCR demo May 2005
Sioux Unit 2	Installed 4/30/1997	
State Line Unit 4	Installed 11/2001(13)	Similar to Joliet 9 Unit 6
Tanners Creek Unit 4	Installed 5/12/2002	
Thomas Hill Unit 1	Installed June 2004(13)	
Thomas Hill Unit 2	Installed November 2000(13)	

Note: This table does not include every installed U.S. coal-fired cyclone boiler OFA retrofit project.
Source: (12) US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005 (except as noted below)
* Vendor experience list (GE Energy for Allen Station Units 1-3; RJM for BL England Unit 2)
(13) Burns & McDonnell internal database.

Coal burning cyclone-fired utility boilers in the United States that have been retrofitted with SCR technology are listed in Table A.2-2. This list includes at least eighteen cyclone-fired boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). The highest emission reductions listed in Table A.2-2 for SCR systems are for clean reactor catalyst and ideal operating conditions.

TABLE A.2-2 – Cyclone-Fired Boiler High-Dust SCR Installations

Facility[1]	**Unit Size[2],MW**	**Tested Control Efficiency[3]**	**Tested Outlet NO_X Emission Rate (lb/mmBtu)[3]**	**2003 Ozone Season Average NO_X Emission Rate[4] (lb/mmBtu)**
Allen 1, 2, & 3[5,6]	330 ea.	91.1/NAD[7]/88.7	0.070/NAD[7]/0.088	0.088/0.077/0.086
Baldwin 1[5,6]	600[3]	82.9	0.072	0.238
Baldwin 2[5,6]	605[3]	83.5	0.067	0.286
Bailly 8[5,6]	422	NAD[7]	NAD[7]	0.84
Coffeen 1[5,6]	389	NAD[7]	NAD[7]	0.114
Coffeen 2[5,6]	617	NAD[7]	NAD[7]	0.120
Dallman 31 & 32	207	NAD[6]	NAD[6]	0.149/0.146
Kincaid 1 & 2[5,6]	660[3] ea.	89/89	0.079/0.079	0.181/1.198
Marion 4	173	94.3	0.067	0.252
Merrimack 1[5,8]	114	50.5[9]	0.148	0.158
Merrimack 2	346	51.3[9]	0.155	0.171
Michigan City 12[5,10]	540	84.2	0.109	0.418
New Madrid 1 & 2[8,10]	600 ea.	87.4/88.1	0.149/0.147	0.319/1.172
Paradise 1 & 2[5,6]	704 ea.	87.7/87.7	0.102/0.101	0.124/0.113
Paradise 3[5,6]	1150	89.1	0.088	0.658
Schahfer 14[5,10]	540	83.5	0.106	0.478

[1] – original design fuel for all listed cyclone boilers was bituminous coal
[2] – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.
[3] – Burns & McDonnell internal database.
[4] – as reported to US EPA, available from their website at http://cfpub.epa.gov/gdm/index.cfm
[5] – includes application of separated overfire air for combustion NO_X control
[6] – current fuel believed to be a blend of subbituminous and bituminous coals
[7] – NAD = no published data from SCR emission testing found on these units.
[8] – original air preheaters were tubular-type; changed to rotary-type during SCR retrofit
[9] – Design NO_X removal efficiency is higher, approx. 90%.
[10] – current fuel believed to be subbituminous coal

For Merrimack Unit 1's SCR, inlet (i.e. uncontrolled) NO_X was 1.34 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. The catalyst was designed for 88.9% NO_X removal efficiency and 5 ppm ammonia slip. SCR commercial service date July 20, 1999. [(14) Babcock Borsig Power 2000 technical paper on SCRs].

For Merrimack Unit 2's SCR, inlet (i.e. uncontrolled) NO_X was 2.66 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. Initial testing demonstrated 70% removal(15), which exceeded the 65% requirement to achieve a 0.92 lb/mmBtu permit limit. The catalyst was designed for 85-95% NO_X removal efficiency and 5 ppm ammonia slip(16).

(15)NETL-DOE Clean Coal Technology 1997 technical paper on SCRs; (16) 1997 ICAC White Paper on SCRs.

Northern Indiana Public Service Company (NIPSCO)
Bailly Unit 8 Crushed Coal, cyclone-fired, opposed-wall-fired 1968 vintage
360 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2004 startup
Boiler fires a blend of 85% western subbituminous (PRB) coal, with Illinois bituminous coal.
Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 2000(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

Northern Indiana Public Service Company (NIPSCO)
Michigan City Unit 12 Crushed Coal, cyclone-fired, opposed-wall-fired 1974 vintage
520 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2003 startup
Boiler fires western subbituminous (PRB) coal.
Commercial Fuel Tech urea-based system installed in 2003 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 1998(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

Northern Indiana Public Service Company (NIPSCO)
Schahfer Unit 14 Crushed Coal, cyclone-fired, opposed-wall-fired 1975 vintage
520 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2004 startup
Boiler fires western subbituminous (PRB) coal.
Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 2000(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

TABLE A-3 – Low-Dust Pulverized Coal-Fired Boiler SCR Installations

Operator/Facility[1,2]	SCR Startup Date[3]	Average NO_X Emission Rates[4] (lb/mmBtu)	Unit Size[5], MW
AEP/Cardinal Unit 3[6]	5/01/03	0.74 / 0.34 / 0.135	650
Carolina P&L/Mayo Unit 1[7]		- / (0.36) / N/A	368 x 2
Carolina P&L/Roxboro Unit 4[7,8]	5/07/01	0.57 / 0.26 / 0.081	372 x 2
Cinergy/East Bend Unit 1	4/01/02	- / (0.28) / 0.067	648
Constellation/Brandon Shores Unit 1[8]	(2001)	0.47 /0.33 / 0.126	685
Constellation/Brandon Shores Unit 2[8]	(2000)	0.45 / 0.31 / 0.094	685
Dayton P&L/Killen Station Unit 2	11/01/03	- / (0.48) / 0.06[9]	666
Dynegy Midwest Gen/Havana Unit 6[10]	(2000)	0.46 /0.20 / 0.102[9]	488
PSEG Power LLC / Mercer Unit 1[11]	(2005)	- / (0.63) / N/A	320
PSEG Power LLC / Mercer Unit 2[11]	(2004)	- / (0.76) / N/A	320

[1] – Burns & McDonnell internal database.

[2] – Current fuel is eastern or midwestern bituminous coal, except Havana

[3] – US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, except where noted. Dates in () are believed to be accurate but have not been confirmed.

[4] – The three values are "Pre-control average", "2004 annual average", and "2003 ozone season average" NO_X emission rates, as reported to US EPA. Pre-control and year 2004 annual average data as shown in US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b. Values shown in parentheses are year 2003 annual average where 2004 data is not available. Year 2003 and 2003 ozone season data is available from the EPA's website at http://cfpub.epa.gov/gdm/index.cfm, includes application of separated overfire air for combustion NO_X control where applicable.

[5] – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.

[6] – This boiler has low-NOx burners for combustion controls.

[7] – Carolina Power & Light plants listed here have two boilers per unit, total nameplate for Mayo is 736 MW, Roxboro is 745 MW; emission numbers are the average of both boilers.

[8] – This boiler has low-NOx burners and overfire air for combustion controls.

[9] – This is preliminary data reported to the US EPA for 2004 ozone season average emission rate.

[10] – This boiler's current fuel is believed to be subbituminous coal.

[11] – Mercer boilers listed have low-dust SCR with flue gas reheat. Unit size is approximate, not nameplate.

N/A = complete 2004 ozone season data is not available, and 2003 ozone season data is not representative of the post-SCR installation emission rate.

SELECTIVE NON-CATALYTIC REDUCTION

Pulverized coal-fired boilers

American Electric Power (AEP) Pulverized Coal, cell-burner, opposed wall-fired B&W boiler
Cardinal Unit 1 1967 vintage; Low NO_x burners installed in October 1998
600 MW (nominal) Brilliant, Ohio
Fuel Tech urea-based SNCR installed in October 1998.
Fuel Tech, DOE, EPRI-member utilities SNCR demonstration project. Tested in March-April 1999, claimed 65% reduction with LNBs + SNCR w/ 5 ppm NH_3 slip, (from pre-LNB retrofit baseline of 1.20 lb/mmBtu*) down to 0.52 lb/mmBtu at 620 MW (100% MCR). SNCR reduced NO_X 31% below LNBs alone (0.75 lb/mmBtu baseline), at 620 MWg (100% MCR), 34% reduction at 75% MCR (450 MWg), and 42% reduction at minimum load (340 MWg, 55% MCR) ≤ 5% ammonia slip(17), burning eastern bituminous coal. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005; (1)ICAC White Paper, (17) 2000 Fuel Tech technical paper, *Riley Power (Babcock Power Inc.) experience list 8/16/04.

Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 SNCR startup
Fuel Tech commercial SNCR installation claimed 25% NOx reduction from low-NO_X burner w/o OFA baseline of 0.58 lb/mmBtu (down to 0.44 lb/mmBtu on SNCR alone). Urea-to-NOx NSR not stated. (Also see FLGR + SNCR installation summaries for pulverized coal boilers).
Source: Fuel Tech experience list dated 1/28/2005.

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 5 1956 vintage; eastern bituminous coal
154 MW CE boiler SNCR startup in 2002
Mobotec USA “Rotamix” ammonia-based SNCR system injects aqueous ammonia liquid into a high velocity boosted separated overfire air (ROFA) system at the boiler.
CP&L technical paper claimed to lower NO_X from 0.28 lb/mmBtu baseline by 43% to 0.16 lb/mmBtu in 2002 with 5 ppm NH_3 slip following the installation of ROFA in 2000.
Overall reduction 73% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.16 lb/mmBtu(18).
Mobotec claimed further NO_X reduction was possible by injecting urea in place of ammonia, achieving 0.13 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 54% decrease from 0.28 lb/mmBtu with ROFA alone, or 78% overall decrease(19). Ammonia-to-NOx NSR not stated.
Source: (18) CP&L 2002 Technical paper; (19) Mobotec 2003 technical paper.

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 6 twin-furnace (eight corner), 1958 vintage; eastern bituminous coal
175 MW CE boiler SNCR startup in 2001
Mobotec USA “Rotamix” ammonia-based SNCR system, injects aqueous ammonia liquid into a high velocity boosted separated overfire air (“ROFA”) system at the boiler.
CP&L technical paper claimed to lower NO_X from 0.23 lb/mmBtu baseline by 22% to 0.18 lb/mmBtu with 5 ppm NH_3 slip following the installation of ROFA+SNCR in 2001(18). Presentation slide graph shows no reduction for Rotamix beyond ROFA alone at full load NO_X emission rate of 0.23 lb/mmBtu. Ammonia-to-NOx NSR not stated.
Overall reduction 67% from full-load pre-ROFA baseline 0.54 lb/mmBtu to 0.18 lb/mmBtu.
Mobotec claimed further NO_X reduction was possible by injecting urea in place of ammonia, achieving 0.10 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 56% decrease from 0.23 lb/mmBtu with ROFA alone, or 81% overall decrease(19). Urea-to-NOx NSR not stated.
Source: (18) CP&L 2002 Technical paper; (19) Mobotec 2003 technical paper.

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Cinergy (formerly Cincinnati G&E) Pulverized Coal, Tangentially-fired,
Miami Fort Unit 6 (Ohio) 1960 vintage; startup prior to 2000
163 MW CE boiler
Fuel Tech urea-based SNCR system, claimed to lower NOx by 35% from 0.55 lb/mmBtu baseline(1).(assume eastern bituminous coal). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, (1) ICAC White Paper.

Conectiv (formerly Delmarva Power & Light)
Edgemoor Unit 3 Pulverized Coal, Tangentially-fired, 1954 vintage
84 MW CE boiler mid-March 1996 startup; (assume eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR system. HRC claimed 35% NOx reduction with less than 10 ppm ammonia slip. Urea-to-NOx NSR not stated.
Another source shows a 30% reduction from 0.54 lb/mmBtu baseline(1).
Source: Hamon experience list (not listed by Fuel Tech); (1) ICAC White Paper.

Conectiv (formerly Delmarva Power & Light) Pulverized Coal
Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage
B&W, DB Riley boilers Spring 2000 startup (eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR system (not listed by Fuel Tech) on both units. HRC claimed 35% NO_X reduction with less than 5 ppm ammonia slip. Urea-to-NOx NSR not stated.
An REI 1999 technical paper shows a pre-SNCR baseline of 0.37 and 0.44 lb/mmBtu, respectively. (20)
Another source listed these units as having a pre-control NO_X baseline of 0.97 and 0.57 lb/mmBtu, and 2004 post-SNCR startup average of 0.32 and 0.33 lb/mmBtu, respectively. (12)
Source: Hamon experience list (not listed by Fuel Tech); (20) REI 1999 technical paper;
(12) US EPA Docket OAR-2002-0076-0446 Excel Spreadsheet 6/15/2005.

Dominion Generation (Virginia E&P Co.) Pulverized Coal, Tangentially-fired
Clover Station, Units 1 & 2 (VA) ABB/CE boilers, 1995, 1996 vintage
2 x 465 MW (eastern bituminous coal)
Urea-based SNCR (Fuel Tech system) 1995, 1996 startup (initial commercial)
Fuel Tech claimed NOx reduced by 25% from 0.32 lb/mmBtu baseline (to 0.24 lb/mmBtu).
Source: Fuel Tech experience list dated 1/28/2005. Urea-to-NOx NSR not stated.

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Vermillion Station, Unit 1 1955 vintage
82 MW CE boiler, bituminous Illinois coal
Mobotec USA "Rotamix" urea-based SNCR system with rotating opposed fired air (ROFA).
Mobotec 2004 technical paper claimed to lower NO_X by 55% from 0.22 lb/mmBtu baseline to 0.10 lb/mmBtu in April 2004 with urea-based Rotamix SNCR and < 5 ppm CO. NH_3 slip not mentioned. Overall reduction 83% from full-load pre-ROFA baseline 0.58 lb/mmBtu to 0.10 lb/mmBtu (21). Urea-to-NOx NSR not stated.
Source: (21) Mobotec 2004 technical paper.

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Eastern Utilities Associates, Pulverized Coal, Tangentially-fired
Montaup Electric Company 1959 vintage
Somerset Unit 8 (Massachusetts) Summer 1995 startup
112 MW CE boiler (eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR (Fuel Tech system), claimed to lower NOx below 0.38 lb/mmBtu (Mass. RACT). Urea-to-NOx NSR not stated.
Another source listed 28-60% NOx reduction from a 0.49-0.89 lb/mmBtu baseline(1).
Source: Hamon experience list, Fuel Tech experience list dated 1/28/2005, (1)ICAC White Paper.

First Energy Pulverized Coal, Tangentially-fired,
Eastlake Unit 3 (Ohio) 1954 vintage
130 MW CE boiler (w/ division wall) (eastern bituminous coal)
Urea-based SNCR (Fuel Tech system) SNCR startup prior to 2000
Fuel Tech claimed to lower NOx from 20-32.5% from 0.34-0.40 lb/mmBtu baseline(1). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, (1) ICAC White Paper.

First Energy Pulverized Coal, wall-fired,
Sammis Unit 2 (Ohio) 1960 vintage
180 MW Foster Wheeler boiler SNCR startup Fall 1999
Urea-based SNCR (Fuel Tech system) (eastern bituminous coal)
Fuel Tech claimed to lower NOx from 25-30% from 0.45 lb/mmBtu baseline (1). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, (1) ICAC White Paper.

First Energy Pulverized Coal, wall-fired,
Sammis Units 6 & 7 (Ohio) 1969 & 1971 vintage
680 MW B&W Universal Pressure boilers (eastern bituminous coal)
Urea-based SNCR (Fuel Tech system) SNCR startup after 1999
Fuel Tech claimed to lower NOx from 25% from 0.38 lb/mmBtu baseline. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005.

New England Power Company (NEPCO)
Salem Harbor Station Pulverized Coal, front wall-fired,
Units 1, 2 & 3 1952, 1952, 1958 vintage (eastern bit. coal)
84 MWe x 2, & 156 MWe B&W boilers SNCR startup prior to 2000
Urea-based SNCR (Fuel Tech system)
Fuel Tech claimed 66% (50-75%) NOx reduction from baseline of 1.0 ± 0.1 (range 0.85-1.12) lb/mmBtu, (which would lower NOx to around 0.34±0.07 lb/mmBtu). Urea-to-NOx NSR not stated. {These NOx reduction percentages may include impact of low-NOx burners}.
Source: Fuel Tech experience list dated 1/28/2005, (1)ICAC White Paper.
(Also see LNB installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)
Schiller Units 4, 5, & 6 Pulverized Coal/#6 Fuel oil, front-wall-fired
50 MWe x 3Foster Wheeler boilers 1952, 1955, 1957 vintage
Urea-based SNCR (Fuel Tech system) Colombian bituminous coal
August 1999 startup
RJM implemented Fuel Tech urea-based commercial SNCR installation on all three boilers.

RJM claimed 50% reduction from 0.50 lb/mmBtu pre-SNCR baseline to 0.25 lb/mmBtu for SNCR coal-firing operation; NO_X baseline 0.82 lb/mmBtu prior to RJM's LNB modifications installed in 1994, 1992, & 1994 (39% reduction); Urea-to-NOx NSR not stated.
Fuel Tech claimed 30% NO_X reduction for SNCR from baseline of 153 ppm firing #6 fuel oil on Units 4 & 6 only.
Source: RJM experience list, Fuel Tech experience list dated 1/28/2005.

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Owensboro Municipal Utilities (KY) Pulverized Coal, Tangentially-fired,
Elmer Smith Unit 2 1974 vintage
300 MW CE boiler eastern bituminous coal
Hamon Research-Cottrell supplied an ammonia-based SNCR system but stated no claims for NOx reduction; (this project is not listed in ICAC White Paper(1)). Ammonia-to-NOx NSR not stated.
Source: Hamon experience list.

PECO Energy (formerly Philadelphia Electric Company)
Cromby Unit 1 Pulverized Coal, front wall-fired divided furnace
160 MWe B&W boiler 1954 vintage eastern bituminous coal
RJM installed Fuel Tech urea-based SNCR with low NO_X burner modifications & OFA in 1999, June 1999 startup.
RJM claimed 29% SNCR NO_X reduction from baseline of 0.35 lb/mmBtu, down to 0.25 lb/mmBtu with urea NSR = 0.8; RJM provided burner modifications of B&W XCL low-NOx burners installed in 1994 + OFA; this reduced NO_X from 0.50 to 0.35 lb/mmBtu (30% reduction) without SNCR. Urea-to-NOx NSR not stated.
Source: RJM experience list; (1)ICAC White Paper.

Exelon (formerly PECO Energy/ Pennsylvania Electric Company)
Eddystone Units 1 & 2 Pulverized Coal Tangentially-fired, 1954 vintage
318, 333 MW each CE boilers 1999 SNCR startup, eastern bituminous coal
Fuel Tech claimed 30% NOx reduction from baseline of 0.26 lb/mmBtu.
Source: Fuel Tech experience list dated 1/28/2005.

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage
660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup
Fuel Tech urea-based commercial SNCR installation claimed 25% (initial) NOx reduction for SNCR alone from baseline of 0.65 lb/mmBtu (down to 0.49 lb/mmBtu). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, also listed in (1)ICAC White Paper. (Also see FLGR+SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]

Mercer Station	(2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired	
Unit 1 and Unit 2	front wall PC, wet-bottom (slagging ash) eastern bituminous coal	
Furnace #11 & #12	1960 vintage	April 1999 startup
Furnace #21 & 22	1961 vintage	May 1999 startup

Fuel Tech urea-based commercial SNCR installation claimed 30-35% NOx reduction from baseline of 2.0 lb/mmBtu on SNCR alone, down to 1.4 lb/mmBtu. Urea-to-NOx NSR not stated.

Source: Fuel Tech experience list dated 1/28/2005; also listed in (1)ICAC White Paper. (Also see FLGR+SNCR installation summaries for pulverized coal boilers)

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Reliant Energy (formerly GPU Genco)   Pulverized Coal
(formerly Sithe, formerly Penelec)   Tangentially-fired
Seward # 15 (PA)   mid-1990's SNCR startup
Units 4 & 5   eastern bituminous coal
62 & 156 MW CE boilers   1950 & 1957 vintage
Urea-based SNCR (Fuel Tech system), later installed an in-duct SCR to reduce NH_3 slip.
Fuel Tech claimed to lower NOx 35% for SNCR only (55% for combined SNCR/SCR from 0.78 lb/mmBtu baseline). Boilers have since been demolished and replaced with CFBs. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, (1)ICAC White Paper.

Rochester Gas & Electric   Pulverized Coal, Tangentially-fired
Russell Station, Units 1-4 (NY) 1948, 1950, 1953, 1957 vintage
1 x 50 MW, 2 x 65 MW, 1 x 85 MW CE boilers   eastern bituminous coal
Urea-based SNCR (Fuel Tech system)   SNCR startup prior to 2000
Vendor claimed to lower NOx by 15-27.5% from 0.28 – 0.42 lb/mmBtu baselines. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005.

HYDROCARBON-ENHANCED AMMONIA SNCR (NOxStar™)

Pulverized coal-fired boilers

Tennessee Valley Authority (TVA)   Pulverized Coal twin-furnace, tangentially-fired,
Kingston Power Station (TN)   1955 vintage   eastern bituminous coal
Unit 9, 200 MWe CE boiler   NOxStar™ startup January 2002
Demonstration of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR installation.
Mitsui Babcock claimed 68% NOx reduction from baseline of 0.55 lb/mmBtu down to 0.17 lb/mmBtu with boosted OFA and NOxStar™ with < 5 ppm ammonia slip; NOxStar™ alone reduced NOx by 53%(22); boosted OFA only reduced NOx from 0.55 to 0.45 lb/mmBtu (18% reduction). Ammonia-to-NOx NSR not stated.
TVA's website reported that "an earlier version of NOxStar was installed at Kingston Fossil Plant Unit 9 in 2002 with mixed results. NOx reductions were achieved, but the boiler was damaged" (http://www.tva.gov/environment/repotrs/envreports/aer/2003/env_compliance.htm)
Source: (22) Mitsui Babcock Technical paper, October 2003.

Tennessee Valley Authority (TVA)   Pulverized Coal, wall-fired
Colbert Station (AL)   1955 vintage
Unit 4, 192 MWe twin-furnace B&W boiler w/ FGR eastern bituminous coal
First commercial installation of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR technology.
Mitsui Babcock showed 80% NOx reduction from baseline of 0.50 to 0.10 lb/mmBtu; using < 0.1% of total boiler heat input for propane input and 1% of total steam flow generated in the boiler for lance cooling(23); 2004 SNCR system startup. Ammonia-to-NOx NSR not stated.
Source: (23) Mitsui Babcock 2004 Technical paper.

REBURN – GAS, CONVENTIONAL

Pulverized coal-fired boilers

Allegheny Power (formerly West Pennsylvania Power)
Hatfield's Ferry Station
Units 2 & 3, 600 MW (nominal) each (B&W boilers)

Pulverized Coal, opposed wall-fired
cell-burner, 1969 & 1972 vintage
eastern bituminous coal

GE-EER Gas Reburn; 1999 startup (Unit 2) & 2003 (Unit 3)
GE-EER Low NOx burners, boosted OFA, gas reburn system.
GE-EER claimed to lower NOx up to 67% from baseline of 0.60 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation on Unit 2, 68% from 0.62 lb/mmBtu to 0.20 lb/mmBtu on Unit 3. No claims of percent reburn fuel included.
GE-EER technical paper shows approx. 35% NOx reduction at 600 MW load with LNB + OFA w/o reburn fuel, and an additional 50% reduction to 0.20 lb/mmBtu with reburn fuel(24).
B&W added 20 OFA ports in 1994 per B&W's experience list. No NOx reduction claims. Source: Sept. 2005 GE-EER experience list; (24) GE-EER 2004 Technical paper. Unit 2 and Unit 3 listed in (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL continued

Pulverized coal-fired boilers)

Conectiv (formerly Delmarva Power & Light)
Edgemoor Unit 4
160 MW CE boiler

Pulverized Coal, Tangentially-fired
1966 vintage, eastern bituminous coal
1999 startup

GE-EER Gas Reburn project added gas supply piping, metering, hangers, supports, reburn injectors and cooling air piping; OFA ductwork, injection nozzles and wall ports, field instrumentation. No FGR or OFA booster fans.
Vendor claimed to lower NOx up to 48% from baseline of 0.32 lb/mmBtu to 0.16 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included.
GE-EER technical paper shows approx. 32% NOx reduction for gas reburn with 4-mill operation at 160 MW load from 0.31 lb/mmBtu LNB + OFA baseline w/o reburn fuel (down to 0.21 lb/mmBtu), and 48% NOx reduction for gas reburn with 3-mill operation, to 0.16 lb/mmBtu (24).
Source: Sept. 2005 GE-EER experience list; (24) GE-EER 2004 Technical paper. Listed in (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)

Dynegy (formerly Illinois Power)
Hennepin Unit 1
71 MW CE boiler

Pulverized Coal, Tangentially-fired
1966 vintage
eastern bituminous coal

GE-EER Gas Reburn, 1990 startup (not currently operating); GE-EER Orimulsion Reburn, 1997.
DOE Clean Coal demonstration project (included sorbent injection).
Vendor claimed gas reburn w/ OFA lowered NOx up to 67% from baseline of 0.75 lb/mmBtu to 0.25 lb/mmBtu) at full load; 65% reduction from baseline of 0.75 lb/mmBtu down to 0.26 lb/mmBtu with subsequent Orimulsion reburn operation.
GE-EER 2004 technical paper shows 18% gas reburn fuel yielded minimum NOx emissions(6).
Another technical paper showed this 80 MW US DOE Clean Coal demonstration project in January 1991-January 1993 lowered NOx by 67% from 0.75 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 18 percent reburn fuel(5).
Source: Sept. 2005 GE-EER experience list; (6) GE-EER 2004 Technical paper; (5) DOE-NETL 2004 Reburn Conference technical paper, and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see Conventional Oil reburn installation summaries for pulverized coal boilers).

REBURN – GAS, CONVENTIONAL continued

Pulverized coal-fired boilers)

AES (formerly New York State Gas & Electric (NYSEG)

Greenidge #6 (NY)	Pulverized Coal, Tangentially-fired,	1953 vintage
100 MW CE boiler	GE-EER Conventional Gas Reburn, 1996 startup	

Vendor claimed to lower NOx 55% from 0.63 lb/mmBtu baseline to 0.28 lb/mmBtu at full load with reburn operation burning eastern bituminous coal. Gas Research Institute predicted would achieve 76% (down to 0.15 lb/mmBtu) w/ advanced gas reburn.
GE-EER 2004 technical paper shows 23% reburn fuel yielded minimum NOx emissions around 0.23 lb/mmBtu(6).
EPA's "Scorecard on Reburning 6/1/2004" shows a 109 MW t-fired boiler (listed as Greenidge Unit 4) lowered NOx by 50% from 0.50 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 10 percent reburn fuel (no longer operating) (5).
Source: Sept. 2005 GE-EER experience list; (6) GE-EER 2004 Technical paper; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station	Pulverized Coal	opposed wall-fired B&W boilers
Units 1 & 2	1964, 1965 vintage	eastern bituminous coal
360 MW (nominal)	GE-EER Gas Reburn, 2000 startup	

Vendor claimed to lower NOx up to 43% and 45% from 0.60 lb/mmBtu baseline to 0.34 and 0.33 lb/mmBtu) at full load with reburn operation, respectively. No claims of percent reburn fuel included.
Source: 2002 GE-EER experience list. Listed in (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3	Pulverized coal, wall-fired, 1962 vintage
175 MW B&W boiler	western bituminous coal
DOE Clean Coal demonstration project	November 1992-January 1995

Gas reburn demonstration performed with Dept. of Energy and Gas Research Institute 1992-1995. Existing boiler with 16 burners was retrofitted with low NO_X burners and GE-EER gas reburn OFA, FGR, and reburn injectors. Added OFA booster fan, 800 hp flue gas recirculation fan for injection mass momentum, for increased gas injection mass momentum (which was subsequently removed). The CGR installation portion has since been decommissioned.
Vendor claimed to lower NOx up to 64% from baseline of 0.73 lb/mmBtu to 0.26 lb/mmBtu) at full load with reburn operation.
GE-EER 2004 technical paper shows 15-20% reburn fuel yielded minimum NOx emissions(6).
A 2004 DOE-NETL technical paper showed this project achieved 0.46 lb/mmBtu NO_X emissions with low NO_X burners alone (37% reduction), further reduced NO_X by 44% with 12.5 percent reburn fuel(5).
A 2001 DOE-NETL technical paper claimed a NOx reduction of 65% at an average reburn gas heat input of 18% of total boiler fuel input, with and without FGR. Demonstrated 70% NOx reduction at higher reburn input rates. Referred to technology as GR-LNB. FGR was added for gas injection momentum but was subsequently removed to reduce fuel input. (25)
Source: Sept. 2005 GE-EER experience list; (6) GE-EER 2004 Technical paper; (5) DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference); (25) DOE-NETL 2001 Technical paper; also in (9) DOE 1999 Topical Report Number 14.

REBURN – OIL, CONVENTIONAL

Pulverized coal-fired boilers

Dynegy (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Hennepin Unit 1 1966 vintage, eastern bituminous coal
71 MW CE boiler 1997 startup

GE-EER Orimulsion Reburn system w/ OFA, claimed orimulsion reburn lowered NOx up to 65% from baseline of 0.75 lb/mmBtu to 0.26 lb/mmBtu at full load with Orimulsion reburn operation (installed after gas reburn was demonstrated in early 1990's). No claims for percent reburn fuel included.

GE-EER 2004 technical paper shows 60% reduction with subsequent Orimulsion reburn (6).

Source: GE-EER experience list; (6) GE-EER 2004 Technical paper. Orimulsion not mentioned in (5) DOE-NETL 2004 Reburn Conference technical paper or DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

New Brunswick Power
Coleson Cove, Bunker C/Orimulsion–fired, opposed-wall
St. John, New Brunswick, Canada
3x 350 MW B&W Boilers

Sixteen new low-NO_X oil/Orimulsion burners, eight reburn burners, nine SOFA ports, two combustion air booster fans, reburn and OFA wall penetration openings, OFA windboxes, ductwork, dampers, and accessories were added(7).

Another technical paper showed this reburn system lowered NOx by 78% from 1.0 lb/mmBtu baseline to 0.22 lb/mmBtu at 25 percent reburn fuel input(5).

Source: (7) B&W 2004 Technical Paper;(5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Georgia Power Pulverized Coal, Tangentially-fired
Scherer Unit 1 1982 vintage
887 MW CE boiler 2000 oil reburn startup

GE-EER Oil Reburn system, claimed to lower NOx from baseline of 0.36 lb/mmBtu.

GE-EER 2004 Technical paper shows reduction up to 48% (to 0.19 lb/mmBtu) at 800 MW load with oil reburn operation. No claims of percent reburn fuel included(24).

Source: Sept. 2005 GE-EER experience list shows this as a coal reburn project with eastern bituminous coal, reducing NO_X emissions 33% from 0.36 to 0.24 lb/mmBtu;
(24) GE-EER 2004 Technical paper. Not listed in (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, MICRONIZED, CONVENTIONAL

Pulverized coal-fired boilers

AES (formerly New York State Electric and Gas Milliken Station Unit 1)
Cayuga tangentially-fired, pulverized coal, 1956 vintage
148 MWe, CE boiler eastern bituminous coal
GE-EER micronized coal reburn system 1996 startup (still operating)

US DOE Clean Coal demonstration project from March 1997-April 1999 lowered NOx with this reburn system by 29% from 0.35 lb/mmBtu baseline to 0.25 lb/mmBtu at 14 percent reburn fuel input(5). Not listed in GE-EER's experience list nor in their 2004 technical paper.

Source: (5) DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, MICRONIZED, CONVENTIONAL continued

Pulverized coal-fired boilers

E. ON US Holdings (formerly Louisville Gas and Electric)
R.D. Green Station Units 1 & 2 (KY)   wall-fired, pulverized coal, vintage unknown
293 MWe, 2 boilers   eastern bituminous coal
GE-EER coal reburn system   Startup dates: 2003 & 2002, respectively
Vendor claimed to lower NOx up to 57% from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation.
Reburn system listed on EPA's "Scorecard on Reburning 6/1/2004" shows NOx lowered by 44% from baseline of 0.45 lb/mmBtu down to 0.25 lb/mmBtu (with unknown reburn fuel input(5)).
Another technical paper showed baseline NOx with existing low-NOx burners was 0.45 lb/mmBtu, and reduced NOx emission 40% to 0.27 lb/mmBtu with OFA, and further reduced NOx emissions 22% down to 0.21 lb/mmBtu with the coal reburn system in operation[26].
Source: (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference);
(24) GE Energy 2004 Technical paper, and (26) March 2004 Modern Power Systems issue.

Cheng Loong (not in United States)
Unit #1, 250 MWe   wall-fired, bituminous pulverized coal, vintage & mfr unknown
GE-EER coal reburn system   2000 Startup (still operating)
Source: GE-EER experience list
Vendor claimed to lower NOx 44% from baseline 0.45 lb/mmBtu to 0.25 lb/mmBtu) at full load with OFA alone; further reduced NOx 28% to 0.18 lb/mmBtu, for 60% overall reduction. Recent (2004) data shows NOx down to 0.14 lb/mmBtu (69% overall) with up to 30 percent reburn fuel(24).
Source: (24) GE Energy 2004 Technical paper; GE-EER experience list. Listed in (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL w SNCR

Pulverized coal-fired boilers)

NRG Somerset   Pulverized Coal, Tangentially-fired,   vintage
Unit 6 Boiler 8 (NY)   GE-EER Conventional Gas Reburn,
120 MW CE boiler   Fuel Tech SNCR, 2003 startup
Reburn vendor claimed to lower NOx 55% from 0.45 lb/mmBtu baseline to 0.20 lb/mmBtu at full load with reburn operation burning Venezuelan coal. The SNCR system further reduced NOx emissions 45% down to 0.11 lb/mmBtu, for an overall reduction of 77%.(26).
Source: Sept. 2005 GE Energy experience list; (26) March 2004 Modern Power Systems issue.

REBURN – FUEL LEAN GAS REBURN (FLGR)

Pulverized coal-fired boilers

Duke Power Company   tangentially-fired, pulverized coal
Riverbend Unit 7   eastern bituminous coal   1954 vintage
140 MWe, CE boiler   1998 FLGR startup, gas reburn decommissioned since then
Previously installed ABB/CE's Low NOx Concentric Firing System (LNCFS-1) with Close-Coupled Overfire Air (CCOFA); (pre-mod NOx + combustion mods date not known).
Commercial FLGR installation claimed 34% NOx reduction from full-load baseline of 0.42 lb/mmBtu down to 0.29 lb/mmBtu w/ the combustion modifications and FLGR gas reburn fuel at 7% of total boiler heat input. CO emissions were above 1000 ppm corrected to 3% O_2.(27)
Vendor claimed to lower NOx 57% from 0.47 lb/mmBtu baseline to 0.20 lb/mmBtu) at full load with separated OFA alone; further reduced NOx 45% to 0.11 lb/mmBtu with low-NOx burners, OFA, gas reburn, and SNCR, for 77% overall reduction; no claims for amount of reburn fuel(24).

EPA's "Scorecard on Reburning 6/1/2004" showed this reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input(5).
Source: (27) ESA, GRI, NGB 1998 Technical paper; (24) GE Energy 2004 Technical paper; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – FUEL LEAN GAS REBURN (FLGR) continued
Pulverized coal-fired boilers
Wisconsin Electric Power Company (WEPCO)
Pleasant Prairie Unit 1 DB Riley, turbo-fired PC, Powder River Basin coal
620 MWg 1980 vintage 1999 startup
Fuel Tech listed FLGR installation and claimed 20% NOx reduction from baseline of 0.45 lb/mmBtu (to 0.36 lb/mmBtu). No claims of percent reburn fuel input included.
Source: Fuel Tech experience list dated 1/28/2005. (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see FLGR + SNCR installation summaries for pulverized coal boilers).

REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR)
Pulverized coal-fired boilers
Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 startup
Commercial urea-based Fuel Tech SNCR +FLGR installation claimed 50% NOx reduction from baseline of 0.58 lb/mmBtu (426 ppm) down to 0.29 lb./mmBtu w/ 5 ppm ammonia slip(1). Low NO_X burners were previously retrofitted in 1997 without separated overfire air(28). This is 33 % lower than 0.44 lb/mmBtu baseline for SNCR alone. (Also see SNCR installation summaries for pulverized coal boilers). Urea-to-NOx NSR not stated.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating(5).
Another technical paper showed 52% NOx reduction down to 0.28 lb/mmBtu at all loads, from 99 MWg to 207 MWg (48% to 100% MCR) with an average NH_3 slip of 3 ppm. FLGR alone achieved 23% NOx reduction with 6% reburn fuel and < 400 ppm CO at full load. (28)
Source: Fuel Tech experience list, (1)ICAC White Paper; (5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference); (28) CP&L and Fuel Tech 2001 Technical paper.
(Also see SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage
660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup
Commercial SNCR + FLGR urea-based Fuel Tech installation claimed 40% NOx reduction from baseline of 0.65 lb/mmBtu (down to 0.39 lb/mmBtu) w/ 10 ppm ammonia slip(1). This is 20 % lower than 0.49 lb/mmBtu baseline for SNCR alone. Urea-to-NOx NSR not stated.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating(5).
Source: Fuel Tech experience list, (1)ICAC White Paper;(5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).
(Also see SNCR installation summaries for pulverized coal boilers).

REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR) continued

Pulverized coal-fired boilers

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Mercer Station (2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired
Unit 1 and Unit 2 front wall PC, wet-bottom (slagging ash) eastern bituminous coal
Furnace #11 & #12 1960 vintage May 1999 startup
Furnace #21 & 22 1961 vintage May 1999 startup
Commercial urea-based Fuel Tech SNCR + FLGR installation claimed 60% NOx reduction from baseline of 1.4 lb/mmBtu (down to 0.56 lb/mmBtu) w/ 5 ppm ammonia slip (1). This is 72 % lower than 2.0 lb/mmBtu baseline without control. Initial demonstration of AEFLGR coinjected amine-enhanced natural gas into Furnace 22 in 1998. Subsequently installed AEFLGR on both units to reduce NOx starting in May 1999 using (2) levels of AEFLGR retractable gas injectors and (2) levels of SNCR injectors(29).
Urea-to-NOx NSR not stated, goal was NSR < 1.25.
{Note both units have since been retrofitted with low-dust tail-end SCRs in 2004; SNCR systems are still capable and operated as needed, mostly for flyash conditioning to aid ESP performance}
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 1999, but not currently operating(5).
Source: Fuel Tech experience list, (1)ICAC White Paper; (29) PSE&G, FT and ESA 2000 Technical paper;(5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Wisconsin Electric Power Company (WEPCO)
Pleasant Prairie Unit 1 DB Riley, turbo-fired PC, Powder River Basin coal
620 MWg 1980 vintage 1999 startup
Fuel Tech urea-based SNCR +FLGR demonstration installation claimed 56% NOx reduction from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu w/ 5 ppm ammonia slip(1). This is 44 % lower than 0.36 lb/mmBtu baseline for FLGR alone.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating(5).
Source: Fuel Tech experience list, (1)ICAC White Paper and F.T. experience list 0207;
(5) DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR

Pulverized coal-fired boilers

AEP Cardinal Unit 1 Pulverized Coal cell-burner, opposed wall-fired B&W boiler
600 MW (nominal) 1967 vintage; Low NO_x burners installed in October 1998
Produced 0.75 lb/mmBtu NOx post-LNB install baseline at full load.
LNBs reduced NO_X 57% from 1.20 down to 0.52*, produce NO_X at approx. 0.57 lb/mmBtu at min. load w/o SNCR (range 0.51 to 0.65) and produce 0.75 lb/mmBtu NO_X at approx. 585 MW (top of load range tested, NO_X range 0.73 to 0.86 lb/mmBtu) (17).
(50) original B&W circular burners were recently replaced on Cardinal Units 2 & 3 by Buckeye Power with DB Riley (now Babcock Power) CCV type low NOx burners.
Source: *Riley Power (Babcock Power Inc.) 8/16/04 experience list; (17) 2000 Fuel Tech technical paper.
(Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 startup
Low NO_X burners were previously retrofitted in 1997 without separated overfire air(22). NOx reduction was 46% from pre-LNB installation baseline of 1.08 lb/mmBtu (12) down to 0.58 lb./mmBtu (28).

(Also see SNCR, and FLGR with SNCR installation summaries for pulverized coal boilers).
Source: (12) 2005 US EPA Docket OAR-2002-0076-0446 Technical Support Document spreadsheet; (28) CP&L and Fuel Tech 2001 Technical paper.

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued
<u>Pulverized coal-fired boilers</u>

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 5 1956 vintage; eastern bituminous coal
154 MW CE boiler ROFA startup in 2000
Mobotec USA's Rotating Opposed Fire Air (ROFA) is a high velocity boosted separated overfire air system claimed to lower NO_X without retrofitting low-NOx burners. This was the first U.S. installation of Mobotec USA's "Rotating Opposed Fire Air" (ROFA) on a utility boiler, which utilizes a booster fan.
CP&L technical paper claimed to lower NO_X 53% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.28 lb/mmBtu with ROFA alone following the installation of ROFA in 2000(18).
Source: (18) CP&L 2002 Technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 6 twin-furnace (eight corner), 1958 vintage; eastern bituminous coal
175 MW CE boiler ROFA startup in 2001
This unit's "ROFA" system was installed as part of a "Rotamix" SNCR + ROFA system.
CP&L technical paper shows ROFA alone reduced NOx 57% from full-load pre-ROFA baseline 0.54 lb/mmBtu to a NO_X emission rate of 0.23 lb/mmBtu. (18)
Source: (18) CP&L 2002 Technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Conectiv (formerly Delmarva Power & Light)
Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage
B&W, DB Riley boilers eastern bituminous coal
REI performed CFD modeling on both units for potential SNCR application.
Unit 3 has Riley Low NOx burners (16), (8) front wall and (8) rear wall OFA ports, (8) wall boundary air ports, (66) side wall OFA slots, claimed baseline NOx around 0.37 lb/mmBtu w/o SNCR (20).
Unit 4 has (24) front and rear wall down-fired burners, (28) front and rear wall SOFA ports, claimed NOx around 0.44 lb/mmBtu w/o SNCR (20) {furnace has "Mae West" belt}.
Riley provided 16 CCV low-NOx burners for Unit 3 in 1994, and claimed to reduce NOx emissions by 67% from pre-LNB baseline of 1.05 lb/mmBtu down to 0.34 lb/mmBtu.
Source: (20)REI 1999 Technical Paper; Riley Power (Babcock Power Inc.) 8/16/04 experience list. (Also see SNCR installation summaries for pulverized coal boilers).

Dayton Power & Light Pulverized Coal, Tangentially-fired
Killen Station, Unit 2 1955 vintage
632 MW CE boiler, bituminous Illinois coal
GE-EER provided low-NOx burners in 1999. Vendor claimed full load NO_X was reduced by 23% from a 0.57 lb/mmBtu baseline down to 0.44 lb/mmBtu.
Source: GE-EER Experience list 2/1/02. (Also see low-dust SCR installation list for pulverized coal boilers)

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, wall-fired
Havana Station, Unit 6 1978 vintage
460 MW B&W boiler, bituminous Illinois coal
GE-EER provided modifications to the original B&W dual-register burners, and an OFA system in 2000. Vendor claimed full load NO_X was unchanged from 0.38 lb/mmBtu baseline.
Source: GE-EER Experience list 2/1/02. (Also see low-dust SCR installation list for pulverized coal boilers)

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Vermillion Station, Unit 1 1955 vintage
82 MW CE boiler, bituminous Illinois coal
This rotating opposed fire air (Mobotec USA ROFA) system was installed in July 2002, as part of a “Rotamix” SNCR + ROFA system, without low-NOx burners.
Mobotec 2004 technical paper claimed to lower full load NO_X by 62% from 0.58 lb/mmBtu baseline to 0.22 lb/mmBtu in July 2002 (without LNB or SNCR). (21)
Source: (21) Mobotec 2004 technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Georgia Power Pulverized coal, opposed wall-fired,
Harlee Branch Unit 1 250 MW B&W boiler, 1965 vintage 2003 startup
Harlee Branch Unit 2 359 MW Riley boiler, 1967 vintage 1998 startup
B&W provided 24 DRB-4Z low NOx burners for Unit 1 B&W boiler, 24 DRB-XCL low NOx burners for Unit 2 Riley boiler (believe southeast coast lignite is primary fuel).
Source: B&W’s experience list. No NOx reduction claims.

Kansas City Power & Light Pulverized coal, opposed wall-fired, 600 MW B&W boiler
Hawthorn Unit 5 30 burners, 2001 vintage, (Powder River Basin coal)
B&W provided 30 DRB-4Z low NOx burners and 11 OFA ports with the new boiler.
Source: B&W’s experience list. No NOx reduction claims.

New England Power Company (NEPCO)
Salem Harbor Station Pulverized Coal, front wall-fired,
Units 1, 2 & 3 1952, 1952, 1958 vintage (eastern bit. coal)
84 MWe x 2, & 156 MWe B&W boilers LNBs startup in 1995, 1995, and 1993
Riley claimed Unit 1 LNBs reduced NOx emissions by 57% from baseline of 1.10 lb/mmBtu down to 0.42 lb/mmBtu; Unit 2’s LNBs achieved 42% NOx reduction from a baseline of 0.95 lb/mmBtu down to 0.55 lb/mmBtu; Unit 3’s LNBs achieved 60% NOx reduction from a baseline of 1.05 lb/mmBtu down to 0.42 lb/mmBtu.
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list.
(Also see SNCR installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)
Shiller Station Pulverized Coal/#6 Fuel oil, front-wall-fired
Units 4, 5, & 6 1952, 1955, 1957 vintage
50 MWe x 3 Foster Wheeler boilers
RJM provided (6) Low NO_x burner modifications per boiler in 1994, 1992, & 1994 respectively;
LNBs reduced NOx 43% from 0.85 to 0.48, 50% from 1.0 to 0.50, and 51% from 0.82 to 0.40 lb/mmBtu.
Source: RJM experience list

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station	Pulverized Coal	opposed wall-fired
Units 1 & 2	1964, 1965 vintage	eastern bituminous coal
360 MW (nominal)	B&W boilers	

DB Riley (now Babcock Power) CCV type low NOx burners retrofitted in 1993 and 1994, respectively. Vendor claimed to lower NOx up to 52% and 50% from 1.35 and 1.40 lb/mmBtu baselines (to 0.65 and 0.70 lb/mmBtu, assumed at full load).
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list. (Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3	Pulverized coal, wall-fired, B&W boiler, 16 burners, 1962 vintage
175 MW	October 1992 baseline testing started (western bituminous coal)

Installed (16) Foster Wheeler Controlled Flow/Split Flame low NO_x replacement burners as part of a DOE Clean Coal Technology gas reburn demonstration performed with Gas Research Institute 1992-1995.
Uncontrolled NOx w/ original B&W flare-type burners was 0.73 lb/mmBtu. Replacement LNBs (assuming OFA included) reduced NO_X 37% to 0.46 lb/mmBtu(25).
Source: (25) DOE NETL 2001 Technical paper.

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APPENDIX B

EERC REPORT

Ash Impacts on SCR Catalyst Performance

ASH IMPACTS ON SCR CATALYST PERFORMANCE

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ASH IMPACTS ON SCR CATALYST PERFORMANCE

EXECUTIVE SUMMARY

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be plagued with problems. The Center lignite fired at the Milton R. Young (MRY) Power Station is highly variable in abundance of various types of ash/slag-forming components. Ash-forming components consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. The alkali and alkaline-earth elements combine with minerals during combustion, resulting in low-melting-point phases that cause a wide range of fireside deposition problems. In addition, the alkali and alkaline-earth elements also form very small particles that are carried into the backpasses of the combustion system and react with flue gas to form sulfates that can cause deposition, blinding, and plugging problems in selective catalytic reduction (SCR) systems. This report analyzes these problems, and concludes that SCR is not a feasible option to control NOx emissions at MRY Power Station because of the high sodium levels present in the coal.

Following is a list of the key problems that are associated with Center lignite which have not been overcome and, in our opinion, make the installation of SCR at the MRY plant technically infeasible for NO_x control.

➢ Blinding of Catalyst Pores by High Sodium Compounds

  X High levels of alkali and alkaline-earth elements present in the coal fired at the MRY plant produce small particles that react to form sulfates that blind the catalyst pores. The high levels of sodium in the coals combined with calcium will produce low-melting-point eutectic sulfate compounds that will form and melt inside the pores of the catalyst.
  - Alkali and alkaline earth sulfates are enhanced by cyclone fired system. The cyclone firing results in partitioning of the ash between bottom slag and the body of the boiler. The sulfate forming materials are more concentrated in the ash as a a result of cyclone firing.

  - Sulfate formation is enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.

  - The sulfate reactions are more severe at MRY because of the high temperature where an SCR would be installed. The higher temperature increases the rate of formation of sulfates and rate of pore plugging.

  - The testing conducted by the Germans found catalyst deactivation and blinding occurs when firing coals with lignite or brown coals that have ashes that are rich in alkali and alkaline-earth elements. .

- The findings by the Germans were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-rich sulfate formation that fill and plug the catalyst at both lignite- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or "popcorn ash," plugging the top of the SCR catalyst is a significant problem because of the extremely high deposition rates of the Center coal. When firing Center coal, deposits form on various parts of the boiler requiring continuous sootblowing. The sootblowing of upstream heat-exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, resulting in plugging. In addition, during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

- Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

➢ Cold Side SCR Installation

- High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces significant levels of homogeneously condensed sodium sulfate that pass through the ESP and wet scrubber.

- These small particles have been shown to pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials require sootblowing to remove the particulate and will result in increased opacity.

- Liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems are known to catalyze the formation of SO_3 from SO_2. The presence of SO_3 significantly enhances the formation of the pyrosulfates.

ASH IMPACTS ON SCR CATALYST PERFORMANCE

INTRODUCTION

Ash produced during combustion of coal in conventional power systems is a major problem that results in decreased efficiency, unscheduled outages, equipment failures, and increased cleaning. The many ways in which the detrimental effects of ash manifest themselves in a boiler system include fireside ash deposition on heat-transfer surfaces, corrosion and erosion of boiler parts, poor slag flow, and production of fine particulates that are difficult to collect. Decades of research have been conducted to develop a better understanding of the chemical and physical processes of ash formation and deposition in combustion systems. Overviews of ash-related issues and compilations of work by many investigators can be found by referring to the work of Mehta and Benson (1), Schobert (2), Baxter and DeSollar (3), Couch (4), Williamson and Wigley (5), Benson and others (6), Benson (7), Bryers and Vorres (8), Raask (9, 10), and Benson (11). This work has led to a detailed understanding of ash formation and behavior in combustion systems as well as the development of predictive methods (12, 13).

The chemical composition and physical characteristics of ash-forming or inorganic components (mineral and organically associated elements) of the fuel(s) fired have an influence on the following processes in the combustion systems:

- Firing conditions such as cyclone, pulverized coal, and low-NO_x burners
- Transformations of coal inorganic components to ash particulate and vapor-phase species
- Boiler design characteristics, including number of burners, radiant section area, tube bank spacing, access for cleaning, and number of sootblowers
- Ash transport to heat-transfer surfaces in utility boilers
- Erosion wear and sticking
- Ash deposit growth and impact on heat transfer
- Ash blinding and plugging of selective catalytic reduction (SCR) catalysts
- Ash deposit removability

The ash deposition in North Dakota lignite-fired power plants is a major problem that impacts all fireside surfaces of the power plant. The ash problems are due to the variable and complex nature of inorganic components associated with lignite coals (2). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. During the gas-cooling processes in the boiler, the gas-phase species condense and the liquid-phase materials solidify. The abundance of these gas-phase and liquid materials entrained in the bulk gas flow is highly dependent upon coal composition and system operating conditions. The inorganic materials are transported to heat-transfer and catalyst surfaces by diffusion, electrophoresis, thermophoresis,

and inertial impaction. The particle sticking and accumulation rates are dependent upon the quantity of ash and the abundance and viscosity of the liquid-phase components. In high-temperature regions of the boiler, high-temperature sodium–calcium–aluminosilicate liquid phases act as the sticky material, causing deposit initiation, growth, and development of deposit strength. As the temperature of the flue gases decreases, the condensation and reaction of flame-volatilized species play a more significant role in the formation of deposits from lignite coals. The formation of sodium and/or calcium magnesium sulfates dominates the deposit accumulation mechanisms at lower temperatures. The aluminosilicate phases are dominant above about 1800°F. Below about 1800°F, the sulfate phases become stable, with an optimum temperature of formation of about 1400°F, and can form at temperatures as low as 300°F.

The most significant problems that prohibit the successful operation of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates and phosphates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16).

INORGANIC COMPOSITION OF LOW-RANK COALS

Inorganic elements in coal occur as discrete minerals, organically associated cations, and cations dissolved in pore water. The fraction of inorganic components that are organically associated varies with coal rank. Lower-ranked subbituminous and lignitic coals have high levels of oxygen, which act as bonding sites for cations such as sodium, magnesium, calcium, potassium, strontium, and barium (other minor and trace elements may also be present in this form). In higher-ranked coals, bituminous and anthracite, inorganic components consist mainly of minerals. Mineral grains are usually the most abundant inorganic component in coal. The major mineral groups found in coals include silicates, aluminosilicates, carbonates, sulfides, sulfates, phosphates, and some oxides.

The behavior of ash produced during coal combustion is related to the abundance, size, and association of mineral grains in the coal. In addition, the association of the mineral grain with the coal matrix influences the temperature and gaseous environment the mineral is exposed to during combustion. A mineral associated with the organic part of a coal particle is said to be included. A mineral that is not associated with organic material is referred to as excluded. The behavior of the organically associated elements, those elements that are atomically dispersed in the coal matrix, must also be measured as to their abundance in the coal. The organically associated elements will react and interact with the other ash-forming constituents during combustion.

The Center lignite is highly variable in abundance of various types of ash/slag-forming constituents. Ash-forming components in the Center lignite are of two types. The first form may constitute up to 50% of the ash and is derived from inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix of the coal. The second type consists of mineral grains (sand, clay, limestone, and pyrite). The minerals are discrete particles of ash-forming species and the sources of silicon, aluminum, iron, titanium, and minor amounts of the calcium and potassium. The Center lignite fired at the Milton R. Young (MRY) plant has been examined extensively because of its problem with ash behavior. Analyses

of as-fired and drill core samples have been conducted. The mean and the range of selected components are shown in Figure 1. The results indicate that both the abundance of ash and the abundance of major oxides in the ash vary significantly. In addition, the abundance of alkali and alkaline-earth elements (Na and Ca) varied dramatically. Variations in Si were found to be the most significant. High levels of Ca and/or Na were found for lower-ash coals as compared to high levels of Al and Si associated with higher-ash coals (17, 18).

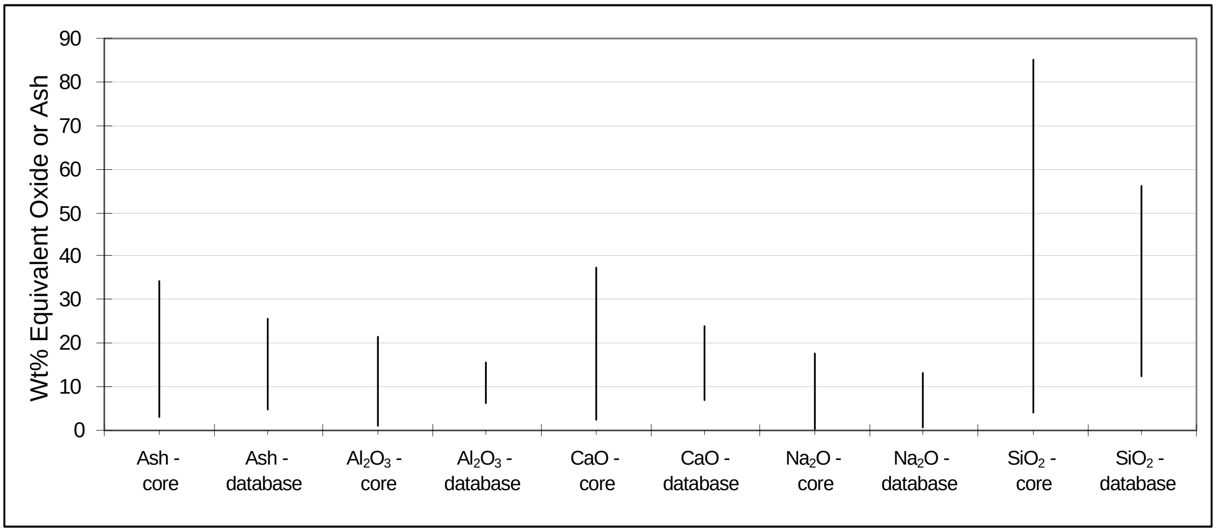


Figure 1. Variability of ash and selected constituents in core analysis database provided by BNI Coal, Ltd. and Minnkota as fired coal analysis database.

The variability of the ash-forming components has been examined for the approximately 5000 samples characterized to date. Wide variations in ash contents and the major ash-forming constituents are observed. During the mining processes, the inorganic components are mixed, and some of the extreme characteristics are diluted (17).

INORGANIC TRANSFORMATIONS AND ASH FORMATION

The inorganic coal components undergo complex chemical and physical transformations during combustion to produce intermediate ash species. The inorganic species consist of vapors, liquids, and solids. The partitioning of the inorganic components during combustion to form ash intermediates depends upon the association and chemical characteristics of the inorganic components, the physical characteristics of the coal particles, the physical characteristics of the coal minerals, and the combustion conditions.

The physical transformation of inorganic constituents depends on the inorganic composition of the coal and combustion conditions. The inorganic components can consist of organically associated cations, mineral grains that are included in coal particles, and excluded mineral grains. There is a wide range of combinations of mineral–mineral, mineral–coal,

mineral–cation–coal, and mineral–mineral–cation–coal associations in coal. These associations are unique to each coal sample.

The physical transformations involved in fly ash formation include 1) coalescence of individual mineral grains within a char particle, 2) shedding of the ash particles from the surface of the chars, 3) incomplete coalescence due to disintegration of the char, 4) convective transport of ash from the char surface during devolatilization, 5) fragmentation of the inorganic mineral particles, 6) formation of cenospheres, and 7) vaporization and subsequent condensation of the inorganic components upon gas cooling. As a result of these interactions, the ash has a bimodal size distribution. The submicron component is largely a result of the condensation of flame-volatilized inorganic components. The mass mean diameter of the larger particles is approximately 12 to 15 μm, depending upon the coal and combustion conditions. The larger-size particles have been called the residual ash by some investigators (19) because these ash particles resemble, to a limited degree, the original minerals in the coal. Processes such as ash mineral coalescence, partial coalescence, ash shedding, and char fragmentation during char combustion and mineral fragmentation, all play an important role in the size and composition of the final fly ash. Loehden and others (20) and Zygarlicke and others (21) indicate that three potential modes for fly ash generation can be used to describe fly ash particle-size and composition evolution. The first, "fine limit," assumes that each mineral grain forms a fly ash particle and that the organically associated elements form fly ash particles of less than 2 μm. The second, "total coalescence," assumes one fly ash particle forms per coal particle. The third, "partial coalescence," suggests that the fly ash composition and particle size evolve because of partial coalescence.

The transformations of excluded minerals are dependent upon the physical characteristics of the mineral. Excluded minerals such as quartz (SiO_2) can be carried through the combustion system with its angular structure still intact. Excluded clay minerals can fragment during dehydration, melt, and form cenospheres. The behavior of excluded pyrite depends upon its morphology. Some of the pyrite may be present as framboids. Framboidal pyrite may fragment more easily than massive pyrite particles. In addition, the decomposition of pyrite is very exothermic, and it transforms to pyrrhotite and oxidizes to FeO, Fe_3O_4, and Fe_2O_3 during combustion.

ASH DEPOSITION ON HEAT-TRANSFER AND OTHER SURFACES EXPOSED TO ASH AND FLUE GAS

The characteristics of a deposit depend upon the chemical and physical characteristics of the intermediate ash species, geometry of the system (gas flow patterns), gas temperature, gas composition, and gas velocity. Figure 2 illustrates the ash deposition phenomena in utility boilers. Ash particle accumulations occur via transport of particles to the fireside surfaces (heat transfer, ceramic materials, support materials, SCR catalysts, baghouse materials, and ESP wires and plates) and sticking of the particles. The transport mechanisms important for ash deposition include small-particle mechanisms for particles less than 10 μm that involve thermophoresis, electrophoresis, and vapor-phase and small-particle diffusion; and large-particle mechanisms for particles greater than 10 μm that involve inertial impaction. The ability of larger particles to stick depends upon the quantity and viscosity of the liquid phase on the particle surface.

Thermophoresis is a phenomenon that involves the transport of very small particles as a result of a thermal gradient from hot gases to cooler surfaces. Electrophoresis is the transport of particles because of a difference in charge. Vapor-phase and small-particle diffusion occurs in the boundary layer next to the surface and results in transport of ash to the surface. Inertial impaction is a larger-particle phenomenon where the particles are of a sufficient size and density to leave airflow patterns around the tube and impinge upon the surface of a tube or deposit. Deposits that form in high-temperature regions of the boiler, such as the radiant section, are called slag deposits. Deposits that form in lower-temperature regions of the boiler, such as in the convective pass on steam tubes and lower-temperature surfaces such as SCR catalysts, are called fouling deposits. Slag deposits are usually associated with a high level of liquid-phase components and are exposed to radiation from the flame. This is a description that many researchers use to aid in classification of deposits since some engineers call any type of deposit "slag". Slag deposits are typically dominated by silicate liquid phases, but may also contain moderate to high levels of reduced iron phases such as FeO and FeS. The liquid characteristics of the silicates are highly dependent upon the quantities of Na, Mg, Ca, K, and Fe ash on the silicates. In addition, the initiating layers of slag deposits may consist of very fine particulate and can produce a reflective ash layer. This phenomenon is especially evident when high organically associated calcium subbituminous coal is fired. These coals produce small CaO particles that usually form the initiating layers.

Fouling deposits form in the lower-temperature regions of the boilers and, in most cases, do not contain the high levels of liquid phases that are usually associated with slagging-type deposits. Fouling deposits contain lower levels of liquid phases as compared to slag deposits. The fouling deposit liquid phases usually consist mainly of sulfates that bind the particles together. Fouling deposits typically form as a result of the reaction of gas-phase sulfur oxide species with particles rich in alkali and alkaline-earth elements.

ASH-RELATED EXPERIENCES AT MRY FACILITY

The MRY is a minemouth electrical generating plant located near Center, North Dakota. The station consists of two units: Unit 1, rated at 276 MWg, began production in 1970; Unit 2, rated at 506 MWg, began production in 1977. Both Units 1 and 2 are equipped with B&W cyclone-fired boilers; the Unit 1 boiler has seven cyclones, and the Unit 2 boiler has twelve cyclones. Annual station gross generation is approximately 5.5 million MWh.

BNI Coal Ltd. is the sole coal supplier for the MRY Station. Coal is mined from the nearby Center mine, which consists of three distinct seams varying from 2½–9 feet thick. Coal is strip-mined using two draglines and is loaded with front-end loaders and delivered to the plant with bottom-dump haul trucks. Annual coal production is 4.3 million tons per year.

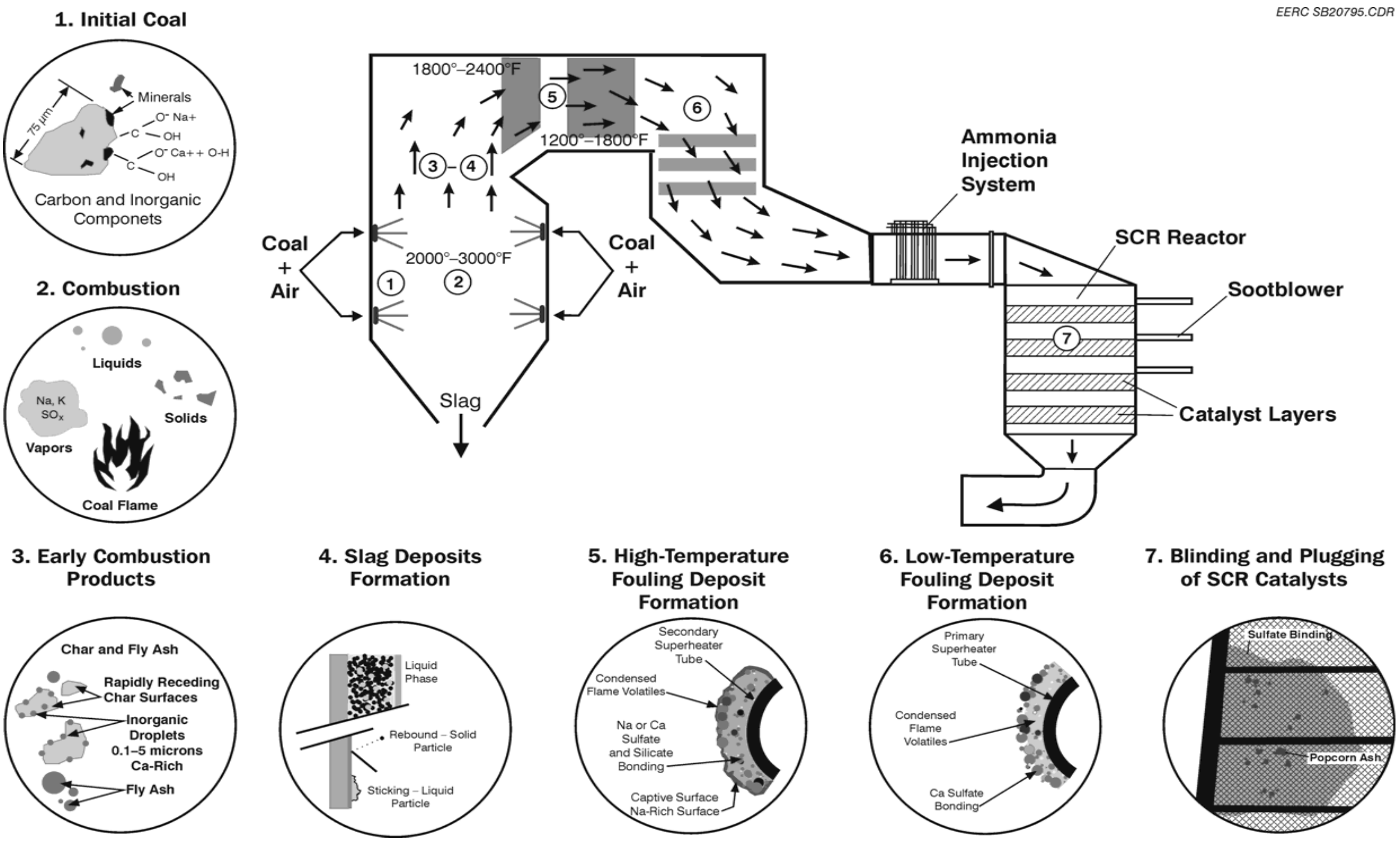


Figure 2. Overall processes of ash deposition typical of a lignite- or subbituminous-fired boiler.

History of Furnace Slagging/Fouling

Prior to 1991, besides annual maintenance outages, load reductions and forced outages due to furnace slagging/fouling were the largest cause of production loss. In 1985, operating guidelines were established that reduced furnace slagging/fouling, including deslagging outages scheduled every six months.

In 1991, a 3-month boiler cleaning cycle was proposed and initiated. The goal of this program was to increase annual generation by running the units at higher sustained loads and scheduling boiler-cleaning outages at 3-month intervals. However, furnace slagging/fouling continued to have a significant impact on plant operations. Success was measured in the number of production days between boiler-cleaning outages.

During the mid-1990s, a major outage every third year was scheduled for each unit. In addition, Unit 1 cleaning outages were scheduled for 80–90-day runs (four cleaning outages per year), and Unit 2 cleaning outages were scheduled for 65–75-day runs (five cleaning outages per year). The problem was that furnace and convection-pass surfaces gradually become coated with ash deposits, which, over time, sootblowers cannot remove. Some of the contributors to the ash deposits were as follows:

- Organically associated sodium is a primary contributor to deposition problems. Sodium is vaporized in the cyclones and condenses on other ash particles, causing them to become sticky and deposit at the furnace exit. The problem is associated with sulfate formation and occurs in the convective pass, including the economizer. Samples show that sodium in the ash varies from 0.6%–13.0%.

- Organically associated calcium is another component that causes deposition problems. Unlike sodium, calcium does not produce a vapor-phase component. Calcium does react with silicate (derived from clays) to cause low-melting-point phases that produce wall deposits and deposits in the high-temperature regions of the convective pass. Calcium also produces very small particles that will be transported to heat-transfer surfaces, resulting in the formation of thin, light-colored layers called reflective ash. These small particles of ash are carried through to the back passes where they are sulfated and can combine with sodium to cause the formation of strongly bonded sulfate-based deposits. Samples show that calcium in the ash varies from 6.8%–24.0%.

- Clay minerals and quartz – Center lignite can contain high levels of illite, which has a 1:3 Al:Si ratio and high levels of potassium, both of which cause wall slagging and high-temperature fouling. Quartz and other clays can significantly contribute to the mass of the deposits. Samples show that ash content varies from 5.0%–25.5%.

Advanced Boiler Performance Indices

Advanced indices are used to relate the coal characteristics as determined by computer-controlled scanning electron microscopy (CCSEM) and chemical fractionation to ash behavior in a coal-fired utility boiler (12). Fuel performance is estimated in terms of slag flow behavior,

abrasion and erosion wear, wall slagging, high-temperature silicate-based convective pass fouling, and low-temperature sulfate-based convective pass fouling. The following indices are used to assess the effects of ash behavior on utility boiler performance:

- Convective-Pass Fouling Indices

  Sulfation Index: Indicates the propensity of deposit to form in the convective pass of the utility boiler in the temperature range from 1000°–1750°F. This index is based on the availability of alkali (Na and K) and alkaline-earth (Ca and Mg) elements to react with SO_2 and SO_3 to form sulfates. The sulfates are the primary materials that cause particle-to-particle bonding in high-calcium coals. The sulfates are thermodynamically stable at temperatures below about 1650°F. Index values range from 1 (low) to 10 (severe).

  Silicate Index: Indicates the propensity of deposits to form from 1600°–2400°F. This index is related to the formation of deposits in which the silicate material is the primary component that bonds the deposits together. The information used to derive the index includes the size of the minerals such as quartz and clay minerals, availability of alkali and alkaline-earth elements, and viscosity of the silicate liquid phase. Index values range from 1 (low) to 200 (severe).

- Waterwall Slagging

  Slagging Index: Indicates the propensity of a deposit to form on the radiant walls from 2000°–3000°F. The basis of the slagging index is the size of the minerals (especially the illite, quartz, and pyrite), association of the calcium (calcite can contribute to slagging), and viscosity of the silicate-based liquid phase. Index values range from 1 (low) to 20 (severe).

- Wear Indices

  Abrasion Index: This index indicates the potential for wear of fuel preparation and handling equipment. The wear is related to the hardness of minerals in the coal. The primary minerals of concern include quartz and pyrite. The index values range from 0.1 (low) to 10 (severe).

  Erosion Index: This index indicates the potential for wear of boiler parts due to the impaction of fly ash particles. The erosion index is dependent upon the size of the ash/mineral particle, size of the particle, and velocity of the particle. The index values range from 0.1 (low) to 1.0 (severe).

- Cyclone Slagging Index: This index provides information on the slag flow behavior in cyclones. The factors that are included in this index include the partitioning of the ash in the cyclone based on size and association of the ash-forming components in the coal. The partitioning of the ash between the slag and entrained ash can significantly influence the flow behavior of the slag. Standard partitioning criteria have been developed to provide the composition of the slag. The composition is used to estimate the viscosity of the slag as a function of temperature. The index values have several ranges as follows: 1 (low viscosity), 1.5–2.5 (optimum viscosity), >3.0 (slag freezing).

- Strength Development Index: The strength index is based on the ability of the deposited material to develop strength. Strength development is primarily dependent upon the abundance and viscosity of the liquid-phase components in the deposits. Index values less than 0.25 indicate that the material will produce weak deposits; index values of 0.25–0.34 indicate weak-to-moderate-strength deposits; index values of 0.34–0.41 indicate high-strength deposits; and index values >0.41 indicate flowing slag.

Indices were calculated for a range of coals from the Center mine, and the propensity for ash deposition in various portions of the boiler indicates wide variations, as shown in Table 1. The BNI numbers indicate the location in the seams where the coal originated: Kinneman Creek seam (KC), Hagel A (HA), and Hagel (HB). Each seam has a different distribution of minerals and organically associated elements that can have a significant impact on the formation of deposits in the system. Comparison of Center lignite to subbituminous and bituminous coals from other regions of the United States, shown in Table 2, indicates significant differences in the potential to form deposits in the boilers. In all cases, the lignite (not the worst coal from Center mine) from the Center mine has a high propensity to produce deposits as compared to the other coals.

Another indication of the variability of lignites can be illustrated based on the calculation of the temperature where the slag flow would occur. This is defined as the T250 temperature, where the slag viscosity is 250 poise. Frequency distributions of the T250 values for all the data for coals analyzed are illustrated in Figure 3. Calculations of T250 values for 1212 samples obtained from the Center mine database (17) were made using empirical relations derived from CCSEM and chemical fractionation data and knowledge of how ash partitions in the cyclone. Figure 3 shows a bimodal distribution in the T250 based on the Urbain equation calculations. The primary mode was at a value of 2000°F. The secondary mode was at about 2700°F. The results indicate that many of the coals have a sufficiently low T250 for good slag flow. However, coals with T250 at 2700°F are not suitable for maintaining good slag flow.

Figures 4 through 6 illustrate the variations in T250 for the various seams of coals characterized. The HA and HB seam coals appear to have large numbers of samples, with T250 values at or near 2000°F. The KC seam coal, as illustrated in Figure 6, has extremely high T250 values. Based on these data, the KC coals are not favored relative to the slag flow behavior of the ash.

Frequency distributions of cyclone slagging index values indicated significant variations in slagging potentials of coals mined from the three seams, KC, HA, and HB. This information proved particularly useful in planning the mining and firing of coal from the KC seam.

During a July 1999 test burn, the composition of the cores was used to examine and illustrate the variability of the delivered coal quality based on base-to-acid ratio calculated from the ash composition. Figure 7 shows the variation in the base-to-acid-ratio and the seam where the coal was loaded. The base-to-acid ratios were calculated from core data that corresponded to the location in the seam where the coal was mined. There is a significant variation in the base-to-acid ratio for the coals. The coals that have the highest base-to-acid ratio are typically from the HA seam. HB seam coals generally have an intermediate base-to-acid ratio. KC or top-seam coal has the lowest base-to-acid ratio. Lower base-to-acid-ratio coals typically produce slag with high viscosities.

Table 1. Characteristics and Indices Calculated for Selected Center Lignite Samples

BNI No.	41-132HB	41-44KC	41-144HA	41-144HB	41-168KC	41-168HA	41-168HB	41-180KC	41-180HA	41-180HB	41-192KC	41-192HA
Mineral wt%, mineral basis												
Total Quartz Content			18.8	9.8	30.3	8.7	8.8	11.4	20.0	3.9	15.0	17.4
Quartz <10 microns		10.8		6.4	24.6	4.4	4.0	6.8	3.3	2.6	9.7	12.7
Total Kaolinite Content		10.6		10.8	7.7	6.4	1.7	9.5	4.4	2.4	14.3	28.0
Kaolinite Content <10 microns		5.1		6.3	4.5	2.6	0.9	4.8	1.1	0.9	10.2	20.8
Total Montmorillonite		10.7		2.7	6.5	1.7	6.1	7.0	2.3	2.4	7.6	5.1
Total Illite		14.1		9.3	6.6	0.2	28.0	19.1	10.2	1.6	6.8	1.9
Total Pyrite		8.0		26.7	18.9	67.1	19.7	9.1	10.9	57.2	22.6	32.3
Pyrite Content <10 microns		4.5		10.5	2.8	9.8	4.7	2.5	2.5	17.0	6.6	7.0
Gypsum Content		6.5		0.0	1.6	2.7	0.8	5.4	0.0	16.1	2.2	0.0
Proximate (wt% as received)												
Moisture		30.95		41.66	36.24	38.23	37.50	37.90	37.99	38.21	37.85	39.52
Volatile Matter		27.26		25.74	26.32	25.90	24.55	25.11	24.42	25.88	26.13	24.27
Fixed Carbon		26.56		27.97	28.18	29.65	30.37	27.94	29.53	31.54	29.15	30.30
Ash		10.30		4.63	9.26	6.22	7.58	9.05	8.1	4.37	6.88	5.91
Total Sulfur (% as received)		0.94		0.55	1.49	1.08	0.75	0.99	0.64	0.86	0.90	0.85
Btu/lb		6597		6593	6791	6957	6806	6584	6653	7194	6881	6835
% Ash (dry basis)	11.64	10.30		7.94	14.52	10.07	12.13	14.57	13.00	7.07	11.07	9.77
Ash Comp. (wt% equiv. Oxide)												
Na_2O		0.50		10.65	0.82	9.25	8.02	0.46	8.15	11.99	1.48	9.69
MgO		3.30		5.74	3.72	4.90	4.45	3.90	5.00	4.59	6.13	5.10
Al_2O_3		11.90		10.37	9.34	5.64	11.81	12.12	10.19	5.23	10.59	7.46
SiO_2		30.60		14.70	33.71	8.47	30.74	35.57	36.25	5.31	25.80	13.06
P_2O_5		0.20		0.06	0.15	0.42	0.25	0.07	0.26	0.23	0.25	0.24
SO_3		23.00		25.50	21.28	35.25	21.05	18.32	15.93	35.75	24.15	32.75
K_2O		1.20		0.96	0.47	0.62	1.52	1.03	1.22	0.47	0.55	0.60
CaO		16.80		21.00	15.31	18.94	12.10	17.15	14.87	15.43	20.01	18.98
TiO_2		1.30		0.39	0.72	0.29	0.40	0.51	0.29	0.16	0.48	0.28
MnO		0.20		0.03	0.07	0.05	0.04	0.10	0.07	0.04	0.07	0.12
Fe_2O_3		10.30		8.43	14.87	15.95	10.44	7.80	6.84	18.88	10.12	13.29
Cyclone Slagging Index		2.77		1.28	2.5	1.1	2.6	3.3	2.9	0.4	2.2	1.3
Silicate		10.71		102.43	29.47	108.33	109.93	16.29	176.22	137.49	14.19	149.54
Sulfate		9.43		3.57	2.2	5.01	3.46	1.75	3.98	4.4	2.21	3.24
Wall Slagging Index		1.18		11	2.67	10.68	9.27	1.79	8.83	12.63	2.2	10.53
Erosion Index		0.19		0.15	0.17	0.19	0.22	0.21	0.27	0.17	0.17	0.17
Abrasion Index		2.14		0.71	6.46	1.55	1.41	2.25	1.93	0.83	1.75	1.68
Strength Index		0.32		0.66	0.35	1.11	0.35	0.3	0.33	1.32	0.43	0.63

Continued . .

Table 2. Advanced Index Values for Other Coals (12)

Advanced Indices	Lignite North Dakota	Powder River Basin	Bituminous Illinois	Bituminous Appalachian
Cyclone Slagging Index	1.6	2.1	3.5	3.2
Convective Pass Fouling				
Silicate	61.8	23.99	10.36	14.21
Sulfate	4.09	2.88	0	0
Wall Slagging Index	9.28	1.85	1.53	1.66
Erosion Index	0.15	0.17	0.14	0.17
Abrasion Index	0.71	1.96	3.94	1.96

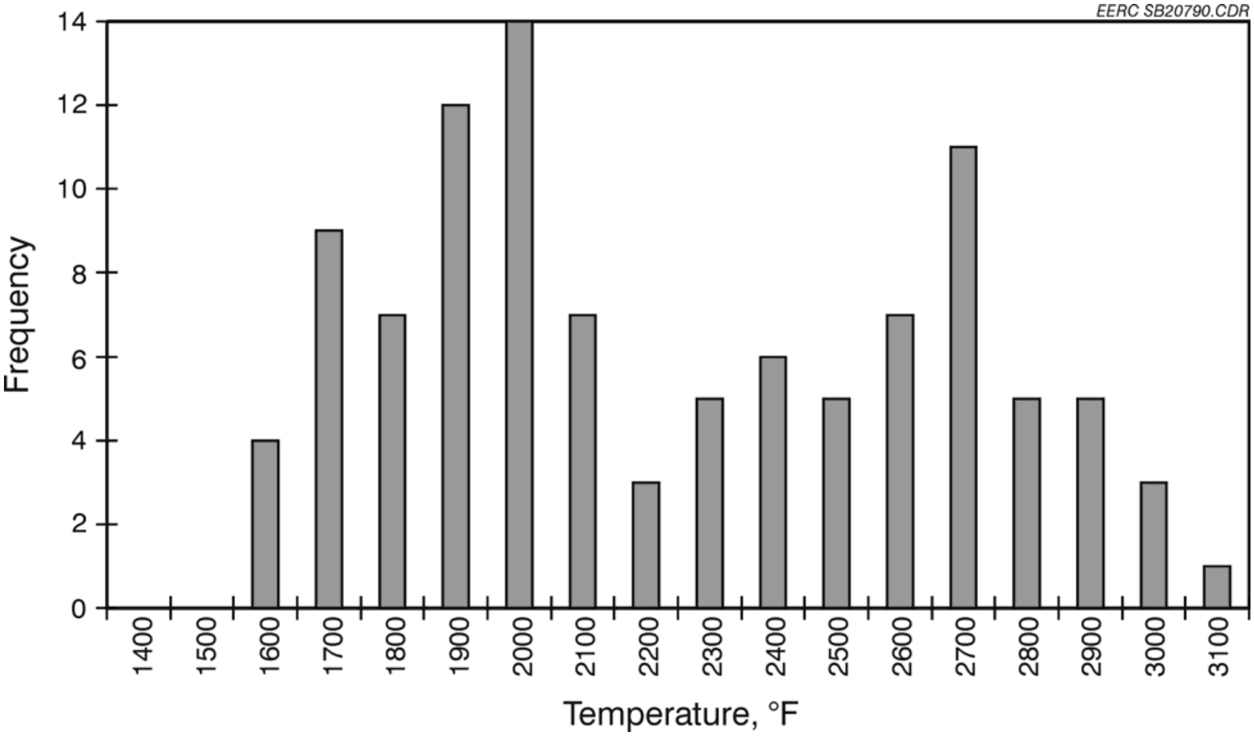


Figure 3. T_{250} frequency distribution for all Coal Quality Management System (CQMS) data, °F.

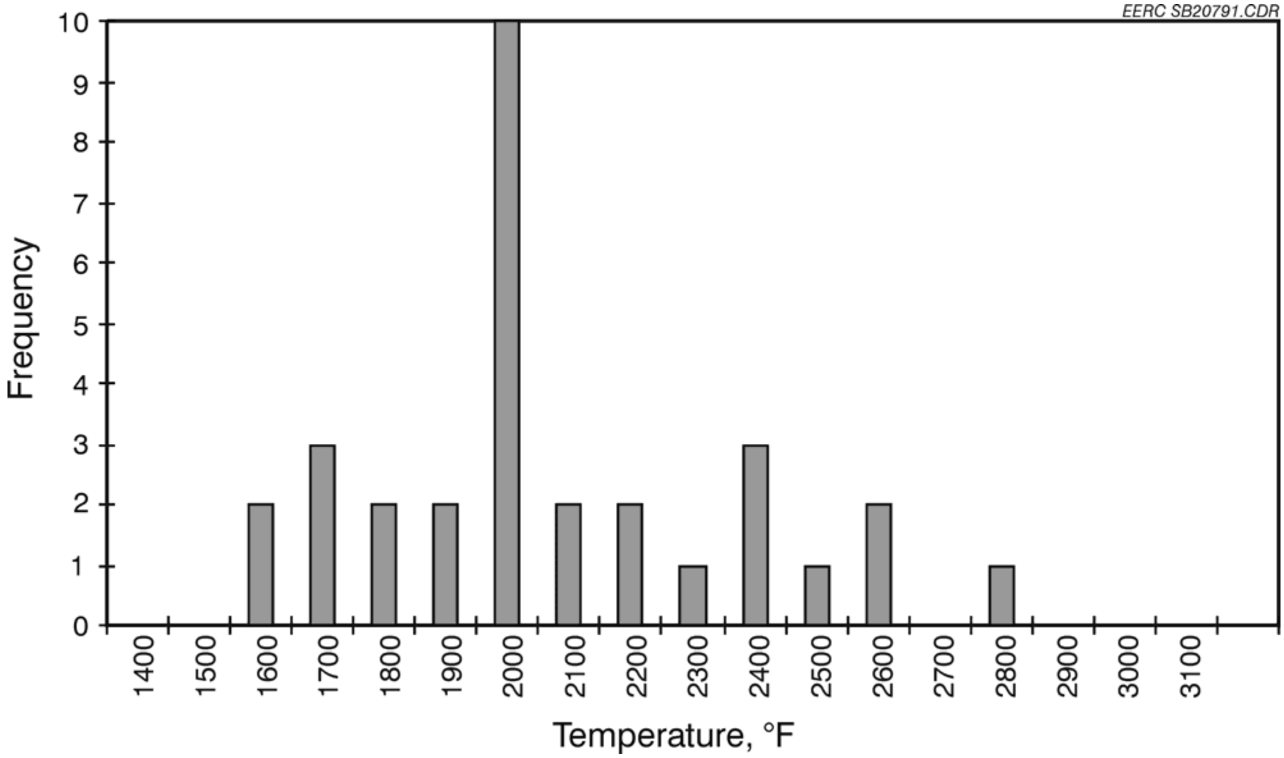


Figure 4. T_{250} distribution for HA seam coal.

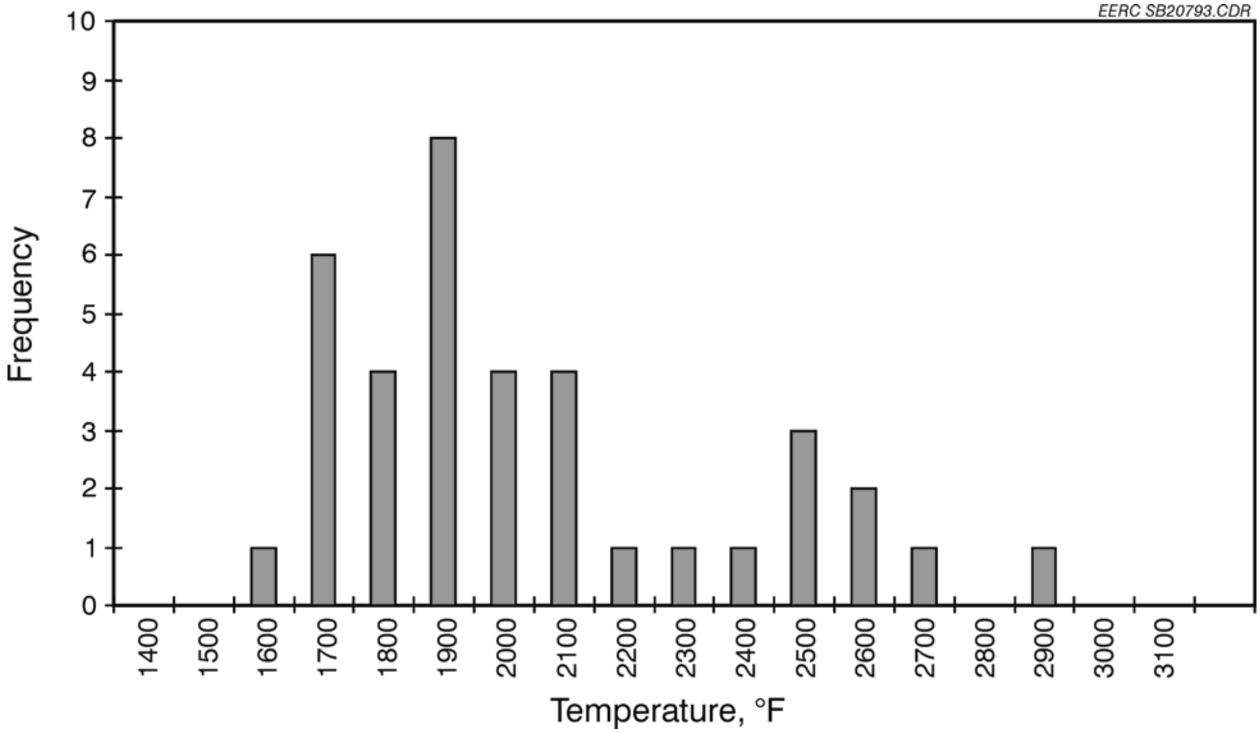


Figure 5. T_{250} distribution for HB seam coal.

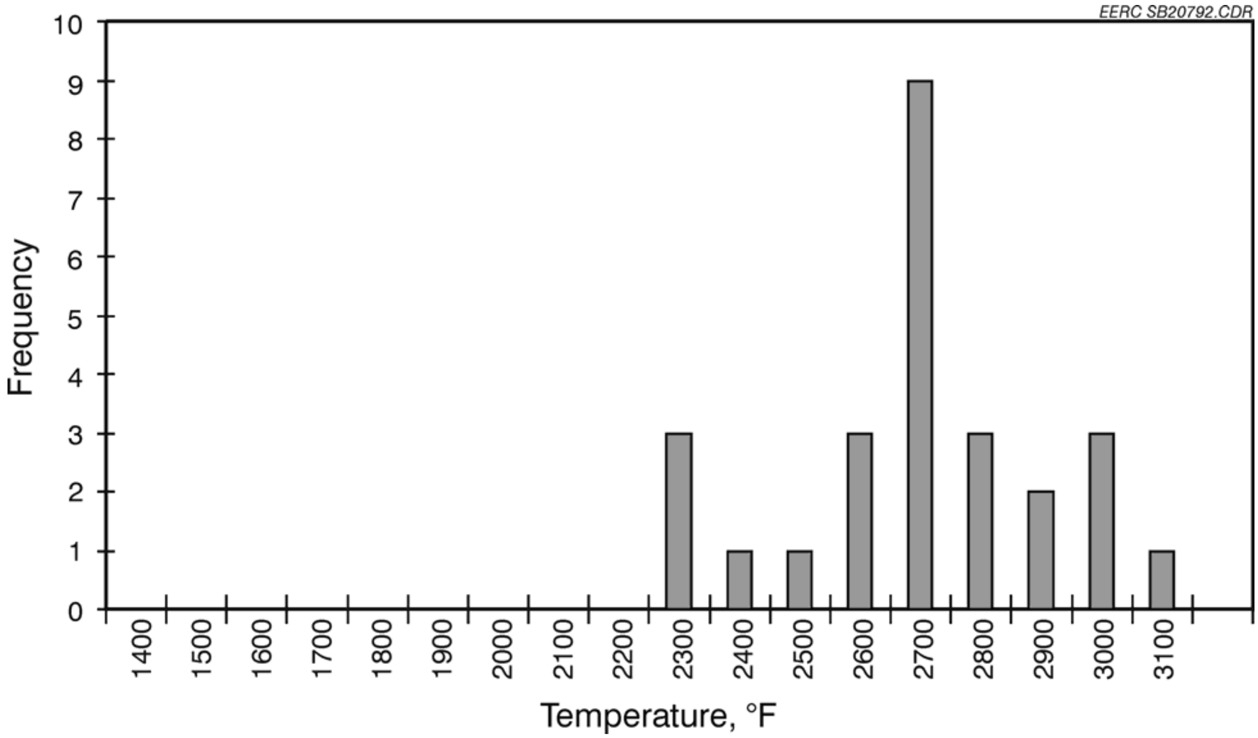


Figure 6. T_{250} distribution for KC seam coal.

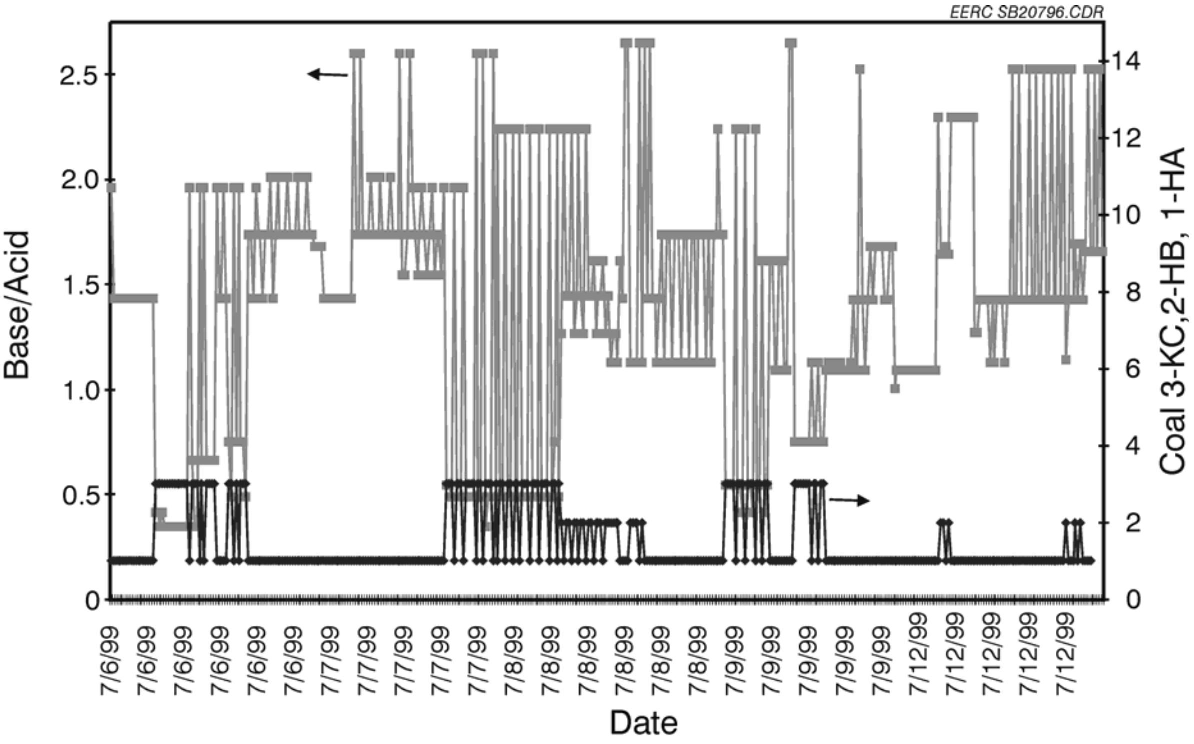


Figure 7. Variations in the delivered coal quality during a test burn period.

Figure 7 shows the sequence of deliveries beginning on July 6 and ending on July 12, 2004. During this period, the majority of the coal delivered was from the HA seam, followed by KC, and HB. Most of the deliveries alternated between KC and HA. Figure 6 shows several instances where significant quantities of KC coal were delivered, on July 6 through July 9. The quantity of KC coal delivered will have the potential to increase the viscosity of the slag and result in poor slag flow from the cyclones.

ASH-RELATED IMPACTS ON SCR CATALYST PERFORMANCE

Ash-related impacts on SCR catalyst performance will depend upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (14–16, 22). The problems currently being experienced on SCR catalysts include the following:

- Formation of sulfate- and phosphate-based blinding materials on the surface of catalysts.
- Carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing on top of the SCR catalysts.

Licata and others (14) conducted tests on a South African and German Ruhr coal and found that the German Ruhr coal significantly increased the pressure drop across the catalyst because of the accumulation of ash. They found that the German coal produced a highly adhesive ash consisting of alkali (K and Na) sulfates. In addition, they reported that the alkali elements are in a water-soluble form and highly mobile and will migrate throughout the catalyst material, reducing active sites. The water-soluble form is typical of organically associated alkali elements in coals. The German Ruhr Valley coal has about 9.5% ash and 0.9 % S on an as-received basis, and the ash consists mainly of Si (38.9%), Al (23.2%), Fe (11.6%), and Ca (9.7%), with lower levels of K (1.85%) and Na (0.85%) (15). Cichanosicz and Muzio (16) summarized the experience in Japan and Germany and indicated that the alkali elements (K and Na) reduced the acidity of the catalyst sites for total alkali content (K+Na+Ca+Mg) of 8%–15% of the ash in European power plants. They also found that alkaline-earth elements such as calcium react with SO_3 on the catalyst, resulting in plugging of pores and a decrease in the ability of NH_3 to bond to catalyst sites. The levels of calcium in the coals that caused blinding ranged from 3%–5% of the ash.

The mechanisms for this type of low-temperature deposition have been examined and modeled in detail at the Energy & Environmental Research Center (EERC) in work termed Project Sodium and Project Calcium in the early 1990s; however, the focus of those projects was specific to primary superheater and economizer regions of boilers and not SCR systems (22, 23). Deposit buildup of this type can effectively blind or mask the catalyst, diminishing its reactivity for converting NO_2 to N_2 and water and potentially creating increased ammonia slip (14). Arsenic and phosphates, which are not uncommon in low-rank coals, may also play a role in catalyst degeneration. Arsenic is a known catalyst poison (14) in applications such as catalytic oxidation for pollution control. Phosphates can occur in low-temperature ash deposits to create blinding effects, and they also occur with arsenic and can cause catalyst poisoning (23).

Lignite and subbituminous coals produce ash that plugs and blinds catalysts (25–28). The problems currently experienced with SCR catalysts include the formation of sulfate- and phosphate-based blinding materials on the surface of catalysts and the carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing them on top of the SCR catalysts (14). The most significant problem that limits the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates, phosphates, and possibly carbonates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16, 27–28). The degree of the ash-related impacts on SCR catalyst performance depends upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (15–16, 24, 27–28).

In studies (7) the impacts of temperature and the presence of catalyst on the ability of ash to sulfate were examined. The tests were conducted using a thermogravimetric analyzer (TGA). TGA testing was conducted using a <5-µm-size fraction of ash produced from Powder River Basin (PRB) coals and lignites and exposing them to vapor-phase sulfur dioxide with and without catalyst at several temperatures. The aim of the testing was to determine the potential of the formation of sulfates to cause particle-to-particle bonding that leads to the formation of deposits in the temperature range where SCR catalysts are used. The TGA testing is focused on determining the reactivity of the <5-µm ash produced from selected PRB and blends to sulfur dioxide and gas-phase phosphorus species as a function of temperature. Testing was conducted to determine the weight gain with flue gas containing ammonia. The impact temperature on the weight gain due to the formation of sulfates for a PRB blend is shown in Figure 8. The rates of sulfation were found to increase with increased temperature. The results show an increase in the weight gains when ammonia and phosphorus were added. Ground catalyst was mixed with PRB and placed in the TGA. Increases in weight gain were observed when catalyst was added as compared to baseline cases for 100% PRB, as shown in Figures 8 and 9, respectively. The presence of catalyst enhances the formation of sulfates.

Full-Scale Slipstream Testing

More recently (8), the behavior of ash and mercury in flue gas produced from the combustion of lignite and subbituminous coals from the United States of America in selective catalytic reduction (SCR) systems for nitrogen oxide removal has been examined. Typically, these coals contain ash-forming components that consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, these coals produce ash that has an abundance of alkali and alkaline-earth-rich oxide particles (<5 µm) that are carried into the backpasses of the combustion system and react with flue gas to form sulfates and possibly carbonates. The forms of mercury in the flue gas produced from the lignite and subbituminous coals are dominated by the elemental form. Slipstream testing was conducted at two subbituminous-fired power plants and one lignite-fired power plant to determine the impacts of ash on SCR plugging, blinding, and mercury oxidation.

The SCR slipstream system consists of two primary components: the control room and the SCR reactor. The reactor section consists of a catalyst section, an ammonia injection system, and sampling ports for NO_x at the inlet and exit of the catalyst section. The control room houses a computer system that logs data and controls the gas flow rates, temperatures, pressure drop across the catalyst, and sootblowing cycles. The computer is programmed to maintain constant temperature of the catalyst, gas flow rates, sootblowing cycles, and ammonia injection. The computer is equipped with a modem that allows for downloading of data and modification of the operation of the reactor from a remote computer located at the EERC.

Flue gas is isokinetically extracted from the convective pass of the boiler upstream of the air heater. The temperature is typically about 790°F. The flue gases pass through a 4-inch pipe equipped with sampling, thermocouple, and pressure ports. Ammonia is injected into the piping upstream of the reactor section. The reactor consists of a steel housing that is approximately 8.5 inches square and 8 feet long. The reactor section has three components, including a flow straightener, a pulse section or sootblower, and a catalyst test section. A metal honeycomb is used as a flow straightener upstream of the catalyst section and is about 6 inches long. A purge section was installed ahead of the catalyst test section to remove accumulated dust and deposits. The catalyst test section is located downstream of the purge section. The entire catalyst section is insulated and equipped with strip heaters for temperature control. The catalyst test section is 3.28 ft (1 m) in length and houses three catalyst sections. Thermocouple and pressure taps are located in the purge sections for measurements before and after each section.

The induced-draft fan is used to extract approximately 400 acfm (200 scfm) of flue gas from the convective pass of the utility boiler to achieve an approach velocity of 5.2 m/s (17.0 ft/s). The gas velocity is similar to that found in full-scale applications. The total gas flow through the reactor represents a thermal load of approximately 300 kW.

The range of operating conditions for the reactor is listed below:

- Gas temperature: ~700°–800°F
- Gas flow rate: 400–500 acfm
- Approach velocity range: 5.0–5.5 m/sec
- Ammonia injection rate: 0.5:1 with NO_x level
- Tempering air for fan: ~ 50–200 scfm
- Catalyst dP: 0.5–1.0 inches water column
- Fan sized for up to 30 inches water column

The catalyst installed at the Baldwin and Coyote Stations was the Haldor Topsoe catalyst. Topsoe's DNX-series of catalysts comprises SCR DENOX catalysts tailored to suit a comprehensive range of process requirements. DNX-series catalysts are based on a corrugated, fiber-reinforced titanium dioxide (TiO_2) carrier impregnated with the active components vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels. The unique catalyst design provides a highly porous structure with a large surface area and an ensuing large number of active sites. The pitch of the catalyst was approximately 6 mm.

The catalyst installed at the Columbia Station was a Babcock Hitachi plate-type catalyst. This catalyst is a TiO_2-based plate catalyst, developed and manufactured by Hitachi. The pitch of the catalyst was approximately 10 mm.

The coals produced ash that had significant accumulations of ash on the catalyst on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation.

The deposits on the surfaces and within the pores of the catalyst consisted of mainly alkali and alkaline-earth element-rich phases that have been sulfated. The results of this testing found that the <5-µm ash rich in alkali and alkaline-earth elements is captured on the surface and within the catalyst pores. These materials react with SO_2/SO_3 in the flue gas, resulting in the formation of a continuous phase that blinds the catalyst. The ability of elemental mercury to be oxidized across the SCR catalyst was investigated at a North Dakota lignite-fired plant. These results showed no oxidation of mercury across the SCR catalyst.

The reactor was installed at the Baldwin Station and operated for a 6-month time period on the Haldor Topsoe catalyst. The information obtained from testing included pressure drop, sootblowing cycles, and reactor temperatures. Figure 10 show the pressure drop across the catalyst test periods from 0 to 2 months. During the first two months of operation, the pressure was about 0.5 inches of water; at the end of two months, the pressure drop was about 0.8 inches of water, indicating plugging had occurred. The air was pulsed a minimum of every 8 hours in an attempt to maintain cleanliness. The reactor was monitored on a daily basis, and adjustments in pulsing cycles were made in order to minimize deposit accumulation. However, for the first two months, the pressure drop steadily increased. There are several periods where the unit was taken off-line; during those times, the temperature of the catalyst was maintained. At 2-month intervals, a section of catalyst was removed and replaced with a new one.

For Months 2 through 4, the pressure drop was highly variable initially but was about 0.8 inches of water. From Months 4 through 6, the pressure drop was maintained between 0.6 and 0.8 inches of water. This is due to the installation of a fresh catalyst section and leaving two thirds of the catalysts in place that were partially plugged. The gas velocity in the single section of new, clean catalyst was high because of channeling, and the result of the high gas flow was less deposition and accumulation. Gas velocity has a significant impact on the potential for deposits to form. However, at high gas velocity, low NO_x conversion is likely.

The reactor was installed at the Columbia Station and operated for a 6-month period of time with the Babcock Hitachi catalyst. The information obtained from the testing included pressure drop information, sootblowing cycles, and reactor temperature. Figure 11 shows the test periods from 0 to 2 months. The pressure drop across the SCR upon installation was about 0.4 inches of water and increased to an average of about 0.5 inches of water, but ranged from less than 0.4 to greater than 0.8 inches of water. The pressure drop for Months 2 to 4 increased from about 0.5 to 0.7 inches of water because of accumulation of ash. After cleaning the reactor and replacing one catalyst section, the pressure drop was about 0.3 but increased to over

0.6 inches of water up to about 4100 hours. There was an outage at the plant, and aggressive pulsing of the reactor was conducted; the pressure drop was brought back down to 0.3 but rapidly increased to over 0.5 inches of water within 500 hours.

The same reactor that was installed at the Baldwin Station was moved and installed at the Coyote Station. In addition, the same Haldor Topsoe catalyst type was used in the reactor. The reactor was operated for a 6-month period of time. Figure 12 shows the test periods from 0 to 2 months. As this paper is being prepared, the reactor is still operating on-site. The pressure drop across the catalyst upon installation was about 0.4 inches of water. After only 750 hours, the pressure drop was 1.5 inches of water, indicating significant plugging and blinding. Very aggressive air pulsing was conducted, with little success in removing the deposits. The pressure drop for the catalyst was over two times greater than the pressure drop observed for the Baldwin Station utilizing the same reactor and same catalyst. At about 1700 hours, the reactor was cleaned, and a section of catalyst was removed for characterization. The pressure drop after cleaning was about 0.8 to 1.0 inches of water. The pressure drop did not increase as rapidly because of the higher velocities through the clean section of the catalyst.

The tops of the catalysts were photographed during inspection and sampling of the catalyst sections. Figure 13 shows the ash materials that accumulated on the catalyst inlet after 2 months of operation. The most significant accumulation was noted for the Coyote Station, followed by Columbia and Baldwin. The Coyote Station had some larger pieces of ash deposit material on the surface as well as plugging of the catalyst passages. The Baldwin Station showed some obvious deposition along the walls of the reactor and some accumulation on the inlet sections. The Columbia Station showed more significant accumulation and plugging than the Baldwin Station.

After 4 months, the tops of the catalysts were photographed during inspection and sampling of the catalyst sections, as shown in Figure 14. The most significant accumulation was noted for the Coyote Station and some accumulation for the Baldwin Station.

SCR Ash Deposit Characterization

The characteristics of the ash materials that collected on the catalyst surfaces and pores were characterized by SEM and x-ray microanalysis and, in selected cases, XRD was used to determine the crystalline phases present. The catalysts were sampled after 2, 4, and 6 months. The sections were sampled, and approximately 2.5-cm squares were mounted for SEM analysis on double-stick tape and in epoxy resin. The double-stick tape samples allowed for characterization of the external morphology of the particles and catalyst surface. The samples mounted in resin were cross-sectioned and polished, which allowed for more detailed and quantitative analysis of the bonding materials and materials that accumulated in the pores of the catalyst. Detailed information on all the samples can be found elsewhere (add FPT reference). Examples of two deposit and catalyst analysis are presented here.

The 6-month sample from the Baldwin Station showed extensive sulfation of the alkaline-earth elements present in the deposits. Figures 15a and 15b show regions of the catalyst where all the pores were blocked and a minimal amount of deposit on the surface of the catalyst. Figure

15c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical compositions of selected points that indicate the presence of high levels of calcium and sulfur are listed in Table 3. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample. In addition, there are some regions of high levels of calcium, aluminum, and sulfur present. The calcium aluminum materials are likely derived from the calcium aluminum phosphate minerals found in the coal fired at this plant.

The 4-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst. Figure 16 shows the 4-month sample from the Coyote Station. The catalyst showed particles adhering to the surface and completely filling and masking the pores in the catalyst. The external morphology of the catalyst surface shows the masking of the catalyst surface. Chemical compositions of selected points are shown in Table 4. The 4-month sample shows more sulfation than the two months of exposure samples. Figures 16b and 16c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of sodium-, calcium-, and sulfur-rich material, likely in the form of calcium sulfate. Significant sodium was found in the deposits, as shown in Table 4. The sample shows significant evidence of sulfation after 4 months of exposure and was much more pronounced than the samples for the Baldwin and Columbia Stations that are fired on PRB coals. The presence of sodium enhances the bonding and sulfation of the particles to form a strongly bonded matrix (22).

SCR Deposit Formation Mechanisms

The mechanism for the formation of deposits that blind SCR catalysts involves the transport of very small particles rich in alkali and alkaline-earth elements, the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. The formation of SO_3 from SO_2 is catalyzed by the SCR; this, in turn, increases the reaction rate of SO_3 to form sulfates. In some cases, the alkali and alkaline-earth elements will also react with CO_2 to form carbonates. XRD analysis identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements including sodium, magnesium, calcium, and potassium, in addition to mineral phases. The primary minerals present in these coals include quartz, clay minerals, carbonates, sulfates, sulfides, and phosphorus-containing minerals (6).

During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component, their association in the coal, and combustion system design and operating conditions. Significant research has been conducted on ash formation mechanisms and relationships to impacts on power plant performance (1–6, 9–13, 19–21, 29). During combustion, the inorganic components associated with western subbituminous and lignite coal typically are distributed into various size fractions of ash. The smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. These ash particles are largely derived from the organically associated cations in the coal. The larger size fraction has higher levels of aluminum and silicon derived from the mineral fraction of the ash-forming component of the coal. Entrained ash was extracted from the Columbia Station at the point of the inlet to the SCR reactor and was aerodynamically classified and analyzed. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst, as shown in Figure 17. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-µm size fraction. The deposited material shows significantly more sulfation than the entrained-ash size fraction, indicating that the sulfation process occurs after the particles are deposited in the catalyst.

The mechanism of SCR catalyst blinding when firing lignite or subbituminous coals is shown in Figure 18 (30). The requirements for the formation of deposits that blind SCR catalyst include firing a coal that produces significant levels of <5-µm-sized particles. The particles are transported into the pores of the catalyst and subsequently react with SO_3 to form sulfates. The sulfate forms a matrix that bonds other ash particles. The SCR catalyzes the formation of SO_3 and thereby increases the rate of sulfation (24, 25). The sulfation of CaO increases the molar volume, resulting in the filling of the pore. For coals that have high sodium contents, formation of low-melting-point phases such as pyrosulfates is possible (31). Pyrosulfate materials can melt at temperatures as low as 535°F in coal-fired power systems.

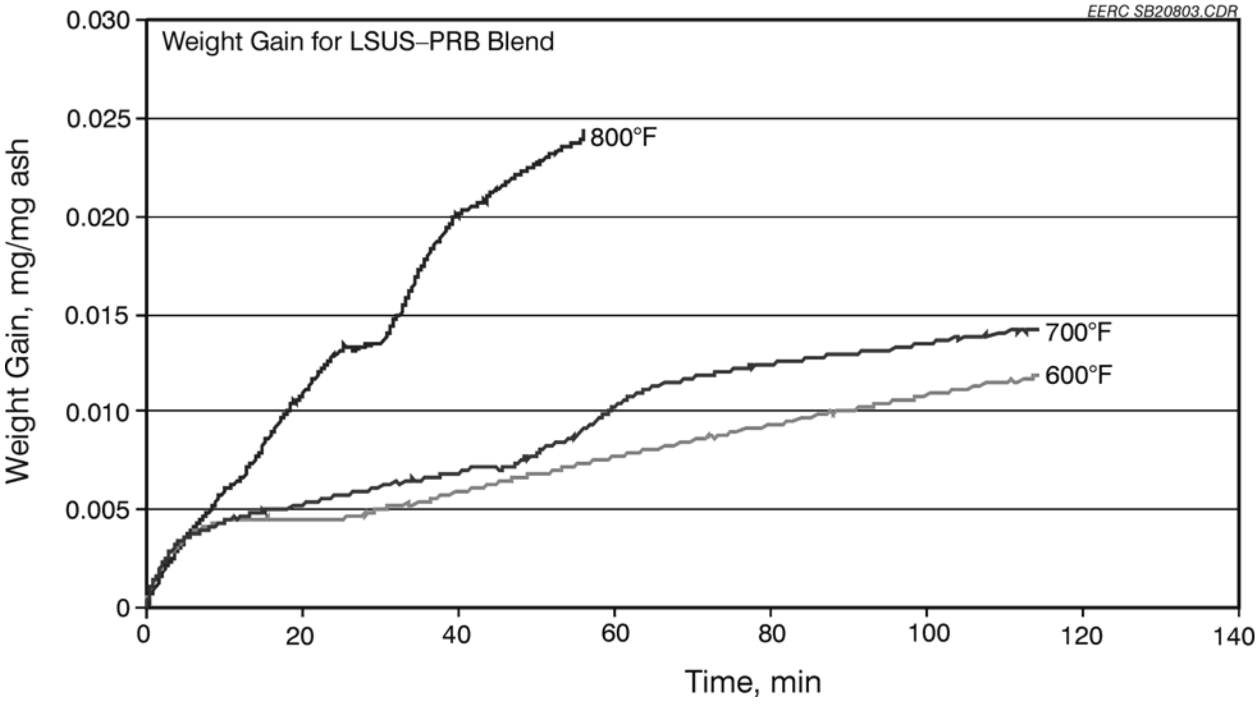


Figure 8. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia at three temperatures.

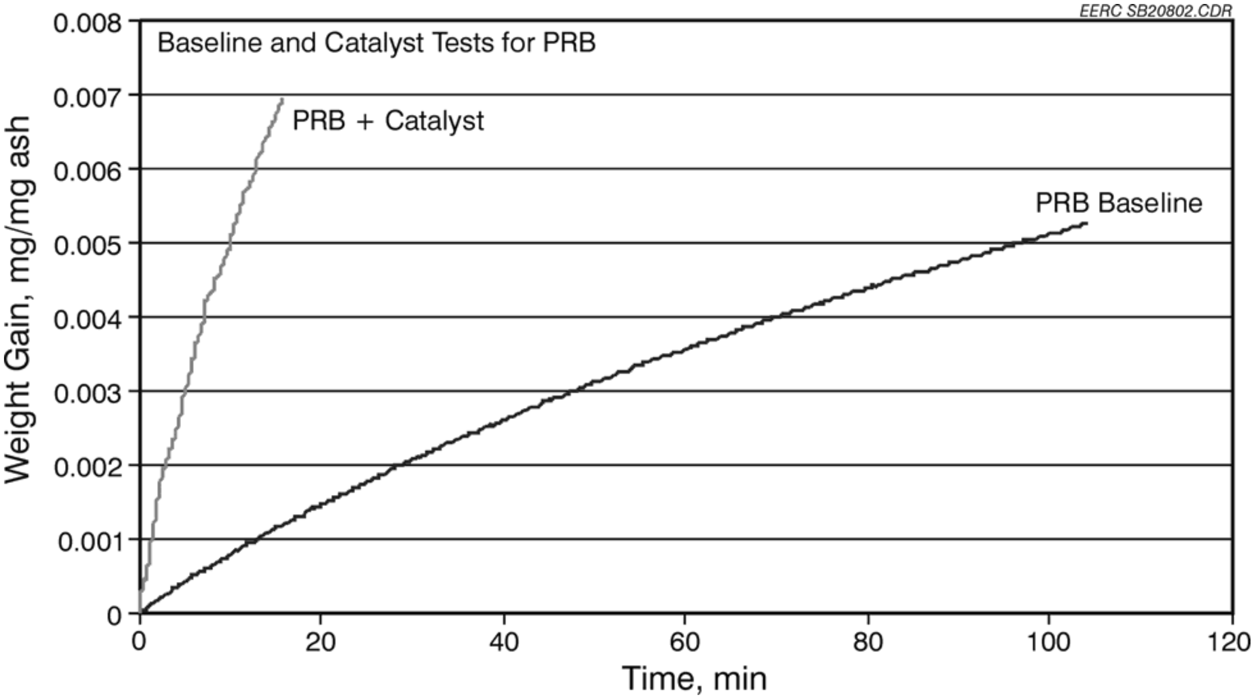


Figure 9. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia with and without SCR catalyst present.

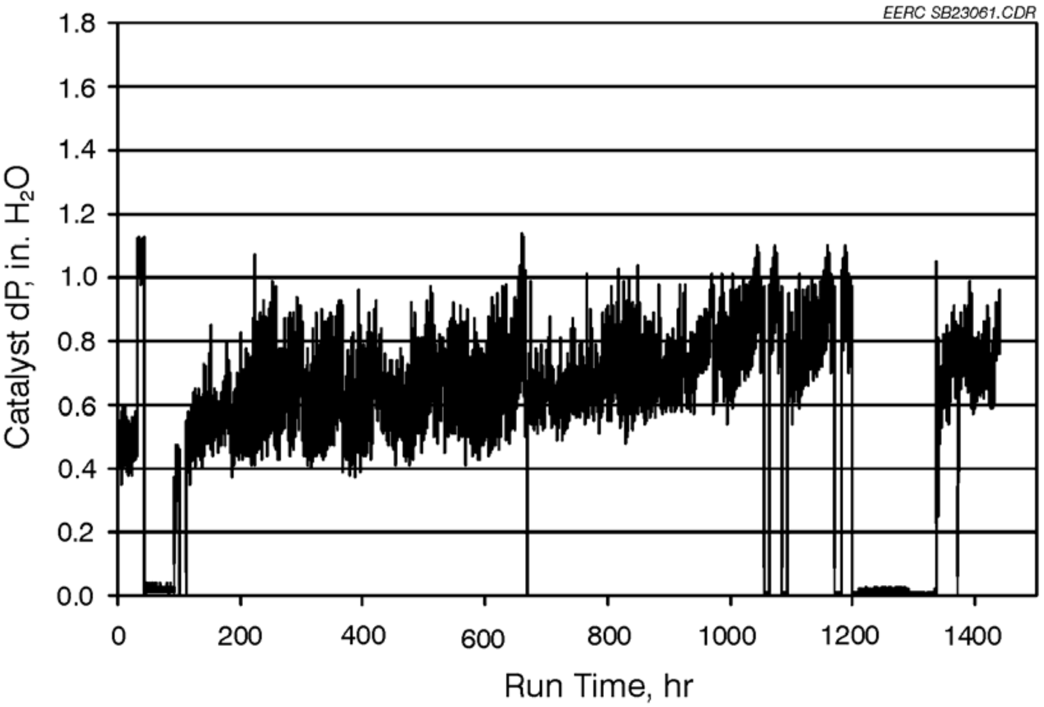


Figure 10. Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.

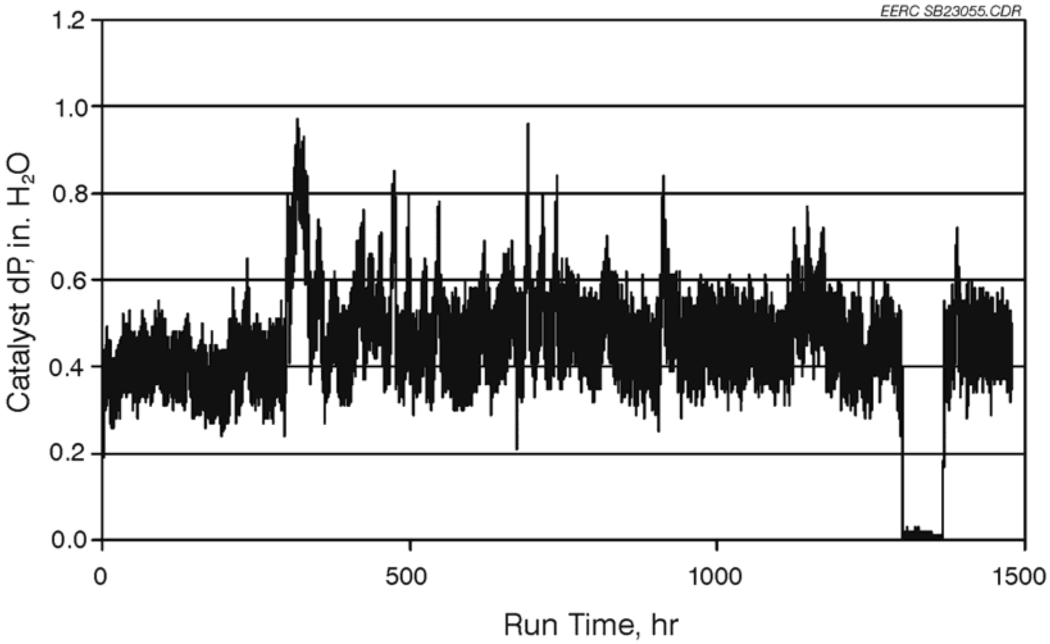


Figure 11. Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.

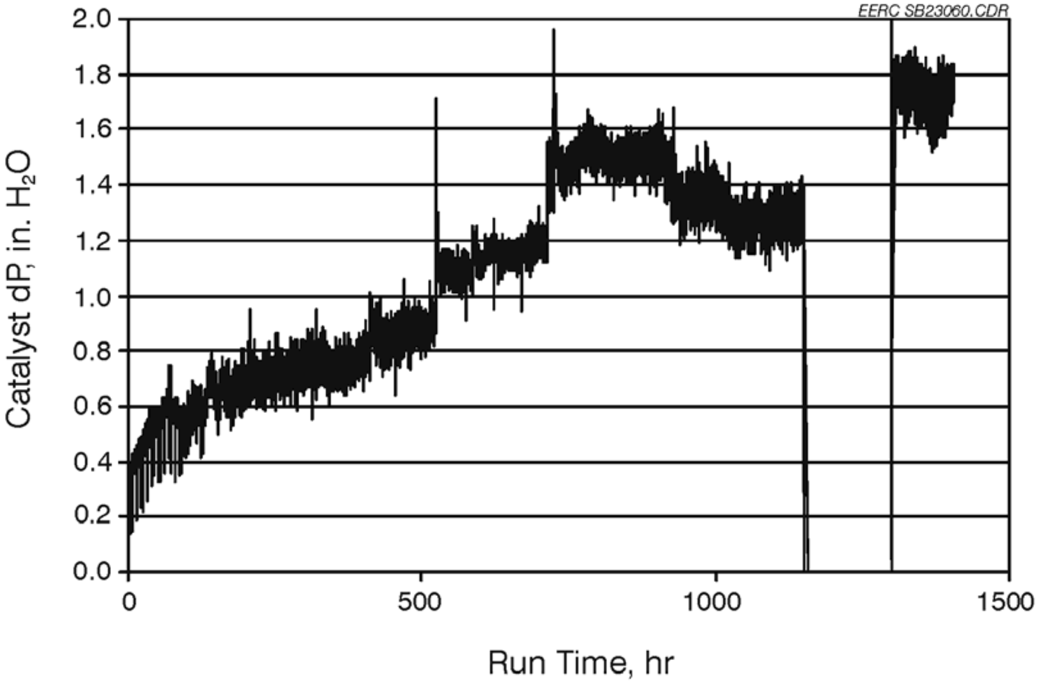
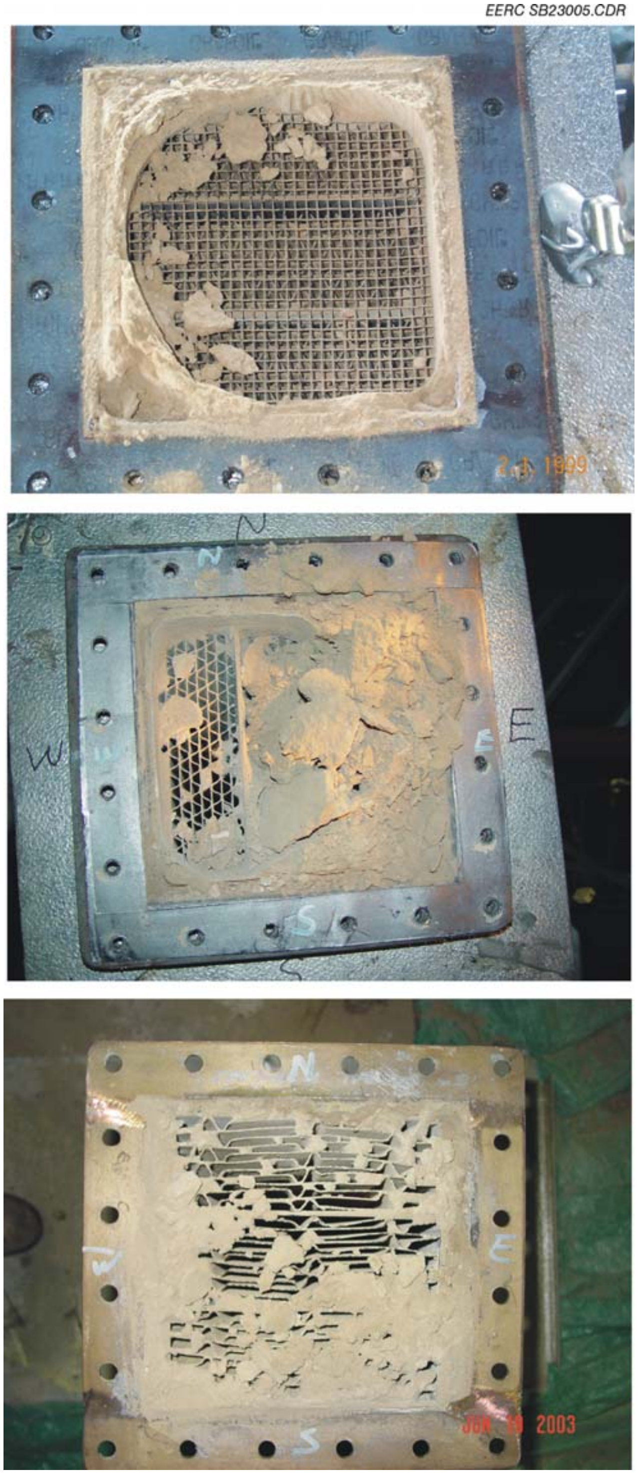


Figure 12. Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.

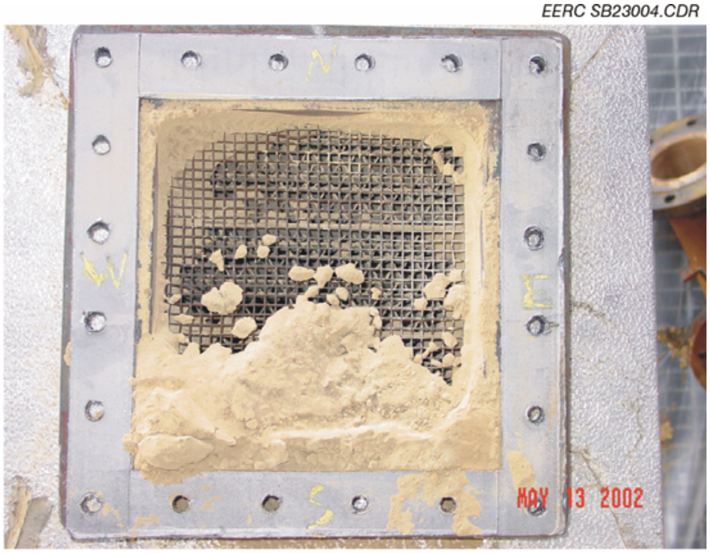


Baldwin Station after 2 months

Coyote Station after 2 months

Columbia Station after 2 months

Figure 13. Pictures of catalyst inlet after about 2 months of testing at each plant.



Baldwin Station after 4 months

Coyote Station after 4 months

Figure 14. Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.

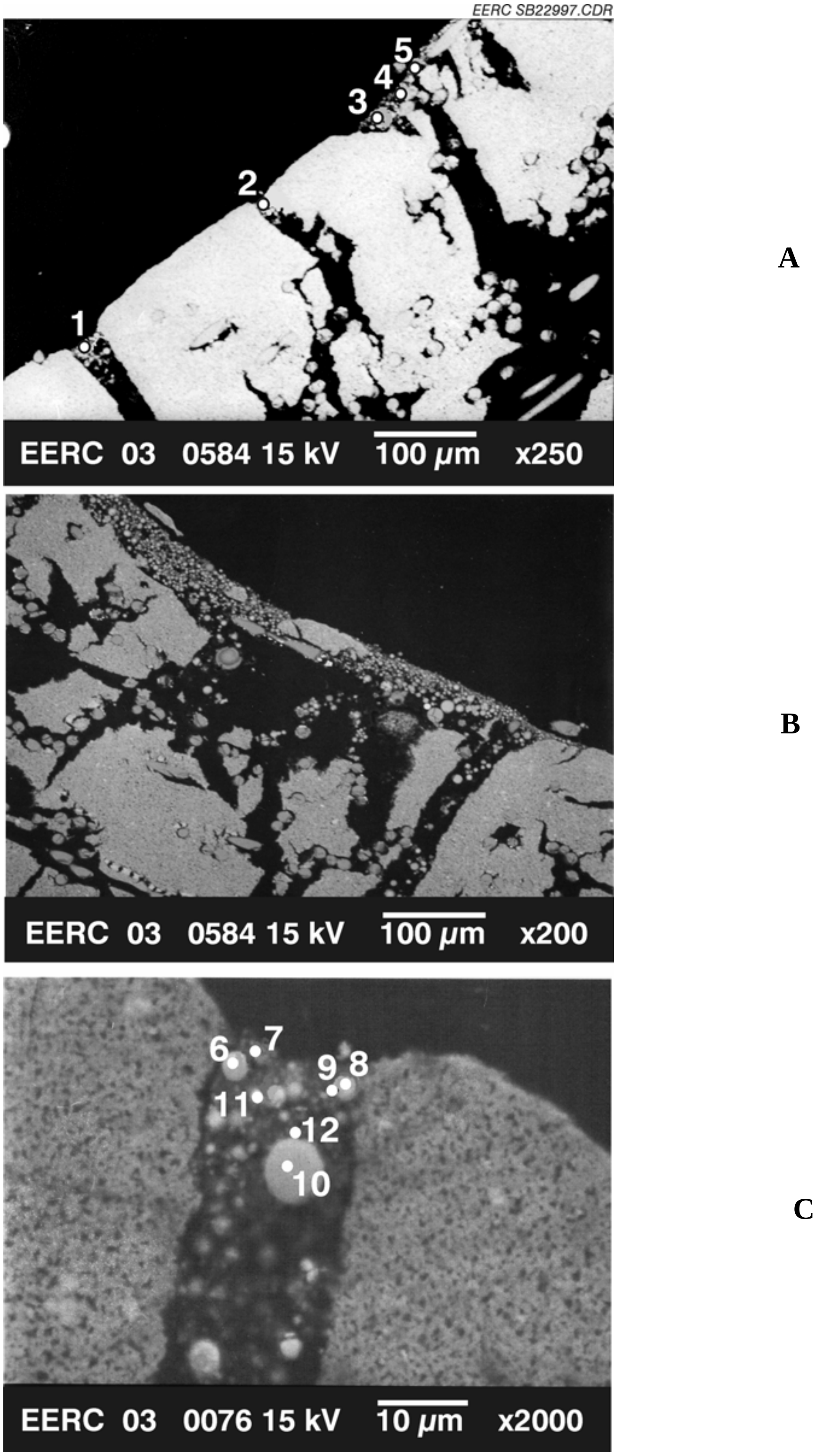


Figure 15. SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure. A) and B) low-magnification images of ash deposit on catalyst surface

and C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

Table 3. Chemical Composition of Selected Points and Areas in Figure 15

	Chemical composition (normalized wt% equivalent oxide)					
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6
1.1.1						
	0.6	1.0	2.1	0.3	0.5	2.7
Na_2O	4.3	2.5	6.3	0.7	1.6	7.6
MgO	14.8	16.0	15.6	15.5	14.7	0.9
Al_2O_3	3.3	7.8	18.8	57.7	7.7	47.3
SiO_2	2.3	2.1	0.5	0.6	1.8	0.0
P_2O_5	30.7	20.4	17.7	0.0	29.0	0.8
SO_3	0.7	0.0	1.0	0.4	0.9	0.9
K_2O	28.8	28.7	28.1	22.5	34.9	28.4
CaO	2.0	7.2	2.2	0.3	1.3	1.1
TiO_2	11.4	12.9	6.2	0.0	7.6	7.9
Fe_2O_3	1.1	1.4	1.4	2.0	0.0	2.5
BaO						
Total	100	100	100	100	100	100

Oxide	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
1.1.2						
	1.7	0.4	0.5	2.2	1.3	1.7
Na_2O	4.5	6.4	5.9	5.0	3.4	6.4
MgO	5.0	2.4	3.0	19.2	10.8	3.8
Al_2O_3	8.4	18.4	18.5	31.0	17.9	16.7
SiO_2	1.8	0.9	1.0	0.0	1.7	1.2
P_2O_5	37.9	1.7	5.3	0.0	22.5	13.9
SO_3	0.4	0.0	0.0	0.9	0.8	0.0
K_2O	31.4	52.6	49.0	28.9	30.6	45.4
CaO	1.9	6.9	7.4	2.4	2.0	1.1
TiO_2	7.1	5.7	6.0	6.3	6.1	6.5
Fe_2O_3	0.0	4.6	3.5	4.2	2.9	3.3
BaO						
Total	100	100	100	100	100	100

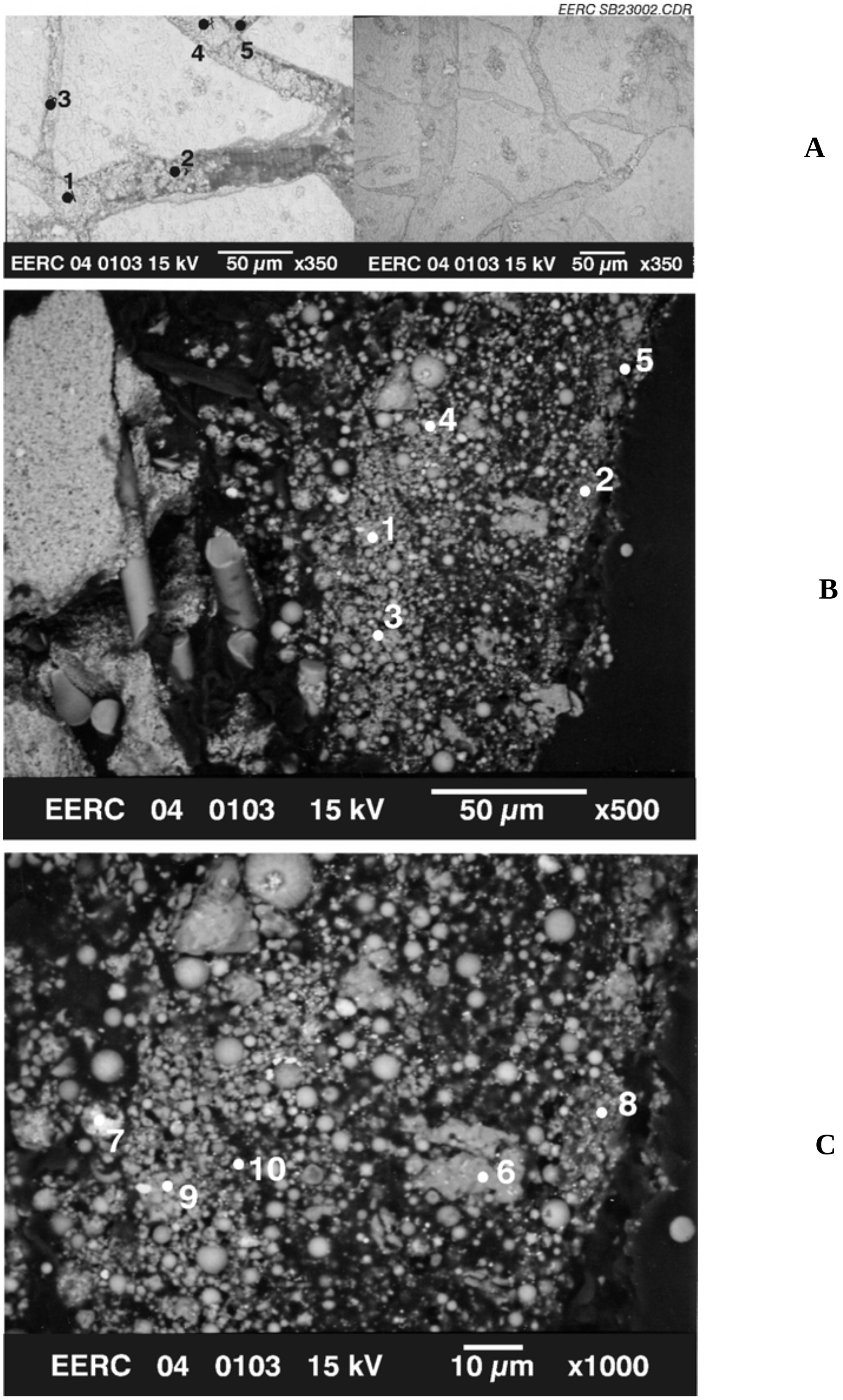


Figure 16. SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure. A) low-magnification image of ash deposit on catalyst surface, B) low-

magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

1.1.2.1 Table 4. Chemical Composition of Selected Points and Areas in Figure 16

	Chemical composition (normalized wt% equivalent oxide)				
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5
1.1.3					
	6.7	1.9	7.1	6.2	3.1
Na_2O	1.1	1.7	1.1	2.6	3.2
MgO	2.6	8.8	4.0	4.8	10.5
Al_2O_3	7.0	21.1	11.3	5.6	32.2
SiO_2	0.2	2.4	0.0	0.2	0.9
P_2O_5	54.7	38.5	56.4	57.5	30.4
SO_3	2.0	2.8	0.7	2.8	2.4
K_2O	18.0	3.4	15.8	9.3	2.3
CaO	0.6	0.8	1.1	1.3	1.5
TiO_2	5.8	5.1	2.1	6.5	9.8
Fe_2O_3	1.4	13.5	0.5	3.4	3.6
BaO					
Total	100	100	100	100	100

Oxide	Point 6	Point 7	Point 8	Point 9	Point 10
1.1.4					
	9.5	2.6	10.4	8.9	4.4
Na_2O	1.2	1.9	1.3	3.0	3.7
MgO	2.6	8.6	4.2	4.9	10.6
Al_2O_3	6.3	18.2	10.5	5.0	28.9
SiO_2	0.1	1.9	0.0	0.1	0.7
P_2O_5	41.8	28.4	44.9	44.5	23.4
SO_3	3.2	4.3	1.2	4.4	3.8
K_2O	24.5	4.4	22.5	12.8	3.1
CaO	0.6	0.8	1.3	1.5	1.8
TiO_2	7.7	6.6	2.9	8.9	13.2
Fe_2O_3	2.4	22.3	0.9	5.9	6.3
BaO					
Total	100	100	100	100	100

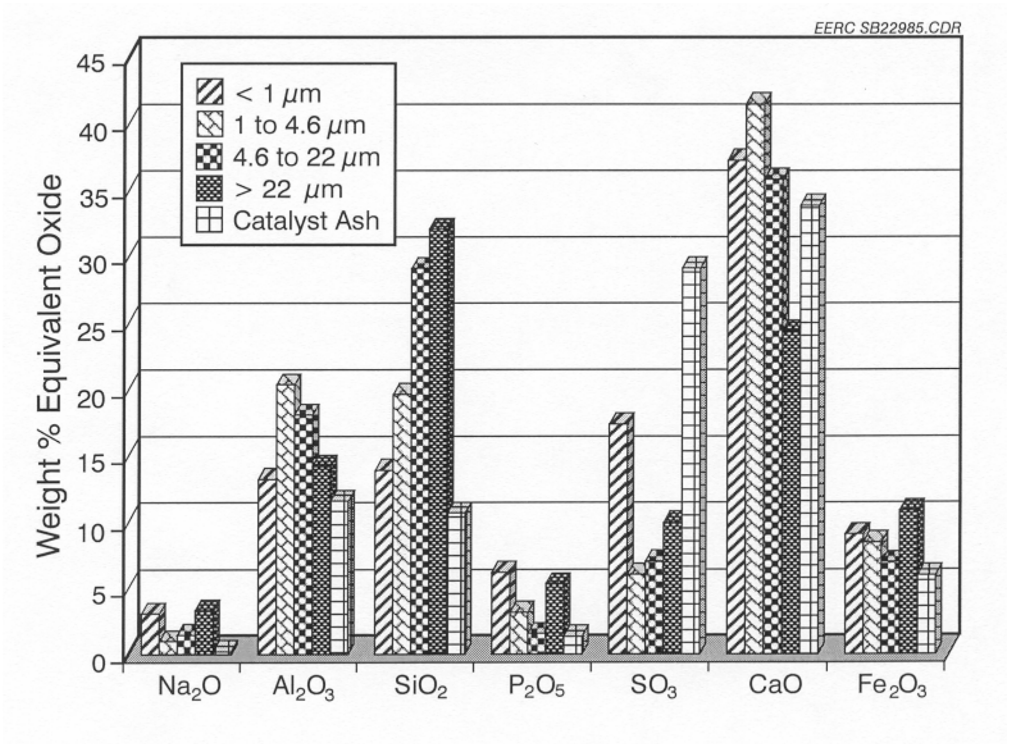


Figure 17. Comparison of entrained ash and deposited ash on catalyst for Columbia Station.

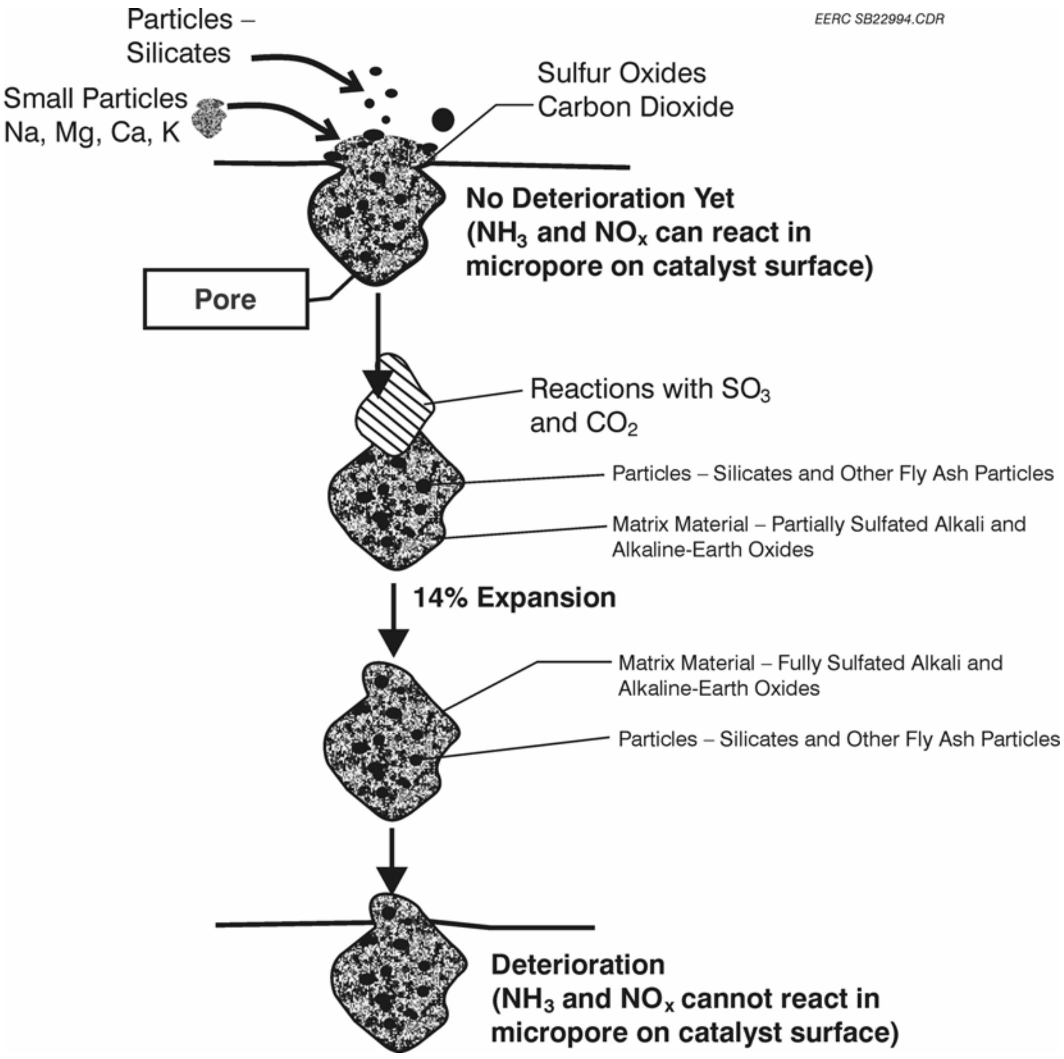


Figure 18. Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard and others [30]).

Low-Temperature Pyrosulfates

The presence of sodium sulfate in the flue gas exiting a scrubber will cause problems to low-dust and tail-end devices such as selective catalytic reduction (SCR) systems for NO_x reduction. There are two problems associated with the fine particulate rich in sodium sulfate on downstream devices. These include accumulation of fine particles on the SCR that, when sootblown, will cause opacity problems, and that the fine particles on the SCR will form pyrosulfates such as $(K_{1.5}Na_{0.5})S_2O_7$ that have melting points as low as 535°F (31) that will blind the catalyst. The presence of these compounds in low-temperature corrosion deposits is well known (32). In addition, the presence of SO_3 enhances the formation of the low-melting-point pyrosulfates (31). The sodium sulfate materials will cause opacity and SCR catalyst blinding problems that limit the feasibility of the low-dust or tail-end SCR technology for use with high-sodium lignite coals.

The sodium sulfate materials will be transported to the catalyst surfaces by diffusion, electrophoresis, and, possibly, inertial impaction. The particles are held in place by weak electrostatic and van der Waals forces. Once accumulation takes place, the sodium sulfate particles will react with flue gas components, resulting in the formation of pyrosulfates. The formation of pyrosulfates involves the following processes (31):

1. Formation of sulfates such as Na_2SO_4 and K_2SO_4

2. Conversion of SO_2 to SO_3 in the bulk gas phase – catalytically active surface such as an SCR catalyst – $SO_2 + \frac{1}{2} O_2 \rightarrow SO_3$

3. Pyrosulfate formation – $Na_2SO_4 + SO_3 \rightarrow Na_2S_2O_7$

The melting points of selected pyrosulfate phases are shown in Table 5.

Table 5. Melting Points of Selected Pyrosulfate Compounds

Compound	Temperature, °C	Temperature, °F
$K_3Fe(SO_4)_3$	618	1144
$K_3Al(SO_4)_3$	654	1209
$KFe(SO_4)_2$	694	1281
$Na_3Fe(SO_4)_3$	624	1155
$Na_3Al(SO_4)_3$	646	1195
$NaFe(SO_4)_2$	690	1274
$Na_2S_2O_7$	401	754
$K_2S_2O_7$	300	572
$(K_{1.5}Na_{0.5})S_2O_7$	279	535

Melting points for pyrosulfates between 535° and 770°F have been reported in the literature. Much of the past work has focused on the formation of these phases on tube surfaces. These species contribute to the corrosion of heat-transfer surfaces in coal-fired power plants. The exact melting point depends on the relative amounts of sodium and/or potassium.

There is significant evidence for the formation of sodium-rich fine particulate in full-scale power plants when firing high-sodium-containing coals. For example, Minnesota Power's Boswell Energy Station found that when it fired high-sodium, lower-ash subbituminous coal, it experienced increases in opacity. Hurley and Katrinak (33) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with an electrostatic precipitator and a wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using an impactor and multicyclone. The sized fractions were analyzed to determine the composition of the submicron-sized fraction.

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of one of the coals. Vapor-phase sodium condenses in the convective pass to form fine sodium sulfate particles or other Na species that later react with ash particles. Pure Na_2SO_4 particles are too small to be removed by scrubbing.

CONCLUSION: SCR IS NOT FEASIBLE FOR NO_X REDUCTION AT MILTON R. YOUNG

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be impossible because of the formation of sodium calcium sulfates in the pores of the catalyst. Following is a list of the key roadblocks associated with lignites which have not been overcome and, in our opinion, make the installation of SCR catalyst at the MRY plant technically infeasible for NO_x control.

- High alkali and alkaline-earth elements present in the coal fired at the MRY plant form sulfates that blind the catalyst.
    - Cyclone-firing partitions the ash during combustion. As a result the level of sodium and calcium in the fly ash is enhanced and will increase the SCR catalyst blinding.
    - Sulfate reactions increase with increasing temperature, and the suggested temperature of installation at the MRY facility is higher than typical installations; therefore, sulfation problems are enhanced.
    - Sulfate formation is also enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.
    - The high levels of sodium in the coals combined with calcium produces low-melting-point eutectic compounds that will melt on the surface.
    - Sulfates form on the surfaces of catalysts firing PRB coals. Lignites will be several orders of magnitude worse because of the higher levels of sodium.

- The ash components to impact SCR performance in Japan and Europe (14–16) include alkali and alkaline-earth elements that result in sulfate formation. The total calcium content and the sum of the calcium, magnesium, potassium, and sodium provide an indication of the problems that occur. For the coals fired at the MRY power plant, the CaO content ranges from 6.8%–19.99%, and the sum of the alkali and alkaline-earth elements range from 9.33%–29.87% of the ash. The levels of calcium in Center lignite are 2 to 4 times higher than the problematic coals in Japan and Europe.

- The finding or work conducted in Germany and Japan were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-rich sulfate formation that fill and plug the catalyst at both lignite (North Dakota)- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or popcorn ash, plugging the top of the SCR catalyst with deposit fragments, is a significant problem because of the extremely high deposition potential of the coal. The formation of deposits in various parts of the boiler requires continuous sootblowing. The deposit fragments are likely going to be carried with the bulk gas flow to the SCR catalyst, resulting in plugging.

- The variability of the lignite is a problem of unique concern at MRY. The deposition potential of the coal is always changing rapidly, resulting in rapid growth and formation of deposits in various sections of the boiler. Aggressive sootblowing of all fireside surfaces is already required to maintain full-load operation. The sootblowing of upstream heat exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, and during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

The ash-related impacts of the lignites from North Dakota are the most complex and severe of any coals in the world, and installation of tail-end SCR systems for NO_x reduction will not be possible. The key problems associated with lignites that have not been overcome and, in our opinion, make the installation of tail-end SCR systems at the MRY plant technically infeasible for NO_x control at MRY's Units 1 and 2 are listed below:

X High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces extreme levels of homogeneously condensed sodium sulfate that pass through the wet scrubber. In addition, the cyclone-firing system captures much of the ash as slag, resulting in a decrease in ash that is available for providing condensation sites for vapor-phase sodium compounds upon gas cooling. This results in an increased homogeneous condensation of sodium sulfate.

X These small particles pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials cannot feasibly be resolved through conventional sootblowing and cleaning technologies to remove the particulate.

X Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

The formation of liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems catalyze the formation of SO_3 from SO_2. The presence of SO_3 significantly enhances the formation of the pyrosulfates at MRY to an extreme level that cannot be dealt with effectively using cleaning technologies that exist today.

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APPENDIX C

COST METHODOLOGY

CAPITAL COST ESTIMATE DETAILS FOR NO_X CONTROLS

O&M COST ESTIMATE DETAILS FOR NO_X CONTROLS

C.1 METHODOLOGY FOR ESTIMATED COSTS

The summary economic evaluations of each alternative are presented in the cost impact sections of the main report. Capital and O&M cost estimates for each alternative are presented individually. The Levelized Total Annual Cost (LTAC) for all the alternatives for control of a single pollutant (i.e. NO_X) from a single unit is then presented together with Unit Control Costs. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 20 year design life, again in current (2006) dollars. As a minimum, the design life for any alternative was taken to be that recommended by "The EPA Air Pollution Control Cost Manual", Sixth Edition, January 2002, EPA/452/B-02-001[i].

The LTAC is also used to calculate the average annual and incremental cost effectiveness of each alternative. The LTAC represents an annual payment in current day dollars sufficient to finance the project over its entire life.

In determining the LTAC a Capital Recovery Factor and an O&M Levelization Factor were calculated from the project economic conditions and then applied separately to the estimated capital and O&M costs. The equation used is shown below.

$$LACC / NPV = \left(\frac{i(1+i)^n}{(1+i)^n - 1} \right) = CRF$$

Where,
LACC = Levelized Annual Capital Cost
NPV = Net Present Value of the capital investments required.
i = discount rate
n = design life in years
CRF = Capital Recovery Factor

Therefore:

LACC = CRF x NPV

For the economic conditions described in Table C.1-1 the Capital Recovery Factor was calculated to be 0.08718.

In determining the levelized annual O&M cost the estimated annual O&M cost, the inflation rate, the discount rate, and the equipment life are taken into account. The O&M Levelization Factor (OMLF) was calculated as follows.

$$LAOMC / A_1 = \left(\frac{1+i_d}{1+i_i} - 1 \right) \left(\frac{i_d (1+i_d)^n}{(1+i_d)^n - 1} \right) = OMLF$$

Where,
A = Levelized Annual O&M Cost (LAOMC)
A_1 = Total annual O&M cost in current dollars
i_d = discount rate
i_i = inflation rate
n = design life in years

Therefore:

$$LAOMC = OMLF \times A_1$$

For the economic conditions described in Table C.1-1 the Operating and Maintenance Levelization Factor was calculated to be 1.24873.

The Levelized Total Annual Cost, or LTAC is the sum of the levelized capital cost and the levelized O&M cost. Therefore:

$$LTAC = LACC + LAOMC = (CRF \times P) + (OMLF \times A_1) = 0.08718 \times P + 1.24873 \times A_1$$

The differences between alternatives are also presented graphically in the form of a plot of the annual emissions reduction (tpy) versus the LTAC for each alternative. This form of plot graphically depicts the cost effectiveness or Unit Control Cost (in $/ton of pollutant reduction) of each alternative relative to all of the others. The cost effectiveness is also referred to as the Unit Control Cost and defined as the LTAC divided by the annual emissions reduction (ton/yr). The area on the plot indicated by the various data points represents the cost effectiveness envelope for the alternatives under consideration. A smooth line is drawn on this plot connecting the rightmost points (those with the lowest cost for a given level of emissions reduction). This line is referred to as the Dominant Control Curve (DCC). The DCC defines the right hand boundary of the envelope encompassing all of the alternatives considered. The DCC is used as a screening tool between considered alternatives. Those alternatives whose plotted position is above and/or to the left of the DCC are not as cost effective as those forming the line and thus can be eliminated from further analysis if desired.

In order to compare various pollutant control alternatives, the Unit Control Cost and the incremental Unit Control Cost of each alternative were also calculated and tabulated for comparison purposes. The Unit

Control Cost compares control technologies on a basis of dollars expended per ton of pollutant reduced ($/ton). This relationship is graphically depicted in the DCC chart.

To more accurately compare between alternatives with different costs and control efficiencies, the incremental cost effectiveness is also determined for those alternatives on the DCC. The incremental cost effectiveness is defined as the LTAC of a given control option minus the LTAC of an alternative, divided by the difference between the annual emissions reduction (tpy) of the given control option and the alternative being evaluated. The combination of these two economic analyses can be used as an argument for the elimination of control technologies with significantly greater marginal control costs than the given case. The equation used for the incremental cost effectiveness is shown below.

$$ICF = \frac{(LTAC_1 - LTAC_2)}{(AE_1 - AE_2)}$$

Where,

ICF = Incremental cost effectiveness ($/incremental ton removed)
$LTAC_1$ = Levelized Total Annual Cost of control alternative No. 1 ($/yr)
$LTAC_2$ = Levelized Total Annual Cost of control alternative No. 2 ($/yr)
AE_1 = Control option No. 1 Annual Emissions Reduction (ton/yr)
AE_2 = Control option No. 2 Annual Emissions Reduction (ton/yr)
(The higher cost, more effective control option is subscript 1 in this equation.)

The economic analyses presented in this report not only include the estimated capital and O&M costs for each alternative, but also the LTAC for economic comparison of the various alternatives. In addition, the Unit Control Cost or cost effectiveness is presented for each alternative. Finally, a comparison between alternatives, in the form of the marginal cost effectiveness, is presented in both numerical and graphical form. Thus a comprehensive comparison of the economic impacts of each alternative, as well as the differences in economic impact between alternatives is clearly presented.

Table C.1-1 – Economic Factors(1),(2)

Total Possible Operating Hours per Year	8,760
Amortization Life, Years	20
Cost of Money	6%
Property Taxes, Insurance, %	NA
Conversion Tax (in lieu of property tax)	NA
Amortization Rate for APC Capital Costs	6%
Interest During Construction (IDC)	6%
Discount Rate (used to calculate NPV)	6%
Construction Cost Escalation	3%
Non-Fuel O&M Escalation	2.5%
Fuel (coal and natural gas) Escalation	2.5%
Auxiliary Electric Power Cost, $/MW-hr	$35.00
Urea Cost, ($/ton delivered, 50% aqueous solution)	$380.00
Natural Gas ($/mmBtu)	$7.98

(1) - All financial percentages and unit auxiliary electric power cost were provided by MPC.
(2) - All costs are in 2006 dollars unless noted otherwise.

C.2 NOx CONTROLS - CAPITAL COST ESTIMATES

The capital costs to implement the various NO_X control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. In the cases of SNCR and FLGR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy, or better.

The limitations of these capital cost estimates developed from unit capital cost factors multiplied by unit output are:

- Scope basis uncertainty – inability to precisely determine what scope of supply, including such things as balance-of-plant (BOP) systems and equipment improvements were required, assumed, or accounted for when developing the unit cost factors. Some alternatives may have higher indirect or BOP capital costs than others. Similarly, the inclusion of general facilities, preproduction and inventory costs, and other indirect costs is not known. It is likely that the utility owner’s final total expenditure for the implementation of the alternatives, especially options that are most capital cost-intensive, will be greater than the calculated cost estimates.
- Location-specific influences – most NO_X control techniques have been applied primarily to eastern bituminous coal-fired plants located near large metropolitan areas, not in largely rural, upper midwestern United States locales. The amount of space available is dependent on the existing powerplant equipment and building layout and property plot area, versus what is expected to be required for implementing various control technologies. Transportation and local/regional labor costs are also variables.
- Size influences – some technologies’ capital costs are more sensitive to “economies of scale” than others.
- Capacity margins – some technologies’ may require higher capacity margins to allow sustained operation at high throughput rates over extended periods of time.
- Reliability concerns – some technologies’ have been refined to a higher degree, and others may require more component redundancy than others in order to avoid performance reductions and potential outages for failures and repairs or replacements.
- Inflationary influences – the significant increases in 2004-2005 for raw material costs, especially steel and alloys for fabrication of structural and mechanical components, has occurred after many of these technologies were installed in projects upon which the referenced unit capital cost factors were based.

- Market conditions – as demand increases for emission controls, some alternatives become more cost-competitive, while others do not. This can be influenced by the relative supply and demand for the technology and number of suppliers who can furnish it. The demand for some alternatives can also be strongly influenced by the stringency of the local, state, and national regulatory requirements. Schedule for implementation and availability of local/regional labor for installation contractors are also market-driven factors.

The estimated NO_X control costs are in addition to capital costs to provide normal replacements of the existing Milton R. Young Station's major power generating equipment.

C.2.1 Separated Overfire Air Capital Cost Estimates

Installation of separated overfire air systems typically includes windbox and/or secondary combustion air supply duct modifications, boiler waterwall tube openings, airflow distribution devices (dampers/registers), airflow controls and measurement instrumentation, and related structural and electrical tie-ins to the existing plant facilities. A basic separated overfire air retrofit system installed on a lignite-fired cyclone boiler includes ports across the front and rear walls of the upper furnace. The unit capital cost factor is expected to be above the high end of the typical published cost range of \$5-10/kW[ii] (\$11.5/kW or \$5.500,000[3] for MRYS Unit 2), due to the large ducts, relatively tall furnace (compared to typical bituminous coal-fired cyclone boilers), and the need to avoid existing obstructions within the boiler house.

An advanced form of SOFA unique to North Dakota lignite-fired boilers will include relocation of the existing lignite drying system vent port openings from the lower primary furnace to the upper furnace, to be placed at the same elevation as the new SOFA ports. This requires extension of the existing cyclones' lignite drying systems' vent piping to supply the new boiler furnace ports. This retrofit will also close-off the existing FGR ports in the lower front and rear furnace walls of Unit 2, currently coinciding with the existing pre-dry vent ports. These FGR ports may be blocked, or relocated to the lower portion of the upper (secondary) furnace, across the front and rear walls. This is expected to cost in the area of +\$9.5/kW or \$4,500,000 for Unit 2's additional capital cost over and above the basic SOFA system. Overall, the advanced version of separated overfire air technology is estimated to have an installed capital cost of approximately \$10.0 Million (\$21.0/kW) for MRYS Unit 2.

C.2.2 Reburn Capital Cost Estimates

C.2.2.1 Coal Reburn Capital Cost Estimates

There is one alternative that includes a new coal reburn system. Capital cost estimates for coal reburn systems are highly dependent on the requirements for reburn fuel preparation and feeding to the boiler. For the purposes of this analysis, the application of a pulverized coal reburn system assumed the need to make extensive additions to the existing fuel preparation equipment in the existing plant facilities and feeding to new furnace injectors. At least two new fine-grind pulverizers, or MPS-89 standard pulverizers followed by dynamic classifiers are expected to supply the amount of finely ground reburn coal for this method.

Addition of new electrical loads for the pulverized coal preparation equipment to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power will be available for powering the new pulverizers/micro-mills and related new coal reburn equipment, but this has not been confirmed.

The existing crusher bays do not have floor space available to allow the new milling equipment for reburn fuel preparation to be located adjacent to the existing coal crushers. This will require a separate building or addition to the existing powerhouse to be built to provide sufficient space to enclose the new milling and coal silo/handling equipment. Separate modified pulverized coal-style burners or coal injectors will be installed through new openings in the upper furnace front and rear waterwalls at or above the elevation of the existing lignite drying system vent ports, along with new overfire air ports located at a higher elevation, above the reburn fuel injectors. This would have the capacity to supply approximately up to thirty percent of the total full load fuel heat input to the boiler through the coal reburn injectors. This coal reburn system design was not expected to change the existing cyclone silo/feeder arrangement, such that all cyclones would remain operational. To achieve maximum NO_X emission control, only the advanced form of SOFA for pulverized coal reburn was included. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

The installed capital cost of pulverized coal reburn for the cyclone boilers at Milton R. Young Station used in this cost effectiveness analysis was estimated based upon a Clean Air Markets Division [CAMD] of the US EPA dollar per kilowatt unit capital cost factor for cyclones. The installed capital cost estimate of $40.65 Million for MRYS Unit 2’s pulverized coal reburn alternative used in this cost effectiveness analysis was estimated based upon applying a 3.5% assumed inflation cost adjustment to the CAMD unit capital cost factor for cyclones of $82.33/kW (x 1.035 = $85.2/kW) included in a WRAP (Western Regional Air Partnership) draft report[iv] published on their website, dated April 26, 2005. The cost to relocate the lignite drying system vent ports and FGR ports was added to the inflation-adjusted CAMD number ($85.2 + $9.5/kW = $94.7/kW), since coal reburn is expected to include separated overfire air but not the extra costs for the special improvements identified for air-staged lignite-firing in cyclone boilers. This increased the installed capital cost by $4.M for MRY Station Unit 2's coal reburn system to a total of $45,154,000. This does not include the additional particulate matter collection capacity considered necessary to limit the expected negative impact on opacity from this option.

To control particulate matter (PM) emissions that would be expected to increase from installation and operation of pulverized or micronized coal reburn, additional PM collection capacity will be required. A hybrid form of PM collection that supplements the existing electrostatic precipitator's performance, referred to as COHPAC (COmpact Hybrid PArticulate Collector). This was estimated in 2002 dollars at $30,200,000 for MRYS Unit 2's COHPAC[3]. Adjusted by an escalation factor of 1.2623, the installed capital cost of the COHPAC addition was estimated to be $36,013,000 for MRYS Unit 2 in 2006 dollars. When the COHPAC addition was combined with the Lignite Reburn and ASOFA alternatives, the resulting total estimated capital costs were $81,167,000 for MRYS Unit 2 ($94.7 + $75.5 = $170.2/kW).

C.2.2.1 Gas Reburn Capital Cost Estimates

Conventional gas reburn options assume that seventeen percent of the total fuel heat input to the boiler is through the new gas reburn injectors to be located in the lower secondary furnace above the top rows of cyclones. Eight to twelve gas reburn injectors would be expected to be required in this case. Seven percent of the total fuel heat input to the boiler through the gas reburn injectors is assumed to be supplied for the fuel lean gas reburn alternatives. Four to eight gas reburn injectors could be assumed in FLGR™ cases. Gas reburn options assume that a new high-pressure gas pipeline would be brought from near Bismarck, ND approximately twenty six miles. The pipeline diameter is proportional to the amount of fuel required for the specific alternative, ranging from 24 inches for conventional gas reburn to 12 inches for fuel lean gas reburn cases. A station gas main, with new gas trains, consisting of valves, metering, and safety shutoff valves for the front and rear boiler for the gas injectors' supply, would be furnished and installed.

The capital costs for conventional gas reburn alternatives were estimated considering unit capital costs published in published technical literature. One vendor that has supplied numerous domestic utility boiler gas reburn systems (GE Energy, formerly GE-EER) published $10/kW for gas reburn in a 2001 technical paper[v]. Another source published a 2005 technical paper[vi] that provided a unit capital cost range for gas reburn of $15/kW to $30/kW. Neither source included a detailed scope description nor cost breakdown for engineering, equipment, materials, and labor to install a gas reburn system.

Site-specific needs and challenges identified for applying conventional gas reburn to Milton R. Young Station, and lack of detailed gas reburn project scope and equipment descriptions available in published technical literature leads to a much greater degree of uncertainty with regards to an accurate capital cost estimate for this alternative. For the purposes of this study, the estimated installed capital cost for a conventional gas reburn system with advanced SOFA on MRYS Unit 2 is expected to be approximately $20.5M ($43/kW), which is above the top end of the previously stated range, before adding the new underground gas pipeline capital costs. This study assumed an average unit capacity capital cost factor of $22/kW for conventional gas reburn, plus the additional costs for the advanced form of SOFA over basic SOFA +$4.5M ($9.5/kW), and the new high-pressure gas pipeline. This results in a an estimated installed capital cost for conventional gas reburn system with advanced SOFA on MRYS Unit 2 of $20.5M ($43/kW) plus the new high-pressure gas pipeline costs. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

Fuel lean gas reburn (without SOFA) capital cost estimates were based upon a late 2004 budgetary proposal[vii] by a vendor (Fuel Tech) with experience in supplying FLGR™ equipment, typically combined with an SNCR system. Estimated capital costs of $3M include budgetary numbers for the equipment installation, including installation management, material and labor, with a +6.0% price adjustment assumed for 477 vs 450 MW for a fuel lean gas reburn system without SOFA on MRY Unit 2, not including the capital cost for the gas supply pipeline. Costs for work outside the vendor's scope, such as balance-of-plant additions plus other indirect costs were estimated to add approximately $1.1M (25% plus 10% contingency) to the adjusted vendor's estimated installed cost of $3.2M for their scope of supply. These adjustments result in a total installed capital cost for FLGR (without SOFA) estimated to be $4.3M plus the capital cost for the gas supply pipeline. Adding the incremental costs for the advanced from of SOFA over no SOFA (+$10M ($21/kW) results in an estimated installed capital cost for a fuel gas reburn system with advanced SOFA on MRYS Unit 2 of $14.3M ($30.0/kW) plus the new high-pressure gas pipeline costs.

The capital cost estimates for the new high-pressure underground gas supply pipeline assumed $7 per inch of diameter per foot of length. This was calculated to be approximately $23M for conventional gas reburning and $11.5M for FLGR™. The cost analysis for each NO_X control alternative involving a particular form of gas reburn assumed that both boilers at Milton R. Young Station select the same alternative that burns natural gas. Therefore, the estimated capital costs for gas reburn alternatives reflect a capacity-based proportional share of the gas pipeline capital costs, avoiding double-counting. This results in an estimated installed capital cost for MRYS Unit 2's share of the gas pipeline to be $15M for the conventional gas reburn alternative and $7.5M for fuel-lean gas reburn alternatives.

The total installed capital costs for conventional gas reburn (with ASOFA) with MRYS Unit 2's share of the total capital cost for the gas supply pipeline estimated to be $35.5M ($74.4/kW). The total installed capital costs for FLGR™ (with ASOFA) with MRYS Unit 2's share of the total capital cost for the gas supply pipeline were estimated to be $21.8M ($45.7/kW). Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

C.2.3 SNCR Capital Cost Estimate

The alternatives that include selective non-catalytic reduction systems assume the use of urea unless noted otherwise. The SNCR systems' preliminary design and estimated capital costs were based upon a 450 MW lignite-fired cyclone boiler in a late 2004 budgetary proposal[7] by a vendor (Fuel Tech) with experience in supplying SNCR equipment. Circulation, metering, dilution, control, and injection equipment is included. A 180,000 gallon field-erected stainless steel storage tank will hold the 50% urea solution (as delivered by truck). Individual and multiple nozzle lances with multiple levels of urea reagent injection will be designed and located to optimize distribution and accommodate various boiler load conditions. Estimated capital costs of $4.9 Million include budgetary numbers for equipment installation, including installation management, material and labor assumed for a SNCR system applied to a 450 MW boiler. Costs for work outside the vendor's scope, such as outdoor reagent storage tank and building enclosure/equipment foundations and containment, and balance-of-plant additions plus other indirect costs were estimated to add approximately $1.9 Million (25% plus 10% contingency) to the vendor's estimated installed cost for their scope of supply. This results in an estimated total capital cost for SNCR (without SOFA) of $6.8M for a 450 MW lignite-fired cyclone boiler.

Applying these adjustments to a 477 MW boiler results in an estimated total installed capital cost for SNCR of $7,120,000 for MRY Station Unit 2 ($14.9/kW).

C2.5 Layered Technology Capital Cost Estimates

Capital costs were generally estimated based upon simple arithmetic addition of individual unit output capital cost factors for combinations of available NO_X reduction technologies, such as SNCR with ASOFA. An advanced form of separated overfire air system included the lignite-fired cyclone boiler equipment changes within the estimated unit capital cost factors.

Adding the advanced SOFA capital cost of $10.0 Million to the previous estimated installed capital cost of $7.12 Million yields a total estimated installed capital cost of $17.128 Million ($35.9/kW) for the SNCR with ASOFA alternative for MRYS Unit 2.

As previously discussed, Lignite (coal) reburn (CR) was assumed to be combined with advanced SOFA and a COHPAC addition considered necessary to limit the expected negative impact on opacity from this option. The installed capital cost of the COHPAC addition was estimated to be $36,013,000 for MRYS Unit 2. When the COHPAC addition was combined with the Lignite Reburn and ASOFA alternatives, the resulting total estimated capital costs were $81,167,000 for MRYS Unit 2 ($94.7 + $75.5 = $170.2/kW).

C.3 Operating and Maintenance Cost Estimates for MRY Station NO_X Control

An evaluation was performed to determine the estimated operating and maintenance cost impacts of installing and continuously operating various feasible NO_X control technologies on Milton R. Young Station Unit 2. These were estimated to be in addition to existing O&M costs to operate and maintain the MRY Station equipment.

The expected loss of electrical power sales from the operation of the specific NO_X control alternative was included as an annualized cost, assuming $35 per megawatt-hour. This was determined to include estimates for:

- Reduction in annual unit output due to an expected negative reliability (i.e. uptime availability) impact for each alternative. This generation reduction was calculated by multiplying the estimated additional numbers of outage hours per year by the average running plant capacity factor for that specific alternative, multiplied by the historic 12-month average unit gross electrical power output (MW_g) determined during the same period as the highest 12-month rolling summation NO_X pounds.
- Net additional auxiliary electric power demand for the added control equipment for each specific alternative based on assumptions for gross horsepower, plus additional power demand for existing fans caused by flue gas pressure drop (COHPAC for additional PM collection capacity), with adjustment for expected reductions in power demand (such as a decrease in existing coal crusher and feeder electric demand for the pulverized coal reburn case).
- The average running plant capacity factor for each alternative, which may also include an expected negative impact on the unit capacity from operation of the technology. This assumes that the control technique limits the gross electrical power output of the Unit (such as causing an increase in flue gas flow) such that the firing rate of the boiler cannot be maintained or raised to compensate for the load impact. Examples are lower boiler thermal efficiency (higher unit heat rate) when firing natural gas (due to higher moisture content of the flue gas).

For the SNCR alternative that involves a chemical reagent injected for NOx control, such as urea, the annual reagent consumption based on an assumed actual stoichiometric ratio (ASR) of moles of equivalent NH_3 injected per mole of uncontrolled NO_X emission estimated at the point of injection, converted to a mass rate (lbs/hr) by multiplying by the estimated annual number of hours of operation and the estimated NOx reduction fraction, and then multiplied by unit reagent cost (for a specific inlet NO_X concentration, emission reduction percentage and ammonia slip level).

General annual maintenance costs were assumed to be 1.5 percent of the estimated installed capital cost for each alternative, except for the coal conveying and grinding equipment portion of the coal reburn alternative, which was assumed to be 3 percent. The periodic bag replacement costs and other COHPAC system maintenance costs were estimated to be approximately 5.3% of the installed capital cost of the additional particulate matter collection equipment.

Additional operating labor costs directly attributable to each alternative were assumed to be zero for all alternatives.

Other operating costs include:

- Reagent dilution water for those alternatives that involve a chemical reagent injected for NOx control, typically four times the amount of urea consumption (assumes urea is a 50% solution as delivered and is injected as a 10% solution); this follows EPA OAQPS convention[1].
- Heat required for urea reagent storage, for those alternatives that involve a chemical reagent injected for NOx control; the source of heat is assumed to be auxiliary electrical power, but could be auxiliary steam (depending on heat source availability and plant preference).
- Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water;
  This follows EPA OAQPS convention[1], but is not accepted practice by an experienced SNCR vendor (Fuel Tech) who claims that the heat produced from the exothermic reaction of urea and NO_X is approximately equal to the heat required to evaporate the dilution water. For the purposes of this study, this additional coal consumption has been included in the annual O&M costs.

The sum of the estimated annual O&M costs was multiplied by the O&M levelization factor (1.24873) for each alternative to yield levelized total annual O&M costs.

C.3.1 Separated Overfire Air O&M Cost Estimate

Operation of SOFA is expected to add a small amount of O&M cost, primarily electricity consumed by the conventional SOFA damper electric drive actuator and airflow measuring system transmitter on each port. Using the existing forced draft, induced draft, and flue gas recirculation fans is not expected to change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. Maintenance of the new overfire air ports and relocated lignite drying system vent ports (and FGR ports for Unit 2) is included, assumed to be 1.5 percent of the installed capital cost. This is included in every control alternative's estimated O&M cost.

SOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers can be routinely established. A Unit availability reduction of 2.2% (181 hours per year), for M.R. Young Station Unit 2 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic cyclone slag tapping operational conditions encountered during substoichiometric cyclone operation with SOFA. The expected loss of electrical power sales from the reduction in annual electrical power output due to a decrease in expected Unit availability from ASOFA operation is included in every control alternative's estimated O&M cost.

Boiler furnace waterwall tube maintenance may increase slightly as a result of more fireside corrosion due to substoichiometric cyclone operation with SOFA. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion from sulfur compounds in the furnace gases being created above the cyclones and below the SOFA injection ports. Due to the relatively moderate amounts of sulfur content in the lignite, modest amount of air-staging of the existing cyclones during SOFA operation, and the potential use of recirculated flue gas along the lower furnace walls, the expected change in corrosion rate of the boiler tubes should be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The additional costs associated with potential change in the frequency of furnace wall tube failures and changeouts are difficult to estimate, and have not been quantified.

C.3.2 Reburn O&M Cost Estimates

The alternatives that include a new coal reburn system assume the use of new equipment for preparing the reburn fuel to replace 25% of the MRY Station Unit 2 boiler's total fuel heat input. Two additional lignite silos, with coal feeders and fine-grind pulverizers followed by dynamic classifier(s), are assumed to be located in a new separate building or powerhouse enclosure. Booster fan(s) addition was included because the existing forced draft fans were assumed to be incapable supplying the additional amount of primary air to the fine-grind pulverizers and dynamic classifier(s) for processing and conveying the reburn fuel. Using the existing forced draft, induced draft, and flue gas recirculation fans is not expected to significantly change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. The expected loss of electrical power sales from the additional auxiliary electric power demand for the reburn milling equipment from an estimated 0.5% (2.5 MW) reduction in net output was included as a cost, assuming $35 per megawatt-hour for MRY Station Unit 2. Electrical power consumed by the increased load on boiler fans to overcome the higher flue gas system pressure drop, plus the COHPAC particulate collection system support equipment was estimated to be a 1.2% (5.8 MW) reduction in net output for Unit 2.

Maintenance of the separate reburn coal injectors, fuel and primary air piping, and reburn fuel milling equipment is expected to be similar to the expenses associated with typical pulverized coal burners. The estimated additional annual maintenance costs for a new micronized coal reburn system was assumed to be 3.0 percent of the installed capital cost, or roughly $1,355,000 per year, for MRY Station Unit 2. The estimated additional annual maintenance costs (inflation adjusted from 2002 to 2006 $) for the COHPAC system was approximately $1,938,000 per year for MRYS Unit 2. Boiler furnace waterwall tube and superheater/reheater tube maintenance may increase slightly as a result of more erosion due to increased particulate emissions or fouling by flyash deposits resulting from coal reburn operation with ASOFA. The additional costs associated with potential change in the frequency of boiler tube failures and changeouts are difficult to estimate, and have not been quantified.

The estimated impacts on operation and maintenance costs for the coal reburn alternative that include a new pulverized or micronized coal reburn system are approximate. The twelve (Unit 2) existing coal crushers for preparing the main (cyclone) fuel fraction will have slightly lower electrical demand. This was estimated as -0.45 MW (-0.09%) for MRYS Unit 2. Addition of new electrical loads for the micronized coal preparation equipment to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power will be available for powering the new pulverizers/classifiers and related new coal reburn equipment, but this has not been confirmed.

Coal Reburn with ASOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers can be routinely established. A Unit availability reduction of 3.7% (3.8% (313 hours per year), for M.R. Young Station Unit 2 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic operational conditions encountered during coal reburn operation with ASOFA. This reduction in annual electrical power output due to a decrease in expected Unit availability is included in the coal reburn control alternative's estimated O&M cost.

A Running Plant Capacity Factor reduction of 0.5% of annual gross electrical output was assumed for the coal reburn alternative. This would result in an estimated 2.2 MW average load decrease for M.R. Young Station Unit 2. This expected loss of electrical power sales from the reduction in net output due to this plant capacity impact was included in the estimated annual O&M costs.

Conventional and fuel-lean gas reburn options will involve higher operating costs compared with the existing operation of M.R. Young Station. Natural gas supply was assumed to be available near Bismarck, ND, but this has not been confirmed. The estimated unit cost of this natural gas was assumed to average $7.98/million Btu on a levelized annual cost basis, with a "credit" of $0.71 per mmBtu for avoided cost of consumption of lignite coal reduced by the natural gas heat input. The estimated annual cost of natural gas for the conventional gas reburning alternative applied to MRYS Unit 2 is approximately $50.3M per year. The estimated annual cost of natural gas for the FLGR™ alternative applied to MRYS Unit 2 is approximately $20.8M per year.

The new gas reburn injectors, station gas main and injector gas trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost. Maintenance of separated overfire air nozzles is expected to be similar to the expenses associated with Unit 2's existing flue gas recirculation ports.

C.3.3 SNCR O&M Cost Estimate

The alternatives that include selective non-catalytic reduction systems will involve higher operating costs compared with the existing operation of MRY Station Unit 2. Urea reagent supply was confirmed to be available regionally. The estimated unit cost of this 50% aqueous urea solution was assumed to average approximately $379/ton delivered (2006$). Consumption of urea reagent for SNCR with ASOFA was based upon preliminary numbers allowing for a boiler flue gas exit ammonia slip of 5 ppmvd. These were estimated as approximately 286 gph for SNCR when applied to MRY Station Unit 2 with ASOFA.

New electrical loads are required for high flow urea circulation, in-line and storage tank heating, water dilution, and reagent metering equipment. These auxiliary electrical demands and reagent dilution water usage were calculated based upon equations published in EPA Office of Air Quality Planning and

Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Oxidation[1]. Compressed air for reagent atomization and lance purging and cooling, as well as multiple nozzle lance water cooling are additional demands on the existing plant facilities. These powerhouse building service supplies were assumed to be available, but this has not been confirmed. The new urea reagent injection nozzle lances, reagent pumps, dilution water pumps, and distribution piping/valve trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost.

SNCR with ASOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming urea injection does not impact the ability to maintain consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers. A Unit availability reduction of 3.2% (263 hours per year), for M.R. Young Station Unit 2 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic operational conditions encountered during SNCR-related operation with ASOFA. This reduction in annual electrical power output due to a decrease in expected Unit availability is included in the these control alternatives' estimated O&M costs.

A Running Plant Capacity Factor reduction of 0.15% of annual gross electrical output was assumed for the SNCR with ASOFA alternative. This would result in an estimated 0.66 MW average load decrease for M.R. Young Station Unit 2. This expected loss of electrical power sales from the reduction in net output due to this plant capacity impact was included in the estimated annual O&M costs.

C.3.4 Layered Technology O&M Cost Estimates

Operating and maintenance costs for combinations of available NO_X reduction technologies were estimated based upon simple arithmetic addition of individual cost estimates. SNCR was combined with advanced SOFA, as previously shown. Pulverized coal reburn was assumed to be combined with advanced SOFA (and a COHPAC addition for PM control). The auxiliary electrical demands and reagent dilution water usage for SNCR with ASOFA were calculated based upon equations published in EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Oxidation[1].

C.3.5 Summary of O&M Costs Estimates for MRY Station NOx Control

The results of this evaluation for estimated variable operating and maintenance costs for the individual NOx control alternatives are summarized in this section. The expected reductions in Unit availability (uptime) and capacity are included in Tables C.3-1 through C.3-7 for MRYS Unit 2. Tables C.3-5 and C.3-6 for MRYS Unit 2 include the estimated urea reagent and dilution water usage rates and costs for the alternatives that involve SNCR with ASOFA NO_X control technologies.

TABLE C.3-1 – Expected Availability Reductions for MRY Unit 2 NO_X Controls

		Estimated Annual Average Unit Operating Time			
Alt. Label(1)	**NOx Control Technique**	**Unit Availability(2)**	**Unit Operating Time(3), hrs/yr**	**Unit Outage Time(4), hrs/yr**	**Unit Operating Time Reduction(5), hrs/yr**
E	SNCR w/ ASOFA	0.909	7965	795	263
D	Gas Reburn w/ ASOFA	0.919	8048	712	181
C	Coal Reburn w/ ASOFA	0.904	7916	844	313
B	FLGR w/ ASOFA	0.919	8048	712	181
A	Advanced SOFA (ASOFA)	0.919	8048	712	181
	Baseline	0.939	8229	531	0

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.
(2) – 12-month baseline availability is assumed at 93.9 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
(3) – Annual operating time is annual average availability multiplied by 8760 hrs/yr of possible uptime.
(4) – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.
(5) – Annual operating time reduction resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.

TABLE C.3-2 – Expected Capacity Reductions for MRY Unit 2 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Unit Electrical Power Generation Reduction from Operating Time Reduction		
		Unit Running Plant(2) Capacity Factor	Unit Generation Reduction(3) kW-hrs/yr	Unit Generation Reduction Cost(4), 1000$/yr
E	SNCR w/ ASOFA	0.951	110,176.095	3,856
D	Gas Reburn w/ ASOFA	0.943	81,416,590	2,850
C	Coal Reburn w/ ASOFA	0.948	130,375.506	4,563
B	FLGR w/ ASOFA	0.949	81,910,024	2,867
A	Advanced SOFA (ASOFA)	0.952	75,859.855	2,655
	Baseline	0.952	0	0

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.

(2) – 12-month baseline running plant capacity factor is assumed at 95.2 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.

(3) – Annual electricity generation reduction is annual operating time reduction multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the 12-month average gross output of 440 MW.

(4) – Annual electricity generation reduction cost is the annual electricity generation reduction (kW-hrs/yr) resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-3 – Expected Auxiliary Electrical Power Demand Changes for MRY Unit 2 NO_X Controls

Alt. Label[1]	NOx Control Technique	Estimated Annual Average APC NOx Equipment Auxiliary Electrical Power Demand and Usage				
		Gross Demand [2] kW	**Credit[3] kW**	**Total Net Demand[4] kW**	**Power Usage[5] kW-hrs/yr**	**Power Usage Cost[6], 1000$/yr**
E	SNCR w/ ASOFA	133.2	0	133.2	1,008,704	35
D	Gas Reburn w/ ASOFA	1	(228)	(227)	(1,724,428)	(60)
C	Coal Reburn w/ ASOFA	8,342	(448)	7,894	59,217,554	2,073
B	FLGR w/ ASOFA	1	(125)	(124)	(949,051)	(33)
A	Advanced SOFA (ASOFA)	1	0	1	7,664	0.3

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.

(2) – The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects. Coal reburn includes 2,484 kW for feed preparation and conveying equipment demand plus 5,857 kW for the COHPAC system addition for PM control.

(3) – The APC NOx equipment auxiliary electrical power demand credit of coal reburn alternatives is the estimated result of lower cyclone coal preparation and feeder power demand due to lower boiler cyclone coal equipment loading. Actual power demands may differ from this due to accuracy of estimates for assumed amount of operating horsepower reduction.

(4) – The total net auxiliary electrical power demand is the sum of the gross demand and credit.

(5) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.

(6) – The annual change in APC NOx equipment auxiliary electrical power demand electricity cost is the annual change in kW-hrs/yr for these alternatives resulting from the implementation of the individual NOx control technique multiplied by the incremental value of auxiliary electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-4 – Expected Auxiliary Electrical Power Demand and Generation Reduction Cost Changes for MRY Unit 2 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Change in Unit Generation Due to APC NOx Equipment Auxiliary Power Electricity Demand and Generation Reduction			
		APC Electrical Power Usage(2) kW-hrs/yr	Unit Generation Reduction(3) kW-hrs/yr	Total Unit Electrical Power Generation Change(4) kW-hrs/yr	Total Unit Electrical Power Generation Change Cost(5) 1000$/yr
E	SNCR w/ ASOFA	1,008,704	110,176.095	111,184,799	3,891
D	Gas Reburn w/ ASOFA	(1,724,428)	81,416,590	79,692,162	2,789
C	Coal Reburn w/ ASOFA	59,217,554	130,375.506	189,593,059	6,636
B	FLGR w/ ASOFA	(949,051)	81,910,024	80,960,972	2,834
A	Advanced SOFA (ASOFA)	7,664	75,859.855	75,867,520	2,655

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.

(2) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.

(3) – Annual electricity generation reduction is annual operating time reduction multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the 12-month average gross output of 440 MW.

(4) – The total unit electrical power generation change is the sum of the annual change in APC NOx equipment auxiliary electrical power demand electricity usage plus the annual electricity generation reduction resulting from the implementation of the individual NOx control technique.

(5) – The total unit electrical power generation change cost is the total generation change (kw-hrs/yr) multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-5 – Expected NOx Reagent Usage and Cost Estimates for MRY Unit 2 NO_X Controls

Alt. Label[1]	NOx Control Technique	NOx Reduction Reagent Urea Usage[2]			NOx Reduction Reagent Dilution Water Usage[3]	
		lbs/hr	tons/yr	1000$/yr	1000 gal/yr	1000$/yr
E	SNCR w/ ASOFA	2,713	9,826	3,727	9,851	10

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – All cost figures in 2006 dollars.
(3) – Reagent dilution water usage assumes potable water is added to create a 10% urea concentration (4 parts water to 1 part urea solution at 50% concentration) prior to injection. Dilution water unit cost assumed to be $1.00 per thousand gallons.

TABLE C.3-6 – Expected Heat Input and Equivalent Coal Cost to Evaporate Aqueous Urea for MRY Unit 2 NO_X Controls

Alt. Label[1]	NOx Control Technique	Estimated Annual Average Unit Equivalent Coal Consumption Cost for Aqueous Urea Evaporation		
		Heat Required to Evaporate Aqueous Urea[2], mmBtu/yr	Equivalent Coal Consumption for Heat Input[2], Tons/yr	Coal Consumption Cost[2], 1000$/yr
E	SNCR w/ ASOFA	73,986	5,553	52

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – Heat required to evaporate urea reagent dilution water assumes 900 Btu/lb required based on a 10% urea concentration (4 parts water to 1 part urea solution at 50% concentration) injected for the estimated amount of urea usage. Coal heat content of 6,662 Btu/lb, unit cost of $0.71/mmBtu.

Appendix C References:

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[i] EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf, Chapter 2 - Selective Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch2.pdf.

[ii] "Stationary Source NOx and PM Emissions in the WRAP Region: An Initial Assessment of Emissions, Controls, and Air Quality Impacts", October 1, 2003 Western Regional Air Partnership Final Report of the WRAP Market Trading Forum, Section VI: Summary of Emission Controls Available for Large Stationary Sources of NOx and PM (by Reaction Engineering International), available at http://www.wrapair.org/forums/mtf/nox-pm.html

[iv] "Analysis of Combustion Controls for Reducing NO_X Emissions From Coal-fired EGU's in the WRAP Region" WRAP Draft Report EGR Contract Number 30204-101, prepared by Eastern Research Group, Inc., dated April 26, 2005, posted at their website: http://www.wrapair.org/forums/ssjf/documents/eictts/NOxEGU/050426Coal-fired%20EGUs_in_WRAP_Region-draft.pdf

[v] "Combustion Modification – An Economic Alternative for Boiler NO_X Control" GER-4192 (04/01), Folsom, Blair A, Tyson, Thomas J. GE Power Systems, Schenectady, NY, (2001) posted at their website: http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger4192.pdf

[vi] "Assessment of Control Technology Options for BART-Eligible Sources, Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities", dated March 2005, posted at their website: http://bronze.nescaum.org/committees/haze/BART_Control_Assessment.pdf

[vii] Budgetary Proposal, Fuel Tech, Inc. NOxOUT® SNCR and SNCR/FLGR® Systems, for one 450 MW cyclone-fired unit, dated December 9, 2004.

Appendix B

Visibility Modeling Detailed Results

Emission Parameters for Minnkota Power Cooperative
BART Modeling Analysis
Milton R. Young Unit 1 & Unit 2

Scenario/ Unit Number	Stack Height		Stack Diameter		Exit Velocity		Exit Temperature		Emission Rate (lbs/hr)			
	Feet	Meters	Feet	Meters	feet/sec	meters/sec	F	K	SO_2	NO_X	PM Fine	PM Coarse
Precontrol												
Unit 1	299.8	91.4	19.0	5.8	60.7	18.5	349.0	449.1	7231.2	2855.2	5.5	36.7
Unit 2	549.7	167.6	24.9	7.6	63.0	19.2	191.8	361.8	6879.0	5364.2	28.1	178.7
Run 1												
Unit 1	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	7231.2	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	6879.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	0.0	0.0	5.5	36.7
Unit2pm	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	0.0	0.0	28.1	178.7
Run 2												
Unit 1	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	2855.2	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.4	5364.2	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	5.5	36.7
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	28.1	178.7
Run 3												
Unit 1	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	7231.2	2855.2	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	6879.0	5364.2	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	0.0	0.0	5.8	38.5
Unit2pm	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	0.0	0.0	21.0	133.7
Run 4												
Unit 1	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	5.8	38.5
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	21.0	133.7
Run 5												
Unit 1	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	5.8	38.5
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	21.0	133.7

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.101	6.334	2.234	2000	74	51	105	2.8	85.77	14.19	0.02	0.02
98th %tile Delta-DV	1.151	3.257	2.106	2000	265	51	105	2.2	92.11	7.79	0.07	0.03
90th %tile Delta-DV	0.351	2.478	2.127	2000	100	51	105	2.3	81.38	18.42	0.14	0.06
2001												
Largest Delta-DV	3.062	5.168	2.106	2001	260	46	46	2.2	97.83	2.07	0.08	0.03
98th %tile Delta-DV	1.219	3.346	2.127	2001	92	52	106	2.3	68.95	30.87	0.13	0.05
90th %tile Delta-DV	0.302	2.429	2.127	2001	144	53	107	2.3	77.98	21.73	0.21	0.07
2002												
Largest Delta-DV	6.180	8.414	2.234	2002	78	53	107	2.8	85.05	14.89	0.03	0.02
98th %tile Delta-DV	2.766	5.021	2.255	2002	26	48	102	2.9	79.59	20.30	0.08	0.02
90th %tile Delta-DV	0.476	2.710	2.234	2002	91	53	107	2.8	82.61	17.36	0.01	0.02
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.457	4.690	2.234	2000	72	82	71	2.8	81.52	18.39	0.06	0.02
98th %tile Delta-DV	1.307	3.413	2.106	2000	217	82	71	2.2	92.58	7.32	0.07	0.03
90th %tile Delta-DV	0.306	2.475	2.170	2000	152	82	71	2.5	82.80	16.99	0.16	0.06
2001												
Largest Delta-DV	3.423	5.657	2.234	2001	64	82	71	2.8	88.52	11.43	0.04	0.01
98th %tile Delta-DV	1.833	3.939	2.106	2001	234	82	71	2.2	99.22	0.62	0.12	0.04
90th %tile Delta-DV	0.419	2.652	2.234	2001	85	82	71	2.8	67.30	32.52	0.12	0.05
2002												
Largest Delta-DV	4.941	7.174	2.234	2002	73	58	47	2.8	79.73	20.16	0.08	0.03
98th %tile Delta-DV	2.413	4.646	2.234	2002	51	84	113	2.8	84.00	15.92	0.05	0.02
90th %tile Delta-DV	0.506	2.634	2.127	2002	110	82	71	2.3	89.40	10.53	0.05	0.02
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.675	5.908	2.234	2000	74	90	72	2.8	86.93	13.03	0.02	0.02
98th %tile Delta-DV	0.823	2.929	2.106	2000	265	90	72	2.2	89.95	9.96	0.07	0.03
90th %tile Delta-DV	0.260	2.366	2.106	2000	261	90	72	2.2	94.09	5.63	0.20	0.08
2001												
Largest Delta-DV	2.417	4.650	2.234	2001	64	90	72	2.8	90.09	9.87	0.03	0.01
98th %tile Delta-DV	1.049	3.176	2.127	2001	92	90	72	2.3	69.93	29.89	0.13	0.05
90th %tile Delta-DV	0.209	2.336	2.127	2001	94	90	72	2.3	87.27	12.70	0.02	0.01
2002												
Largest Delta-DV	6.042	8.276	2.234	2002	73	90	72	2.8	80.78	19.11	0.08	0.03
98th %tile Delta-DV	2.465	4.699	2.234	2002	39	90	72	2.8	89.53	10.34	0.08	0.05
90th %tile Delta-DV	0.321	2.427	2.106	2002	255	90	72	2.2	95.00	4.58	0.28	0.14
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.150	6.425	2.275	2000	47	97	79	2.9	91.79	8.15	0.04	0.02
98th %tile Delta-DV	1.248	3.587	2.340	2000	336	97	79	3.2	87.73	12.20	0.04	0.03
90th %tile Delta-DV	0.537	2.682	2.145	2000	261	99	81	2.3	98.43	1.20	0.27	0.10
2001												
Largest Delta-DV	4.993	7.332	2.340	2001	326	99	81	3.2	87.88	12.05	0.05	0.02
98th %tile Delta-DV	2.003	4.278	2.275	2001	41	91	73	2.9	79.93	19.98	0.06	0.03
90th %tile Delta-DV	0.488	2.720	2.232	2001	208	99	81	2.7	93.60	6.33	0.05	0.02
2002												
Largest Delta-DV	3.121	5.396	2.275	2002	74	97	79	2.9	85.98	13.97	0.03	0.02
98th %tile Delta-DV	1.834	3.980	2.145	2002	111	99	81	2.3	84.27	15.60	0.10	0.03
90th %tile Delta-DV	0.436	2.581	2.145	2002	100	91	73	2.3	86.69	13.26	0.02	0.02

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 33
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.360	6.593	2.234	2000	74	51	105	2.8	75.04	24.79	0.08	0.09
98th %tile Delta-DV	1.273	3.548	2.276	2000	316	46	46	3	67.31	32.39	0.22	0.08
90th %tile Delta-DV	0.358	2.591	2.234	2000	46	6	6	2.8	34.02	64.43	1.20	0.35
2001												
Largest Delta-DV	3.019	5.125	2.106	2001	260	46	46	2.2	95.13	4.35	0.37	0.14
98th %tile Delta-DV	1.476	3.625	2.149	2001	205	51	105	2.4	86.70	11.94	1.07	0.30
90th %tile Delta-DV	0.332	2.438	2.106	2001	230	41	41	2.2	90.53	7.68	1.40	0.40
2002												
Largest Delta-DV	6.478	8.712	2.234	2002	78	53	107	2.8	75.48	24.27	0.14	0.11
98th %tile Delta-DV	3.008	5.262	2.255	2002	26	48	102	2.9	66.05	33.52	0.32	0.11
90th %tile Delta-DV	0.528	2.634	2.106	2002	241	48	102	2.2	94.68	5.14	0.12	0.06
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.588	4.821	2.234	2000	72	82	71	2.8	68.73	30.9	0.28	0.1
98th %tile Delta-DV	1.345	3.451	2.106	2000	217	82	71	2.2	85.57	13.95	0.33	0.15
90th %tile Delta-DV	0.317	2.445	2.127	2000	286	82	71	2.3	65.24	34.25	0.35	0.16
2001												
Largest Delta-DV	3.474	5.708	2.234	2001	64	82	71	2.8	79.09	20.68	0.16	0.07
98th %tile Delta-DV	1.793	3.899	2.106	2001	234	82	71	2.2	97.90	1.29	0.62	0.19
90th %tile Delta-DV	0.442	2.676	2.234	2001	55	82	71	2.8	65.06	34.64	0.21	0.09
2002												
Largest Delta-DV	5.446	7.679	2.234	2002	73	63	52	2.8	65.53	33.99	0.35	0.12
98th %tile Delta-DV	2.692	4.925	2.234	2002	51	82	71	2.8	71.04	28.62	0.24	0.11
90th %tile Delta-DV	0.554	2.682	2.127	2002	138	82	71	2.3	67.69	31.23	0.76	0.32
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.876	6.11	2.234	2000	74	90	72	2.8	76.78	23.06	0.07	0.09
98th %tile Delta-DV	0.922	3.156	2.234	2000	69	90	72	2.8	61.84	37.64	0.36	0.16
90th %tile Delta-DV	0.278	2.512	2.234	2000	32	90	72	2.8	60.45	39.14	0.23	0.18
2001												
Largest Delta-DV	2.419	4.653	2.234	2001	64	90	72	2.8	81.69	18.11	0.14	0.06
98th %tile Delta-DV	1.131	3.364	2.234	2001	84	90	72	2.8	64.16	35.36	0.34	0.15
90th %tile Delta-DV	0.215	2.342	2.127	2001	101	90	72	2.3	84.12	15.80	0.04	0.04
2002												
Largest Delta-DV	6.564	8.797	2.234	2002	73	90	72	2.8	67.55	32.01	0.33	0.11
98th %tile Delta-DV	2.513	4.768	2.255	2002	29	90	72	2.9	69.55	30.13	0.23	0.09
90th %tile Delta-DV	0.339	2.466	2.127	2002	125	90	72	2.3	62.64	37.12	0.05	0.19
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.043	6.319	2.275	2000	47	97	79	2.9	79.16	20.58	0.18	0.09
98th %tile Delta-DV	1.393	3.669	2.275	2000	48	99	81	2.9	73.88	25.93	0.12	0.07
90th %tile Delta-DV	0.585	2.881	2.297	2000	12	99	81	3	72.77	26.8	0.26	0.18
2001												
Largest Delta-DV	5.139	7.479	2.340	2001	327	99	81	3.2	71.41	28.32	0.18	0.09
98th %tile Delta-DV	2.042	4.188	2.145	2001	259	97	79	2.3	91.38	8.26	0.26	0.10
90th %tile Delta-DV	0.580	2.791	2.211	2001	179	99	81	2.6	69.45	29.47	0.82	0.26
2002												
Largest Delta-DV	3.287	5.562	2.275	2002	74	97	79	2.9	75.12	24.66	0.14	0.08
98th %tile Delta-DV	1.935	4.274	2.340	2002	312	99	81	3.2	71.84	27.82	0.17	0.17
90th %tile Delta-DV	0.466	2.611	2.145	2002	247	97	79	2.3	96.79	2.20	0.70	0.31

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 41
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 39
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 2
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.580	4.814	2.234	2000	72	53	107	2.8	11.93	87.88	0.14	0.05
98th %tile Delta-DV	0.583	2.817	2.234	2000	41	1	1	2.8	6.55	93.18	0.19	0.08
90th %tile Delta-DV	0.200	2.327	2.127	2000	287	46	46	2.3	23.65	76.13	0.15	0.07
2001												
Largest Delta-DV	3.062	5.168	2.106	2001	260	46	46	2.2	97.82	2.07	0.08	0.03
98th %tile Delta-DV	1.219	3.346	2.127	2001	92	52	106	2.3	68.94	30.87	0.14	0.05
90th %tile Delta-DV	0.302	2.429	2.127	2001	144	53	107	2.3	77.98	21.73	0.21	0.07
2002												
Largest Delta-DV	3.954	6.187	2.234	2002	78	45	45	2.8	14.93	84.96	0.06	0.04
98th %tile Delta-DV	1.768	4.023	2.255	2002	29	3	3	2.9	13.56	86.31	0.09	0.04
90th %tile Delta-DV	0.247	2.523	2.276	2002	330	47	101	3.0	15.64	84.29	0.03	0.04
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.396	4.630	2.234	2000	36	82	71	2.8	9.63	90.16	0.14	0.07
98th %tile Delta-DV	0.762	2.889	2.127	2000	98	84	113	2.3	10.23	89.46	0.24	0.07
90th %tile Delta-DV	0.144	2.419	2.276	2000	336	63	52	3.0	4.02	95.71	0.21	0.06
2001												
Largest Delta-DV	3.423	5.657	2.234	2001	64	82	71	2.8	88.52	11.43	0.04	0.01
98th %tile Delta-DV	1.833	3.939	2.106	2001	234	82	71	2.2	99.21	0.62	0.12	0.04
90th %tile Delta-DV	0.419	2.652	2.234	2001	85	82	71	2.8	67.30	32.52	0.12	0.05
2002												
Largest Delta-DV	3.890	6.123	2.234	2002	73	63	52	2.8	11.76	88.06	0.14	0.04
98th %tile Delta-DV	1.522	3.776	2.255	2002	29	85	114	2.9	12.95	86.92	0.10	0.04
90th %tile Delta-DV	0.244	2.414	2.170	2002	154	82	71	2.5	19.45	80.22	0.24	0.09
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	2.018	4.251	2.234	2000	74	90	72	2.8	19.61	80.31	0.04	0.04
98th %tile Delta-DV	0.528	2.677	2.149	2000	184	90	72	2.4	45.84	53.38	0.56	0.21
90th %tile Delta-DV	0.122	2.292	2.170	2000	164	90	72	2.5	62.36	36.69	0.68	0.27
2001												
Largest Delta-DV	2.417	4.650	2.234	2001	64	90	72	2.8	90.08	9.87	0.03	0.01
98th %tile Delta-DV	1.049	3.176	2.127	2001	92	90	72	2.3	69.93	29.88	0.13	0.05
90th %tile Delta-DV	0.209	2.336	2.127	2001	94	90	72	2.3	87.27	12.70	0.02	0.01
2002												
Largest Delta-DV	4.326	6.559	2.234	2002	73	90	72	2.8	13.02	86.81	0.12	0.04
98th %tile Delta-DV	1.589	3.843	2.255	2002	29	90	72	2.9	13.69	86.19	0.09	0.04
90th %tile Delta-DV	0.148	2.276	2.127	2002	116	90	72	2.3	5.46	94.29	0.18	0.07
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.844	5.119	2.275	2000	47	97	79	2.9	17.17	82.73	0.07	0.03
98th %tile Delta-DV	0.870	3.037	2.167	2000	216	97	79	2.4	20.55	79.22	0.18	0.05
90th %tile Delta-DV	0.277	2.510	2.232	2000	196	91	73	2.7	51.06	47.79	0.82	0.33
2001												
Largest Delta-DV	4.993	7.333	2.340	2001	326	99	81	3.2	87.88	12.05	0.05	0.02
98th %tile Delta-DV	2.003	4.278	2.275	2001	41	91	73	2.9	79.94	19.98	0.05	0.03
90th %tile Delta-DV	0.488	2.720	2.232	2001	208	99	81	2.7	93.60	6.33	0.05	0.02
2002												
Largest Delta-DV	1.721	3.996	2.275	2002	74	97	79	2.9	18.00	81.90	0.06	0.03
98th %tile Delta-DV	0.899	3.239	2.340	2002	312	91	73	3.2	14.82	85.04	0.07	0.08
90th %tile Delta-DV	0.201	2.411	2.211	2002	172	99	81	2.6	37.25	61.19	1.18	0.38

Duration Events Largest Delta-DV
TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 2
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.153	6.387	2.234	2000	72	53	107	2.8	13.85	85.69	0.34	0.12
98th %tile Delta-DV	1.159	3.392	2.234	2000	69	56	110	2.8	11.29	88.21	0.36	0.13
90th %tile Delta-DV	0.340	2.467	2.127	2000	301	54	108	2.3	3.47	94.82	1.31	0.41
2001												
Largest Delta-DV	3.019	5.125	2.106	2001	260	46	46	2.2	95.13	4.35	0.37	0.14
98th %tile Delta-DV	1.476	3.625	2.149	2001	205	51	105	2.4	86.70	11.94	1.07	0.30
90th %tile Delta-DV	0.332	2.438	2.106	2001	230	41	41	2.2	90.53	7.68	1.40	0.40
2002												
Largest Delta-DV	6.473	8.706	2.234	2002	78	45	45	2.8	16.99	82.74	0.16	0.11
98th %tile Delta-DV	3.080	5.335	2.255	2002	29	3	3	2.9	15.06	84.61	0.23	0.10
90th %tile Delta-DV	0.497	2.624	2.127	2002	294	47	101	2.3	14.54	84.71	0.51	0.24
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.452	5.685	2.234	2000	36	82	71	2.8	11.65	87.78	0.38	0.18
98th %tile Delta-DV	1.332	3.566	2.234	2000	74	67	56	2.8	20.92	78.90	0.08	0.11
90th %tile Delta-DV	0.257	2.384	2.127	2000	119	82	71	2.3	15.13	83.25	1.23	0.38
2001												
Largest Delta-DV	3.474	5.708	2.234	2001	64	82	71	2.8	79.09	20.68	0.16	0.07
98th %tile Delta-DV	1.793	3.899	2.106	2001	234	82	71	2.2	97.90	1.29	0.62	0.19
90th %tile Delta-DV	0.442	2.676	2.234	2001	55	82	71	2.8	65.06	34.64	0.21	0.09
2002												
Largest Delta-DV	6.094	8.327	2.234	2002	73	63	52	2.8	13.44	86.13	0.32	0.11
98th %tile Delta-DV	2.666	4.900	2.234	2002	75	82	71	2.8	17.44	82.13	0.28	0.16
90th %tile Delta-DV	0.410	2.685	2.276	2002	352	71	60	3.0	13.41	86.31	0.18	0.10
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.513	5.747	2.234	2000	74	90	72	2.8	21.72	78.08	0.09	0.11
98th %tile Delta-DV	1.068	3.174	2.106	2000	247	90	72	2.2	68.84	28.73	1.68	0.74
90th %tile Delta-DV	0.201	2.307	2.106	2000	239	90	72	2.2	43.86	55.24	0.58	0.32
2001												
Largest Delta-DV	2.419	4.653	2.234	2001	64	90	72	2.8	81.69	18.11	0.14	0.06
98th %tile Delta-DV	1.131	3.364	2.234	2001	84	90	72	2.8	64.16	35.36	0.34	0.15
90th %tile Delta-DV	0.215	2.342	2.127	2001	101	90	72	2.3	84.12	15.80	0.04	0.04
2002												
Largest Delta-DV	6.981	9.214	2.234	2002	73	90	72	2.8	14.69	84.89	0.31	0.11
98th %tile Delta-DV	2.789	5.044	2.255	2002	29	90	72	2.9	15.14	84.54	0.23	0.09
90th %tile Delta-DV	0.259	2.387	2.127	2002	116	90	72	2.3	6.26	93.09	0.47	0.18
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.227	6.502	2.275	2000	47	97	79	2.9	19.67	80.05	0.19	0.09
98th %tile Delta-DV	1.443	3.718	2.275	2000	48	99	81	2.9	19.14	80.64	0.14	0.08
90th %tile Delta-DV	0.494	2.639	2.145	2000	114	91	73	2.3	29.95	68.59	0.87	0.59
2001												
Largest Delta-DV	5.139	7.479	2.340	2001	327	99	81	3.2	71.41	28.32	0.18	0.09
98th %tile Delta-DV	2.042	4.188	2.145	2001	259	97	79	2.3	91.38	8.26	0.26	0.10
90th %tile Delta-DV	0.580	2.791	2.211	2001	179	99	81	2.6	69.45	29.47	0.82	0.26
2002												
Largest Delta-DV	3.117	5.392	2.275	2002	74	97	79	2.9	19.78	79.98	0.16	0.09
98th %tile Delta-DV	1.486	3.654	2.167	2002	239	93	75	2.4	33.81	65.60	0.41	0.18
90th %tile Delta-DV	0.405	2.572	2.167	2002	234	97	79	2.4	38.85	60.11	0.64	0.40

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 39
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 5

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 3
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.878	7.111	2.234	2000	74	51	105	2.8	69.15	30.81	0.02	0.02
98th %tile Delta-DV	1.464	3.740	2.276	2000	316	46	46	3.0	60.13	39.82	0.04	0.01
90th %tile Delta-DV	0.412	2.518	2.106	2000	214	46	46	2.2	97.63	2.18	0.15	0.05
2001												
Largest Delta-DV	3.145	5.251	2.106	2001	260	46	46	2.2	94.80	5.09	0.08	0.03
98th %tile Delta-DV	1.576	3.725	2.149	2001	205	51	105	2.4	84.26	15.47	0.21	0.06
90th %tile Delta-DV	0.373	2.479	2.106	2001	224	53	107	2.2	96.76	3.06	0.14	0.04
2002												
Largest Delta-DV	6.961	9.194	2.234	2002	78	53	107	2.8	72.32	27.63	0.03	0.02
98th %tile Delta-DV	3.552	5.807	2.255	2002	26	48	102	2.9	59.46	40.46	0.06	0.02
90th %tile Delta-DV	0.611	2.844	2.234	2002	91	56	110	2.8	63.16	36.81	0.01	0.01
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.135	5.368	2.234	2000	72	82	71	2.8	61.67	38.26	0.05	0.02
98th %tile Delta-DV	1.469	3.575	2.106	2000	217	82	71	2.2	81.65	18.26	0.07	0.03
90th %tile Delta-DV	0.373	2.501	2.127	2000	286	82	71	2.3	58.48	41.43	0.06	0.03
2001												
Largest Delta-DV	4.011	6.244	2.234	2001	64	82	71	2.8	73.23	26.73	0.03	0.01
98th %tile Delta-DV	1.853	3.959	2.106	2001	234	82	71	2.2	98.06	1.77	0.13	0.04
90th %tile Delta-DV	0.488	2.615	2.127	2001	112	58	47	2.3	51.71	48.11	0.15	0.04
2002												
Largest Delta-DV	6.257	8.490	2.234	2002	73	63	52	2.8	58.28	41.64	0.06	0.02
98th %tile Delta-DV	3.026	5.259	2.234	2002	51	82	71	2.8	64.37	35.56	0.04	0.02
90th %tile Delta-DV	0.639	2.766	2.127	2002	138	82	71	2.3	61.20	38.60	0.14	0.06
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	4.342	6.576	2.234	2000	74	90	72	2.8	71.00	28.97	0.01	0.02
98th %tile Delta-DV	1.084	3.317	2.234	2000	69	90	72	2.8	54.54	45.37	0.06	0.03
90th %tile Delta-DV	0.341	2.469	2.127	2000	139	90	72	2.3	85.26	14.66	0.05	0.03
2001												
Largest Delta-DV	2.795	5.029	2.234	2001	64	90	72	2.8	76.35	23.62	0.03	0.01
98th %tile Delta-DV	1.321	3.555	2.234	2001	84	90	72	2.8	56.81	43.10	0.06	0.03
90th %tile Delta-DV	0.239	2.473	2.234	2001	55	90	72	2.8	59.90	40.06	0.03	0.01
2002												
Largest Delta-DV	7.443	9.677	2.234	2002	73	90	72	2.8	60.67	39.25	0.06	0.02
98th %tile Delta-DV	2.783	5.017	2.234	2002	39	90	72	2.8	78.00	21.88	0.08	0.04
90th %tile Delta-DV	0.404	2.531	2.127	2002	125	90	72	2.3	55.44	44.52	0.01	0.03
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.473	6.748	2.275	2000	47	97	79	2.9	83.69	16.26	0.04	0.02
98th %tile Delta-DV	1.685	3.960	2.275	2000	70	93	75	2.9	50.80	49.11	0.06	0.03
90th %tile Delta-DV	0.660	2.805	2.145	2000	131	93	75	2.3	57.84	42.02	0.12	0.03
2001												
Largest Delta-DV	5.789	8.129	2.340	2001	327	99	81	3.2	64.91	35.04	0.03	0.02
98th %tile Delta-DV	2.227	4.566	2.340	2001	333	99	81	3.2	64.47	35.44	0.05	0.04
90th %tile Delta-DV	0.596	2.742	2.145	2001	107	97	79	2.3	44.73	55.14	0.09	0.04
2002												
Largest Delta-DV	3.766	6.041	2.275	2002	74	97	79	2.9	68.87	31.09	0.03	0.01
98th %tile Delta-DV	2.195	4.427	2.232	2002	205	91	73	2.7	82.94	16.95	0.08	0.03
90th %tile Delta-DV	0.504	2.800	2.297	2002	31	97	79	3.0	78.62	21.36	0.01	0.01

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 43
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 42
Number of days with Delta-Deciview > 1.00: 28
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 44
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 3
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	5.577	7.811	2.234	2000	74	51	105	2.8	54.92	44.99	0.05	0.05
98th %tile Delta-DV	1.647	3.817	2.170	2000	152	54	108	2.5	36.38	62.85	0.57	0.20
90th %tile Delta-DV	0.511	2.638	2.127	2000	101	47	101	2.3	34.53	65.12	0.23	0.12
2001												
Largest Delta-DV	3.297	5.530	2.234	2001	64	46	46	2.8	58.91	40.96	0.09	0.04
98th %tile Delta-DV	2.001	4.235	2.234	2001	84	46	46	2.8	40.75	59.03	0.15	0.06
90th %tile Delta-DV	0.397	2.503	2.106	2001	234	51	105	2.2	94.76	4.72	0.40	0.12
2002												
Largest Delta-DV	8.275	10.508	2.234	2002	73	48	102	2.8	44.60	55.19	0.15	0.05
98th %tile Delta-DV	4.338	6.444	2.106	2002	250	53	107	2.2	63.35	36.16	0.35	0.15
90th %tile Delta-DV	0.780	2.907	2.127	2002	294	47	101	2.3	42.15	57.47	0.26	0.12
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.754	5.988	2.234	2000	72	82	71	2.8	44.56	55.26	0.13	0.05
98th %tile Delta-DV	1.660	3.766	2.106	2000	217	82	71	2.2	68.22	31.49	0.20	0.09
90th %tile Delta-DV	0.421	2.570	2.149	2000	191	67	56	2.4	91.41	7.97	0.48	0.15
2001												
Largest Delta-DV	4.537	6.771	2.234	2001	64	82	71	2.8	57.23	42.65	0.09	0.04
98th %tile Delta-DV	2.082	4.188	2.106	2001	260	86	115	2.2	87.36	12.37	0.19	0.08
90th %tile Delta-DV	0.517	2.666	2.149	2001	205	58	47	2.4	92.58	6.69	0.54	0.19
2002												
Largest Delta-DV	7.694	9.928	2.234	2002	73	63	52	2.8	40.95	58.83	0.16	0.06
98th %tile Delta-DV	3.703	5.937	2.234	2002	75	82	71	2.8	49.80	49.97	0.14	0.08
90th %tile Delta-DV	0.773	3.006	2.234	2002	91	82	71	2.8	47.25	52.60	0.09	0.06
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	5.037	7.270	2.234	2000	74	90	72	2.8	55.53	44.39	0.04	0.05
98th %tile Delta-DV	1.497	3.730	2.234	2000	69	90	72	2.8	37.02	62.75	0.16	0.07
90th %tile Delta-DV	0.349	2.519	2.170	2000	152	90	72	2.5	53.35	46.14	0.35	0.16
2001												
Largest Delta-DV	3.117	5.350	2.234	2001	64	90	72	2.8	61.14	38.75	0.08	0.03
98th %tile Delta-DV	1.795	4.028	2.234	2001	84	90	72	2.8	39.07	60.70	0.15	0.07
90th %tile Delta-DV	0.272	2.399	2.127	2001	94	90	72	2.3	56.09	43.84	0.04	0.02
2002												
Largest Delta-DV	8.901	11.134	2.234	2002	73	90	72	2.8	43.67	56.12	0.16	0.05
98th %tile Delta-DV	3.057	5.291	2.234	2002	39	90	72	2.8	63.55	36.10	0.22	0.14
90th %tile Delta-DV	0.415	2.564	2.149	2002	198	90	72	2.4	93.95	5.38	0.47	0.20
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.587	6.862	2.275	2000	47	97	79	2.9	67.76	32.07	0.11	0.06
98th %tile Delta-DV	1.965	4.240	2.275	2000	55	91	73	2.9	67.87	31.96	0.09	0.08
90th %tile Delta-DV	0.810	3.085	2.275	2000	65	91	73	2.9	61.71	38.02	0.17	0.11
2001												
Largest Delta-DV	6.953	9.293	2.340	2001	327	99	81	3.2	47.65	52.21	0.09	0.04
98th %tile Delta-DV	2.731	5.070	2.340	2001	333	99	81	3.2	48.63	51.13	0.14	0.10
90th %tile Delta-DV	0.806	2.973	2.167	2001	240	91	73	2.4	70.59	29.06	0.23	0.11
2002												
Largest Delta-DV	4.457	6.732	2.275	2002	74	97	79	2.9	52.05	47.83	0.07	0.04
98th %tile Delta-DV	2.318	4.550	2.232	2002	205	91	73	2.7	71.61	28.05	0.25	0.09
90th %tile Delta-DV	0.601	2.768	2.167	2002	218	99	81	2.4	84.33	15.25	0.21	0.22

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 37
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 52
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 37
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 29
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 50
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 48
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 4
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.269	3.502	2.234	2000	74	51	105	2.8	37.96	61.85	0.09	0.09
98th %tile Delta-DV	0.265	2.499	2.234	2000	69	56	110	2.8	23.55	75.98	0.35	0.13
90th %tile Delta-DV	0.094	2.221	2.127	2000	109	53	107	2.3	9.18	88.60	1.69	0.53
2001												
Largest Delta-DV	0.592	2.720	2.127	2001	112	51	105	2.3	23.91	75.37	0.57	0.15
98th %tile Delta-DV	0.344	2.620	2.276	2001	328	45	45	3	38.61	61.25	0.08	0.06
90th %tile Delta-DV	0.060	2.188	2.127	2001	101	45	45	2.3	50.01	49.86	0.07	0.06
2002												
Largest Delta-DV	2.023	4.256	2.234	2002	78	45	45	2.8	32.34	67.42	0.14	0.10
98th %tile Delta-DV	0.847	3.081	2.234	2002	64	54	108	2.8	28.28	71.37	0.22	0.13
90th %tile Delta-DV	0.118	2.246	2.127	2002	118	53	107	2.3	41.52	58.16	0.20	0.12
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.116	3.349	2.234	2000	36	82	71	2.8	22.10	77.41	0.33	0.16
98th %tile Delta-DV	0.342	2.469	2.127	2000	98	84	113	2.3	23.30	75.97	0.57	0.16
90th %tile Delta-DV	0.068	2.196	2.127	2000	286	82	71	2.3	28.79	70.86	0.22	0.13
2001												
Largest Delta-DV	0.849	3.082	2.234	2001	64	82	71	2.8	42.62	57.12	0.19	0.07
98th %tile Delta-DV	0.385	2.513	2.127	2001	109	63	52	2.3	22.79	76.20	0.74	0.28
90th %tile Delta-DV	0.079	2.185	2.106	2001	254	83	112	2.2	52.02	46.01	1.46	0.52
2002												
Largest Delta-DV	1.894	4.128	2.234	2002	73	63	52	2.8	26.80	72.76	0.33	0.11
98th %tile Delta-DV	0.734	2.967	2.234	2002	75	82	71	2.8	32.58	67.06	0.23	0.13
90th %tile Delta-DV	0.131	2.237	2.106	2002	248	82	71	2.2	39.07	60.31	0.39	0.23
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.042	3.276	2.234	2000	74	90	72	2.8	39.92	59.91	0.08	0.09
98th %tile Delta-DV	0.246	2.480	2.234	2000	69	90	72	2.8	24.81	74.77	0.29	0.13
90th %tile Delta-DV	0.059	2.165	2.106	2000	239	90	72	2.2	67.12	32.25	0.41	0.22
2001												
Largest Delta-DV	0.539	2.772	2.234	2001	64	90	72	2.8	46.77	53.00	0.16	0.07
98th %tile Delta-DV	0.304	2.538	2.234	2001	84	90	72	2.8	26.81	72.78	0.29	0.12
90th %tile Delta-DV	0.041	2.211	2.170	2001	153	90	72	2.5	63.10	35.53	0.99	0.38
2002												
Largest Delta-DV	2.175	4.409	2.234	2002	73	90	72	2.8	29.00	70.61	0.29	0.10
98th %tile Delta-DV	0.790	3.024	2.234	2002	39	90	72	2.8	32.31	67.19	0.32	0.18
90th %tile Delta-DV	0.071	2.198	2.127	2002	117	90	72	2.3	7.64	91.19	0.67	0.51
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.446	3.721	2.275	2000	47	97	79	2.9	36.30	63.46	0.16	0.08
98th %tile Delta-DV	0.421	2.589	2.167	2000	217	91	73	2.4	58.25	40.61	0.85	0.28
90th %tile Delta-DV	0.139	2.479	2.340	2000	363	93	75	3.2	23.15	76.56	0.15	0.14
2001												
Largest Delta-DV	2.207	4.547	2.340	2001	327	99	81	3.2	32.49	67.26	0.16	0.09
98th %tile Delta-DV	0.517	2.857	2.340	2001	355	93	75	3.2	14.59	84.46	0.71	0.23
90th %tile Delta-DV	0.141	2.480	2.340	2001	314	99	81	3.2	19.49	80.24	0.16	0.11
2002												
Largest Delta-DV	0.857	3.133	2.275	2002	74	97	79	2.9	37.79	62.00	0.14	0.08
98th %tile Delta-DV	0.435	2.602	2.167	2002	239	93	75	2.4	56.71	42.83	0.32	0.14
90th %tile Delta-DV	0.102	2.248	2.145	2002	100	91	73	2.3	38.78	61.00	0.12	0.10

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 4
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.255	4.489	2.234	2000	74	51	105	2.8	40.92	58.76	0.15	0.17
98th %tile Delta-DV	0.569	2.845	2.276	2000	316	46	46	3	31.91	67.61	0.35	0.13
90th %tile Delta-DV	0.159	2.287	2.127	2000	98	47	101	2.3	37.13	62.29	0.38	0.21
2001												
Largest Delta-DV	1.149	3.382	2.234	2001	64	46	46	2.8	47.43	52.13	0.31	0.13
98th %tile Delta-DV	0.667	2.900	2.234	2001	84	46	46	2.8	30.36	68.93	0.50	0.21
90th %tile Delta-DV	0.122	2.228	2.106	2001	248	48	102	2.2	87.52	10.40	1.33	0.76
2002												
Largest Delta-DV	3.621	5.854	2.234	2002	78	45	45	2.8	35.44	64.14	0.25	0.17
98th %tile Delta-DV	1.612	3.846	2.234	2002	64	54	108	2.8	31.00	68.38	0.38	0.24
90th %tile Delta-DV	0.238	2.366	2.127	2002	118	53	107	2.3	44.33	55.09	0.35	0.22
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.716	3.949	2.234	2000	36	82	71	2.8	25.66	73.41	0.63	0.30
98th %tile Delta-DV	0.687	2.921	2.234	2000	74	67	56	2.8	41.89	57.84	0.12	0.16
90th %tile Delta-DV	0.132	2.281	2.149	2000	187	58	47	2.4	90.71	7.99	0.83	0.47
2001												
Largest Delta-DV	1.644	3.877	2.234	2001	64	82	71	2.8	45.70	53.86	0.31	0.13
98th %tile Delta-DV	0.706	2.833	2.127	2001	109	58	47	2.3	26.13	72.08	1.27	0.52
90th %tile Delta-DV	0.162	2.268	2.106	2001	230	82	71	2.2	86.55	10.92	1.72	0.80
2002												
Largest Delta-DV	3.194	5.427	2.234	2002	73	63	52	2.8	29.97	69.30	0.54	0.19
98th %tile Delta-DV	1.397	3.630	2.234	2002	75	82	71	2.8	35.54	63.80	0.42	0.24
90th %tile Delta-DV	0.213	2.341	2.127	2002	110	82	71	2.3	48.55	50.84	0.42	0.18
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.926	4.160	2.234	2000	74	90	72	2.8	43.05	56.66	0.13	0.16
98th %tile Delta-DV	0.487	2.720	2.234	2000	69	90	72	2.8	27.15	72.11	0.51	0.23
90th %tile Delta-DV	0.097	2.225	2.127	2000	110	90	72	2.3	8.76	86.96	3.19	1.10
2001												
Largest Delta-DV	1.066	3.299	2.234	2001	64	90	72	2.8	49.81	49.79	0.28	0.12
98th %tile Delta-DV	0.594	2.827	2.234	2001	84	90	72	2.8	29.11	70.18	0.50	0.22
90th %tile Delta-DV	0.082	2.358	2.276	2001	345	90	72	3	39.25	59.94	0.61	0.20
2002												
Largest Delta-DV	3.812	6.046	2.234	2002	73	90	72	2.8	31.97	67.35	0.50	0.18
98th %tile Delta-DV	1.447	3.680	2.234	2002	39	90	72	2.8	37.08	61.97	0.59	0.35
90th %tile Delta-DV	0.133	2.282	2.149	2002	189	90	72	2.4	90.95	6.52	1.77	0.76
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.302	4.577	2.275	2000	47	97	79	2.9	39.98	59.59	0.29	0.14
98th %tile Delta-DV	0.731	3.007	2.275	2000	48	99	81	2.9	39.13	60.53	0.22	0.12
90th %tile Delta-DV	0.264	2.604	2.340	2000	359	97	79	3.2	21.84	77.89	0.13	0.14
2001												
Largest Delta-DV	3.339	5.679	2.340	2001	327	99	81	3.2	35.97	63.60	0.28	0.16
98th %tile Delta-DV	0.863	3.138	2.275	2001	89	99	81	2.9	34.01	65.28	0.49	0.22
90th %tile Delta-DV	0.264	2.409	2.145	2001	96	99	81	2.3	34.38	63.87	1.21	0.55
2002												
Largest Delta-DV	1.635	3.910	2.275	2002	74	97	79	2.9	40.73	58.89	0.24	0.14
98th %tile Delta-DV	0.756	3.031	2.275	2002	76	99	81	2.9	33.01	65.91	0.83	0.25
90th %tile Delta-DV	0.201	2.476	2.275	2002	52	97	79	2.9	41.69	58.00	0.19	0.12

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 1 & 2
BART Run 5
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	3.279	5.513	2.234	2000	74	51	105	2.8	39.91	59.82	0.13	0.14
98th %tile Delta-DV	0.817	3.092	2.276	2000	316	45	45	3	31.35	68.24	0.30	0.11
90th %tile Delta-DV	0.241	2.369	2.127	2000	109	53	107	2.3	9.98	86.72	2.50	0.80
2001												
Largest Delta-DV	1.671	3.905	2.234	2001	64	46	46	2.8	46.41	53.21	0.27	0.11
98th %tile Delta-DV	0.987	3.221	2.234	2001	84	46	46	2.8	29.56	69.83	0.43	0.18
90th %tile Delta-DV	0.179	2.285	2.106	2001	248	48	102	2.2	87.47	10.70	1.17	0.66
2002												
Largest Delta-DV	5.058	7.291	2.234	2002	78	45	45	2.8	34.50	65.14	0.21	0.15
98th %tile Delta-DV	2.336	4.569	2.234	2002	64	54	108	2.8	30.11	69.36	0.33	0.21
90th %tile Delta-DV	0.354	2.481	2.127	2002	118	53	107	2.3	43.40	56.11	0.30	0.19
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.656	4.889	2.234	2000	36	82	71	2.8	24.37	74.87	0.51	0.25
98th %tile Delta-DV	0.979	3.212	2.234	2000	74	67	56	2.8	40.71	59.06	0.10	0.14
90th %tile Delta-DV	0.200	2.434	2.234	2000	65	82	71	2.8	34.83	63.06	1.36	0.75
2001												
Largest Delta-DV	2.367	4.601	2.234	2001	64	82	71	2.8	44.70	54.92	0.27	0.11
98th %tile Delta-DV	1.058	3.186	2.127	2001	109	58	47	2.3	25.40	73.08	1.08	0.44
90th %tile Delta-DV												
2002												
Largest Delta-DV	4.597	6.831	2.234	2002	73	63	52	2.8	28.90	70.47	0.46	0.16
98th %tile Delta-DV	2.031	4.265	2.234	2002	75	82	71	2.8	34.66	64.78	0.36	0.20
90th %tile Delta-DV	0.330	2.500	2.170	2002	154	82	71	2.5	45.03	54.16	0.59	0.23
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	2.791	5.025	2.234	2000	74	90	72	2.8	42.02	57.73	0.11	0.14
98th %tile Delta-DV	0.721	2.954	2.234	2000	69	90	72	2.8	26.39	72.98	0.43	0.20
90th %tile Delta-DV	0.178	2.454	2.276	2000	316	90	72	3	30.15	69.40	0.33	0.12
2001												
Largest Delta-DV	1.551	3.784	2.234	2001	64	90	72	2.8	48.82	50.84	0.24	0.10
98th %tile Delta-DV	0.880	3.113	2.234	2001	84	90	72	2.8	28.37	71.02	0.43	0.19
90th %tile Delta-DV	0.126	2.296	2.170	2001	153	90	72	2.5	64.15	33.83	1.44	0.57
2002												
Largest Delta-DV	5.337	7.570	2.234	2002	73	90	72	2.8	31.03	68.39	0.43	0.15
98th %tile Delta-DV	2.020	4.254	2.234	2002	39	90	72	2.8	37.65	61.51	0.53	0.31
90th %tile Delta-DV	0.195	2.343	2.149	2002	189	90	72	2.4	91.03	6.75	1.56	0.66
LOSTWOOD NWA												
2000												
Largest Delta-DV	3.458	5.734	2.275	2000	47	97	79	2.9	38.71	60.93	0.24	0.12
98th %tile Delta-DV	1.161	3.437	2.275	2000	37	97	79	2.9	23.36	76.08	0.37	0.18
90th %tile Delta-DV	0.393	2.669	2.275	2000	67	97	79	2.9	36.18	63.42	0.25	0.14
2001												
Largest Delta-DV	4.964	7.304	2.340	2001	327	99	81	3.2	34.66	64.98	0.23	0.13
98th %tile Delta-DV	1.332	3.608	2.275	2001	89	93	75	2.9	31.34	68.02	0.45	0.19
90th %tile Delta-DV	0.411	2.751	2.340	2001	314	99	81	3.2	20.85	78.74	0.24	0.17
2002												
Largest Delta-DV	2.366	4.642	2.275	2002	74	97	79	2.9	39.77	59.90	0.21	0.12
98th %tile Delta-DV	1.140	3.285	2.145	2002	131	99	81	2.3	30.86	67.70	1.10	0.34
90th %tile Delta-DV	0.303	2.578	2.275	2002	52	97	79	2.9	40.58	59.15	0.17	0.10

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 4

BART DETERMINATION STUDY

for

Milton R. Young Station Unit 1 and 2
Minnkota Power Cooperative, Inc.

October 2006
Revised
August 2007

41440

Minnkota Power
COOPERATIVE, INC.
A Touchstone Energy℠ Partner

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INDEX AND CERTIFICATION

BART Determination Study
Milton R. Young Station Unit 1 and 2
Minnkota Power Cooperative, Inc.

Project 41440

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Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by the Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the laws and rules of the North Dakota State Board of Registration under Title 28 Administrative Code.

Minnkota Power Cooperative, Inc.
Milton R. Young Station
Units 1 and 2
Best Available Retrofit Technology Determination Study

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EXECUTIVE SUMMARY

This document presents the Best Available Retrofit Technology (BART) analysis for each of three major pollutants: nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM) for Minnkota Power Cooperative, Inc.'s (Minnkota's) Unit 1 and Square Butte Electric Cooperative's (Square Butte's) Unit 2 at the Milton R. Young Station (MRYS) located near Center, North Dakota. On July 6, 2005, the United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for BART Determinations. The final regulations require eligible sources to be analyzed to determine a BART emission limit for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). The North Dakota Department of Health (NDDH) reviewed the operational history of North Dakota sources and determined which sources were BART-eligible and provided a state-specific modeling protocol for use in the analysis. Milton R. Young Station Unit 1 and Unit 2 were determined to be BART-eligible by the NDDH. As discussed in the introduction to the BART analysis, small emission units at MRYS produce emissions in levels anticipated to be too low to affect visibility in Class 1 areas and were excluded from further consideration in the study. This BART determination was conducted in accordance with the eligibility conclusion made by NDDH and follows the NDDH protocol.

Once a source is determined to be eligible, there are five predefined steps for conducting a BART analysis for each pollutant. Steps 1 through 3 include identifying control technologies, evaluating feasibility, and ranking feasible options by control effectiveness. Step 4 involves a technical evaluation of various impacts related to each feasible control technology. The evaluation reviews include economics, energy, and non-air environmental impacts. Visibility impairment impacts in the nearest Class 1 areas for the dominant controls are evaluated in Step 5. A summary ranking of control technologies for regulated pollutants that provide a cost effective system of emission reduction and visibility impact reduction is developed. The results of conducting this five step analysis is a recommendation for selection of BART, which is then translated into an emission rate constituting BART that must be achieved by the eligible source for each major regulated pollutant. Although the impacts requiring analysis are explicitly stated within the RHR and Guidelines, no methodology is provided for using the impacts to select a control technology. Thus, each State has discretion in weighing the various impacts identified in the BART analysis for emission sources within their jurisdiction based upon source characteristics, reviewed technologies, and background information used to perform the evaluation.

This analysis used several reference works, including the RACT/BACT/LAER Clearinghouse (RBLC), to identify which control technologies to evaluate. The technologies were then reviewed for feasibility and those deemed to be infeasible were eliminated from further study. The feasible control technologies were ranked by control efficiency and estimates of costs to implement, operate, and maintain such technologies were developed. Comparing average and incremental control costs allowed inferior controls to be removed from the list. Remaining technologies were evaluated based upon other impacts and predicted reductions in visibility impairment. The final BART recommendations were then made for each pollutant and are summarized in the tables below.

Prior to the completion of this analysis, Minnkota entered into a Consent Decree (CD) with the EPA and the NDDH. This CD requires Minnkota and Square Butte to perform a Best Available Control Technology (BACT) analysis for NO_X emissions controls, and establishes minimum removal rates for SO_2 and maximum PM emission rates for Unit 1 and Unit 2 at MRYS. For NO_X emissions control, certain control technologies were evaluated as required by the CD. The BART evaluation process for NO_X control technologies was modified to use the BACT analysis study. Submittal of the BACT analysis and additional support documents to the NDDH occurred on October 6, 2006, March 19, and April 23, 2007 respectively. For sulfur dioxide and particulate matter emissions, a BART analysis for each Unit at MRYS was performed.

Based upon an evaluation of the 90th percentile visibility impairment modeling results, the control technologies recommended as BACT for NO_X emissions and those recommended as BART for SO_2 and PM emissions had an acceptable impact reduction. Because there was an acceptable impact reduction in all cases, the BART recommendation consists of the control technologies at the modeled emission rates. The BART recommendations for each pollutant and each unit are summarized in the tables below. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

MRYS Unit 1 Recommended BART 30-Day Rolling Average

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.36*
SO_2	Wet Flue Gas Desulfurization (FGD) Process	0.15
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See referenced BACT analysis for a detailed discussion.

MRYS Unit 2 Recommended BART 30-Day Rolling Average

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.35*
SO_2	Upgrade of Existing Wet Flue Gas Desulfurization (FGD) Process	0.30
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See referenced BACT analysis for a detailed discussion.

1.0 INTRODUCTION

The United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for Best Available Retrofit Technology (BART) Determinations[1] in the Federal Register on July 6, 2005 (70 FR 39104). BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). This document presents the BART analysis for each of three major pollutants: nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM) for Minnkota Power Cooperative, Inc.'s (Minnkota's) Unit 1 and Square Butte Electric Cooperative's (Square Butte's) Unit 2 at the Milton R. Young Station (MRYS) located near Center, North Dakota.

1.1 BART ELIGIBILITY

A BART eligible source is one that meets three criteria identified by EPA in the RHR and Guidelines for the determination of BART. A source is BART eligible if operations fall within one of 26 specifically listed source categories (70 FR 39158), the source entered into service between August 7, 1962 and August 7, 1977, and the source has the potential to emit 250 tons per year or more of a visibility-impairing air pollutant (SO_2, NO_X or PM). The North Dakota Department of Health (NDDH) reviewed the operational history of sources within North Dakota and independently determined which of those sources are BART-eligible. The NDDH classified the electric generating units (EGUs) at Milton R. Young Station as BART-eligible. For the purposes of this report, the NDDH's determination will be used and Units 1 and 2 at MRYS are assumed to be subject to a BART analysis.

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[1] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations"; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.

1.2 BART ANALYSIS PROCESS

Where a particular source is determined to be eligible, the general steps for determining BART for each pollutant are as follows (70 FR 39164):

STEP 1 - Identify all available retrofit control technologies (within the BART Guidelines).
STEP 2 - Eliminate technically infeasible options.
STEP 3 - Evaluate control effectiveness of remaining control technologies.
STEP 4 - Evaluate the following impacts for each feasible control technology and document results:
(70 FR 39166).

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

STEP 5 – Evaluate the visibility impacts.

Minnkota Power Cooperative, Inc. retained Burns & McDonnell to assist in the completion of the Best Available Retrofit Technology analysis for Milton R. Young Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services to the power industry since the 1970s. As a result of their long history providing these services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies and control technology analysis similar to a BART analysis.

1.2.1 IDENTIFICATION OF RETROFIT CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit control technologies. In order to identify the applicable control technologies, several reference works are consulted. A preliminary list of control technologies and their estimated capabilities is developed.

1.2.2 FEASIBILITY ANALYSIS

The second step of the BART process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology.

A control technology is considered available, “if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term” or “if it has reached the stage of licensing and commercial availability.” On the contrary, a control technology is not considered available, “in the pilot scale testing stages of development.” (70 FR 39165) When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” The EPA also does not “expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type.” (70 FR 39165) “A technology that is available and applicable is technically feasible.” (70 FR 39165)

1.2.3 EVALUATE TECHNICALLY FEASIBLE CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the BART analysis, the control efficiency is reviewed and presented with the description of each technology. The evaluation of the technically feasible BART alternatives concludes with the alternatives ranked in descending order of control effectiveness.

1.2.4 IMPACT ANALYSIS

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis. The BART Determination will consider the following four factors in the impact analysis:

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

The first three of the four factors considered in the impact analysis are discussed in the associated pollutant section. The remaining useful life of the source is included as part of the cost of compliance.

1.2.5 METHODOLOGY FOR ESTIMATED COSTS

The cost summary of each alternative is presented in the section for each pollutant. Installed capital and annual O&M cost estimates for each alternative are presented individually. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 20 year design life, in current (2006) dollars. The LTAC represents an annual payment in current day dollars sufficient to finance the project over its entire life.

In determining the LTAC, a Capital Recovery Factor and an O&M Levelization Factor were calculated from the project economic conditions and then applied separately to the estimated capital and O&M costs. The equation used is shown below.

$$LACC / NPV = \left(\frac{i_d (1+i_d)^n}{(1+i_d)^n - 1} \right) = CRF$$

Where,
LACC = Levelized Annual Capital Cost
NPV = Net Present Value of the capital investments required.
i_d = discount rate
n = design life in years
CRF = Capital Recovery Factor

Therefore:

LACC = CRF x NPV

For the economic conditions described in Table 1.2-1, the Capital Recovery Factor was calculated to be 0.08718.

In determining the levelized annual O&M cost the estimated annual O&M cost, the escalation rate, the discount rate, and the equipment life are taken into account. The O&M Levelization Factor (OMLF) was calculated as follows.

$$LAOMC / A_1 = \frac{\left(\frac{(1+i)^n - 1}{i} \right)}{(1+i)^n} \left(\frac{i_d (1+i_d)^n}{(1+i_d)^n - 1} \right) = OMLF$$

The inflation rate (i) used in the above calculation is determined as follows.

$$i = \left(\frac{1 + i_d}{1 + i_i} - 1 \right)$$

Where,
LAOMC = Levelized Annual O&M Cost
A_1 = Estimated annual O&M cost in current dollars
i_d = discount rate
i_i = escalation rate
i = inflation rate
n = design life in years
OMLF = O&M Levelization Factor

Therefore:

$$\text{LAOMC} = \text{OMLF} \times A_1$$

For the economic conditions described in Table 1.2-1, the Operating and Maintenance Levelization Factor was calculated to be 1.24873.

The Levelized Total Annual Cost, or LTAC is the sum of the levelized capital cost and the levelized O&M cost. Therefore:

$$\text{LTAC} = \text{LACC} + \text{LAOMC} = (\text{CRF} \times \text{NPV}) + (\text{OMLF} \times A_1) = 0.08718 \times \text{NPV} + 1.24873 \times A_1$$

The economic analyses presented in this report not only include the estimated capital and annual O&M costs for each alternative, but also the LTAC for economic comparison of the various alternatives.

Table 1.2-1 – Economic Factors[1]

Total Possible Operating Hours per Year	8,760
Plant Capacity Factor	85%
Amortization Life, Years	20
Cost of Money	6%
Property Taxes, Insurance, %	NA
Amortization Rate for APC Capital Costs	6%
Interest During Construction (IDC)	6%
Discount Rate	6%
Construction Cost Escalation	3%
Non-Fuel O&M Escalation	2.5%
Fuel (coal and natural gas) Escalation	2.5%
Operating Labor Rate, $/hr	$40.00
Auxiliary Electric Power Cost, $/MW-hr	$35.00

1. All costs are in 2006 dollars unless noted otherwise.

1.3 BART ANALYSIS APPROACH

The purpose of the Regional Haze Rule (RHR) is to address visibility impairment in mandatory Class 1 areas that results from the emission of SO_2, NO_X, PM, Volatile Organic Compounds (VOCs) and ammonia from certain major sources. The only control method for VOCs identified in the RACT/BACT/LAER Clearinghouse (RBLC) database is good combustion practices. This control technique is already in place at MRYS. If an analysis were performed for VOCs, good combustion practices would be the most probable method chosen for BART. The visibility impact of VOCs and ammonia are considered negligible for a BART analysis, according to the NDDH's November 2005 modeling protocol[2], and are not addressed further in this report. Before the actual BART analysis can begin for SO_2, NO_X, and PM, the approach used to conduct the analysis should be addressed. The following sections present specific subjects related to MRYS's background, which warrant mention due to their effects on the contents of the report.

1.3.1 BACKGROUND

Minnkota Power Cooperative, Inc. operates the Milton R. Young Station near Center, North Dakota. MRYS is a steam electric generating plant with two units. Unit No. 1 is a Babcock & Wilcox (B&W) cyclone-type coal-fired boiler burning lignite coal, serving a turbine generator with a nameplate rating of 257 MW.[3] Particulate control is provided by a Research-Cottrell Electrostatic Precipitator rated at approximately 99% control. Unit 1 has no sulfur dioxide (SO_2) control system and exhausts to a 300 foot tall stack. Unit No. 2 is a B&W cyclone-fired unit burning lignite coal, with a turbine-generator name plate rating of 477 MW.[4] Particulate control for Unit 2 is provided by a Wheelabrator-Lurgi precipitator rated at approximately 99% control. Unit 2 has a Combustion Equipment Associates wet flue gas desulfurization (FGD) system (modified by Combustion Engineering) that treats approximately 78 percent of the flue gas with the remaining flue gas by-passed for stack gas reheat. The FGD system achieves approximately 75 percent SO_2 removal and exhausts to a 550 foot tall stack. Unit 1 began commercial operation on November 20, 1970 and Unit 2 on May 11, 1977.

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[2] "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota"; North Dakota Department of Health, Division of Air Quality; November, 2005.

[3] "Generator Nameplate Data"; Emissions & Generation Resource Integrated Database (eGRID); U.S. Environmental Protection Agency; April, 2003.

[4] Ibid footnote 3 reference.

On June 17, 2002, Minnkota Power Cooperative, Inc. received a Notice of Violation (NOV) from the EPA. The NOV states that Minnkota allegedly violated the Prevention of Significant Deterioration (PSD) regulations. The NOV was issued pursuant to Section 113 of the Clean Air Act. The alleged violation was caused by modifications to both Unit 1 and 2 at MRYS which allegedly resulted in a potential increase of SO_2, NO_X and PM. Without an admission of liability, Minnkota entered into a settlement in the form of a Consent Decree (CD) with the EPA and NDDH to resolve the issues. The CD requires that Minnkota perform a BACT analysis for NO_X emissions and to install controls in a two-part, phased approach. SO_2 and PM emissions for Unit 1 and Unit 2 at MRYS are required to achieve at or below the specified levels of unit emission rates (lb per million Btu), and also minimum levels of removal for sulfur dioxide emissions. The effect of the CD on the BART analysis and the requirements to install emission controls NO_X, SO_2, and PM are discussed later in the report.

1.3.2 CONTROL TECHNOLOGY EVALUATION AND BACT VS. BART

As stated above, once a source is determined to be eligible, there are general steps for conducting a BART analysis for each pollutant. All retrofit control technologies are first identified. A brief review of the processes and their capabilities is then performed to determine availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to control capability and an analysis then reviews the probable impacts of each technology. The visibility impact is included in the impact analysis. Finally, the results of the analyses are tabulated and possible BART control options are listed.

As stated in the proposed BART guidelines dated 5 May 2004 (69 FR 25218), a BART analysis is similar to a Best Available Control Technology (BACT) analysis.

> “The process for a BART analysis is very similar to the BACT review as described in the New Source Review Workshop Manual (Draft, October 1990). Consistent with the Workshop Manual, the BART engineering analysis requires that all available control technologies be ranked in descending order of control effectiveness (i.e. percent control). You [meaning States] must examine the most stringent alternative first. That alternative is selected as the ‘‘best’’ unless you demonstrate and document that the alternative cannot be justified based upon the consideration of the five statutory factors discussed below. If you eliminate the most stringent technology in this fashion, you then consider the next most stringent alternative, and so on.

> Although very similar in process, BART reviews differ in several respects from the BACT review described in the NSR Draft Manual."

The proposed guidelines stated that a BART analysis is similar to a BACT review and provided a few examples of similarities and differences, but it did not explicitly state how the two analyses could be used in conjunction to obtain a determination. Because BACT and BART are similar, there are many aspects that can be combined to reduce the steps of an analysis. However, because there are some differences, a BART analysis must address some additional aspects that a BACT review does not.

A BART analysis is always conducted for existing sources and a BACT review is usually conducted for a new source. Because BACT is usually performed for a source that is a new design or reconstruction, the review must take into account all available technologies and must include the most effective controls that have been demonstrated on similar units. BACT is considered to be more stringent than BART because it usually is not limited by the design of existing equipment or current operating conditions as is required for a retrofit application. Although MRYS is eligible to perform an analysis to determine BART, the Consent Decree (CD) also requires that MRYS install levels of control equivalent to BACT. Thus, the BART analysis can be shortened to only include the BACT-level control technologies specified in the CD or technologies that are more stringent.

Although Unit 1 and Unit 2 at MRYS are BART-eligible, the Consent Decree (CD) also requires that the NDDH establish BACT for NO_X control. With the specification to establish BACT for NO_X, the BART analysis was modified to replace the first four BART evaluation steps with the NO_X BACT analysis. The first four steps of BART are usually used to identify technologies, determine feasibility and evaluate cost, energy, non-air quality and useful life impacts. Because a BACT analysis results in the selection of the best available control technology, the visibility impacts evaluation is the only remaining step in the determination that must be performed to satisfy BART for NO_X. The MRYS NO_X BACT analysis study reports and additional support documents were submitted to the NDDH on October 6, 2006, March 19, and April 23, 2007 respectively. In addition, because the CD also requires a minimum level of control for both SO_2 and PM, this analysis evaluates the visibility impairment impacts of the BACT-level control technologies specified for SO_2 and PM. The BART analysis does not review technologies that do not achieve the minimum level of control specified in the CD. The final BART recommendation is based upon an acceptable degree of visibility improvement in Class 1 areas.

1.3.3 EMISSION SOURCE APPLICABILITY

There are two subjects within the Guidelines related to the applicability of BART to emission sources. The first subject deals with the presumptive BART emission limits and their application to power plants smaller than 750 MW in size. The Guidelines for BART Determination include the following statement with regard to presumptive BART for SO_2 (70 FR 39171):

> "You [meaning States] must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lbs/mmBtu, for each EGU greater than 200 MW that is currently uncontrolled unless you determine that an alternative control level is justified based on a careful consideration of the statutory factors. For a currently uncontrolled EGU greater than 200 MW in size, but located at a power plant smaller than 750 MW in size, such controls are generally cost effective and could be used in your BART determination….."

Similarly for NO_X, the EPA states (70 FR 39171):

> "For coal-fired EGUs greater than 200 MW located at greater than 750 MW power plants and operating without post-combustion controls, we have provided presumptive NO_X limits differentiated by boiler design and type of coal burned. You may determine that an alternative control level is appropriate based on a careful consideration of the statutory factors. For coal-fired EGUs greater than 200 MW located at power plants 750 MW or less in size and operating without post-combustion controls, you should likewise presume that these same levels are cost-effective."

For power plants greater than 750 MW in size, the EPA requires state agencies to apply the presumptive limits for BART as a floor for NO_X control. However, for power plants smaller than 750 MW in size, the presumptive BART limits are described as being "cost-effective" but not set as a minimum performance requirement. Thus, BART for EGUs at power plants smaller than 750 MW in size, like MRYS, is not required to meet the presumptive limits. This BART analysis for MRYS will evaluate potential control options that achieve the control levels and are below the emission limits set forth in the Consent Decree. Because the States have final discretion in how they choose to weigh the various impacts as part of their BART determinations for each EGU emission source, the recommended BART control options may not achieve the EPA's presumptive BART limits based upon the visibility analysis.

The second part of the Guidelines that should be addressed relates to which emission units are subject to BART for a particular pollutant. The Guidelines state that:

> "Once you determine that a source is subject to BART for a particular pollutant, you must establish BART for that pollutant. The BART determination must address air pollution control measures for each emissions unit or pollutant emitting activity subject to review." (70 FR 39163)

According to this statement, the BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2 and PM) regardless of size. The BART analysis for MRYS will review control options for the main boilers for Unit 1 and Unit 2. Smaller emissions sources at the facility are anticipated to provide negligible contribution to visibility impacts from MRYS in Class 1 areas. Smaller sources at MRYS are discussed in Section 1.3.4 and 1.3.5.

1.3.4 SMALL SOURCE EMISSION UNITS

The BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2 and PM) regardless of size. However, smaller emissions sources (e.g., auxiliary boilers and emergency generators) at the facility are anticipated to provide negligible contributions to visibility impairment in Class 1 areas. The nearest Class 1 area is Theodore Roosevelt National Park (TRNP) located approximately 160 km to the west. Although technically eligible, smaller source emissions units were not reviewed because they have limited hours of operation or they are material handling sources with a level of emissions anticipated to be too low to affect visibility impact on TRNP. Consequently, small emission sources are excluded from further consideration in the study.

1.3.5 FUGITIVE DUST

The primary source of fugitive dust is from the outside coal storage area and other plant activities normally found at a coal-fired electrical generating facility. The coal stockpile, access roads and plant activities are performed and maintained with good operating practices. On the coal stockpile and on other applicable fugitive sources, dust suppression is achieved through the use of water sprays or surfactants. The level of fugitive PM emissions is not expected to affect the visibility in Class 1 areas based upon the approximate 160 km distance to the nearest Class 1 area, the large particle size and relatively small emission rates. As such, fugitive sources were not evaluated in this BART analysis for MRYS.

1.3.6 CONDENSABLE PARTICULATE

Particulate matter emissions are composed of filterable and condensable particles. Condensable particulate matter (condensable PM) may react with atmospheric or flue gas constituents as flue gas moves through the different processes and then either condenses into a droplet, coalesces into a solid particle, or forms a solid particle as more volatile components evaporate. Condensable PM may include both organic and inorganic constituents. Organic constituents in the flue gas can exist as a vapor at stack temperatures and a liquid or solid at ambient temperatures. Control technologies designed to minimize the formation of condensable organic emissions are the same technologies that are used to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions. A review of the RBLC database shows that good combustion practices are universally used to control CO/VOC emissions for similar units. Both MRYS units already practice good combustion practices while maintaining combustion efficiency in the boiler and controlling NO_X emissions. Because good combustion practices would likely be considered BART and are already in use at both units, the organic portion of condensable PM is not addressed further in this report.

Sulfuric acid (H_2SO_4) mist is the most widely recognized form of inorganic condensable PM emitted by combustion sources. Other inorganic condensable PM constituents may include to a lesser extent other acid gases, ammonium sulfate ($(NH_4)_2SO_4$), and unidentified inorganic species. Control technologies designed to reduce sulfuric acid mist will also reduce the other inorganic constituents. H_2SO_4 is typically generated in the flue gas when sulfur trioxide (SO_3) reacts with water. SO_3 is a by-product created during the combustion of fuels containing sulfur and is formed when sulfur dioxide (SO_2) in the flue gas is oxidized. Limited data is available on the quantity of SO_2 that will be converted to SO_3 in a lignite fired unit. Estimates of the conversion range from 0.2 to 1.0 percent.

Combustion controls commonly used to control NO_X (e.g., staged combustion and separated overfire air) provide a co-benefit of sulfuric acid mist control by limiting the oxygen available in the boiler and reducing formation of SO_3 in the boiler. The H_2SO_4 vapor will adsorb on the fly ash as the flue gas cools under appropriate temperature and moisture conditions. Consequently, when those conditions exist, H_2SO_4 is removed from the gas stream by particulate control equipment. Control technologies designed to remove SO_2 will also achieve SO_3 removal and reduce emissions of H_2SO_4. Typical SO_3 removal associated with a wet FGD process is 40 to 60 percent, and higher removal is typical for semi-dry FGD processes. The Southern Company estimates a minimum 50% reduction in H_2SO_4 emissions for use of a FGD process.[5] Thus, control technologies used to control NO_X, SO_2 and filterable PM are also able to provide H_2SO_4 control.

Recommended BART for condensable PM is the co-benefit of NO_X, SO_2 and filterable PM control devices to be analyzed in this report and is not addressed further. Therefore this BART analysis for particulate emissions investigates control methods to reduce filterable PM only.

1.4 METHODOLOGY FOR VISIBILITY IMPACTS DETERMINATION

In the BART Determination Guidelines, as discussed in Section 1.2 of this report, the EPA provides five basic steps for a case-by-case BART analysis. The fifth step involves evaluating visibility impacts utilizing dispersion modeling. Visibility impairment impacts for modeled pre-control and post-control emission levels and visibility improvements are to be assessed in deciViews (dV). The BART guidelines describe the thresholds for visibility impairment as:

> “A single source that is responsible for a 1.0 dV change or more should be considered to “cause” visibility impairment; a source that causes less than a 1.0 dV change may still contribute to visibility impairment..... any threshold that you (the States) use for determining whether a source “contributes” to visibility impairment should not be higher than 0.5 dV.” (70 FR 39161)

The NDDH BART protocol does not distinguish between a source that “causes” or “contributes” to visibility impairment but follows the EPA’s Regional Haze Rule threshold recommendations. Thus, 0.5 dV is the deminimis threshold level of visibility impairment impact for an otherwise BART-eligible source under the NDDH BART protocol. In other words, a BART-eligible source for which modeling predicts a visibility impairment impact of greater than 0.5 dV is deemed to have a visibility impairment impact and thus is subject to a BART analysis under the NDDH BART protocol. A BART-eligible source for which the modeling predicts less than a 0.5 dV impact would be deemed to not have a visibility impairment impact, and thus could be exempted from BART on that basis. Most

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[5] “An Updated Method for Estimating Total Sulfuric Acid Emissions from Stationary Power Plants”; Monroe, Larry S. & Harrison, Keith E.; Southern Company Generation and Energy Marketing; Revised March, 2003.

noticeably, the EPA refrains from addressing the question of whether or not a difference in visibility impairment impact improvement of less than 0.5 dV between two BART alternatives would constitute equivalency under the visibility analysis, or if any difference in the model results, no matter how slight, should be interpreted as ranking one solution over the other. The approach taken in the BART analysis for MRYS incorporates the visibility impact analysis results as a verification of visibility improvement.

1.5 THE ROLE OF MODELING AND CALPUFF IN A BART ANALYSIS

The BART guidelines list visibility impact at a Class I area as one of the factors in a BART determination. The EPA interpreted the statutory provision of Section 169A of the Clean Air Act to require that a BART-eligible source is one that is "reasonably anticipated to cause or contribute" to regional haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area (70 FR 39161). A Class I area, as listed by the EPA, is an area of the country with pristine air quality that is sensitive to changes in visibility. Two Class 1 areas have been identified for inclusion in the visibility analysis for MRYS. These are the Theodore Roosevelt National Park (TRNP), and the Lostwood National Wildlife Refuge (Lostwood NWR), which are approximately 160 and 180 km (100 and 112 miles), from Milton R. Young Station, respectively. For Class I areas more than 50 km from a source, the EPA has identified CALPUFF as a guideline model for long-range transport that is suitable for predicting potential changes in visibility. CALPUFF is a non-steady-state meteorological and air quality dispersion modeling system used to access long-range transport of pollutants.

The NDDH modeling protocol confirmed that the two Class I areas to be considered for visibility impairment analysis are the TRNP and Lostwood NWR. However, the three units or areas of the TRNP are to be treated as separate Class I areas for the analysis.

1.5.1 CALPUFF MODELING METHODOLOGY

Visibility impairment is caused by a combination of particles and gases in the atmosphere. Some particles and gases scatter light, others absorb light. The combined effect of scattering and absorption is called "light extinction" which is most commonly seen as haze. This haziness is measured in deciView (dV) units, and is related to light extinction coefficient by the following equation:

$$dV = 10 \ln(b_{ext}/10)$$

Where b_{ext} is light extinction coefficient in inverse megameters.

Visibility impairment is a function of light extinction. Light extinction occurs when light energy is either scattered or absorbed by particles in the air. The amount of moisture in the air also plays a role in light extinction. Certain gases combine with moisture in the air to form small light scattering particles. These gases, most notably SO_2 and NO_X, are significant components of coal-fired power plant emissions. Particulate Matter (PM) also contributes to light extinction. In the BART Determination Guidelines, the EPA states that “You [the State] may use PM_{10} as an indicator for particulate matter. We do not recommend the use of Total Suspended Particulates (TSP). As emissions of PM_{10} include the components of $PM_{2.5}$ as a subset, there is no need to have separate 250 ton thresholds for PM_{10} and $PM_{2.5}$; 250 tons of PM_{10} represents at most 250 tons of $PM_{2.5,}$ and at most 250 tons of any individual particulate species such as elemental carbon, crustal material, etc.” (70 FR 39160). The NDDH modeling protocol states that particulate matter emissions should be specified as either coarse (PM_{10} minus $PM_{2.5}$) or fine ($PM_{2.5}$). The distinction between coarse and fine particulate occurs in the modeling.

The NDDH modeling protocol recommends a specific version of the CALPUFF modeling system as modified by the NDDH to specifically address terrain, climate, and emission characteristics of MRYS. (CALMET and CALPUFF were recompiled by the NDDH while the CALPOST executable used for this visibility analysis was the EPA guideline executable). Along with the CALPUFF modeling system, the NDDH also provided the RUC2-MM5 gridded wind field data (2000-2002), surface, upper air, and precipitation files, and CALMET and CALPUFF input files. The input files contained the specific coordinate grid points, wind field options, terrain, dispersion options, receptor coordinates and plume characteristics and other model parameters that the NDDH has determined best represents the region. The NDDH version of CALPUFF was used for modeling.

In order to predict the change in light extinction at TRNP and Lostwood NWR areas, SO_2, NO_X, and PM were modeled with CALPUFF using pre-control and post-control emission scenarios. A variety of post-control scenarios were used to determine the reduction in visibility impact for each control technology. The NDDH identified 104 receptors allocated over both TRNP and Lostwood NWR. These receptors are location points for which CALPUFF was used to perform a visibility calculation.

The BART guideline states that a visibility improvement is based upon the modeled change in visibility impacts, measured in deciViews, for the pre-control and post-control emission scenarios.

The comparison should be made for the 98th percent days (70 FR 39170). The NDDH modeling protocol provides additional clarification about BART applicability by stating, "…the context of the 98th percentile 24-hour delta-deciView prediction is with respect to days of the year, and is not receptor specific. A 24-hour prediction greater than 0.5 delta-deciView at any receptor in a Class I area would constitute a day of exceedance, and up to 7 days of exceedance would be allowed per year per Class I area (i.e., the 98th percentile is approximated by the eighth-highest daily prediction)." In other words, visibility impacts should be compared on an annual basis using the eighth highest day for comparison (365 * (1-.98) = 7 days of acceptable exceedance). However, NDDH subsequently advised that the delta-deciView comparison should be made at the 90th percentile to be consistent with the Western Regional Air Partnership (WRAP) protocol. Therefore, the analysis of visibility impairment impact reduction presented for each control scenario in this section is based on the 90th percentile value. The predictions of 24-hour 98th percentile deciView data are also provided in Appendix A.

1.5.2 MODELING SCENARIOS

Since a BART analysis is based on the degree of reduction achieved by the application of control technologies, the CALPUFF analysis examined multiple operating scenarios based upon the feasible control technologies identified for each pollutant. These scenarios represent the emissions of SO_2, NO_X, and PM under the following conditions:

- NDDH BART Modeling Protocol emission rates
- Post-Control NO_X emissions based upon recommended NO_X BACT-level emission rates from the Consent Decree
- Post-Control SO_2 and PM emissions based upon minimum emission rates as required by the Consent Decree and more stringent emission rates representative of potential BART alternatives

The emission rates modeled in each scenario are presented in Table 1.5-1.

Table 1.5-1 – Milton R. Young Station Modeling Scenarios

Scenario	Unit 1			Unit 2		
	NO_X (lb/hr)	SO_2 (lb/hr)	PM Coarse/Fine (lb/hr)	NO_X (lb/hr)	SO_2 (lb/hr)	PM Coarse/Fine (lb/hr)
Screening	Protocol	Protocol	Protocol	Protocol	Protocol	Protocol
1	1,070.7	Protocol	Protocol	2,011.6	Protocol	Protocol
2A	Protocol	723.1	Protocol	Protocol	1,574.4	Protocol
2B	Protocol	361.6	Protocol	Protocol	773.7	Protocol
3A	Protocol	Protocol	38.5 / 5.8	Protocol	Protocol	133.7 / 21.0
3B	Protocol	Protocol	77.1 / 11.6			
4	1,070.7	361.6	77.1 / 11.6	2,011.6	1,574.0	133.7 / 21.0
5	1,070.7	361.6	77.1 / 11.6	2,011.6	1,574.0	133.7 / 21.0

These scenarios represent the emission rates evaluated for consideration in making a BART recommendation. The emission rates presented in Table 1.5-1 correspond to control options and efficiencies considering the results of the NO_X BACT analyses and BART analyses for SO_2 and PM. The screening scenario from the NDDH BART modeling protocol is based on the historical maximum 24-hour emission rates for MRYS between 2000 and 2002. These rates were supplied to the NDDH by Minnkota, but were based upon operations that were not representative of stack conditions associated with new or modified retrofit control technologies.

Due to analyses performed on plant operations and historical emissions data, Minnkota has determined that unit operating conditions associated with these protocol rates are not representative of future maximum 24-hour emissions and has requested NDDH to allow the use of an alternative stack parameters and hourly baseline conditions for modeled post-control emission rates. NDDH agreed to the use of alternative post-control conditions. The alternative post-control scenarios are based upon various control technology emission reductions being applied to maximum 24-hour average heat input of 2,955 mmBtu/hr for Unit 1 and 5,158 mmBtu/hr for Unit 2. The emission rates associated with each scenario are discussed in the section related to the controlled pollutant.

As shown in Table 1.5-1, multiple modeling scenarios were conducted to determine the specific visibility impact reduction associated with the control of each pollutant. To determine a specific visibility impact for a particular pollutant, the emission rate for the pollutant of concern was changed from the protocol rate to the post-control rate. The other two major pollutants' emission rates were modeled at the protocol rates. Thus, any visibility impairment impact reduction for that modeling scenario was due solely to the application of the individual pollutant’s control technology.

Additional modeling runs were conducted to determine the overall visibility impairment impact reduction caused by simultaneous application of all control technologies. In Table 1.5-1, modeling scenario 4 was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies for each unit individually. Modeling scenario 5 was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies for both units combined. The modeling results are summarized and discussed in the sections below.

2.0 NO_X BART EVALUATION

The BART analyses for NO_X emissions from MRYS Unit 1 and Unit 2 are described in this section. Technical descriptions of MRYS Unit 1 and Unit 2 boilers and existing air pollution control equipment are provided. As discussed in the introduction, Minnkota has entered into a Consent Decree (CD) that requires MRYS to install BACT-level NO_X control technologies on both units. For NO_X emissions control, the CD required that a complete BACT analysis be performed for MRYS to determine the applicable control technologies for each unit. The BACT analysis reports and additional support documents were submitted to the NDDH on October 6, 2006, March 19, and April 23, 2007 respectively.

It was assumed that a NO_X emissions control alternative considered as BACT would also satisfy similar ranking and non-visibility impacts of a BART determination process. Therefore, the alternative with the highest-performing, most cost-effective combination of control technologies identified by the NO_X BACT analysis for each Unit at MRYS that was not eliminated for technical infeasibility or adverse non-visibility impacts would be evaluated for impacts on the nearest Class 1 area in the subsequent BART visibility impairment analysis.

2.1 NO_X EVALUATION BASIS – UNIT 1

Milton R. Young Station Unit 1 includes a Babcock and Wilcox steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. Original unit design steam generating capacity is 1.714 million lbs/hr at 1,920 psi with a fuel heat input of 2,510 mmBtu/hr. The boiler is fired by seven ten-foot diameter cyclone burners, arranged “three over four” across the front wall of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the electrostatic precipitator (ESP). Unit 1’s boiler serves a turbine generator with a nameplate rating of 257 MW[6] and has a nominal 235 MW net design output capacity rating. Unit 1 is typically capable of sustained output of approximately 253 MW gross, and has an ultimate short-term maximum gross output (URGE) rating of 278 MW. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a

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[6] Ibid EPA’s eGRID database; April, 2003.

mine located adjacent to the site. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boiler.

2.1.1 NO_X VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the BART NO_X analysis was to conduct a visibility improvement determination for Unit 1. Due to the association of the Consent Decree and requisite BACT analysis, the visibility analysis was the only subsequent impact evaluation necessary to establish BART. In addition, because the BACT analysis resulted in one control alternative for NO_X emissions control, only one related emission rate was modeled to determine the post-control visibility impairment impacts.

The modeling for Unit 1 uses two NO_X emission rates as a basis for the visibility impairment impacts. The NDDH BART protocol[7] NO_X emission rate of 2,855.2 lb /hr was modeled to determine a pre-control baseline visibility impact. This protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. This is equivalent to a unit NO_X emission rate of 0.898 lb/mmBtu at a boiler heat input rate of 3,180 mmBtu/hr. The baseline visibility impact was then compared with the results predicted from a modeled post-control NO_X emission rate based upon the control technology specified for Unit 1 in the BACT analysis.

According to the BACT analysis required by the Consent Decree, Selective Non-Catalytic Reduction (SNCR) post-combustion technology used in conjunction with an advanced combustion control application of Separated Overfire Air (ASOFA) was considered the best available technology and therefore was evaluated as BART for Unit 1. The second NO_X emission rate of 1,070.7 lb /hr was based upon application of SNCR with ASOFA control technologies for a reduction of approximately 62.5 percent from the protocol mass emission rate. This is equivalent to a unit NO_X emission rate of 0.362 lb/mmBtu at a more representative maximum 24-hour average boiler fuel heat input of 2,955 mmBtu/hr. The visibility modeling conditions are presented in Table 2.1-1.

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[7] Ibid NDDH Final BART Protocol; November, 2005.

Table 2.1-1 – Milton R. Young Station Unit 1 Visibility Model Conditions

	NDDH Protocol	SNCR with ASOFA[(1)]
NO_X Emission Rate lb/hr	2,855.2	1,070.7
lb/mmBtu	0.898	0.362
Heat Input, mmBtu/hr	3,180.0	2954.5

(1) – Post-control NO_X emission rate reflects recommended BACT w/ adjusted reduction.

The results of the visibility modeling at the protocol baseline NO_X emission rate for MRYS Unit 1 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control NO_X emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for all Class 1 areas at the post-control BACT-level NO_X emission rate was below the 0.50 dV threshold level. The modeling results are presented in Table 2.1-2.

Table 2.1-2 – NO_X Visibility Impairment Impacts and Reductions at NOx BACT Post-Control Emissions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.549	0.377	0.172
TRNP-North Unit	0.628	0.413	0.215
TRNP-Elkhorn Ranch	0.374	0.266	0.108
Lostwood NWR	0.750	0.487	0.263

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

2 - NO_X emissions reduction by 62.5% over NDDH protocol baseline case. This scenario assumes protocol emission rates for SO_2 and PM. Refer to Appendix A for complete protocol and revised post-control visibility model results.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 2.1-3. Similarly, the same information for the post-control NO_X emission rates is summarized and shown in Table 2.1-3. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control NO_X emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 1. The impact in terms of days exceeding 0.50 dV varies from an approximately 17% reduction for TRNP – Elkhorn in 2001 to an approximately 40% reduction for TRNP – South in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 15% for TRNP – Elkhorn in 2002 to approximately 53% for TRNP – South in 2000.

A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the SNCR with ASOFA-controlled post-control emission rates with pre- and post-control SO_2 and PM alternatives is included in Figures 2.1-1 through 2.1-9.

Table 2.1-3 – Visibility Impairment Improvements for NOx BACT Post-Control Emissions – MRYS Unit 1 NO_X Scenarios

Class 1 Area	NO_X Control Technique	Days[1] Exceeding 0.5 dV in 2000	Days[1] Exceeding 0.5 dV in 2001	Days[1] Exceeding 0.5 dV in 2002	Days[1] Exceeding 1.0 dV in 2000	Days[1] Exceeding 1.0 dV in 2001	Days[1] Exceeding 1.0 dV in 2002	Consecutive Days[1] Exceeding 0.5 dV 2000	Consecutive Days[1] Exceeding 0.5 dV 2001	Consecutive Days[1] Exceeding 0.5 dV 2002
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	SNCR w/ ASOFA	23	20	35	9	10	19	2	3	3
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	SNCR w/ ASOFA	24	31	38	9	13	20	2	4	4
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	SNCR w/ ASOFA	18	20	27	6	8	17	2	3	4
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	SNCR w/ ASOFA	38	36	33	17	19	20	3	3	4

1 - Number of days for predicted visibility impairment impacts provided in Appendix A.

Figure 2.1-1 – Reduction in Days of Visibility Impairment > 0.5 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 1

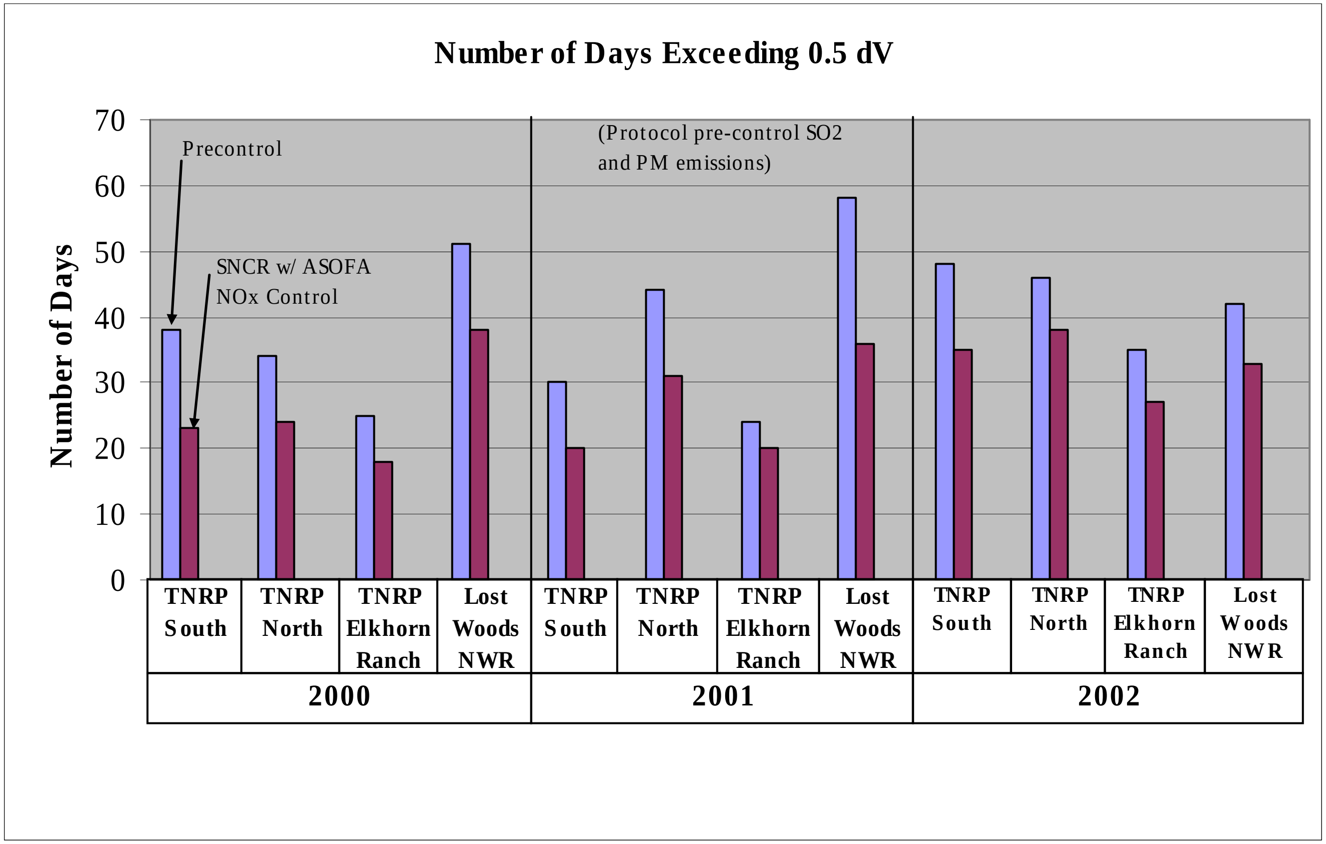


Figure 2.1-2 – Reduction in Days of Visibility Impairment > 1.0 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 1

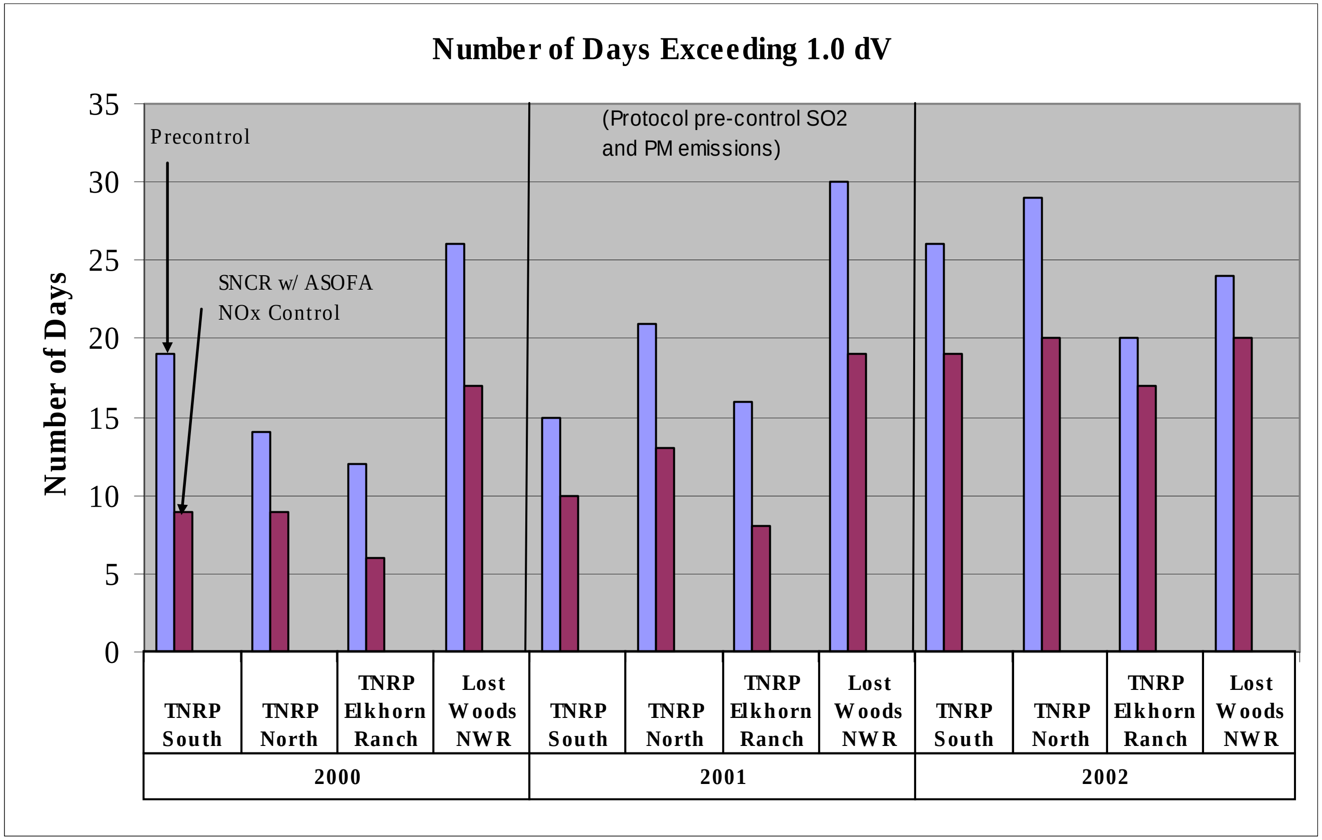


Figure 2.1-3 – Reduction in Maximum Consecutive Days Exceeding 0.5 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 1

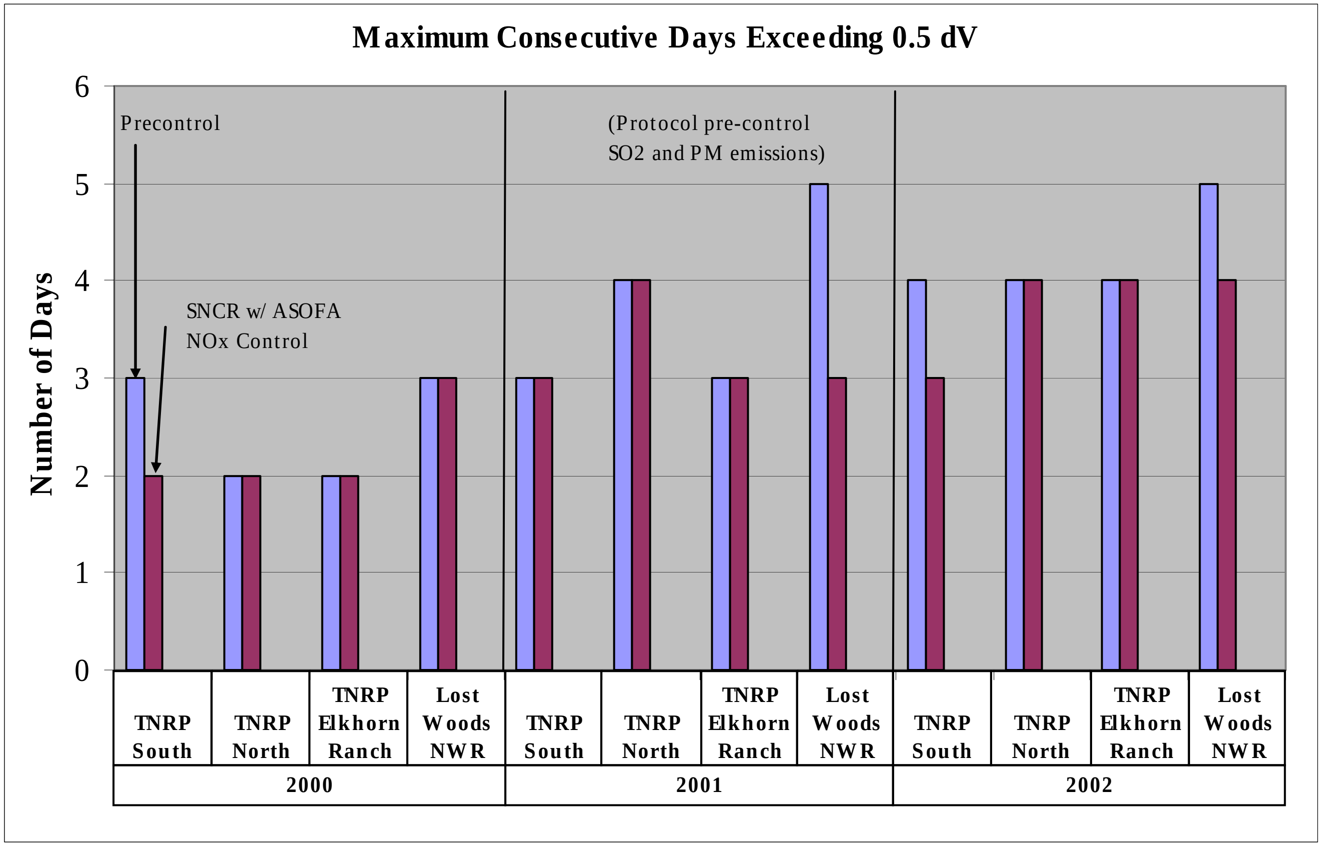


Figure 2.1-4 – Incremental Visibility Impairment Improvements – Days > 0.5 dV
SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions
with Various Post-Control SO_2 and PM Emissions
MRYS Unit 1

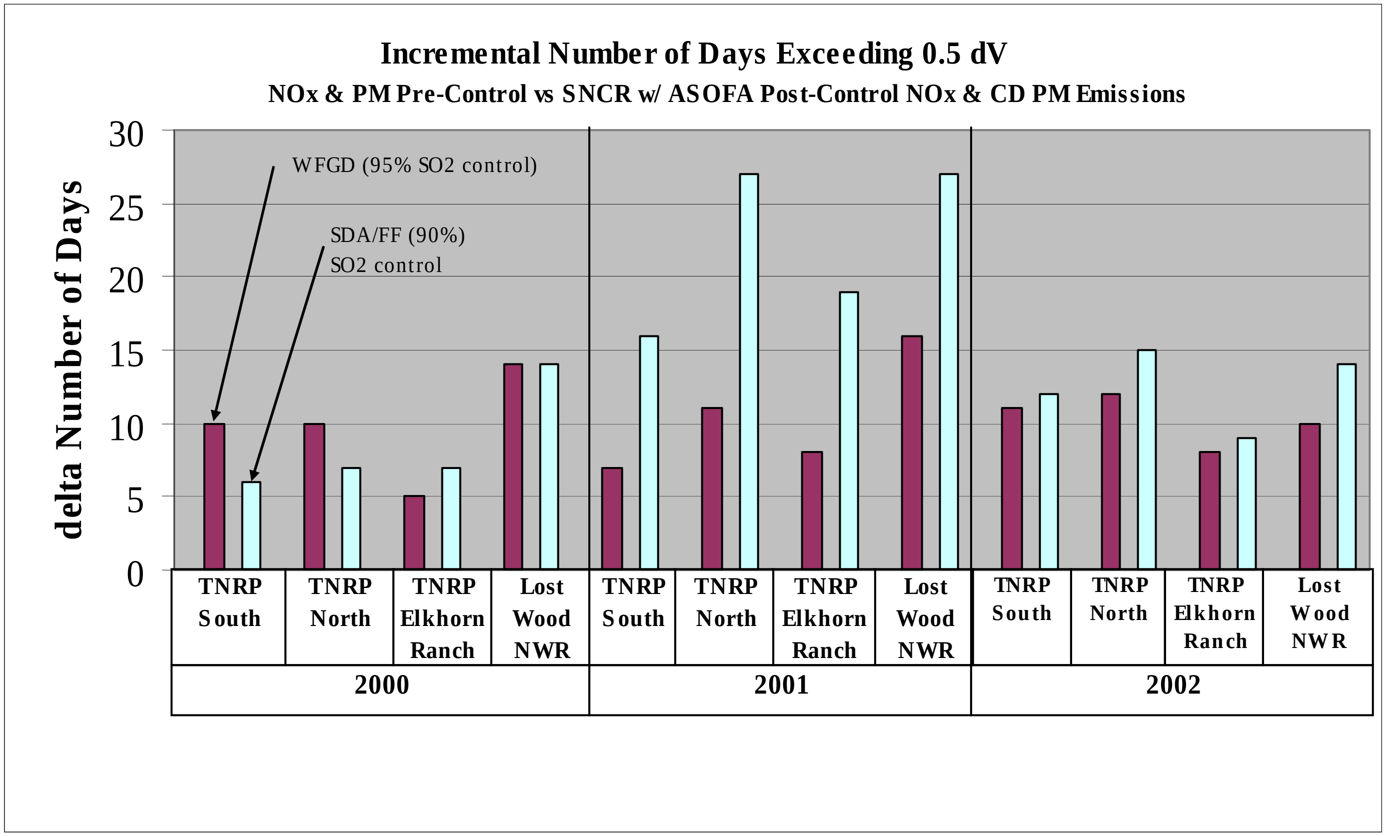
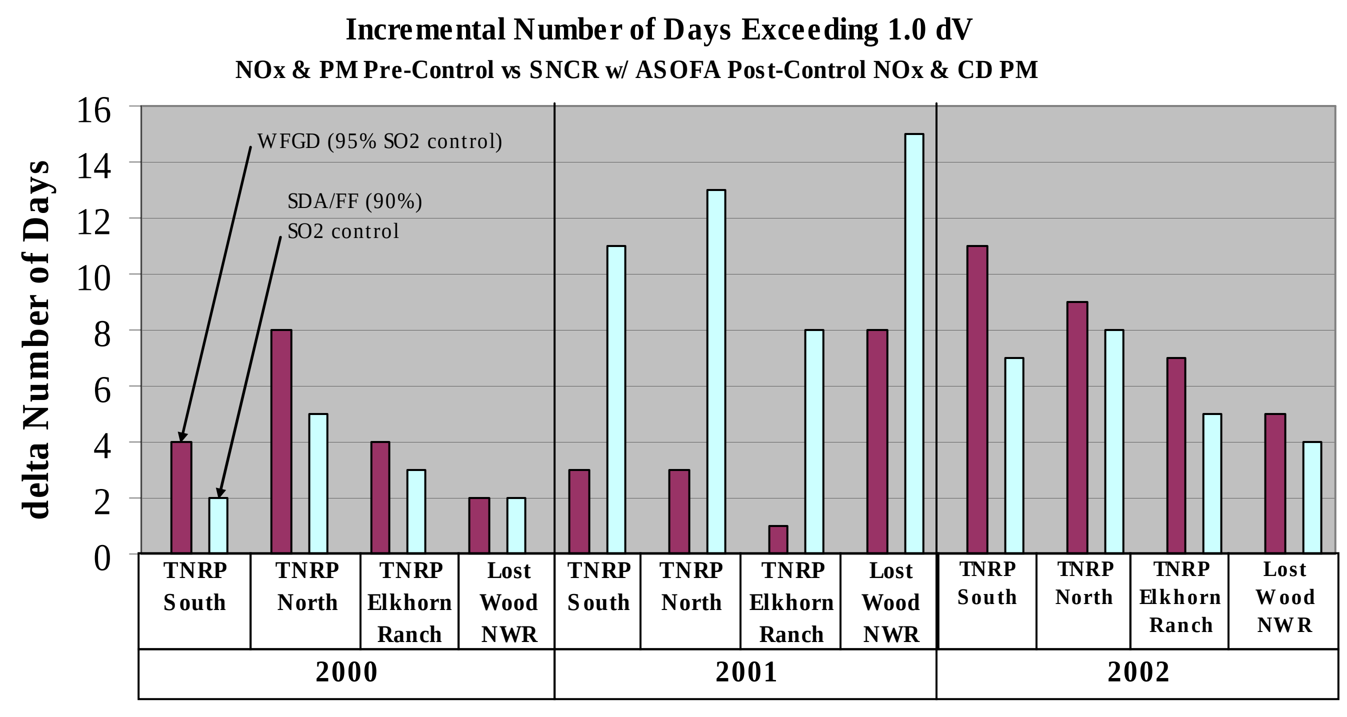


Figure 2.1-5 – Incremental Visibility Impairment Improvements – Days > 1.0 dV SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions with Various Post-Control SO_2 and PM Emissions MRYS Unit 1



Year	Site	WFGD (95% SO2 control)	SDA/FF (90%) SO2 control
2000	TNRP South	4	2
2000	TNRP North	8	5
2000	TNRP Elkhorn Ranch	4	3
2000	Lost Wood NWR	2	2
2001	TNRP South	3	11
2001	TNRP North	3	13
2001	TNRP Elkhorn Ranch	1	8
2001	Lost Wood NWR	8	15
2002	TNRP South	11	7
2002	TNRP North	9	8
2002	TNRP Elkhorn Ranch	7	5
2002	Lost Wood NWR	5	4

Figure 2.1-6 – Incremental Visibility Impairment Reductions – Maximum Consecutive Days Exceeding 0.5 dV SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions with Various Post-Control SO_2 and PM Emissions MRYS Unit 1

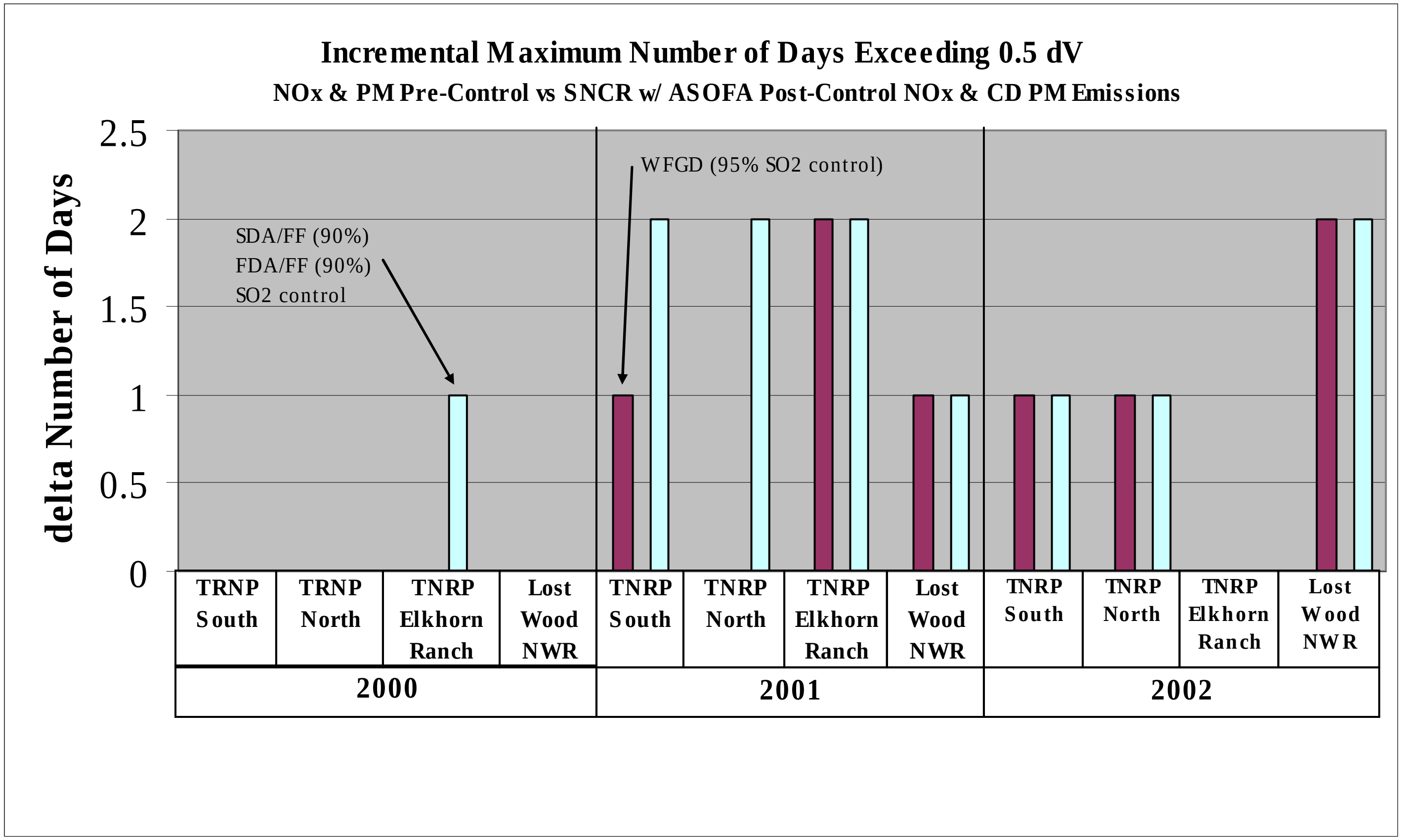


Figure 2.1-7 – Days of Visibility Impairment > 0.5 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 1

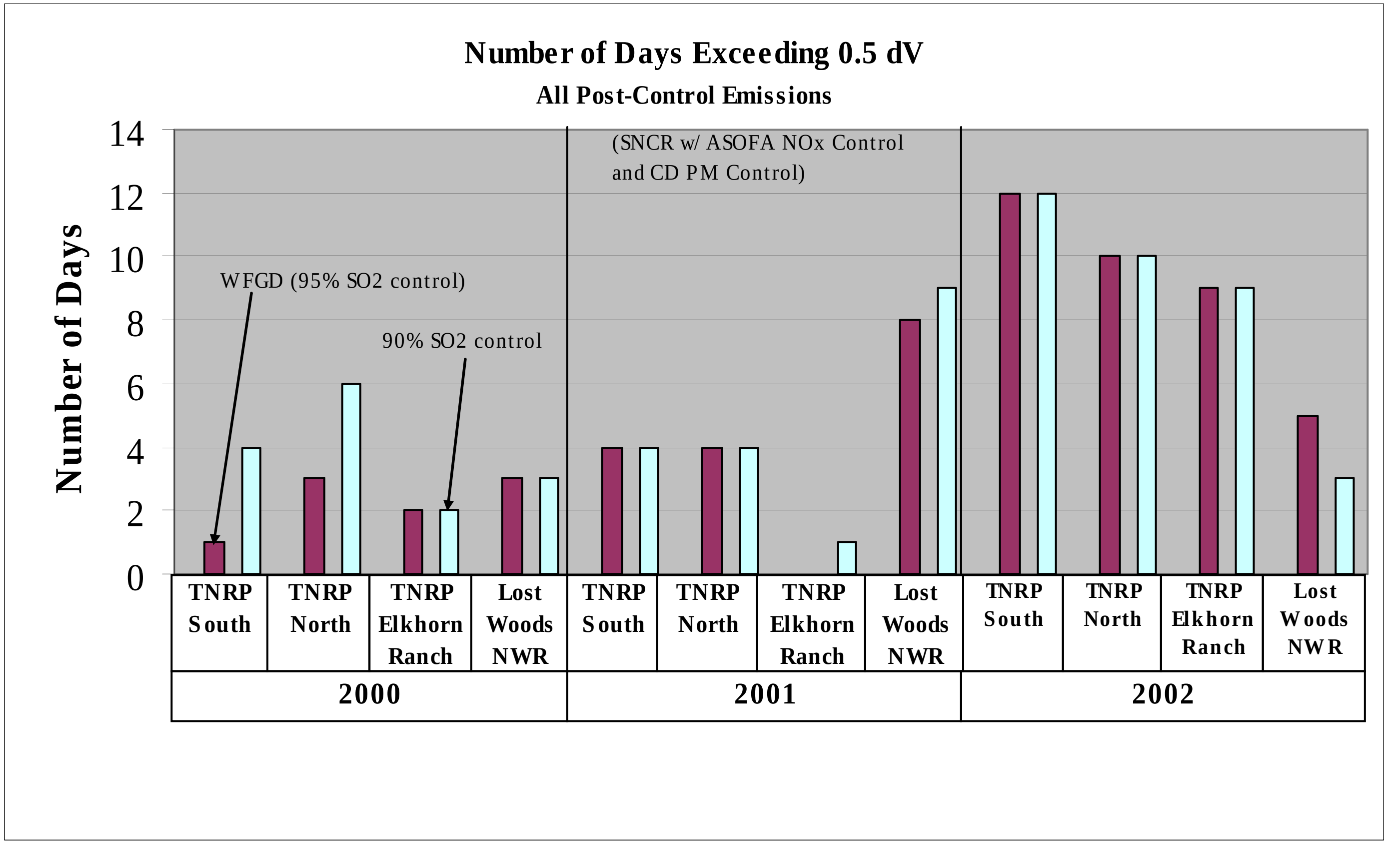


Figure 2.1-8 – Days of Visibility Impairment > 1.0 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 1

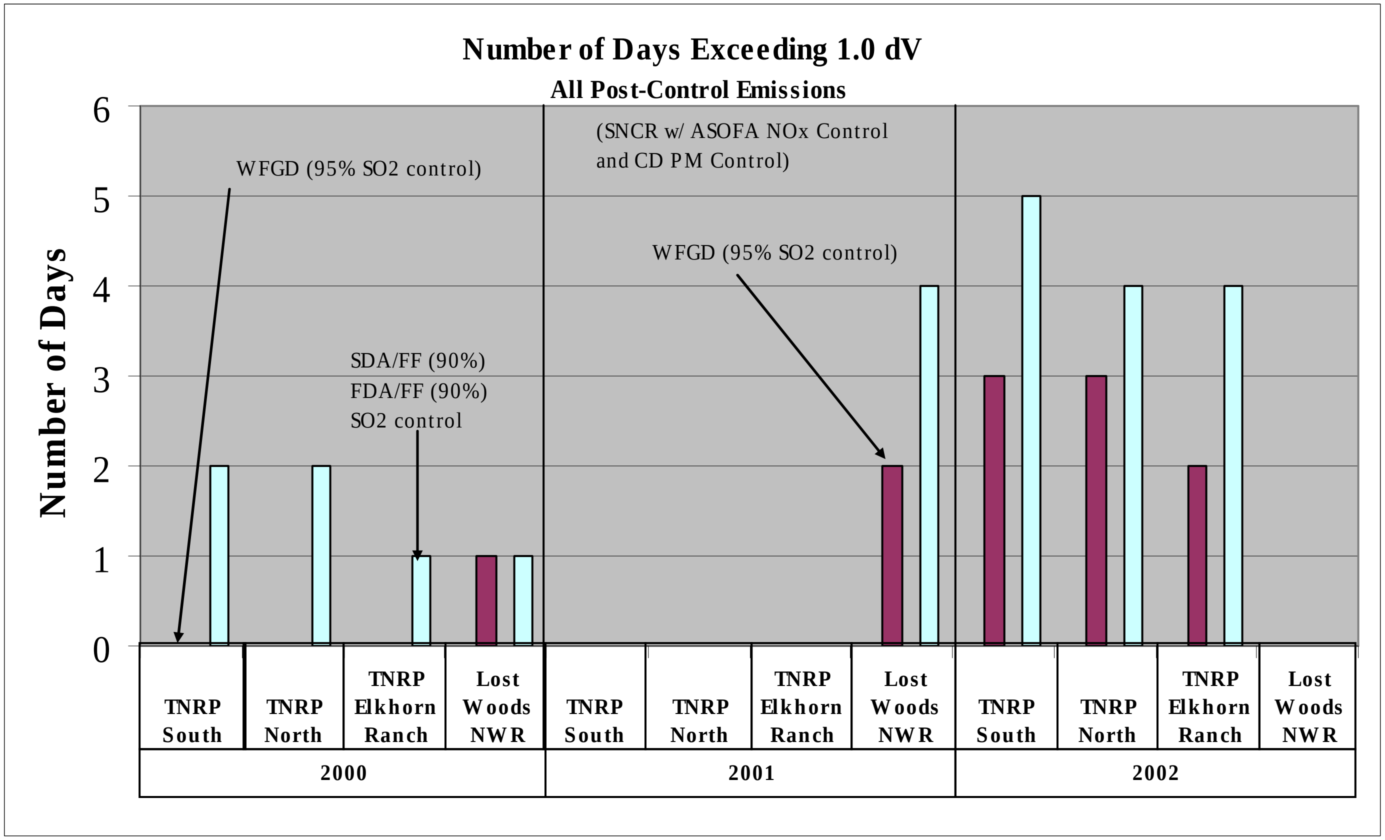
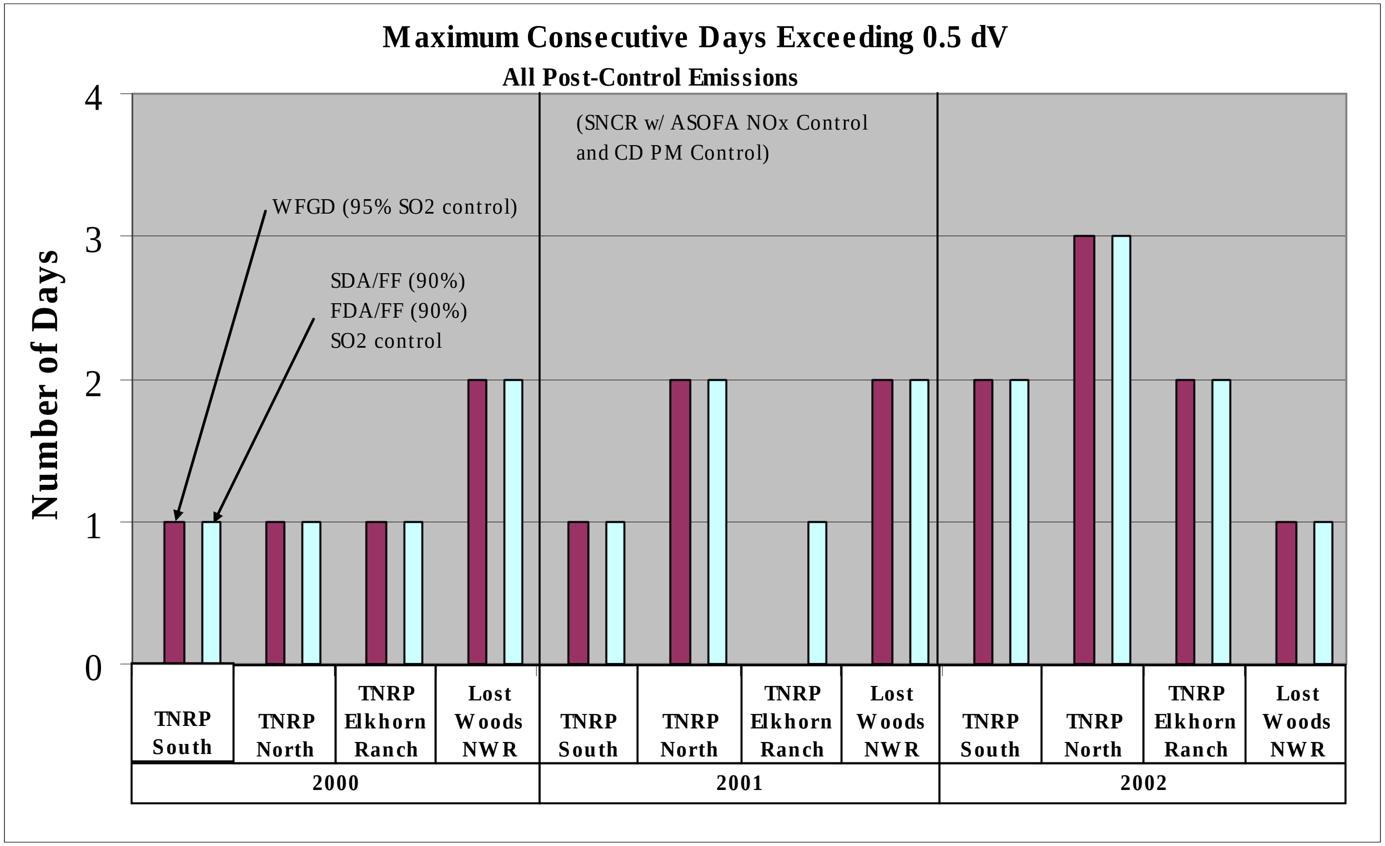


Figure 2.1-9 – Visibility Impairment Improvements – Reductions in Maximum Consecutive Days Exceeding 0.5 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 1



2.2 NO_X EVALUATION BASIS – UNIT 2

Milton R. Young Unit 2 is a Babcock and Wilcox steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. Original unit design steam generating capacity is 3.20 million lbs/hr at 2,620 psi with a fuel heat input of 4,696 mmBtu/hr. The boiler is fired by twelve ten-foot diameter cyclone burners, arranged “three over three” across the front and rear walls of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 2’s boiler serves a turbine-generator with a name plate rating of 477 MW[8], and has a nominal 439 MW net design output capacity rating. Unit 2 is capable of sustained output of approximately 462 MW gross, and has an ultimate short-term maximum gross output (URGE) of 512 MW. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boiler.

2.2.1 NO_X VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the BART NO_X analysis was to conduct a visibility improvement determination for Unit 2. Due to the association of the Consent Decree and requisite BACT analysis, the visibility analysis was the only subsequent impact evaluation necessary to establish BART. In addition, because the BACT analysis resulted in one recommended control alternative, only one related emission rate was modeled to determine the visibility impairment impacts.

The modeling for Unit 2 uses two NO_X emission rates as a basis for the visibility impairment impacts. The NDDH BART protocol[9] NO_X emission rate of 5,364.2 lb /hr was modeled to determine a pre-control baseline visibility impact. This protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. This is equivalent to a unit NO_X emission rate of 0.894 lb/mmBtu at a boiler heat input rate of 5,999 mmBtu/hr. The baseline visibility impact was then compared with the result predicted from a modeled post-control NO_X emission rate based upon the control technology specified for Unit 2 in the BACT analysis. According to the BACT

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[8] Ibid EPA’s eGRID database; April, 2003.
[9] Ibid NDDH Final BART Protocol; November, 2005.

analysis required by the Consent Decree, Selective Non-Catalytic Reduction (SNCR) used in conjunction with Advanced Separated Overfire Air (ASOFA) was considered the best technology and therefore was evaluated as BART for Unit 2. The second emission rate of 2,011.6 lb NO_X/hr was based upon application of SNCR and ASOFA control technologies for a reduction of approximately 62.5 percent from the protocol mass emission rate. This is equivalent to a unit NO_X emission rate of 0.390 lb/mmBtu at a more representative maximum 24-hour average boiler fuel heat input of 5,158 mmBtu/hr. The visibility modeling conditions are presented in Table 2.2-1.

Table 2.2-1 – Milton R. Young Station Unit 2 Visibility Model Conditions

	NDDH Protocol	SNCR with ASOFA(1)
NOx Emission Rate lb/hr	5,364.2	2,011.6
lb/mmBtu	0.894	0.390
Heat Input, mmBtu/hr	5,999.1	5,158.0

(1) – Post-control NO_X emission rate reflects recommended BACT w/ adjusted reduction.

The results of the visibility modeling at the protocol baseline NO_X emission rate for MRYS Unit 2 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control NO_X emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for three of the Class 1 areas at the post-control BACT-level NO_X emission rate were below the 0.50 dV threshold level. The Lostwood NWR Class 1 area had a modeled visibility impairment impact of 0.543 dV. The modeling results are presented in Table 2.2-2.

Table 2.2-2 – NO_X Visibility Impairment Impacts and Reductions at NOx BACT Post-Control Emissions, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.580	0.406	0.174
TRNP-North Unit	0.619	0.438	0.181
TRNP-Elkhorn Ranch	0.360	0.278	0.082
Lostwood NWR	0.775	0.543	0.232

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

2 - NO_X emissions reduction by 62.5% over NDDH protocol baseline case. This scenario assumes protocol emission rates for SO_2 and PM. Refer to Appendix A for complete protocol and revised post-control visibility model results.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 2.2-3. Similarly, the same information for the post-control NO_X emission rates is summarized and shown in Table 2.2-3. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control NO_X emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 2. The impact in terms of days exceeding 0.50 dV varies from an approximately 9% reduction for TRNP – Elkhorn in 2001 to an approximately 37% reduction for TRNP – South in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 15% for TRNP – Elkhorn in 2002 to approximately 50% for TRNP – North in 2000.

A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the SNCR with ASOFA-controlled post-control emission rates with pre- and post-control SO_2 and PM alternatives is included in Figures 2.2-1 through 2.2-9.

Table 2.2-2 – Visibility Impairment Improvements for NOx BACT Post-Control Emissions – MRYS Unit 2 NO_X Scenarios

Class 1 Area	NO_X Control Technique	Days[1] Exceeding 0.5 dV in 2000	Days[1] Exceeding 0.5 dV in 2001	Days[1] Exceeding 0.5 dV in 2002	Days[1] Exceeding 1.0 dV in 2000	Days[1] Exceeding 1.0 dV in 2001	Days[1] Exceeding 1.0 dV in 2002	Consecutive Days[1] Exceeding 0.5 dV 2000	Consecutive Days[1] Exceeding 0.5 dV 2001	Consecutive Days[1] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	SNCR w/ ASOFA	26	20	40	11	11	21	2	3	3
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	SNCR w/ ASOFA	24	32	40	9	13	23	2	4	4
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	SNCR w/ ASOFA	22	21	30	7	10	17	2	3	4
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	SNCR w/ ASOFA	41	39	34	19	22	20	3	3	4

1 - Number of days for predicted visibility impairment impacts provided in Appendix A.

Figure 2.2-1 – Reduction in Days of Visibility Impairment > 0.5 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 2

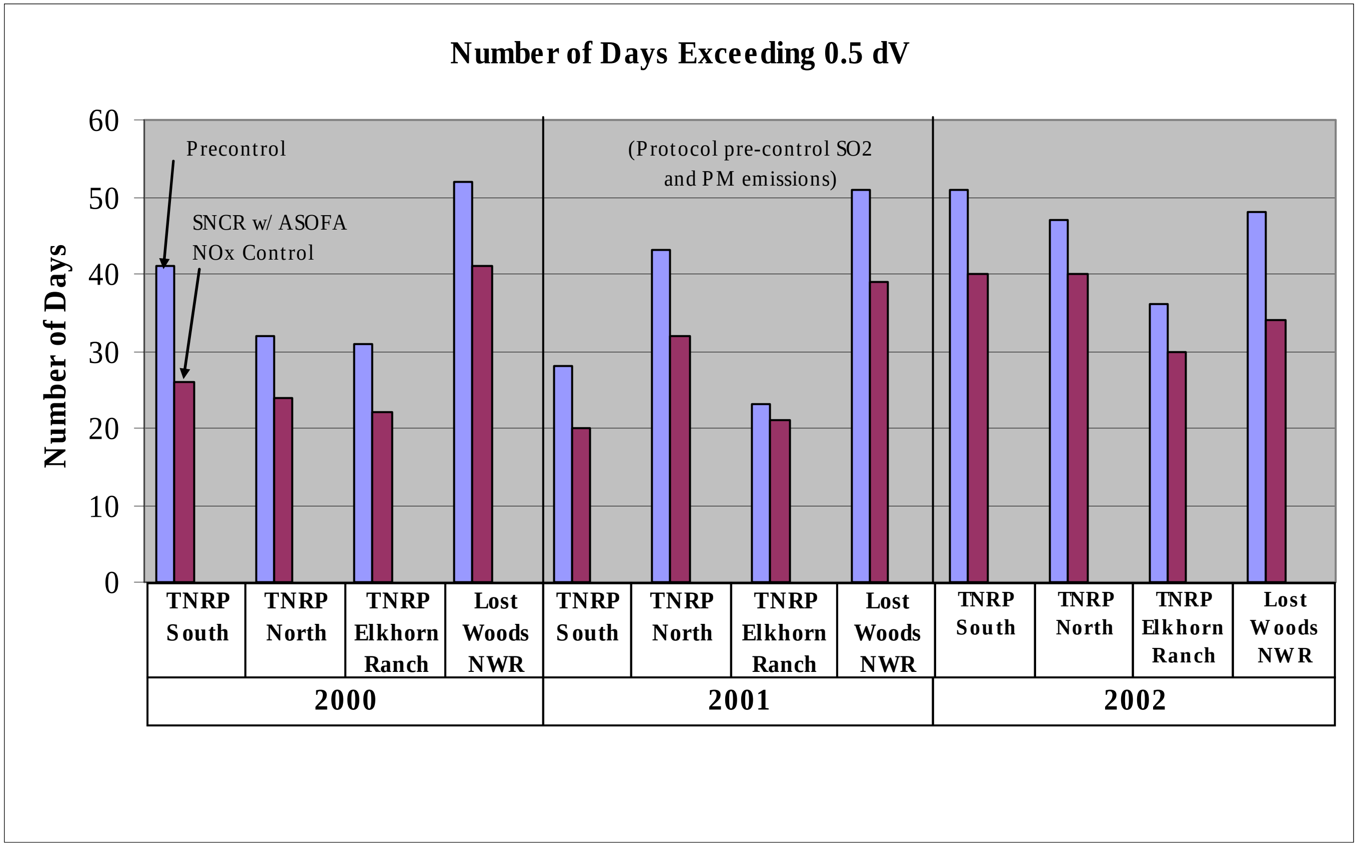


Figure 2.2-2 – Reduction in Days of Visibility Impairment > 1.0 dV
SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions
MRYS Unit 2

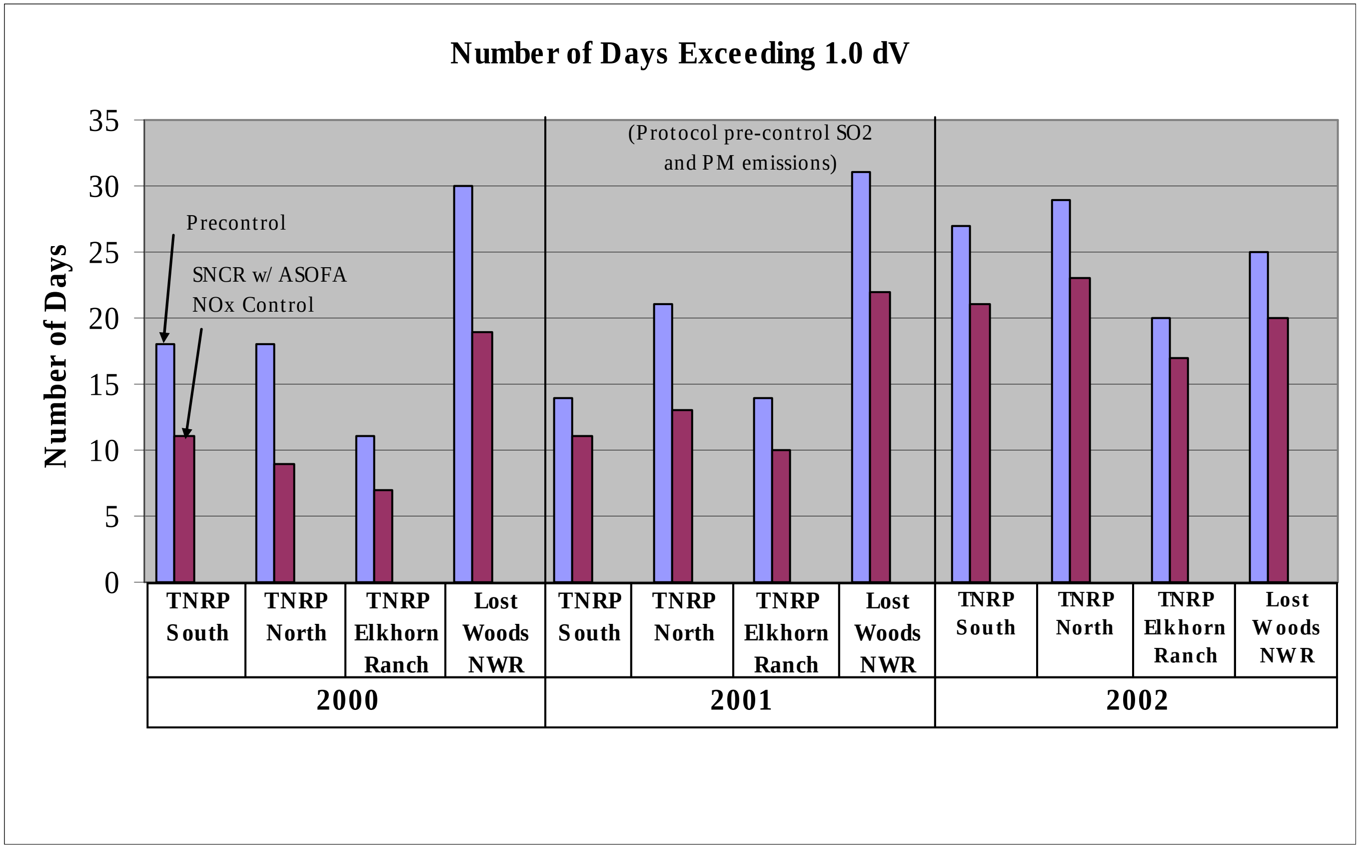


Figure 2.2-3 – Reduction in Maximum Consecutive Days Exceeding 0.5 dV SNCR w/ ASOFA BART NO_X Control with Protocol Pre-Control SO_2 and PM Emissions MRYS Unit 2

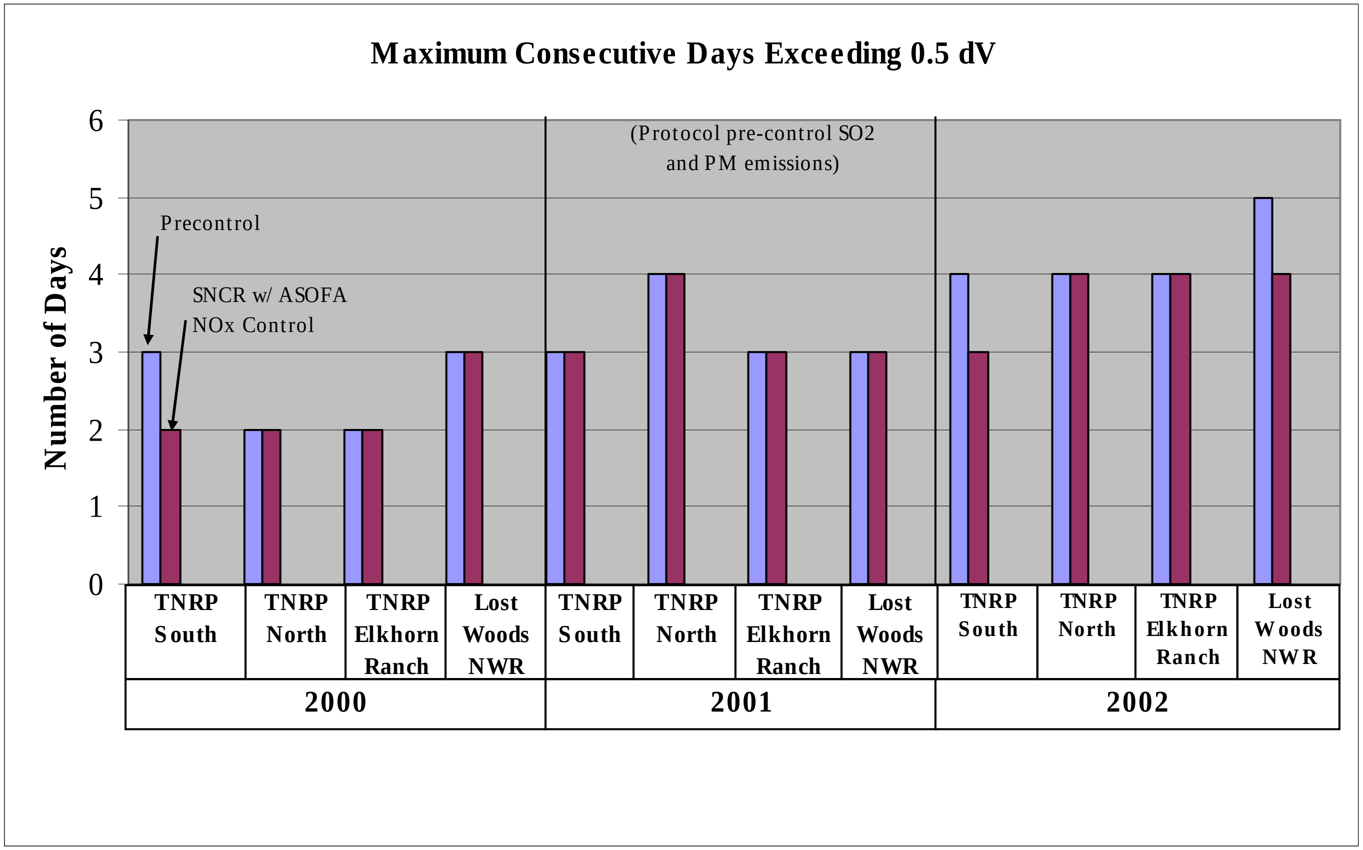


Figure 2.2-4 – Incremental Visibility Impairment Improvements – Days > 0.5 dV SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions with Various Post-Control SO_2 and PM Emissions
MRYS Unit 2

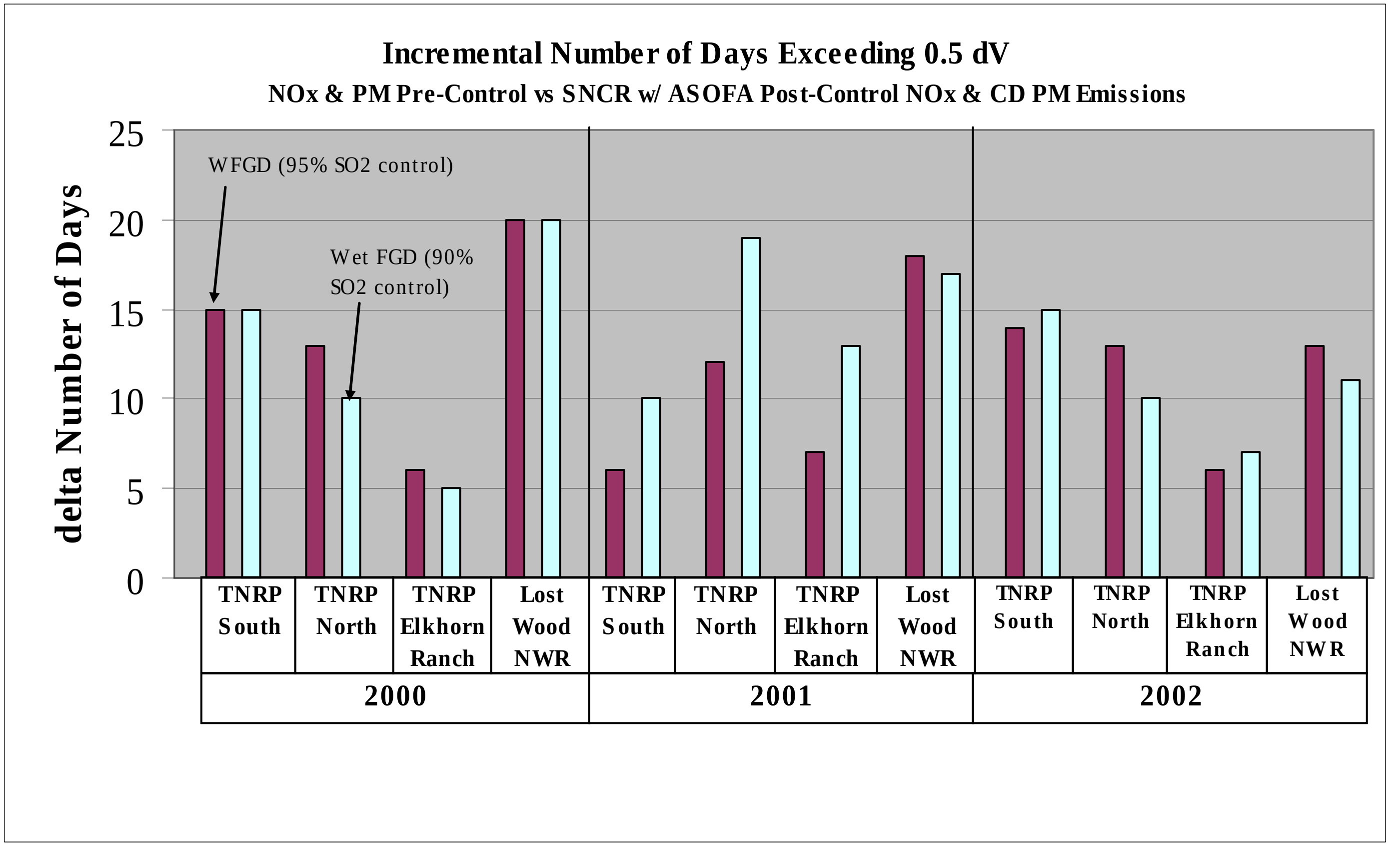


Figure 2.2-5 – Incremental Visibility Impairment Improvements – Days > 1.0 dV
SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions
with Various Post-Control SO_2 and PM Emissions
MRYS Unit 2

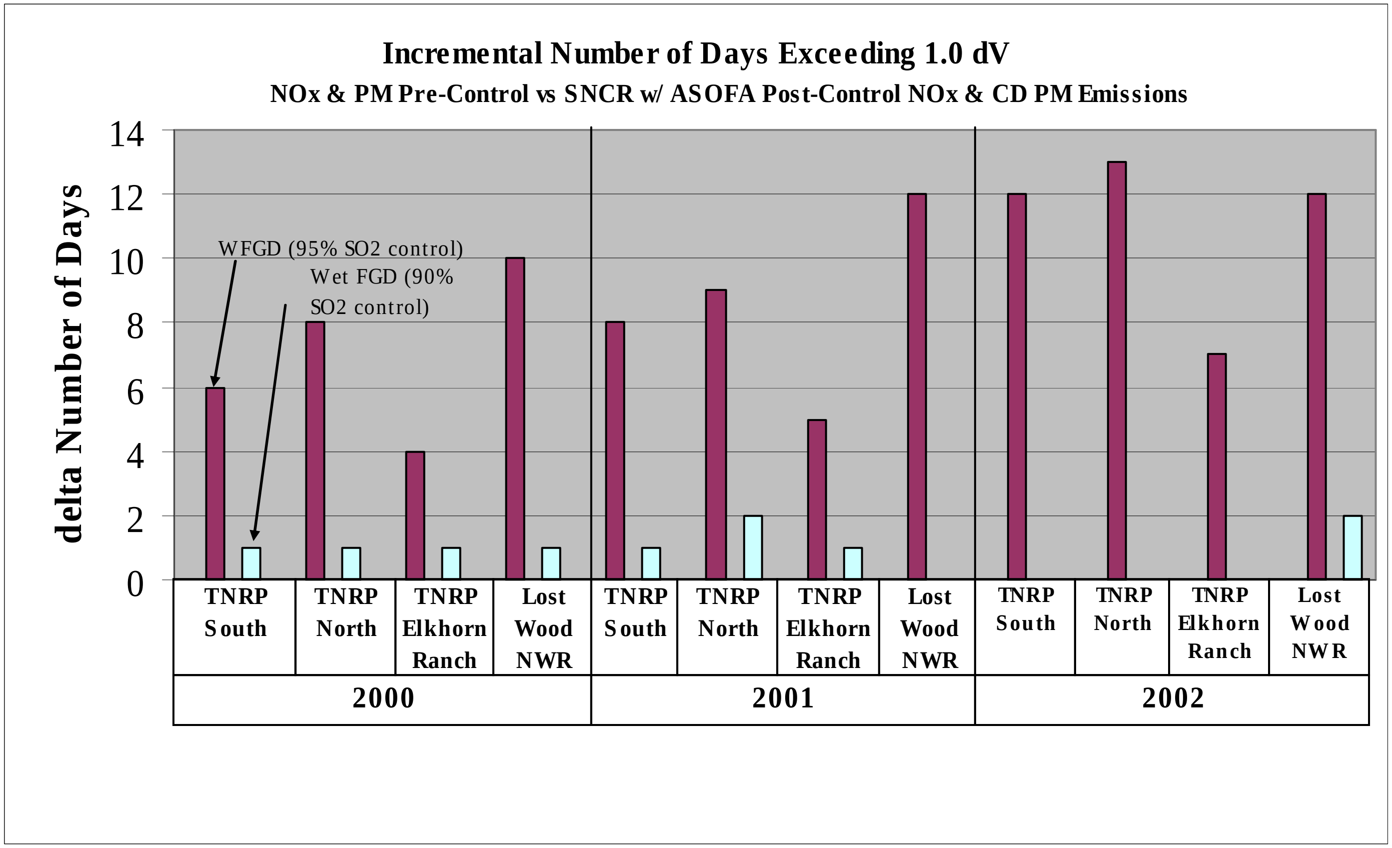


Figure 2.2-6 – Incremental Visibility Impairment Reductions – Maximum Consecutive Days Exceeding 0.5 dV
SNCR w/ ASOFA BART NO_X Control vs Protocol Pre-Control NO_X Emissions
with Various Post-Control SO_2 and PM Emissions
MRYS Unit 2

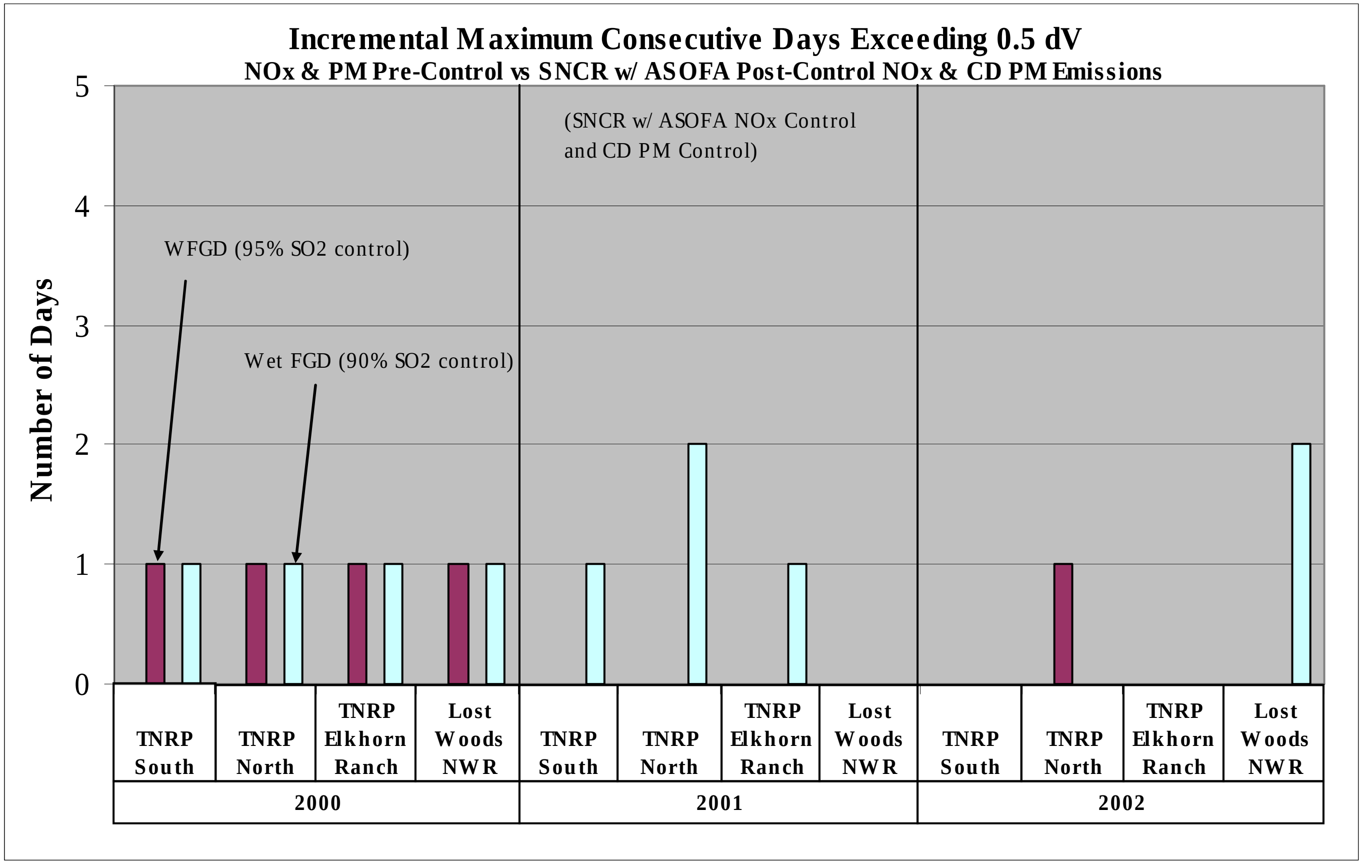


Figure 2.2-7 – Reduction in Days of Visibility Impairment > 0.5 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 2

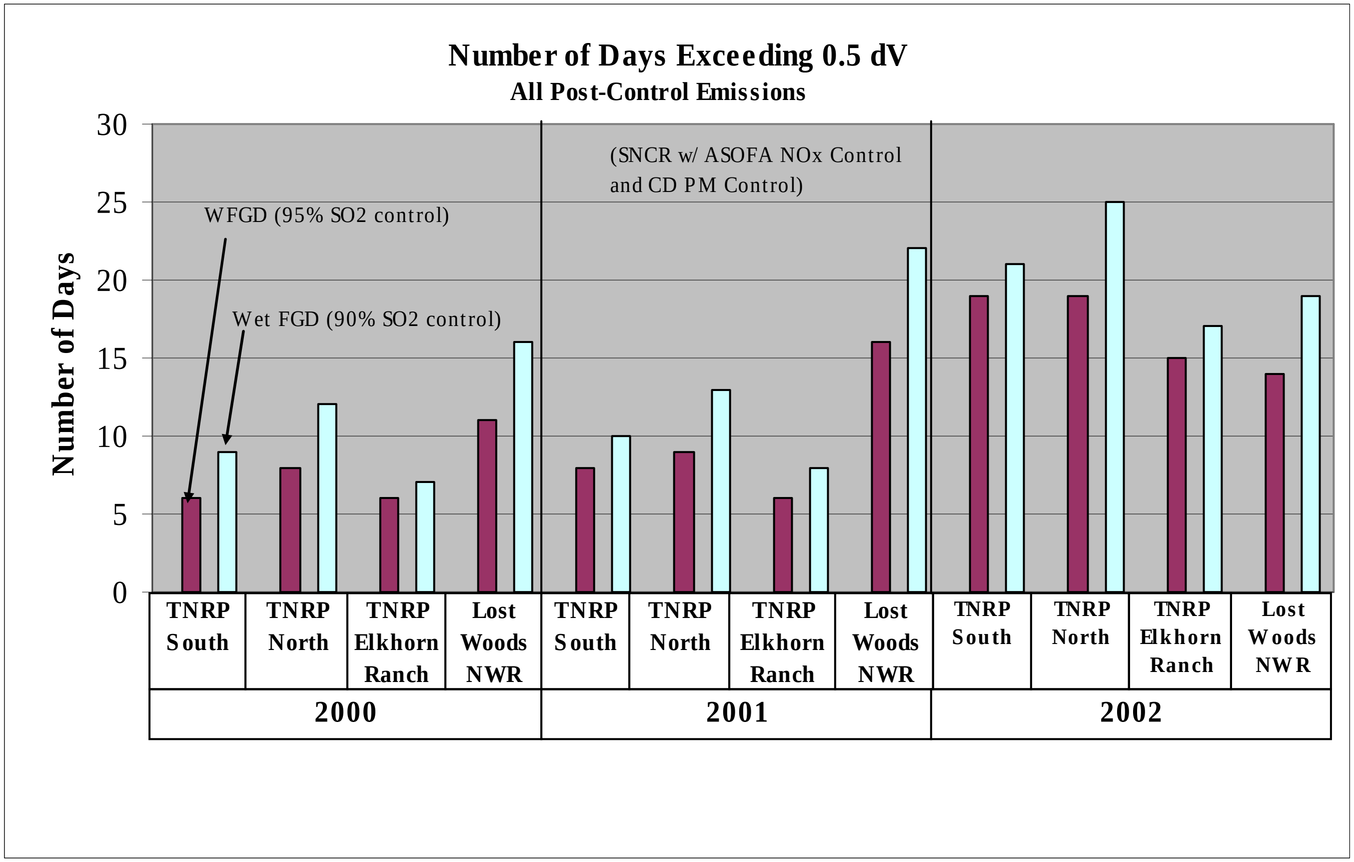


Figure 2.2-8 – Reduction in Days of Visibility Impairment > 1.0 dV SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls MRYS Unit 2

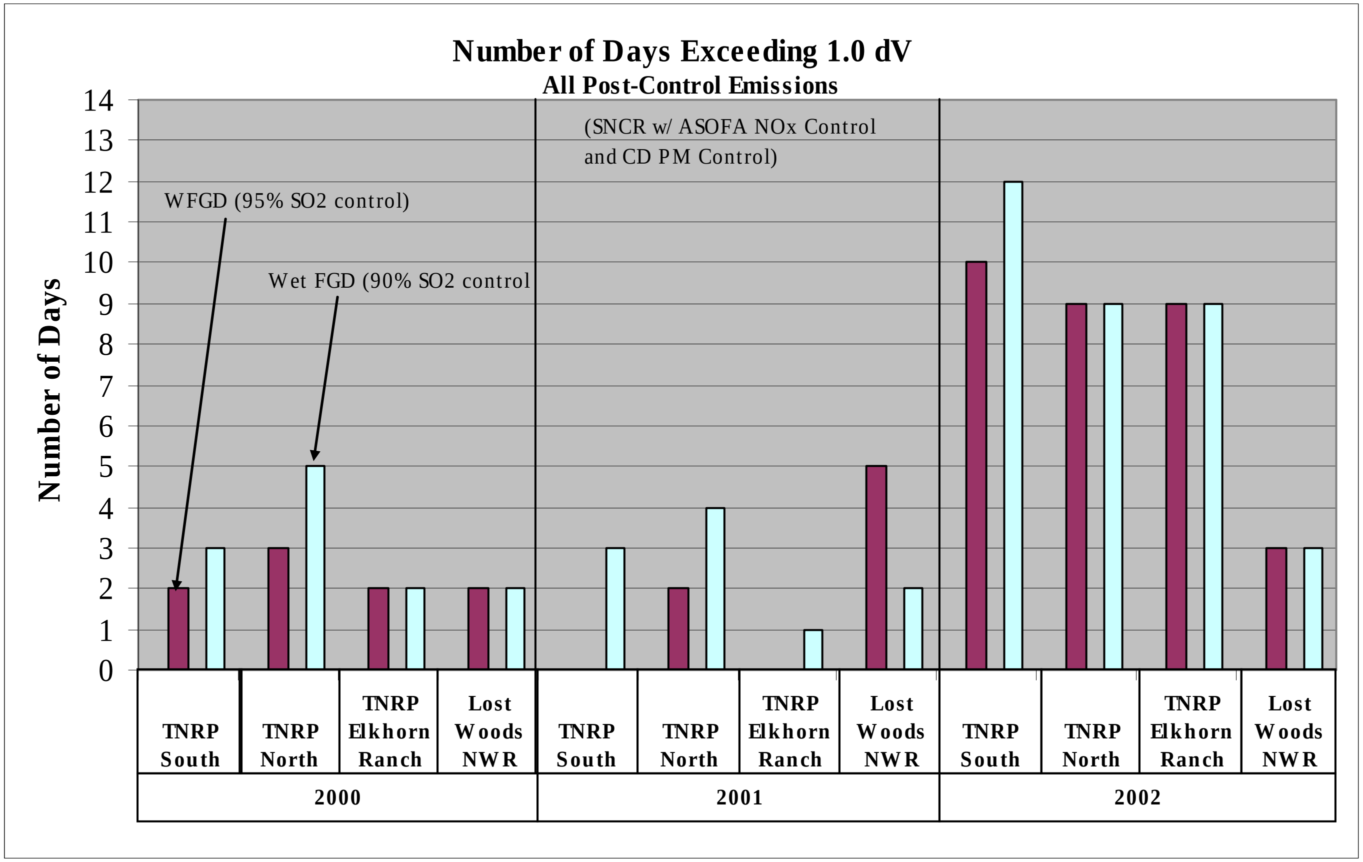
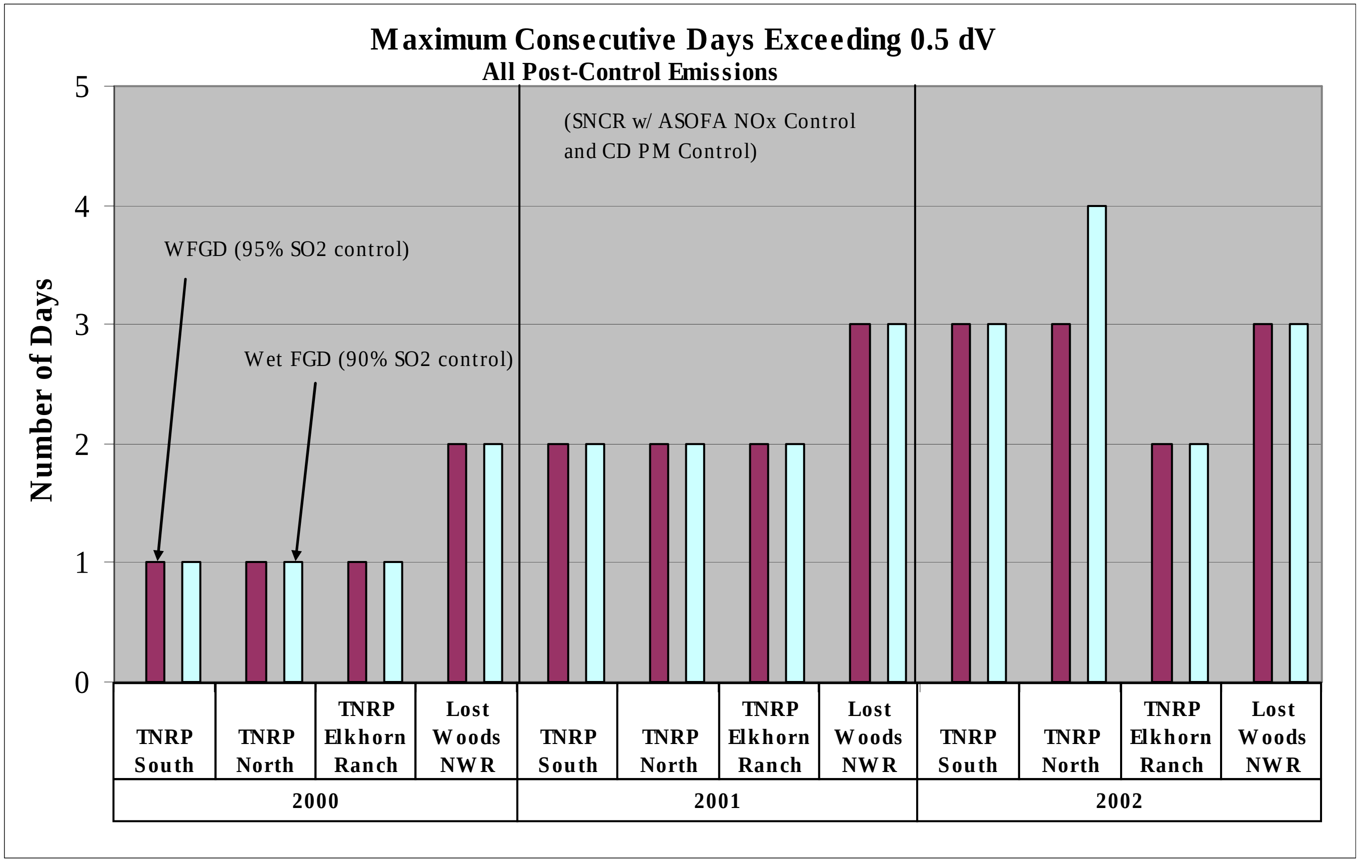


Figure 2.2-9 – Visibility Impairment Improvements – Reductions in Maximum Consecutive Days Exceeding 0.5 dV
SNCR w/ ASOFA BART NO_X Control with SO_2 and PM Controls
MRYS Unit 2



3.0 SO_2 BART EVALUATION

The BART determination process has five predefined steps as described in Section 1. In this section, steps 1 through 5 of the BART determination for Milton R. Young Station (MRYS) are described for SO_2 and a presentation is made of the results. Potentially applicable SO_2 control technologies are first identified. A brief description of the processes and their capabilities are then reviewed for availability and feasibility. A detailed technical description of each control technology is provided in Appendix B. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal SO_2 control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. In the final step of the analysis, feasible and available technologies are assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the impact analyses are tabulated and potential BART control options are listed.

3.1 IDENTIFICATION OF RETROFIT SO_2 CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit SO_2 control technologies. In order to identify the applicable SO_2 control technologies, several reference works were consulted, including “Controlling SO_2 Emissions: A Review of Technologies (EPA-600/R-00-093, October 2000) and the RACT/BACT/LAER Clearinghouse (RLBC). From these and other literature sources, a preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. However, as discussed in the introduction, Minnkota has entered into a Consent Decree (CD) that requires MRYS to install or modify SO_2 control technologies on both units to achieve emission rates that do not exceed specified levels. The Consent Decree defines the minimum levels of SO_2 control removal efficiencies applicable for technology installation options on MRYS Unit 1 and requires that the existing wet FGD process be upgraded to maintain a 30-day rolling average SO_2 removal efficiency of ninety percent (90%) for Unit 2. Thus, the control technologies included in the BART analysis either meet the minimum level of control specified by the CD or have more stringent removal efficiency. Table 3.1-1 contains the results of this effort.

TABLE 3.1-1 – SO_2 Control Technologies Identified for BART Analysis

Control Technology	Approximate Control Efficiency
Wet Flue Gas Desulfurization (FGD)	95%
Dry Flue Gas Desulfurization (FGD)	90%
Powerspan ECO™	98%

3.2 TECHNICAL DESCRIPTION AND FEASIBLITY ANALYSIS

The second step in the BART analysis procedure is a technical feasibility analysis of the options identified in Step 1. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology. A control technology is considered available, “if it has reached the stage of licensing and commercial availability.” (70 FR 39165) On the contrary, a control technology is not considered available, “if it is in the pilot scale testing stages of development.” (70 FR 39165) When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” (70 FR 39165) The technical and feasibility analysis is presented below for each identified option.

3.2.1 WET FLUE GAS DESULFURIZATION

Wet FGD technology utilizing lime or limestone as the reagent is commonly applied to coal-fired boilers. Wet FGD utilizes am absorber, such as an open spray tower or a spray tower with a perforated plate contactor, to expose flue gas to the neutralizing slurry. Absorbed SO_2 is converted to calcium sulfite and then may be oxidized to calcium sulfate dihydrate (gypsum) which is filtered from the scrubber solution and either disposed of in a permitted disposal facility, or possibly sold for either wallboard or cement production. Lime is utilized as the reagent in the wet FGD technology analysis, because the plant currently uses lime in the Unit 2 FGD process, has existing lime reagent preparation equipment, and because limestone availability is limited in North Dakota. Note that although existing reagent preparation equipment is available, a new system is required to supply sufficient volume for controlling both EGUs.

Historically, wet FGD systems have operated with SO_2 control efficiency anywhere from 70% to 95%. Several new coal-fired power plant projects such as Thoroughbred, Trimble County and Mustang have been proposed with SO_2 control efficiency of 98 percent. However, the “EPA has concluded that 98 percent control is possible with certain control and boiler configurations under ideal conditions. The amended standard for SO_2 is based on a 30-day average that includes the variability that occurs from non-ideal operating conditions”. This comes from the NSPS “Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units; Final Rule” recently promulgated by EPA as final rule amendments to 40 CFR part 60, subparts Da, Db, and Dc emission standards effective February 27, 2006[10]. Achieving ideal operating conditions such that an average 98% level of SO_2 emissions control could be sustained for every 30-day rolling period has not been demonstrated by the new power projects mentioned. For the purposes of this analysis, wet FGD performance was evaluated at 95% SO_2 control as representative of presumptive BART requirements. Further technical characteristics associated with wet FGD are described in Appendix B.

Based on the ability of a wet FGD system to achieve 95 percent SO_2 removal efficiencies and commercial availability and applicability, wet FGD systems were found to be an acceptable BART alternative for MRYS Unit 1’s SO_2 emission control.

This report evaluates the wet FGD process currently operating on Unit 2 as a possible BART alternative. The existing wet FGD system currently treats approximately 78 percent of the flue gas with the remaining flue gas by-passed for stack gas reheat and achieves approximately 75 percent SO_2 removal. However, the Consent Decree requires that the existing wet FGD process be upgraded to maintain a 30-day rolling average SO_2 removal efficiency of ninety percent (90%) for Unit 2. Thus, the wet FGD process is evaluated at 90% SO_2 removal efficiency. Because some wet FGD systems are capable of achieving 95% control, modifications required to increase the removal efficiency of the existing wet FGD process to 95% is also evaluated as BART for Unit 2. Note that although 95% removal efficiency is evaluated as part of this analysis, a detailed engineering analysis is required to determine if the existing wet FGD process can be modified to achieve 95% control and is not included in the scope of this report.

3.2.2 DRY FLUE GAS DESULFURIZATION

As an alternative to wet FGD technology, the control of SO_2 emissions can be accomplished using dry FGD technology. The most common dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection. There are several variations of the dry process in use today. This section addresses the spray dryer FGD process. Two other variations, the Flash Dryer

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[10] Federal Register /Vol. 71, No. 38, page 9870.

Absorber (FDA) and Circulating Dry Scrubber (CDS) are similar in nature. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. Technical characteristics associated with the SDA, FDA and CDS are described in Appendix B.

No variation of dry FGD systems has clearly demonstrated the ability to achieve SO_2 removal levels similar to wet FGD systems in the U.S. Two units were recently permitted with SO_2 emission rates representing removal efficiencies of 94.5% and 95%. However, Burns & McDonnell recently completed a study of the emission reduction performance of existing, electric utility, dry FGD systems.[11] Information utilized for the evaluation was derived from EIA coal quality data and EPA SO_2 stack emissions and heat input data. The evaluation determined that the highest SO_2 removal efficiency maintained on a continuous basis was just above 90%. No dry FGD unit was able to maintain an average efficiency of 95% for continuous 30-day rolling periods. For the purpose of this BART determination, dry FGD is considered a viable alternative for Unit 1, but the upper bound on SO_2 removal efficiency was set at 90% based on a review of the historic performance of this technology.

3.2.3 POWERSPAN ELECTRO-CATALYTIC OXIDATION TECHNOLOGY

The Powerspan Electro-Catalytic Oxidation (ECO™) system is a multipollutant control technology designed to control emissions of NO_X, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO™ process has two main process vessels; a barrier discharge reactor and a multi-level wet scrubber. Additional technical characteristics associated with the ECO™ process are described in Appendix B.

Powerspan claims a routine SO_2 removal efficiency of 98% with inlet concentrations up to approximately 2,000 ppm and testing at a pilot plant has demonstrated performance, reliability and economics. However, no full size commercial scale ECO™ systems have been installed or are operating at the time of this report. The ECO system was determined not to be a feasible BART alternative because it is not commercially available.

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[11] SO_2 Removal Efficiency Achieved in Practice by U.S. Electric Utility Semi-Dry FGD Systems"; Electric Utility Environmental Conference (EUEC); Weilert, C. and Randall, D.; Tucson, AZ; January 2006.

3.2.4 RESULTS OF FEASIBILITY ANALYSIS

The evaluations of the identified BART alternatives following the feasibility analysis are summarized in Table 3.2-1.

TABLE 3.2-1 – MRYS BART SO_2 Control Feasibility Analysis Results

Control Technology	In full-scale service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable To Milton R. Young Station
Wet FGD	Yes	Yes	Yes	Yes
Dry FGD	Yes	Yes	Yes	Yes
Powerspan ECO™	No	No	No	Yes

3.3 EVALUATE TECHNICALLY FEASIBILE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the BART analysis, the SO_2 control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining BART alternatives following the feasibility analysis are summarized in Table 3.3-1. The alternatives are ranked in descending order according to their effectiveness in SO_2 control.

TABLE 3.3-1 – Feasible SO_2 Control Technologies Identified for BART Analysis

Control Technology	Unit 1	Unit 2
Wet FGD	95% Control	90% and 95% Control
Dry FGD	90% Control	NA*

*Dry FGD is not evaluated for Unit 2 because the existing wet FGD can be used to achieve equivalent removal efficiency while using existing equipment.

3.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS – UNIT 1

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for MRYS. In addition, as described in Section 1.4, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

3.4.1 COST ESTIMATES

Cost estimates for the wet and dry SO_2 control technologies were completed utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the U.S. Environmental Protection Agency and engineering estimates based upon Burns & McDonnell's in-house experience. The CUECost model is a spreadsheet-based computer model that was specifically developed to estimate the cost of air pollution control technologies for utility power plants within +/- 30 percent accuracy. The EPA released the version of the model used for this study in February 2000. The model is available for download from the U.S. EPA website at www.epa.gov/ttn/catc/products. Operating information utilized as input into the model for the purpose of cost estimating is presented in Appendix C. Economic information utilized as input into the model is given in Table 1.2-1.

3.4.1.1 WET FGD CAPITAL COST ESTIMATE

The capital cost estimate for the wet FGD system includes the SO_2 control system, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. The wet FGD system cost estimated by CUECost is broken down into the major subsystems of reagent preparation, SO_2 absorption tower, dewatering systems, flue gas handling systems (new ID fans and ductwork) and support systems. BOP costs are described below in more detail.

The addition of a wet FGD absorber to Unit 1 will require a wet stack to exhaust the flue gas. The existing Unit 1 stack is in poor physical condition and is not sufficient for wet stack operations. Although not designed for wet stack operations, it would however be possible to reuse the existing Unit 2 stack to exhaust the flue gas from Unit 1. To make the Unit 2 stack suitable for wet stack operation, the existing liner would either have to be demolished and replaced with an alloy-clad liner or it would have to be lined from the stack breeching upwards with a corrosion resistant material such as alloy wallpaper or Penngard block or similar coating. A stack drain system would be required to collect and remove moisture dropout from the flue gas. BOP costs include modifications to the existing Unit 2 stack for wet stack operation, long lengths of ductwork to the Unit 2 stack inlet, and electrical subcontract. The results of the capital cost estimate are given in Table 3.4-1.

Table 3.4-1 – Capital Cost Estimate for MRYS Unit 1 Wet Lime FGD System

DIRECT COSTS	**Estimated Cost ($2,006)**	**General Facilities Markup (10%)**	**Total Direct Cost**
Wet Lime FGD System			
Reagent Prep System	$15,748,000	$1,575,000	$17,323,000
SO_2 Absorption System	$25,640,000	$2,564,000	$28,204,000
Flue Gas Handling System	$10,185,000	$1,019,000	$11,204,000
Byproduct Handling System	$504,000	$50,000	$554,000
Support Equipment	$2,538,000	$254,000	$2,792,000
		Wet Lime Total Direct Cost =	**$60,077,000**
BOP Costs			
Electrical Subcontract	$8,055,000	NA	$8,055,000
Stack Modifications	$9,783,000	NA	$9,783,000
Additional Ductwork	$1,364,000	NA	$1,364,000
		BOP Total Direct Cost =	**$19,202,000**
		Total Direct Cost =	**$79,278,000**
INDIRECT COSTS			
		Contingency (20% of DC)	$15,856,000
		A/E Engineering and Construction Management (10% of DC)	$7,928,000
		Prime Contractor's Fee (3% of DC)	$2,378,000
		Allowance For Funds During Construction (AFDC 3.8%)	$3,013,000
		Indirect Cost Subtotal	$29,174,000
		Total Plant Investment (TPI)	**$108,452,000**
		Pre-Production Costs	$3,108,000
		Inventory	$215,000
		Total Capital Requirement	**$111,776,000**

The CUECost estimating model includes a cost estimate for a wet stack, but this estimate was deleted from the model results and a revised estimate by Burns & McDonnell was included in the BOP costs for modifications to the existing Unit 2 stack. The estimate includes the demolition of the existing stack liner and installation of a new C-276 clad liner and provisions for stack icing mitigation.

The total estimated capital cost estimate for a complete, stand-alone wet FGD system utilizing lime reagent is $111,776,000, or $430/kW.

3.4.1.2 DRY FGD CAPITAL COST ESTIMATE

Estimated direct costs for the dry FGD system include the SDA, fabric filter, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a lime SDA/FF system supplier. The SDA/FF system costs estimated by CUECost are broken down into the major subsystems of reagent preparation, spray dryer absorber, waste handling systems, flue gas handling systems (new ID fans and ductwork) and support systems. A fabric filter is included in the estimate for the capture of entrained absorption products. BOP costs are described below in more detail.

As previously discussed, the existing Unit 1 stack is in poor physical condition and is to short for reuse. It would be possible to reuse the existing Unit 2 stack to exhaust the flue gas from Unit 1. Other than modifying the ductwork, significant modifications would not be required to make the Unit 2 stack suitable for operation with a dry FGD flue gas. BOP costs include long lengths of ductwork to the Unit 2 stack inlet and electrical subcontract. The results of the capital cost estimate are given in Table 3.4-2.

TABLE 3.4-2 – Capital Cost Estimate for MRYS Unit 1 Dry FGD/FF System

DIRECT COSTS	Estimated Cost ($2,006)	General Facilities Markup (10%)	Total Direct Cost
SDA System			
Reagent Prep System	$9,347,000	$935,000	$10,282,000
SO_2 Absorption System	$9,883,000	$988,000	$10,871,000
Flue Gas Handling System	$8,120,000	$812,000	$8,932,000
Byproduct Handling System	$1,902,000	$190,000	$2,092,000
Support Equipment	$3,078,000	$308,000	$3,386,000
		Dry FGD Total Direct Cost =	**$35,563,000**
Fabric Filter			
Fabric Filter Housing	$7,996,000	$800,000	$8,796,000
Bags	$1,268,000	$127,000	$1,395,000
Ash Handling System	$2,460,000	$246,000	$2,706,000
Instruments & Controls	$254,000	$25,000	$279,000
Freight	$636,000	$64,000	$700,000
Installation	$9,131,000	$913,000	$10,044,000
		Fabric Filter Total Direct Cost =	**$23,920,000**
BOP Costs			
Electrical Subcontract	$8,055,000	NA	$8,055,000
Additional Ductwork	$2,007,000	NA	$2,007,000
		BOP Total Direct Cost =	**$10,063,000**
		Total Direct Cost =	**$69,545,000**
INDIRECT COSTS			
		Contingency (20% of DC)	$13,909,000
		A/E Engineering and Construction Management (10% of DC)	$6,955,000
		Prime Contractor's Fee (3% of DC)	$2,086,000
		Allowance For Funds During Construction (AFDC 3.8%)	$2,643,000
		Indirect Cost Subtotal	$25,593,000
		Total Plant Investment (TPI)	**$95,138,000**
		Pre-Production Costs	$3,016,000
		Inventory	$258,000
		Total Capital Requirement	**$98,412,000**

A new stack was not included in the capital cost estimate. It was assumed for the purpose of the estimate that the existing Unit 2 stack would be reused.

The total estimated capital cost estimate for a complete, stand-alone lime SDA FGD system with a fabric filter, utilizing lime as a reagent is $98,412,000, or $383/kW.

3.4.1.3 WET FGD O&M COST ESTIMATE

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The operating labor cost was developed as part of the CUECost model and is based on unit size and an operating labor rate of $40 per hour. However, because BOP estimates were modified, administrative and support labor and maintenance where calculated as described below. Table 3.4-3 summarizes the O&M cost estimates for the wet FGD system.

The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. The maintenance material and labor cost was estimated as approximately 3% of the wet FGD system direct capital cost in Table 3.4-1. Administrative and support labor cost was estimated as 12% of the maintenance material and labor cost plus 30% of the operating labor costs. Previous studies and guidelines for FGD O&M costs by EPRI and others are in line with these percentages.

TABLE 3.4-3 – O&M Cost Estimate for MRYS Unit 1 Wet Lime FGD System

Fixed Costs	
Operating Labor	$1,490,000
Admin and Support labor	$741,000
Maintenance Material and Labor	$2,449,000
Total Fixed O&M Costs =	$4,680,000
Variable Costs	
Lime Reagent	$3,620,000
Byproduct Disposal	$555,000
Water	$88,000
Auxiliary Power	$1,339,000
Total Variable O&M Costs =	$5,602,000
Total Annual O&M Costs	**$10,282,000**
Net Annual O&M Cost ($/MWh)	**$5.40**

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on consumption rates modeled by the CUECost model and the unit cost information provided in Table 1.2-1 Economic Design Criteria. A cost of $6 per ton for pumping the FGD waste slurry to the disposal pond was included for waste disposal.

3.4.1.4 DRY FGD O&M COST ESTIMATE

The O&M cost estimate for the SDA/FF alternative was estimated using CUECost. Lime usage was set at 1.3 lbmol of lime (CaO) per lbmol of SO_2 removed. A ratio of 7.5 lb of recycled solids per pound of lime added and 30% solids slurry were set as design conditions. A total of 13” w.g. pressure drop across the combined SDA/FF system was also specified. The Fabric Filter was sized for a gas-to-cloth ratio of 3.5 $ACFM/Ft^2$. A three year bag life was assumed. The purposes of this study, it was assumed that the ESP would be completely de-energized and result in a cost savings as shown. The results of the SDA/FF O&M cost estimate are summarized in Table 3.4-4.

TABLE 3.4-4 – O&M Cost Estimate for MRYS Unit 1 SDA/FF System

Fixed Costs	
Operating Labor	$1,199,000
Admin and Support Labor	$467,000
Maintenance Material and Labor	$3,233,000
Total Fixed O&M Costs =	**$4,899,000**
Variable Costs	
Lime Reagent	$4,806,000
Byproduct Disposal	$1,213,000
Water	$88,000
ESP Power Savings	($125,000)
Auxiliary Power	$1,208,000
Total Variable O&M Costs =	**$7,190,000**
Total Annual O&M Costs	**$12,089,000**
Net Annual O&M Cost ($/MWh)	**$6.32**

3.4.1.5 LEVELIZED TOTAL ANNUAL COST

In order to effectively compare the cost of installing, operating and maintaining each of the SO_2 control systems, capital and O&M costs can be evaluated on a levelized basis.

A Net Present Value (NPV) was calculated for the each alternative utilizing the estimated costs in Tables 3.4-1 through 3.4-4 and the economic conditions given in Table 1.2-1. The NPV calculation was based on a two year construction period, followed by a 20 year service life ending December 31, 2031. Estimated capital costs were split evenly over a two year construction period for all alternatives.

A system startup date of December 31, 2011 was used based upon the requirements of the Consent Decree. O&M costs were included through the end of the calendar year 2031. No salvage value was assumed at the end of the service life for any of the alternatives. The NPV for all SO_2 control technology alternatives are presented in Table 3.4-5.

The Levelized Total Annual Cost (LTAC) for all alternatives was calculated based on the same economic conditions and a 20 year project life and are presented below in Table 3.4-6 along with the emissions reduction, resultant emissions rate and the Unit Control Cost. The Unit Control Cost is the LTAC divided by the annual tons of SO_2 emissions that would be controlled by implementation of the respective alternative.

Table 3.4-5 – NPV of SO_2 Control Alternatives for MRYS Unit 1

SO_2 Control Alternative	Control Efficiency	Net Present Value (NPV) ($2006)
Wet FGD	95%	**$222,742,000**
Dry FGD	90%	**$232,880,000**

Service Life:	Through 2031
Interest:	6%
Construction Period:	2 years
Startup Date:	Dec. 31, 2011
Inflation Rate:	3% For Construction and 2.5% for O&M

Table 3.4-6 – Levelized Total Annual Cost of SO_2 Control Alternatives for MRYS Unit 1

SO_2 Control Alternative	Control Efficiency[4]	Annual Emission Reduction (tpy)	Installed Capital Cost ($2006)[1]	Annual O&M Cost ($2006)	Levelized Total Annual Cost ($2006)[2]	Actual Unit Control Cost ($/ton)[3]
Wet FGD	95%	20,460	$111,776,000	$10,282,000	**$22,584,000**	$1,104
SDA/FF	90%	19,383	$98,412,000	$12,089,000	**$23,676,000**	$1,221

1. All Costs in 2006 dollars.
2. For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.24873.
3. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.
4. SO_2 removal is across the FGD system.

The annual tons of SO_2 reduction in this BART analysis are calculated as the difference between the pre-controlled emissions from the historic highest 24-month rolling average pre-control baseline (firing lignite fuel at the historic 24-month average heat input with the historic 24-month average sulfur and heat contents and the historic 24-month average unit operating time) and the controlled emissions assumed to be at the same input conditions and unit operating time.

The Levelized Total Annual Cost and Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. As can be seen from a review of Tables 3.4-5 and 3.4-6, the wet lime FGD alternative is the highest capital cost alternative but the lowest levelized total annual cost and net present value. Because the accuracy of the estimate (± 30%) is greater than the variance of the estimated LTACs (± 4%) and the Unit Control Costs (± 10%) for all post combustion control alternatives, none of the alternatives were excluded from further analysis on a cost basis.

The next step in the cost effectiveness analysis for the BART alternatives is to review the incremental cost effectiveness between the remaining alternatives. Table 3.4-7 contains a repetition of the cost and control information from Table 3.4-6 and the incremental cost effectiveness for each control alternative.

TABLE 3.4-7 – Incremental Cost Effectiveness of Unit 1 SO_2 BART Control Alternatives

BART Alternative	Levelized Total Annual Cost(1)	Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Wet FGD	$22,584,000	20,460	-$1,014
Dry FGD	$23,676,000	19,383	NA

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1. 24873.

In the BART Determination guidelines, EPA does not provide definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. The incremental cost effectiveness for wet FGD versus dry FGD in Table 3.4-7 is within the range of reasonable costs used in other regulatory analyses and thus does not indicate that wet FGD is prohibitively expensive relative to the dry FGD alternative.

The cost analysis portion of the BART determination for MRYS Unit 1 has shown that none of the Unit Control Costs for the remaining alternatives are exceedingly expensive on a Unit Control Cost basis. From an economic analysis viewpoint, wet FGD appears to be the most cost effective evaluated SO_2 control alternative for MRYS Unit 1. However, because the capital costs of all of these technologies are subject to market conditions at the time of purchase, such as; alloy pricing, major equipment lead times (i.e., slurry pumps, ID fans, etc.) the relative closeness of the estimated capital costs is a good indicator that the cost ranking of these alternatives might even be reversed at the time of actual purchase.

3.4.2 ENERGY IMPACTS

The energy impacts of each alternative, in terms of both estimated kW of energy usage and the percent of total generation, are given in Table 3.4-8. The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps, blowers, booster fans, reagent preparation and vacuum pumps for byproduct slurry dewatering. The largest energy users for the dry FGD are pumps, blowers, atomizers, reagent preparation, additional fabric filter and ID fans. Building HVAC and interior and exterior lighting loads are also included, but the major energy consumption is due to the primary systems described above.

TABLE 3.4-8 – Energy Requirements of MRYS Unit 1 BART SO_2 Control Alternatives

BART Alternative	Energy Demand (kW)	Percent of Nominal Generation
Wet FGD	5,140	2.2%
Dry FGD	4,113	1.8%

3.4.3 NON-AIR QUALITY ENVIRONMENTAL IMPACTS

Non-air quality environmental impacts of the installation and operation of the various BART alternatives include hazardous waste generation, solid and aqueous waste streams, and salable products that could result from the implementation of various BART alternatives.

Captured mercury in the solid waste stream from any post combustion alternative would be present as a trace contaminant in the solid waste, not affecting disposal options as long as the waste passes the Toxic Characteristic Leaching Procedure (TCLP), which FGD system wastes have historically.

A wet FGD system for MRYS Unit 1 is estimated to produce approximately 12 tons per hour of solid waste. The waste stream would consist of solids and inerts in a slurry at approximately 10-15% solids. Over the course of a year, the total solid waste quantity from the wet FGD is estimated to be approximately 105,000 tons of solids which would be landfilled in the current permitted solid waste disposal facility near the plant. A dry FGD system for MRYS Unit 1 is estimated to produce approximately 28 tons per hour of solid waste or approximately 245,000 tons per year. The dry FGD waste stream contains approximately 95% solids and the majority is carried through to downstream particulate control. The increase in solids is mainly attributed to mixing with the fly ash which most likely has insufficient quality for sale. Thus, the dry FGD solids would be landfilled in the current permitted disposal facility.

3.4.4 SO_2 VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the BART SO_2 analysis was to conduct a visibility improvement determination for Unit 1. The NDDH Modeling Protocol[12] SO_2 emission rate of 7,231.2 lb/hr was modeled to determine a pre-control baseline visibility impact for MRYS Unit 1. This protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The baseline visibility impact was then compared with the results predicted from a modeled post-control SO_2 emission rate based upon a 90% control dry scrubbing technology alternative SO_2 emission rate and a 95% control wet scrubbing technology alternative SO_2 emission rate relative to the protocol Unit 1 pre-control SO_2 emission rate.

According to the BART non-visibility impact analysis, wet flue gas desulfurization (FGD) was considered the most effective technology and therefore was evaluated as BART for Unit 1. The lowest post-control SO_2 emission rate of 361.6 lb/hr was based upon application of wet FGD control technology for a reduction of approximately 95 percent from the protocol mass emission rate. The next lowest post-control SO_2 emission rate of 723.1 lb/hr was based upon application of dry FGD control technology for a reduction of approximately 90 percent from the protocol mass emission rate.

The results of the visibility impairment modeling at the protocol baseline SO_2 emission rate for MRYS Unit 1 showed that three of the four Class 1 areas had a 90th percentile visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The 90th percentile visibility modeling results for the post-control 90% and 95% SO_2 reduction emission rates showed reductions in visibility impairment impact for all four Class 1 areas. In addition, the modeled 90th percentile visibility impairment impacts for all Class 1 areas at the post-control SO_2 emission rates were below the 0.50 dV threshold level. The predicted visibility impairments from the

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[12] Ibid NDDH Final BART Protocol; November 2005.

modeling are presented in Table 3.4-9. This value is the average visibility impairment impact reduction over the three modeled years (2000-2002) for each affected Class 1 area. The predictions of 24-hour 98th percentile deciView data are also provided in Appendix A.

Table 3.4-9 – SO_2 Visibility Impairment Impacts and Reductions, MRYS Unit 1

Federal Class 1 Area	**Visibility Impairment Impacts[1] (deciView)**			**Visibility Impairment Reduction (deciView)**	
	Protocol Emissions	**Post-Control Emissions[2]**		**Post-Control Emissions[2]**	
		90% Control	**95% Control**	**90% Control**	**95% Control**
TRNP-South Unit	0.549	0.250	0.173	0.299	0.375
TRNP-North Unit	0.628	0.269	0.165	0.359	0.463
TRNP-Elkhorn Ranch	0.374	0.160	0.111	0.214	0.263
Lostwood NWR	0.750	0.322	0.248	0.428	0.502

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

2 - SO_2 emissions reduction by 90% and 95% over protocol baseline case. This scenario assumes protocol emission rates for NO_X and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model. The results for the predicted protocol and post-control 90% and 95% SO_2 reduction emission rates from MRYS Unit 1 are summarized in Table 3.4-10 and Table 3.4-11, respectively. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control SO_2 emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

Table 3.4-10 – Visibility Impairment Improvements – MRYS Unit 1 Dry FGD SO_2 Control Impacts (Days)

Class 1 Area	**SO_2 Control Technique**	**Days[2] Exceeding 0.5 dV in 2000**	**Days[2] Exceeding 0.5 dV in 2001**	**Days[2] Exceeding 0.5 dV in 2002**	**Days[2] Exceeding 1.0 dV in 2000**	**Days[2] Exceeding 1.0 dV in 2001**	**Days[2] Exceeding 1.0 dV in 2002**	**Consecutive Days[2] Exceeding 0.5 dV 2000**	**Consecutive Days[2] Exceeding 0.5 dV 2001**	**Consecutive Days[2] Exceeding 0.5 dV 2002**
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	Dry FGD	10	20	24	4	11	12	1	3	3
	Reduction	*28*	*10*	*24*	*15*	*4*	*14*	*2*	*0*	*1*
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	Dry FGD	13	31	25	7	13	12	1	4	4
	Reduction	*21*	*13*	*21*	*7*	*8*	*17*	*1*	*0*	*0*
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	Dry FGD	9	20	18	4	8	9	2	3	2
	Reduction	*16*	*4*	*17*	*8*	*8*	*11*	*0*	*0*	*2*
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	Dry FGD	17	36	17	3	19	4	2	3	3
	Reduction	*34*	*22*	*25*	*23*	*11*	*20*	*1*	*2*	*2*

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels that are a reduction of 90%.
2 - Number of days for predicted visibility impairment impacts provided in Appendix A.

Table 3.4-11 – Visibility Impairment Improvements – MRYS Unit 1 Wet FGD SO_2 Control Impacts (Days)

Class 1 Area	**SO_2 Control Technique**	**Days[2] Exceeding 0.5 dV in 2000**	**Days[2] Exceeding 0.5 dV in 2001**	**Days[2] Exceeding 0.5 dV in 2002**	**Days[2] Exceeding 1.0 dV in 2000**	**Days[2] Exceeding 1.0 dV in 2001**	**Days[2] Exceeding 1.0 dV in 2002**	**Consecutive Days[2] Exceeding 0.5 dV 2000**	**Consecutive Days[2] Exceeding 0.5 dV 2001**	**Consecutive Days[2] Exceeding 0.5 dV 2002**
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	Wet FGD	11	11	23	4	3	14	1	2	3
	Reduction	*27*	*19*	*25*	*15*	*12*	*12*	*2*	*1*	*1*
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	Wet FGD	13	15	22	8	3	12	1	2	3
	Reduction	*21*	*29*	*24*	*6*	*18*	*17*	*1*	*2*	*0*
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	Wet FGD	7	8	17	4	1	9	1	2	2
	Reduction	*18*	*16*	*18*	*8*	*15*	*11*	*1*	*1*	*2*
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	Wet FGD	17	24	15	3	10	5	2	0	3
	Reduction	*34*	*34*	*27*	*23*	*20*	*19*	*1*	*5*	*2*

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels that are a reduction of 95%.

2 - Number of days for predicted visibility impairment impacts provided in Appendix A.

3.5 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS – UNIT 2

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for MRYS. In addition, as described in Section 1.4, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

As previously stated in Section 3.2.1, the Consent Decree requires MRYS to modify the existing wet FGD system on Unit 2 to achieve a removal efficiency of at least 90%. Modifications to the existing wet FGD were evaluated as the minimum level of control for BART. In addition, because some wet FGD systems are capable of achieving 95% removal efficiency, modifications required to achieve 95% control were also evaluated for the wet FGD process.

3.5.1 COST ESTIMATES

The two wet FGD scenarios at 90 and 95 percent control involve modifications to the existing FGD process. Because the two control scenarios involve modifications to existing technology, the CUECost was not used to estimate costs for the Unit 2 SO_2 control alternatives. Instead, costs for retrofitting and operating the two BART alternatives were estimated from various literature sources and Burns & McDonnell's in-house experience and resources. Information from such sources was adjusted for known local conditions. Modifications to the existing wet FGD system and support equipment were identified and costs were estimated for comparison of the two wet FGD alternatives.

A Net Present Value (NPV) and Levelized Total Annual Cost (LTAC) was calculated for the each alternative utilizing the costs presented in the following sections, the same methodology presented in Section 3.4.1.5 and the economic conditions given in Table 1.2-1.

3.5.1.1 WET FGD COST ESTIMATE FOR 90% REMOVAL

The Consent Decree requires MRYS to upgrade the existing Unit 2 FGD system to achieve and maintain 90% SO_2 removal on a 30-day rolling average including any flue gas routed though a bypass duct. This analysis assumes that to achieve 90% removal, the bypass will be eliminated and lime reagent usage will increase. If the flue gas bypass is eliminated, the flue gas exiting the wet FGD will be at a saturated condition. Because the existing stack is not designed for saturated conditions and modifications to the existing stack require an extended outage that is incompatible with MRYS operations, the recommended solution is to construct a new stack suitable for saturated flue gas. Due to the arrangement of existing equipment, the new stack would be located approximately 220 feet from the existing stack and new ductwork would be required. Scrubbing 100% of the flue gas will also increase the volume of flow through each absorber module, thus increasing the velocity inside the vessel. New high velocity mist eliminators should be installed to account for the higher velocity and prevent corrosion issues caused by mist carryover into the ductwork and stack. The cost estimate for a wet FGD system achieving 90% control is summarized in Table 3.5-1.

Table 3.5-1 – Cost Estimate for MRYS Unit 2 Wet FGD System at 90% Control

Retrofit Capital Costs	
New Stack	$ 16,850,000
New Ductwork	$ 1,565,000
New Mist Eliminators	$ 810,000
Total Capital Costs =	**$ 19,225,000**
Annual O&M Costs	
Lime Reagent	$ 2,816,000
Byproduct Disposal	$ 477,000
Water	$ 163,000
Auxiliary Power	$ 1,074,000
Total O&M Costs =	**$ 4,530,000**
Net Present Value (NPV)	**$ 71,752,000**
Levelized Total Annual Cost (LTAC)	**$ 7,333,000**

3.5.1.2 WET FGD COST ESTIMATE FOR 95% REMOVAL

To modify the existing wet FGD system to achieve and maintain 95% SO_2 removal on a 30-day rolling average will require the bypass to be eliminated and cause lime reagent usage to increase. The capital improvements and associated costs will include the same new stack, new ductwork and new mist eliminators that were required to achieve 90% control. To modify the existing process to achieve the additional 5% control requires a detailed engineering analysis and design review which is outside the scope of this evaluation. However, at a minimum, the absorber modules would require the addition of perforated trays to increase the removal efficiency. The addition of trays in the absorber will increase the pressure drop across the system and will require ID fan modifications. Thus, Table 3.5-2 includes additional capital costs associated with the addition of trays and modification to the existing ID fans.

Table 3.5-2 – Cost Estimate for MRYS Unit 2 Wet FGD System at 95% Control

Retrofit Capital Costs	
New Stack	$ 16,850,000
New Ductwork	$ 1,565,000
New Mist Eliminators	$ 810,000
Absorber Trays	$ 853,000
ID Fan Modifications	$ 4,911,000
Total Capital Costs =	**$ 24,989,000**
Annual O&M Costs	
Lime Reagent	$ 2,964,000
Byproduct Disposal	$ 502,000
Water	$ 172,000
Auxiliary Power	$ 1,355,000
Total O&M Costs =	**$ 4,993,000**
Net Present Value (NPV)	**$ 82,424,000**
Levelized Total Annual Cost (LTAC)	**$ 8,414,000**

The next step in the analysis for the BART alternatives is to review the unit control cost and incremental cost effectiveness of the remaining scenarios. Table 3.5-3 contains a repetition of the cost information from Tables 3.5-1 and 3.5-2.

Because Unit 2 has existing SO_2 control, the historic highest 24-month rolling average represents a controlled emission rate. Thus, the baseline annual tons of SO_2 for Unit 2 in this BART analysis are calculated as the pre-controlled emissions from firing lignite fuel containing 1% sulfur at a heat input of 5,158 mmBtu/hr with the unit operating at 85% capacity. The resulting uncontrolled emissions are 15,600 pounds per hour or 58,000 tons per year. The controlled emissions assumed application of the respective removal efficiency to the baseline emission rate with the same input conditions and unit operating time. The annual tons of SO_2 reduction for Unit 2 are calculated as the difference between the protocol emissions and the controlled emissions associated to the respective removal efficiency.

TABLE 3.5-3 – Incremental Cost Effectiveness of Unit 2 SO_2 BART Control Alternatives

BART Alternative	Levelized Total Annual Cost[1]	Annual Emission Reduction (tpy)	Actual Unit Control Cost ($/ton)[2]	Incremental Cost Effectiveness ($/ton)
95% Control Wet FGD	$8,414,000	22,700	$371	$373
90% Control Wet FGD	$7,333,000	19,800	$370	NA

1. For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1. 24873.
2. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.

The Levelized Total Annual Cost and Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. Because this is a comparison of the same technology at different removal efficiencies, one would expect the LTAC to be greater with the higher removal efficiency option.

In the BART Determination guidelines, EPA does not provide a definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. The incremental cost effectiveness for 95% control versus 90% control in Table 3.5-3 is within the range of reasonable costs used in other regulatory analyses and thus does not indicate that wet FGD at 95% control is prohibitively expensive relative to the 90% control alternative.

The cost analysis portion of the BART determination for MRYS Unit 2 has shown that none of the Unit Control Costs for the remaining alternatives are exceedingly expensive on a Unit Control Cost basis.

3.5.2 ENERGY AND NON-AIR QUALITY IMPACTS

The primary energy impacts of the wet FGD process consist of the additional electrical load resulting from pumps, blowers, booster fans, reagent preparation and vacuum pumps for byproduct slurry dewatering. Because the 90% control alternative evaluated for Unit 2 only includes modifications to existing equipment, the energy impacts are due to operational differences created by the modifications and are difficult to quantify. Thus, the energy impacts are estimated in terms of total system energy usage in kW and are included as part of the cost evaluation. An increase in energy usage for the 95% control alternative is a result of installing perforated trays and increasing the pressure drop of the absorber modules. The increase in pressure drop requires approximately 733 kW of additional ID fan power. A new category of non-air quality impact is not caused by the modifications to the existing system. The non-air quality impacts include increases to existing waste generation, are considered in the cost analysis portion of the analysis and no additional evaluation was performed.

3.5.3 SO_2 VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the BART SO_2 analysis was to conduct a visibility improvement determination for Unit 2. The NDDH BART protocol[13] SO_2 emission rate of 6,879.0 lb/hr was modeled to determine a pre-control baseline visibility impact for MRYS Unit 2. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The baseline visibility impact was then compared with the results predicted from a modeled post-control SO_2 emission rate based upon 90% and 95% control wet scrubbing technology alternatives that utilize the modified, existing wet FGD system.

According to the BART non-visibility impact analysis, modifications to the existing wet FGD achieving 95% removal efficiency was the most effective technology and therefore was evaluated as BART for Unit 1. The 95% removal efficiency equates to an emission rate of 773.7 lb/hr SO_2. The next lowest post-control SO_2 emission rate of 1,574.4 lb/hr was based upon an upgrade of the existing wet FGD process to achieve 90% SO_2 reduction. The post-control CALPUFF model scenario for MRYS Unit 2 was conducted with the protocol NO_X and PM emission rates and the post-control SO_2 emission rate as discussed in Section 1.5.5 and Table 1.5-1.

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[13] Ibid, NDDH Modeling Protocol.

The results of the visibility impairment modeling at the protocol baseline SO_2 emission rate for MRYS Unit 2 showed that three of the four Class 1 areas had a 90th percentile visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The 90th percentile visibility modeling results for the post-control 90% and 95% SO_2 reduction emission rates showed reductions in visibility impairment impact for all four Class 1 areas. In addition, the modeled 90th percentile visibility impairment impacts for all Class 1 areas at the post-control SO_2 emission rates were below the 0.50 dV threshold level. The predicted visibility impairments from the modeling are presented in Table 3.5-4. This value is the average visibility impairment impact reduction over the three modeled years (2000-2002) for each affected Class 1 area.

Table 3.5-4 – SO_2 Visibility Impairment Impacts and Reductions, MRYS Unit 2

Federal Class 1 Area	**Visibility Impairment Impacts[1] (deciView)**			**Visibility Impairment Reduction (deciView)**	
	Protocol Emissions	**Post-Control Emissions[2] 90% and 95% Control**		**Post-Control Emissions[2] 90% and 95% Control**	
TRNP-South Unit	0.580	0.390	0.304	0.190	0.276
TRNP-North Unit	0.619	0.370	0.271	0.249	0.348
TRNP-Elkhorn Ranch	0.360	0.225	0.171	0.135	0.189
Lostwood NWR	0.775	0.493	0.405	0.282	0.370

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

2 - SO_2 emissions reduction by 90% and 95% over protocol baseline case. This scenario assumes protocol emission rates for NO_X and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model. The results are summarized and presented in Table 3.5-5 and 3.5-6. The visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control 90% and 95% SO_2 reduction emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

Table 3.5-5 – Visibility Impairment Improvements – MRYS Unit 2 90% Wet FGD SO_2 Control Impacts (Days)

Class 1 Area	**SO_2 Control Technique**	**Days[2] Exceeding 0.5 dV in 2000**	**Days[2] Exceeding 0.5 dV in 2001**	**Days[2] Exceeding 0.5 dV in 2002**	**Days[2] Exceeding 1.0 dV in 2000**	**Days[2] Exceeding 1.0 dV in 2001**	**Days[2] Exceeding 1.0 dV in 2002**	**Consecutive Days[2] Exceeding 0.5 dV 2000**	**Consecutive Days[2] Exceeding 0.5 dV 2001**	**Consecutive Days[2] Exceeding 0.5 dV 2002**
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	Wet FGD Upgraded to 90% Control	24	20	36	8	11	23	2	3	3
	Reduction	*17*	*8*	*15*	*10*	*3*	*4*	*1*	*0*	*1*
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	Wet FGD Upgraded to 90% Control	22	32	35	11	13	25	2	4	4
	Reduction	*10*	*11*	*12*	*7*	*8*	*4*	*0*	*0*	*0*
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	Wet FGD Upgraded to 90% Control	12	21	24	8	10	16	2	3	2
	Reduction	*19*	*2*	*12*	*3*	*4*	*4*	*0*	*0*	*2*
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	Wet FGD Upgraded to 90% Control	36	39	30	14	22	16	3	3	5
	Reduction	*16*	*12*	*18*	*16*	*9*	*9*	*0*	*0*	*0*

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix A.

Table 3.5-6 – Visibility Impairment Improvements – MRYS Unit 2 95% Wet FGD SO_2 Control Impacts (Days)

Class 1 Area	**SO_2 Control Technique**	**Days[2] Exceeding 0.5 dV in 2000**	**Days[2] Exceeding 0.5 dV in 2001**	**Days[2] Exceeding 0.5 dV in 2002**	**Days[2] Exceeding 1.0 dV in 2000**	**Days[2] Exceeding 1.0 dV in 2001**	**Days[2] Exceeding 1.0 dV in 2002**	**Consecutive Days[2] Exceeding 0.5 dV 2000**	**Consecutive Days[2] Exceeding 0.5 dV 2001**	**Consecutive Days[2] Exceeding 0.5 dV 2002**
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	Wet FGD Upgraded to 95% Control	21	14	33	8	8	22	2	2	3
	Reduction	*20*	*14*	*18*	*10*	*6*	*5*	*1*	*1*	*1*
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	Wet FGD Upgraded to 95% Control	21	21	32	11	11	22	2	2	4
	Reduction	*11*	*22*	*15*	*7*	*10*	*7*	*0*	*2*	*0*
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	Wet FGD Upgraded to 95% Control	12	13	21	6	5	16	2	2	2
	Reduction	*19*	*10*	*15*	*5*	*9*	*4*	*0*	*1*	*2*
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	Wet FGD Upgraded to 95% Control	31	34	27	12	17	15	3	3	3
	Reduction	*21*	*17*	*21*	*18*	*14*	*10*	*0*	*0*	*2*

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels.

2 - Number of days for predicted visibility impairment impacts provided in Appendix A.

4.0 PARTICULATE MATTER BART EVALUATION

Steps 1 through 5 of the BART analyses for PM emissions from MRYS Unit 1 and Unit 2 are described in this section. Potentially applicable SO_2 control technologies are first identified. A brief description of potential control options and their capabilities, including MRYS Unit 1 and Unit 2 existing PM air pollution control equipment, is provided. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal PM control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative, including taking a look at Balance Of Plant (BOP) requirements. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. In the final step of the analysis, feasible and available technologies are assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the impact analyses are tabulated and potential BART control options are listed.

4.1 IDENTIFICATION OF RETROFIT PM CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit PM control technologies. In order to identify the applicable PM control technologies, several reference works were consulted, including the RACT/BACT/LAER Clearinghouse (RLBC). A preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. As discussed in the introduction, Minnkota has entered into a Consent Decree (CD). The CD requires MRYS to maintain or upgrade the existing PM controls on both units to achieve specified emission rates. Because the CD specified the PM emission rate, the control technologies included in the BART analysis either meet the minimum emission rate specified by the CD or have more stringent emission rate. Table 4.1-1 contains the results of this effort.

TABLE 4.1-1 – PM Control Technologies Identified for BART Analysis

Control Technology	Approximate Control Efficiency
Fabric Filter or Baghouse	99.7%
COHPAC Baghouse	99.7%
New Electrostatic Precipitator	99.7%
Existing Electrostatic Precipitator	99.0%

4.2 TECHNICAL DESCRIPTION AND FEASIBLITY ANALYSIS

The second step in the BART analysis procedure is a technical feasibility analysis of the options identified in Step 1. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology. A control technology is considered available, “if it has reached the stage of licensing and commercial availability.” (70 FR 39165) On the contrary, a control technology is not considered available, “if it is in the pilot scale testing stages of development.” (70 FR 39165) When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” (70 FR 39165) All PM control technologies identified for this analysis are proven technologies that are technically feasible for review as a potential BART alternative for either Unit 1 or 2. The identified BART alternatives following the feasibility analysis are summarized in Table 4.2-1.

TABLE 4.2-1 – MRYS BART PM Control Feasibility Analysis Results

Control Technology	In full-scale service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable To Milton R. Young Station
Fabric Filter or Baghouse	Yes	Yes	Yes	Yes
COHPAC Baghouse	Yes	Yes	Yes	Yes
New Electrostatic Precipitator	Yes	Yes	Yes	Yes
Existing Electrostatic Precipitator	Yes	Yes	Yes	Yes

4.3 EVALUATE TECHNICALLY FEASIBILE PM CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. The PM control efficiency was reviewed and presented as part of the technology identification in Step 1 of the analysis. The alternatives are summarized in Table 4.3-1 and are ranked in descending order according to their effectiveness in PM control.

TABLE 4.3-1 – Feasible PM Control Technologies Identified for BART Analysis

Control Technology	Unit 1	Unit 2
Fabric Filter or Baghouse	0.015	0.015
COHPAC Baghouse	0.015	0.015
New Electrostatic Precipitator	0.015	0.015
Existing Electrostatic Precipitator	0.030	0.030

4.4 EVALUATION OF IMPACTS FOR FEASIBLE PM CONTROLS – UNIT 1

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for MRYS. In addition, as described in Section 1.4, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

4.4.1 COST ESTIMATES

Cost estimates for the PM control technologies were completed utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the U.S. Environmental Protection Agency and engineering estimates based upon Burns & McDonnell's in-house experience. The CUECost model is a spreadsheet-based computer model that was specifically developed to estimate the cost of air pollution control technologies for utility power plants within +/- 30 percent accuracy. The EPA released the version of the model used for this study in February 2000. The model is available for download from the U.S. EPA website at www.epa.gov/ttn/catc/products. Operating information utilized as input into the model for the purpose of cost estimating is presented in Appendix C. Economic information utilized as input into the model is given in Table 1.2-1. The cost estimates for a PM control alternatives are summarized in Table 4.4-1. A Net Present Value (NPV) and Levelized Total Annual Cost (LTAC) were calculated for the each alternative utilizing the costs summarized in Table 4.4-1.

TABLE 4.4-1 – Cost Estimates for Unit 1 PM Control Alternatives

	FF	COHPAC[1]	NEW ESP	EXISTING ESP[2]
Capital Costs				
Direct Costs	$21,133,000	$13,684,000	$23,112,000	$0
Indirect Costs	$8,453,000	$5,474,000	$9,245,000	$0
Total Capital Costs	**$29,856,000**	**$19,158,000**	**$32,357,000**	**$0**
O&M Costs				
Includes Maintenance Costs, Power Costs, and Replacement Costs (if any)				
Total O&M Costs	**$2,166,000**	**$1,571,000**	**$1,459,000**	**$1,459,000**
Net Present Value (NPV)	**$52,232,000**	**$35,862,000**	**$46,106,000**	**$17,667,000**
Levelized Total Annual Cost (LTAC)	**$5,284,000**	**$3,632,000**	**$4,643,000**	**$1,822,000**

1. COHPAC costs are scaled down to represent a similar fabric filter with a flue gas to cloth ratio of 6 ACFM/ft^2.
2. Costs associated with the operation of the existing ESP are assumed equal to the operating costs for a new ESP.

The next step in the analysis for the BART alternatives is to review the unit control cost and incremental cost effectiveness of the remaining scenarios. Table 4.4-2 contains a repetition of the cost information from Table 4.4-1.

Because Unit 1 has existing PM control, the historic highest 24-month rolling average represents a controlled emission rate. Thus, the baseline annual tons of PM for Unit 1 in this BART analysis are calculated as the pre-controlled emissions from firing lignite fuel with an ash content of 9.6% at a heat input of 2,955 mmBtu/hr with the unit operating at 85% capacity. Using the conservative approach that 50% of the ash is emitted as fly ash and 50% of the ash becomes bottom ash; the resulting uncontrolled emissions are approximately 32,100 tons per year. The controlled emissions assumed application of the respective removal efficiency to the baseline emission rate with the same input conditions and unit operating time. The annual tons of PM reduction for Unit 1 are calculated as the difference between the protocol emissions and the controlled emissions associated to the respective removal efficiency.

TABLE 4.4-2 – Incremental Cost Effectiveness of Unit 1 PM BART Control Alternatives

BART Alternative	Levelized Total Annual Cost[1]	Annual Emission Reduction (tpy)	Actual Unit Control Cost ($/ton)[2]	Incremental Cost Effectiveness ($/ton)
Fabric Filter or Baghouse	$5,284,000	61	$86,600	$56,800
New Electrostatic Precipitator	$4,643,000	61	$76,100	$46,200
COHPAC Baghouse	$3,632,000	61	$59,500	$29,700
Existing Electrostatic Precipitator	$1,822,000	Baseline	Baseline	Baseline

1. For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1. 24873.
2. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.

The Levelized Total Annual Cost and Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. As can be seen from a review of Table 4.4-1 and 4.4-2, the fabric filter alternative is in the middle range for capital cost but has the highest levelized total annual cost and net present value.

In the BART Determination guidelines, EPA does not provide definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits between successively less effective alternatives. Because all the alternatives requiring new equipment for Unit 1 have the same removal rate, the incremental cost effectiveness is not effective for ranking the different technologies. However, the incremental cost is calculated for comparison between the existing ESP alternative and the other control options. The incremental cost effectiveness for each new control alternatives in Table 4.4-2 is above the range of reasonable costs used in other regulatory analyses and indicates that each new technology is prohibitively expensive. However, due to the lack of guidance on reasonable costs, the visibility analysis is conducted to determine if the additional controls are necessary to reduce visibility impacts.

4.4.2 PM VISIBLITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the Unit 1 BART PM analysis was to conduct a visibility improvement determination. The modeling for Unit 1 uses two PM emission rates that distinguish between coarse and fine particulate as a basis for the visibility impairment impacts. One baseline emission rate representing the NDDH Modeling Protocol values of 36.7 lb PM_{Coarse}/hr and 5.5 lb PM_{Fine}/hr was modeled. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. However, as discussed in Section 1.5.5, the protocol emission rates are based upon actual maximum historical 24-hour emissions that are not representative of future maximum 24-hour emissions. After obtaining approval from NDDH to use alternative emission rates based upon representative stack conditions, Minnkota based the post-control emission rates upon application of CD specified rates applied to a more representative maximum heat input of 2,955 mmBtu/hr.

The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 1 to achieve an emission rate of 0.015 lb PM/mmBtu if a dry FGD process is selected for SO_2 control or 0.030 lb PM/mmBtu if a wet FGD process is selected. A detailed engineering evaluation is required to determine if the existing ESP can achieve an emission rate of 0.015 lb PM/mmBtu for an extended period of time and that evaluation is outside the scope of this analysis. For the purposes of this report, it is assumed that the existing equipment will be able to meet the 0.030 lb PM/mmBtu emission rate specified by the CD. Post-control rates of 38.5 lb PM_{Coarse}/hr and 5.8 lb PM_{Fine}/hr were calculated and modeled based upon the CD emission rate of 0.015 lb PM/mmBtu and post-control rates of 77.1 lb PM_{Coarse}/hr and 11.6 lb PM_{Fine}/hr were calculated and modeled based upon the CD emission rate of 0.030 lb PM/mmBtu.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 1. The post-control CALPUFF model scenarios for MRYS Unit 1 were conducted with the protocol NO_X and SO_2 emission rates and the post-control PM emission rates as discussed previously in this section and in Table 1.5-1.

The results of the visibility impairment modeling at the protocol baseline PM emission rate for MRYS Unit 1 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for both post-control PM emission rates showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for two of the Class 1 areas at both post-control PM emission rates was below the 0.50 dV threshold level. The TRNP – North and Lostwood Class 1 areas had a modeled visibility impairment impact above the 0.50 dV threshold level. The modeling results are presented in Table 4.4-3.

Table 4.4-3 – PM Visibility Impairment Impacts and Reductions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)			Visibility Impairment Reduction (deciView)	
	Protocol Emissions	Post-Control Emissions[2] 0.030 and 0.015 Emission Rates		Post-Control Emissions[2] 0.030 and 0.015 Emission Rates	
TRNP-South Unit	0.549	0.466	0.465	0.083	0.084
TRNP-North Unit	0.628	0.503	0.500	0.125	0.128
TRNP-Elkhorn Ranch	0.374	0.328	0.328	0.046	0.046
Lostwood NWR	0.750	0.591	0.587	0.159	0.163

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

2 - PM emissions corresponding to the 0.030 and 0.015 lb/mmBtu rates specified in the CD. This scenario assumes protocol emission rates for NO_X and SO_2.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol and post-control emission rates. The results are presented in Appendix A. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control PM emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

4.5 EVALUATION OF IMPACTS FOR FEASIBLE PM CONTROLS – UNIT 2

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for MRYS. In addition, as described in Section 1.4, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

4.5.1 COST ESTIMATES

Cost estimates for the PM control technologies were completed utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the U.S. Environmental Protection Agency and engineering estimates based upon Burns & McDonnell's in-house experience. The CUECost model is a spreadsheet-based computer model that was specifically developed to estimate the cost of air pollution control technologies for utility power plants within +/- 30 percent accuracy. The EPA released the version of the model used for this study in February 2000. The model is available for download from the U.S. EPA website at www.epa.gov/ttn/catc/products. Operating information utilized as input into the model for the purpose of cost estimating is presented in Appendix C. Economic information utilized as input into the model is given in Table 1.2-1. The cost estimates for a PM control alternatives are summarized in Table 4.5-1. A Net Present Value (NPV) and Levelized Total Annual Cost (LTAC) were calculated for the each alternative utilizing the costs summarized in Table 4.5-1.

TABLE 4.5-1 – Cost Estimates for Unit 2 PM Control Alternatives

	FF	**COHPAC[1]**	**NEW ESP**	**EXISTING ESP[2]**
Capital Costs				
Direct Costs	$31,774,000	$20,445,000	$37,251,000	$0
Indirect Costs	$12,710,000	$8,178,000	$14,900,000	$0
Total Capital Costs	**$44,484,000**	**$28,623,000**	**$52,151,000**	**$0**
O&M Costs				
Includes Maintenance Costs, Power Costs, and Replacement Costs (if any)				
Total O&M Costs	**$3,500,000**	**$2,552,000**	**$2,381,000**	**$2,381,000**
Net Present Value (NPV)	**$81,479,000**	**$56,059,000**	**$74,667,000**	**$28,832,000**
Levelized Total Annual Cost (LTAC)	**$8,249,000**	**$5,682,000**	**$7,520,000**	**$2,973,000**

1. COHPAC costs are scaled down to represent a similar fabric filter with a flue gas to cloth ratio of 6 ACFM/ft^2.
2. Costs associated with the operation of the existing ESP are assumed equal to the operating costs for a new ESP.

The next step in the analysis for the BART alternatives is to review the unit control cost and incremental cost effectiveness of the remaining scenarios. Table 4.5-2 contains a repetition of the cost information from Table 4.5-1.

Because Unit 2 has existing PM control, the historic highest 24-month rolling average represents a controlled emission rate. Thus, the baseline annual tons of PM for Unit 2 in this BART analysis are calculated as the pre-controlled emissions from firing lignite fuel with an ash content of 9.6% at a heat input of 5,158 mmBtu/hr with the unit operating at 85% capacity. Using the conservative approach that 50% of the ash is emitted as fly ash and 50% of the ash becomes bottom ash; the resulting uncontrolled emissions are approximately 56,100 tons per year. The controlled emissions assumed application of the respective removal efficiency to the baseline emission rate with the same input conditions and unit operating time. The annual tons of PM reduction for Unit 2 are calculated as the difference between the protocol emissions and the controlled emissions associated to the respective removal efficiency.

TABLE 4.5-2 – Incremental Cost Effectiveness of Unit 2 PM BART Control Alternatives

BART Alternative	Levelized Total Annual Cost[1]	Annual Emission Reduction (tpy)	Actual Unit Control Cost ($/ton)[2]	Incremental Cost Effectiveness ($/ton)
Fabric Filter or Baghouse	$8,249,000	602	$13,700	$8,700
New Electrostatic Precipitator	$7,520,000	602	$12,500	$7,600
COHPAC Baghouse	$5,682,000	602	$9,400	$4,500
Existing Electrostatic Precipitator	$2,973,000	Baseline	Baseline	Baseline

1. For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1. 24873.
2. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.

The Levelized Total Annual Cost and Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. As can be seen from a review of Table 4.5-1 and 4.5-2, the fabric filter alternative is in the middle range for capital cost but has the highest levelized total annual cost and net present value.

In the BART Determination guidelines, EPA does not provide definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits between successively less effective alternatives. Because all the alternatives requiring new equipment for Unit 2 have the same removal rate, the incremental cost effectiveness is not effective for ranking the different technologies. However, the incremental cost is calculated for comparison between the existing ESP alternative and the other control options. The incremental cost effectiveness for each new control alternatives in Table 4.5-2 is above the range of reasonable costs used in other regulatory analyses and indicates that each new technology is prohibitively expensive. However, due to the lack of guidance on reasonable costs, the visibility analysis is conducted to determine if the additional controls are necessary to reduce visibility impacts.

4.5.2 PM VISIBLITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the Unit 2 BART PM analysis was to conduct a visibility improvement determination. The modeling for Unit 2 uses two PM emission rates that distinguish between coarse and fine particulate as a basis for the visibility impairment impacts. One baseline emission rate representing the NDDH Modeling Protocol values of 178.7 lb PM_{Coarse}/hr and 28.1 lb PM_{Fine}/hr was modeled. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. However, as discussed in Section 1.5.5, the protocol emission rates are based upon actual maximum historical 24-hour emissions that are not representative of future maximum 24-hour emissions. After obtaining approval from NDDH to use alternative emission rates based upon representative stack conditions, Minnkota based the post-control emission rates upon application of CD specified rates applied to a more representative maximum heat input of 5,158 mmBtu/hr.

The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 2 to achieve an emission rate of 0.030 lb PM/mmBtu. To achieve an emission rate greater than the 0.030 lb PM/mmBtu for an extended period of time may require the use of new control technology and would require a detailed engineering determination that is outside the scope of this analysis. For the purposes of this analysis, it is assumed that the existing equipment will be able to meet the 0.030 lb PM/mmBtu emission rate specified by the CD. Post-control rates of 133.7 lb PM_{Coarse}/hr and 21.0 lb PM_{Fine}/hr were calculated and modeled based upon the CD emission rate of 0.030 lb PM/mmBtu. No other PM emission rates were modeled based upon the results of the cost analysis.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 2. The post-control CALPUFF model scenario for MRYS Unit 2 was conducted with the protocol NO_X and SO_2 emission rates and the post-control PM emission rate as discussed previously in this section and in Table 1.5-1.

The results of the visibility impairment modeling at the protocol baseline PM emission rate for MRYS Unit 2 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control PM emission rate showed a reduction in visibility impairment impact for all Class 1 areas. The modeling results are presented in Table 4.5-3.

Table 4.5-3 – PM Visibility Impairment Impacts and Reductions, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	**Post-Control Emissions[2]**	
TRNP-South Unit	0.580	0.563	0.017
TRNP-North Unit	0.619	0.570	0.049
TRNP-Elkhorn Ranch	0.360	0.345	0.015
Lostwood NWR	0.775	0.739	0.036

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

2 - PM emissions corresponding to the 0.030 lb/mmBtu specified in the CD. This scenario assumes protocol emission rates for NO_X and SO_2.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results were summarized and presented in Table 4.5-4. Similarly, the same information for the post-control PM emission rates was summarized and is shown in Table 4.5-4. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control PM emission rates were reduced in the majority of cases. The TRNP – South Class 1 area in 2001 and 2002 each had one additional day with a visibility impairment impact exceeding 0.50 dV. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 2. The TRNP – South Class 1 area in 2001 and 2002 each had a impact increase of one day in terms of days exceeding 0.50 dV. The approximate visibility impact increase for 2001 was 4% and for 2002 was 2%. The impact reduction in terms of days exceeding 0.50 dV varies from approximately 0% in multiple areas and years to approximately 14% for TRNP – North in 2001. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 0% in multiple areas and years to approximately 13% for Lostwood NWR in 2000.

There are several plausible explanations for an increase in the number of days with a visibility impairment impact exceeding 0.50 dV for TRNP – South in 2001 and 2002. One possible cause could be the reduced exit velocity that was due to an increase in stack diameter and an increased flow rate caused by scrubbing of all of the flue gas. Because the modeling results presented in Table 4.5-3 showed a reduction in visibility impairment impacts for all Class 1 areas, additional research was not conducted to determine the cause of the increase.

Table 4.5-4 – Visibility Impairment Improvements – MRYS Unit 2 PM Scenarios

Class 1 Area	PM Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	Maintain ESP	37	29	52	16	13	27	3	3	4
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	Maintain ESP	29	37	45	18	21	29	2	4	4
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	Maintain ESP	29	23	36	11	13	19	2	3	4
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	Maintain ESP	50	48	45	27	27	25	3	3	4

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control PM emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix A.

5.0 BART RECOMMENDATIONS

This report presents the analysis of control technologies for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Minnkota Power Cooperative Inc.'s (Minnkota's) Milton R. Young Station (MRYS) Units 1 and 2. The final result of this analysis is a recommendation of the Best Achievable Retrofit Technology (BART) for each unit based upon "the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). The presented emission rates in this section are the BART recommendation.

As stated previously in Section 1.3.2, this report uses the requirements of the Consent Decree (CD) and associated NO_X BACT analysis as part of the analysis. Although Unit 1 and Unit 2 at MRYS are BART-eligible, the CD also requires that the NDDH establish BACT for NO_X control. With the specification to establish BACT for NO_X, the BART analysis was modified to replace the first four BART evaluation steps with the NO_X BACT analysis. The first four steps of BART are usually used to identify technologies, determine feasibility and evaluate cost, energy, non-air quality and useful life impacts. Because a BACT analysis results in the selection of the best available control technology, the visibility impacts evaluation is the only remaining step in the determination that must be performed to satisfy BART for NO_X. The MRYS NO_X BACT analysis study reports and additional support documents were submitted to the NDDH on October 6, 2006, March 19, and April 23, 2007 respectively. In addition, because the CD also requires a minimum level of control for both SO_2 and PM, this analysis evaluates the visibility impairment impacts of the BACT-level control technologies specified for SO_2 and PM in the CD and control technologies that exceed the specified level of control. The BART analysis does not review technologies that do not achieve the minimum level of control specified in the CD.

5.1 UNIT 1 BART RECOMMENDATIONS

As stated in previous sections of the report, the steps of the technology evaluation provided in the BART Determination Guidelines were completed for Unit 1. Each pollutant required a different approach in order to determine BART. This section provides a brief description of the approach used for each pollutant and summarizes the results for Unit 1.

The Consent Decree required a NO_X BACT analysis. Because a BACT analysis results in the selection of the best available the control technology, the visibility impacts evaluation is the only remaining step in the determination that must be performed to satisfy BART for NO_X. According to the BACT analysis, Selective Non-Catalytic Reduction (SNCR) post-combustion technology used in conjunction with Advanced Separated Overfire Air (ASOFA) was considered the best available technology and therefore was evaluated as BART for Unit 1. The results of the visibility impact analysis for this combination of NO_X control technologies demonstrate a visibility impairment impacts reduction in all Class 1 areas to levels below the discernable 0.5 dV threshold levels. Based upon the BACT analysis and the visibility impact analysis, SNCR in conjunction with ASOFA is recommended as BART for NO_X emissions.

For SO_2 emissions, the CD requires MRYS to install either a dry FGD process at 90% control or a wet FGD process at 95% control. Thus, both of these technologies were evaluated. The Powerspan Electro-Catalytic Oxidation (ECO™) system would meet the CD requirements but was determined infeasible because it is not commercially proven in a full scale unit. The cost analysis for Unit 1 resulted in wet FGD technology being the most cost effective alternative due to its lower levelized total annual cost and higher control efficiency. The energy and non-air quality impacts for dry and wet FGD were similar in quantity and nature and considered negligible in differentiating between the two technologies. The visibility impairment impacts for both dry and wet FGD were reduced to levels below the discernable 0.5 dV threshold levels. Based upon the impact analyses, the technology recommended as BART for SO_2 emissions is the wet FGD process.

The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 1 to achieve an emission rate of 0.015 lb PM/mmBtu if a dry FGD process is selected for SO_2 control or 0.030 lb PM/mmBtu if a wet FGD process is selected. Both emission rates were evaluated as part of this analysis. Based solely on the cost estimates for the Unit 1 PM control alternatives, the options requiring new equipment would be eliminated from the analysis due to their excessive expense. However, because the BART guidelines do not provide a specific value associated with eliminating individual control alternatives, visibility impacts were evaluated to verify the necessity of the more restrictive PM emission rate. The visibility impact analysis indicates that either evaluated emission rate reduces visibility impairment in the Class 1 areas. The maximum additional improvement in visibility impairment impact provided by the more stringent emission rate is less than 1% of the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. Thus, based upon the cost and visibility impact analyses, the technology recommended as BART for PM emissions is maintaining the existing ESP.

Table 5.1-1 summarizes the control technologies and associated emission rates that are recommended as BART for each pollutant. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

Table 5.1-1 – Recommended BART 30-Day Rolling Average, MRYS Unit 1

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.36*
SO_2	Wet Flue Gas Desulfurization (FGD) Process	0.15
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See referenced BACT analysis for a detailed discussion.

The pollutant specific modeling results for MRYS Unit 1 described previously in the analysis represent the visibility impairment impact reduction attributable to a technology used to control an individual pollutant of concern. While this result supports an individual technology in terms of visibility impact reduction, the result is not representative of actual plant-wide operations. Application of the BART-recommended technologies will result in simultaneous control of all pollutants. Thus, a comparison of the visibility impairment reduction due to reducing the protocol emission rates to post-control emission rates for all pollutants on Unit 1 simultaneously is more representative of actual expected results. A modeling scenario was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies to Unit 1 and the results are presented in Table 5.1-2.

Table 5.1-2 – Visibility Impairment Impacts for Control of all Pollutants, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction
	Protocol Emissions	Post-Control Emissions	
TRNP-South Unit	0.549	0.077	0.472
TRNP-North Unit	0.628	0.075	0.553
TRNP-Elkhorn Ranch	0.374	0.050	0.324
Lostwood NWR	0.750	0.112	0.638

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

The simultaneous control of all pollutants for MRYS Unit 1 results in visibility impairment impacts that are less than one fourth of the threshold the EPA designates as contributing to visibility impairment. These modeling results provide additional support for proposing the control technologies recommended in this report for NO_X, SO_2 and PM emissions as BART.

5.2 UNIT 2 BART RECOMMENDATIONS

As stated in previous sections of the report, the steps of the technology evaluation provided in the BART Determination Guidelines were completed for Unit 2. Each pollutant required a different approach in order to determine BART. This section provides a brief description of the approach used for each pollutant and summarizes the results for Unit 2.

As stated previously in the report, the Consent Decree required a NO_X BACT analysis. Because a BACT analysis results in the selection of the best available the control technology, the visibility impacts evaluation is the only remaining step in the determination that must be performed to satisfy BART for NO_X. According to the BACT analysis, Selective Non-Catalytic Reduction (SNCR) post-combustion technology used in conjunction with Advanced Separated Overfire Air (ASOFA) was considered the best available technology and therefore was evaluated as BART for Unit 2. The results of the visibility impact analysis for this combination of NO_X control technologies demonstrate a visibility impairment impacts reduction for three of the Class 1 areas to levels below the discernable 0.5 dV threshold levels. The Lostwood NWR Class 1 area had a modeled visibility impairment impact of 0.543 dV. Based upon the BACT analysis and the visibility impact analysis, SNCR in conjunction with ASOFA is recommended as BART for NO_X emissions.

For SO_2 emissions, the CD requires MRYS to modify the existing wet FGD system on Unit 2 to achieve a removal efficiency of at least 90%. Modifications to the existing wet FGD at 90% control were evaluated as the minimum level of control for BART. In addition, because some wet FGD systems are capable of achieving 95% removal efficiency, modifications required to achieve 95% control were also evaluated for the wet FGD process. The Powerspan Electro-Catalytic Oxidation (ECO™) system would meet the CD requirements but was determined infeasible because it is not commercially proven in a full scale unit. The cost analysis for Unit 2 resulted in 90% control wet FGD technology being the most cost effective alternative due to its lower levelized total annual cost. The energy and non-air quality impacts for both wet FGD control levels were similar in quantity and nature and considered negligible in differentiating between the two technologies. The visibility impairment impacts for 90% and 95% wet FGD processes were reduced to levels below the discernable 0.5 dV threshold levels.

Because this is an evaluation of the same technology at different control levels, the evaluated impacts are relatively similar. Thus, an additional parameter was evaluated to determine which control level should be recommended as BART. The levelized total annual cost (LTAC) and the average visibility impact reduction for the 4 areas were combined to obtain dollars per deciView of improvement. The difference between LTAC is $795,000. The average difference in visibility impact reduction is 0.082 dV. Thus, the cost for the additional impact reduction is approximately $9,700,000 per deciView of improvement. The cost to achieve relatively little visibility improvement is exceedingly high because either control level already improves visibility impact to below the discernable threshold levels. Based upon the impact analyses, the technology recommended as BART for SO_2 emissions is the wet FGD process at 90% removal efficiency.

The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 2 to achieve an emission rate of 0.030 lb PM/mmBtu. Control technologies meeting this emission rate and a more stringent emission rate of 0.015 lb PM/mmBtu were evaluated as part of this analysis. Based solely on the cost estimates for the Unit 2 PM control alternatives, the options requiring new equipment would be eliminated from the analysis due to their excessive expense. However, because the BART guidelines do not provide a specific value associated with eliminating individual control alternatives, visibility impacts were evaluated to verify the necessity of more restrictive PM controls. The visibility impact analysis indicates that an emission rate of 0.030 lb PM/mmBtu reduces visibility impairment in the Class 1 areas. Thus, based upon the incremental cost and visibility impact analyses, the technology recommended as BART for PM emissions is maintaining the existing ESP.

Table 5.2-1 summarizes the control technologies and associated emission rates that are recommended as BART for each pollutant. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

Table 5.2-1 – Recommended BART 30-Day Rolling Average, MRYS Unit 2

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.35*
SO_2	Upgrade of Existing Wet Flue Gas Desulfurization (FGD) Process	0.30
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See referenced BACT analysis for a detailed discussion.

The pollutant specific modeling results for MRYS Unit 2 described previously in this analysis represent the visibility impairment impact reduction attributable to a technology used to control an individual pollutant of concern. While this result supports an individual technology in terms of visibility impact reduction, the result is not representative of actual plant-wide operations. Application of the BART recommended technologies will result in simultaneous control of all pollutants. Thus, a comparison of the visibility impairment reduction due to reducing the protocol emission rates to post-control emission rates for all pollutants simultaneously is more representative of actual expected results. A modeling scenario was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies and the results are presented in Table 5.2-2.

Table 5.2-2 – Visibility Impairment Impacts for Control of all Pollutants, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction
	Protocol Emissions	Post-Control Emissions	
TRNP-South Unit	0.580	0.173	0.407
TRNP-North Unit	0.619	0.169	0.450
TRNP-Elkhorn Ranch	0.360	0.104	0.256
Lostwood NWR	0.775	0.243	0.532

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.5-1 and the modeling results are presented in Appendix A.

The simultaneous control of all pollutants for MRYS Unit 2 results in visibility impairment impacts that are less than one half of the threshold the EPA designates as contributing to visibility impairment.

These modeling results provide additional support for proposing the control technologies recommended as BACT for NO_X emissions and those recommended for SO_2 and PM emissions as BART.

In addition to the visibility impairment impact modeling scenario conducted to determine the effects of simultaneous control of all pollutants for the individual units, another modeling scenario was conducted to combine the effects of both units. The modeling showed that the visibility impairment impact for all Class 1 areas was reduced to below the threshold the EPA designates as contributing to visibility impairment. Results of this scenario (labeled Run 5) are provided in Appendix A.

Appendix A

Visibility Modeling Detailed Results

Emission Parameters for Minnkota Power Cooperative
BART Modeling Analysis
Milton R. Young Unit 1 & Unit 2

Scenario/ Unit Number	Stack Height		Stack Diameter		Exit Velocity		Exit Temperature		Emission Rate (lbs/hr)			
	Feet	Meters	Feet	Meters	feet/sec	meters/sec	F	K	SO_2	NO_X	PM Fine	PM Coarse
Precontrol												
Unit 1	299.8	91.4	19.0	5.8	60.7	18.5	349.0	449.1	7231.2	2855.2	5.5	36.7
Unit 2	549.7	167.6	24.9	7.6	63.0	19.2	191.8	361.8	6879.0	5364.2	28.1	178.7
Run 1												
Unit 1	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	7231.2	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	6879.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	0.0	0.0	5.5	36.7
Unit2pm	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	0.0	0.0	28.1	178.7
Run 2												
Unit 1 A	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	2855.2	0.0	0.0
Unit 1 B	549.7	167.6	21.6	6.6	55.0	16.8	144.3	335.4	361.6	2855.2	0.0	0.0
Unit 2 A	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.4	5364.2	0.0	0.0
Unit 2 B	549.7	167.6	30.8	9.4	55.0	16.8	144.3	335.4	773.7	5364.2	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	5.5	36.7
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	28.1	178.7
Run 3												
Unit 1	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	7231.2	2855.2	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	6879.0	5364.2	0.0	0.0
Unit1pm A	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	0.0	0.0	5.8	38.5
Unit1pm B	549.7	167.6	21.8	6.6	68.7	20.9	349.0	449.1	0.0	0.0	11.55	77.08
Unit2pm	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	0.0	0.0	21.0	133.7
Run 4												
Unit 1	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	11.6	77.1
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	21.0	133.7
Run 5												
Unit 1	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	11.6	77.1
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	21.0	133.7

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.101	6.334	2.234	2000	74	51	105	2.8	85.77	14.19	0.02	0.02
98th %tile Delta-DV	1.151	3.257	2.106	2000	265	51	105	2.2	92.11	7.79	0.07	0.03
90th %tile Delta-DV	0.351	2.478	2.127	2000	100	51	105	2.3	81.38	18.42	0.14	0.06
2001												
Largest Delta-DV	3.062	5.168	2.106	2001	260	46	46	2.2	97.83	2.07	0.08	0.03
98th %tile Delta-DV	1.219	3.346	2.127	2001	92	52	106	2.3	68.95	30.87	0.13	0.05
90th %tile Delta-DV	0.302	2.429	2.127	2001	144	53	107	2.3	77.98	21.73	0.21	0.07
2002												
Largest Delta-DV	6.180	8.414	2.234	2002	78	53	107	2.8	85.05	14.89	0.03	0.02
98th %tile Delta-DV	2.766	5.021	2.255	2002	26	48	102	2.9	79.59	20.30	0.08	0.02
90th %tile Delta-DV	0.476	2.710	2.234	2002	91	53	107	2.8	82.61	17.36	0.01	0.02
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.457	4.690	2.234	2000	72	82	71	2.8	81.52	18.39	0.06	0.02
98th %tile Delta-DV	1.307	3.413	2.106	2000	217	82	71	2.2	92.58	7.32	0.07	0.03
90th %tile Delta-DV	0.306	2.475	2.170	2000	152	82	71	2.5	82.80	16.99	0.16	0.06
2001												
Largest Delta-DV	3.423	5.657	2.234	2001	64	82	71	2.8	88.52	11.43	0.04	0.01
98th %tile Delta-DV	1.833	3.939	2.106	2001	234	82	71	2.2	99.22	0.62	0.12	0.04
90th %tile Delta-DV	0.419	2.652	2.234	2001	85	82	71	2.8	67.30	32.52	0.12	0.05
2002												
Largest Delta-DV	4.941	7.174	2.234	2002	73	58	47	2.8	79.73	20.16	0.08	0.03
98th %tile Delta-DV	2.413	4.646	2.234	2002	51	84	113	2.8	84.00	15.92	0.05	0.02
90th %tile Delta-DV	0.506	2.634	2.127	2002	110	82	71	2.3	89.40	10.53	0.05	0.02
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.675	5.908	2.234	2000	74	90	72	2.8	86.93	13.03	0.02	0.02
98th %tile Delta-DV	0.823	2.929	2.106	2000	265	90	72	2.2	89.95	9.96	0.07	0.03
90th %tile Delta-DV	0.260	2.366	2.106	2000	261	90	72	2.2	94.09	5.63	0.20	0.08
2001												
Largest Delta-DV	2.417	4.650	2.234	2001	64	90	72	2.8	90.09	9.87	0.03	0.01
98th %tile Delta-DV	1.049	3.176	2.127	2001	92	90	72	2.3	69.93	29.89	0.13	0.05
90th %tile Delta-DV	0.209	2.336	2.127	2001	94	90	72	2.3	87.27	12.70	0.02	0.01
2002												
Largest Delta-DV	6.042	8.276	2.234	2002	73	90	72	2.8	80.78	19.11	0.08	0.03
98th %tile Delta-DV	2.465	4.699	2.234	2002	39	90	72	2.8	89.53	10.34	0.08	0.05
90th %tile Delta-DV	0.321	2.427	2.106	2002	255	90	72	2.2	95.00	4.58	0.28	0.14
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.150	6.425	2.275	2000	47	97	79	2.9	91.79	8.15	0.04	0.02
98th %tile Delta-DV	1.248	3.587	2.340	2000	336	97	79	3.2	87.73	12.20	0.04	0.03
90th %tile Delta-DV	0.537	2.682	2.145	2000	261	99	81	2.3	98.43	1.20	0.27	0.10
2001												
Largest Delta-DV	4.993	7.332	2.340	2001	326	99	81	3.2	87.88	12.05	0.05	0.02
98th %tile Delta-DV	2.003	4.278	2.275	2001	41	91	73	2.9	79.93	19.98	0.06	0.03
90th %tile Delta-DV	0.488	2.720	2.232	2001	208	99	81	2.7	93.60	6.33	0.05	0.02
2002												
Largest Delta-DV	3.121	5.396	2.275	2002	74	97	79	2.9	85.98	13.97	0.03	0.02
98th %tile Delta-DV	1.834	3.980	2.145	2002	111	99	81	2.3	84.27	15.60	0.10	0.03
90th %tile Delta-DV	0.436	2.581	2.145	2002	100	91	73	2.3	86.69	13.26	0.02	0.02

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 33
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 1
2000-2002

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.360	6.593	2.234	2000	74	51	105	2.8	75.04	24.79	0.08	0.09
98th %tile Delta-DV	1.273	3.548	2.276	2000	316	46	46	3	67.31	32.39	0.22	0.08
90th %tile Delta-DV	0.358	2.591	2.234	2000	46	6	6	2.8	34.02	64.43	1.20	0.35
2001												
Largest Delta-DV	3.019	5.125	2.106	2001	260	46	46	2.2	95.13	4.35	0.37	0.14
98th %tile Delta-DV	1.476	3.625	2.149	2001	205	51	105	2.4	86.70	11.94	1.07	0.30
90th %tile Delta-DV	0.332	2.438	2.106	2001	230	41	41	2.2	90.53	7.68	1.40	0.40
2002												
Largest Delta-DV	6.478	8.712	2.234	2002	78	53	107	2.8	75.48	24.27	0.14	0.11
98th %tile Delta-DV	3.008	5.262	2.255	2002	26	48	102	2.9	66.05	33.52	0.32	0.11
90th %tile Delta-DV	0.528	2.634	2.106	2002	241	48	102	2.2	94.68	5.14	0.12	0.06
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.588	4.821	2.234	2000	72	82	71	2.8	68.73	30.9	0.28	0.1
98th %tile Delta-DV	1.345	3.451	2.106	2000	217	82	71	2.2	85.57	13.95	0.33	0.15
90th %tile Delta-DV	0.317	2.445	2.127	2000	286	82	71	2.3	65.24	34.25	0.35	0.16
2001												
Largest Delta-DV	3.474	5.708	2.234	2001	64	82	71	2.8	79.09	20.68	0.16	0.07
98th %tile Delta-DV	1.793	3.899	2.106	2001	234	82	71	2.2	97.90	1.29	0.62	0.19
90th %tile Delta-DV	0.442	2.676	2.234	2001	55	82	71	2.8	65.06	34.64	0.21	0.09
2002												
Largest Delta-DV	5.446	7.679	2.234	2002	73	63	52	2.8	65.53	33.99	0.35	0.12
98th %tile Delta-DV	2.692	4.925	2.234	2002	51	82	71	2.8	71.04	28.62	0.24	0.11
90th %tile Delta-DV	0.554	2.682	2.127	2002	138	82	71	2.3	67.69	31.23	0.76	0.32
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.876	6.11	2.234	2000	74	90	72	2.8	76.78	23.06	0.07	0.09
98th %tile Delta-DV	0.922	3.156	2.234	2000	69	90	72	2.8	61.84	37.64	0.36	0.16
90th %tile Delta-DV	0.278	2.512	2.234	2000	32	90	72	2.8	60.45	39.14	0.23	0.18
2001												
Largest Delta-DV	2.419	4.653	2.234	2001	64	90	72	2.8	81.69	18.11	0.14	0.06
98th %tile Delta-DV	1.131	3.364	2.234	2001	84	90	72	2.8	64.16	35.36	0.34	0.15
90th %tile Delta-DV	0.215	2.342	2.127	2001	101	90	72	2.3	84.12	15.80	0.04	0.04
2002												
Largest Delta-DV	6.564	8.797	2.234	2002	73	90	72	2.8	67.55	32.01	0.33	0.11
98th %tile Delta-DV	2.513	4.768	2.255	2002	29	90	72	2.9	69.55	30.13	0.23	0.09
90th %tile Delta-DV	0.339	2.466	2.127	2002	125	90	72	2.3	62.64	37.12	0.05	0.19
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.043	6.319	2.275	2000	47	97	79	2.9	79.16	20.58	0.18	0.09
98th %tile Delta-DV	1.393	3.669	2.275	2000	48	99	81	2.9	73.88	25.93	0.12	0.07
90th %tile Delta-DV	0.585	2.881	2.297	2000	12	99	81	3	72.77	26.8	0.26	0.18
2001												
Largest Delta-DV	5.139	7.479	2.340	2001	327	99	81	3.2	71.41	28.32	0.18	0.09
98th %tile Delta-DV	2.042	4.188	2.145	2001	259	97	79	2.3	91.38	8.26	0.26	0.10
90th %tile Delta-DV	0.580	2.791	2.211	2001	179	99	81	2.6	69.45	29.47	0.82	0.26
2002												
Largest Delta-DV	3.287	5.562	2.275	2002	74	97	79	2.9	75.12	24.66	0.14	0.08
98th %tile Delta-DV	1.935	4.274	2.340	2002	312	99	81	3.2	71.84	27.82	0.17	0.17
90th %tile Delta-DV	0.466	2.611	2.145	2002	247	97	79	2.3	96.79	2.20	0.70	0.31

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 41
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 39
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 2A
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.580	4.814	2.234	2000	72	53	107	2.8	11.93	87.88	0.14	0.05
98th %tile Delta-DV	0.583	2.817	2.234	2000	41	1	1	2.8	6.55	93.18	0.19	0.08
90th %tile Delta-DV	0.200	2.327	2.127	2000	287	46	46	2.3	23.65	76.13	0.15	0.07
2001												
Largest Delta-DV	3.062	5.168	2.106	2001	260	46	46	2.2	97.82	2.07	0.08	0.03
98th %tile Delta-DV	1.219	3.346	2.127	2001	92	52	106	2.3	68.94	30.87	0.14	0.05
90th %tile Delta-DV	0.302	2.429	2.127	2001	144	53	107	2.3	77.98	21.73	0.21	0.07
2002												
Largest Delta-DV	3.954	6.187	2.234	2002	78	45	45	2.8	14.93	84.96	0.06	0.04
98th %tile Delta-DV	1.768	4.023	2.255	2002	29	3	3	2.9	13.56	86.31	0.09	0.04
90th %tile Delta-DV	0.247	2.523	2.276	2002	330	47	101	3.0	15.64	84.29	0.03	0.04
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.396	4.630	2.234	2000	36	82	71	2.8	9.63	90.16	0.14	0.07
98th %tile Delta-DV	0.762	2.889	2.127	2000	98	84	113	2.3	10.23	89.46	0.24	0.07
90th %tile Delta-DV	0.144	2.419	2.276	2000	336	63	52	3.0	4.02	95.71	0.21	0.06
2001												
Largest Delta-DV	3.423	5.657	2.234	2001	64	82	71	2.8	88.52	11.43	0.04	0.01
98th %tile Delta-DV	1.833	3.939	2.106	2001	234	82	71	2.2	99.21	0.62	0.12	0.04
90th %tile Delta-DV	0.419	2.652	2.234	2001	85	82	71	2.8	67.30	32.52	0.12	0.05
2002												
Largest Delta-DV	3.890	6.123	2.234	2002	73	63	52	2.8	11.76	88.06	0.14	0.04
98th %tile Delta-DV	1.522	3.776	2.255	2002	29	85	114	2.9	12.95	86.92	0.10	0.04
90th %tile Delta-DV	0.244	2.414	2.170	2002	154	82	71	2.5	19.45	80.22	0.24	0.09
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	2.018	4.251	2.234	2000	74	90	72	2.8	19.61	80.31	0.04	0.04
98th %tile Delta-DV	0.528	2.677	2.149	2000	184	90	72	2.4	45.84	53.38	0.56	0.21
90th %tile Delta-DV	0.122	2.292	2.170	2000	164	90	72	2.5	62.36	36.69	0.68	0.27
2001												
Largest Delta-DV	2.417	4.650	2.234	2001	64	90	72	2.8	90.08	9.87	0.03	0.01
98th %tile Delta-DV	1.049	3.176	2.127	2001	92	90	72	2.3	69.93	29.88	0.13	0.05
90th %tile Delta-DV	0.209	2.336	2.127	2001	94	90	72	2.3	87.27	12.70	0.02	0.01
2002												
Largest Delta-DV	4.326	6.559	2.234	2002	73	90	72	2.8	13.02	86.81	0.12	0.04
98th %tile Delta-DV	1.589	3.843	2.255	2002	29	90	72	2.9	13.69	86.19	0.09	0.04
90th %tile Delta-DV	0.148	2.276	2.127	2002	116	90	72	2.3	5.46	94.29	0.18	0.07
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.844	5.119	2.275	2000	47	97	79	2.9	17.17	82.73	0.07	0.03
98th %tile Delta-DV	0.870	3.037	2.167	2000	216	97	79	2.4	20.55	79.22	0.18	0.05
90th %tile Delta-DV	0.277	2.510	2.232	2000	196	91	73	2.7	51.06	47.79	0.82	0.33
2001												
Largest Delta-DV	4.993	7.333	2.340	2001	326	99	81	3.2	87.88	12.05	0.05	0.02
98th %tile Delta-DV	2.003	4.278	2.275	2001	41	91	73	2.9	79.94	19.98	0.05	0.03
90th %tile Delta-DV	0.488	2.720	2.232	2001	208	99	81	2.7	93.60	6.33	0.05	0.02
2002												
Largest Delta-DV	1.721	3.996	2.275	2002	74	97	79	2.9	18.00	81.90	0.06	0.03
98th %tile Delta-DV	0.899	3.239	2.340	2002	312	91	73	3.2	14.82	85.04	0.07	0.08
90th %tile Delta-DV	0.201	2.411	2.211	2002	172	99	81	2.6	37.25	61.19	1.18	0.38

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 2B
2000-2002

						SEQ	ND	% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.536	4.770	2.234	2000	72	54	108	2.8	6.26	93.55	0.15	0.05
98th %tile Delta-DV	0.594	2.870	2.276	2000	336	53	107	3.0	1.94	97.71	0.27	0.08
90th %tile Delta-DV	0.167	2.294	2.127	2000	287	46	46	2.3	13.51	86.24	0.17	0.08
2001												
Largest Delta-DV	1.268	3.396	2.127	2001	112	36	36	2.3	5.54	94.14	0.25	0.07
98th %tile Delta-DV	0.635	2.911	2.276	2001	338	28	28	3.0	6.70	92.87	0.30	0.13
90th %tile Delta-DV	0.095	2.328	2.234	2001	43	52	106	2.8	9.93	89.85	0.16	0.05
2002												
Largest Delta-DV	3.823	6.056	2.234	2002	78	45	45	2.8	8.02	91.87	0.07	0.05
98th %tile Delta-DV	1.694	3.927	2.234	2002	64	53	107	2.8	6.78	93.05	0.10	0.06
90th %tile Delta-DV	0.258	2.385	2.127	2002	117	6	6	2.3	1.96	97.65	0.22	0.17
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.746	4.980	2.234	2000	36	82	71	2.8	4.77	95.00	0.15	0.07
98th %tile Delta-DV	1.097	3.330	2.234	2000	54	82	71	2.8	9.69	90.05	0.20	0.07
90th %tile Delta-DV	0.157	2.327	2.170	2000	152	82	71	2.5	8.30	91.29	0.30	0.12
2001												
Largest Delta-DV	1.888	4.142	2.255	2001	12	83	112	2.9	11.43	88.31	0.20	0.07
98th %tile Delta-DV	0.837	2.964	2.127	2001	92	63	52	2.3	3.47	96.29	0.18	0.06
90th %tile Delta-DV	0.117	2.244	2.127	2001	275	82	71	2.3	11.28	88.16	0.34	0.21
2002												
Largest Delta-DV	3.855	6.088	2.234	2002	73	63	52	2.8	6.18	93.63	0.15	0.05
98th %tile Delta-DV	1.594	3.827	2.234	2002	66	83	112	2.8	3.85	95.82	0.24	0.09
90th %tile Delta-DV	0.222	2.328	2.106	2002	234	67	56	2.2	20.43	78.42	0.90	0.25
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.890	4.123	2.234	2000	74	90	72	2.8	10.82	89.09	0.04	0.05
98th %tile Delta-DV	0.482	2.716	2.234	2000	41	90	72	2.8	5.46	94.34	0.12	0.08
90th %tile Delta-DV	0.109	2.236	2.127	2000	299	90	72	2.3	11.75	88.14	0.07	0.04
2001												
Largest Delta-DV	1.095	3.222	2.127	2001	92	90	72	2.3	3.68	96.12	0.15	0.06
98th %tile Delta-DV	0.525	2.631	2.106	2001	261	90	72	2.2	23.67	75.91	0.28	0.13
90th %tile Delta-DV	0.068	2.344	2.276	2001	315	90	72	3.0	6.65	93.22	0.08	0.05
2002												
Largest Delta-DV	4.225	6.459	2.234	2002	73	90	72	2.8	6.90	92.92	0.13	0.04
98th %tile Delta-DV	1.533	3.808	2.276	2002	336	90	72	3.0	7.54	92.24	0.17	0.05
90th %tile Delta-DV	0.155	2.282	2.127	2002	116	90	72	2.3	2.76	96.99	0.18	0.07
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.864	5.139	2.275	2000	47	97	79	2.9	9.39	90.49	0.08	0.04
98th %tile Delta-DV	0.820	2.987	2.167	2000	216	97	79	2.4	11.41	88.34	0.19	0.05
90th %tile Delta-DV	0.274	2.549	2.275	2000	45	91	73	2.9	7.82	92.11	0.04	0.03
2001												
Largest Delta-DV	4.434	6.774	2.340	2001	327	99	81	3.2	7.98	91.90	0.07	0.04
98th %tile Delta-DV	1.194	3.534	2.340	2001	333	99	81	3.2	7.17	92.60	0.14	0.09
90th %tile Delta-DV	0.280	2.447	2.167	2001	235	99	81	2.4	5.98	93.00	0.80	0.23
2002												
Largest Delta-DV	1.619	3.895	2.275	2002	74	97	79	2.9	9.86	90.04	0.07	0.04
98th %tile Delta-DV	0.839	3.115	2.275	2002	69	99	81	2.9	4.83	95.07	0.05	0.05
90th %tile Delta-DV	0.189	2.334	2.145	2002	100	91	73	2.3	10.37	89.52	0.06	0.05

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 2A
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.153	6.387	2.234	2000	72	53	107	2.8	13.85	85.69	0.34	0.12
98th %tile Delta-DV	1.159	3.392	2.234	2000	69	56	110	2.8	11.29	88.21	0.36	0.13
90th %tile Delta-DV	0.340	2.467	2.127	2000	301	54	108	2.3	3.47	94.82	1.31	0.41
2001												
Largest Delta-DV	3.019	5.125	2.106	2001	260	46	46	2.2	95.13	4.35	0.37	0.14
98th %tile Delta-DV	1.476	3.625	2.149	2001	205	51	105	2.4	86.70	11.94	1.07	0.30
90th %tile Delta-DV	0.332	2.438	2.106	2001	230	41	41	2.2	90.53	7.68	1.40	0.40
2002												
Largest Delta-DV	6.473	8.706	2.234	2002	78	45	45	2.8	16.99	82.74	0.16	0.11
98th %tile Delta-DV	3.080	5.335	2.255	2002	29	3	3	2.9	15.06	84.61	0.23	0.10
90th %tile Delta-DV	0.497	2.624	2.127	2002	294	47	101	2.3	14.54	84.71	0.51	0.24
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.452	5.685	2.234	2000	36	82	71	2.8	11.65	87.78	0.38	0.18
98th %tile Delta-DV	1.332	3.566	2.234	2000	74	67	56	2.8	20.92	78.90	0.08	0.11
90th %tile Delta-DV	0.257	2.384	2.127	2000	119	82	71	2.3	15.13	83.25	1.23	0.38
2001												
Largest Delta-DV	3.474	5.708	2.234	2001	64	82	71	2.8	79.09	20.68	0.16	0.07
98th %tile Delta-DV	1.793	3.899	2.106	2001	234	82	71	2.2	97.90	1.29	0.62	0.19
90th %tile Delta-DV	0.442	2.676	2.234	2001	55	82	71	2.8	65.06	34.64	0.21	0.09
2002												
Largest Delta-DV	6.094	8.327	2.234	2002	73	63	52	2.8	13.44	86.13	0.32	0.11
98th %tile Delta-DV	2.666	4.900	2.234	2002	75	82	71	2.8	17.44	82.13	0.28	0.16
90th %tile Delta-DV	0.410	2.685	2.276	2002	352	71	60	3.0	13.41	86.31	0.18	0.10
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.513	5.747	2.234	2000	74	90	72	2.8	21.72	78.08	0.09	0.11
98th %tile Delta-DV	1.068	3.174	2.106	2000	247	90	72	2.2	68.84	28.73	1.68	0.74
90th %tile Delta-DV	0.201	2.307	2.106	2000	239	90	72	2.2	43.86	55.24	0.58	0.32
2001												
Largest Delta-DV	2.419	4.653	2.234	2001	64	90	72	2.8	81.69	18.11	0.14	0.06
98th %tile Delta-DV	1.131	3.364	2.234	2001	84	90	72	2.8	64.16	35.36	0.34	0.15
90th %tile Delta-DV	0.215	2.342	2.127	2001	101	90	72	2.3	84.12	15.80	0.04	0.04
2002												
Largest Delta-DV	6.981	9.214	2.234	2002	73	90	72	2.8	14.69	84.89	0.31	0.11
98th %tile Delta-DV	2.789	5.044	2.255	2002	29	90	72	2.9	15.14	84.54	0.23	0.09
90th %tile Delta-DV	0.259	2.387	2.127	2002	116	90	72	2.3	6.26	93.09	0.47	0.18
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.227	6.502	2.275	2000	47	97	79	2.9	19.67	80.05	0.19	0.09
98th %tile Delta-DV	1.443	3.718	2.275	2000	48	99	81	2.9	19.14	80.64	0.14	0.08
90th %tile Delta-DV	0.494	2.639	2.145	2000	114	91	73	2.3	29.95	68.59	0.87	0.59
2001												
Largest Delta-DV	5.139	7.479	2.340	2001	327	99	81	3.2	71.41	28.32	0.18	0.09
98th %tile Delta-DV	2.042	4.188	2.145	2001	259	97	79	2.3	91.38	8.26	0.26	0.10
90th %tile Delta-DV	0.580	2.791	2.211	2001	179	99	81	2.6	69.45	29.47	0.82	0.26
2002												
Largest Delta-DV	3.117	5.392	2.275	2002	74	97	79	2.9	19.78	79.98	0.16	0.09
98th %tile Delta-DV	1.486	3.654	2.167	2002	239	93	75	2.4	33.81	65.60	0.41	0.18
90th %tile Delta-DV	0.405	2.572	2.167	2002	234	97	79	2.4	38.85	60.11	0.64	0.40

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 39
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 5

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 2B
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	3.913	6.147	2.234	2000	72	53	107	2.8	7.32	92.19	0.36	0.13
98th %tile Delta-DV	1.096	3.329	2.234	2000	69	56	110	2.8	5.89	93.58	0.39	0.14
90th %tile Delta-DV	0.317	2.445	2.127	2000	106	48	102	2.3	4.07	94.75	0.92	0.26
2001												
Largest Delta-DV	2.223	4.351	2.127	2001	92	52	106	2.3	3.96	95.53	0.37	0.15
98th %tile Delta-DV	1.095	3.370	2.276	2001	328	45	45	3.0	11.21	88.62	0.10	0.08
90th %tile Delta-DV	0.154	2.260	2.106	2001	266	51	105	2.2	4.72	93.42	1.47	0.39
2002												
Largest Delta-DV	6.099	8.332	2.234	2002	78	45	45	2.8	9.05	90.66	0.17	0.12
98th %tile Delta-DV	2.876	5.131	2.255	2002	29	4	4	2.9	7.99	91.65	0.25	0.10
90th %tile Delta-DV	0.442	2.569	2.127	2002	136	54	108	2.3	4.66	93.59	1.37	0.38
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.286	5.520	2.234	2000	36	82	71	2.8	6.07	93.33	0.40	0.20
98th %tile Delta-DV	1.199	3.432	2.234	2000	74	67	56	2.8	11.50	88.29	0.09	0.12
90th %tile Delta-DV	0.241	2.368	2.127	2000	301	63	52	2.3	1.91	96.26	1.38	0.45
2001												
Largest Delta-DV	2.801	4.929	2.127	2001	98	62	51	2.3	8.18	90.90	0.68	0.23
98th %tile Delta-DV	1.314	3.547	2.234	2001	43	82	71	2.8	10.44	89.04	0.39	0.13
90th %tile Delta-DV	0.214	2.320	2.106	2001	254	83	112	2.2	20.20	76.56	2.35	0.89
2002												
Largest Delta-DV	5.781	8.015	2.234	2002	73	63	52	2.8	7.08	92.45	0.35	0.12
98th %tile Delta-DV	2.464	4.697	2.234	2002	75	82	71	2.8	9.38	90.15	0.30	0.17
90th %tile Delta-DV	0.359	2.529	2.170	2002	159	78	67	2.5	8.35	89.00	1.75	0.90
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.182	5.416	2.234	2000	74	90	72	2.8	11.99	87.79	0.10	0.12
98th %tile Delta-DV	0.827	2.976	2.149	2000	184	90	72	2.4	32.57	64.75	1.96	0.72
90th %tile Delta-DV	0.175	2.345	2.170	2000	164	90	72	2.5	46.62	50.12	2.29	0.97
2001												
Largest Delta-DV	1.918	4.046	2.127	2001	92	90	72	2.3	4.10	95.38	0.37	0.15
98th %tile Delta-DV	0.863	2.969	2.106	2001	258	90	72	2.2	28.24	70.13	1.23	0.40
90th %tile Delta-DV	0.119	2.225	2.106	2001	248	90	72	2.2	64.38	30.48	3.36	1.77
2002												
Largest Delta-DV	6.606	8.840	2.234	2002	73	90	72	2.8	7.79	91.76	0.33	0.12
98th %tile Delta-DV	2.601	4.856	2.255	2002	29	90	72	2.9	8.06	91.59	0.25	0.10
90th %tile Delta-DV	0.219	2.325	2.106	2002	270	90	72	2.2	5.80	93.28	0.68	0.24
LOSTWOOD NWA												
2000												
Largest Delta-DV	3.905	6.180	2.275	2000	47	97	79	2.9	10.64	89.04	0.21	0.10
98th %tile Delta-DV	1.311	3.586	2.275	2000	48	99	81	2.9	10.41	89.34	0.16	0.09
90th %tile Delta-DV	0.421	2.567	2.145	2000	114	91	73	2.3	17.32	80.96	1.02	0.69
2001												
Largest Delta-DV	5.734	8.074	2.340	2001	327	99	81	3.2	9.14	90.57	0.19	0.11
98th %tile Delta-DV	1.654	3.929	2.275	2001	89	93	75	2.9	8.09	91.40	0.36	0.15
90th %tile Delta-DV	0.450	2.617	2.167	2001	304	93	75	2.4	4.84	94.03	0.90	0.24
2002												
Largest Delta-DV	2.845	5.121	2.275	2002	74	97	79	2.9	10.80	88.92	0.18	0.10
98th %tile Delta-DV	1.343	3.618	2.275	2002	69	99	81	2.9	5.46	94.25	0.16	0.13
90th %tile Delta-DV	0.344	2.555	2.211	2002	172	99	81	2.6	25.57	69.53	3.68	1.22

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 14
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 33
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 15
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 3A
2000-2002

						SEQ	ND		% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.878	7.111	2.234	2000	74	51	105	2.8	69.15	30.81	0.02	0.02
98th %tile Delta-DV	1.464	3.740	2.276	2000	316	46	46	3.0	60.13	39.82	0.04	0.01
90th %tile Delta-DV	0.412	2.518	2.106	2000	214	46	46	2.2	97.63	2.18	0.15	0.05
2001												
Largest Delta-DV	3.145	5.251	2.106	2001	260	46	46	2.2	94.80	5.09	0.08	0.03
98th %tile Delta-DV	1.576	3.725	2.149	2001	205	51	105	2.4	84.26	15.47	0.21	0.06
90th %tile Delta-DV	0.373	2.479	2.106	2001	224	53	107	2.2	96.76	3.06	0.14	0.04
2002												
Largest Delta-DV	6.961	9.194	2.234	2002	78	53	107	2.8	72.32	27.63	0.03	0.02
98th %tile Delta-DV	3.552	5.807	2.255	2002	26	48	102	2.9	59.46	40.46	0.06	0.02
90th %tile Delta-DV	0.611	2.844	2.234	2002	91	56	110	2.8	63.16	36.81	0.01	0.01
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.135	5.368	2.234	2000	72	82	71	2.8	61.67	38.26	0.05	0.02
98th %tile Delta-DV	1.469	3.575	2.106	2000	217	82	71	2.2	81.65	18.26	0.07	0.03
90th %tile Delta-DV	0.373	2.501	2.127	2000	286	82	71	2.3	58.48	41.43	0.06	0.03
2001												
Largest Delta-DV	4.011	6.244	2.234	2001	64	82	71	2.8	73.23	26.73	0.03	0.01
98th %tile Delta-DV	1.853	3.959	2.106	2001	234	82	71	2.2	98.06	1.77	0.13	0.04
90th %tile Delta-DV	0.488	2.615	2.127	2001	112	58	47	2.3	51.71	48.11	0.15	0.04
2002												
Largest Delta-DV	6.257	8.490	2.234	2002	73	63	52	2.8	58.28	41.64	0.06	0.02
98th %tile Delta-DV	3.026	5.259	2.234	2002	51	82	71	2.8	64.37	35.56	0.04	0.02
90th %tile Delta-DV	0.639	2.766	2.127	2002	138	82	71	2.3	61.20	38.60	0.14	0.06
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	4.342	6.576	2.234	2000	74	90	72	2.8	71.00	28.97	0.01	0.02
98th %tile Delta-DV	1.084	3.317	2.234	2000	69	90	72	2.8	54.54	45.37	0.06	0.03
90th %tile Delta-DV	0.341	2.469	2.127	2000	139	90	72	2.3	85.26	14.66	0.05	0.03
2001												
Largest Delta-DV	2.795	5.029	2.234	2001	64	90	72	2.8	76.35	23.62	0.03	0.01
98th %tile Delta-DV	1.321	3.555	2.234	2001	84	90	72	2.8	56.81	43.10	0.06	0.03
90th %tile Delta-DV	0.239	2.473	2.234	2001	55	90	72	2.8	59.90	40.06	0.03	0.01
2002												
Largest Delta-DV	7.443	9.677	2.234	2002	73	90	72	2.8	60.67	39.25	0.06	0.02
98th %tile Delta-DV	2.783	5.017	2.234	2002	39	90	72	2.8	78.00	21.88	0.08	0.04
90th %tile Delta-DV	0.404	2.531	2.127	2002	125	90	72	2.3	55.44	44.52	0.01	0.03
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.473	6.748	2.275	2000	47	97	79	2.9	83.69	16.26	0.04	0.02
98th %tile Delta-DV	1.685	3.960	2.275	2000	70	93	75	2.9	50.80	49.11	0.06	0.03
90th %tile Delta-DV	0.660	2.805	2.145	2000	131	93	75	2.3	57.84	42.02	0.12	0.03
2001												
Largest Delta-DV	5.789	8.129	2.340	2001	327	99	81	3.2	64.91	35.04	0.03	0.02
98th %tile Delta-DV	2.227	4.566	2.340	2001	333	99	81	3.2	64.47	35.44	0.05	0.04
90th %tile Delta-DV	0.596	2.742	2.145	2001	107	97	79	2.3	44.73	55.14	0.09	0.04
2002												
Largest Delta-DV	3.766	6.041	2.275	2002	74	97	79	2.9	68.87	31.09	0.03	0.01
98th %tile Delta-DV	2.195	4.427	2.232	2002	205	91	73	2.7	82.94	16.95	0.08	0.03
90th %tile Delta-DV	0.504	2.800	2.297	2002	31	97	79	3.0	78.62	21.36	0.01	0.01

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 43
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 42
Number of days with Delta-Deciview > 1.00: 28
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 44
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 3B
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.897	7.130	2.234	2000	74	51	105	2.8	69.17	30.76	0.03	0.03
98th %tile Delta-DV	1.464	3.740	2.276	2000	316	46	46	3.0	60.09	39.80	0.08	0.03
90th %tile Delta-DV	0.413	2.519	2.106	2000	214	46	46	2.2	97.44	2.18	0.29	0.09
2001												
Largest Delta-DV	3.153	5.259	2.106	2001	260	46	46	2.2	94.72	5.07	0.15	0.06
98th %tile Delta-DV	1.581	3.729	2.149	2001	205	51	105	2.4	84.03	15.43	0.43	0.11
90th %tile Delta-DV	0.373	2.479	2.106	2001	224	53	107	2.2	96.59	3.05	0.28	0.09
2002												
Largest Delta-DV	6.957	9.191	2.234	2002	78	53	107	2.8	71.90	28.00	0.06	0.04
98th %tile Delta-DV	3.568	5.823	2.255	2002	26	48	102	2.9	59.40	40.45	0.12	0.04
90th %tile Delta-DV	0.612	2.846	2.234	2002	91	56	110	2.8	63.14	36.81	0.02	0.03
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.152	5.386	2.234	2000	72	82	71	2.8	61.59	38.27	0.10	0.03
98th %tile Delta-DV	1.471	3.577	2.106	2000	217	82	71	2.2	81.57	18.24	0.13	0.06
90th %tile Delta-DV	0.372	2.500	2.127	2000	286	82	71	2.3	58.45	41.37	0.13	0.05
2001												
Largest Delta-DV	4.019	6.253	2.234	2001	64	82	71	2.8	73.17	26.75	0.06	0.02
98th %tile Delta-DV	1.856	3.962	2.106	2001	234	82	71	2.2	97.90	1.76	0.26	0.08
90th %tile Delta-DV	0.496	2.623	2.127	2001	112	58	47	2.3	51.62	48.01	0.29	0.07
2002												
Largest Delta-DV	6.269	8.503	2.234	2002	73	63	52	2.8	58.22	41.61	0.13	0.04
98th %tile Delta-DV	3.033	5.266	2.234	2002	51	82	71	2.8	64.29	35.58	0.09	0.04
90th %tile Delta-DV	0.641	2.769	2.127	2002	138	82	71	2.3	61.01	38.59	0.28	0.11
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	4.360	6.593	2.234	2000	74	90	72	2.8	70.99	28.95	0.03	0.03
98th %tile Delta-DV	1.084	3.318	2.234	2000	69	90	72	2.8	54.49	45.33	0.13	0.06
90th %tile Delta-DV	0.340	2.467	2.127	2000	139	90	72	2.3	85.21	14.62	0.11	0.06
2001												
Largest Delta-DV	2.798	5.031	2.234	2001	64	90	72	2.8	76.31	23.62	0.05	0.02
98th %tile Delta-DV	1.322	3.556	2.234	2001	84	90	72	2.8	56.76	43.06	0.12	0.05
90th %tile Delta-DV	0.241	2.369	2.127	2001	147	90	72	2.3	94.64	5.14	0.16	0.06
2002												
Largest Delta-DV	7.463	9.697	2.234	2002	73	90	72	2.8	60.61	39.23	0.12	0.04
98th %tile Delta-DV	2.795	5.029	2.234	2002	39	90	72	2.8	78.17	21.59	0.15	0.09
90th %tile Delta-DV	0.402	2.529	2.127	2002	125	90	72	2.3	55.41	44.51	0.02	0.07
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.440	6.715	2.275	2000	47	97	79	2.9	82.72	17.17	0.08	0.04
98th %tile Delta-DV	1.686	3.961	2.275	2000	70	93	75	2.9	50.75	49.07	0.12	0.06
90th %tile Delta-DV	0.661	2.807	2.145	2000	131	97	79	2.3	59.10	40.58	0.25	0.07
2001												
Largest Delta-DV	5.865	8.204	2.340	2001	327	99	81	3.2	64.90	35.01	0.07	0.03
98th %tile Delta-DV	2.229	4.569	2.340	2001	333	99	81	3.2	64.39	35.43	0.10	0.07
90th %tile Delta-DV	0.597	2.742	2.145	2001	107	97	79	2.3	44.68	55.07	0.17	0.08
2002												
Largest Delta-DV	3.788	6.063	2.275	2002	74	97	79	2.9	68.85	31.07	0.05	0.03
98th %tile Delta-DV	2.180	4.519	2.340	2002	312	99	81	3.2	65.40	34.47	0.07	0.06
90th %tile Delta-DV	0.516	2.813	2.297	2002	31	97	79	3.0	78.58	21.38	0.02	0.01

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 43
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 42
Number of days with Delta-Deciview > 1.00: 28
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 44
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 3
2000-2002

						SEQ	ND	% of Modeled Extinction by Species			
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	5.577	7.811	2.234	2000	74	51	105	2.8	54.92	44.99	0.05	0.05
98th %tile Delta-DV	1.647	3.817	2.170	2000	152	54	108	2.5	36.38	62.85	0.57	0.20
90th %tile Delta-DV	0.511	2.638	2.127	2000	101	47	101	2.3	34.53	65.12	0.23	0.12
2001												
Largest Delta-DV	3.297	5.530	2.234	2001	64	46	46	2.8	58.91	40.96	0.09	0.04
98th %tile Delta-DV	2.001	4.235	2.234	2001	84	46	46	2.8	40.75	59.03	0.15	0.06
90th %tile Delta-DV	0.397	2.503	2.106	2001	234	51	105	2.2	94.76	4.72	0.40	0.12
2002												
Largest Delta-DV	8.275	10.508	2.234	2002	73	48	102	2.8	44.60	55.19	0.15	0.05
98th %tile Delta-DV	4.338	6.444	2.106	2002	250	53	107	2.2	63.35	36.16	0.35	0.15
90th %tile Delta-DV	0.780	2.907	2.127	2002	294	47	101	2.3	42.15	57.47	0.26	0.12
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.754	5.988	2.234	2000	72	82	71	2.8	44.56	55.26	0.13	0.05
98th %tile Delta-DV	1.660	3.766	2.106	2000	217	82	71	2.2	68.22	31.49	0.20	0.09
90th %tile Delta-DV	0.421	2.570	2.149	2000	191	67	56	2.4	91.41	7.97	0.48	0.15
2001												
Largest Delta-DV	4.537	6.771	2.234	2001	64	82	71	2.8	57.23	42.65	0.09	0.04
98th %tile Delta-DV	2.082	4.188	2.106	2001	260	86	115	2.2	87.36	12.37	0.19	0.08
90th %tile Delta-DV	0.517	2.666	2.149	2001	205	58	47	2.4	92.58	6.69	0.54	0.19
2002												
Largest Delta-DV	7.694	9.928	2.234	2002	73	63	52	2.8	40.95	58.83	0.16	0.06
98th %tile Delta-DV	3.703	5.937	2.234	2002	75	82	71	2.8	49.80	49.97	0.14	0.08
90th %tile Delta-DV	0.773	3.006	2.234	2002	91	82	71	2.8	47.25	52.60	0.09	0.06
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	5.037	7.270	2.234	2000	74	90	72	2.8	55.53	44.39	0.04	0.05
98th %tile Delta-DV	1.497	3.730	2.234	2000	69	90	72	2.8	37.02	62.75	0.16	0.07
90th %tile Delta-DV	0.349	2.519	2.170	2000	152	90	72	2.5	53.35	46.14	0.35	0.16
2001												
Largest Delta-DV	3.117	5.350	2.234	2001	64	90	72	2.8	61.14	38.75	0.08	0.03
98th %tile Delta-DV	1.795	4.028	2.234	2001	84	90	72	2.8	39.07	60.70	0.15	0.07
90th %tile Delta-DV	0.272	2.399	2.127	2001	94	90	72	2.3	56.09	43.84	0.04	0.02
2002												
Largest Delta-DV	8.901	11.134	2.234	2002	73	90	72	2.8	43.67	56.12	0.16	0.05
98th %tile Delta-DV	3.057	5.291	2.234	2002	39	90	72	2.8	63.55	36.10	0.22	0.14
90th %tile Delta-DV	0.415	2.564	2.149	2002	198	90	72	2.4	93.95	5.38	0.47	0.20
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.587	6.862	2.275	2000	47	97	79	2.9	67.76	32.07	0.11	0.06
98th %tile Delta-DV	1.965	4.240	2.275	2000	55	91	73	2.9	67.87	31.96	0.09	0.08
90th %tile Delta-DV	0.810	3.085	2.275	2000	65	91	73	2.9	61.71	38.02	0.17	0.11
2001												
Largest Delta-DV	6.953	9.293	2.340	2001	327	99	81	3.2	47.65	52.21	0.09	0.04
98th %tile Delta-DV	2.731	5.070	2.340	2001	333	99	81	3.2	48.63	51.13	0.14	0.10
90th %tile Delta-DV	0.806	2.973	2.167	2001	240	91	73	2.4	70.59	29.06	0.23	0.11
2002												
Largest Delta-DV	4.457	6.732	2.275	2002	74	97	79	2.9	52.05	47.83	0.07	0.04
98th %tile Delta-DV	2.318	4.550	2.232	2002	205	91	73	2.7	71.61	28.05	0.25	0.09
90th %tile Delta-DV	0.601	2.768	2.167	2002	218	99	81	2.4	84.33	15.25	0.21	0.22

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 37
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 52
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 37
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 29
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 50
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 48
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 4
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.269	3.502	2.234	2000	74	51	105	2.8	37.96	61.85	0.09	0.09
98th %tile Delta-DV	0.265	2.499	2.234	2000	69	56	110	2.8	23.55	75.98	0.35	0.13
90th %tile Delta-DV	0.094	2.221	2.127	2000	109	53	107	2.3	9.18	88.60	1.69	0.53
2001												
Largest Delta-DV	0.592	2.720	2.127	2001	112	51	105	2.3	23.91	75.37	0.57	0.15
98th %tile Delta-DV	0.344	2.620	2.276	2001	328	45	45	3	38.61	61.25	0.08	0.06
90th %tile Delta-DV	0.060	2.188	2.127	2001	101	45	45	2.3	50.01	49.86	0.07	0.06
2002												
Largest Delta-DV	2.023	4.256	2.234	2002	78	45	45	2.8	32.34	67.42	0.14	0.10
98th %tile Delta-DV	0.847	3.081	2.234	2002	64	54	108	2.8	28.28	71.37	0.22	0.13
90th %tile Delta-DV	0.118	2.246	2.127	2002	118	53	107	2.3	41.52	58.16	0.20	0.12
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.116	3.349	2.234	2000	36	82	71	2.8	22.10	77.41	0.33	0.16
98th %tile Delta-DV	0.342	2.469	2.127	2000	98	84	113	2.3	23.30	75.97	0.57	0.16
90th %tile Delta-DV	0.068	2.196	2.127	2000	286	82	71	2.3	28.79	70.86	0.22	0.13
2001												
Largest Delta-DV	0.849	3.082	2.234	2001	64	82	71	2.8	42.62	57.12	0.19	0.07
98th %tile Delta-DV	0.385	2.513	2.127	2001	109	63	52	2.3	22.79	76.20	0.74	0.28
90th %tile Delta-DV	0.079	2.185	2.106	2001	254	83	112	2.2	52.02	46.01	1.46	0.52
2002												
Largest Delta-DV	1.894	4.128	2.234	2002	73	63	52	2.8	26.80	72.76	0.33	0.11
98th %tile Delta-DV	0.734	2.967	2.234	2002	75	82	71	2.8	32.58	67.06	0.23	0.13
90th %tile Delta-DV	0.131	2.237	2.106	2002	248	82	71	2.2	39.07	60.31	0.39	0.23
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.042	3.276	2.234	2000	74	90	72	2.8	39.92	59.91	0.08	0.09
98th %tile Delta-DV	0.246	2.480	2.234	2000	69	90	72	2.8	24.81	74.77	0.29	0.13
90th %tile Delta-DV	0.059	2.165	2.106	2000	239	90	72	2.2	67.12	32.25	0.41	0.22
2001												
Largest Delta-DV	0.539	2.772	2.234	2001	64	90	72	2.8	46.77	53.00	0.16	0.07
98th %tile Delta-DV	0.304	2.538	2.234	2001	84	90	72	2.8	26.81	72.78	0.29	0.12
90th %tile Delta-DV	0.041	2.211	2.170	2001	153	90	72	2.5	63.10	35.53	0.99	0.38
2002												
Largest Delta-DV	2.175	4.409	2.234	2002	73	90	72	2.8	29.00	70.61	0.29	0.10
98th %tile Delta-DV	0.790	3.024	2.234	2002	39	90	72	2.8	32.31	67.19	0.32	0.18
90th %tile Delta-DV	0.071	2.198	2.127	2002	117	90	72	2.3	7.64	91.19	0.67	0.51
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.446	3.721	2.275	2000	47	97	79	2.9	36.30	63.46	0.16	0.08
98th %tile Delta-DV	0.421	2.589	2.167	2000	217	91	73	2.4	58.25	40.61	0.85	0.28
90th %tile Delta-DV	0.139	2.479	2.340	2000	363	93	75	3.2	23.15	76.56	0.15	0.14
2001												
Largest Delta-DV	2.207	4.547	2.340	2001	327	99	81	3.2	32.49	67.26	0.16	0.09
98th %tile Delta-DV	0.517	2.857	2.340	2001	355	93	75	3.2	14.59	84.46	0.71	0.23
90th %tile Delta-DV	0.141	2.480	2.340	2001	314	99	81	3.2	19.49	80.24	0.16	0.11
2002												
Largest Delta-DV	0.857	3.133	2.275	2002	74	97	79	2.9	37.79	62.00	0.14	0.08
98th %tile Delta-DV	0.435	2.602	2.167	2002	239	93	75	2.4	56.71	42.83	0.32	0.14
90th %tile Delta-DV	0.102	2.248	2.145	2002	100	91	73	2.3	38.78	61.00	0.12	0.10

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 4
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.255	4.489	2.234	2000	74	51	105	2.8	40.92	58.76	0.15	0.17
98th %tile Delta-DV	0.569	2.845	2.276	2000	316	46	46	3	31.91	67.61	0.35	0.13
90th %tile Delta-DV	0.159	2.287	2.127	2000	98	47	101	2.3	37.13	62.29	0.38	0.21
2001												
Largest Delta-DV	1.149	3.382	2.234	2001	64	46	46	2.8	47.43	52.13	0.31	0.13
98th %tile Delta-DV	0.667	2.900	2.234	2001	84	46	46	2.8	30.36	68.93	0.50	0.21
90th %tile Delta-DV	0.122	2.228	2.106	2001	248	48	102	2.2	87.52	10.40	1.33	0.76
2002												
Largest Delta-DV	3.621	5.854	2.234	2002	78	45	45	2.8	35.44	64.14	0.25	0.17
98th %tile Delta-DV	1.612	3.846	2.234	2002	64	54	108	2.8	31.00	68.38	0.38	0.24
90th %tile Delta-DV	0.238	2.366	2.127	2002	118	53	107	2.3	44.33	55.09	0.35	0.22
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.716	3.949	2.234	2000	36	82	71	2.8	25.66	73.41	0.63	0.30
98th %tile Delta-DV	0.687	2.921	2.234	2000	74	67	56	2.8	41.89	57.84	0.12	0.16
90th %tile Delta-DV	0.132	2.281	2.149	2000	187	58	47	2.4	90.71	7.99	0.83	0.47
2001												
Largest Delta-DV	1.644	3.877	2.234	2001	64	82	71	2.8	45.70	53.86	0.31	0.13
98th %tile Delta-DV	0.706	2.833	2.127	2001	109	58	47	2.3	26.13	72.08	1.27	0.52
90th %tile Delta-DV	0.162	2.268	2.106	2001	230	82	71	2.2	86.55	10.92	1.72	0.80
2002												
Largest Delta-DV	3.194	5.427	2.234	2002	73	63	52	2.8	29.97	69.30	0.54	0.19
98th %tile Delta-DV	1.397	3.630	2.234	2002	75	82	71	2.8	35.54	63.80	0.42	0.24
90th %tile Delta-DV	0.213	2.341	2.127	2002	110	82	71	2.3	48.55	50.84	0.42	0.18
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.926	4.160	2.234	2000	74	90	72	2.8	43.05	56.66	0.13	0.16
98th %tile Delta-DV	0.487	2.720	2.234	2000	69	90	72	2.8	27.15	72.11	0.51	0.23
90th %tile Delta-DV	0.097	2.225	2.127	2000	110	90	72	2.3	8.76	86.96	3.19	1.10
2001												
Largest Delta-DV	1.066	3.299	2.234	2001	64	90	72	2.8	49.81	49.79	0.28	0.12
98th %tile Delta-DV	0.594	2.827	2.234	2001	84	90	72	2.8	29.11	70.18	0.50	0.22
90th %tile Delta-DV	0.082	2.358	2.276	2001	345	90	72	3	39.25	59.94	0.61	0.20
2002												
Largest Delta-DV	3.812	6.046	2.234	2002	73	90	72	2.8	31.97	67.35	0.50	0.18
98th %tile Delta-DV	1.447	3.680	2.234	2002	39	90	72	2.8	37.08	61.97	0.59	0.35
90th %tile Delta-DV	0.133	2.282	2.149	2002	189	90	72	2.4	90.95	6.52	1.77	0.76
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.302	4.577	2.275	2000	47	97	79	2.9	39.98	59.59	0.29	0.14
98th %tile Delta-DV	0.731	3.007	2.275	2000	48	99	81	2.9	39.13	60.53	0.22	0.12
90th %tile Delta-DV	0.264	2.604	2.340	2000	359	97	79	3.2	21.84	77.89	0.13	0.14
2001												
Largest Delta-DV	3.339	5.679	2.340	2001	327	99	81	3.2	35.97	63.60	0.28	0.16
98th %tile Delta-DV	0.863	3.138	2.275	2001	89	99	81	2.9	34.01	65.28	0.49	0.22
90th %tile Delta-DV	0.264	2.409	2.145	2001	96	99	81	2.3	34.38	63.87	1.21	0.55
2002												
Largest Delta-DV	1.635	3.910	2.275	2002	74	97	79	2.9	40.73	58.89	0.24	0.14
98th %tile Delta-DV	0.756	3.031	2.275	2002	76	99	81	2.9	33.01	65.91	0.83	0.25
90th %tile Delta-DV	0.201	2.476	2.275	2002	52	97	79	2.9	41.69	58.00	0.19	0.12

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 1 & 2
BART Run 5
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	3.279	5.513	2.234	2000	74	51	105	2.8	39.91	59.82	0.13	0.14
98th %tile Delta-DV	0.817	3.092	2.276	2000	316	45	45	3	31.35	68.24	0.30	0.11
90th %tile Delta-DV	0.241	2.369	2.127	2000	109	53	107	2.3	9.98	86.72	2.50	0.80
2001												
Largest Delta-DV	1.671	3.905	2.234	2001	64	46	46	2.8	46.41	53.21	0.27	0.11
98th %tile Delta-DV	0.987	3.221	2.234	2001	84	46	46	2.8	29.56	69.83	0.43	0.18
90th %tile Delta-DV	0.179	2.285	2.106	2001	248	48	102	2.2	87.47	10.70	1.17	0.66
2002												
Largest Delta-DV	5.058	7.291	2.234	2002	78	45	45	2.8	34.50	65.14	0.21	0.15
98th %tile Delta-DV	2.336	4.569	2.234	2002	64	54	108	2.8	30.11	69.36	0.33	0.21
90th %tile Delta-DV	0.354	2.481	2.127	2002	118	53	107	2.3	43.40	56.11	0.30	0.19
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.656	4.889	2.234	2000	36	82	71	2.8	24.37	74.87	0.51	0.25
98th %tile Delta-DV	0.979	3.212	2.234	2000	74	67	56	2.8	40.71	59.06	0.10	0.14
90th %tile Delta-DV	0.200	2.434	2.234	2000	65	82	71	2.8	34.83	63.06	1.36	0.75
2001												
Largest Delta-DV	2.367	4.601	2.234	2001	64	82	71	2.8	44.70	54.92	0.27	0.11
98th %tile Delta-DV	1.058	3.186	2.127	2001	109	58	47	2.3	25.40	73.08	1.08	0.44
90th %tile Delta-DV												
2002												
Largest Delta-DV	4.597	6.831	2.234	2002	73	63	52	2.8	28.90	70.47	0.46	0.16
98th %tile Delta-DV	2.031	4.265	2.234	2002	75	82	71	2.8	34.66	64.78	0.36	0.20
90th %tile Delta-DV	0.330	2.500	2.170	2002	154	82	71	2.5	45.03	54.16	0.59	0.23
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	2.791	5.025	2.234	2000	74	90	72	2.8	42.02	57.73	0.11	0.14
98th %tile Delta-DV	0.721	2.954	2.234	2000	69	90	72	2.8	26.39	72.98	0.43	0.20
90th %tile Delta-DV	0.178	2.454	2.276	2000	316	90	72	3	30.15	69.40	0.33	0.12
2001												
Largest Delta-DV	1.551	3.784	2.234	2001	64	90	72	2.8	48.82	50.84	0.24	0.10
98th %tile Delta-DV	0.880	3.113	2.234	2001	84	90	72	2.8	28.37	71.02	0.43	0.19
90th %tile Delta-DV	0.126	2.296	2.170	2001	153	90	72	2.5	64.15	33.83	1.44	0.57
2002												
Largest Delta-DV	5.337	7.570	2.234	2002	73	90	72	2.8	31.03	68.39	0.43	0.15
98th %tile Delta-DV	2.020	4.254	2.234	2002	39	90	72	2.8	37.65	61.51	0.53	0.31
90th %tile Delta-DV	0.195	2.343	2.149	2002	189	90	72	2.4	91.03	6.75	1.56	0.66
LOSTWOOD NWA												
2000												
Largest Delta-DV	3.458	5.734	2.275	2000	47	97	79	2.9	38.71	60.93	0.24	0.12
98th %tile Delta-DV	1.161	3.437	2.275	2000	37	97	79	2.9	23.36	76.08	0.37	0.18
90th %tile Delta-DV	0.393	2.669	2.275	2000	67	97	79	2.9	36.18	63.42	0.25	0.14
2001												
Largest Delta-DV	4.964	7.304	2.340	2001	327	99	81	3.2	34.66	64.98	0.23	0.13
98th %tile Delta-DV	1.332	3.608	2.275	2001	89	93	75	2.9	31.34	68.02	0.45	0.19
90th %tile Delta-DV	0.411	2.751	2.340	2001	314	99	81	3.2	20.85	78.74	0.24	0.17
2002												
Largest Delta-DV	2.366	4.642	2.275	2002	74	97	79	2.9	39.77	59.90	0.21	0.12
98th %tile Delta-DV	1.140	3.285	2.145	2002	131	99	81	2.3	30.86	67.70	1.10	0.34
90th %tile Delta-DV	0.303	2.578	2.275	2002	52	97	79	2.9	40.58	59.15	0.17	0.10

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 4

Appendix B

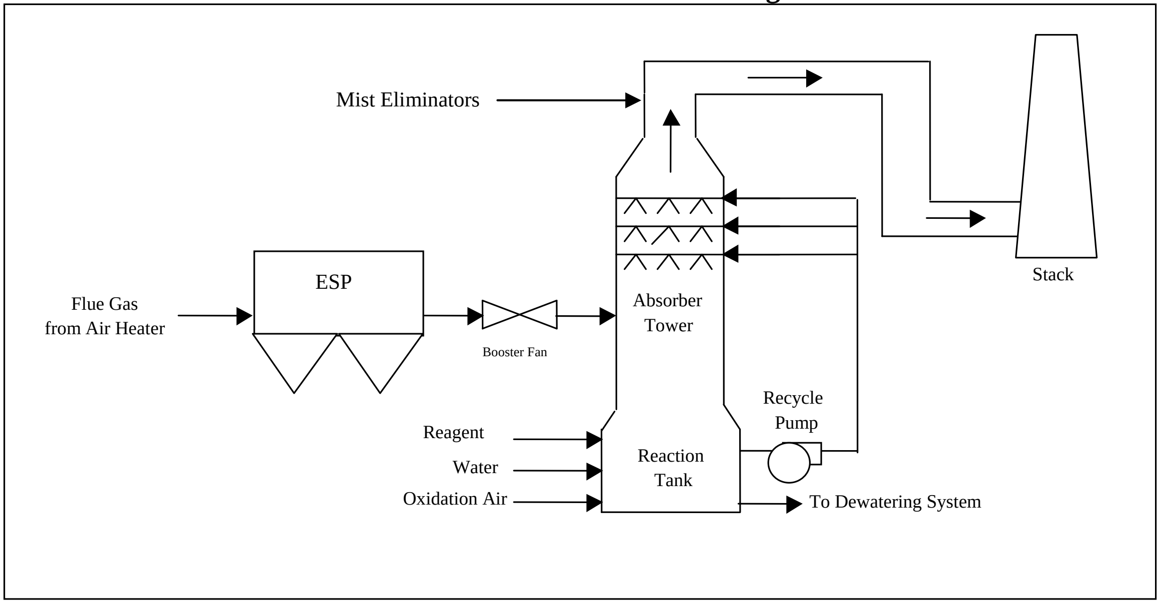
Detailed Description of SO_2 Control Technologies

Conventional Wet Scrubber (Wet FGD)

Wet FGD technology utilizing lime or limestone as the reagent and employing forced oxidation to produce gypsum (calcium sulfate dihydrate, $CaSO_4 \cdot 2H_2O$) as the byproduct, is a common method of SO_2 control for coal-fired boilers. The gypsum byproduct is either landfilled or sold for commercial reuse.

A flow diagram of the wet FGD process is provided in the below figure. In the wet FGD process, a slurry of finely ground reagent (typically limestone or lime) in water is recirculated through an absorber tower where it is brought into turbulent contact with the flue gas. The contact between the flue gas and the slurry cools and saturates the gas via evaporation of water from the slurry. SO_2 is simultaneously absorbed into the slurry where it forms sulfurous acid which reacts with the reagent, forming calcium sulfite hemihydrate ($CaSO_3 \bullet \frac{1}{2}H_2O$), which can then be disposed of as a waste product or oxidized to calcium sulfate dihydrate, or gypsum, ($CaSO_4 \bullet 2H_2O$) before disposal or for commercial reuse. No commercial uses for sulfite waste products have been identified. Disposal of the sulfite waste can be somewhat difficult because of the thixotropic nature of the material. Sulfite wastes are often combined with fly ash to form a more easily handled waste solid. Disposal of the sulfate, or gypsum, as a waste is a bit more straightforward. The gypsum, depending upon its cleanliness, can be sold as a raw material for the manufacture of wallboard or cement. Where a gypsum product is desired, the most common approach is to sparge the reaction tank, or a separate holding tank with compressed air to convert the sulfite waste. Such systems are often referred to as Limestone Forced Oxidation (LSFO) systems.

Wet FGD Process Flow Diagram



In a limestone scrubber, as the limestone in the recirculating slurry is depleted, it is replenished with fresh slurry prepared by wet grinding of crushed limestone using reclaimed liquid from the dewatering system. Fresh water is also required to replace water lost to evaporation in the flue gas cooling process. Fresh water is often used to wash the mist eliminators; devices located at the scrubber exit to capture slurry droplets entrained in the exiting flue gas stream and return them to the scrubber. The mist eliminator wash removes accumulated materials from the mist eliminator chevrons, thus preventing solids buildup and pluggage. In addition, depending upon the mineral content of the coal, a portion of the reclaimed liquid may be blown down, or disposed of, to prevent excessive accumulation of mineral salts in the slurry which could result in mineral scaling or corrosion within the absorber equipment. The blow down rate varies with each plant. Fresh water makeup, both through the mist eliminator wash system and in the limestone grinding process, replaces the blow down and evaporative losses.

Lime scrubbers are very similar to limestone scrubbers. The use of lime rather than limestone can reduce the liquid-to-gas ratio and/or absorber size required to achieve a given SO_2 removal rate. Lime is sometimes used in wet FGD systems where extremely high SO_2 removal rates are desired or where limestone is not readily available. However, since lime is more expensive than limestone, the reagent cost is much higher for a lime system. Therefore, the vast majority of wet FGD systems are designed to use limestone as the neutralizing reagent.

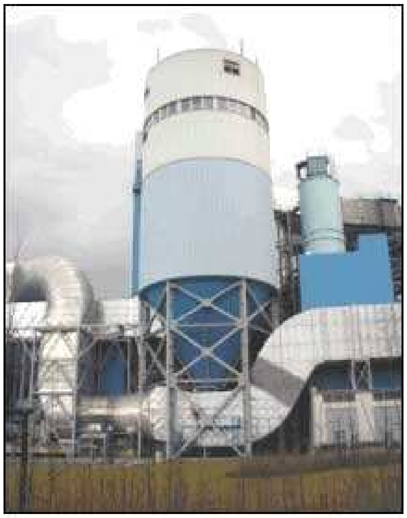
Advantages of the wet FGD systems include lower operating costs, primarily due to the ability to use limestone instead of lime as a reagent, the production of a salable by-product and high removal efficiency. Also, wet FGD systems have a high turndown capability and plant operational flexibility is not hindered to the same degree as the semi-dry, CFB and FDA processes. This last advantage is important where wet FGD systems are applied to load following units.

Disadvantages of wet FGD systems include corrosion due to a wet environment with corrosive chemicals including salts of sulfurous and sulfuric acid and hydrochloric acid. Also, because the wet systems are more mechanically complex, they typically require larger maintenance staff than some of the other alternatives. The greater mechanical complexity also contributes to a greater capital cost for wet FGD systems. Finally, because wet FGD systems completely saturate the flue gas stream, nearly all the SO_3 or H_2SO_4 vapor in the entering flue gas is condensed into aerosol droplets which are too small to be efficiently captured in the scrubber. Fifty percent or more of these droplets pass through the scrubber. Where units are burning high sulfur fuels, this can cause a plume opacity problem.

Wet FGD systems saturate the flue gas stream with moisture and as a result, operate with a wet stack. Two problems can occur with a wet stack. The first is entrainment of condensed liquids from the stack liner interior. The pressure of the flue gas changes as it traverses the stack and additional moisture condenses as a result. Some of that condensation occurs on the interior of the stack liner because it is normally a bit cooler than the flue gas. The condensed liquid runs down the interior of the liner and a significant fraction can become entrained in the flue gas stream, especially where droplets gather on liner surface irregularities such as mortar joints between bricks. Wet stacks are typically designed to have full load flue gas velocities of no more than approximately 60 feet per second to combat this reentrainment.

Conventional Dry Scrubbers (Dry FGD)

As an alternative to wet FGD technology, the control of SO_2 emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a Fabric Filter (FF) for downstream particulate collection. The semi-dry FGD process became popular in the U.S. beginning in the late 1970s as a way to comply with the New Source Performance Standards (NSPS) for electric utility steam generating units for which construction commenced after September 18, 1978 (40 CFR Part 60, Subpart Da). These standards require that all new coal-fired electric utility boilers be equipped with a “continuous system of emission reduction” for SO_2. However, the standards allowed SO_2 removal efficiency as low as 70 percent for facilities burning low-sulfur coal. The semi-dry FGD process could meet this requirement, and was often selected as the SO_2 control technology for many new coal-fired power plants that were built in the 1970s and 1980s and designed to burn low-sulfur western coal. In the late 1980s and through the 1990s, most of the new coal-fired boilers built in the U.S. were for small Independent Power Producer (IPP) projects, and many of these also selected the semi-dry FGD process.

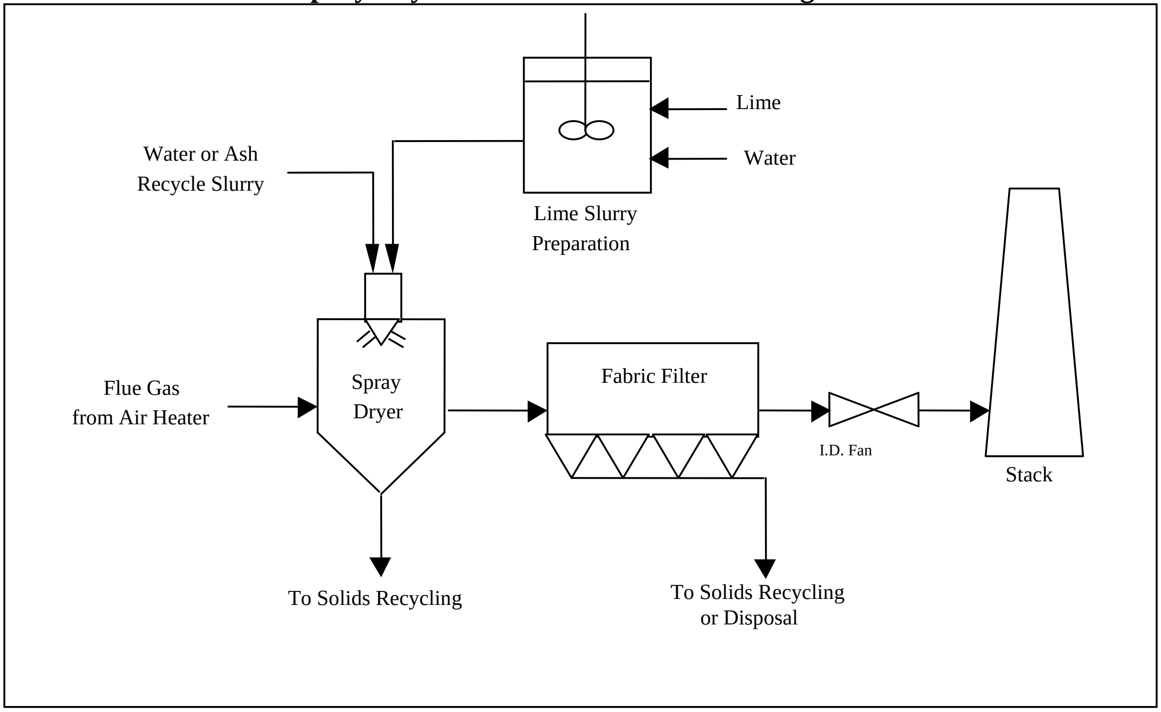

Typical SDA at a 533 MWe power plant in the Czech Republic.

Spray Dryer Absorber

There are several variations of the semi-dry process in use today. This section addresses the spray dryer absorber (SDA) process. Two other variations, the Flash Dryer Absorber (FDA) and Circulating Fluidized Bed (CFB) Scrubber are addressed in following sections. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling.

A schematic diagram of the spray dryer absorber process is provided in the below figure. In the spray dryer absorber process, boiler flue gas is introduced into a Spray Dryer Absorber (SDA) into which hydrated lime (calcium hydroxide, $Ca(OH)_2$) and water are added as dispersed droplets. The $Ca(OH)_2$ reacts with SO_2 that has been absorbed into the water to form primarily calcium sulfite and some calcium sulfate. The heat from the flue gas causes the water to evaporate, cooling the gas and drying the reaction products. Because the total water feed rate is much lower than that of the wet FGD process, the reaction products are dried in the SDA and the flue gas is only partially saturated. The amount of water added to the process is carefully controlled so that the flue gas temperature is maintained well above the saturation, or dewpoint, temperature (typically 30-40 ^{0}F above saturation) to avoid corrosion problems. Cooling the gas to this point significantly increases the SO_2 control efficiency over injection of lime into hot, dry flue gas. The reaction product leaves the SDA as fine dry particles entrained in the flue gas. The flue gas enters the SDA at the top and flows downward, co-current with the introduced lime slurry. This characteristic is the opposite of the wet FGD system which introduces flue gas into the bottom of the absorber, countercurrent to the falling slurry spray.

Spray Dryer Absorber Process Flow Diagram



In the lime spray drying process, quicklime (CaO) is slaked with water to form lime slurry which is then injected into the SDA along with additional water through a rotary atomizer or dual fluid nozzle or similar apparatus. Recycled particulate matter (PM) from the PM control equipment downstream of the SDA is often mixed with the lime slurry before injection into the SDA to provide additional surface area for SO_2 absorption. The flue gas is introduced into the SDA in a manner designed to maximize the contact between the gas and the droplets and to prevent slurry impingement on the walls of the SDA. The turbulent mixing of the flue gas and the slurry droplets promotes rapid absorption of SO_2 into the water of the slurry droplets. The chemical reactions between the absorbed SO_2 and the calcium hydroxide take place within the droplet as the flue gas moves through the SDA. The flue gas is cooled and partially humidified as the water evaporates, leaving a mixture of fly ash and dry powdered reaction product entrained in the flue gas. Some of the solid particles fall to the bottom of the reactor and are collected by a waste handling system. Entrained particles are collected in an electrostatic precipitator (ESP) or fabric filter (FF) downstream of the SDA.

An additional distinguishing characteristic of the SDA is that it must be located upstream of a particulate control device, as opposed to the wet FGD process which is normally the last flue gas treatment process before discharge to the stack. For new plants, this point is not of such great importance. However, when retrofitting FGD equipment to an existing coal-fired plant, which already has particulate control equipment installed, this becomes an important point. If a suitable location exists for the insertion of a new SDA upstream of an existing PM control device, and if the performance of the existing PM control device would not be overly degraded by the additional PM loading, then the retrofit process would consist only of installation of the SDA, reagent preparation and waste handling systems. However, many times one, or both, of these conditions do not exist and the choice to utilize an SDA requires the installation of a new PM control device, such as an ESP or fabric filter. Where this situation exists, the capital cost of the SDA option increases significantly.

Semi-dry processes have some notable advantages compared to wet FGD processes including a dry byproduct which can be handled with conventional ash handling systems. Because the semi-dry system does not have a truly wet zone, corrosion problems in the SDA are eliminated, or significantly reduced, to the point exotic materials of construction are not required. Spray dryer systems utilize less complex equipment resulting in a reduced capital cost and allowing somewhat smaller operations and maintenance staff. Where a fabric filter is utilized as the downstream particulate control device for a semi-dry process, the lime content of the filter cake on the fabric filter reacts with condensed SO_3 in the flue gas stream capturing and neutralizing much of the acid aerosol. Consequently, semi-dry FGD options, paired with a fabric filter for PM control, have very low emissions of acid aerosols.

The primary disadvantages of the lime spray dryer process make it less likely to be applied to large power plant boilers, especially those firing high-sulfur coal. The lime spray dryer requires the use of lime, which is typically much more expensive than limestone. While lime contains approximately 1.8 times more calcium than limestone on a mass basis, lime can cost up to five times more than limestone on a mass basis. Therefore, reagent costs for a lime based process are typically higher than a limestone-based process for a given application.

Wastes from semi-dry processes have very limited possibility for reuse due to fly ash contamination. Also, where fly ash might be sold for other uses, contamination with the semi-dry FGD reaction products typically eliminates commercial options for reuse. Where fly ash sales are to be maintained, a second PM control device would be required for the semi-dry FGD system exhaust stream, increasing both capital and O&M costs.

Spray dryer absorbers have much more stringent size limitations than wet FGD scrubbers. Typically units larger than 250 to 300 MW will require at least two SDA vessels, thus driving up capital costs and system complexity for larger units, while wet FGD systems can handle up to 1000 MW in a single absorber module. SDAs do not have the same turndown capabilities as wet FGD absorbers, further limiting applicability for load following units. Finally, lime spray dryer systems do not have the same level of experience with high SO_2 removal requirements in high sulfur applications that wet FGD systems have.

Flash Dryer Absorber

The Flash Dryer Absorber (FDA) is a further development of the lime spray dryer process. The approach is similar in that the flue gas is only partially saturated during the process and thus corrosion problems are either reduced or eliminated. Like the SDA, waste solids from the particulate control process can be added to the reagent feed stream to the reactor. Similar to the SDA, the FDA mixes lime, water and recycled PM for enhanced surface area. Recycled PM, along with absorption products and unreacted lime, are collected downstream of the FDA and a sizable fraction recycled to the FDA. Unlike the SDA, the FDA recycles a very high fraction of the captured PM. Because of this, the ratio of solids to liquid in the reagent stream injected into the FDA reactor is much higher than the SDA. The ratio is so much higher that the wetted recycled solids appear to be a relatively dry free flowing stream after wetting in the mixing stage.[14] Because the reagent stream starts off much higher in solids, the liquid film thickness on the wetted solids is much thinner and the drying time for the injected solids is much shorter than a typical SDA. This allows the FDA to function with a significantly smaller reactor compared to the typical SDA absorber vessel. Like the SDA, the water injection rate of the FDA is controlled to lower the flue gas temperature to optimize the SO_2 control efficiency while avoiding saturation and the accompanying corrosion problems. Unlike the SDA, the flue gas flows vertically upward in the FDA. The figure below is a schematic presentation of the FDA design.

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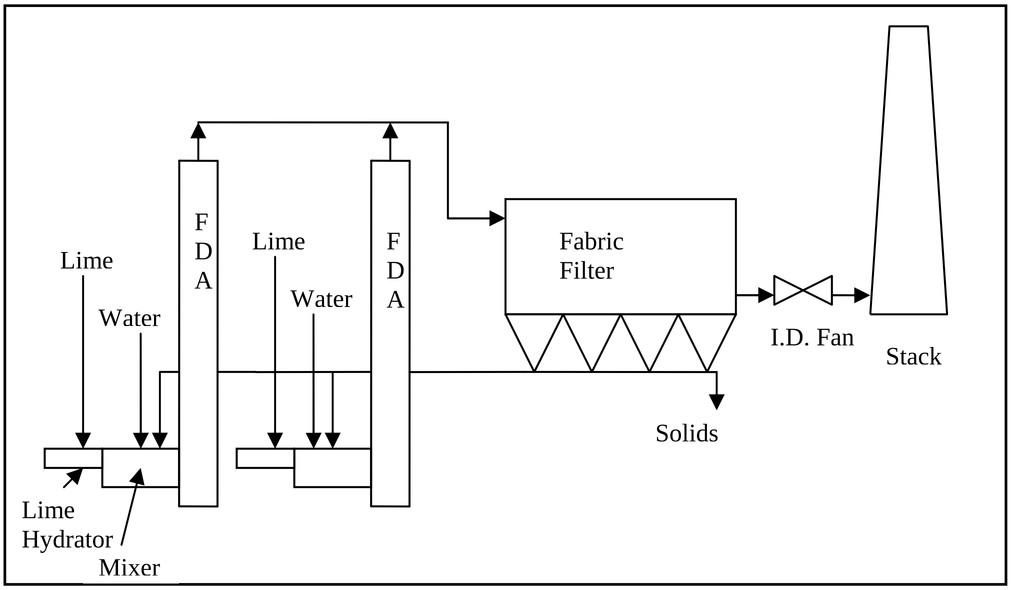
[14] "Use of a Circulating Fluid Bed for Flue Gas Desulfurization"' Toher, John, G. Lurgi-Lentjes N. America.

Flash Dryer Absorber FGD Process Flow Diagram



The FDA utilizes quicklime (CaO) instead of hydrated lime as a reagent. The reasoning given for this by the designers is that when purchasing lime, although the price per ton is similar, the quicklime has 32% more calcium (SO_2 neutralization component) per ton than hydrated lime. Also, because quicklime is denser (900-1,200 kg/m^3 for quicklime vs. 450-640 kg/m^3 for hydrated lime), both transport and onsite storage capacity requirements can be smaller. However, direct injection of quicklime has resulted in less efficient reagent utilization compared to hydrated lime use. This is theorized to be due to hot spots created in the reaction zone by the hydration of the quicklime. The heat of hydration of quicklime is approximately 1.1 mmBtu/ton, so there is considerable heat evolved during the hydration step. To avoid adding this heat to the flue gas or creating hot spots that could reduce lime utilization, the FDA design incorporates a separate lime hydration stage where more than the stoichiometrically required amount of water is added to the quicklime in stages. The super stoichiometric water is heated during the slaking process and evaporates, leaving dry hydrated lime. The hydrated lime, recycled solids and water are then combined in a mixing vessel just prior to injection into the reactor.

Like the SDA, the FDA must be followed by a PM control device to capture the dry solids in the FDA exhaust. The great majority of these solids are recycled back to the FDA. The non recycled fraction is a mixture of calcium sulfite/sulfate solids, unreacted lime and fly ash for which limited possibilities for reuse exist. Also, in those instances where fly ash sales produce an income for the power plant, addition of the FDA solids to the fly ash will likely render the waste solids stream without value. Where the plant receives revenue from fly ash sales, the lost revenue would be an additional cost of FDA implementation.

The FDA is a relatively recent modification of the semi-dry FGD concept and as such, has not established a significant field record at this time. In their paper on FDA technology in 2002[15] Alstom cited a 280 MW plant in China with an 85% SO_2 removal efficiency. This plant had an FDA installed upstream of an ESP. Dry and semi-dry scrubbers installed upstream of a fabric filter have been consistently shown to achieve approximately 5-10% greater acid gas removal efficiency due to absorption and neutralization taking place in the filter cake of the fabric filter. Typically ESPs downstream of an FDA or other dry or semi-dry SO_2 scrubbing system are attributed no more than 5% SO_2 removal efficiency.

Advantages of the FDA over wet FGD systems are similar to those for the semi-dry process described previously, including ease of byproduct handling, much less aggressive corrosion conditions allowing the use of more common, less expensive materials of construction, less complex equipment, and potentially enhanced SO_3 control when combined with a fabric filter. FDA advantages also include a significantly smaller reactor/absorber which translates into a lower area requirement than either wet or semi-dry FGD systems, though manufacturers often provide multiple FDA's, even on smaller units.

Disadvantages of the FDA, when compared to the wet FGD system are similar to those described for the semi-dry process, including reactor size limitations, lower turndown ratio, more expensive reagent, and lack of byproduct market value.

Circulating Fluidized Bed Absorber (CFB)

In the circulating fluidized bed dry scrubbing process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle, and mixed with water, hydrated lime, recycled flyash and FGD reaction products. High velocity movement of the gas through the reactor suspends the solids creating a fluidized bed. A CFB absorber vessel would be a smaller diameter than the SDA discussed previously in this report. A schematic representation of the CFB process is shown in the below figure. The smaller diameter absorber helps maintain higher flue gas velocities required to maintain the fluidized bed. Water injected into the venturi throat cools the flue gas and wets the recycled solids similar to the process described previously for the FDA. Dry, powdered, hydrated lime is injected into the bed near the bottom of the absorber vessel, above the venturi, and dissolves in the thin water film on the recycled solids. SO_2 from the flue gas is also absorbed into the evaporating water film and reacts with the lime to produce both calcium sulfite and sulfate reaction products. Flue gas temperatures are typically

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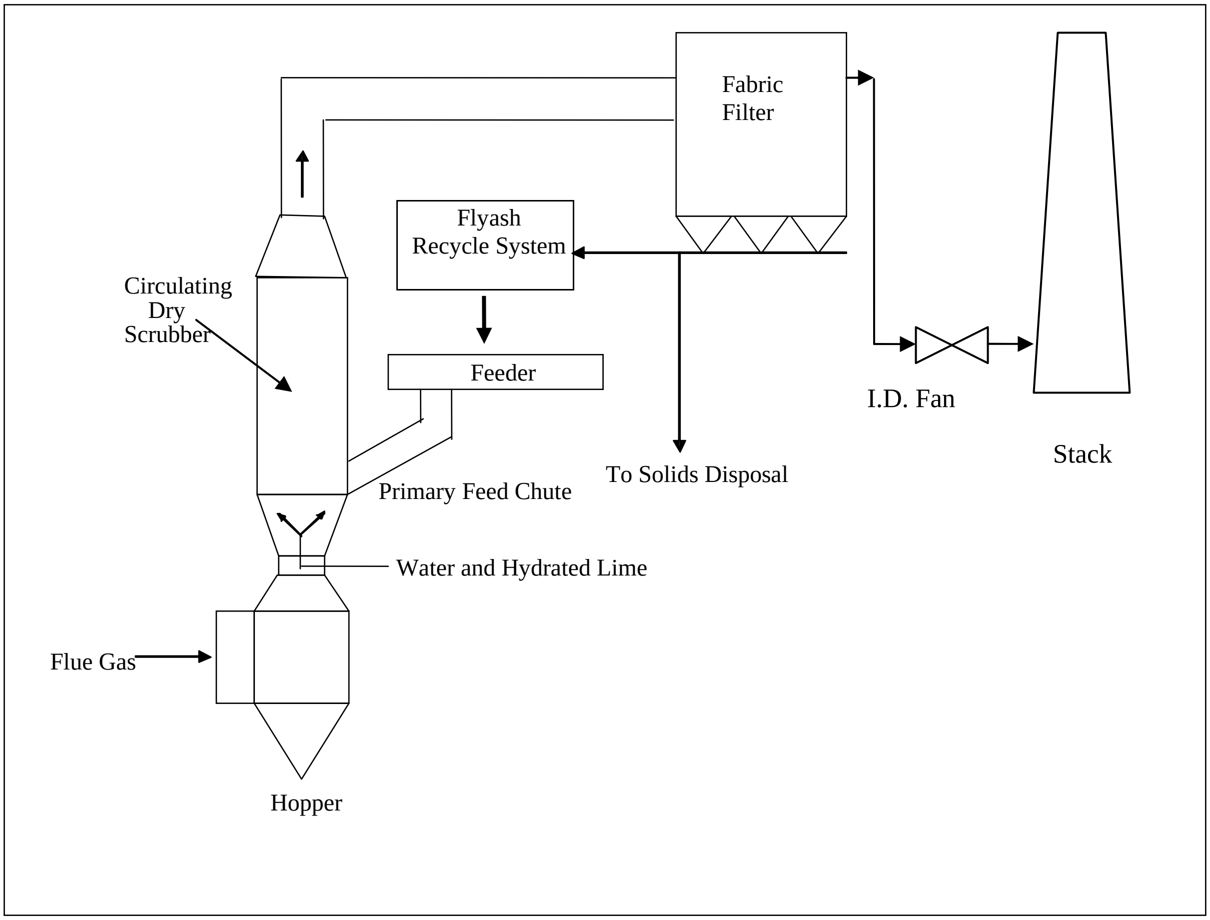
[15] "Alstom Power's Flash Dryer Absorber For Flue Gas Desulfurization", Ahman, Barranger and Marin, Proceedings of IJPGC '02, June 24-26, 2002.

reduced from 300 ^{0}F to approximately 160 ^{0}F to optimize SO_2 removal efficiency. The evaporation of the water cools and partially humidifies the flue gas and maintains the bed in a slightly moist, powdery condition. The continuous motion of the bed helps prevent solids deposition inside the absorber and promotes regeneration of the particle surfaces, exposing additional lime to react with absorbed SO_2. Particles that are entrained in the flue gas leaving the top of the reactor are collected in an ESP or fabric filter downstream of the CFB absorber. A large portion of the collected particles is recycled to the reactor, sustaining the bed and improving lime utilization. CFB absorbers have been installed with both fabric filters and ESPs for particulate control.

Circulating Fluidized Bed FGD System



The CFB absorber dry scrubbing process utilizes a bed of fluidized particles to provide an extended surface area for wetting, evaporation and SO_2 absorption. The extended surface decreases the time required for SO_2 absorption. Even though the gas velocity is higher than a wet FGD absorber or an SDA, the CFB absorber is not taller than either of these vessels.

The CFB has many of the same advantages of the SDA and FDA such as a dry byproduct, simplified waste handling systems and conventional materials of construction. CFBs also have less rotating equipment than wet FGD or SDA systems, thus simplifying maintenance requirements somewhat. Like the SDA and FDA, the CFB application with a fabric filter for particulate collection will also achieve very good acid aerosol control. Unlike the SDA the CFB does not require dual fluid nozzles or atomizers in the absorber. This feature simplifies the absorber maintenance of a CFB over that of the SDA. Also, because lime and water are injected separately into the CFB, increased reagent requirements can be met without increasing saturation of the flue gas.

Disadvantages of the CFB process include higher reagent cost and lower utilization than SDAs in similar applications and more limited turndown capability. In a recent study[16] the National Lime Association determined that compared to CFBs in similar applications, the SDA achieved slightly lower SO_2 removal with slightly better reagent utilization. Because CFBs must maintain gas velocities within a fluidizing range, a flue gas recycle duct from the absorber exhaust to the inlet is sometimes included to allow for partial recycle of flue gas to maintain bed velocity and improve the turndown ratio. Similar to the SDA and FDA processes, CFBs are size limited and multiple absorbers are required for applications larger than 250-300 MW.

An additional disadvantage of the CFB is pressure drop. Because the CFB must maintain the fluidized bed condition, the pressure drop across the absorber is typically 8-10 in. w.g. compared to an SDA at 6-8 in. w.g. and a wet FGD system at approximately 6 in. w.g.

Powerspan Electro-Catalytic Oxidation (ECO™) System

The Powerspan Electro-Catalytic Oxidation (ECO™) system is a multipollutant control technology designed to control emissions of NO_x, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO™ process has two main process vessels, a barrier discharge reactor and a multi-level wet scrubber.

Powerspan is also making the technology available for systems that do not require NO_x removal by removing the barrier discharge reactor. Powerspan claims a routine SO_2 removal efficiency of 98% with inlet concentrations up to approximately 2,000 ppm.

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[16] "Economics of Lime and Limestone for Control of Sulfur Dioxide"; DePriest, William & Gaikwas, Rajendra P; National Lime Association (www.lime.org/NLADryFGD.PDF); September, 2002.

The system utilizes aqueous ammonia as a reagent in two scrubber loops, with varying pH to control collection efficiency in the lower and upper loops. The ammonia reacts with the collected SO_2 in aqueous solution to produce ammonium sulfate as a byproduct.

50-MW ECO Demo at FirstEnergy's R.E. Burger Plant

The ammonium sulfate is then salable as fertilizer, thus turning byproduct disposal into a profitable venture for system operators. Captured mercury and other oxidized metals are removed from the scrubber bleed stream with activated carbon and disposed of as a hazardous waste. Ash and insoluble metals are filtered from the scrubber bleed stream before fertilizer production and disposed of with other particulate wastes from upstream particulate control equipment. The ammonium sulfate can be sold as an aqueous product or crystallized, granulated and sold.

Appendix C

CUECost Model Input Summary

APC Technology Choices

Description	Units	Case 1	Case 2	Case 3	Case 4
FGD Process	Integer	1	2	1	1
(1 = LSFO, 2 = LSD)					
Particulate Control	Integer	2	1	2	2
(1 = Fabric Filter, 2 = ESP)					
NOx Control	Integer	2	2	2	2
(1 = SCR, 2 = SNCR, 3 = LNBs, 4 = NGR)					

INPUTS

Description	Units	Case 1	Case 2	Case 3	Case 4
General Plant Technical Inputs					
Location - State	Abbrev.	ND	ND	ND	ND
MW Equivalent of Flue Gas to Control System	MW	257	257	477	477
Net Plant Heat Rate	Btu/kWhr	11,498	11,498	10,813	10,813
Plant Capacity Factor	%	85%	85%	85%	85%
Total Air Downstream of Economizer	%	120%	120%	120%	120%
Air Heater Leakage	%	0%	0%	0%	0%
Air Heater Outlet Gas Temperature	°F	300	300	300	300
Inlet Air Temperature	°F	80	80	80	80
Ambient Absolute Pressure	In. of Hg	27.86	27.86	27.86	27.86
Pressure After Air Heater	In. of H2O	-12	-12	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013	0.013	0.013
Ash Split:					
Fly Ash	%	49%	49%	49%	49%
Bottom Ash	%	51%	51%	51%	51%
Seismic Zone	Integer	0	0	0	0
Retrofit Factor	Integer	1.3	1.3	1.3	1.3
(1.0 = new, 1.3 = medium, 1.6 = difficult)					
Select Coal	Integer	7	7	7	7
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No	No	No
Economic Inputs					
Cost Basis -Year Dollars	Year	2007	2007	2007	2007
Sevice Life (levelization period)	Years	20	20	20	20
Inflation Rate	%	3%	3%	3%	3%
After Tax Discount Rate (current $'s)	%	6%	6%	6%	6%
AFDC Rate (current $'s)	%	4%	4%	4%	4%
First-year Carrying Charge (current $'s)	%	9%	9%	9%	9%
Levelized Carrying Charge (current $'s)	%	9%	9%	9%	9%
First-year Carrying Charge (constant $'s)	%	9%	9%	9%	9%
Levelized Carrying Charge (constant $'s)	%	9%	9%	9%	9%
Sales Tax	%	0%	0%	0%	0%
Escalation Rates:					
Consumables (O&M)	%	3%	3%	3%	3%
Capital Costs:					
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer	468.2	468.2	468.2	468.2
If "No" input escalation rate.	%	3%	3%	3%	3%
Construction Labor Rate (Not Used N Calc)	$/hr	$35	$35	$35	$35
Prime Contractor's Markup	%	3%	3%	3%	3%
Operating Labor Rate	$/hr	$40	$40	$40	$40
Power Cost	Mills/kWh	35	35	35	35
Steam Cost	$/1000 lbs	3.5	3.5	3.5	3.5

Limestone Forced Oxidation (LSFO) Inputs					
Any By-Pass around the scrubber		2	2	2	2
(1 = yes, 2 = no)					
Percent of By-Passed Gas	%	0.0%	0.0%	0.0%	0.0%
SO2 Removal Required	%	95.0%	90.0%	95.0%	90.0%
L/G Ratio	gal / 1000 acf	50	50	50	50
Design Scrubber with Dibasic Acid Addition?	Integer	2	2	2	2
(1 = yes, 2 = no)					
Adiabatic Saturation Temperature	°F	135	135	135	135
Reagent Feed Ratio	Factor	1.03	1.03	1.03	1.03
(Mole CaCO3 / Mole SO2 removed)					
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	1	1	1	1
(1 = stacking, 2 = lanfill, 3 = wallboard)					
Number of Absorbers	Integer	1	1	2	2
(Max. Capacity = 700 MW per absorber)					
Absorber Material	Integer	1	1	1	1
(1 = alloy, 2 = RLCS)					
Absorber Pressure Drop	in. H2O	6	6	6	6
Reheat Required ?	Integer	2	2	2	2
(1 = yes, 2 = no)					
Amount of Reheat	°F	0	0	0	0
Reagent Bulk Storage	Days	30	30	30	30
Reagent Cost (delivered)	$/ton	$114	$114	$114	$114
Landfill Disposal Cost	$/ton	$30	$30	$30	$30
Stacking Disposal Cost	$/ton	$6	$6	$6	$6
Credit for Gypsum Byproduct	$/ton	$0	$0	$0	$0
Maintenance Factors by Area (% of Installed Cost)					
Reagent Feed	%	3%	3%	3%	3%
SO2 Removal	%	3%	3%	3%	3%
Flue Gas Handling	%	3%	3%	3%	3%
Waste / Byproduct	%	3%	3%	3%	3%
Support Equipment	%	3%	3%	3%	3%
Contingency by Area (% of Installed Cost)					
Reagent Feed	%	20%	20%	20%	20%
SO2 Removal	%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%

Lime Spray Dryer (LSD) Inputs					
SO2 Removal Required	%	90%	90%	90%	90%
Adiabatic Saturation Temperature	°F	135	135	135	135
Flue Gas Approach to Saturation	°F	25	25	25	25
Spray Dryer Outlet Temperature	°F	160	160	160	160
Reagent Feed Ratio	Factor	1.30	1.30	1.30	1.30
(Mole CaO / Mole Inlet SO2)					
Recycle Rate	Factor	7.5	7.5	7.5	7.5
(lb recycle / lb lime feed)					
Recycle Slurry Solids Concentration	Wt. %	30%	30%	30%	30%
Number of Absorbers	Integer	1	1	1	1
(Max. Capacity = 300 MW per spray dryer)					
Absorber Material	Integer	3	3	3	3
(1 = alloy, 2 = RLCS)					
Spray Dryer Pressure Drop	in. H2O	5	5	5	5
Reagent Bulk Storage	Days	30	30	30	30
Reagent Cost (delivered)	$/ton	$114	$114	$114	$114
Dry Waste Disposal Cost	$/ton	$7	$7	$7	$7
Maintenance Factors by Area (% of Installed Cost)					
Reagent Feed	%	2%	2%	2%	2%
SO2 Removal	%	2%	2%	2%	2%
Flue Gas Handling	%	2%	2%	2%	2%
Waste / Byproduct	%	2%	2%	2%	2%
Support Equipment	%	2%	2%	2%	2%
Contingency by Area (% of Installed Cost)					
Reagent Feed	%	20%	20%	20%	20%
SO2 Removal	%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Particulate Control Inputs					
Outlet Particulate Emission Limit	lbs/MMBtu	0.03	0.015	0.03	0.03
Fabric Filter:					
Pressure Drop	in. H2O	8	8	8	8
Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	2	2	2	2
Gas-to-Cloth Ratio	ACFM/ft^2	3.5	3.5	3.5	3.5
Bag Material (RGFF fiberglass only)	Integer	3	3	3	3
(1 = Fiberglass, 2 = Nomex, 3 = Ryton)					
Bag Diameter	inches	6	6	6	6
Bag Length	feet	26	26	26	26
Bag Reach		3	3	3	3
Compartments out of Service	%	10%	10%	10%	10%
Bag Life	Years	3	3	3	3
Maintenance (% of installed cost)	%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%
ESP:					
Strength of the electric field in the ESP = E	kV/cm	10.0	10.0	10.0	10.0
Plate Spacing	in.	16	16	16	16
Plate Height	ft.	36	36	36	36
Pressure Drop	in. H2O	2	2	2	2
Maintenance (% of installed cost)	%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Screening Analysis
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	6.603	8.836	2.234	2000	74	50	104	2.8	70.96	29.01	0.02	0.02
98th %tile Delta-DV	1.454	3.560	2.106	2000	265	51	105	2.2	85.72	14.18	0.07	0.03
90th %tile Delta-DV	0.533	2.639	2.106	2000	239	46	46	2.2	85.41	14.51	0.05	0.03
2001												
Largest Delta-DV	3.272	5.505	2.234	2001	64	46	46	2.8	73.39	26.57	0.03	0.01
98th %tile Delta-DV	2.082	4.337	2.255	2001	13	54	108	2.9	37.90	61.87	0.18	0.05
90th %tile Delta-DV	0.407	2.513	2.106	2001	234	51	105	2.2	97.52	2.34	0.11	0.03
2002												
Largest Delta-DV	7.426	9.659	2.234	2002	73	48	102	2.8	61.17	38.76	0.05	0.02
98th %tile Delta-DV	3.770	6.025	2.255	2002	29	56	110	2.9	60.91	39.03	0.04	0.02
90th %tile Delta-DV	0.706	2.876	2.170	2002	166	6	6	2.5	43.87	55.91	0.16	0.06
TRNP NORTH UNIT												
2000												
Largest Delta-DV	5.111	7.345	2.234	2000	36	85	114	2.8	52.81	47.07	0.08	0.04
98th %tile Delta-DV	1.998	4.232	2.234	2000	74	67	56	2.8	68.31	31.66	0.01	0.01
90th %tile Delta-DV	0.454	2.687	2.234	2000	70	83	112	2.8	56.42	43.53	0.03	0.02
2001												
Largest Delta-DV	5.554	7.809	2.255	2001	12	83	112	2.9	88.34	11.58	0.06	0.02
98th %tile Delta-DV	2.252	4.527	2.276	2001	328	82	71	3	71.04	28.93	0.02	0.01
90th %tile Delta-DV	0.659	2.765	2.106	2001	230	82	71	2.2	96.25	3.59	0.11	0.05
2002												
Largest Delta-DV	7.165	9.399	2.234	2002	73	58	47	2.8	57.32	42.60	0.07	0.02
98th %tile Delta-DV	3.297	5.531	2.234	2002	66	63	52	2.8	40.75	59.07	0.13	0.05
90th %tile Delta-DV	0.772	3.006	2.234	2002	91	82	71	2.8	61.98	37.97	0.03	0.02
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	5.865	8.098	2.234	2000	74	90	72	2.8	73.32	26.64	0.02	0.02
98th %tile Delta-DV	1.636	3.870	2.234	2000	66	90	72	2.8	66.64	33.30	0.04	0.02
90th %tile Delta-DV	0.367	2.494	2.127	2000	97	90	72	2.3	52.10	47.82	0.05	0.03
2001												
Largest Delta-DV	3.124	5.357	2.234	2001	64	90	72	2.8	75.07	24.89	0.03	0.01
98th %tile Delta-DV	1.942	4.070	2.127	2001	112	90	72	2.3	53.12	46.72	0.13	0.03
90th %tile Delta-DV	0.317	2.466	2.149	2001	196	90	72	2.4	94.38	5.57	0.03	0.02
2002												
Largest Delta-DV	8.239	10.472	2.234	2002	73	90	72	2.8	59.54	40.39	0.06	0.02
98th %tile Delta-DV	3.354	5.609	2.255	2002	29	90	72	2.9	61.21	38.73	0.04	0.02
90th %tile Delta-DV	0.438	2.544	2.106	2002	219	90	72	2.2	94.78	5.14	0.05	0.03
LOSTWOOD NWA												
2000												
Largest Delta-DV	6.551	8.826	2.275	2000	47	97	79	2.9	94.45	5.49	0.04	0.02
98th %tile Delta-DV	1.864	4.139	2.275	2000	44	99	81	2.9	62.58	37.38	0.02	0.02
90th %tile Delta-DV	0.762	2.929	2.167	2000	215	91	73	2.4	74.41	25.36	0.15	0.08
2001												
Largest Delta-DV	9.694	12.033	2.340	2001	327	99	81	3.2	64.35	35.60	0.03	0.02
98th %tile Delta-DV	2.763	5.103	2.340	2001	355	93	75	3.2	38.92	60.87	0.15	0.06
90th %tile Delta-DV	0.867	3.143	2.275	2001	55	99	81	2.9	30.40	69.45	0.10	0.05
2002												
Largest Delta-DV	4.537	6.813	2.275	2002	51	91	73	2.9	65.69	34.26	0.03	0.01
98th %tile Delta-DV	2.294	4.634	2.340	2002	363	93	75	3.2	64.79	35.18	0.02	0.01
90th %tile Delta-DV	0.620	2.852	2.232	2002	195	99	81	2.7	65.40	34.36	0.18	0.06

Duration Events

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 15
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 48
Number of days with Delta-Deciview > 1.00: 26
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 44
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 46
Number of days with Delta-Deciview > 1.00: 29
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 51
Number of days with Delta-Deciview > 1.00: 26
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 58
Number of days with Delta-Deciview > 1.00: 30
Max number of consecutive days with Delta-Deciview > 0.50: 5
2002
Number of days with Delta-Deciview > 0.50: 42
Number of days with Delta-Deciview > 1.00: 24
Max number of consecutive days with Delta-Deciview > 0.50: 5

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Screening Analysis
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	--------	--------	-----------	------	----	-------	-------	--------	--------	--------	---------	------
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	6.043	8.277	2.234	2000	74	51	105	2.8	54.97	44.90	0.06	0.07
98th %tile Delta-DV	1.606	3.776	2.170	2000	164	45	45	2.5	94.72	4.34	0.70	0.24
90th %tile Delta-DV	0.560	2.709	2.149	2000	191	47	101	2.4	49.13	49.90	0.75	0.21
2001												
Largest Delta-DV	3.596	5.830	2.234	2001	64	46	46	2.8	58.23	41.60	0.12	0.05
98th %tile Delta-DV	2.057	4.163	2.106	2001	261	48	102	2.2	76.32	23.35	0.22	0.11
90th %tile Delta-DV	0.405	2.511	2.106	2001	254	46	46	2.2	89.47	9.62	0.61	0.30
2002												
Largest Delta-DV	8.415	10.649	2.234	2002	73	48	102	2.8	44.55	55.18	0.19	0.07
98th %tile Delta-DV	4.503	6.757	2.255	2002	29	3	3	2.9	43.76	56.03	0.14	0.06
90th %tile Delta-DV	0.775	2.881	2.106	2002	234	53	107	2.2	19.22	79.50	1.01	0.28
TRNP NORTH UNIT												
2000												
Largest Delta-DV	4.487	6.721	2.234	2000	36	82	71	2.8	37.07	62.52	0.28	0.13
98th %tile Delta-DV	2.167	4.400	2.234	2000	74	67	56	2.8	53.63	46.26	0.05	0.06
90th %tile Delta-DV	0.432	2.581	2.149	2000	191	85	114	2.4	93.35	5.87	0.58	0.20
2001												
Largest Delta-DV	4.907	7.141	2.234	2001	64	82	71	2.8	56.51	43.32	0.12	0.05
98th %tile Delta-DV	2.276	4.382	2.106	2001	258	86	115	2.2	86.80	12.79	0.29	0.12
90th %tile Delta-DV	0.596	2.766	2.170	2001	178	84	113	2.5	75.83	23.46	0.49	0.22
2002												
Largest Delta-DV	8.009	10.242	2.234	2002	73	63	52	2.8	40.72	58.97	0.23	0.08
98th %tile Delta-DV	3.797	6.030	2.234	2002	75	82	71	2.8	50.17	49.54	0.18	0.10
90th %tile Delta-DV	0.829	2.978	2.149	2002	184	82	71	2.4	96.03	3.10	0.64	0.24
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	5.380	7.613	2.234	2000	74	90	72	2.8	55.83	44.06	0.05	0.07
98th %tile Delta-DV	1.481	3.715	2.234	2000	69	90	72	2.8	37.05	62.65	0.21	0.10
90th %tile Delta-DV	0.349	2.477	2.127	2000	139	90	72	2.3	73.80	25.84	0.22	0.14
2001												
Largest Delta-DV	3.397	5.631	2.234	2001	64	90	72	2.8	60.46	39.40	0.10	0.04
98th %tile Delta-DV	1.809	4.042	2.234	2001	84	90	72	2.8	39.09	60.62	0.21	0.09
90th %tile Delta-DV	0.290	2.438	2.149	2001	196	90	72	2.4	88.86	10.92	0.14	0.07
2002												
Largest Delta-DV	9.140	11.373	2.234	2002	73	90	72	2.8	43.62	56.10	0.21	0.07
98th %tile Delta-DV	4.092	6.347	2.255	2002	29	90	72	2.9	43.83	55.96	0.14	0.06
90th %tile Delta-DV	0.440	2.715	2.276	2002	352	90	72	3	49.83	50.05	0.06	0.05
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.860	7.136	2.275	2000	47	97	79	2.9	71.21	28.55	0.16	0.08
98th %tile Delta-DV	2.279	4.554	2.275	2000	48	99	81	2.9	50.94	48.93	0.09	0.05
90th %tile Delta-DV	0.811	3.087	2.275	2000	45	91	73	2.9	45.29	54.60	0.06	0.05
2001												
Largest Delta-DV	8.556	10.896	2.340	2001	327	99	81	3.2	47.51	52.32	0.11	0.06
98th %tile Delta-DV	2.709	4.855	2.145	2001	261	97	79	2.3	75.73	23.66	0.46	0.15
90th %tile Delta-DV	0.825	3.058	2.232	2001	201	97	79	2.7	67.28	32.23	0.38	0.11
2002												
Largest Delta-DV	4.764	7.039	2.275	2002	74	97	79	2.9	51.96	47.89	0.09	0.05
98th %tile Delta-DV	2.365	4.705	2.340	2002	351	93	75	3.2	63.42	36.06	0.36	0.16
90th %tile Delta-DV	0.690	2.966	2.275	2002	52	97	79	2.9	52.92	46.96	0.08	0.05

Duration Events

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 41
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 51
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 43
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 47
Number of days with Delta-Deciview > 1.00: 29
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 52
Number of days with Delta-Deciview > 1.00: 30
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 51
Number of days with Delta-Deciview > 1.00: 31
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 48
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 5

Minnkota Power
MPC COOPERATIVE, INC.
Your Touchstone Energy® Partner

1822 Mill Road • P.O. Box 13200 • Grand Forks, ND 58208-3200 • Phone (701) 795-4000

November 29, 2007

DEC 2007
Received
Air Quality

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Subject: Milton R. Young Station
BART Conference –11/21/2007

Dear Mr. O'Clair:

This letter is to follow-up on our discussions during the above subject meeting. As I indicated during the meeting, the methodologies the Department is pursuing with respect to the various emission limitations has merit. However, we do take exception to some of the actual limitations proposed. These are addressed below.

Unit 1

The Department proposed a SO_2 limitation of 95% removal (30 d.r.a.) or 0.12 lb/10^6 Btu (30 d.r.a.). The Department may wish to remove the lb/10^6 emission rate provision, as Minnkota is subject to a Consent Decree which stipulates that the removal shall be 95%.

The Department has proposed a NO_x limitation of 0.36 lb/10^6 Btu (30 d.r.a.), except during startups. Minnkota requests the exception be extended to startups, shutdowns, and malfunctions. Unless all cyclones are in operation over-fired air and selective non-catalytic reduction technologies are ineffective or of limited effectiveness. During startups and shutdowns, individual cyclones are put in service or taken out of service as the Unit generation is increased or decreased. A malfunction can also cause cyclones to be taken out of operation.

The Department proposed a NO_x startup limitation of 1070.7 lb/hr (24-hr rolling avg.) Utilizing a NO_x lb/hr emission rate for startups that is derived from data obtained when the Unit is at full load is not appropriate; The NO_x controls are effective at full load conditions whereas the NO_x controls are ineffective or of limited effectiveness during startup. Based upon the information presented previously in the NO_x BACT analysis, Minnkota requests a NO_x startup/shutdown/malfunction limitation of 2070.2 lb/hr (24-hr rolling average).

Unit 2

The Department proposed a SO_2 limitation of 95% removal (30 d.r.a.) or 0.12 $lb/10^6$ Btu (30 d.r.a.). The limitation of 0.12 $lb/10^6$ Btu (30 d.r.a.) is not acceptable to Minnkota. During periods of time when the sulfur content of the coal being burned is lower than normal, wet FGD systems can not remove as high a percentage of the SO_2 as would normally be removed, due to mass transfer limitations. Minnkota requests the SO_2 emission limitation be increased to 0.15 $lb/10^6$ Btu (30 d.r.a.). As Minnkota has a SO_2 limitation of 90% removal requirement under a Consent Decree, the Department may wish to add this restriction for clarity. Therefore, the revised limitation would be 95% SO_2 removal (30 d.r.a.) or 0.15 $lb/10^6$ Btu (30 d.r.a.), whichever is least restrictive, but not less than 90% removal (30 d.r.a.)

The Department has proposed a NO_x limitation of 0.35 $lb/10^6$ Btu (30 d.r.a.), except during startups. Minnkota requests the exception be extended to startups, shutdowns, and malfunctions. Unless all cyclones are in operation over-fired air and selective non-catalytic reduction technologies are ineffective or of limited effectiveness. During startups and shutdowns, individual cyclones are put in service or taken out of service as the Unit generation is increased or decreased. A malfunction can also cause cyclones to be taken out of operation.

The Department proposed a NO_x startup limitation of 2011.6 lb/hr (24-hr rolling avg.) Utilizing a NO_x lb/hr emission rate that is derived from data obtained when the Unit is at full load is not appropriate; The NO_x controls are effective at full load conditions whereas the NO_x controls are ineffective or of limited effectiveness during startup. Based upon the information presented previously in the NO_x BACT analysis, Minnkota requests a NO_x startup/shutdown/malfunction limitation of 3995.6 lb/hr (24-hr rolling average).

As discussed, a more exact definition of startup is needed than initially proposed by the Department. Minnkota proposes the following:

Startup is that period of time from initial fuel combustion to the point in time when:

- The measured heat input to the boiler on a 6-hour rolling average basis is greater than or equal to (2500 million Btu/hr for Unit 1, or 4800 million Btu/hr for Unit 2); or
- The amount of time reported for the longest individual startup period during actual operation between January 1, 2001 and December 31, 2005 (61 hrs. for Unit 1, or 115 hrs. for Unit 2) elapses, whichever occurs first; or
- Fuel firing is discontinued prior to satisfying either previous criteria.

The above definition was included in our previously submitted BACT analysis.

A definition of "shutdown" may also be appropriate. Minnkota proposes the following definition (if a definition is required):

> Shutdown is that period of time beginning when the Unit's generation is reduced in a continuous manner with the intention of discontinuing fuel firing, until fuel firing is discontinued.

Because the anticipated NO_x emissions are based upon computer modeling of the boiler and the chemistry associated with the particular NO_x control technology, the NO_x emissions may be more or less than indicated in the BACT and BART analyses. Therefore, Minnkota reserves the right to request changes to an operating permit which may be issued, or the State Implementation Plan, which incorporates NO_x limitations.

Minnkota thanks the Department for its attention to the issues raised during our recent meeting and those in this letter. Should you have any questions concerning the above, please contact me at 701-795-4221 or at jgraves@minnkota.com.

Sincerely,

John T. Graves

John T. Graves, P.E.
Environmental Manager

C: David Sogard
Luther Kvernen
Craig Bleth
Kevin Thomas
Stu Libby
Tom Anseth
Young Station File

Minnkota Power
MPC COOPERATIVE, INC.
Your Touchstone Energy® Partner

1822 Mill Road • P.O. Box 13200 • Grand Forks, ND 58208-3200 • Phone (701) 795-4000

August 16, 2007

AUG 2007
Received
Air Quality

Terry O'Clair, Director
Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Subject: SCR Pilot Testing

Dear Mr. O'Clair:

Enclosed, please find a report entitled "APPROPRIATENESS OF CONDUCTING PILOT TESTING OF SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY AT MILTON R. YOUNG STATION UNITS 1 AND 2, FOR USE IN A NO_X BACT ANALYSIS". This report is submitted response to the Department's request that Minnkota consider a pilot test of SCR catalysts, at Milton R. Young Station, to gather additional data for use in Minnkota's previously submitted NOx BACT analysis. This report addresses three aspects that must be considered when making a decision to pursue SCR catalyst pilot test. The aspects are: 1) the legal basis for the testing; 2) is there a reasonable expectation that the results would be different than the results of previous testing; 3) could the testing be accomplished in the required amount of time.

Based upon the information presented in the enclosed report, Minnkota has decided not to pursue SCR pilot testing at Milton R. Young Station, as elaborated in the document.

Should you have any questions concerning the above, or the enclosed document, please contact me by telephone at 701-795-4221 or by email at jgraves@minnkota.com.

Yours truly,

MINNKOTA POWER COOPERATIVE, INC.

John T. Graves

John T. Graves, P.E.
Environmental Manager

C: David Sogard
Luther Kvernen
Craig Bleth
Kevin Thomas
Stu Libby
Tom Anseth
Young Station File

APPROPRIATENESS OF CONDUCTING PILOT TESTING OF SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY AT MILTON R. YOUNG STATION UNITS 1 AND 2, FOR USE IN A NO_X BACT ANALYSIS

Prepared For
MINNKOTA POWER COOPERATIVE, INC

By

Dennis L. Arfmann
Hogan & Hartson

Steven A. Benson
Energy & Environmental Research Center

Carl V. Weilert
Burns & McDonnell

August 14, 2007

BACKGROUND

The North Dakota Department of Health (NDDH) has requested that Minnkota Power Cooperative (Minnkota) consider performing a pilot test at the Milton R. Young Station (MRYS) to investigate the technical feasibility of Selective Catalytic Reduction (SCR) technology for control of emissions of nitrogen oxides (NO_x) from the North Dakota lignite-fired cyclone boilers at that power plant. The results of the pilot test would be used in the NOx BACT analysis for MRYS. Technical feasibility of SCR application to utility boilers firing this fuel is a principal issue in the determination of best available control technology (BACT) for NO_x emission control at MRYS. The determination of BACT for NO_x emission control at MRYS is a requirement of the Consent Decree (CD) filed in the case *United States of America and State of North Dakota v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative.*

Minnkota has evaluated NDDH's request and has decided not to pursue SCR pilot testing at MRYS for three reasons as elaborated in this document, below. The reasons for not conducting further pilot testing prior to the BACT determination are:

1. Pilot testing is specifically not required by the BACT determination procedures established by the U.S. Environmental Protection Agency (EPA).
2. Previous research, including previous SCR pilot testing conducted at the Coyote Station, indicates that there is not sufficient reason to believe that the pilot testing suggested by NDDH will produce results any different from those obtained from the prior pilot test.
3. The compliance schedule for installation of NO_x BACT technology at MRYS as established by the CD cannot be met if pilot testing of SCR, followed by installation of SCR, is selected as the basis for BACT.

Each of these points is explained further in the text that follows.

REGULATORY BASIS FOR MINNKOTA'S DECISION NOT TO CONDUCT PILOT SCR TESTING

Minnkota's decision not to conduct pilot testing of SCR technology is supported on a regulatory basis for the following reasons:

1. EPA Guidance Specifically Describes When an Emission Control Technology is "Technically Feasible"

EPA has prepared a New Source Review Workshop Manual (Draft, October 1990) that explains, in detail, the evidence and analysis necessary to support a BACT determination. This process of defending a particular BACT recommendation is summarized in the Workshop Manual as follows:

> The applicant's role is primarily to provide information on the various control options and, when it proposes a less stringent control option, provide a detailed

> rationale and supporting documentation for eliminating the more stringent options. It is the responsibility of the permit agency to review the documentation and rationale presented and: (1) ensure that the applicant has addressed all of the most effective control options that could be applied; and (2) determine that the applicant has adequately demonstrated that energy, environmental, or economic impacts justify any proposal to eliminate the more effective control options. Where the permit agency does not accept the basis for the proposed elimination of a control option, the agency may inform the applicant of the need for more information regarding the control option. However, the BACT selection essentially should default to the highest level of control for which the applicant could not adequately justify its elimination based on energy, environmental and economic impacts. If the applicant is unable to provide to the permit agency's satisfaction an adequate demonstration for one or more control alternatives, the permit agency should proceed to establish BACT and prepare a draft permit based on the most effective control option for which an adequate justification for rejection was not provided. [Workshop Manual at B.53.]

The Workshop Manual requires an applicant to "make a good faith effort to compile appropriate information from available information sources, including any sources specified as necessary by the permit agency." [*Id.* at B.11]. This analysis should at least identify technologies that may be potentially transferable to the particular source, though later those technologies may prove technically infeasible or economically cost-ineffective.

For each alternative emission control technique, the applicant should analyze whether the control technique is feasible. EPA defines a *technically feasible alternative as one that is available* (i.e., commercially available for the application in question) *and applicable* (i.e., whether the available controls may reasonably be deployed on the source in question). The Workshop Manual provides a detailed analysis of the availability and applicability of a control technology, which bears quoting at length:

> In step 2, the technical feasibility of the control options identified in step 1 is evaluated. This step should be straightforward for control technologies that are demonstrated—if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and technically feasible. For control technologies that are not demonstrated in the sense indicated above, the analysis is somewhat more involved.
>
> Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

> Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:
>
> - Concept stage;
> - Research and patenting;
> - Bench scale or laboratory testing;
> - Pilot scale testing;
> - Licensing and commercial demonstration; and
> - Commercial sales.
>
> A control technology is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. *Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review.* An exception would be if the technology were proposed and permitted under the qualifications of an innovative control device consistent with the provision of 40 CFR 52.21(v) or, where appropriate, the applicable SIP.
>
> Commercial availability by itself, however, is not necessarily sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under construction.
>
> Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on any existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary. [*Id.* at B.17–B.18] (emphasis added).

The *proper method for showing technical infeasibility* is identified by the Workshop Manual as follows:

> [T]he applicant should make a factual demonstration of infeasibility based on commercial unavailability and/or unusual circumstances which exist with application of the control to the applicant's emission units. Generally, such a demonstration would involve an evaluation of the pollutant-bearing gas stream characteristics and the capabilities of the technology. Also a showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g., size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source). Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process.
>
> A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts which, in turn, may form the basis for eliminating a control technology (see later discussion at V.D.2). [*Id.* at B.19–B.20.]

Each of the elements of demonstrating technical infeasibility, along with background and supporting information as necessary, must be decisively documented.

2. Following the Guidance from the Workshop Manual, Minnkota has Decisively Documented that SCR is Technically Infeasible at Milton R. Young Station

SCR has not been demonstrated on any North Dakota lignite-fired cyclone unit. In light of this lack of demonstration, NDDH has asked Minnkota to consider conducting pilot testing of SCR to determine the life expectancy of a particular SCR catalyst. However, the 1990 Workshop Manual concludes that pilot testing of an undemonstrated technology cannot be required as a part of a BACT analysis.

The Workshop Manual addresses technical feasibility in the context of both demonstrated technologies (not applicable to Minnkota here) and undemonstrated technologies (Minnkota's situation). As set forth in detail above, the key questions in determining whether the undemonstrated technology is feasible are whether the technology is "available" and "applicable." Most importantly, the Workshop Manual states:

> "A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type.

> Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review." [*Id.* at B.18].

As Minnkota has demonstrated in its previous filings, EERC and Burns & McDonnell have demonstrated SCR cannot be reasonably installed and operated on the Milton R. Young Station. SCR is therefore unavailable and inapplicable, and NDDH may not require Minnkota to conduct extensive pilot testing as a part of a BACT analysis to experiment with the availability or applicability of SCR to North Dakota lignite-fired cyclone boilers.

In conclusion, Minnkota has demonstrated that SCR is not technically feasible, that that SCR is not "available" under the EPA guidance, that SCR is not "applicable" under the EPA guidance, and that a pilot test is not allowed under the EPA guidance for BACT.

TECHNICAL BASIS FOR MINNKOTA'S DECISION NOT TO CONDUCT PILOT SCR TESTING

In order to determine if additional pilot testing of SCR catalysts on lignite fueled cyclone-fired boiler would produce similar or potentially different results from previous testing, the fouling and poisoning mechanisms must be examined. This is necessary in order to evaluate design changes that could be made to reduce or eliminate the fouling and poisoning of the SCR catalysts.

Fouling and poisoning of SCR catalysts are affected by the following:

- Lignite properties
- Combustion processes
- Partitioning of sodium and other elements during combustion
- SCR catalyst characteristics and properties
- Chemical and physical mechanisms of pore plugging

The primary concern for lignite coals from the Northern Great Plains of North America is blinding and poisoning of SCR catalysts because of the presence of alkali and alkaline elements in the coal and their fate upon combustion. Mussatti (2002) indicated in the "EPA Air Pollution Control Cost Manual – Sixth Edition" the following primary mechanisms for catalyst deactivation:

> "Poisoning - Certain fuel constituents which are released during combustion act as catalyst poisons. Catalyst poisons include **calcium oxide and magnesium oxide**, potassium, **sodium**, arsenic, chlorine, fluorine, and lead. These constituents deactivate the catalyst by diffusing into active pore sites and occupying them irreversibly. Catalyst poisoning represents the main cause of catalyst deactivation."
>
> "Blinding/Plugging/Fouling - Ammonia-sulfur salts, fly ash, and other particulate matter in the flue gas cause blinding, plugging or fouling of the catalyst. The particulate matter deposits on the surface and in the active pore sites of the catalyst. This results in a decrease

of the number of sites available for NO_x reduction and an increase in flue gas pressure loss across the catalyst."

Based on research, development, and demonstration testing to date these challenges have not been overcome. Significant fundamental research is required to further develop NO_x reduction technologies for lignite coals.

Lignite Properties

Lignite from the Center Mine in North Dakota is part of the Fort Union region. The Fort Union region represents the lignite bearing reserves in North America. The age of lignite in the Fort Union ranges from late Cretaceous through Eocene. The younger lignite coals have higher levels of oxygen as compared to higher ranked coals. Lignites can contain as high as 20% oxygen on a moisture and ash free basis. The most important oxygen containing group in lignite is the carboxylic acid group accounting for up to 65% of the oxygen (Schobert, 1995). The carboxylic acid groups act as bonding sites for various elements such as Ba, Ca, Mg, Na, and Sr and are enriched in lignite coals as compared to bituminous coals (Schobert, 1995). As coal rank increases the oxygen functional groups are lost due to the coalification process. The carboxylic acids act as ion exchange sites for sodium and other elements such as Mg, Ca, Sr, and Ba that are accumulated from ground water. The abundance of sodium and other elements that are associated with the carboxylic acid groups in the coal are determined using chemical fractionation (Benson and Holm, 1985). The chemical fractionation results for Center lignite indicates that 76% of the total sodium is ion-exchangeable indicating an organic association in the coal with the remaining in a water soluble form (Schobert, 1995). In addition to the organic and water associated impurities, lignites contain significant levels of mineral grains. The types of minerals present in lignite consist of pyrite, quartz, clay minerals, sulfates, carbonates, and others (Benson and others, 1993).

Lignite fired at the Milton R. Young (MRY) plant is mined from three seams at the Center mine of the Fort Union Region, the Kinneman Creek (KC), Hagel A (HA), and Hagel B (HB). The coal fired in the Units 1 and 2 represent some blending of the coal through handling and delivery. The variability selected coal quality components for the as-fired Center lignite is shown in Table 1. The average, maximum, and minimum as well as the percentiles were derived from analysis of the as-fired coal database. The database consists of 1316 samples of coal collected using sampling systems on Unit 2. The elements that are largely organically associated as described above are highlighted. These elements are largely organically associated and can contribute to the formation of reactive fine particulate during combustion and gas cooling.

Table 1. Center lignite composition (moisture, ash, sulfur, and heating value expressed on an as-received basis; and ash composition expressed as weight percent equivalent oxide of the ash produced at 750 °C).

	Moisture, %	Ash, %	Sulfur %	Btu/lb	Al_2O_3	BaO	CaO	Fe2O3	MgO	P_2O_5	K_2O	SiO_2	Na_2O	SO_3
Average	37.13	9.64	0.98	6578	11.68	0.52	13.15	8.90	3.99	0.12	1.33	36.04	4.40	18.39
Max	39.37	25.46*	2.55	7101	15.62	1.22	23.96	24.72	7.09	1.00	2.30	55.98	13.03	34.50
Min	33.56	4.97	0.47	5852	6.31	0.20	6.80	5.38	2.30	0.01	0.16	12.30	0.55	8.12
90th Perc.	38.10	12.51	1.29	6820	14.23	0.84	19.92	12.20	5.68	0.41	1.92	45.98	8.71	26.25
10th Perc.	35.95	7.06	0.72	6359	9.58	0.37	9.73	7.08	3.00	0.04	0.61	22.70	1.99	14.35
45th Perc.	37.17	9.33	0.90	6552	11.62	0.47	12.15	8.34	3.81	0.09	1.36	36.99	4.09	17.30
55th Perc.	37.37	9.75	0.94	6592	11.97	0.50	12.74	8.68	3.97	0.10	1.44	38.36	4.61	18.02

* High value may be an analysis or reporting error. Sample could not be reanalyzed to verify.

Figures 1 - 3 show the frequency distributions with the 10th, 50th, and 90th percentile values for sodium, base-to-acid ratio, and ash content in the as-fired database. In addition, the future Center lignite characteristics in ten-year averages for % sodium oxide in ash, base/acid ratio, and % ash are plotted on the frequency distribution diagrams in Figures 1-3. The future Center lignite characteristics are based on weighted averages of analysis conducted for drill cores. This information was used to calculate the weighted averages for 10-year spans. The frequency distribution of the sodium content of the ash is shown in Figure 1. The projections for the future have similar sodium levels to the upper mode of sodium contents. The sodium content of the future coals appears to be decreasing initially from the upper mode and then increasing from 2036–2064. The base-to-acid ratio shown in Figure 2 indicates coals typical of lower ash contents and high levels of sodium, calcium, potassium, and iron relative to silicon, aluminum, and titanium. This information indicates that the future coals will have a higher propensity on average to cause low-temperature fouling than coals fired over the past several years. Lower ash content and higher base-to-acid ratio coals produce more low temperature fouling due to sulfate formation. Figure 3 shows the projected ash values compared to the as-fired database. The data from 2006–2015 show similar data to the as-fired database with decreasing levels of ash in the latter years.

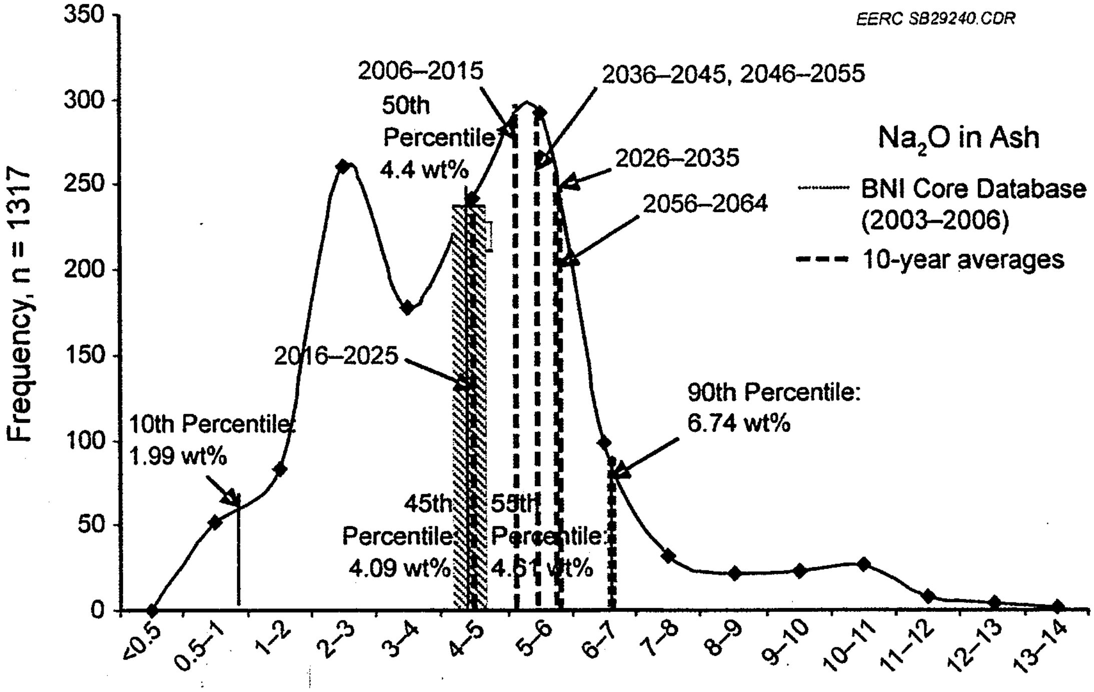

Figure 1. Sodium oxide in ash frequency distribution for as-fired database compared to 10-year averages and weighted Core Database values.

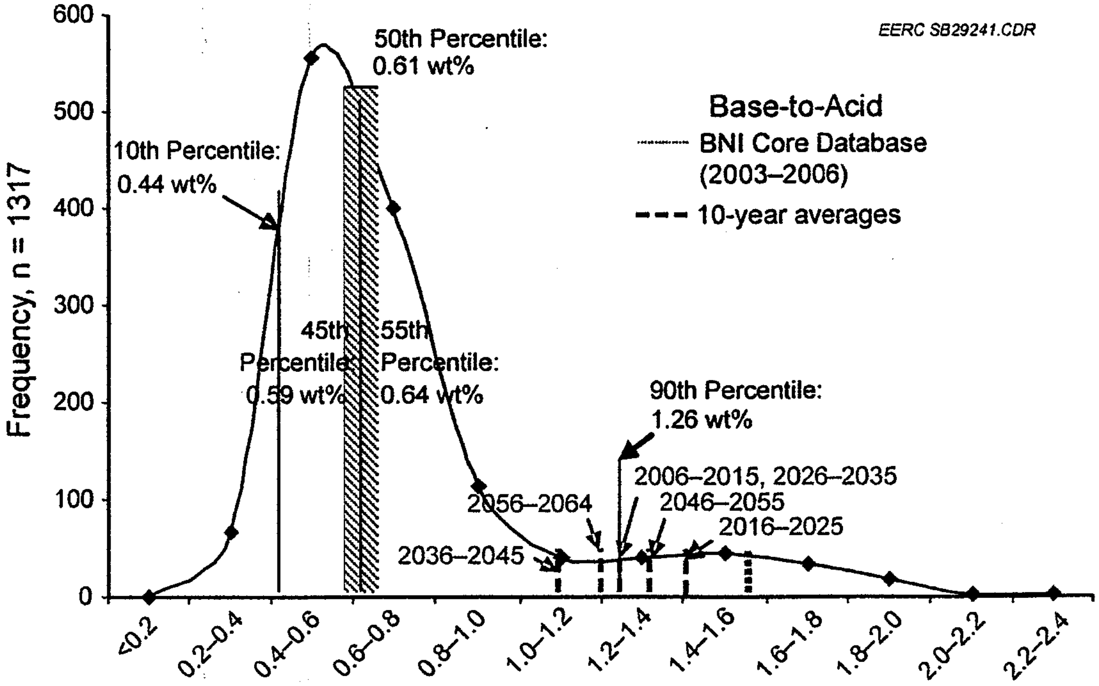

Figure 2. Base-to-acid ratio of ash frequency distribution for as-fired database compared to10-year averages and weighted Core Database values.

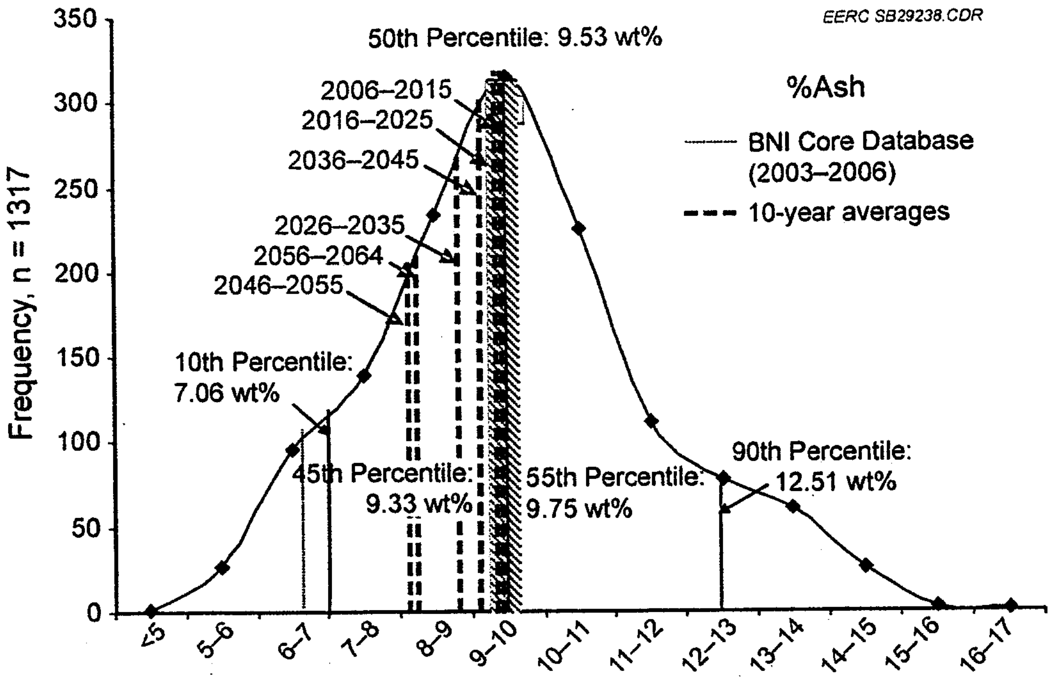

Figure 3. Ash frequency distribution for as-fired database compared to 10-year averages and weighted Core Database values.

Combustion Processes and Partitioning

The inorganic coal components undergo complex chemical and physical transformations during combustion to produce intermediate ash species in the form of inorganic vapors, liquids, and solids. The partitioning of the inorganic components during combustion to form ash intermediates depends upon the association and chemical characteristics of the inorganic components, the physical characteristics of the coal particles, the physical characteristics of the coal minerals, and the combustion conditions. The physical transformations involved in fly ash formation illustrated in Figure 4 include 1) coalescence of individual mineral grains within a char particle, 2) shedding of the ash particles from the surface of the chars, 3) incomplete coalescence due to disintegration of the char, 4) convective transport of ash from the char surface during devolatilization, 5) fragmentation of the inorganic mineral particles, 6) formation of cenospheres, and 7) vaporization and subsequent condensation of the inorganic components upon gas cooling. As a result of these interactions, the resulting ash composition and mass distribution as a function of size is also shown in Figure 4. Typical ash derived from coal combustion has a bimodal to multimodal size distribution that consists of a submicron and supermicron size fraction as shown in Figure 5. The submicron component is largely a result of the condensation of flame-volatilized inorganic components such as sodium. The intermediate size mode at about 2 micrometers is derived from the more refractory organically associated elements such as calcium and magnesium. The larger particles at approximately 12 to 15 μm are derived from the mineral grains present in the coal. The larger-size particles have been called the residual ash by some investigators (Sarofim and others, 1977) because these ash particles resemble, to a limited degree, the original minerals in the coal. During the gas-cooling processes in the boiler, the gas-phase species condense and the liquid-phase materials solidify. The abundance of these gas-phase and liquid materials entrained in the bulk gas flow is highly dependent upon coal composition and system operating conditions.

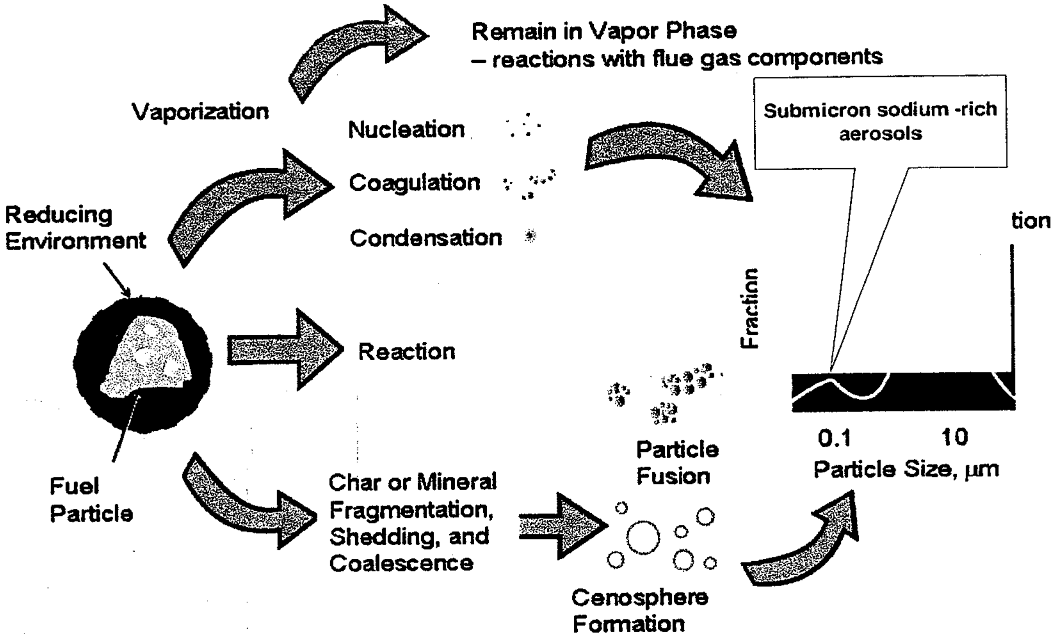

Figure 4. Transformation of inorganic components present in coal during combustion.

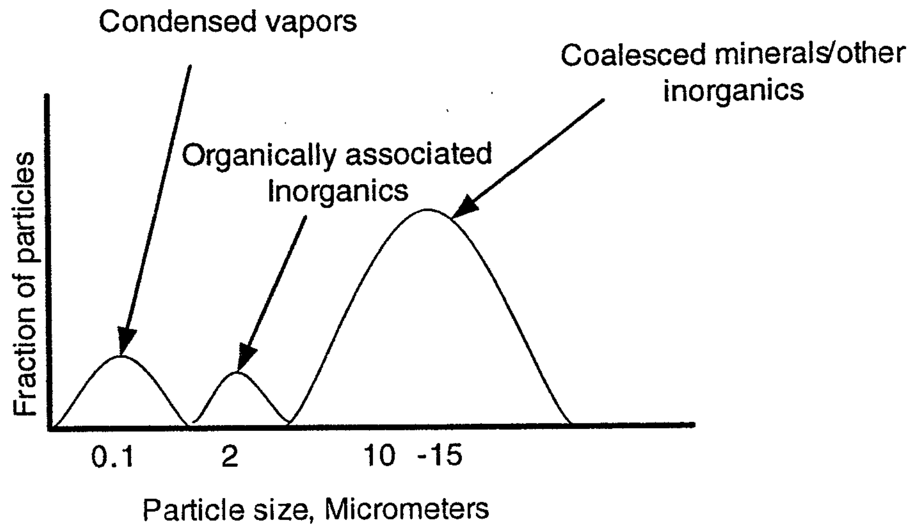

Figure 5. Final size distribution of ash particles produced upon combustion of lignitic coals (Benson and Laumb, 2007).

Cyclone fired systems enhance the partitioning of the inorganic components both by high temperatures and cyclonic action. The partitioning of sodium between the slag and coal is shown in Figure 6. The results show the sodium present in the as-fired coal ash presented with and without SO_3. The retention of sulfur in the ash is an artifact of the ashing procedure. In comparing the level of sodium in the slag to the coal fired for the high-sodium cases, only about half of the sodium is retained in the slag. The slag samples were recovered from the slag tap for the boiler. These slag samples include deposits that fall from the walls and the high-temperature convective pass.

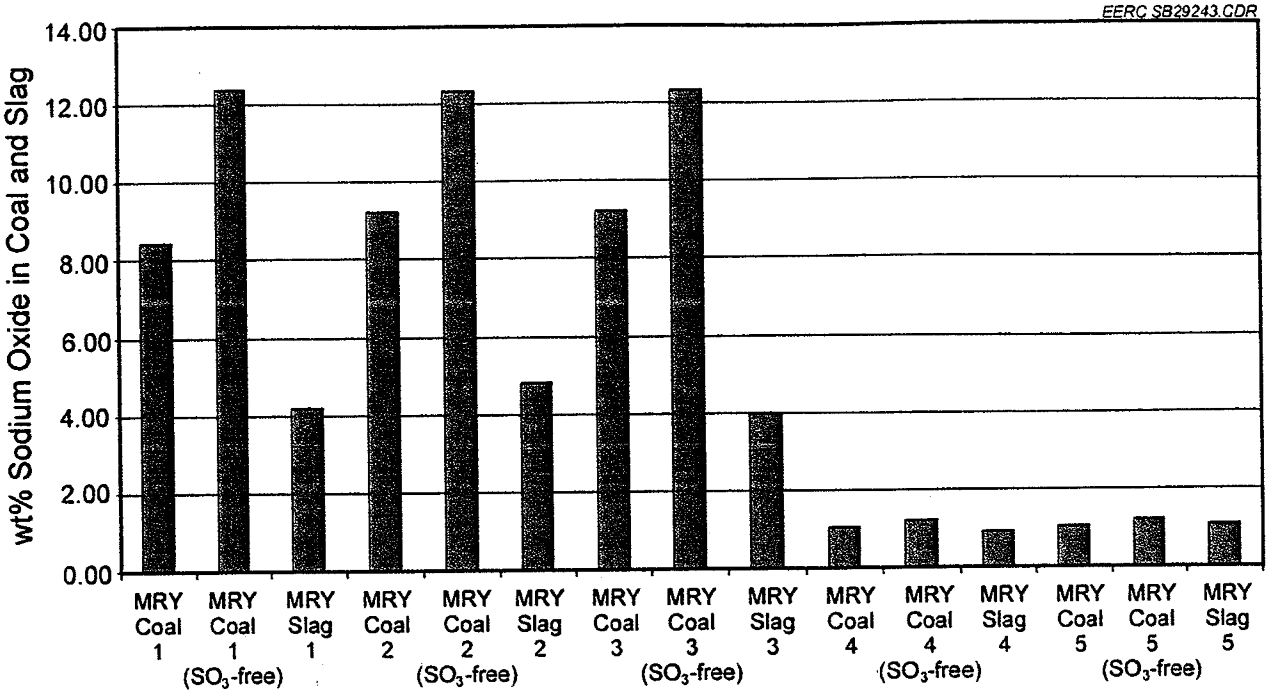

Figure 6. Comparison of sodium levels in Center lignite coal and slag samples.

The transport of intermediate ash species (i.e., inorganic vapors, liquids, and solids) to surfaces within a combustion system (combustion and air pollution control system) is a function of the state and size of the ash species and system conditions such as gas flow patterns, gas velocity, and temperature. Several processes are involved in the transport of ash particles to surfaces in the combustion system. These processes have been described in detail by Raask (1985) and Rosner (1986). The primary transport mechanisms are illustrated in Figure 7. For larger particles inertial impaction and eddy impaction in turbulent regions are the dominant mechanisms. The small particles (<1 μm) and vapor-phase species are transported by the vapor phase and small particle diffusion. The inorganic materials are transported to heat-transfer and catalyst surfaces by diffusion, electrophoresis, and inertial impaction. Thermophoresis is not a significant contributor to the transport of particles as it related to SCR materials. However, thermophoresis is a contributor to particle transport on heat transfer surfaces because of the temperature gradient.

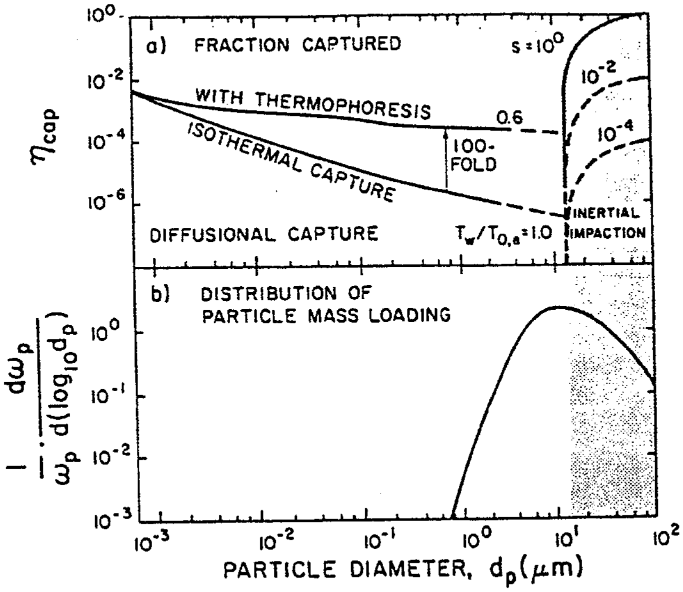

Figure 7. Overview of ash transport mechanisms (Rosner, 1986); (a) particle size dependence of captured fraction n_{cap}; (b) size distribution of the mainstream particle mass loading. The accumulation rate will involve a combination of a and b.

The vapor phase and small particles are characteristically rich in flame-volatilized species that condense upon gas cooling in the bulk gas or in the gas boundary layer next to the surface. The diffusion mechanisms important with respect to the transport of vapor species and small particles to the surface of SCR catalysts include:

1. Fick diffusion – molecular level.
2. Brownian diffusion – particles suspended by a host liquid.
3. Eddy diffusion – turbulent systems.

SCR Catalyst Characteristics and Properties

SCR catalysts for coal combustion applications consist of ceramic material with high porosity that contains imbedded active catalytic sites. The NO_x reduction occurs on the active surface of the catalyst. The active surface of the catalyst consists of flat surfaces and pores within the flat surface of the catalyst. The flat surfaces and pores in the catalyst are designed to provide gas contact with the active surface of the catalyst. The pores consist of open macropores and micropores that occur on the surface of the catalyst structures.

The size of the openings in honey comb catalyst impacts the velocity of the gases flowing through the catalyst. Pitch is the term used to describe the openings between the flat surfaces of the catalyst. Figure 8 illustrates the pitch, p and the wall thickness, a. Lower gas velocities will result for higher pitch numbers while small numbers will result in higher gas velocities through the catalyst. Catalyst vendors have methods to identify the proper pitch for specific fuel types and ash characteristics to minimize bridging or plugging where the dominant transport mechanism is inertial impaction and eddy impaction for the large particles. Selecting a pitch that will minimize the transport of small particles and vapor phase species is not as straightforward. High pitch catalysts will result in lower velocity gas flow through the catalyst and will create a thicker boundary layer resulting in an increased potential for small particle transport. Catalyst geometry plays a significant impact on gas flow patterns through the catalyst. Evaluation of the literature and information provided by catalyst vendors indicate that the geometries of catalysts have not been improved to minimize small particle and vapor phase deposition on the surface and within the pores of catalyst (Hansen, 2007).

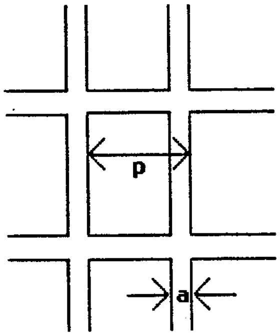

Figure 8. Catalyst pitch (Mussatti, 2002).

An example of the macropore structure is shown in Figure 9 for an actual surface for a honeycomb type catalyst. The openings in the catalysts create porosity and surface area to expose the reactive components of the catalyst to gas phase components. These openings are prone to filling with small particles and large particles through the transport processes of diffusion and impaction, respectively. Once these particles are transported to the surfaces they will be held in place by weak electrostatic and van der Waals forces and they will react with vapor phase sulfur oxide species.

Chemical and physical mechanisms of pore plugging

The most significant problems that limit the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency. Studies conducted at Coyote station (Benson and others, 2005) found significant blinding and filling of the pores with small particles as shown in Figure 9. Rapid filling of the pores occurred with the catalyst pitch of 6 mm. These materials were subjected to air pulsing that did not remove the materials from the catalyst. The characteristics of the materials filling the pore were rich in sodium and calcium sulfates. A high magnification image of the materials coating the catalyst and filling the pore is shown in Figure 10. This image shows the importance of the very small particles less than 1 micrometer and their impact on the bonding of the deposited materials. These small particles readily interact with gas phase SO_2 and SO_3 expanding to create a bonded matrix as shown in Figure 11 that completely fills the pores of the catalyst with a continuous bonded phase. A high magnification cross-section is shown in Figure 12 of a highly sulfated bonded matrix.

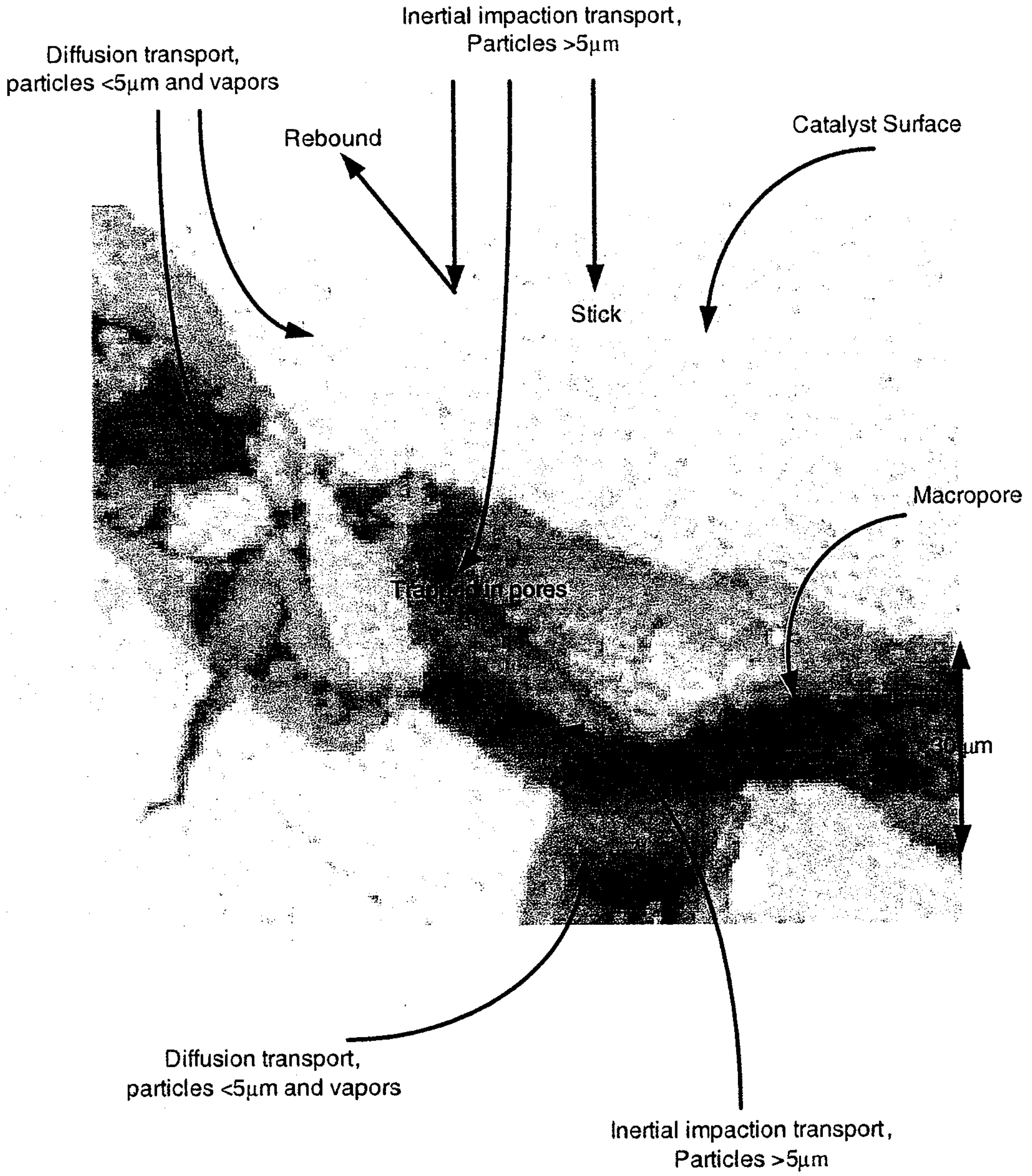

Figure 9. Scanning electron microscope secondary electron image of the macropore structure of an SCR catalyst with transport process descriptions.

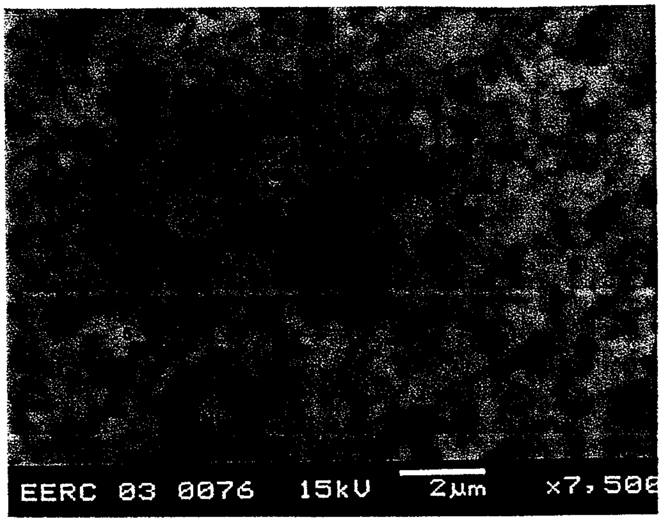

Figure 10. High magnification secondary electron image of ash filling pores and covering catalysts.

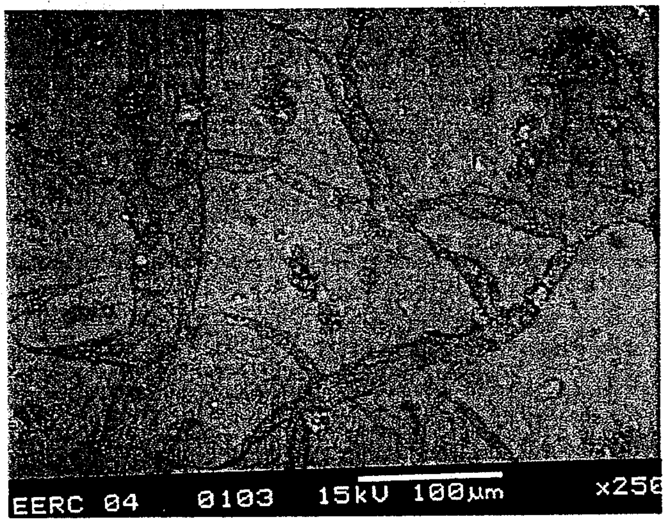

Figure 11. Scanning electron microscopy image of ash materials filling the pores of catalyst exposed to flue gases derived from the firing of Beulah lignite at Coyote Stations (Benson and others, 2005).

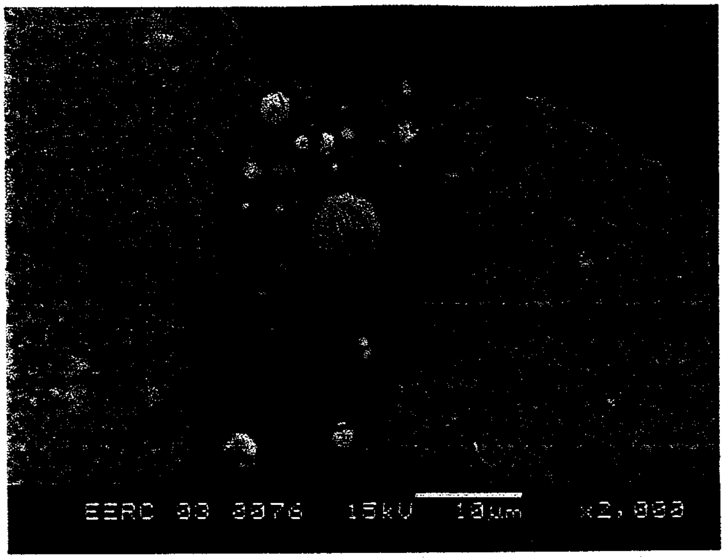

Figure 12. High magnification image of materials typical of ash filling pores that has sulfated and bonded.

Pyrosulfates are present in ash deposits and will likely form in SCR catalysts. Melting points for pyrosulfates between 535° and 770°F have been reported in the literature (Singer, 1981). Much of the past work has focused on the formation of these phases on tube surfaces. These species contribute to the corrosion of heat-transfer surfaces in coal-fired power plants. The exact melting point depends on the relative amounts of sodium and/or potassium. The melting points of selected pyrosulfate phases are shown in Table 2.

The formation of pyrosulfates involves the following processes

1. Formation of sulfates such as Na_2SO_4 and K_2SO_4
2. Conversion of SO_2 to SO_3 in the bulk gas phase – catalytically active surface such as an SCR catalyst – $SO_2 + \frac{1}{2} O_2 \rightarrow SO_3$
3. Pyrosulfate formation – $Na_2SO_4 + SO_3 \rightarrow Na_2S_2O_7$

A diagram depicting the physical and chemical reactions involved in the filling and plugging of catalyst pores is shown in Figure 13 (Benson and others, 2005).

Table 2. Melting Points of Selected Pyrosulfate Compounds

A. Compound	Temperature, °C	Temperature, °F
$K_3Fe(SO_4)_3$	618	1144
$K_3Al(SO_4)_3$	654	1209
$KFe(SO_4)_2$	694	1281
$Na_3Fe(SO_4)_3$	624	1155
$Na_3Al(SO_4)_3$	646	1195
$NaFe(SO_4)_2$	690	1274
$Na_2S_2O_7$	401	754
$K_2S_2O_7$	300	572
$(K_{1.5}Na_{0.5})S_2O_7$	279	535

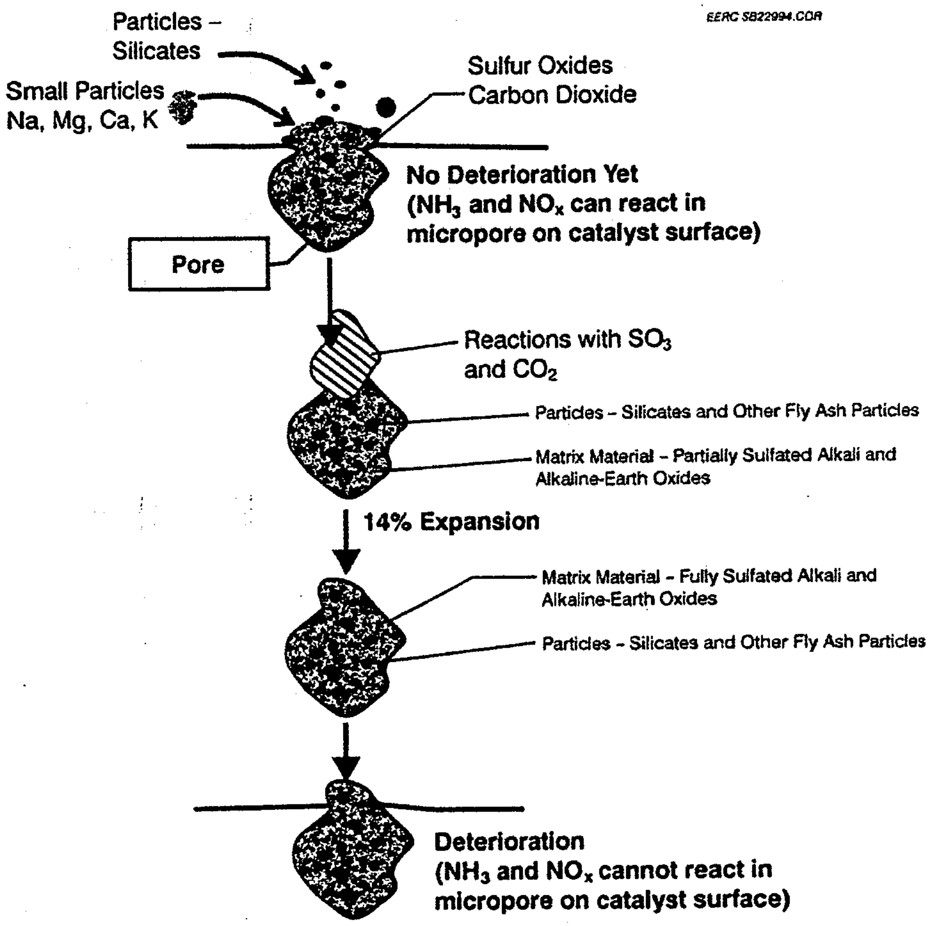

Figure 13. Overall mechanism of SCR Catalyst blinding (modified after Pritchard and others (1995)).

Sodium-related catalyst deactivation mechanisms

Alkali elements such as sodium and potassium are known to cause catalyst deactivation. Prichard and others (1995) indicate that the alkali elements can interact with the catalyst active sites and cause them to lose their activity as shown in Figure 14. They indicate that the degree of deactivation is dependent upon the concentration of alkali elements and the form of the alkali. Based on the evaluations conducted and/or reported by Cormetech (Prichard and others, 1995), Topsoe (1999), EPRI (Broske, 2005), and EPA (Mussatti, 2002) the water soluble form of the alkali is the problematic form since these alkali species are highly mobile allowing them to migrate into the catalyst. Cormetech (Prichard and others, 1995) incorrectly indicate the following:

> *"For the subject catalyst in coal-fired applications, it is our experience that this type of poisoning has a small impact, since most of the alkaline metals in the coal ash are not water soluble."*

This comment is very surprising and is likely indicative of catalyst vendor's level of understanding of lignite coals. Much work has been conducted for decades on the solubility of alkali and alkaline earth elements in coal ash. Sodium in Center lignite is associated in the groundwater and with the organic matrix of the coal (Benson and Holm, 1985; Schobert, 1995). Very little of the sodium is associated with the mineral fraction of the coal such as clays. During combustion, the sodium in the water soluble and organic association will vaporize and become dispersed in the gas stream and react with sulfur oxides to form soluble sodium sulfates species. Combustion Engineering conducted an analysis of the impact of soluble and organically associated sodium with fouling potential (Singer, 1981). The results of the analysis are summarized in Table 3. The soluble alkali shown for lignite and subbituminous coals is very high, with North Dakota lignite and Montana high-sodium subbituminous coals having the highest available sodium for low-temperature fouling processes.

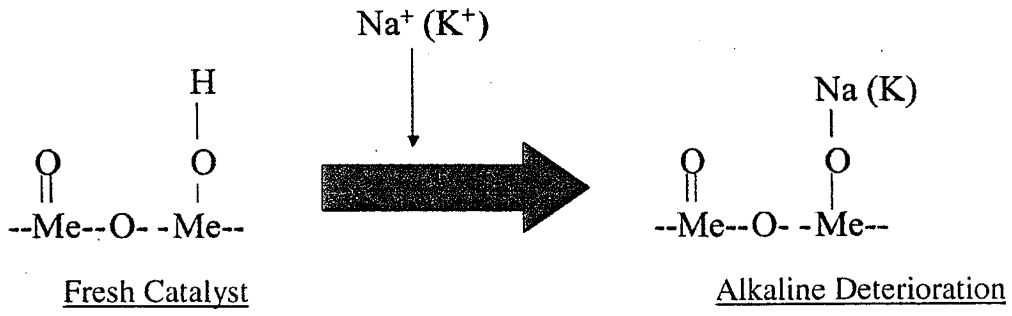

Figure 14. Alkaline (alkali) SCR catalyst deterioration mechanism (Prichard and others, 1995).

Table 3. Comparative Alkali Content Analysis for U.S. Coals (Singer, 1981)

Rank **Region**	**Lignite** **ND**	**Sub B** **MT**	**Lignite** **TX (Yegua)**	**Lignite** **TX (Wilcox)**	**hvBb** **UT**	**hvAb** **PA**	**Lignite** **TX (Wilcox)**
HHV, Btu/lb, Dry Basis	10640	12130	7750	9710	12870	13200	8420
Ash Composition (%)							
SiO_2	20.0	33.9	62.1	52.3	52.5	51.1	57.9
Al_2O_3	9.1	11.4	15.1	17.4	18.9	30.7	21.8
Fe_2O_3	10.3	10.8	3.5	5.3	1.1	10.0	3.9
CaO	22.4	21.0	6.2	9.4	13.2	1.6	7.1
MgO	6.4	2.7	0.7	3.2	1.3	0.9	2.1
Na_2O	5.0	5.8	3.6	0.9	3.8	0.4	0.7
K_2O	0.5	1.6	1.9	1.2	0.9	1.7	0.8
TiO	0.4	0.7	0.9	1.2	1.2	2.0	1.1
SO_3	21.9	12.0	6.1	9.6	6.2	1.4	4.4
Fouling Potential	Severe	High	High	Moderate	Moderate	Low	Low
Lb Ash/10^6 Btu, Dry Basis	9.0	4.6	43.3	20.1	7.9	10.2	34.4
Acetic-Acid-Soluble							
Sodium (Na, ppm)	3980	2680	9650	1030	1120	250	340
Potassium (K, ppm)	...	...	1230	85	85	...	110
Alkali in Ash, % Wt.							
Na_2O	5.0	5.8	3.6	0.9	3.8	0.4	0.7
K_2O	0.5	1.6	1.9	1.2	0.9	1.7	0.8
Equiv. Sol. Alkali in Ash, % Wt. of Ash							
Na_2O	5.58	6.45	3.88	0.71	1.49	0.15	0.16
K_2O	...	...	0.44	0.04	0.08	...	0.05
% Sol. Alkali of Total (Equiv. Sol. Na_2O)/ (Na_2O in Ash)	112	111	108	79	39	38	23
(Lbs Sol. Na)/ (10^6 Btu Fired)	0.374	0.221	1.245	0.106	0.087	0.018	.040
(Lbs Sol. Na)/(lb Ash/ 10^6 Btu Fired)	0.044	0.048	0.223	0.005	0.014	0.002	0.001

The following summarizes the state-of-the-art relative to the application of SCR for use in high sodium lignite combustion systems such as at the MRY plant.

- Coal properties
    - Center lignite coal contains organically associated sodium, magnesium and calcium
    - The levels of sodium in the Center lignite will remain constant and will likely increase in the future years
- Ash formation
    - Sodium vaporizes during combustion to form very small particles
    - Sodium is in a soluble form

- Catalyst properties
  - Catalysts have high porosity in the form of macropores and micropores that have active components dispersed within them allowing for NOx reduction reaction
  - Pitch of the catalyst appears to be the only change in geometry available to minimize deposition
  - Catalyst are prone to deactivation because of the presence of soluble sodium
- Ash transport in SCR catalyst
  - Ash particle transport mechanisms are dependent upon gas velocity
  - Particles greater than approximately 10 micrometers are transported to the surfaces of catalysts by inertial impaction mechanisms
  - Vapor phase and small particles are transported through diffusion processes into the pores of the catalyst across the stagnant gas boundary layer next to the surface
  - Small ash particles rich in sodium, calcium, and sulfur infiltrate deep into the catalyst pores causing blinding and plugging and possibly deactivation

The following are changes that could be made in future pilot testing and, based on the previously presented information, the impacts of those changes that could reasonably be anticipated to occur.

- Test catalysts with larger openings (greater Pitch)

  Impacts: The current recommendation (for the coal-fired industry in general) by catalyst vendors is to use catalysts that have a larger pitch. Using catalysts with a larger pitch will likely decrease the velocity through the catalyst and decrease the impaction rates of the larger particles. However, this does not address the key problem of vapor phase and small particle diffusion into the pores of the catalysts that is associated with the combustion of high sodium Center lignite. By decreasing the velocity, the gas boundary layer may be larger resulting in an increase in the diffusion processes resulting in increased deposition of the smaller particles into the pores. In addition, decreasing gas velocity will decrease the scrubbing action of impacting particles that aids in removing deposited ash particles.

- Test catalyst with modified pore structure that does not accumulate small particles

  Impacts: The use of these catalysts should have a positive impact on reducing catalyst poisoning and pore plugging. However, discussions with catalyst vendors and literature searches indicate that little or no work has been conducted on such formulations. Most of the work being conducted by catalyst vendors is focused on reducing SO_3 production and enhancements for mercury oxidation. As a result, these catalysts are not available.

- Enhanced cleaning technologies for removal of particles in the pores of catalysts

  Impacts: The use of acoustic horns appears to clean the surfaces as well as sootblowers on subbituminous and bituminous fueled boilers. However, this technology has not been demonstrated on lignite fueled boilers. There is significant uncertainty in the ability of acoustic horns to clean the ash particles from the pores of the catalyst.

There does not appear to be a catalyst material that has shown significantly improvement over the past catalyst relative to the performance in high sodium containing system. The specific question was asked to Flemming Hansen (Hansen, 2007) as to whether improvements have been made in catalysts over the ones tested at Coyote station that warrant further testing. He indicated that no formulation or design changes have been made to improve their performance in high sodium containing flue gases.

The testing at Coyote station indicated that the macropores and the catalyst openings were plugged. The blinding of the catalyst from the Coyote station testing was so severe that the catalyst vendor could not make deactivation measurements. Cleaning the catalyst and measuring deactivation was not performed based on recommendation of the catalyst vendor. The reason for not cleaning and conducting the measurements were based on concerns expressed by the vendor that the results of such deactivation testing after cleaning would not provide meaningful data on deactivation rates.

At the present time, there is not sufficient evidence to indicate that further pilot testing, even though it could be significantly reconfigured from previous testing, would yield significantly different results from that of testing already conducted at the Coyote station. Additionally, there is nothing to suggest that further testing would necessarily result in catalyst samples being made available that would allow for the measurement of deactivation rates.

SCHEDULE BASIS FOR MINNKOTA'S DECISION NOT TO CONDUCT PILOT SCR TESTING

The CD requires that compliance with the "30-day Rolling Average NO_x Emission Rate" established as BACT in accordance with the CD be achieved for Unit 2 at MRYS not later than December 31, 2010. For the hypothetical case in which an SCR pilot test were conducted to potentially establish the technical basis for SCR application to the Units at MRYS, the following tasks would need to be completed prior to this date:

1. Design the SCR pilot test protocol and obtain concurrence of NDDH and EPA
2. Design, procure and install the pilot SCR
3. Conduct the SCR pilot testing and evaluate the results
4. Conduct a technical feasibility analysis of the boiler modifications that would be necessary for Units 1 and 2 to allow reduction of flue gas temperatures (which are currently well above the required range for SCR operation, as previously documented in Minnkota's submittals to NDDH) while maintaining the ability to dry the lignite as required for combustion.
5. Revise the BACT analysis based on the results of Steps 3 and 4 (hypothetically assuming that they concluded it was technically possible to install SCR) to establish the revised "30-day Rolling Average NO_x Emission Rate" based on the hypothetical use of SCR.

6. Receive the final determination from NDDH regarding the "30-day Rolling Average NO_x Emission Rate" representing BACT in accordance with the CD.
7. Incorporate the results of steps 3 through 6 (hypothetically assuming that they concluded it was technically possible to install SCR and established an SCR-based value for the "30-day Rolling Average NO_x Emission Rate") into a procurement specification for the SCR system in accordance with RUS requirements.
8. Procure the SCR system on a "furnish and erect" basis, obtaining a vendor guarantee that assured compliance with the BACT emission limit as set forth in Step 6.
9. Design, fabricate, and erect the SCR systems and the necessary boiler modifications, using the Contractor selected in Step 8.
10. Start-up and commission the SCR system for Unit 2 and achieve stable performance to allow continuous compliance with the BACT emission limit as set forth in Step 6.

Based on Burns & McDonnell's evaluation, the time required to complete these tasks would be approximately 65 months from initiation of Task 1. Thus it would not be possible to comply with the CD date certain of December 31, 2010 for compliance with the "30-day Rolling Average NO_x Emission Rate" established as BACT in accordance with the CD.

The estimate of 65 months duration to complete this process is based on the following assumptions for the duration of the individual steps:

Step 1 is assumed to require two months. It should be noted that the EPA and its consultants have claimed that the previous SCR pilot testing at Coyote was fundamentally flawed. Thus it is essential that this step be thoroughly and carefully conducted and documented in order to assure the "buy in" of the interested parties.

Step 2 is estimated to require six months.

Step 3 is estimated to require 24 months. It is believed that the collection of 18 months of data will be necessary to properly evaluate the technical feasibility of SCR at MRYS. Due to the operating characteristics of the Units and based on prior experience with pilot testing, it is believed that the duration of pilot testing needed to acquire 18 months of data will be 24 months.

Step 4 is estimated to require six months, based on consultation with the boiler OEM. It should be noted that although Step 4 is assumed to be performed concurrently with Steps 1 through 3, all other steps must be conducted sequentially. Also, it should be noted that the subsequent sequence is based on the hypothetical assumption that the results of Steps 3 and 4 are favorable to the technical feasibility of SCR.

Steps 5 and 6 are estimated to require two months each. Because no SCR vendor has experience with SCR operation on North Dakota lignite, the determination of an emission rate corresponding to the hypothetical use of SCR will require the dissemination of the pilot test results from the catalyst vendors (which are assumed to be active participants in the pilot SCR program) to the SCR system suppliers. This is because the establishment of a NO_x emission rate representing BACT will require at least a preliminary indication from the system suppliers that such a level can be guaranteed. It is assumed that the system suppliers will guarantee the emission rate established in Step 6, and will otherwise respond favorably to the procurement process in Step 8.

The development of the technical specifications for the SCR procurement contract (Step 7) is estimated to require two months. The specifications must incorporate not only the results of the pilot SCR testing from Step 3 but the boiler modifications identified in the study conducted in Step 4. Again, the sequence assumes that it will be possible to find a feasible way of modifying the boilers to simultaneously achieve the flue gas temperature range required for SCR operation while continuing to achieve proper pre-drying of the lignite.

The period for bidding and award of the SCR contract (Step 8) is estimated to be four months. Typical bid period for a complex "furnish and erect" SCR retrofit contract such as this will be three months. One month is assumed for evaluation and negotiation.

For Step 9 it has been assumed that the period from award of the SCR contract to the completion of erection and tie-in will be 20 months. It is anticipated that the duration of construction of an SCR system in North Dakota will require somewhat longer than would be expected for other parts of the country due to the severity of the winter. Also, depending upon the complexity of the required boiler modifications, the construction period can be expected to be extended compared to a "typical" SCR project schedule which does not include the need for extensive boiler modifications.

The startup, commissioning and tuning of the SCR system (Step 10) has been estimated to require three months. It should be noted that concerns with the characteristics of the fly ash are anticipated to extend the time that would routinely be required for this step. Also, unlike most retrofit SCR projects completed to date in the U.S., this installation would be subject to a "not to exceed" emission limitation on a 30-day rolling average. Assurance that the limit could be continuously met would require more than the usual extent of operational tuning.

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Minnkota Power
MPC COOPERATIVE, INC.
Your Touchstone Energy® Partner

1822 Mill Road • P.O. Box 13200 • Grand Forks, ND 58208-3200 • Phone (701) 795-4000

May 8, 2008

Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, North Dakota 58501-1947

Re: Consent Decree – July 27, 2006
Minnkota Power Cooperative, Inc., et al
U.S. District Court for the District of ND
Civil Action No. 1:06-CV-034

Dear Mr. O'Clair:

Enclosed, please find a report on vendor responses you recently requested from Minnkota. This report, which was prepared by Burns & McDonnell, also includes recent additions and clarifications from vendors. As the report indicates, vendors are not able to make viable guarantees. Additionally, the vendors generally indicate that additional testing would need to be done prior to any design of an SCR for use on a North Dakota lignite-fired cyclone unit.

Should you have any questions, please contact me at jgraves@minnkota.com or 701-795-4221.

Should you have any questions concerning this submittal, please contact me at (701) 795-4221.

Sincerely yours,

MINNKOTA POWER COOPERATIVE, INC.

John T. Graves

John T. Graves, P.E.
Environmental Manager

C: David Sogard w/o encl.
Luther Kvernen w/o encl.
Craig Bleth w/o encl.
Stu Libby w/o encl.
Tom Anseth w/o encl.
Young Station File w/o encl.

MINNKOTA POWER COOPERATIVE, Inc. and SQUARE BUTTE ELECTRIC COOPERATIVE

ADDITIONAL INFORMATION AND DISCUSSION OF VENDOR RESPONSES ON SCR TECHNICAL FEASIBILITY NORTH DAKOTA'S NOx BACT DETERMINATION for MILTON R. YOUNG STATION UNITS 1 & 2

May 8, 2008

In order to address the issue of vendor guarantees in the NSR Workshop Manual, Burns & McDonnell and Energy & Environmental Research Center (EERC) developed an SCR Vendor Query[1] which was emailed by Burns & McDonnell on April 18, 2007 to selective catalytic reduction (SCR) technology system suppliers and catalyst suppliers. The query requested information from these vendors pertaining to their willingness to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at North Dakota lignite-fired Units 1 and 2 at Minnkota's Milton R. Young Station (MRYS) near Center, North Dakota. Burns & McDonnell described the unit-specific SCR system design conditions and site-specific technical challenges in this query document and its attachments.

This query document (without vendor responses) was originally submitted to the NDDH and EPA as part of an April 18, 2007 response[2] to NDDH's request for information (RFI)[3] regarding their review of the two BACT Analysis Study reports for control of NO_X emissions from existing Unit 1 and Unit 2 at MRYS required by the Consent Decree[4] that were originally submitted to the agencies in October 2006. Additional comments from Region 8 of U.S. EPA[5] were also attached to the NDDH's RFI. A summary of vendor initial responses was initially presented at a meeting of the NDDH, EPA Region 8, and Minnkota on May 23, 2007, in Bismarck by Burns & McDonnell[6].

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[1] See Reference number 1, April 18, 2007.
[2] See Reference number 2, April 18, 2007.
[3] See Reference number 3, February 1, 2007.
[4] See Reference number 4, April 24, 2006.
[5] Ibid Reference number 3.
[6] See Reference number 5, May 23, 2007.

In April 2008, Burns & McDonnell became aware that the record on the BACT determination issue for Unit 1 and Unit 2 at MRYS was still open. Due to the fact that one year had passed since the development of the initial SCR Vendor Query document and the vendor responses, Burns & McDonnell initiated contact with several of the vendors in order to more fully understand their initial responses, and to gather additional information.

Appendix A to this document contains emails and letter received from six of the eight SCR technology system suppliers and catalyst suppliers that responded to the referenced original SCR Vendor Query. Subsequently, followup telephone conferences have been held and emails have been exchanged with four of the six companies that responded to the original query. The following are comments pertaining to the SCR vendor's original and followup responses to the April 18, 2007 query.

SCR Vendor Query:

In the referenced April 18, 2007 SCR Vendor Query, Burns & McDonnell requested any information that the SCR system or catalyst supplier could provide regarding the following:

- Detailed information regarding the post-combustion controlled emission rates that full-scale, full-time SCR systems in lignite-fired coal-burning boiler operations have consistently achieved over a period of time, with appropriate pre-controlled baseline emission data.

  That is, Burns & McDonnell requested information that supports a level of emission reductions that could be guaranteed over the course of time, and not merely performance test or limited-duration emissions data, including the following.
    - Data of source-specific boiler and SCR design and operating parameters, along with lignite coal quality characteristics (analytical data) representative of the lignite-fired coal-burning boiler operations associated with long-term post-combustion controlled emission rates that SCR systems have achieved in practice at full-scale installations.
    - If provided, non-full scale laboratory, pilot or bench-scale exposure testing, short-term full-scale compliance or acceptance test data shall be clearly identified as such.

- Definitive statements of expected guaranteed life and control effectiveness performance for SCR catalyst when located in high-dust, hot-side applications at MRYS.

  These statements were requested to be supported by detailed descriptions of the vendor's interpretation of the technical information Burns & McDonnell provided, the vendor's awareness of proven methods of dealing with similar site-specific applications, the vendor's own qualifications and experience, and any stated or assumed design and operational requirements. That is, the guarantee must specifically reference the site-specific operating conditions at MRYS, with an SCR system calibrated to operate in that environment.
- Definitive statements regarding Burns & McDonnell's and EERC's serious concerns involving catalyst blinding and deactivation due to high sodium concentrations along with sulfate and other known components in the flue gas expected from cyclone boilers firing North Dakota lignite.

  Burns & McDonnell provided an analysis of the lignite fuel fired at MRYS, and asked that the guarantee specifically discuss the impact of this particular fuel on SCR system and catalyst performance and longevity.
- A detailed description of the vendor's approach to mitigating Minnkota's risks of failure to meet NO_X emissions control requirements and catalyst activity versus life guarantees, stating what the vendor would do to improve the probability of success prior to initial operation, and how they would respond if the emission control effectiveness and catalyst activity did not match the expectations of the guarantee.

It was understood that the vendor was expected to make certain assumptions regarding SCR system design operating conditions, because detailed development of MRYS unit-specific design schemes to deal with the high boiler outlet flue gas temperatures and other conditions resulting from operation of these cyclone boilers firing North Dakota lignite have not been confirmed. Recognizing that such SCR design details were not currently available, SCR system and catalyst vendors were requested to review the technical information Burns & McDonnell provided. This data was offered as a supplement to the vendors' own technical knowledge, commercial experience, and proprietary data to aid in the understanding of technical feasibility of installing and successfully operating and maintaining currently-available coal-fired SCR system technology on the referenced North Dakota lignite-fired cyclone boilers.

The SCR vendors were also advised of the background of the Consent Decree and BACT Analysis that included Selective Catalytic Reduction (SCR) technology for the Milton R. Young Station. They were made aware that the EPA had issued comments regarding the agency's reviews of the NO_X BACT Analyses. A basic issue to be resolved in order to address the EPA's comments was stated as:

- Would continuous exposure of available high-dust SCR catalyst to current flue gas temperatures and flyash with high sodium concentrations along with sulfate and other known components in the flue gas expected from MRYS cyclone boilers cause severe catalyst fouling, deactivation, and degradation resulting in unacceptable long-term NO_X emission control effectiveness, catalyst life, and cost-effectiveness?

The SCR system and catalyst vendors were asked to consider the current operating conditions and identify solutions to address boiler outlet flue gas temperatures and other conditions resulting from operation of these cyclone boilers firing North Dakota lignite. Vendor responses also needed to consider historic MRYS boiler outlet flue gas temperature data provided with the query that showed wide variations with boiler fireside cleanliness and load.

<u>Comments on SCR Vendor Query Responses:</u>

Information requests via email were sent to four SCR system vendors and four catalyst vendors[7]. Two of the original eight SCR system vendors and catalyst vendors (Argillon and Cormetech) indicated they would provide a response but subsequently did not, even after further followup. Six of the eight vendors did provide information: Alstom Power Environment, Babcock & Wilcox, Babcock Power Environmental, Ceram, Haldor Topsoe, and Hitachi.

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[7] See Reference number 6, April 18, 2007.

None of the vendors provided all of the information requested. The initial vendor responses that were unclear or provided information appearing to be stated without substantive basis or backup with identified source data were targeted for followup and telephone conference. The following includes comments by Burns & McDonnell (and EERC where so indicated) regarding the initial individual vendor responses from May 2007, and the subsequent supplemental responses following the late April 2008 telephone conference calls.

<u>Summary of Alstom Power's Responses and 2008 Followup</u>:

Alstom Power's initial response was provided in a letter dated May 30, 2007[8] submitted via email. Their initial comments provided information on lignite-fired boiler SCR applications, alternative tail-end SCR, predicted SCR performance, and indicative pricing and delivery for conventional SCR technology.

Alstom confirmed that there have not been any SCRs applied to boilers in the United States firing North Dakota or Texas lignites. Experience with an in-situ mini SCR reactor installed at TXU Energy's Martin Lake Unit 3, tested with two types of catalyst, was not detailed. Alstom recognized that North Dakota lignite is higher in sodium than Texas lignite, but stated that fuels high in sodium and potassium can be treated with specially selected catalyst. Wood and biomass-fired European boilers equipped with a hot-side electrostatic precipitators (ESPs) were cited as examples of dealing effectively with these catalyst poisons in such hot-side SCR applications.

Alstom expects acceptable emissions control and maintenance requirements can be achieved on North Dakota lignite service, assuming that the SCR system operates between 600-750°F. They anticipate that a modification or replacement of the economizer will be required to control boiler flue gas temperature within an acceptable range.

A Tail End SCR was mentioned as an alternative solution, with advantages and disadvantages briefly described. No plants firing fuels similar to North Dakota lignite with a Tail End SCR were identified.

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[8] See Reference number 7, included in Appendix A, dated May 30, 2007.

Alstom predicts that a properly designed SCR (presumably on a boiler firing North Dakota lignite) should be capable of achieving up to 90% [NO_X] removal efficiency with 2 ppm ammonia slip. They acknowledge minimal field data to predict how often the catalyst would need to be replaced, with 16,000 hours between replacements as a suggested average based on lab results.

Indicative pricing for materials and labor to provide conventional SCR technology at MRYS was stated, absent detailed analysis and without potential additional scope because of unusual design requirements to deal with the boiler flue temperatures and catalyst contaminants.

Alstom's April 28, 2008 Telephone Conference Call and Followup Response:

Alstom could not offer any new or different information that agrees with or refutes information presented in the October 2005 EERC report of slipstream catalyst testing at Coyote Unit 1 referenced in the SCR vendor query. Alstom acknowledged that "there are no known existing applications of SCR to ND lignite fired boilers, therefore there is some risk on any first [of] a kind application". Alstom's May 2008 letter also states:

> "Application of a traditional SCR to Lignite fired units will require some R&D, custom engineering, and likely a pilot testing program. This will be time consuming and expensive but will reduce the risks involved in a new application such as this one".

Alstom indicated its belief that Tail End SCR downstream of a hot-side ESP would be immune to catalyst poisoning from sodium-potassium-sulfur compounds. They agree that biomass and wood-fired boiler SCR experience with low sulfur is not the same situation as cyclone boilers firing North Dakota lignite.

Based on current data, Alstom indicated that they cannot guarantee SCR system performance for MRYS boilers firing North Dakota lignite because it hasn't been installed full-scale on a boiler firing this fuel. Additional pilot-testing of at least one year would be needed.[9]

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[9] See Reference number 8, included in Appendix A, dated May 5, 2008.

Comments on Alstom Power's Responses and April 28, 2008 Telephone Conference Call: Alstom did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Sources of field and laboratory test results of catalyst were cited but not substantiated with actual technical references or submittal of data.
An Alstom representative involved with Alstom's initial and followup responses (John Buschmann) acknowledged familiarity with the October 2005 EERC report of the SCR catalyst pilot testing at Coyote station.

Alstom did not appear to fully recognize how the method of firing the fuel in a cyclone boiler alters the character and composition of the flyash exhausted from the boiler, and that such contaminants pass through high-efficiency air cleaning equipment and create deposits that can blind and plug catalyst. The temperature of cyclone firing is higher and causes more vaporization of sodium and potassium in the lignite ash than occurs with a wood-fired boiler system. The wood-fired boiler systems have lower flame temperatures and thus less vaporization of alkali elements. This is evident based on the abundance of sodium and potassium-rich particles in the small ash size fraction found in the Coyote pilot SCR test catalyst and the particulate filter described in the referenced SCR vendor query. The sodium and potassium-rich materials combine with sulfur species to form sulfates that are significantly different and more problematic in their impacts on catalyst than Alstom's wood-fired boiler SCR experience indicates.

Alstom's wood-fired boiler SCR experience is not closely comparable to North Dakota lignite firing in cyclone boilers at MRYS. In general, alkali content of fly ash from wood firing is similar to the alkali content in the fly ash from the cyclones firing Center lignite. However, the form of the alkali in fly ash from the lignite-fired cyclone is likely in the oxide/hydroxide and partially sulfated forms; in wood fly ash, it will take another form, such as a chloride, if available. The lignite cyclone combustion derived alkali species are highly reactive with sulfur oxides resulting in the formation of a cohesive ash that produce stronger bonds and fill and coat catalyst pores and surfaces.

Alstom appeared to be unfamiliar with the unique high temperature air and flue gas requirements associated with the lignite drying systems on these MRYS boilers. Their expectation that a boiler economizer modification or replacement would resolve the low load-clean boiler-low flue gas temperature and high load-dirty boiler-high flue gas temperature situation appears to be a gross assumption based on an incomplete understanding of the thermodynamics of the flue gas, air, and fuel treatment systems employed at this facility[10].

No offer of any kind of SCR performance or service life guarantee was made by Alstom. The 16,000 hours between replacements, suggested as an average based on lab results[11], is not a guarantee or warranty, and was stated without the source data of the laboratory tests.

Summary of Argillon's Responses:

Argillon acknowledged the initial emailed query but failed to provide an actual initial response via phone call or email.[12]

Summary of Babcock & Wilcox's Responses:

Babcock & Wilcox did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Babcock & Wilcox's initial response via email[13] confirmed that there is not any full-scale operational experience with SCR systems retrofit to boilers firing North Dakota lignite or any other type of lignite in the United States. Therefore, neither B&W nor any other SCR system supplier can "provide detailed information regarding the post-combustion controlled emissions rates that full-scale, full-time SCR systems in lignite-fired coal-burning boiler operations have consistently achieved over a period of time."

B&W agrees with Burns & McDonnell that there are significant challenges associated with both boiler operation (high economizer exit gas temperature) and lignite firing (flue gas constituents) at Milton R. Young Station (MRYS). They mentioned the lack of justification and the need to invest significant dollars in research and development efforts to fully

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[10] See Reference number 9.

[11] Ibid Reference number 7, included in Appendix A, dated May 30, 2007.

[12] See Reference number 10, included in Appendix A.

[13] See Reference number 11, included in Appendix A.

investigate and understand both technical and commercial risks involved with applying SCRs on a limited number of units firing North Dakota lignites.

B&W has not fully explored the issues presented in the SCR vendor query with catalyst suppliers to better understand and quantify these challenges, or what may be needed to identify their concerns or the lengths to which they may need to go to address them especially if catalyst guarantees must be offered.

No offer of any kind of SCR performance or service life guarantee was made by B&W.

Summary of Babcock Power's Responses and 2008 Followup:

Babcock Power Environmental's (BPE's) initial response[14] recognized that "there have been a few tests performed to ascertain the possibility of using a high dust SCR on lignite and the potential for fouling/poisoning of the catalyst has been in question". BPE also indicated an expectation that "an SCR system could be successfully utilized on a boiler fired with Northern lignite fuel", while recognizing uncertainty regarding the ability of a high dust SCR on a boiler firing North Dakota lignite because there has not been any testing or installation of an SCR reactor of any significant size on such a boiler. BPE also "identified the MY1 and MY2 boilers as a very difficult one on which a high dust SCR would be applied because of the unique configuration of the boiler and the wide temperature swings that are encountered".

BPE indicated that "several possible solutions exist with varying certainties of outcome. The SCR technology location may potentially mitigate the issues with the possible poisoning of the catalyst by constituents in the gas from the combustion of Northern lignite". Babcock Power recommended that "an engineering study be conducted to evaluate three key issues":

- Initial estimates of the actual deactivation of SCR catalyst in the high dust location by the use of coupons positioned in the hot gas stream downstream of the economizer.
- Initial estimates of the actual deactivation of SCR catalyst in other locations by the use of coupons positioned in the gas stream downstream of the airheater.

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[14] See Reference number 12, included in Appendix A.

- Possibility of a retrofit of an SCR into the MY1 and MY2 boiler considering the wide range of temperature for the flue gas and possible boiler modifications required.

<u>Comments on Babcock Power's Responses and April 28, 2008 Telephone Conference Call</u>: Babcock Power Environmental did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. BPE's original email statements seem to be based upon the vendor's experience with other lignite fuels not specifically identified by location or composition. Subsequent email[15] and telephone[16] followup in 2008 indicated that the use of high activity SCR catalyst coupons positioned in the hot gas stream downstream of the boiler economizer, would also include test locations downstream of the existing cold-side electrostatic precipitator (and in Unit 2's case, a wet lime/flyash scrubber). BPE considers this a kind of "fatal flaw" investigation that would be conducted first. This would allow BPE to analyze the test catalyst coupons for deactivation to see if a high-dust SCR location could work. This initial testing would be conducted without ammonia reagent being injected into the flue gas stream ahead of the test catalyst. If BPE determined that there was potential for SCR success after analyzing the test catalyst coupons, a test reactor of appropriate size would be designed and built and installed. BPE indicated that such a test SCR reactor would need to be operated for a minimum of 4000 hours.

A Babcock Power Environmental representative involved with BPE's initial and followup responses (Clay Erickson) appears to be familiar with the October 2005 EERC report of the SCR catalyst pilot testing at Coyote station. BPEI's second emailed response stated that they have not nor know of any further work on this topic since the response they previously provided via email on May 11th 2007[17].

No offer of any kind of SCR performance or service life guarantee was initially made by Babcock Power Environmental. BPE would not guarantee performance unless the catalyst vendors would provide such a guarantee[18]. Furthermore, BPE indicated that it would not

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[15] See Reference number 13, included in Appendix A.
[16] See Reference number 14.
[17] Ibid Reference number 13, included in Appendix A.
[18] Ibid Reference number 14.

provide a guarantee of SCR performance on this fuel at these units without additional data such as that which would be derived from the test reactor described above[19].

Summary of Ceram's Responses and 2008 Followup:
Ceram reviewed the information provided by Burns & McDonnell regarding the technical feasibility of SCR on the Milton R. Young Station Units 1 and 2 firing North Dakota Lignite fuel[20]. Ceram's initial response comments acknowledged the lack of any catalyst installations currently operating with North Dakota lignite fuel. One brown coal SCR installation (not specifically identified) in Europe, and a large experience base with coals, refineries and incinerators combined with familiarity with the effects of a wide range of fuel and flue gas constituents was mentioned. They indicated that their brown coal from Europe was more like a Texas lignite ash. They indicated that sodium is a concern since it has a potential to infiltrate into the catalyst and cause deactivation especially during heat-up and cool-down. They were not familiar with cyclone firing and enhancement of sodium in the fines[21].

Ceram initially noted that North Dakota Lignite fuel and ash characteristics present certain challenges related to SCR operation and reliability. Additionally, the high flue gas temperatures needed for purposes of drying the fuel were mentioned as a challenge for SCR catalyst design, but no specific solution to this situation other than "flue gas tempering" being required was proposed.

Ceram's initial comments pertinent for this SCR application largely included items that needed to be considered or included in the SCR catalyst selection and reactor design, such as the presence of pyrosulfates (sodium, iron and sulfur) having the potential to increase the oxidation of sulfur (SO_2 to SO_3 conversion rate). Ceram could only guarantee the initial SO_2 to SO_3 conversion rate and not the end of life conversion rate.

Ceram provided a preliminary catalyst design that utilized a 7.4 mm pitch catalyst to minimize the risk of catalyst pluggage due to high concentrations of calcium and sulfates in the fuel. A

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[19] Ibid Reference number 14.
[20] See Reference number 15, included in Appendix A.
[21] See Reference number 16.

full SCR bypass system with an air drying or dehumidification system was recommended to keep the catalyst warm and dry during lay-up periods because of the high sodium and iron concentrations. The maximum continuous operating temperature of the preliminary SCR catalyst design was 850° F, with an allowance of short periods of operation up to 900 degrees F. A high temperature reference list of Ceram's SCR catalyst installations was provided.

Ceram developed a preliminary catalyst design for each Unit (outlined in attached files) that were expected to provide 85% NOx reduction (0.08 lb/MBtu outlet) with an SO_2 to SO_3 conversion rate of 1.0% and ammonia slip of 2.0 ppm for a guarantee life of 16,000 hours.

A Ceram representative involved with Ceram's initial response (Noel Rosha) acknowledged he was unfamiliar with the October 2005 EERC report of the SCR catalyst pilot testing at Coyote station[22]. After the April 23, 2008 telephone conference call, Ceram obtained a copy of the referenced October 2005 EERC report. The Ceram representative responding to the followup request (John Cochran) after reviewing EERC's report believed it was "certainly premature to assume that there is a fatal flaw for the use of high dust SCR behind cyclones burning North Dakota lignite". Also, Ceram stated: "Certainly a number of circumstances are present that necessitate a pragmatic approach to the application of catalyst for a lignite application" and "Sodium is not a poison to catalyst at SCR operating temperatures. Significant deactivation can occur if condensed moisture transports sodium residing at the surface into the catalyst pore structure during outage or layup"[23].

Ceram's second emailed response included Ceram's reasons for why it believes the application of SCR technology on North Dakota lignite-fired cyclone boilers can be successful. Ceram also advised that "in no event would any ammonia be allowed to be injected below 530 F for any likely combination of reasonable sulfur and NOx removal parameters. The NOx reduction for a reduced MOT [minimum operating temperature] should be considered in 30-day rolling average scenarios. Minimum flue gas temperatures listed for Units 1 and 2 are well below this threshold"[24].

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[22] Ibid Reference number 16.

[23] See Reference number 17, included in Appendix A.

[24] Ibid Reference number 17.

Ceram also included the following statement in their followup response: "based on the information provided as well as our large foundation of work related to the fuel considerations noted in the query and study CERAM can provide a commercial offering regarding this project. However, considering some of the remaining uncertainties we would recommend further testing to ensure a successful result"[25].

Comments on Ceram's Responses and April 23, 2008 Telephone Conference Call:
Ceram did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Their comments mentioned high sodium contents and fine fume as concerns reported by Dr. Benson and the EERC report on slipstream pilot SCR testing having "flawed pitch and resultant pluggage of the catalyst used during Coyote Station testing" as "inadequate evidence ... that this could be a fatal flaw to application of SCR"[26].

What appears to be missing from Ceram's comments are recognition that North Dakota lignite firing in cyclones promotes formation of low melting point eutectic combinations of sodium, potassium, and sulfur to form sulfates which produce extremely strong deposits that fill and plug the pores of the catalyst, regardless of the pitch. The effects of this eutectic melting and blinding was not considered, as Ceram's comments focus on the issue of significant deactivation from sodium due to mobilization of sodium if condensed moisture becomes available.

Ceram's initial response mentions a guaranteed catalyst service life of 16,000 hours and the initial SO_2 to SO_3 conversion rate, but did not actually expressly state that they would guarantee NOx reduction performance. Their willingness to provide a commercial offering is based upon recommended "further testing to ensure a successful result"[27].

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[25] Ibid Reference number 17.
[26] Ibid Reference number 17.
[27] Ibid Reference number 17.

Summary of Cormetech's Response:

Cormetech acknowledged the initial emailed query but failed to provide an actual initial response via phone call or email.[28]

Summary of Haldor Topsoe's Responses and 2008 Followup:

After its initial review of information and data provided by Burns & McDonnell regarding the viability of SCR technology on the Milton R. Young Station (MRYS) Units 1&2, Haldor Topsoe (HT) indicated that two separate issues exist with this application: extremely high flue gas exit temperatures (FGET) and lack of flue gas temperature control over the long term; and fuel-related issues specific to this variety of North Dakota lignite[29]. Haldor Topsoe did not address the high FGET as a unit-specific problem, presumably because they are not boiler heat transfer solution providers. HT indicated that they don't have a catalyst for coal-fired boiler applications that will survive 900°F flue gas that can be offered with a guarantee[30].

Based on the provided fuel and ash analysis of the North Dakota lignite that is burned at MRYS, Haldor Topsoe estimates that the deactivation rate of the catalyst will be high but manageable. A deactivation rate in line with wood-fired boilers which have been successfully fitted with SCR was predicted in HT's initial response; now, HT states this rate is higher than what they have seen on wood-fired boilers[31]. HT initially expected the deactivation rate to be steep initially but to flatten out considerably after about 4000 hours, and has recently (May 2008) modified this estimated time frame to 10,000 hours, where the catalyst is expected to lose about 60 percent of its initial activity during this time period. HT stated that the revised deactivation rate number is based mostly on comparison of the expected catalyst service conditions compared to that of wood-fired boilers. Higher flyash loading and catalyst attrition, combined with much more sulfur that leads to blinding of the catalyst were briefly described[32].

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[28] See Reference number 18, included in Appendix A.
[29] See Reference number 19, included in Appendix A.
[30] See Reference number 20.
[31] See Reference number 21, included in Appendix A.
[32] Ibid Reference number 21, included in Appendix A.

HT originally stated that the expected catalyst poisons are mostly water soluble, therefore periodic water washing of the catalyst can be used to regain activity and to increase overall service life. This technique is used on many wood and some PRB coal-fired applications.

Besides the deactivation, Haldor Topsoe identified another catalyst impact problem: clogging[33]. Ineffective sootblower simulation in the Coyote pilot test was the primary concern/experience, which HT infers does not represent full-scale SCR installations.

HT suggests that the next step is to install a larger pilot scale experiment with cross section of catalyst on the order of 2 meters by 2 meters. This would allow better catalyst cleaning and give a better determination of the catalyst degradation over time[34].

Based on the fuel analysis provided to HT and assuming that FGET can be controlled, HT would be willing to guarantee SCR catalyst performance on these units[35]. Haldor Topsoe expects 60 percent deactivation over the first 10,000 operating hours. HT can not provide a "make good" guarantee, but is willing to warrant their catalyst performance up to the contract value[36].

A subsequent email dated May 7, 2008 from Dr. Joakim Thøgersen of Haldor Topsoe (Denmark) to Robert Blakley to address additional followup questions to Flemming Hansen's May 5, 2008 email response provided further information regarding the wood-fired boiler SCR experience versus a hypothetical North Dakota cyclone boiler SCR situation[37].

One issue was the difference in flyash loading between ND lignite-fired cyclone boilers and wood-fired boilers mentioned previously by HT. The fly ash concentration in lignite flue gas is 5-10 times higher than in wood-fired boiler flue gas. But the fraction of alkali in flyash that deposits in the catalyst is a much smaller portion of the total flyash loading in lignite flue gas than wood-fired boilers. The reason according to Dr. Thøgersen has to do with the alkali being

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[33] Ibid Reference number 21, included in Appendix A.
[34] Ibid Reference number 21, included in Appendix A.
[35] Ibid Reference number 19, included in Appendix A.
[36] Ibid Reference number 21, included in Appendix A.
[37] See Reference number 22, included in Appendix A.

bound in coarse aluminum/silicate fly ash particles that don't contribute to the deposits in the catalyst to the same extent. When the alkali is incorporated in aluminum/silicate fly ash, the alkali also becomes inactive as a SCR poison. The lignite fly ash also has a cleaning effect by attrition of the surface that causes re-entrainment of particle deposits. Attrition is re-entrainment or cleaning of the catalyst surface by particle impaction[38].

Another issue was the much higher concentration of sulfur in ND lignite cyclone boiler flue gas compared to wood-fired boiler flue gas. Haldor Topsoe recognizes that SO_2 levels in ND lignite flue gas are 700-800 ppm whereas it is less than 10 ppm in wood flue gas. The sulfur leads to a strengthening and densification of the blinding layers that originates from deposition of calcium, sodium, and potassium aerosols[39]. The sulfur reacts with deposited sodium chloride (NaCl), calcium oxide (CaO), and potassium chloride (KCl), which means that the particles swell and the blinding layer becomes more impermeable[40].

A telephone conversation between Dr. Joakim Thøgersen and Steve Benson on May 2, 2008 indicated that the deactivation rates would be greater than that of the worst wood-fired system because of the high sodium and sulfur (greater than 60% in 10,000 hours). Dr. Thøgersen indicated that at this point, Haldor Topsoe would not be in a position to make a 100% "make good" guarantee[41]. Haldor Topsoe's predictions of SCR catalyst deactivation are somewhat semi quantitative since the predictions are based on extrapolation/interpolation from wood firing and PRB fired boilers[42].

<u>Comments on Haldor Topsoe's Responses and April 24, 2008 Telephone Conference Call</u>: Haldor Topsoe (HT) did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Sources of catalyst experience on wood-fired boilers were cited but not substantiated with actual technical references or submittal of data.

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[38] Ibid Reference number 22, included in Appendix A.
[39] Ibid Reference number 21, included in Appendix A.
[40] Ibid Reference number 22, included in Appendix A.
[41] See Reference number 23.
[42] Ibid Reference number 22, included in Appendix A.

The Haldor Topsoe representative involved with their initial response (Wayne Jones) acknowledged he was unfamiliar with the October 2005 EERC report of the SCR catalyst pilot testing at Coyote station[43]. Flemming Hansen provided the followup response, and was a participant in the referenced Coyote Station SCR catalyst pilot testing.

The amount and basis of HT's initial estimate of 4000 hours for rapid catalyst deactivation when exposed to North Dakota lignite-fired cyclone boiler flue gas and flyash was not provided, only that it was originally of the same magnitude as wood-fired boiler SCRs[44]. Now the expectation is stated to be worse than wood-fired boiler SCRs, with 60% deactivation over the first 10,000 operating hours[45].

Haldor Topsoe' apparent initial willingness to guarantee SCR catalyst performance on Unit 1 and Unit 2 at Milton R. Young Station firing North Dakota lignite is based largely on their experience on boilers firing wood with SCRs that have 5 to 10 times less flyash and 70 to 80 times less sulfur[46]. It also requires that the high flue gas temperatures presented in the query document are lowered and controlled, without knowing if or how this might be accomplished.

Haldor Topsoe's wood-fired boiler SCR experience is not closely comparable to North Dakota lignite firing in cyclone boilers at MRYS. In general, alkali content of fly ash from wood firing is similar to the alkali content in the fly ash from Center lignite. However, the form of the alkali in fly ash from cyclone-fired lignite is an oxide/hydroxide and sulfate; in wood fly ash, it will take another form, such as a chloride, if available. There are differences in reactivity between these forms of alkali with sulfur oxides that make the lignite flyash produce stronger bonded deposits on catalyst surfaces and in pores.

The temperature of cyclone firing is higher and causes more vaporization of alkali elements in the lignite ash than occurs with a wood-fired boiler system. The wood-fired boiler systems have lower flame temperatures and thus less vaporization of alkali elements. This is evident

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[43] See Reference number 24.
[44] Ibid Reference number 19, included in Appendix A.
[45] Ibid Reference number 21, included in Appendix A.
[46] Ibid Reference number 21, included in Appendix A

based on the abundance of sodium and potassium-rich particles in the small ash size fraction found in the Coyote pilot SCR test catalyst and the particulate filter described in the referenced SCR vendor query. The sodium and potassium-rich materials combine with sulfur species to form sulfates are significantly different and more problematic in their impacts on catalyst than HT's wood-fired boiler SCR experience.

The pathway to the formation of bonded deposits on catalyst surfaces and pores for wood firing is different in lignite fired systems. HT suggested sodium chloride (NaCl) and potassium chloride (KCl) along with calcium oxide (CaO) are the intermediate species that become sulfated for the lignite application. It is evident that HT bases their assumptions on wood firing. In lignite, the intermediate species differ from wood because of the low levels of chlorine in the lignite coal. The reactions for sodium and potassium likely follow the path from vaporized atomic sodium and potassium in the flame to condensed sodium and potassium oxides or hydroxides. The calcium oxide (CaO) particles will form on the surface of the burning char particles and will be released as the char burns out. This resulting mixture (Na_2O/NaOH, K_2O/KOH, and CaO) of small particles (aerosols) will undergo minor sulfation during entrainment. As the particles are being transported with the bulk gas flow through the catalyst, they will deposit in the pores and on the surface of the catalyst. Once deposited, the particles will react with SO_3 to form sulfates and pyrosulfates causing the particles to swell filling pores and creating an impermeable layer. Another key point is that the rate of reaction to form sulfate is very fast in the pores because of the ability of the catalyst to convert SO_2 to SO_3.

Regarding the differences between ND lignite-fired cyclone boilers and wood-fired boilers mentioned previously by HT, loadings of ash are presumably higher for Center lignite and the potential for the scrubbing action of the silicate materials is possible. However, this scrubbing action will be unlikely for operations firing lignite with high sodium-low ash combinations supplied from the Center mine. In the low ash cases of ND lignite from the Center mine, the sulfated sodium and calcium particles are highly cohesive because of sulfate/pyrosulfate bonding that occurs between the particles. These types of bonded phases will be resistant to attrition and sulfate/pyrosulfate materials will capture the silicate particles resulting in increased growth and plugging. The scanning electron microscope (SEM) images in the October 2005 EERC paper[47] show evidence of captured aluminosilicate particles bonded in a sodium calcium sulfate matrix. The attrition effect described by Dr. Thøgersen assumes that erosion of the deposited materials will take place subsequent to particle impaction. However, if the deposit on the catalyst surface is cohesive and sticky, deposit growth will take place as described above.

Summary of Hitachi's Response:

Hitachi did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Hitachi's initial response via email[48] confirmed that there has been very little testing and data available on North Dakota lignite. After their initial review of information and data provided by Burns & McDonnell regarding the viability of SCR technology on the Milton R. Young Station (MRYS) Units 1&2, Hitachi expressed several concerns about the difficulty of installing and operating a hot-side, high-dust SCR:

- Without a plan to reduce the flue gas temperature, the catalyst will deactivate very quickly above 850 degrees F.
- High sodium content of the ash may cause serious deactivation of the catalyst.
- High sulfur trioxide (SO_3) content in ash may also cause faster catalyst deactivation.
- Sticky ash will cause a pluggage problem.

Because of all these unknowns, Hitachi strongly recommended that a slipstream test be performed to confirm the applicability of the catalyst for this flue gas[49].

Summary Comments on SCR System Suppliers' and Catalyst Suppliers' Responses:

The responses were mixed, with the SCR System Suppliers (boiler original equipment manufacturers) being pessimistic (B&W, Hitachi) to optimistic (Alstom, BPE) about the ability of an SCR system to be successful on these cyclone boilers burning North Dakota lignite. The SCR Catalyst Suppliers that provided technical responses (Ceram, Haldor Topsoe, and Hitachi) were mixed in their response, with Ceram and HT being more positive and Hitachi more

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[47] See Reference number 25.
[48] See Reference number 26, included in Appendix A.
[49] Ibid Reference number 26, included in Appendix A.

negative. Of the catalyst vendors that were favorable, both indicated that their willingness to offer performance guarantees requires solving the flue gas temperature problems for which they are not responsible. Haldor Topsoe further qualified their willingness to warrant their catalyst performance was not a "make good" guarantee, but is limited to the amount of contract value of supplying the catalyst, which is a small portion of a typical full-scale full-time SCR system installation. Ceram did not specify their catalyst performance guarantee nor service life warranty limits. None of the SCR system suppliers offered any performance guarantees, not even Alstom and Babcock Power who believe that SCRs could be successfully utilized on MRYS cyclone boilers firing North Dakota lignite.

SCR suppliers and catalyst suppliers did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Some responses were more detailed than others; none included reference plant information or specific fuel and ash analysis data that presumably forms the basis of their opinions, estimates and predictions.

The vendors did not offer any new or different field pilot testing or laboratory/bench scale information including catalyst analysis from samples exposed to flue gas and flyash created from firing North Dakota lignite that agrees with or refutes information presented in the October 2005 EERC report of slipstream catalyst testing at Coyote Unit 1 referenced in the SCR vendor query. Several acknowledged that there are no known existing applications of full-scale, full-time SCR technology to ND lignite fired boiler, therefore there is some risk in this application. Suppliers did not provide much detail in identifying solutions to mitigate risks; mostly their comments suggested or recommended various tail-end SCR or low-dust SCR configurations to minimize flyash deposition. These responses largely ignored the evidence presented in the April 2007 query and October 2005 EERC report that fine alkali particles pass though the dust collection equipment (ESPs) that would be located ahead of these SCR reactors, which will plug pores and blind the catalyst surfaces, making the catalyst ineffective in reducing NOx emissions.

Of the SCR suppliers and catalyst suppliers providing additional responses, all recommend or favor a course of further research and pilot-scale testing before they would be confident of catalyst deactivation rates, service life, location in the gas stream for placement of the SCR reactor, and amount of catalyst required.

Conclusions on SCR Technical Feasibility for North Dakota's BACT Determination:

Minnkota has previously submitted arguments regarding the appropriateness of conducting pilot testing of selective catalytic reduction (SCR) technology at Milton R. Young Station Units 1 and 2 for use in a NOx BACT Analysis[50]. The vendor responses summarized and included herein have not altered the rationale of Minnkota's arguments that:

- Pilot-scale testing of SCR technology is specifically not required by the BACT determination procedures established by the U.S. Environmental Protection Agency (EPA).
- Previous research, including previous SCR pilot testing conducted at Coyote Station[51], indicates that there is not sufficient reason to believe that additional pilot testing suggested by SCR system suppliers and catalyst suppliers will produce results substantially different than those obtained from the prior pilot test.

Vendor responses to an SCR Vendor Query[53] did not adequately address guarantees and warranty of system performance and catalyst service life to mitigate potentially significant, long-term operational and financial risks based on the specific applications involved. This query sought information that forms the basis of the vendors' responses to the issue of guarantees, including:

- Whether such guarantees would satisfy a "make good" requirement;
- Would the vendor provide a catalyst service life guarantee and replacement warranty; and

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[50] See Reference number 27.
[51] Ibid Reference number 25.
[53] Ibid Reference number 1, April 18, 2007.

- Whether any catalyst service life that a vendor would propose is based on the special nature of this fuel and ash composition method of firing (in a cyclone) and the location relative to gas cleaning equipment.

All vendors that responded to the query mentioned the significant challenges involved with the design considerations for applying SCR technology to these MRYS boilers. Only two vendors provided responses that included willingness to offer any guarantees on catalyst performance, with significant limitations on acceptable operating conditions which are yet to be achieved and would require solutions provided by other vendors. One of these catalyst suppliers responded that they would not be willing to offer a "make good" guarantee. The lack of suppliers' willingness to extend system and catalyst performance guarantees that satisfy "make good" requirements, as well as a lack of detail on service life warranty offers, does not support a substantial endorsement of applying SCR technology to these MRYS boilers with sufficient guarantees and certainty of results without having to perform substantial pilot testing, research and development, and specialized design as provided in the vendor responses.

Minnkota has previously presented the regulatory basis for the decision to not conduct pilot testing, as well as the reasons for technical infeasibility of SCR technology, for use in a NOx BACT Analysis[54]. The significant limitations stated by the catalyst suppliers regarding acceptable operating conditions which are yet to be attained and would require solutions provided by other vendors are significant caveats to believe that any suggested guarantees on catalyst performance or service life would be achieved with certainty. The fact that all the SCR suppliers responding to query recommend or favor pilot testing means that this technology is insufficiently developed to be considered "available" for the Unit 1 and Unit 2 boilers at MRYS burning North Dakota lignite as discussed in the EPA's NSR Manual[55].

Minnkota has provided sufficient information and documentation to NDDH and EPA, including responses to issues raised and requests made after submittal of the BACT Analysis Study reports[56] in October, 2006, to establish that SCR cannot be reasonably installed and

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[54] Ibid Reference number 27.

[55] See Reference number 28,

[56] See Reference number 29, October, 2006,

operated on the cyclone-fired boilers burning North Dakota lignite located at Milton R. Young Station.

REFERENCES

1 Burns & McDonnell and Energy & Environmental Research Center (EERC), *"Information Request"* (SCR Vendor Query and Attachments), April 2007.

2 Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative "*Responses To NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns, Milton R. Young Station Unit 1 And Unit 2 NOx BACT Analysis Study, April 18, 2007*".

3 North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: BACT Determination Milton R. Young Station*, dated February 1, 2007, with enclosure from United States Environmental Protection Agency Region 8, letter to Terry O'Clair, North Dakota Department of Health Division of Air Quality, *Re: Transmittal of EPA Non-SCR concerns and additional information required for Minnkota BACT Analysis Study*, dated January 26, 2007.

4 Consent Decree filed in the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034, filed April 24, 2006.

5 Burns & McDonnell and Energy & Environmental Research Center (EERC) presentation to North Dakota Department of Health, Environmental Health Section, Division of Air Quality, and United States Environmental Protection Agency, *"Summary of Responses to EPA/DOH Questions on Minnkota Power's NOx BACT Analysis for Milton R. Young Units 1 & 2"*, May 23, 2007.

6 Burns & McDonnell list of SCR System Suppliers and SCR Catalyst Suppliers (for sending SCR Vendor Query Information Request via email), 4/18/2007.

7 Electronic mail, Robert Blakley to Chuck Nordhausen (Alstom Power) April 18, 2007, and Letter (submitted via email), Michael G. Phillips (Alstom Power Environmental Control Systems) to Robert Blakley, May 30, 2007. See Appendix A for copies.

8 Electronic mail, Robert Blakley to John Buschmann (Alstom Power Environmental Control Systems), April 28, 2008; and Letter (submitted via email), Michael G. Phillips (Alstom Power Environmental Control Systems) to Robert Blakley, May 5, 2008. See Appendix A for copies.

9 Personal notes from Telephone Conference, John Buschmann (Alstom Power Environmental Control Systems) with Robert Blakley, Carl Weilert, and Steve Benson (EERC), April 28, 2008.

10 Electronic mail, Robert Blakley to Cindy Khalaf (Argillon) April 18, 2007, and April 19, 2007 email reply. See Appendix A for copies.

11 Electronic mail, Robert Blakley to Steve Moorman (Babcock & Wilcox) April 18, 2007, and May 10, 2007 email reply. See Appendix A for copies.

12 Electronic mail, Robert Blakley to Rich Abrams (Babcock Power Environmental) April 18, 2007, and response email, May 11, 2007. See Appendix A for copies.

13 Electronic mail, Robert Blakley to Clay Erickson (Babcock Power Environmental, April 28, 2008, and response email May 6, 2008. See Appendix A for copies.

14 Personal notes from Telephone Conference, Clay Erickson and Joe Langone (Babcock Power Environmental) with Robert Blakley, Carl Weilert, and Steve Benson (EERC), April 28, 2008.

15 Electronic mail, Robert Blakley to John Cochran (Ceram) April 18, 2007, and response email from Noel Rosha with attachments, May 11, 2007. See Appendix A for copies.

16 Personal notes from Telephone Conference, Noel Rosha (Ceram) with Robert Blakley, Carl Weilert, and Steve Benson (EERC), April 23, 2008.

17 Electronic mail, Robert Blakley to Noel Rosha (Ceram) April 22, 2008, and response email from John Cochran, May 6, 2008. See Appendix A for copies.

18 Electronic mail, Robert Blakley to Scot Pritchard (Cormetech) April 18, 2007, and May 14, 2007 email reply. See Appendix A for copies.

19 Electronic mail, Robert Blakley to Flemming Hansen (Haldor Topsoe) April 18, 2007, and response email, May 10, 2007. See Appendix A for copies.

20 Personal notes from Telephone Conference, Flemming Hansen (Haldor Topsoe), with Robert Blakley, Carl Weilert, and Steve Benson (EERC), April 24, 2008.

21 Electronic mail, Robert Blakley to Flemming Hansen (Haldor Topsoe), April 28, 2008, and response email May 5, 2008. See Appendix A for copies.

22 Electronic mail, Robert Blakley to Flemming Hansen (Haldor Topsoe), May 5, 2008, and response email by Joakim Thøgersen (Haldor Topsoe) May 7, 2008. See Appendix A for copies.

23 Personal notes from Telephone Conference, Dr. Joakim Thøgersen (Haldor Topsoe) call to EERC with Steve Benson (EERC), May 2, 2008.

24 Personal notes from Telephone Conference, Wayne Jones (Haldor Topsoe), with Robert Blakley, April 22, 2008.

25 "*Ash Impacts On SCR Catalyst Performance*", Steven A. Benson, Ph.D., Energy & Environmental Research Center (EERC) of the University of North Dakota", October 2005.

26 Electronic mail, Robert Blakley to Anthony Favale (Hitachi), April 18, 2007, and response email, May 11, 2007. See Appendix A for copies.

27 Burns & McDonnell, EERC, and Hogan & Hartson, *"Appropriateness Of Conducting Pilot Testing Of Selective Catalytic Reduction (SCR) Technology At Milton R. Young Station Units 1 And 2 For Use In A NOx BACT Analysis, August 14, 2007".*

28 *EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990* (The "NSR Manual").

29 Burns & McDonnell, "*BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc.*" and a separate "*BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative*", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "*BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc. Final Report, October 2006*" submitted by Minnkota to North Dakota Department of Health.

APPENDIX A -

Initial Vendor Responses to 4/18/2007 SCR Vendor Query Information Request (and Attachments), May 2007, and Followup Vendor Responses to 4/18/2007 SCR Vendor Query Information Request (and Attachments), May 2008, arranged in alphabetical and chronological order by vendor name.

From: Blakley, Robert
Sent: Wednesday, April 18, 2007 3:58 PM
To: 'Charles.nordhausen@power.alstom.com'
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Chuck,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Alstom to review the attached request document and respond within three weeks if possible. If Alstom's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: charles.nordhausen@power.alstom.com [mailto:charles.nordhausen@power.alstom.com]
Sent: Wednesday, May 30, 2007 11:03 AM
To: Blakley, Robert
Cc: mike.phillips@power.alstom.com; john.buschmann@power.alstom.com; kthingelstad@minnkota.com; jgraves@minnkota.com
Subject: Re: Request for Lignite SCR Feasibility Commercial and Technical Information

Bob,

Please find attached the Alstom ECS response to the Burns and McDonnell RFI on behalf of Minnkota Power. If you have any further questions or would like to discuss this topic further, do not hesitate to contact me.

Best Regards,

Chuck

Chuck Nordhausen
Alstom GPS
Office: (913) 393-2585
Mobile: (651) 492-7420

ALSTOM

Power Turbo-Systems / Power Environment
Environmental Control Systems
North America

May 30, 2007

Mr. Robert Blakley
Burns and McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Subject: Request For SCR Information
Milton Young Units 1&2

Dear Mr. Blakley:

As Burns and McDonnell and Minnkota Power are aware, ND Lignite does create many challenges for SCRs, but even with all of those challenges, it is possible to use ND Lignite if the system is designed properly and Minnkota Power elects to pay for the increased capital and O&M costs associated with this fuel. Alstom Power Environmental Control Systems (ECS) would like to offer Burns and McDonnell and Minnkota Power the following information in response to your request for SCR information on ND Lignite:

- Prior Applications of SCR to ND lignite fired boilers
- Alternative Tail End SCR
- Predicted SCR Performance
- Indicative Pricing and Delivery for Conventional SCR

Prior Applications of SCR to ND lignite fired boilers

Lignite coal burning units have not yet had any post combustion NOx controls installed on these units as environmental regulations have not yet required the installation of these controls. Investigative tests were performed on TXU Energy's Martin Lake Unit 3 to evaluate SCR catalyst performance on Texas-lignite-fired units. An in-situ mini SCR reactor was used for long-term tests on two types of catalyst to collect data on the effects of Texas lignite on SCR catalyst life and performance. After approximately 8000 hours of exposure to economizer outlet flue gas at typical SCR velocities of 15-20 ft./sec. (4.6-6.1 m/sec), both honeycomb and plate-type catalyst samples were shown, by field test, to have relative activities (K/K0) in the range of 0.70 to 0.75. Laboratory tests of catalyst activity performed by the catalyst vendors were consistent with these field test results. These results are expected to be representative of the first layer of a full-scale SCR reactor system. Erosion of the catalyst samples was not significant enough to affect catalyst performance. Test results further suggest that applying SCR catalyst technology (using even a high-dust design) to Texas-lignite-fired power generating units may be a practical approach for NOx control. (Electric Power Research Institute, December 2003, “Impacts of Texas Lignite Coal on SCR Catalyst Life and Performance: Field Data from TXU's Martin Lake Plant”)

It should be noted that North Dakota lignite is higher in sodium than Texas lignite. Fuels high in sodium and potassium require special selection of catalyst, but can be treated by SCR. An example of a such an application would be wood and other biofuel fired boilers in Europe. While SCR catalyst life in ND lignite service is not expected to be as long as in bituminous coal service, it is expected that acceptable emissions control and maintenance requirements can be achieved. Based on experience with wood fired units, a hot side (600-750 deg F) ESP is effective in removing the fly ash compounds that result in catalyst poisoning.

Proper operation of the SCR generally requires that the system operate in a temperature range of 600 to 750 deg F. Per the information provided, the Milton R Young boiler flue gas temperature at the economizer outlet currently varies quite a bit outside this range. Based on this temperature information, we anticipate that modification or replacement of the economizer will be required to control the temperature within an acceptable range.

Alternative Tail End SCR

While likely more expensive, an alternative solution to the conventional SCR , is a Tail End SCR where the SCR is located just before the stack. For this application, the location of the SCR just before the stack can provide significant advantages. The economizer outlet temperature variations will have no effect on the SCR, and the fly ash constituents that can poison the catalyst will have been removed from the flue gas stream by the existing ESPs. This would mean that modification of the existing economizer and any existing ESP would not be required with the application of a Tail End SCR.

The key disadvantage of the Tail End SCR is that the flue gas stream will need to be reheated from the current stack temperature up to approximately 600 deg F. Typically the flue gas is reheated using natural gas, however high pressure steam has been used in some cases. Heat recovery can be utilized to reduce the amount of energy required, however, the heating requirement is typically in the range of tens of millions of Btu per hour.

Predicted SCR Performance

Designed properly, the SCR should be capable of up to 90% removal efficiencies with an associated ammonia slip below 2 ppm. The significant unknown is how often the catalyst itself would need to be replaced. There is minimal field data to demonstrate expected catalyst life, but lab results suggest an average up to 16,000 hours between replacements.

Indicative Pricing, Sizing and Delivery

Because of the unusual design associated with this SCR and the potential additional scope items (heat exchangers or hot ESPs) required, it is expected that the cost will be significantly higher than for a conventional bituminous coal fired SCR. Without detailed anlaysis, the material and labor pricing below is our best estimate of the cost of a conventional SCR based on the increased sizing requirements.

Milton Young 1:	$50M
Milton Young 2:	$75M
Lead Time:	32 to 36 months

This estimated pricing does not include BOP costs, costs to modify the economizer, costs to modify existing precipitators, or costs to install gas to gas heat exchangers. Obviously, depending on the path forward and the resultant equipment required, the costs could be even more than stated above.

Alstom Power ECS hopes that this information can assist you in your SCR decision for Milton Young. In summary, it is possible to design and operate an SCR on this fuel if required, but doing so is not without challenges and can be very costly depending on which approach you may choose to pursue. Should you decide to pursue an SCR for these units, Alstom would be very interested in supporting you as we consider ourselves one of the industry leaders in this technology. Please contact Chuck Nordhausen, John Buschmann or me at your convenience with any questions or clarifications regarding this discussion.

Respectfully Submitted,

Michael G. Phillips
Business Applications Manager
Environmental Control Systems

CC: John Graves
Karen Thingelstad

From: Blakley, Robert
Sent: Monday, April 28, 2008 3:29 PM
To: 'john.buschmann@power.alstom.com'
Cc: 'charles.nordhausen@power.alstom.com'; 'mike.phillips@power.alstom.com'
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

John -

Thank you for discussing the issues of SCR feasibility involving North Dakota lignite-fired cyclone boilers.

Hopefully you've gotten a chance to revisit the April 18, 2007 query, and review results of pilot SCR testing performed at Coyote Station, on a boiler of the same size, cyclones and similar fuel as fired at Milton R. Young Station's Unit 2 boiler.

We would appreciate an email response to this followup, with discussion of the technical research and experience basis of Alstom's positions on catalyst fouling, poisoning, and blinding appropriate to high sodium, medium sulfur coal flyash and flue gas produced from these boilers, both in hot-side/high-dust and low-dust/tail end SCR applications.

We are interested in learning more about the basis of lab results mentioned in discussion of the 16,000 hours as a suggested number of operating hours between catalyst replacements. Particularly, if Alstom were asked to provide a catalyst service life guarantee and replacement warranty, whether this or any other operating time that Alstom would propose is based on the special nature of this fuel and ash composition method of firing (in a cyclone) and the location relative to gas cleaning equipment. As mentioned during our telephone conference, the April 2007 SCR vendor query contained evidence of fine sodium particles downstream of MRY Station Unit 2's cold-side ESP and wet FGD scrubber.

We are also interested in knowing more about Alstom's willingness to offer SCR performance guarantees, and what that would include from a commercial standpoint along with a catalyst warranty. Of particular interest is whether Alstom's guarantee would satisfy a "make good" requirement, require full-scale field testing of each boiler prior to catalyst selection and design, testing catalyst in a slipstream arrangement or other exposure demonstrations, and if there are any other qualifiers beyond the assumption that the high flue gas temperatures in a conventional hot-side, high-dust SCR were limited by a solution to these temperature conditions yet to be developed.

It would be beneficial to reference Alstom's previous May 30, 2007 response when sending a supplemental response addressing this subject and issues raised in today's discussion.

We realize that this is a concentrated effort that does not allow much time to review and provide such responses.

We ask that Alstom provide their email response by Monday, 5/5 12 pm (noon), so that we can review this and forward to Minnkota.

Again, thank you for your attention to this matter.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: mike.phillips@power.alstom.com
[mailto:mike.phillips@power.alstom.com]
Sent: Tuesday, May 06, 2008 8:55 AM
To: Blakley, Robert
Cc: charles.nordhausen@power.alstom.com;
john.buschmann@power.alstom.com
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Sorry for the delay!

(See attached file: Response to B&M for Minnkota SCR Inquiry 050608.doc.zip)

Regards,
Mike

Michael G. Phillips
513-543-0055 mobile
865-560-1389 office
1409 Centerpoint Blvd.
Knoxville, TN. 37932

ALSTOM

Power Turbo-Systems / Power Environment
Environmental Control Systems
North America

May 5, 2008

Mr. Robert Blakely
Burns and McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Subject: Minnkota Power Cooperative
Milton R Young SCR Inquiry

Dear Mr. Blakely:

Alstom Power Environmental Control Systems (ECS) has reviewed the information available to us regarding SCR installations on ND Lignite units and feel that our original response to Minnkota dated May 27, 2007 is still valid. The highlights of that letter are clarified / summarized below.

- There are no known existing applications of SCR to ND lignite fired boilers, therefore there is some risk on any first a a kind application
- Alstom believes that hot side SCRs can be utilized in this application if a hot ESP is used upstream for ash collection before the SCR, but would as a result be very expensive from both a capital and O&M standpoint compared to non ND lignite SCRs
- In order to provide catalyst life guarantees, it is anticipated that catalyst manufacturers would require a pilot test of at least one year
- Tail end SCRs remain an alternative, but are also very expensive from a O&M standpoint

While SCR catalyst life in ND lignite service is not expected to be as long as in bituminous coal service, it is expected that acceptable emissions control and maintenance requirements can be achieved. Based on experience with wood fired units, a hot side (600-750 deg F) ESP is effective in removing the fly ash compounds that result in catalyst poisoning.

Proper operation of the SCR generally requires that the system operate in a temperature range of 600 to 750 deg F. Per the information provided, the Milton R Young boiler flue gas temperature at the economizer outlet currently varies quite a bit outside this range. Based on this temperature information, we anticipate that modification or replacement of the economizer will be required to control the temperature within an acceptable range.

Application of a traditional SCR to Lignite fired units will require some R&D, custom engineering, and likely a pilot testing program. This will be time consuming and expensive but will reduce the risks involved in a new application such as this one.

1409 Centerpoint Blvd.
Knoxville, TN (USA) 37932-1962
Tel : 865 693-7550
Fax: 865 694-5203
www.alstomenvironmental.com

While likely more expensive, an alternative solution to the conventional SCR , is a Tail End SCR where the SCR is located just before the stack. For this application, the location of the SCR just before the stack can provide significant advantages. The economizer outlet temperature variations will have no effect on the SCR, and the fly ash constituents that can poison the catalyst will have been removed from the flue gas stream by the existing ESPs. This would mean that modification of the existing economizer and any existing ESP would not be required with the application of a Tail End SCR.

We hope this helps assist you with Minnkota on its future NOx requirements Please contact Chuck Nordhausen, John Buschmann or me at your convenience with any questions or clarifications. We look forward to having the opportunity to meet with you to discuss our proposal in detail.

Respectfully Submitted,

Michael G. Phillips
Business Sales Manager
Environmental Control Systems

Cc: Chuck Nordhausen – Alstom GPS
John Buschmann – Alstom ECS

From: Khalaf Cindy R [mailto:Cindy.Khalaf@argillon.com]
Sent: Thursday, April 19, 2007 4:50 AM
To: Blakley, Robert
Subject: Re: Request for Lignite SCR Feasibility Commercial and Technical Information

Robert,
We'll take a look and let you know if we need longer. Bruce Gobbel will be responding. Have you taken Bob Johnson's pllace?
Regards,
Cindy

Sent from my BlackBerry Wireless Handheld

From: Blakley, Robert
Sent: Wednesday, April 18, 2007 3:48 PM
To: 'cindy.khalaf@argillon.com'
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Cindy,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Argillon to review the attached request document and respond within three weeks if possible. If Argillon's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Wednesday, April 18, 2007 3:59 PM
To: Moorman, Steve A
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Steve,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Babcock & Wilcox to review the attached request document and respond within three weeks if possible. If B&W's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Moorman, Steve A [mailto:samoorman@babcock.com]
Sent: Wednesday, May 09, 2007 4:44 PM
To: Blakley, Robert
Cc: Telesz, Robert W; Hansen, Elizabeth A
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Robert,

The Babcock & Wilcox Company has reviewed your request of April 18, 2007 regarding information related to the application of SCR technology on steam generating units that fire North Dakota lignite.

As you indicate in your Information Request, there is no full scale operational experience with SCR systems that have been retrofit onto an ND lignite-fired boiler. In fact, we are aware of no SCR retrofit that to date has been done on any boiler here in the US where lignite of any type has been fired. Therefore, neither we nor any other SCR system supplier can "provide detailed information regarding the post-combustion controlled emissions rates that full-scale, full-time SCR systems in lignite-fired coal-burning boiler operations have consistently achieved over a period of time."

B&W agrees with Burns & McDonnell that there are significant challenges associated with both boiler operation (high economizer exit gas temperature) and lignite firing (flue gas constituents) at Milton R. Young Station (MRYS). We have had cursory conversations with catalyst suppliers in an attempt to better understand and quantify these challenges. However we have not been able to fully explore these issues and at this time have no knowledge of the full extent of the catalyst suppliers concerns or the lengths to which they may need to go to address them especially if catalyst guarantees must be offered. In addition, with the limited number of units firing North Dakota lignites, it would be difficult for a supplier like B&W to justify investing significant dollars in R&D efforts to fully investigate and understand both the technical and commercial risks that would be involved when installing SCRs on ND lignite fired boilers.

During our delivery of over 26,000 MW of SCR systems and our evaluation of several times that many customer inquiries, B&W has identified creative solutions to address a host of boiler-SCR system integration challenges. Some were implemented while others were necessarily abandoned as economically unfeasible. B&W would welcome the opportunity to work with Burns & McDonnell and the Minnkota Power Cooperative, Inc. to further investigate opportunities to successfully meet the NOx emission challenges at MRYS should Minnkota find it necessary to do so.

Steve Moorman

Steve Moorman --- District Sales Manager, Babcock & Wilcox

2096 Edgcumbe Road Saint Paul, MN 55116

Office 651-690-3795, Home 651-690-1558, Cell 612-670-8261

From: Blakley, Robert
Sent: Wednesday, April 18, 2007 4:02 PM
To: 'rabrams@babcockpower.com'
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Rich,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Babcock Power to review the attached request document and respond within three weeks if possible. If Babcock Power's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: rabrams@babcockpower.com [mailto:rabrams@babcockpower.com]
Sent: Friday, May 11, 2007 1:37 PM
To: Blakley, Robert
Cc: cerickson@babcockpower.com; MGialanella@babcockpower.com; Perrie Schafer; dgustafson@babcockpower.com
Subject: Re: Request for Lignite SCR Feasibility Commercial and Technical Information

Dear Mr. Blakely:

Babcock Power Environmental (BPE) has reviewed the information provided to us on Milton Young Units 1 & 2 lignite fired boiler and the request for information on the applicability of SCR technology these boilers and their fuel. As you are aware, there have been a few tests performed to ascertain the possibility of using a high dust SCR on lignite and the potential for fouling/poisoning of the catalyst has been in question.

BPE and its licensor have supplied >60,000 MW of SCR systems around the world, including in applications with lignite in Europe and active lignite projects in the states. We have examined the various lignite fuels from around the world and, while there are differences, we expect an SCR system could be successfully utilized on a boiler fired with Northern lignite fuel however, uncertainty exists because an SCR has yet to be tested/provided on a meaningful scale to a Northern lignite application.

Furthermore, during our review of the information provided, we have identified the MY1 and MY2 boilers as a very difficult one on which a high dust SCR would be applied because of the unique configuration of the boiler and the wide temperature swings that are encountered.

BPE is very interested in working with Burns & McDonnell and Minnkota Power to provide the optimum solution to this problem. Several possible solutions exist with varying certainties of outcome. The SCR technology location may potentially mitigate the issues with the possible poisoning of the catalyst by constituents in the gas from the combustion of Northern lignite.

We recommend an engineering study be conducted to evaluate three key issues:

Initial estimates of the actual deactivation of SCR catalyst in the high dust location by the use of coupons positioned in the hot gas stream downstream of the economizer.

Initial estimates of the actual deactivation of SCR catalyst in other locations by the use of coupons positioned in the gas stream downstream of the airheater.

Possibility of a retrofit of an SCR into the MY1 and MY2 boiler considering the wide range of temperature for the flue gas and possible boiler modifications required.

BPE would lead this effort with collaboration from Burns & McDonnell and Minnkota Power. .

BPE is planning to be in the Bismarck area during the week of June 18 and offer to visit the plant and to meet to discuss our thoughts on the program, its cost, and the sharing of those costs. Furthermore, we would like to discuss issue #3 in greater detail to better understand options in the boiler area. Please let me know the availability of Minnkota and B&Mc personnel to meet and discuss this subject. We look forward to hearing from you.

Rich Abrams
Director of Business Development
Babcock Power Environmental Inc.
Worcester, Massachusetts
Phone: 508.854.1140

From: Blakley, Robert
Sent: Monday, April 28, 2008 3:41 PM
To: cerickson@babcockpower.com
Cc: MGialanella@babcockpower.com; rabrams@babcockpower.com; Tyler Schafer; 'jlangone@babcockpower.com'; Perrie Schafer
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Clay -

Thank you for discussing the issues of SCR feasibility involving North Dakota lignite-fired cyclone boilers.

Hopefully you've gotten a chance to revisit the April 18, 2007 query, and review results of pilot SCR testing performed at Coyote Station, on a boiler of the same size, cyclones and similar fuel as fired at Milton R. Young Station's Unit 2 boiler.

We would appreciate an email response to this followup, with discussion of the technical research and experience basis of Babcock Power's positions on catalyst fouling, poisoning, and blinding appropriate to high sodium, medium sulfur coal flyash and flue gas produced from these boilers, both in hot-side/high-dust and low-dust/tail end SCR applications.

We are interested in learning more about the "fatal flaw" SCR catalyst coupon testing approach mentioned in today's discussion, and additional pilot-scale SCR catalyst testing in various locations relative to gas cleaning equipment.

We are also interested in knowing more about Babcock Power's willingness to offer SCR performance guarantees, and what that would include from a commercial standpoint along with a catalyst warranty. Of particular interest is whether Babcock Power's guarantee would satisfy a "make good" requirement, require full-scale field testing of each boiler prior to catalyst selection and design, testing catalyst in a slipstream arrangement or other exposure demonstrations, and if there are any other qualifiers beyond the assumption that the high flue gas temperatures in a conventional hot-side, high-dust SCR were limited by a solution to these temperature conditions yet to be developed. Particularly, if Babcock Power were asked to provide a catalyst service life guarantee and replacement warranty, whether a minimum operating time that Babcock Power would propose is based on the special nature of this fuel and ash composition method of firing (in a cyclone) and the location relative to gas cleaning equipment. As mentioned during our telephone conference, the April 2007 SCR vendor query contained evidence of fine sodium particles downstream of MRY Station Unit 2's cold-side ESP and wet FGD scrubber.

It would be beneficial to reference Babcock Power's previous May 11, 2007 response when sending a supplemental response addressing this subject and issues raised in today's discussion.

We realize that this is a concentrated effort that does not allow much time to review and provide such responses.

We ask that Babcock Power provide their email response by Monday, 5/5 12 pm (noon), so that we can review this and forward to Minnkota.

Again, thank you for your attention to this matter.

Bob Blakley
Burns & McDonnell

From: cerickson@babcockpower.com [mailto:cerickson@babcockpower.com]
Sent: Tuesday, May 06, 2008 10:58 AM
To: Blakley, Robert
Cc: MGialanella@babcockpower.com; jlangone@babcockpower.com
Subject: Lignite SCR Response

Robert,

Per our phone conversion concerning the application of SCR technology to Northern Lignite fired boilers, BPEI has not nor knows of any further work on this topic since the response provided below on May 11th 2007. As discussed BPEI believes the issues related to the application of SCR technology for northern lignite fired units to be addressable in design.
The EERC reports have indicated significant issues however BPEI feels further tests investigating different locations and using tests alternate methods must be performed to make a final determination. BPEI, as the worldwide leader in SCR technology, continues to offer its services for to the industry to resolve the application of SCR technology to northern lignite fired units.

If you have further questions please contact me or Joe Langone.

Clay Erickson

May 11th 2007 Response below

Babcock Power Environmental (BPE) has reviewed the information provided to us on Milton Young Units 1 & 2 lignite fired boiler and the request for information on the applicability of SCR technology these boilers and their fuel. As you are aware, there have been a few tests performed to ascertain the possibility of using a high dust SCR on lignite and the potential for fouling/poisoning of the catalyst has been in question.

BPE and its licensor have supplied >60,000 MW of SCR systems around the world, including in applications with lignite in Europe and active lignite projects in the states. We have examined the various lignite fuels from around the world and, while there are differences, we expect an SCR system could be successfully utilized on a boiler fired with Northern lignite fuel however, uncertainty exists because an SCR has yet to be tested/provided on a meaningful scale to a Northern lignite application.

Furthermore, during our review of the information provided, we have identified the MY1 and MY2 boilers as a very difficult one on which a high dust SCR would be applied because of the unique configuration of the boiler and the wide temperature swings that are encountered.

BPE is very interested in working with Burns & McDonnell and Minnkota Power to provide the optimum solution to this problem. Several possible solutions exist with varying certainties of outcome. The SCR technology location may potentially mitigate the issues with the possible poisoning of the catalyst by constituents in the gas from the combustion of Northern lignite.

We recommend an engineering study be conducted to evaluate three key issues:

Initial estimates of the actual deactivation of SCR catalyst in the high dust location by the use of coupons positioned in the hot gas stream downstream of the economizer.

Initial estimates of the actual deactivation of SCR catalyst in other locations by the use of coupons positioned in the gas stream downstream of the airheater.

Possibility of a retrofit of an SCR into the MY1 and MY2 boiler considering the wide range of temperature for the flue gas and possible boiler modifications required.

BPE would lead this effort with collaboration from Burns & McDonnell and Minnkota Power. .

(Embedded image moved to file: pic24350.gif)

BabcockPower

Clayton Erickson, PhD
Director, Process Engineering
Babcock Power Inc.
5 Neponset Street
Worcester, MA 01606

T: 508-854-4039 F: 508-854-1177
M: 508-245-2383

cerickson@babcockpower.com
http://www.babcockpower.com

From: Blakley, Robert
Sent: Wednesday, April 18, 2007 3:50 PM
To: 'john.cochran@ceram-usa.com'
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

John,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Ceram to review the attached request document and respond within three weeks if possible. If Ceram's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Noel Rosha [mailto:Noel.Rosha@CERAM-USA.COM]
Sent: Friday, May 11, 2007 4:44 PM
To: Blakley, Robert
Cc: John Cochran
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Mr. Blakley,

CERAM has reviewed the information provided by Burns & McDonnell regarding the technical feasibility of SCR on the Milton R. Young Station Units 1 and 2 firing North Dakota Lignite fuel. Based on the information provided we have developed preliminary catalyst designs for each Unit, as outlined in the attached files. Unit 1 and Unit 2 were both designed with 85% NOx reduction (0.08 lb/MBtu outlet) with an SO_2 to SO_3 conversion rate of 1.0% and ammonia slip of 2.0 ppm for a guarantee life of 16,000 hours. We have also included for your information our high temperature reference list.

CERAM currently does not have a catalyst installation with North Dakota Lignite fuel. CERAM does have a very wide fuels experience base for coals, including one brown coal reference in Europe. We also have a large experience base with refineries and incinerators and are familiar with the affects of a wide range of fuel and flue gas constituents.

North Dakota Lignite fuel and ash characteristics present certain challenges related to SCR operation and reliability. Additionally, the high flue gas temperatures needed for purposes of drying the fuel can be a challenge for SCR catalyst design. Please note the following technical clarifications that CERAM feels are pertinent for this application:

- The presence of pyrosulfates (sodium, iron and sulfur) have the potential to increase the SO_2 to SO_3 conversion rate. Based on this, CERAM could only guarantee the initial SO_2 to SO_3 conversion rate and not the end of life conversion rate.
- CERAM has utilized a 7.4 mm pitch catalyst to minimize risk of catalyst pluggage. High concentrations of calcium and sulfates in the fuel increase the potential for catalyst pluggage.
- Due to the high sodium and iron concentrations, CERAM would recommend a full SCR bypass system be installed. During lay-up periods the catalyst would need to remain warm and dry, for instance with an air drying or dehumidification system.
- CERAM would require the maximum continuous operating temperature of the SCR be designed for 850° F. Short periods of operation up to 900° F could be allowed. Boiler outlet temperatures greater than these would require flue gas tempering prior to reaching the SCR reactor.

Please let us know if you have further questions or would like additional information.

Best regards,

Noel Rosha
Applications Engineer

CERAM Environmental, Inc.
7304 W. 130th Street, Suite 140
Overland Park, KS 66213

Phone: (913) 239-9896
Fax: (913) 239-9821

CERAM CATALYSTS + HONEYCOMBS	**PROJECT**	**Milton R. Young Unit 1**
	DATE	4/23/2007
	PREPARED BY	Noel Rosha
	REVISION	0
	PROPOSAL NO.	NR042307-1

Design Basis:

	Case	Limiting case
		Design Load
	Load	Design Load
	Fuel	North Dakota Lignite
Gas flow	acfm,w	2483737
Gas temperature	°F	850
H_2O	Vol%	18.87
O_2-actual	Vol%,w	2.87
O_2-reference	Vol%,d	3.00
Inlet NOx	lb/MMBtu	0.53
SO_2	lb/hr	8970.0
SO_3	lb/hr	135.0
Particulate	lb/hr	20809.0

Catalyst Design:

Orientation		Vertical
Catalyst Volume per reactor	m^3	**625.7**
Number of SCR reactors	[-]	1
Number of units	[-]	1
Catalyst Volume, total	m^3	**625.7**
Cells of catalyst n x n	[-]	20
Specific area of catalyst Ap	m^2/m^3	469
Pitch of catalyst	mm	7.4
Catalyst length	mm	1071
Catalyst elements per one module	n x n	6 x 12
Number of layers per reactor		3
Module arrangement per layer	n x n	12 x 10
Module dimensions:		
length x width	mm x mm	958 x 1901
	ft x ft	3.14 x 6.24
height	mm	1411
	ft	4.63
Reactor dimensions:		
length x width	mm x mm	11816 x 19830
	ft x ft	38.77 x 65.06
Weight per module incl. catalyst	kg	1115
	lb	2457
Module frame material		H II

CERAM CATALYSTS + HONEYCOMBS	**PROJECT**	**Milton R. Young Unit 1**
	DATE	4/23/2007
	PREPARED BY	Noel Rosha
	REVISION	0
	FILE	NR042307-1

Catalyst Performance:

	Case	Limiting case
		Design Load
	Load	Design Load
	Fuel	North Dakota Lignite
NOx outlet	ppmvd,ref.O_2	43.2
	lb/MMBtu	0.08
NOx reduction rate	%	85
NH_3 slip	ppmvd,ref.O2	2.0
NH3 100% consumption per reactor	kg/h	249.5
	lb/h	550.0
Catalyst pressure drop, clean	mbar	6.0
	inwg	2.4
	mm WC	61.1
Catalyst pressure drop, dirty	mbar	6.6
	inwg	2.7
	mm WC	67.4
SO_2/SO_3 conversion rate	%	1.00
Catalyst life	hr / years	16000 / 2

Technical Requirements:

Minimum NH_3 injection temperature	°C	317
	°F	602
Molar ratio distribution	% absolute	10
Velocity distribution	% absolute	15
Temperature distribution	°C absolute	10
Soot blower or sonic horns	yes / no	y

CERAM
CATALYSTS + HONEYCOMBS

PROJECT	**Milton R. Young Unit 2**
DATE	4/23/2007
PREPARED BY	Noel Rosha
REVISION	0
PROPOSAL NO.	NR042307-1

Design Basis:

	Case	Limiting case
		Design Load
	Load	Design Load
	Fuel	North Dakota Lignite
Gas flow	acfm,w	4371000
Gas temperature	°F	818
H_2O	Vol%	17.08
O_2-actual	Vol%,w	4.77
O_2-reference	Vol%,d	3.00
Inlet NOx	lb/MMBtu	0.52
SO_2	lb/hr	15474.0
SO_3	lb/hr	236.0
Particulate	lb/hr	34584.0

Catalyst Design:

Orientation		Vertical
Catalyst Volume per reactor	m^3	**947.1**
Number of SCR reactors	[-]	1
Number of units	[-]	1
Catalyst Volume, total	m^3	**947.1**
Cells of catalyst n x n	[-]	20
Specific area of catalyst Ap	m^2/m^3	469
Pitch of catalyst	mm	7.4
Catalyst length	mm	1298
Catalyst elements per one module	n x n	6 x 12
Number of layers per reactor		2
Module arrangement per layer	n x n	15 x 15
Module dimensions:		
length x width	mm x mm	958 x 1901
	ft x ft	3.14 x 6.24
height	mm	1638
	ft	5.37
Reactor dimensions:		
length x width	mm x mm	14750 x 29735
	ft x ft	48.39 x 97.56
Weight per module incl. catalyst	kg	1310
	lb	2889
Module frame material		H II

CERAM CATALYSTS + HONEYCOMBS		
	PROJECT	**Milton R. Young Unit 2**
	DATE	4/23/2007
	PREPARED BY	Noel Rosha
	REVISION	0
	FILE	NR042307-1

Catalyst Performance:

	Case	Limiting case
		Design Load
	Load	Design Load
	Fuel	North Dakota Lignite
NOx outlet	ppmvd,ref.O_2	44.7
	lb/MMBtu	0.08
NOx reduction rate	%	85
NH_3 slip	ppmvd,ref.O2	2.0
NH3 100% consumption per reactor	kg/h	370.5
	lb/h	816.7
Catalyst pressure drop, clean	mbar	4.3
	inwg	1.8
	mm WC	44.2
Catalyst pressure drop, dirty	mbar	4.8
	inwg	1.9
	mm WC	48.7
SO_2/SO_3 conversion rate	%	1.00
Catalyst life	hr / years	16000 / 2

Technical Requirements:

Minimum NH_3 injection temperature	°C	316
	°F	602
Molar ratio distribution	% absolute	10
Velocity distribution	% absolute	15
Temperature distribution	°C absolute	10
Soot blower or sonic horns	yes / no	y

CERAM
CATALYSTS + HONEYCOMBS

Reference List for High Temperature SCR Applications (≥ 400°C / 752°F)

as of August 2006

Project	Client	End user / Engineering company	Plant location	Application	SCR-temperature	Shipped quantity	Delivery date
FHKW Mellach	SGP	STEWEAG	AUT	Bituminous coal, High dust	400°C 752°F	287 m^3	1986
BHKW Donaustadt Block 2	SGP	Wiener Stadtwerke	AUT	Oil / Gas	420°C 788°F	80 m^3	1987
BHKW Donaustadt Block 1	SGP	Wiener Stadtwerke	AUT	Oil / Gas	420°C 788°F	80 m^3	1988
FHKW Mellach 4. Lage	SGP	STEWEAG	AUT	Bituminous coal, High dust	400°C 752°F	94 m^3	1988
Weiher 3	Steinmüller	SaarEnergie	DEU	Coal, High dust	400 - 420°C 752 - 788°F	617 m^3	1990
VA-Stahl 85 MW Block 6	AEE	VÖEST Alpine Stahl	AUT	Blast furnance-, Coking plant- and Natural gas	420°C 788°F	41 m^3	1994
FHKW Mellach	AEE	STEWEAG	AUT	Bituminous coal, High dust, Additional delivery	400°C 752°F	95 m^3	1995
Smurfit Newsprint, Pomona	WAHLCO	Energy Products of Idaho	USA	Natural gas	440°C 824°F	26 m^3	2000
Hot Strip Mill Oven 22	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp.	550°C 1022°F	37 m^3	2000
Tripan	Tripan Leichtbauteile		AUT	Diesel engine	550°C 1022°F	1 m^3	2000
KW Weiher 3	BASF	Saarenergie	DEU	Coal, High dust, Additional delivery	400 - 420°C 752 - 788°F	369 m^3	2001
Hot Strip Mill Oven 21	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp.	550°C 1022°F	37 m^3	2002
PSEG Tracy	HRC	GWF Energy	USA	Natural gas, Simple cycle, High temp.	466 - 549°C 870 - 1020°F	44 m^3	2002
Michigan City Unit 12	Black & Veatch	NIPSCO	USA	Coal, High dust	427°C 800°F	583m^3	2002
KW Weiher 3	BASF	Saarenergie	DEU	Coal, High dust, Additional delivery	400 - 420°C 752 - 788°F	369 m^3	2002
Hot Strip Mill Oven 22	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp., Additional del.	550°C 1022°F	39 m^3	2002
Dallman Station Unit 33	Black & Veatch	City of Springfield	USA	Bituminous Coal, High dust	410°C 770°F	218 m^3	2002/3
Tracy	GWF Energy		USA	Nat. gas, GT Simple cycle, High temp., Additional del.	466 - 549°C 870 - 1020°F	44 m^3	2004

Reference List for High Temperature SCR Applications ($\geq$ 400°C / 752°F)

as of August 2006

Project	Client	End user / Engineering company	Plant location	Application	SCR-temperature	Shipped quantity	Delivery date
Grenelle	HRC	CPCU	FRA	Heavy oil, High dust	420°C 788°F	35 m^3	2005
FHKW Mellach, Repl. 4th layer	VERBUND	VERBUND	AUT	Coal, High dust, Additional delivery	400°C 752°F	94 m^3	2005
Gas engines	BASF	Steuler	FRA	Gas engines, High temp.	approx. 500°C approx. 932°F	4 m^3	2005
Hot Strip Mill - Oven 23	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	420°C 788°F	12 m^3	2006
Thomas Hill Unit 3	Associated Electric Coop.	Associated Electric Coop.	USA	Coal, High dust	404 - 427°C 760 - 800°F	802 m^3	2007
Hot Strip Mill - Oven 21	Seiler	Corus Strip Products	NLD	Steel mill Additional delivery	550°C 1022°F	21 m^3	2006
TOTAL AMOUNT						**3,425 m^3**	

From: Blakley, Robert
Sent: Monday, April 28, 2008 3:50 PM
To: 'Noel Rosha'
Cc: 'John Cochran'
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Noel -

We also would like Ceram to comment on this question: if Ceram were asked to provide a catalyst service life guarantee and replacement warranty, whether a minimum operating time that Ceram would propose would be based on the special nature of this fuel and ash composition method of firing (in a cyclone) and the location relative to gas cleaning equipment. As mentioned during our telephone conference, the April 2007 SCR vendor query contained evidence of fine sodium particles downstream of MRY Station Unit 2's cold-side ESP and wet FGD scrubber.

It would be good to note in the response to the above question whether Ceram would require additional SCR catalyst coupons or slip-stream pilot testing with laboratory analysis in order to be confident in their proposed catalyst selection, design, and performance and service life guarantees.

It would be beneficial to reference Ceram's previous May 11, 2007 response when sending a supplemental response addressing this subject and issues raised in our 4/23/08 discussion.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: Blakley, Robert
Sent: Monday, April 28, 2008 8:47 AM
To: 'Noel Rosha'
Cc: 'John Cochran'
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Noel & John -

Thank you for discussing the issues of SCR feasibility involving North Dakota lignite-fired cyclone boilers.

Hopefully you've gotten a chance to obtain Dr. Benson's paper on the pilot SCR testing performed at Coyote Station, on a boiler of the same size, cyclones and similar fuel as fired at Milton R. Young Station's Unit 2 boiler.

We would appreciate an email response to this followup, with discussion of the technical research and experience basis of Ceram's positions on catalyst fouling, poisoning, and blinding appropriate to high sodium, medium sulfur coal flyash and flue gas produced from these boilers.

We are also interested in knowing more about Ceram's willingness to offer performance guarantees, and what that would include from a commercial standpoint along with a catalyst warranty. Of particular interest is whether Ceram's guarantee would satisfy a "make good" requirement, require full-scale field testing of each boiler prior to catalyst selection and design, testing catalyst in a slipstream arrangement or other exposure demonstrations, and if there are any other qualifiers beyond the assumption that the high flue gas temperatures in a conventional hot-side, high-dust SCR were limited by a solution developed by others.

We realize that this is a concentrated effort that does not allow much time to review and provide such responses.

We ask that Ceram provide their email response by Monday, 5/5 12 pm (noon), so that we can review this and forward to Minnkota.

Again, thank you for your attention to this matter.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: John Cochran [mailto:John.Cochran@CERAM-USA.COM]
Sent: Tuesday, May 06, 2008 3:12 PM
To: Blakley, Robert
Cc: Noel Rosha; Greg Holscher; kurt.orehovsky@frauenthal.net
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Bob,

My apologies for not being able to meet your schedule for return of a response regarding your emails dated April 28, 2008.

We have reviewed the information provided including Dr. Benson's paper. We believe that the information and test work presented indicate that it is certainly premature to assume that there is a fatal flaw for the use of high dust SCR behind cyclones burning North Dakota lignite. The concerns presented are similar in argument to those that were used 10 years ago against the application of PRB for high dust applications. The results of the cited test reactor work for Baldwin and Columbia would even seemingly indicate that the use of high dust SCR on PRB applications would be similarly difficult to an installation on a lignite application. Meanwhile, dating from 1999 starting with the New Madrid project (a 2 by 660 MW cyclone base project burning 100% PRB where I was the responsible process engineer for Black & Veatch) there has been in excess of 25,000 MW of SCR installed on PRB fueled cyclone, wall, and tangential fired units with good success. Operating results for PRB units nonetheless indicate great success. The backpass fouling cited in the vendor query document is very similar to that found at the New Madrid project where backend temperatures rise from 720 F to 800 F every 6 months dependent on cleanliness. Meanwhile the cleanliness of the catalyst has been maintained to very low levels after 8 to 9 years of SCR operation.

Certainly a number of circumstances are present that necessitate a pragmatic approach to the application of catalyst for a lignite application. CERAM has more than 20 years of experience with dealing with all variety of fuels. Of particular concern with low rank fuels such as lignite and sub-bituminous coal is proper geometric and chemical design to address the unique characteristics of the ash and flue gas. As was well illustrated by the testing, the first critical parameter to consider is the geometric design of the catalyst. CERAM has experience with the slipstream test reactor used for testing at Baldwin and can confirm that this reactor is susceptible to ash accumulation due to wall effects. Additionally, the 6 mm pitch Haldor Topsoe catalyst used for the Coyote Station testing was an inadequate choice considering the ash loading and ash characteristics. Considering this choice of catalyst pitch and use of this slipstream reactor the results cannot be assumed to be representative of a full scale application. Based on the ash loading and chemistry for Milton R. Young Units 1 and 2 we would consider that at least a 7.4 mm pitch catalyst be utilized. This is the catalyst pitch we proposed in our May 11, 2007 budgetary sizing. A more conservative approach would be to use either an 8.2 or 9.2 mm catalyst. This could have alleviated the noted test element ash pluggage issues.

Sodium is a catalyst poison. Concerns reported by Dr. Benson regarding high sodium contents and fine fume are duly noted, but inadequate evidence is presented that this could be a fatal flaw to application of SCR considering the flawed pitch and resultant pluggage of the catalyst used during Coyote Station testing. Sodium is not a poison to catalyst at SCR operating temperatures. Significant deactivation can occur if condensed moisture transports sodium residing at the surface into the catalyst pore structure during outage or layup. CERAM has experience with high sodium applications to substantiate this effect. Important to avoid deactivation from sodium is the need to protect the catalyst from going through a condensation event.

With consideration of these factors we would agree that there is good cause for further testing on a lignite fired unit to further mitigate risks and optimize design. For this testing we would propose a program utilizing our CoPilot reactor (description attached) whereas wall effects can be minimized and representative ash loading can be better assured. The CoPilot reactor would be installed directly in the flue gas stream at the economizer outlet. The CoPilot reactor has been used in a number of difficult fuel circumstances to obtain accurate results supporting full scale design. If this testing is of interest to you we could prepare a test program proposal for your review.

CERAM can certainly confirm that there are certainly challenges present regarding the application of SCR to the Milton R Young Station. The following lists design requirements necessary to assure successful application of catalyst for Units 1 or 2.

- For coal, lignite, or sub-bituminous fired applications CERAM catalyst can be used to a maximum steady-state single point temperature of 900 F. Beyond this temperature severe permanent degradation of the catalyst will occur due to sintering. System configuration and design must ensure temperatures are maintained below 900 F. A design temperature of 850 F ±20 °F would be necessary.
- Based on the fuel quality presented a catalyst pitch of 7.4 mm or greater should be used. Fly ash angles entering the catalyst should be maintained approximately within ±15° from vertical. Sootblowers are recommended in this circumstance to maintain catalyst cleanliness.
- High carbon ash would carry the risk of increasing the pluggage of catalyst and possible result in a fire within the catalyst. Unburned carbon should be limited to less than approximately 15% to minimize the chance for pluggage and fire. Any catalyst that has a fire will be permanently destroyed due to sintering.
- Large particle ash (LPA) must be controlled prior to the catalyst. LPA escaping capture will cause pluggage of the catalyst.
- Ammonia should not be injected below minimum operating temperatures (MOT). Based on the SO2 and SO3 reported the MOT would be approximately 600 F. For lower sulfur fuels and/or reduced NOx removal performance a lower MOT would be possible. Additionally, brief periods of operation below the MOT would be possible without permanent degradation. In no event would any ammonia be allowed to be injected below 530 F for any likely combination of reasonable sulfur and NOx removal parameters. The NOx reduction for a reduced MOT should be considered in 30-day rolling average scenarios. Minimum flue gas temperatures listed for Units 1 and 2 are well below this threshold.
- Due to the high sodium and iron concentrations it is recommended that a full SCR bypass system be installed. During lay-up periods the catalyst would need to remain warm and dry (above condensing conditions), for instance with an air drying or

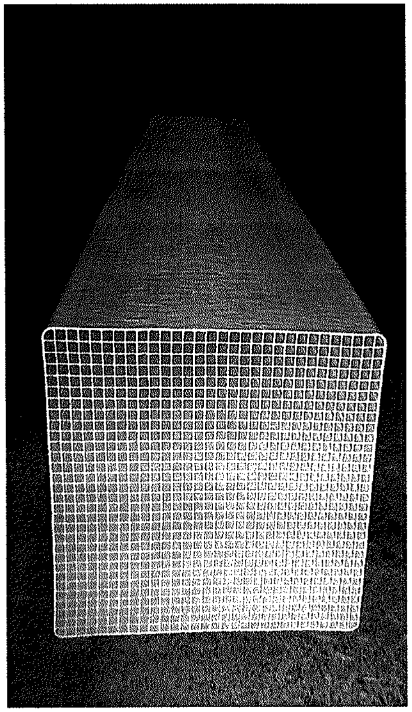
dehumidification system. This may necessitate the use of a dehumidifier and air lock system to access the reactor.
- Molar ratio NH3/NOx distribution ± 10% absolute.
- Gas velocity distribution ± 15% absolute.

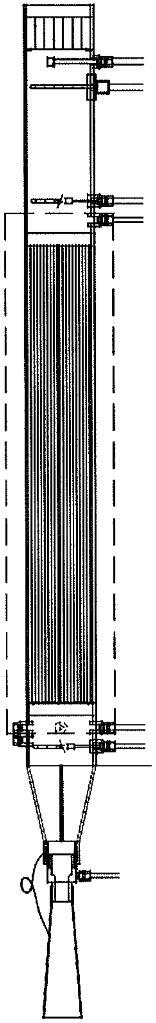
I would like to note that in CERAM's catalyst production history dating from 1985 and concerning more than 350 deliveries we have never had a guarantee or warrantee claim. We certainly want to maintain this record of success. However, based on the information provided as well as our large foundation of work related to the fuel considerations noted in the query and study CERAM can provide a commercial offering regarding this project. However, considering some of the remaining uncertainties we would recommend further testing to ensure a successful result. We agree that it would be beneficial to jointly explore common concerns to ensure that any full scale application would be a success. Please advise if we could be of help to further develop a test plan or answer any questions.

Best Regards,
John Cochran

CERAM Environmental, Inc.
www.frauenthal.net
913.239.9896 (phone)
913.205.5615 (cell)

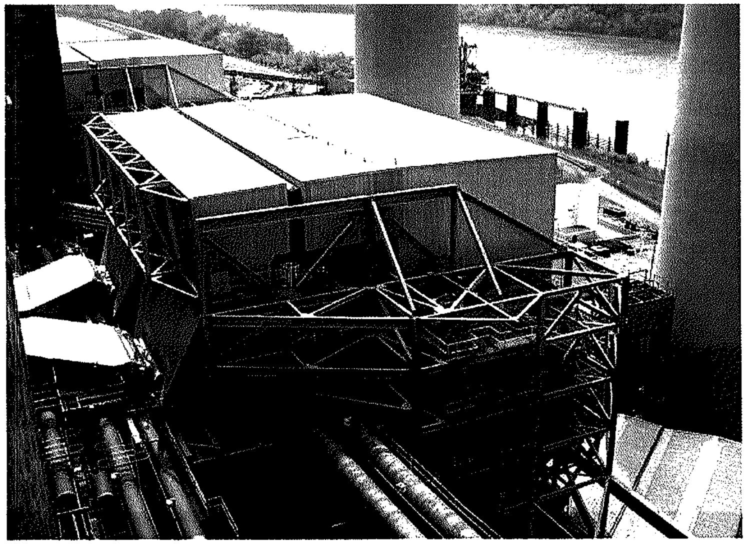
CERAM's CoPilot® Catalyst Test Reactor

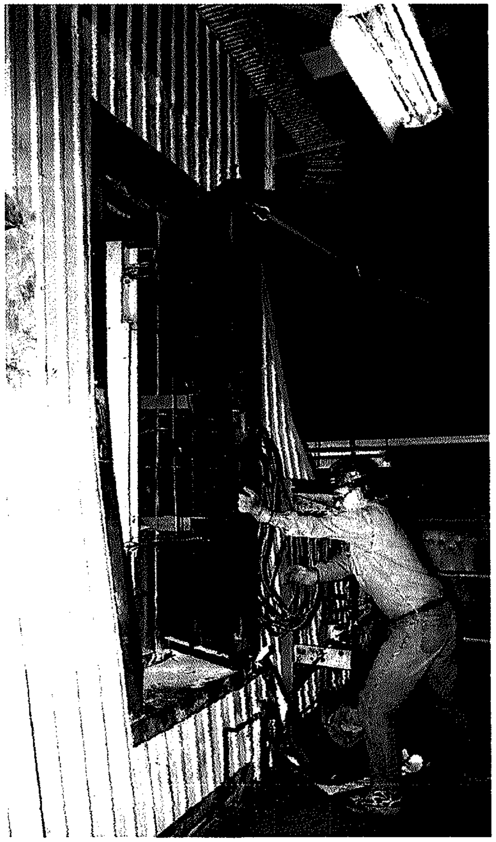




CERAM

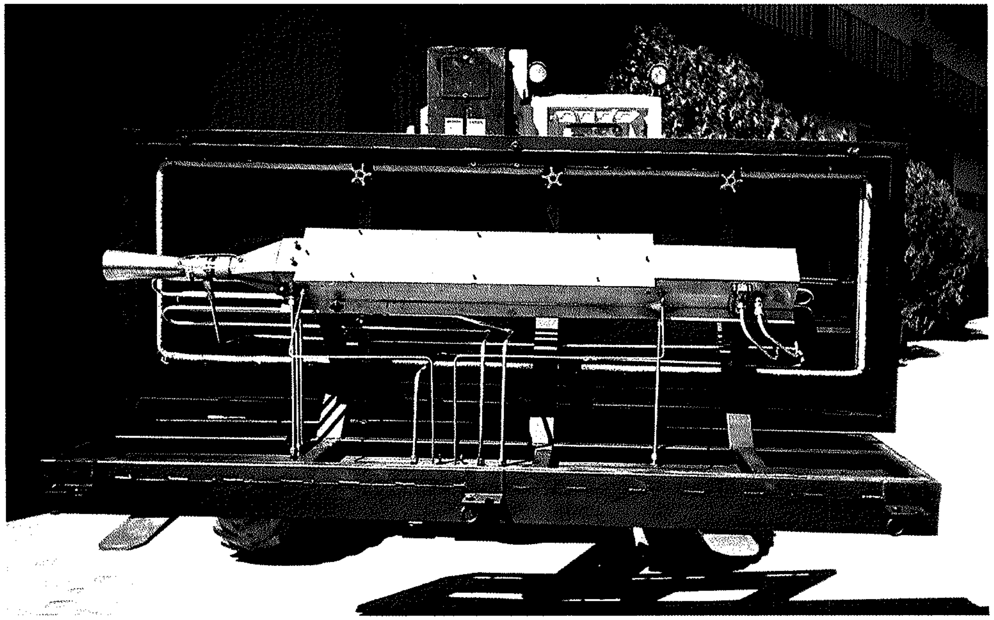
ENVIRONMENTAL, INC.





CoPilot® Catalyst Test Reactor

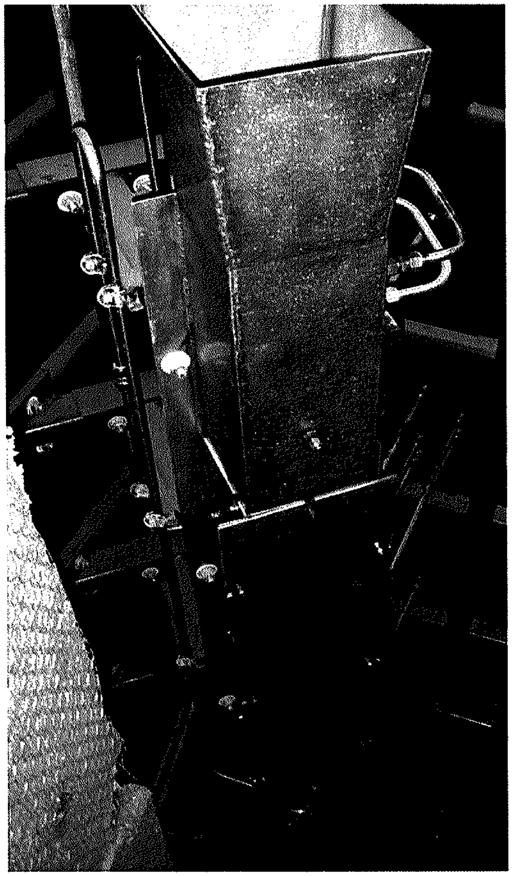
- Patented In-Situ Self Contained Catalyst Testing Apparatus
- In-Situ Reactor Allows for Catalyst Exposure to Actual Flue Gas Conditions Present
  - Fly Ash
  - Flue Gas Constituents
  - Temperature
- Allows Modulation of Gas Flow Velocity to Match SCR Reactor Conditions
- Allows On-Line Access to Test Elements – No Outage Required for Access
- Proven on 8 References



CoPilot® Catalyst Test Reactor

CERAM ENVIRONMENTAL, INC.

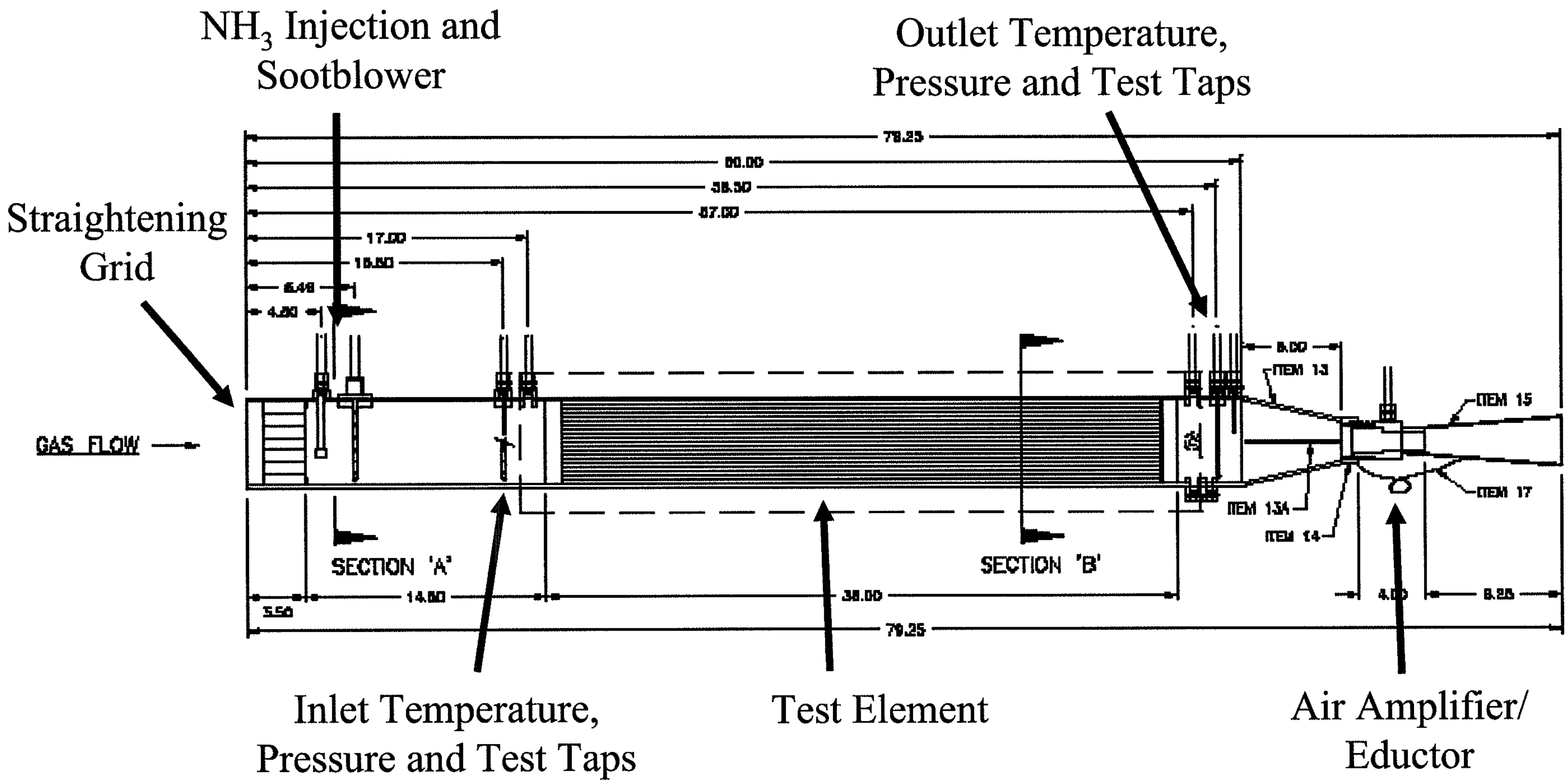
CoPilot® Catalyst Test Reactor



- Can House Honeycomb, Plate, or Fiber Based Catalyst Elements (6” x 6” x 38” long)
- Venturi Flow Inductor for Control of Flue Gas Velocity to Match SCR Reactor Conditions
- Includes Sootblower and LPA Screen to Maintain Catalyst Cleanliness
- Temperature, Pressure, and Inlet/Outlet Sampling Taps for On-Line Monitoring
- Allows for On-Line NOx Measurement
- Provisions for NH_3 Injection to Fully Replicate Reactor Conditions

CERAM
ENVIRONMENTAL, INC.

CoPilot® Catalyst Test Reactor



NH_3 Injection and Sootblower

Outlet Temperature, Pressure and Test Taps

Straightening Grid

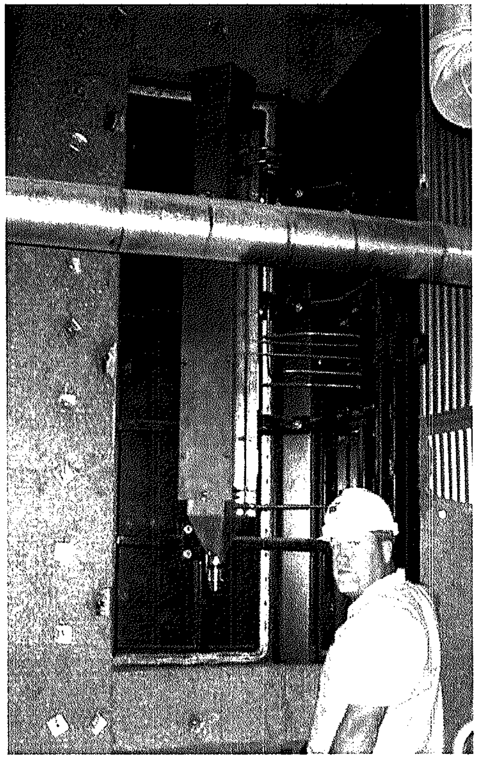
Inlet Temperature, Pressure and Test Taps

Test Element

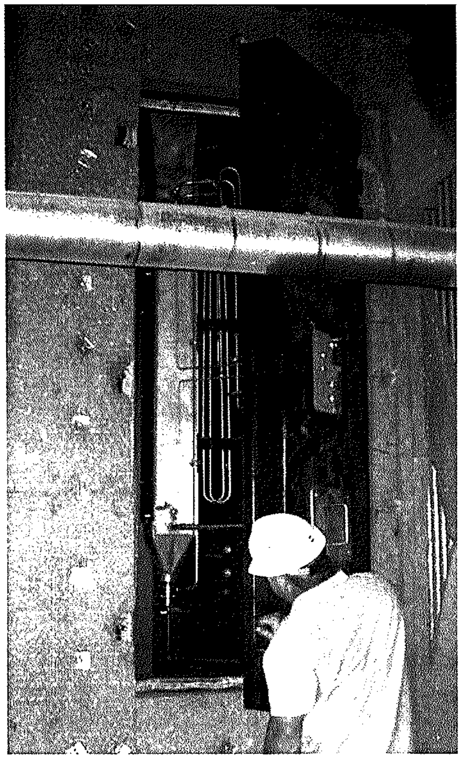
Air Amplifier/ Eductor

CERAM
ENVIRONMENTAL, INC.

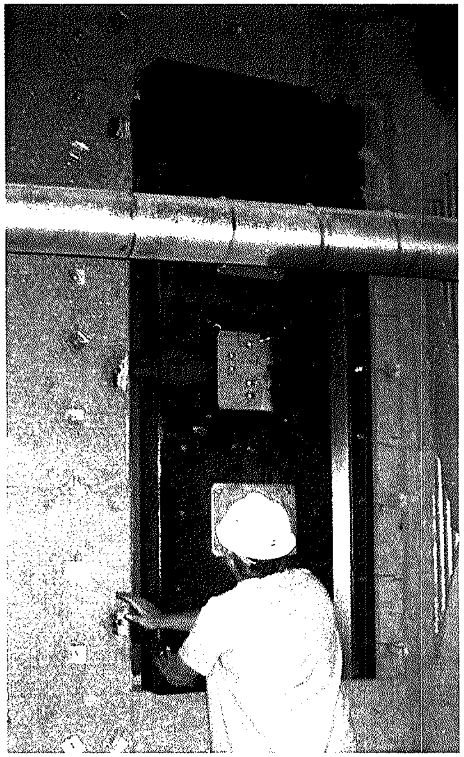
Door Operation



1. Open Door



2. Remove/Install Element



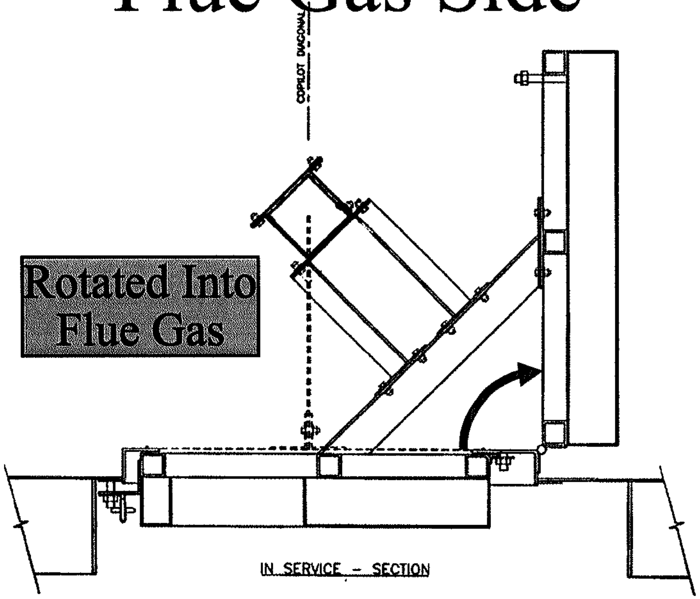
3. Close Door

CERAM
ENVIRONMENTAL, INC.

CoPilot® Door Action

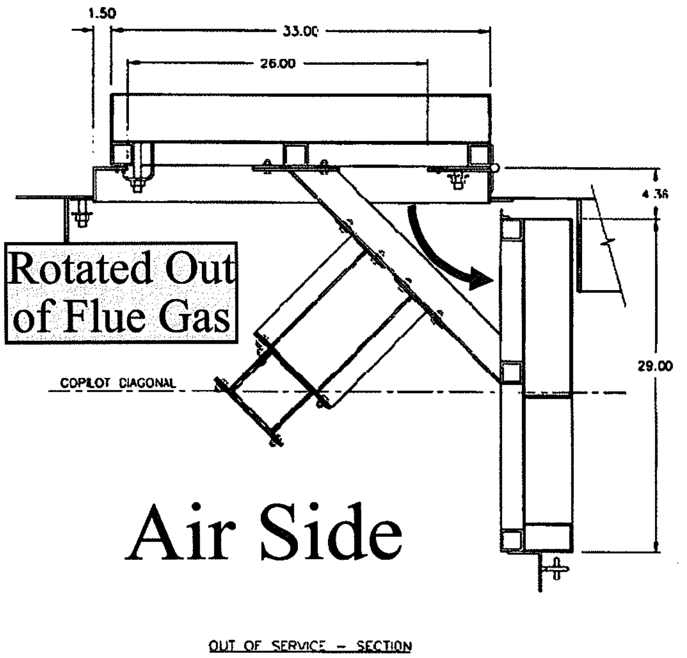
Allows for Catalyst Test Element Removal Without Unit Outage

Flue Gas Side



Rotated Into Flue Gas

Air Side



Rotated Out of Flue Gas

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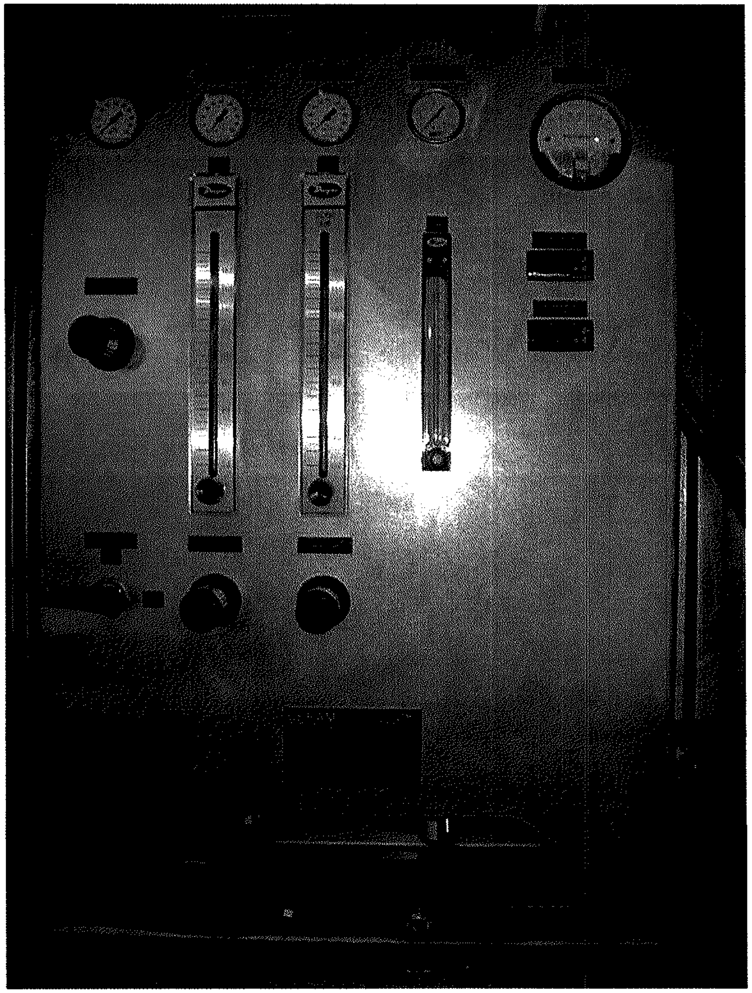
Instrument Panel



- Regulates Flue Gas Flow Through Test Reactor
- Interface for Sootblowing
- Monitor Pressure Drop and Temperature
- Ammonia Injection Flow Control (if required)
- Main Supply Air Shut Off

CERAM
ENVIRONMENTAL, INC.

CoPilot® Uses and Advantages

- Allows Assessment of Process Feasibility for New Application Types
- Allows Accurate Assessment of Impacts on SCR Catalyst from Existing Fuels and Plant Operations
- Minimizes Chances for Surprises Prior to Initial Operation
    - Excessive Catalyst Deactivation
    - Large Particle Ash
    - High LOI

CERAM
ENVIRONMENTAL, INC.

Fuels Assessment

- Determine SCR Catalyst Impacts of Specific Fuels
  - Highly Erosive Ash (Catalyst Mechanical Durability, Wall Thickness)
  - High Ash Loadings (Catalyst Pitch Selection)
  - Determine Impacts of Challenging Fuels (Catalyst Deactivation and Oxidation Rates)

Year-Round Catalyst Management

- Annual Catalyst Sample Testing is Recommended
- Year-Round SCR Operation will Limit the Opportunity to Remove Catalyst Samples for Testing
- CoPilot® Provides On-line Access to Catalyst Samples Exposed to Real Flue Gas Conditions
- Will Allow "Anytime" Access to Elements for Annual Catalyst Testing for Units With 2 to 3 Year Outage Intervals

CoPilot® Installation Locations

- Preferred Location: Long Vertical Downward Section of Duct Downstream of Economizer
- Ash Exposure Important Component of Simulating SCR Application
  - Representative Pluggage Risk
  - Ash Abrasion Effect on Catalyst
  - Catalyst Absorption of Catalyst Poisons

Installation

- Required Duct Opening of Approximately 36 x 101 inches
- Lift CoPilot® Into Place and Weld Frame to Duct Wall
- Install Instrument Panel on Floor/Grating/Handrail in Vicinity of the CoPilot®
- Connect Air Supply, Eductor Air, Sootblower Air, Differential Pressure Lines, and Ammonia (if applicable)
- Install Thermocouples
- Install Catalyst Test Element and Seal to Prevent Leakage

CERAM Can Provide Full Installation Support

-----Original Message-----
From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Wednesday, April 18, 2007 4:52 PM
To: Pritchard, Scot G.
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Scot,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Cormetech to review the attached request document and respond within three weeks if possible. If Cormetech's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Blakley, Robert
Sent: Tuesday, June 26, 2007 3:28 PM
To: 'Pritchard, Scot G.'
Cc: Rutherford, Scott J.; Freeman, Jeremy T.
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Scot -

We have not been favored with a final response from Cormetech on this request. We want to inform Minnkota about the timing of when Cormetech expects to reply. They have been asked by the NDDH for the vendor's responses.

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Pritchard, Scot G. [mailto:PritchardSG@Cormetech.com]
Sent: Monday, May 14, 2007 11:00 PM
To: Blakley, Robert
Cc: Rutherford, Scott J.; Freeman, Jeremy T.
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Robert,

Thank you for the inquiry and opportunity to discuss the the subject opportunity. We have started the review process, however we will require additional time to provide our comments and any related questions back to you. At this time we expect that we will be bale to submit initial information at the end of the month.

Please acknowledge receipt and let us know if any additional relevant information has become available on the subject project to date.

Thank you and regards,

Scot Pritchard
VP, Sales & Marketing
Cormetech
919-595-8708 o
919-815-2380 c

From: Blakley, Robert
Sent: Wednesday, April 18, 2007 3:54 PM
To: 'fgh@topsoe.com'
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Flemming,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Haldor Topsoe to review the attached request document and respond within three weeks if possible. If Haldor Topsoe 's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Thursday, May 10, 2007 10:24 AM
To: Blakley, Robert
Subject: HTI: Comments to SCR Technology at MRYS Units 1&2

Bob,

Haldor Topsoe has reviewed in detail the information and data sent regarding the viability of SCR technology on the Milton R. Young Station (MRYS) Units 1&2. We believe that two separate issues exist with this application. First are the extremely high flue gas exit temperatures (FGET) and lack of flue gas temperature control over the long term and second are the fuel related issues specific to this variety of North Dakota lignite. Since high (FGET) is a unit specific problem we are not going to address this issue. We will however address the North Dakota lignite fuel that is burned at MRYS.

Based on the fuel and ash analysis that was provided, we estimate that the deactivation rate of the catalyst will be high but manageable. We expect a deactivation rate in line with wood fired boilers which have been successfully fitted with SCR. We also expect the deactivation rate to be steep initially but to flatten out considerably after about 4000 hours.

The expected poisons are mostly soluble, therefore periodic water washing of the catalyst can be used to regain activity and to increase overall service life. This technique is used on many wood and some PRB fired applications.

Based on the fuel analysis provided to HT and assuming that FGET can be controlled HT would be willing to guarantee SCR catalyst performance on these units.

Regards,
Wayne

Wayne S. Jones
Account Manager, SCR Catalyst & Technology
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

From: Blakley, Robert
Sent: Monday, April 28, 2008 3:57 PM
To: 'fgh@topsoe.com'
Cc: 'Wayne Jones'
Subject: RE: Comments to SCR Technology at MRYS Units 1&2

Flemming -

We would like Haldor Topsoe to comment on this question: if Haldor Topsoe were asked to provide a catalyst performance and service life guarantee and replacement warranty, whether a minimum operating time that Haldor Topsoe would propose would be based on the special nature of this fuel and ash composition method of firing (in a cyclone) and the location relative to gas cleaning equipment. As mentioned during our telephone conference, the April 2007 SCR vendor query contained evidence of fine sodium particles downstream of MRY Station Unit 2's cold-side ESP and wet FGD scrubber.

We are also interested in learning more about the basis of statements mentioned in the May 10, 2007 response of the 4,000 hours as a suggested number of operating hours for the initially steep but tapering catalyst deactivation rate. It would be good to note in the response to the above questions whether Haldor Topsoe would require additional SCR catalyst coupons or slip-stream pilot testing with laboratory analysis in order to be confident in their proposed catalyst selection, design, and performance and service life guarantees.

It would be beneficial to reference Haldor Topsoe's previous May 10, 2007 response when sending a supplemental response addressing this subject and issues raised in our 4/24/08 discussion.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: Blakley, Robert
Sent: Monday, April 28, 2008 8:54 AM
To: 'fgh@topsoe.com'
Cc: 'Wayne Jones'
Subject: RE: Comments to SCR Technology at MRYS Units 1&2

Flemming -

Thank you for discussing the issues of SCR feasibility involving North Dakota lignite-fired cyclone boilers.

Hopefully you've gotten a chance to review the April 18, 2007 query, and pilot SCR testing performed at Coyote Station, on a boiler of the same size, cyclones and similar fuel as fired at Milton R. Young Station's Unit 2 boiler.

We would appreciate an email response to this followup, with discussion of the technical research and experience basis of Haldor Topsoe's positions on catalyst fouling, poisoning, and blinding appropriate to high sodium, medium sulfur coal flyash and flue gas produced from these boilers. We are interested in learning more about the experience you mentioned about washing of catalyst fouled with high sodium alkalis that was ineffective at restoring catalyst activity.

We are also interested in knowing more about Haldor Topsoe's willingness to offer performance guarantees, and what that would include from a commercial standpoint along with a catalyst warranty. Of particular interest is whether Haldor Topsoe's guarantee would satisfy a "make good" requirement, require full-scale field testing of each boiler prior to catalyst selection and design, testing catalyst in a slipstream arrangement or other exposure demonstrations, and if there are any other qualifiers beyond the assumption that the high flue gas temperatures in a conventional hot-side, high-dust SCR were limited by a solution developed by others.

We realize that this is a concentrated effort that does not allow much time to review and provide such responses.

We ask that Haldor Topsoe provide their email response by Monday, 5/5 12 pm (noon), so that we can review this and forward to Minnkota.

Again, thank you for your attention to this matter.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: Flemming Hansen [mailto:FGH@topsoe.com]
Sent: Monday, May 05, 2008 1:42 PM
To: Blakley, Robert
Cc: Wayne Jones; jmj@topsoe.dk; hajh@topsoe.dk; trs@topsoe.dk
Subject: RE: Comments to SCR Technology at MRYS Units 1&2

Bob,

We have reviewed the design basis and experience on ND lignite.

Our general conclusion was that the deactivation rate is probably going to be at the high in the initial 10,000 hours. Somewhat longer than the 4,000 hours stated earlier. The deactivation rate will be tapering off as the catalyst ages. We expect the catalyst to loos about 60% of its initial activity over the first 10,000 operating hours. This deactivation rate is higher than what we have seen for wood fired boilers.

The number is based on the following assumptions:

1) Alkali content is at the same order as it is found in a wood fly ash.

2) The fly ash load is 5 to 10 times higher than it is seen in wood fired boilers which means that the deactivation should be 5 -10 higher with ND lignite with the assumption that the fraction of alkali aerosol that is captured in the catalyst is constant (this is not the case, cf. 3).

3) The fly ash size distribution of North Dakota lignite is broader compared to wood fly ash, which is an advantage since the attrition of the catalyst surface is higher. However, the attrition effect is not as high as in most coal fired applications since cyclone fired boilers are typically used in ND lignite fired boilers. The carry over of coarse fly ash from the furnace is much lower in cyclone fired boilers. All together we expect that the effect of fly ash distribution compensates for the higher fly ash load compared to a wood fired boiler.

3) The effect of sulfur in the flue gas adds to the deactivation rate compared to typical wood firing. SO2 levels in ND lignite flue gas are 700-800 ppm whereas it is <10 ppm in wood flue gas. The sulfur leads to a strengthening and densification of the blinding layers that originates from deposition of Ca, Na, K aerosols.

Besides the deactivation there is a clogging issue. At the Coyote station test this was the primary concern/experience. It is well known that soot blowing is difficult in pilot scale due to edge effects but also due to the dimensions of the soot blower tubes (max about 1/2"). Orifices have to be smaller compared to full scale in order to distribute the soot blower air. As a consequence the soot blower should be moved closer to the catalyst in order to obtain the same dynamic pressure at the catalyst surface which makes it difficult to actually cover the entire catalyst surface. We suggest that the next step is a larger pilot scale experiment with in the order of 2x2m of catalyst installed. We would like to participate in such an experiment. This would allow better catalyst cleaning and give a better determination of the catalyst degradation over time.

Based on our current information we expect 60% deactivation over the first 10,000 operating hours.
We can not provide a "make good" guarantee, but are willing to warrant the catalyst performance up to the contract value.

I trust the above will be helpful in your design of SCRs for this type of application.

Flemming G. Hansen
Manager SCR DeNOx Catalyst
Haldor Topsoe, Inc.
281-228-5120 (office)
281-228-5129 (fax)
281-684-8820 (cell)
FGH@Topsoe.com
www.topsoe.com

From: Blakley, Robert
Sent: Monday, May 05, 2008 5:44 PM
To: 'Flemming Hansen'
Cc: Wayne Jones; jmj@topsoe.dk; hajh@topsoe.dk; trs@topsoe.dk
Subject: RE: Comments to SCR Technology at MRYS Units 1&2

Flemming -

We have reviewed your response to our followup to the query, and had some clarifications:

Do we understand your meaning correctly in item 1 of your email that due to the increased flyash loading for a hot-side, high-dust SCR application at MRY Station, Haldor Topsoe thinks the deactivation rate will be 5-10 percent higher than what is typically seen in wood-fired boiler SCR applications?

The meaning of the attrition effect is not readily understood. We are not sure if you are referring to erosion or gross pluggage of the catalyst gas passages from the flyash particles.
Can you provide some additional explanation?

The expected impact of sulfur on the catalyst deactivation rate compared to wood firing was not provided, as was given for the higher flyash loading. It would seem to be a much more significant impact if it is at all related to the gross difference in sulfur concentration (70-80 times more sulfur on a volume basis).
Can you provide some additional explanation of the expected impact of sulfur on the catalyst deactivation rate compared to wood firing, especially given that the Coyote pilot SCR test catalyst pores were completely filled with sodium and potassium-sulfate compounds.

We also assume that the comments about sootblowing and clogging of catalyst with flyash relate to the impact largely as an issue of avoiding gross flow channeling or maldistribution that would make some sections of the catalyst non-effective, assuming that the pores were otherwise not blinded or plugged?

We would appreciate any immediate reply to these questions, so that we can forward these to Minnkota.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: Joakim Reimer Thøgersen [mailto:jmj@topsoe.dk]
Sent: Wednesday, May 07, 2008 8:09 AM
To: Blakley, Robert
Cc: Wayne Jones; jmj@topsoe.dk; hajh@topsoe.dk; trs@topsoe.dk
Subject: Re: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

Some answers to your questions/comments:

Do we understand your meaning correctly in item 1 of your email that due to the increased flyash loading for a hot-side, high-dust SCR application at MRY Station, Haldor Topsoe thinks the deactivation rate will be 5-10 percent higher than what is typically seen in wood-fired boiler SCR applications?

No we don't think the the deactivation is 5-10 times higher. The alkali concentration in the fly ash is similar. The fly ash concentration is 5-10 times higher i lignite flue gas. But the fraction of flue alkali alkali that deposits in the catalyst is much smaller in lignite flue gas. The reason is that part of the alkali ihe furnace is bound in coarse aluminum/silicate fly ash that don't to the same extent deposits in the catalyst. When the alkali is incorporated in aluminum/silicate fly ash the alkali also becomes inactive as a SCR poison. The lignite fly ash also has a cleaning effect by attrition of the surface that causes re-entrainment of particle deposits.

The meaning of the attrition effect is not readily understood. We are not sure if you are referring to erosion or gross pluggage of the catalyst gas passages from the flyash particles.
Can you provide some additional explanation?

Re-entrainment or cleaning of the catalyst surface by particle impaction

The expected impact of sulfur on the catalyst deactivation rate compared to wood firing was not provided, as was given for the higher flyash loading. It would seem to be a much more significant impact if it is at all related to the gross difference in sulfur concentration (70-80 times more sulfur on a volume basis).
Can you provide some additional explanation of the expected impact of sulfur on the catalyst deactivation rate compared to wood firing, especially given that the Coyote pilot SCR test catalyst pores were completely filled with sodium and potassium-sulfate compounds.

The sulfur reacts with deposited NaCl, CaO, KCl which means that the particles swell and the blinding layer becomes more impermeable.

We also assume that the comments about sootblowing and clogging of catalyst with flyash relate to the impact largely as an issue of avoiding gross flow channeling or maldistribution that would make some sections of the catalyst non-effective, assuming that the pores were otherwise not blinded or plugged? Exactly.

Our predictions are somewhat semi quantitative since the predictions are based on extrapolation/interpolation from wood firing and PRB fired boilers. I hope these clarifications are sufficient. Otherwise you can call me (+45) 22754374.

Best Regards, Joakim

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Wednesday, April 18, 2007 4:55 PM
To: Anthony C. Favale
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Tony,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Hitachi to review the attached request document and respond within three weeks if possible. If Hitachi's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Anthony C. Favale [mailto:Anthony.Favale@hal.hitachi.com]
Sent: Friday, May 11, 2007 1:53 PM
To: Blakley, Robert
Cc: David Paz; David J. Brozek; Stephen Guglielmo; Masayuki Hirano; Isato Morita; Jennine Eickmeyer
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Robert,
As you know there has been very little testing and data available in North Dakota lignite. Hitachi has reviewed this data and we have the following comments:
1. Basically, it is quite difficult to install and operate the SCR at temperature over 850F. If there is no plan to reduce the flue gas temperature, the catalyst will deactivate very quickly above 850F.
2. The ash tables show the Na content as very high. It may cause serious deactivation of the catalyst.
3. Also, SO3 content in ash is very high. This means that there is Sulfur compounds in addition to the oxides. It may also cause faster catalyst deactivation.
4. There is also a concern over how sticky the ash is and if this will cause a pluggage problem.
Whit all these unknowns we strongly recommend that a slipstream test be performed to confirm the applicability of the catalyst for this flue gas.

Please advise if you have any comments,

Best Regards,

Tony Favale

Hitachi Power Systems America
645 Martinsville Rd.
Basking Ridge, NJ 07920
Office: 908 605 2758
FAX: 908 604 6211
Cell: 914 882 9384

ENCLOSURE 2

EPA COMMENTS ON NDDH PRELIMINARY BACT DETERMINATION

EPA COMMENTS ON NDDH PRELIMINARY BACT DETERMINATION

I. NDDH'S ANALYSIS OF TECHNICAL FEASIBILITY OF TAIL-END AND LOW-DUST SCR AT MRYS IS INCORRECT AND BASED ON INCOMPLETE INFORMATION.

In previous comment letters, EPA explained that the applicability of SCR downstream of pollution control equipment (tail-end SCR (TESCR) or low-dust SCR (LDSCR)) would effectively eliminate the catalyst plugging and deactivation problems described in the Minnkota BACT analysis and that the costs associated with plant modifications and flue gas reheat in order achieve proper catalyst operating temperatures are a matter of cost and not technical feasibility.[1] B&McD's response to EPA's comments was that the information provided by the Energy & Environmental Research Center (EERC) shows that, "effective solutions to prevent or remove micropore pluggage and blinding of SCR catalyst from sodium-sulfur compounds evident in the flue gas stream exhausted from a North Dakota lignite-fired boiler, whether installed in a conventional hot-side or cold-side application downstream of a wet scrubber, have not been developed by SCR catalyst vendors" and that, "these are credible arguments that adequately describe the reasons that preclude the successful deployment of this technology on the cyclone boilers at MRYS."[2] B&McD does not agree that an economic analysis would be required because, "[t]he extensive plant modifications anticipated to deploy SCR at Unit 1 and Unit 2 at MRYS still do not resolve the catalyst micropore plugging and blinding problems evident in the Coyote Station pilot-scale testing."[3] EERC adds that, "[t]here is evidence of sodium, potassium, calcium, and sulfur deposition downstream of the ESP as illustrated in Figure 1 presented in response to ERC Core Issue number 2."[4]

Based on these responses, it appears that the basis for Minnkota's assertion that TESCR and LDSCR are technically infeasible is solely based the perceived catalyst micropore plugging and deactivation problems extrapolated from the results of the Coyote Station pilot testing and the flue gas sampling performed on MRYS Unit 1 downstream of the electrostatic precipitator at 300° F.

The NDDH BACT determination states that the site constraint and flue gas reheat issues are a matter of economics instead of technical feasibility, but "catalyst deactivation of a low-dust or tail-gas SCR due to alkali compounds is an issue that will require extensive research, design and pilot testing to determine whether the technology can be successfully applied to units fired on North Dakota lignite. Therefore, these technologies are not

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[1] See EPA's January 9, 2007 letter to NDDH (sent via fax), pages 13-16 and October 4, 2007 letter to NDDH and Minnkota, pages 31-35.

[2] See Minnkota's November 9, 2007 letter to NDDH, page A-28.

[3] See Minnkota's November 9, 2007 letter to NDDH, page A-29.

[4] See Minnkota's November 9, 2007 letter to NDDH, page A-29. Figure 1 shows a "Cross-section of a surface exposed to flue gas at about 300° F in MRY Unit 1" and the relative weight percentages of sodium, silicon, sulfur, potassium, calcium, and iron.

considered applicable and not technically feasible at this time."[5,6] The NDDH BACT determination cites the sampling provided in Minnkota's November 9, 2007 letter which showed weight percentages of various compounds collected downstream of the electrostatic precipitator and previous experience at the Minn-Dak Farmer's Coop. coal-fired facility, which had problems maintaining compliance with a particulate limit and subsequently had to limit their fuel sodium content.[7] As more fully set forth below, Minnkota has failed to produce sufficient evidence to show that TESCR or LDSCR would experience extreme catalyst deactivation that would preclude the successful operation at MRYS.

Coyote Station Pilot Testing

Minnkota cites the Coyote Station pilot testing results as they relate to catalyst deactivation and plugging caused by sodium compounds and other alkali compounds as evidence that MRYS would not be suitable for a TESCR or LDSCR installation. This assertion is completely unfounded for a number of reasons. First, as described in previous EPA comment letters and as supplemented by the expert opinion report of Mr. Hartenstein provided herein, the Coyote Station pilot testing was clearly flawed and does not even provide meaningful conclusions to apply to a full-scale installation of high-dust SCR (HDSCR). Furthermore, since the Coyote Station pilot testing used flue gas upstream of the pollution control equipment, there is even less reason to believe that test results (even the qualitative results expounded on by Minnkota) have any relevance to a TESCR or LDSCR application, which would have substantially less ash constituents downstream of an

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[5] See NDDH BACT determination, pages 56-57.

[6] The NDDH has made the determination that SCR would be technically feasible in its analysis of the Westmoreland Power, Inc. Gascoyne 500 Generating Station. In its May 2007 analysis of the Gascoyne 500 project, the NDDH states, "[b]y reheating the flue gas and locating the SCR downstream of the other air pollution control devices, SCR appears to be technically feasible. However, the Department is not certain that this technology will work with a Dakota lignite-fired unit because it has not been used before. For these reasons, the Department retained, with reservations, it as a technologically feasible control option." (See pages 58-59.) This proposed project would consist of two 285 MW-gross circulating fluidized bed boilers controlled by a dry scrubber and baghouse. The SCR would be located downstream of both control devices. In this case, the applicant (Westmoreland) cited many of the same concerns stated by Minnkota and the NDDH regarding uncertainty with North Dakota lignite and the significant engineering involved in applying SCR to this facility (Westmoreland even cited the EERC report on the pilot testing at Coyote Station), but concluded low-dust SCR was still technically feasible. In their permit application, Westmoreland states, "it is likely that Westmoreland would incur significant engineering and testing to ensure the viability of a low-dust SCR control system on a lignite-fired CFB boiler. However, there does not appear to be any technical basis to exclude low-dust SCR from the BACT determination." Apparently, the NDDH agrees with Westmoreland that the significant engineering and testing does not preclude technical feasibility AND agrees with Minnkota who believes that such activities do preclude technical feasibility. Low-dust SCR was eventually eliminated from consideration for mainly economic reasons, primarily due to the low uncontrolled NOx emissions from the Gascoyne boilers. While the configuration in the Westmoreland determination is referred to as low-dust SCR, it should be considered tail-end SCR, as it is downstream of a both a particulate control device and SO_2 scrubber.

[7] See NDDH BACT determination, pages 55-56.

electrostatic precipitator (for LDSCR) and wet scrubber (TESCR). Thus, the Coyote Station pilot testing did not provide any meaningful data in terms of evaluating HDSCR and is even less useful for evaluating technical feasibility of TESCR and LDSCR.

MRYS Unit 1 Sampling

Minnkota's November 9, 2007 letter, which is cited in the NDDH BACT determination, explains that flue gas sampling of MRYS Unit 1 was conducted downstream of the electrostatic precipitator and a cross-sectional analysis of the constituents was performed. Minnkota and the EERC asserts that the sampling shows a high degree of sulfated potassium and sodium compounds similar to the compounds observed at the Coyote Station pilot test. Therefore, Minnkota believes that the electrostatic precipitator would not remove much of the vaporized sodium and potassium and implies that similar results would have been produced during the Coyote Station pilot test if conducted downstream of the electrostatic precipitator. Aside from the fact that the Coyote Station pilot testing had significant design and operational problems, the results of the flue gas sampling presented in Minnkota's November 9, 2007 letter in no way quantifies the total amount of particulate material that was collected and would be expected to exist in a LDSCR environment. The data that was presented is only in terms weight percentages and only provides evidence that there will be sodium and potassium downstream of the electrostatic precipitator. While these compounds may exist in a LDSCR environment, no attempt was made by Minnkota to quantify how these weight percentage would translate to loading to a LDSCR and how that would affect catalyst life. Therefore, using this data to show that the presence of sodium and potassium compounds downstream of the electrostatic precipitator would preclude the successful operation of a LDSCR is completely speculative and highly questionable.

The NDDH BACT determination uses this data in conjunction with an emission factor comparison presented in the NDDH analysis to reach a similar conclusion. Without knowing what the total amount of loading is downstream of the electrostatic precipitator and how these weight percentages relate to LDSCR loading and catalyst life, however, the conclusions in the NDDH BACT determination are pure speculation and highly questionable. The NDDH BACT determination also uses this data to support that conclusion that these catalyst poisons will enter a TESCR, even though the sampling was done without wet scrubbing. Using this data in any way to support the conclusion that a TESCR could not be successfully operated is completely without merit. As explained in the expert opinion report by Mr. Hartenstein provided herein, soluble compounds would almost completely be removed by a wet scrubber and the flue gas temperatures after gas reheat for either a TESCR or LDSCR system would be higher than those expected for condensation of any trace sodium or potassium compounds remaining. Therefore, the MRYS Unit 1 sampling presented does not demonstrate, to any degree, that a TESCR or LDSCR could not be successfully operated at MRYS.[8]

Minn-Dak Farmer's Coop. Experience

As explained in detail in Mr. Hartenstein's expert opinion report, using the experience at the Minn-Dak Farmer's Coop. facility to make the claim that TESCR and LDSCR is technically infeasible at MRYS is unfounded. First, the pollution control at the Minn-Dak facility is completely unlike that at MRYS. The Minn-Dak boilers are equipped with multiclones and a venturi scrubber. The lack of similarity of MRYS to other facilities that have successfully operated SCR has been used extensively elsewhere in the NDDH BACT determination to support the claim of SCR technical infeasibility, yet this fact seems to be unimportant to the NDDH in this instance. The NDDH BACT determination also makes no attempt to relate the particulate matter emissions experienced at Minn-Dak to a theoretical TESCR sodium loading rate and catalyst life at MRYS that would support the claim that the Minn-Dak situation is evidence that TESCR would not be technically feasible at MRYS. This is likely because no such case could be made. Furthermore, as explained elsewhere herein and in Hans Hartenstein's expert opinion report, stack temperature conditions (and how those temperatures relate to the physical state of catalyst poison compounds) during a particulate matter stack test (as would have been the case in the Minn-Dak situation) and the operation of a TESCR after flue gas reheat are very different. Therefore, to use the NDDH's experience with the Minn-Dak facility to support the conclusion that TESCR could not be successfully operated at MRYS is completely speculative and highly questionable.

SCR System and Catalyst Vendor Responses on TESCR

The NDDH BACT determination fails to adequately address the vendor responses provided by Minnkota in the evaluation of TESCR or LDSCR. This is likely because the B&McD SCR system and catalyst vendor query appears to have been specifically directed at only getting responses related to a HDSCR application and with no attempt made to get information about vendor opinions or guarantees related to TESCR or LDSCR.

As detailed in Mr. Hartenstein's expert opinion report, an additional query was made to the same vendors that were contacted by B&McD to get information on technical feasibility, the need for additional research, and guarantees related to TESCR.

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[8] Although not referenced in the NDDH BACT determination, Minnkota also submitted some sampling information for Unit 2 that may have been taken downstream of the electrostatic precipitator and SO_2 scrubber (although the bypass was operating during the sampling). As explained in Mr. Hartenstein's expert opinion report, this data cannot be considered relevant for any reasonable judgment concerning the technical feasibility of a TESCR.

The responses received from SCR system suppliers (Alstom and Babcock Power) and catalyst vendors (Argillion, CERAM, and Haldor Topsoe) that have extensive experience with TESCR demonstrate that TESCR is available and applicable to MRYS without the need to do additional pilot testing. This information is very important, because these experts have actual experience with these installations. While much of this experience is outside of the United States, that should not influence the analysis of technical feasibility. Clearly, these companies will make TESCR available to Minnkota and believe the physical and chemical characteristics of the flue gas at MRYS in a TESCR environment poses no significant differences that would preclude the successful operation at MRYS.

Conclusion on TESCR Technical Feasibility

Based on the evidence outlined above, in addition to the substantial explanation provided in the expert opinion report of Mr. Hartenstein, a leading expert in SCR installations at power plants, TESCR is a technically feasible control option at MRYS and needs to be evaluated to at least step 4 of the Top-Down BACT analysis.

Conclusion on LDSCR Technical Feasibility

Since no apparent attempt was made to query vendors related to LDSCR, this analysis remains incomplete. While both Minnkota and the NDDH have made technical arguments as to why LDSCR would be technically infeasible at MRYS due to catalyst plugging and deactivation, these arguments are based on pure speculation and improper comparisons with other situations that do not quantitatively provide any evidence that LDSCR could not be successfully operated at MRYS. EPA believes LDSCR is very likely technically feasible.

II. NDDH'S TECHNICAL FEASIBILITY ANALYSIS OF HIGH-DUST SCR IS INCORRECT AND BASED UPON FLAWED DATA.

As more fully set forth below, the NDDH BACT determination's conclusion that HDSCR is technically infeasible is not supported by the record and is based upon an incorrect interpretation of EPA's NSR Manual. NDDH's BACT determination provides twelve reasons to support its decision that HDSCR is technically infeasible. These individual points are examined in detail in Mr. Hartenstein's expert opinion report and will not be expounded upon here in detail.

HDSCR Catalyst Plugging & Deactivation

- The catalyst plugging and deactivation problems cited in the NDDH's BACT determination are largely based upon the Coyote Station pilot test conducted by EERC, which was fundamentally flawed and would not be indicative of a full-scale operation.

- The NDDH BACT determination acknowledges the fundamental problems with Coyote Station pilot test and states that it provided little useful data. However, the pilot test is cited throughout the HDSCR technical feasibility analysis as a basis for supporting the position that HDSCR is technically infeasible.[9]

- The comparison of different coal-type emission factors in the NDDH BACT determination is used to support the conclusion that the differences in flue gas characteristics of sodium and total primary alkali constituents (CaO, Na_2O, MgO, and K_2O) would "preclude the successful application of existing (presumably high-dust) SCR technology to the M.R. Young Station."[10] This conclusion is complete speculation. While the NDDH BACT determination correctly points out that a linear relationship does not exist between the loading rates of alkali constituents derived from emission factors and catalyst deactivation, the NDDH BACT determination uses this comparison to draw the conclusion that the flue gas characteristics at MRYS would be sufficiently "different" than other fuel types where SCR has been successfully applied. Again, there is no clear basis for this conclusion. The comparison shows cyclone units firing North Dakota lignite to emit about six times as much NaO and about twice as much primary alkali constituents as wall-fired or tangentially-fired plants burning Wyoming Powder River Basin (PRB) subbituminous coal. The NDDH BACT determination does not attempt to relate these ratios to expected catalyst life.

- For the current coal analyses, the ratios of primary alkali loading for Center Mine cyclone units compared to Texas Lignite cyclones, Texas Lignite pulverized units, and PRB subbituminous pulverized units are 1.7, 2.0, and 2.3 respectively. There is a larger disparity between the same primary alkali constituents on units within other fuel and boiler types that have successfully demonstrated SCR use. For example, the ratio of primary alkali constituent loading between pulverized coal units burning PRB subbituminous coal versus eastern bituminous coal on a lb/MMBtu basis would be 3.0. This difference is higher than the 2.3 ratio between a Center Mine cyclone unit and the same pulverized unit burning PRB. Therefore, based on the methodology and

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[9] For example, on pages 49-50, the NDDH BACT determination states, "[t]he pilot scale SCR plugged after only 2 months and little useful data was obtained.....Operation of an SCR system for only 2 months between catalyst replacement is not considered successful operation of SCR technology." Based on this discussion, the NDDH is strongly implying that a HDSCR at MRYS would need a catalyst replacement due to deactivation after only two months, although it is widely known that information related to catalyst plugging on a pilot scale is not applicable to full-scale installations and no activation data was obtained on the Coyote Station pilot test. The NDDH BACT determination also states the Coyote Station pilot test was "ill-designed for a unit combusting North Dakota lignite" (see page 7), which makes the use of this 2-month prediction of catalyst replacement based on pilot-scale plugging results even more baffling.

[10] See NDDH BACT determination, page 51.

rationale presented in the NDDH BACT determination, HDSCR could not have been successfully applied to pulverized coal units burning PRB subbituminous coal because there was three times as much primary alkali constituent loading in the flue gas compared to the eastern bituminous coal plants, where SCR had already been successfully operated.

- Despite the considerable and varied experience that exists worldwide with applying SCR on different source and fuel types, the NDDH BACT determination dismisses the notion that HDSCR is technically feasible at MRYS as "speculation." However, the NDDH believes a mathematical comparison showing elevated amounts of sodium and other alkali constituents in the flue gas with some unknown effect on catalyst life in a HDSCR location is "evidence" that HDSCR is technically infeasible at MRYS.

- The responses from two of the three catalyst manufacturers (CERAM and Haldor Topsoe) to the B&McD query related to HDSCR indicates that catalyst suppliers would be willing to guarantee HDSCR performance if the temperature issue unique to the units at MRYS was resolved by SCR system suppliers. The catalyst vendors expressed concern about the flue gas constituents of North Dakota lignite, but did not indicate there was a fatal flaw to operating HDSCR based on the fuel type. The issue of sodium poisoning was specifically discussed by CERAM and was not a cause of concern based on their past experience with high sodium applications. Haldor Topsoe was also made aware of the sodium issue and was able to provide an industry-standard guarantee. The catalyst suppliers were able to estimate the catalyst life of a HDSCR application at MRYS based on their previous experience.

- It is apparent that the catalyst suppliers that responded affirmatively to being able to provide performance guarantees on a HDSCR if the temperature variation issue was resolved (CERAM and Haldor Topsoe) were prompted by B&McD to issue statements that pilot testing on North Dakota lignite would be required prior to such guarantees.[11] As noted in Mr. Hartenstein's expert opinion report, catalyst vendors would always be in favor of doing HDSCR pilot testing for a new fuel type, as it minimizes their risks at little or no cost to themselves.

- CERAM responded to B&McD's follow-up by stating that "we agree that there is good cause for further testing on a lignite fired unit to further mitigate the risks and optimize design." This statement is clearly a recommendation that acknowledges testing would enhance the applicability of their catalyst in a HDSCR application to North Dakota lignite, not a requirement in order to develop its availability. In its May 11, 2007 response to the B&McD query, CERAM outlined detailed design of the

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[11] See April 28, 2008 emails from Robert Blakley (B&McD) to Noel Rasha (CERAM) and Flemming Hansen (Haldor Topsoe).

catalyst and guaranteed a catalyst life of 16,000 hours. Contrary to statements in the NDDH BACT determination that a HDSCR could not be designed at MRYS due to uncertainties in deactivation rates of the catalyst, a very experienced and reputable catalyst vendor has expressed confidence that it could do so (if the temperature variation issue is resolved) and provided such information.

- Haldor Topsoe responded to B&McD's follow-up by stating, "[w]e suggest that the next step is a larger pilot scale experiment with in the order of 2x2m of catalyst installed. We would like to participate in such an experiment. This would allow better catalyst cleaning and give a better determination of the catalyst degradation over time. Based on our current information, we expect 60% deactivation over the first 10,000 operating hours. We can not provide a 'make good' guarantee', but are willing to warrant the catalyst performance up to the contract value." These statements are clearly a recommendation that acknowledge testing would enhance the applicability of their catalyst in a HDSCR application to North Dakota lignite, not a requirement in order to develop its availability. In fact, contrary to statements in the NDDH BACT determination that a HDSCR could not be designed at MRYS due to uncertainties in deactivation rates of the catalyst, a very experienced and reputable catalyst vendor has expressed confidence that it could do so, provided the temperature variation issue is resolved. As explained in Mr. Hartenstein's expert opinion report, the guarantee up to the contract value is a standard industry guarantee. Thus, the statements by Haldor Topsoe do not support the notion that HDSCR would require pilot testing in order for commercial availability, as outlined in the NDDH BACT determination.

- The export opinion report of Mr. Hartenstein clearly indicates that based on his extensive knowledge and experience with SCR applications under widely different flue gas conditions and discussions he had with catalyst vendors and SCR system suppliers, catalyst and plugging and deactivation would not be a fatal flaw to installing HDSCR at MRYS.

- As will be explained in more detail in a later section, the docket information for the TXU Oak Grove New Source Review permit (a proposed project that will include HDSCR and burn 100% Texas lignite) provides further evidence that, despite the challenges that exist in applying HDSCR to a new fuel type, the utility industry believes that SCR is technically feasible and any questions about the its application are a matter of cost. This is evident not only in the permit docket, but also in a letter from the Electric Power Research Institute that was originally sent to the NDDH in EPA's January 8, 2007 letter. In addition, the Texas Commission on Environmental Quality determined that the uncertainties involved with firing a new fuel type and the accelerated HDSCR catalyst plugging and deactivation that was expected from exclusively firing Texas lignite was not a reason to find that SCR would be technically infeasible. While the properties of North Dakota and Texas lignite might not be the same, the same basic principle applies that the accelerated catalyst replacement requirements are a matter of economics and not technical feasibility.

Based on the information and observations above, EPA concludes that the successful operation and technical feasibility of HDSCR at MRYS would not be precluded by the catalyst plugging and deactivation issues related to the cyclone-firing North Dakota lignite described by Minnkota and in the NDDH BACT determination. Catalyst vendors believe the challenges involved would be manageable and they would be able to design a suitable catalyst with a performance guarantee. While the vendors would prefer to conduct some testing to mitigate risks, optimize the design, and better predict catalyst life, these same vendors also appear willing to make the catalyst commercially available. Therefore, HDSCR should not be eliminated as being technically infeasible on the basis of catalyst plugging and deactivation.

MRYS Temperature Variation Issue Related to HDSCR

- The SCR system supplier responses indicate that the temperature variation issue would likely be very challenging for a HDSCR installation at MRYS (and more unique than the potential catalyst plugging and deactivation issues for cyclone-firing of North Dakota lignite). Although the B&McD query was clearly directed toward a response only on HDSCR, SCR system suppliers (Alstom and Backbock Power) suggested looking at the possibility of TESCR as a way of avoiding both the concerns with temperature variations and fuel characteristics.

- The other SCR system supplier (Babcock & Wilcox, which does not have extensive TESCR experience) certainly did not dismiss the possibility of being able to overcome the challenges presented at MRYS for SCR installation and welcomed working with Minnkota to explore “creative solutions.”

- EPA received information in response to a Clean Air Act Section 114 request pertaining to the vendor query conducted by B&McD.[12] This information is included herein. Babcock & Wilcox (B&W), who was the original manufacturer of the boilers at MRYS, indicates that modifications to the boiler likely could be made that would address the temperature problems, or that out of boiler modifications/changes (e.g. auxiliary fuel drying) would be necessary. In either case, the temperature issue appears to a resolvable technical problem, albeit at a likely high cost.

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[12] See July 18, 2007 e-mail from Steve Moormann (Babcock & Wilcox) to Robert Blakely (Burns & McDonnell).

EPA believes that the technical issue with the temperature variation in the backpass end of the boilers at MRYS where a HDSCR would be located presents a significant challenge. However, it appears that the technical challenges with the temperature variation can be resolved. Furthermore, the issue of backpass boiler temperature variation completely goes away in the case of TESCR and LDSCR. Therefore, no matter what the implications are of resolving the temperature variation issue, there are other options for installing SCR technology that would avoid this problem altogether.

EPA's Conclusion on HDSCR

In summary, EPA believes the NDDH BACT analysis incorrectly eliminates HDSCR as technically infeasible at MRYS because pilot testing would be required on Center Mine lignite fuel before application at MRYS. The uniqueness of the fuel at MRYS (Center Mine lignite) does not appear to pose technical problems that catalyst vendors do not believe can be managed in order to provide a reasonable guarantee. The soluble sodium deactivation issue cited in the NDDH BACT determination as a fatal flaw to installing HDSCR is not supported by any useful or relevant data and is speculative. Furthermore, the opinions of catalyst suppliers and leading SCR expert Mr. Hartenstein indicate that catalyst poisoning by sodium is only an issue during periods when the catalyst is allowed to cool well below its normal operating temperature. This would be an infrequent occurrence and can be managed by isolating the catalyst during shut-downs. Additionally, catalyst regeneration is a viable option (that is currently used in practice) for restoring catalyst life by either in-situ, on-site, or off-site water washing.[13] The temperature variation problem appears to be a more significant challenge for the successful operation of HDSCR (but not TESCR or LDSCR), but the necessary modifications to resolve this problem would be a matter of cost.

III. THE NDDH BACT DETERMINATION INCORRECTLY APPLIES THE CONCEPT OF PILOT TESTING IN EPA'S NSR MANUAL TO CONCLUDE THAT SCR IS NOT TECHNICALLY FEASIBLE.

NDDH has misinterpreted EPA's NSR Manual to support a finding of technical infeasibility of SCR at MRYS because it has been suggested pilot testing and/or engineering research would be required. EPA has previously clarified for Minnkota and the NDDH that this reference in EPA's NSR Manual is only relevant to whether a control option was

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[13] On page 46, the NDDH BACT determination states that there are "no known engineering solutions to….restore the catalytic reactions by removing particles from catalyst pores." This is simply not true and it appears that the NDDH did not investigate this possibility in any depth. As one example of actual regeneration experience, EPA is enclosing a 2007 NOx Round Table & Expo Presentation by Reinhold Environmental Ltd (February 5-6, 2007 in Cincinnati, OH) that details in-situ and on-site catalyst washing experience at the Avedore Station in Denmark.

"available." There is little question that SCR is "available" for installation at MRYS and, in fact, the Minnkota BACT analysis already conceded that SCR is "available."[14]

The NDDH BACT determination relies upon the lack of demonstrated application of SCR technology and mitigating tools used to manage ash deposition and catalyst deactivation (such as screens, baffles, soot-blowing, rejuvenation, etc.) on a cyclone boiler firing North Dakota lignite to conclude that it is necessary for the source to do additional pilot testing and engineering studies. According to NDDH's interpretation of EPA's NSR Manual, this additional step precludes the technology from being considered technically feasible.

The NDDH BACT determination states that, "[t]he fundamental question for this BACT determination is whether SCR is an available technology for North Dakota lignite-fired cyclone boilers such as Minnkota Units 1 and 2."[15] The concept of <u>availability</u> of a control technology is introduced in the NDDH BACT determination by quoting EPA's NSR Manual, which states, "[a] control technique is considered available, within the context presented above, if it has reached the licensing and commercial state of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review."[16]

The NDDH BACT determination concludes, "SCR has not reached this stage for North Dakota lignite-fired cyclone boilers, and because of the difference in the gas stream[17], the Department concludes that Minnkota need not experience extended trials to learn how to apply the technology on such a dissimilar source type."[18]

With this statement, NDDH has erroneously combined two steps which are described in EPA's NSR Manual as separate steps for determining technical feasibility of a control option,

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[14] See EPA's October 4, 2007 letter to NDDH and Minnkota, page 31 and Minnkota BACT analysis, page A1-32, where B&McD states, "SCR technology is an available technology which has been installed on numerous powerplant facilities around the world and there are a large number of manufacturers that market the technology. The question is whether SCR technology is "applicable" for a unit firing North Dakota lignite." In its November 13, 2007, letter, Minnkota appears to have reversed course on the issue of SCR availability, and attempts to focus on the dissimilar aspects of MRYS to other facilities that have installed SCR. Notwithstanding the statements in this letter, however, there is no disputing that the Minnkota BACT analysis clearly stated that SCR is available and that the only question is whether it is applicable.

[15] See NDDH BACT Determination, page 5.

[16] See EPA's NSR Manual, page B.18.

[17] The concept of evaluating differences in the gas stream between the source under review and other sources where a control option has been applied is introduced in EPA's NSR Manual during the discussion of whether an available control option is also <u>applicable</u>.

[18] See NDDH BACT Determination, page 6.

namely, availability and applicability. A plain reading of EPA's NSR Manual shows that EPA saw the technical feasibility determination as two separate steps. First, the reviewing authority should determine whether a control option is available. As stated in the EPA NSR Manual, if a ***new*** control option is only in the early developmental stage, it is not considered (commercially) available. Therefore, under the Top-Down BACT analysis, the control option is eliminated from consideration as being technically infeasible, without any analysis on whether the control option is applicable to the source under review and does not require the same degree of technical analysis and judgment on the part of the reviewing authority. EPA's NSR Manual specifically mentions pilot testing as a component of determining availability, which is defined as the "process commonly used for bringing a control technology concept to reality as a commercial product.

- concept stage;
- research and patenting;
- bench scale or laboratory testing;
- ***pilot scale testing;*** (emphasis added)
- licensing and commercial demonstration; and
- commercial sales." [19]

For determining whether a control option is available, EPA's NSR Manual does not describe the comparison of gas stream characteristics between the source under review and other sources. Commercial availability of SCR is a plain fact, evidenced by the SCR system supplier and catalyst vendor responses garnered by B&McD and supplemented by EPA herein, the extensive applications of SCR to coal-fired power plants and other industrial sources worldwide for decades, and even as stated in the Minnkota BACT analysis. [20]

The second step of the technical feasibility analysis is to determine whether an available control option is also applicable to the source under review. As noted correctly in the NDDH BACT determination, the EPA's NSR Manual "provides that technical judgment of the review authority must be exercised in determining whether a control alternative is *applicable* to the source type under consideration"[21] (emphasis added) and cites a portion EPA's NSR Manual regarding applicability, which states, "a commercially *available* control option will be presumed to be *applicable* if it has been or is soon to be deployed (e.g. is

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[19] See EPA's NSR Manual, page B.17.

[20] EPA also strongly disagrees with the assertion in the NDDH BACT determination that a control option can be eliminated under the Top-Down BACT process if any "engineering study" is required. This very vague and broad term could be applied to any phase of designing a piece of pollution equipment or technique. Presumably, every major piece of pollution control equipment (i.e. scrubber, SCR, baghouse, Electrostatic Precipitator, etc.) applied to a utility boiler has entailed engineering study. EPA categorically dismisses use of this term in NDDH's BACT determination and believes that this extremely narrow view of what is required in the Top-Down BACT process is particularly problematic.

[21] See NDDH BACT Determination, page 5 and EPA's NSR Manual page B.18.

specified in a permit) on the same or similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison of the gas stream characteristics of the source types to which the technology has been applied previously."[22] (Emphasis added.) Hence, a comparison of gas stream characteristics would only be required once it has already been established that the control option is available. Furthermore, the question of whether pilot testing and conducting additional research is necessary no longer applies to the analysis, since it is only relevant for a determination of availability, which would have already been confirmed. Contrary to EPA's NSR Manual, the NDDH BACT determination makes a determination of availability based, in part, on the comparison of gas stream characteristics.

The NDDH BACT determination states, "all responses (to the B&McD vendor query) indicated the following: 1) The need for additional testing to either determine if there were any fatal flaws or to obtain data for the design of a potentially successful SCR system."[23] Clearly, this is not the type of pilot testing that is referenced in the EPA NSR Manual for developing a new control technology from concept stage to the commercial state of development. This type of testing would instead provide more certainty to designers and likely result in a more optimum SCR system design at MRYS, as it would to any application of SCR to a new plant. In other words, this type of testing would be used to enhance the applicability of SCR at MRYS. The responses from SCR system suppliers and catalyst vendors are speaking to the advantages of doing additional testing on North Dakota lignite to enhance the applicability of (HD)SCR at MRYS, not on whether SCR is a commercially available control technology. For example, when prompted by B&McD on the prospect of doing pilot testing, CERAM stated, "we would agree that there is good cause for further testing on a lignite fired unit to *further mitigate the risks and optimize design*."[24] (Emphasis added.)

Since SCR has been so widely applied to coal-fired boilers and other industrial sources, commercial availability of SCR should be determined primarily based on whether the SCR system suppliers and catalyst suppliers are willing to commercially provide and install the technology on the source in question, not based on whether the reviewing authority believes additional testing would provide more certainty and lead to a better designed SCR. It is clear from the record that vendors are willing to do so. Many of the vendors responses from the B&McD query clearly indicate that they believe SCR can work at MRYS[25] and do not

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[22] See EPA's NSR Manual, page B.18.

[23] See NDDH BACT Determination, pages 39-40.

[24] See May 6, 2008 email from Ceram Environmental, Inc. to B&McD.

[25] See May 30, 2007 and May 5, 2008 letters from Alstom Power to B&McD; see May 11, 2007 and May 6, 2008 emails from Babcock Power Environmental, Inc. to B&McD; see May 11, 2007 and May 6, 2008 emails from Ceram Environmental, Inc. to B&McD; see May 10, 2007 and May 5, 2008 emails from Haldor Topsoe, Inc. to B&McD. Note that these responses have been greatly supplemented by the vendor responses related to TESCR

require that pilot testing be conducted upfront to make the technology commercially available.

Lastly, the NDDH BACT Determination for LDSCR and TESCR at MRYS also concludes, "catalyst deactivation of a low-dust or tail gas SCR due to alkali compounds is an issue that will require extensive research, design and pilot testing to determine whether the technology can be successfully applied to units fired on North Dakota lignite. Therefore, these technologies are not considered applicable and not technically feasible at this time."[26] Again, this rationale is a misinterpretation of the EPA NSR Manual. The question of whether LDSCR and TESCR are in the pilot testing stage of development is only relevant in terms of whether it is an available control option. Both LDSCR and TESCR are not only available control options, but would also be applicable to MYRS. In fact, the responses from the supplemental SCR system catalyst vendor query conducted by Mr. Hartenstein, and provided in the Enclosure herein, clearly indicates that vendors would provide a TESCR at MRYS with a guarantee and do not support doing any additional pilot testing.

IV. THE NDDH BACT DETERMINATION FRUSTRATES THE TECHNOLOGY-FORCING FUNCTION OF THE BACT PROCESS THAT WAS INTENDED BY CONGRESS.

The NDDH BACT determination is not only at odds with EPA's NSR Manual, but it also frustrates the technology-forcing function of the BACT process. As described above, the NDDH BACT determination repeatedly notes a lack of actual experience with SCR on North Dakota lignite and cyclone boilers as a primary basis for concluding that "experimentation" and/or "extensive, and correspondingly expensive, engineering studies" would be necessary to determine if uncertainties could be overcome. Congress developed the case-by-case BACT process so that the best technology becomes as widespread as possible. The NDDH BACT determination takes the position that a control option is technically infeasible because no other power plant with the exact same design and fuel source has applied the control option. Under this presumption, the best technology would not become widely used, unless some independent "proof" of it working on the exact type of source and flue gas characteristics under review was provided. This application of the BACT process is contrary to the technology-forcing function of the BACT process that congress intended when enacting Clean Air Act.

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gathered by Mr. Hartenstein.

[26] See NDDH BACT Determination, page 57.

V. OTHER COMMENTS ON THE NDDH BACT DETERMINATION

1. Page 4 of NDDH BACT Determination: "Information from Sargent and Lundy indicates that not enough information is available to determine whether SCR technology can be successfully adapted to units burning North Dakota lignite."

   EPA Response: This is not what Sargent & Lundy actually said in the May 2007 presentation to NDDH and EPA. In Sargent and Lundy's Conclusion Summary, they state, "[s]ome important unanswered questions pose significant risks for an SCR design engineer:

   An unknown catalyst deactivation rate will prevent:

   - optimum selection of a catalyst design
   - selection of an appropriate reactor size

   This could burden the operator with a long term costly maintenance requirements (sic) and unscheduled outages"

   Sargent & Lundy states that premature catalyst failure will require more frequent catalyst replacement, ammonia slip and subsequent airheater pluggage, and higher auxiliary power requirements. These conclusions suggest that Sargent & Lundy's opinion is that the lack of data specific to North Dakota lignite on SCR operation would result in a less than optimal design and as a result increased capital and operating costs. While this opinion indicates that applying SCR to North Dakota lignite without obtaining further data might not be the best engineering approach, Sargent & Lundy did not opine that SCR could not be "successful" on units firing North Dakota lignite.

2. Page 7 of the NDDH BACT determination: "The advances made in the last few years for controlling popcorn ash are not shown to be applicable to a cyclone boiler burning North Dakota lignite. Extensive engineering analyses, and likely pilot scale testing, will be necessary to determine if these advances can be applied at M.R. Young Station."

   EPA Response: This statement and conclusion is inconsistent with the discussions between NDDH, EPA, and Minnkota at the May 23, 2007 meeting held in Bismarck. During this meeting popcorn ash was discussed and EPA's consultant, Roger Christman, stated that he believed the popcorn ash problem had been dealt with successfully at many other facilities and that it would not pose a significant problem at MRYS. Mr. Christman asked Minnkota and B&McD whether they agreed that the effects of popcorn ash is solvable at MRYS and whether it could be "taken off the table" as a real issue in the discussion of HSSCR technical feasibility. Minnkota agreed that it was a solvable issue and certainly did not indicate that pilot testing would be required to address the effects of popcorn ash at MRYS. In light of these discussions, it is unclear why NDDH still believes that this is a technical barrier for the successful operation of HDSCR at MRYS.

3. Pages 13-15 of the NDDH BACT determination: In identifying all control technologies under Step 1 of the Top-Down BACT analysis, the NDDH BACT determination lists, "Fuel Switching/Blending/Cleaning." In the Step 2 analysis for this control option, the NDDH BACT determination cites experience at the Big Stone Power Plant in South Dakota with switching to PRB fuel as not lowering NO_x emissions and then references a Seventh Circuit Appeals Court decision regarding the Prairie State Generating Station PSD permit that stated fuel switching is not required for mine mouth power plants in the BACT analysis. Therefore, the NDDH BACT determination concludes that switching or blending fuels other than Center Mine lignite in order to mitigate the effects of the fuel on other control options would not be required.

   EPA Response: While the NDDH BACT determination appears to have looked at fuel switching and blending, it ignores the possibility of fuel cleaning in Step 2, although fuel cleaning was correctly listed under Step 1. Many of the technical problems described in the NDDH BACT determination for installation of other control options, such as SCR, are due to downstream conditions caused by the poor quality of the Center Mine lignite fuel (i.e. high ash, high sodium, high moisture, low heating content, the need to do fuel predrying in the cyclone boiler, etc.). Therefore, it appears that NDDH should explore potential fuel cleaning possibilities to address these effects. While EPA does not agree that fuel cleaning would be required in order for SCR to be considered technically feasible, the conclusions of the NDDH BACT determination are further flawed and incomplete without such an analysis.

4. Page 29 of the NDDH BACT determination: "Consumers Energy indicated they purchase coal from several western mines as well as eastern mines. They also indicated that none of the coal obtained from the Spring Creek Mine is fed to a unit equipped with an SCR system. Based on this information the Department is not aware of any power plant that is equipped with an SCR system and burns Spring Creek Mine coal."

   EPA Response: There is a reference to a May 13, 2008 email from Bradely Plummer of Consumers Energy to Tom Bachman of NDDH. This email was not made part of the administrative record, but appears to be information that the NDDH relied upon in making its BACT determination. This email should be made publically available and part of the administrative record for this BACT determination.

5. EPA would like to add the documents identified in Sections VI through VIII, below, to the administrative record for the NDDH to consider in its Final BACT determination.

VI. DOCKET INFORMATION FOR THE TXU OAK GROVE NSR PERMIT IS EVIDENCE THAT THE UTILITY INDUSTRY & OTHER STATE AGENCIES BELIEVE THAT SCR IS TECHNICALLY FEASIBLE & CAN BE APPLIED TO NEW FUEL TYPES & BOILER TYPES.

On July 27, 2005, Oak Grove Management Company, LLC (Oak Grove) applied to the Texas Commission on Environmental Quality (TCEQ) for a Prevention of Significant Deterioration (PSD) permit to construct a new 1,600 MW (net) pulverized coal power plant consisting of two 860 MW (gross) units. The proposed facility would be fired on 100% Texas lignite. On February 21, 2006, the TCEQ Executive Director issued a preliminary decision and draft permit that required HDSCR and a limit of 0.08 lb/MMBtu as BACT for NO_X. At Oak Grove's request, the application and determination was referred to the State Office of Administrative Hearings (SOAH) for hearing on whether it complied with all applicable statutory and regulatory requirements.

On August 23, 2006, the SOAH Administrative Law Judges (ALJs) issued a Proposal for Decision (PFD) with a finding that Oak Grove failed "prove by a preponderance of the evidence that its BACT proposal to use SCR with lignite-fired boilers can reasonably be expected to achieve a 0.08 lb/MMBtu NOx emission rate."[27] Essentially, the ALJs found that since HDSCR has not been previously proven in practice on a plant burning 100% Texas lignite, there were uncertainties with the application of, "a relatively new technology that has never been used in the United States on a commercial scale with a lignite-fired electric power plant."[28]

While Oak Grove took the position that there were uncertainties and challenges with the design of an SCR reactor for lignite coal firing, the company argued that SCR is technically feasible and that, "the PFD failed to make the distinction between 'technical practicability' and 'economic reasonableness'."[29] Oak Grove takes the position that, "[t]o the extent that there is any issue or question regarding the use SCR (sic) at the proposed facility, it is a question of cost."[30] Oak Grove's reason for pointing out the uncertainties with

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[27] See ALJ's Proposal for Decision and Order, August 23, 2006, page 24.

[28] See ALJ's Proposal for Decision and Order, August 23, 2006, page 24.

[29] See Applicant's Exception to the Proposal for Decision, September 12, 2006 page 10.

[30] See Applicant's Exception to the Proposal for Decision, September 12, 2006, page 10.

applying SCR to a fuel type that has never been demonstrated in practice was an attempt to have the NO_x limit raised in the final permit, not to show that SCR should be considered technically infeasible.

Additionally, Babcock Power Environmental, as the Air Quality Control System supplier for Oak Grove, sent a letter to the TCEQ's Executive Director (August 30, 2006) outlining why it believes the ALJ's PFD is incorrect and SCR is technically feasible for the Oak Grove plant. Interestingly, Babcock Power cites the EERC Coyote Station pilot testing results and dismisses those problems based on moisture problems introduced by the sootblowers that caused much of the plugging during that test.

The TCED permit engineer for the Oak Grove permit, Randy Hamilton, also believed that HDSCR should not only be considered technically feasible, but Mr. Hamilton also recommended a lower NO_x limit of 0.07 lb/MMBtu to the TCEQ Environmental Director. Although the ALJs appear to have misconstrued a statement made by Mr. Hamilton in his written deposition to SOAH, where Mr. Hamilton describes the hypothetical best and worst case possibilities of SCR ash deposition on the Oak Grove units,[31] Mr. Hamilton confirmed with EPA that it was never his professional opinion that the worst case scenario he described was a real possibility, but only a rhetorical examination of two logically possible outcomes.[32]

Ultimately, the TCEQ's Final Order (June 21, 2007) rejected the arguments over technical infeasibility of SCR at Oak Grove, overturned the ALJ's PFD, and granted the PSD permit to Oak Grove with a NO_x BACT determination of SCR and a limit of 0.08 lb/MMBtu. In short, the Commission found that the ALJs "placed too much emphasis on the absence of previous applications of the proposed technologies with regard to Texas lignite."[33]

The positions taken by the TCEQ (technical staff, Executive Director, and Final Order), Oak Grove, and Babcock Power largely coincide with and support EPA's position with regard to general technical feasibility of SCR on different fuel types and whether questions of feasibility are a matter of technical feasibility or economic feasibility. EPA also generally agrees with these parties that the position taken by the ALJs (and likewise by Minnkota and the NDDH in the case of MRYS), "will remove an essential element of the air emissions permitting process as contemplated by both state and federal Clean Air Acts – the advancement of air pollution control process.....Simply stated, the ALJ's interpretation of the

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31 See ALJ's Proposal for Decision and Order, August 23, 2006, page 15, "[t]he uncertainty with regard to ash deposition is not mathematically convertible to a NOx emission limit adjustment. The ideal outcome would be that plugging proves to be no problem at all. Under this scenario, NOx emissions could be as low as any coal-fired boiler and the BACT emission limit could have been lower. The worst outcome would be that the SCR plugs with flyash rapidly and completely and no engineering solution can be found. Under this scenario, SCR would be technically infeasible, and BACT would have to be higher, based on the next most effective technology..."

32 See April 16, 2008 email from Randy Hamilton (TCEQ) to Hans Buenning (EPA Region 8).

33 See TCEQ Final Order, June 21, 2007, page 45.

technical practicability element of the BACT analysis would categorically prevent the first-time application of new control technologies in Texas."[34] The same could be said of the state of North Dakota under the positions taken in the NDDH BACT determination.

EPA is submitting the TCEQ/SOAH Docket information for the Oak Grove permit proceeding to be entered in the administrative record and considered in NDDH's Final BACT determination (see Enclosure 3). While EPA understands that there are differences between Texas and North Dakota lignites, as well as the boiler configurations at Oak Grove and MRYS that make the technical application of SCR different, the principles illustrated in the Oak Grove permit proceeding related to the BACT process largely parallel those in the Minnkota NOx BACT determination. EPA is also submitting additional information relative to the Oak Grove permit proceeding that is not contained in the docket (also part of Enclosure 3). The docket can be accessed electronically at:

http://www7.tceq.state.tx.us/uploads/eagendas/Agendas/2007/6-13-2007/Oak%20Grove.pdf

VII. B&McD 114 RESPONSE DOCUMENTS

On June 20, 2008, EPA issued a Clean Air Act, Section 114 request for information to B&McD asking for information related to the SCR system and catalyst vendor query that was conducted by B&McD on behalf of Minnkota. EPA received B&McD's response on July 3, 2008. EPA is submitting portions of the response herein as part of Enclosure 3 for the state to include in the administrative record and consider in NDDH's Final BACT determination. To summarize some significant findings, the B&McD response indicates:

- Early draft versions of the vendor query document prepared by B&McD asked for vendor opinions of the temperature variation issue for HDSCR at MRYS and possible boiler modifications that could address this problem. At Minnkota's direction, this request was removed from the final query document.

- Based on B&McD's call notes following up with the vendors that gave more optimistic responses in early 2007 (those that were less optimistic were deemed by Minnkota as not needing follow-up), it is clear that catalyst vendors were not swayed by the arguments set forth by B&McD and EERC related to the potential severity of sodium catalyst poisoning. Also, SCR system suppliers told B&McD that they believe tail-gas SCR would resolve the problems being advanced by B&McD and EERC related to lignite fuel firing. Why B&McD did not pursue the tail-gas option with vendors after it had been suggested is unclear.

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[34] See Applicant's Exception to the Proposal for Decision, September 12, 2006, page 8.

- In two separate documents (comments on a draft response to EPA comments dated February 6, 2007 and an email correspondence dated May 10, 2007), Robert Johnson (who was working as a consultant, but it is believed previously worked for Argillion and then B&McD) opined on many of the technical issues for an SCR at MRYS. The positions taken by Mr. Johnson largely support positions taken by EPA, namely that there is no useful underlying data that supports the claims of EERC regarding the severity of sodium catalyst poisoning (in HDSCR, LDSCR, or TESCR), the Coyote Station pilot testing "was a flawed test and the results should not be used to draw any conclusions other than that a full scale system design needs to be done very carefully", sodium is not much of a concern as a catalyst poison at SCR operating temperatures, and that TESCR is a likely candidate for MRYS.

- It appears Minnkota has conducted a cost analysis of SCR at MRYS using different expected catalyst life spans of 12,000 and 24,000 hours. This information has not been made publically available to EPA's knowledge.

VIII. DOCKET INFORMATION FOR THE CLEAN AIR INTERSTATE RULE (CAIR), BEST AVAILABLE RETROFIT TECHNOLOGY (BART) GUIDELINES, AND NEW SOURCE PERFORMANCE STANDARDS (NSPS) STATES THAT EPA DETERMINED THAT SCR IS TECHNICALLY FEASIBLE FOR LIGNITE FIRED UTILITY BOILERS.

In a January 8, 2007 letter (sent via fax), EPA provided the NDDH with docket information and references related to various rulemakings (CAIR, BART Guidelines, NSPS), where EPA determined SCR to be feasible at lignite-fired utility boilers. This information does not appear to be completely in the administrative record for the NDDH BACT determination, so EPA is providing information related to these rulemakings herein as part of Enclosure 3 for the NDDH to include in the administrative record and consider in NDDH's Final BACT determination. As mentioned in the January 8, 2007 letter, through these three rulemakings, EPA determined SCR to be technically feasible and rejected commenter's concerns that SCR would not be technically feasible for lignite units, including those fired on North Dakota lignite. EPA reiterates that the position now being taken in the NDDH BACT determination is contrary to that established by EPA in these three national rulemakings.

ENCLOSURE 3

ADDITIONAL DOCUMENTATION FOR ADMINISTRATIVE RECORD

2007 NOx ROUND TABLE & EXPO
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Feasibility of SCR Technology for NOx Control Technology for the Milton R. Young Station, Center, North Dakota

Expert Report of

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ON BEHALF OF THE

UNITED STATES DEPARTMENT OF JUSTICE

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1. INTRODUCTION AND OVERVIEW

1.1 Information Required for the Expert Report

The following is a listing of the items provided with this report:

(1) This report contains my personal opinions, conclusions and the reasons therefore.

(2) The body of the report and **Appendix A** list the data and other information considered in forming these opinions.

(3) **Appendix B** provides a copy of the e-mail correspondence with several selective catalytic reduction (SCR) catalyst manufacturers and SCR equipment vendors concerning the technical feasibility of tail-end SCR (TESCR).

(4) **Appendix C** includes a listing of publications authored during the past ten years.

(5) Section III presents a statement of my qualifications; my resume is attached as **Appendix D**.

(6) I am being compensated for the preparation of this report and my testimony by the U.S. Department of Justice.

(7) I have provided previous testimony within the preceding four years as an expert at trial or by deposition.

1.2 Purpose of the Report

This report is written under a consulting contract and pursuant to a request from the Department of Justice (DOJ) for an analysis of whether or not the SCR technology would be a technically feasible and available technology for the reduction of nitrous oxides (NOx) for installation at the Milton R. Young Station located near Center, North Dakota.

A preliminary Best Available Control Technology (BACT) determination for control of NOx for the M.R. Young Station conducted by the Division of Air Quality of the North Dakota Department of Health[1] (the Department) concludes that the SCR technology is not

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[1] Preliminary Best Available Control Technology Determination for Nitrogen Oxides for M.R. Young Station Units 1 and 2, Division of Air Quality ND Department of Health, 918 E. Divide Avenue, Bismarck, ND, June 2008.

technically feasible at this time. I was asked to review the information in and provided by this preliminary BACT determination and render an expert opinion concerning the technical feasibility of the SCR technology for retrofit at the M.R. Young Station.

2. SUMMARY OF CONCLUSIONS

In summary, and for the reasons described herein, I have concluded that the SCR technology is technically feasible and principally available for installation at both units at the Milton R. Young Station for NOx reduction. I have further concluded that even though the high-dust SCR (HDSCR) principle was investigated in some detail prior to the BACT determination:

- The depth of the investigation concerning the technical feasibility of HDSCR in this case by means of pilot testing conducted at the Coyote Station (Coyote Pilot Testing) was insufficient and the conclusions drawn from this pilot testing were speculative and premature.
- Virtually no investigation of the technical feasibility of low-dust SCR (LDSCR) and TESCR was conducted at all and both distinctly different SCR principles were incorrectly treated as if they would be essentially the same.
- The HDSCR Coyote Pilot Testing was ill-designed and inadequately conducted.
- The data generated by the Coyote Pilot Testing for these reasons is inconclusive and meaningless of the purpose of this determination.
- The conclusions suggested by the Department based on the data presented are not reasonably founded but premature, purely speculative and mostly incorrect.

Consequently, it is my opinion that the conclusions presented by the North Dakota Department of Health in the BACT determination[2], namely, that the SCR technology is not technically feasible at this time for both units at the M.R. Young Station, is wrong. Such a conclusion cannot be drawn correctly based on the available data. The SCR technology must be considered principally, technically feasible for Minnkota's Milton R. Young Station. This is even true for HDSCR even though not without significant but technically resolvable challenges, which may result in HDSCR not being the economically most advantageous SCR principle. However, whether HDSCR, LDSCR or TESCR is the economically most viable SCR solution for M.R. Young is beyond the scope of this report.

Finally, I have concluded that no sufficiently detailed investigation was conducted for LDSCR and/or TESCR in this case and the record of investigation provided by the

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[2] Preliminary Best Available Control Technology Determination for Nitrogen Oxides for M.R. Young Station Units 1 and 2, Division of Air Quality ND Department of Health, 918 E. Divide Avenue, Bismarck, ND, June 2008.

Department is insufficient, inadequate and incomplete. Both of these SCR principles were incorrectly treated by the Department as being essentially the same, which is incorrect and unacceptable as the flue gas composition and characteristics entering a LDSCR are completely different from the one entering a TESCR.

The statement made by the Department that none of the various principles of the SCR technology (HDSCR, LDSCR, TESCR) can be considered applicable and technically feasible at this time is not only purely speculative but factually incorrect. As a matter of fact a quick vendor survey conducted by me confirmed that all contacted vendors consider TESCR as being unquestionably technically feasible, available and applicable for M.R. Young Station. This was not only unanimously confirmed by all leading catalyst manufacturers (Argillon, CERAM, Cormetech, Haldor Topsoe and Hitachi) but also by leading SCR equipment vendors (Alstom, Babcock Power and Babcock & Wilcox). Furthermore, these SCR equipment vendors and catalyst manufacturers confirmed my opinion by stating that they also consider LDSCR as technically feasible and probably even HDSCR, however not without significant but resolvable technical challenges such as limiting the boiler outlet temperature variations to a range tolerable for SCR catalyst and eliminating the popcorn ash problem. The temperature variations at the boiler outlets appear to be the biggest hurdle for the application of HDSCR at this time; however, this issue is considered to be technically resolvable as indicated by Babcock & Wilcox[3], who supplied both boilers at M.R. Young Station. Answering the question of whether or not the extent of modifications of existing equipment required to resolve the temperature variation issue makes HDSCR economically less attractive in comparison to LDSCR or even TESCR is beyond the scope of this report.

However, it is my opinion that the available data presented in the Department's BACT determination[4] is insufficient, inconclusive and interpreted largely incorrectly when concluding the HDSCR is technically infeasible. This conclusion cannot be supported by the available data at all. Furthermore, concluding that LDSCR and/or TESCR are not technically feasible based on the available data is incorrect, since no relevant data was presented that supports such a conclusion in any way. Based on my more than 20 years of SCR experience and my evaluation of the vendor responses, it is my opinion that the SCR technology is technically feasible and principally available for installation at both units at the Milton R. Young Station for NOx reduction. The only design engineering challenge is the proper selection of the best suitable type of SCR principle[5] to be applied and the correct SCR process and catalyst design. This, however, is neither a question of technical feasibility nor of applicability or availability of the SCR technology but simply a question of economics.

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[3] E-mail from Steve Moormann (Babcock &Wilcox) to Robert Blakley (Burns & McDonnell) dated July 18, 2007.

[4] Preliminary Best Available Control Technology Determination for Nitrogen Oxides for M.R. Young Station Units 1 and 2, Division of Air Quality ND Department of Health, 918 E. Divide Avenue, Bismarck, ND, June 2008.

[5] Defined by its location on the flue gas pass as HDSCR, LDSCR or TESCR.

3. QUALIFICATIONS

I have been involved in the business development, proposal engineering and estimating, project management, process and design engineering, component and equipment procurement, construction, erection, commissioning and start-up and operation of air pollution control equipment for utility and industrial power plants as well as waste incinerators (municipal waste, hazardous waste, sewage sludge, medical waste etc.) in a variety of capacities for over twenty years. I began my career in the field of air pollution control in 1983 as a staff engineer working for Mercedes-Benz in automobile engine development adapting standard type European automobile engines with catalytic converters, secondary air injection systems, exhaust gas recirculation systems etc. in order to comply with more stringent emission regulations in entities such as California, the U.S. (48 states), Japan etc.

In late 1987, I accepted a position with L&C Steinmüller GmbH in Germany, which was one of the leading engineering and equipment vendors supplying power utility boilers, including the associated air pollution control equipment. Initially, my field of responsibility included business development for all environmental control technologies (air, water, waste) in Southern Germany. In 1990, I became Department Manager of the Department of Gas Cleaning for waste incineration facilities. In 1993, I became General Manager for Flue Gas Cleaning at L&C Steinmüller. Between 1988 and 1999, I was personally fully involved in the following retrofit phases in Europe:

- Retrofitting all fossil fuel fired boilers (utility and industrial) with a thermal heat input of more than 300 MW with flue gas desulfurization (FGD) systems ensuring a continuous SO_2 removal efficiency of at least 85% at all times, mostly wet limestone forced oxidation (LSFO) FGDs producing wallboard quality gypsum as a byproduct. This retrofit phase started in Western Europe in the late 1970s and ended in Eastern Europe in the late 1990s. FGD retrofits focused on Austria, Belgium, Bulgaria, Czech Republic, Denmark, Finland, Germany, Greece, Holland, Hungary, Poland, Slovenia, Slovakia, Spain, Sweden, Turkey and the U.K.

- Retrofitting all fossil fuel fired boilers with a thermal heat input of more than 300 MW with nitrous oxide removal (DeNOx) systems ensuring a NOx emission rate of less than 100 ppm[6] at all times, almost exclusively selective catalytic reduction (SCR) DeNOx systems. This retrofit phase started in Europe in the mid 1980s and is still ongoing. SCR retrofits focused on Austria, Belgium, Denmark, Finland, Germany, Holland, Italy, and Sweden.

- Retrofitting all waste incineration facilities regardless of the type of waste (municipal, industrial, hazardous, sewage sludge, medical etc.) with extensive flue gas cleaning

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[6] At the following flue gas characteristics: NOx concentration by volume on a dry basis @ 5% O_2, 1 atm., 273 K.

> systems for the removal of acid gases (SOx, HCl, HF), NOx, particulate matter (PM), heavy metals including mercury (Hg), cadmium (Cd), lead (Pb) and numerous others as well as dioxins (PCDD) and furans (PCDF). This retrofit phase started in Europe in the early 1990s and is still ongoing. Waste incinerator retrofits focused on Austria, Denmark, Finland, France, Germany, Holland, Norway, Sweden, and the U.K.

In 1999, I became a co-founder and Managing Director of E&EC – Energy & Environmental Consultants GmbH, an international engineering consulting firm with offices in Germany and a representation in the U.S. Through E&EC I assisted a German SCR catalyst manufacturer in a concentrated effort to supply SCR catalyst and system expertise to the North American market. Also, through E&EC I assisted Babcock Borsig Power in Germany to align their German subsidiary Babcock Borsig Power Environment (former L&C Steinmüller) with their U.S. subsidiary DB Riley (today Babcock Power) in Worcester, Massachusetts in order to take full advantage of the business opportunities provided through the NOx SIP call under the Clean Air Act Amendments (CAAA) Title I Groundlevel Ozone Requirements[7].

Three months into the project, I was offered to take over the environmental business unit of DB Riley, Inc. (later renamed Babcock Borsig Power, Inc., now renamed Babcock Power, Inc.) in Worcester, Ma. After accepting this position, I was responsible for the SCR retrofits for the coal-fired units of American Electric Power (AEP), Detroit Edison (DTE), Duke Power, Louisville Gas & Electric (LG&E) and its subsidiaries Kentucky Utilities (KU) and Western Kentucky Energy (WKE), all now consolidated under E.ON-US, Northern Utilities (NU), Pennsylvania Power & Light (PP&L), Santee Cooper (SC), and Wisconsin Electric Energies (WE Energies) as well as the development of the emerging markets for FGDs and mercury-removal technologies. I left DB Riley and refocused on E&EC shortly before DB Riley's German parent company declared bankruptcy.

Through E&EC I founded SCR-Tech LLC together with a German partner and was acting president of SCR-Tech between 2001 and 2005. SCR-Tech was dedicated to providing the North American utility industry with SCR management and catalyst regeneration services.

After the sale of SCR-Tech in 2004, I left SCR-Tech in 2005 and joined Steag LLC, a wholly owned subsidiary of Steag AG in Germany. Steag AG (now renamed Evonik Steag GmbH) is part of Evonik Industries AG and dedicated to power generation and engineering. Evonik Steag GmbH owns and operates more than 10,000 MW of mostly coal-fired power plants around the world. In 2005, I accepted the position as president of Evonik Energy Services LLC (formerly Steag LLC), which has been dedicated to serve the North American utility industry with SCR design and management services since 1992 and also with catalyst regeneration services since 2007.

Through E&EC, I am also assisting the North American utility industry in their SCR and

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[7] Call by USEPA for State Implementation Plans in 19 Eastern States in order to reduce the NOx emissions of large sources (e.g. coal fired power plants) as required by the 1990 Clean Air Act Amendments (CAAA) under Title I – Groundlevel Ozone.

FGD needs by fully utilizing my experience and expertise, which I developed over the past 21 years working as an engineer solely in the area of air pollution control systems for fossil fuel fired power plants and waste incineration facilities with a focus on FGDs and SCRs.

4. THE MILTON R. YOUNG STATION: BACKGROUND

The M. R Milton Station consists of two North Dakota lignite-fired steam electric generation units, with gross electric generating capacities of approximately 257 megawatts electric (MWe) (Unit 1) owned by Minnkota Power Cooperative and 477 MWe (Unit 2) owned by Square Butte Electric Cooperative. The units went into operation in 1970 (Unit 1) and 1977 (Unit 2). Both units feature cyclone-fired Babcock & Wilcox (B&W) boilers followed by tubular air pre-heaters. Air pollution control equipment consists of overfire air (OFA) systems for both units (Unit 2 OFA is scheduled in 2007 and Unit 1 OFA in 2009), a cold-side electrostatic precipitator (ESP) for particulate matter (PM) control for both units and a lime/fly ash wet scrubber for sulfur dioxide (SO_2) control for Unit 2[8]. Unit 1 will be retrofitted also with a wet lime scrubber supplied by Marsulex, which is scheduled to commence operation in April 2011[9]. Additionally, Minnkota Power Cooperative and Square Butte Electric Cooperative are committed to retrofit BACT for NOx control for both units under a Consent Decree with the United States and the State of North Dakota, dated July 27, 2006. The NOx control technology to be retrofitted must be determined by a top-down BACT Analysis, which must evaluate various technologies including SCR.

5. SCR TECHNOLOGY

The selective catalytic reduction (SCR) technology was originally developed in Japan under a government grant in the 1970s and subsequently retrofitted to most Japanese fossil fuel fired power plants[10]. SCR involves injecting gaseous ammonia generated from UREA, aqueous or anhydrous ammonia into the flue gas at a specific temperature before it reaches a catalyst. The catalyst significantly lowers the temperature required to complete the reaction of the injected ammonia with NO_x (mostly nitrogen oxide NO and nitrogen dioxide NO_2) to form nitrogen and water. Therefore the SCR reactor can be operated at a lower temperature zone at a suitable location in the flue gas path. Compared to the same reactions taking place without the presence of a catalyst, which is commonly referred to as selective non-catalytic reduction (SNCR) and requires flue gas temperatures between 1,500 F (~800 °C) and 2000 F

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[8] Milton R. Young Station – Our Jewel on the Prairie, brochure published by Minnkota Power Cooperative and Square Butte Electric Cooperative on Minnkota's website: www.minkota.com.

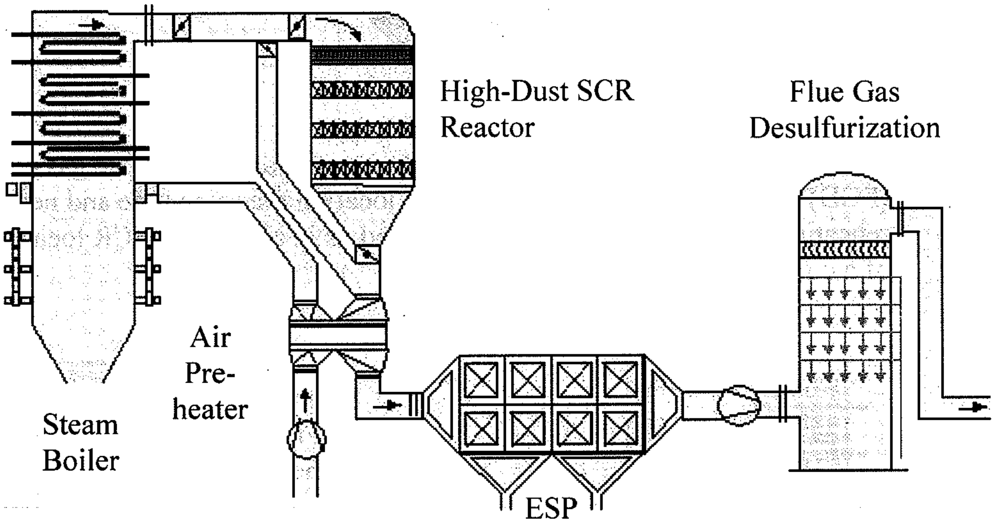
[9] McIlvaine Utilitiy E-Alert #868, April 4, 2008.

[10] Ando, Jumpei, "SO_2 and NO_x Removal for Coal Fired Boilers in Japan," presented at the Seventh Symposium on Flue Gas Desulfurization, May, 1992.

(~1,100 °C), the SCR process allows for a much higher NOx removal efficiency compared to the SNCR process while ensuring a very low (typically less than 2 ppmvd @ 3% O_2) ammonia slip. Continuous NOx removal efficiencies of well above 90% with NOx outlet concentrations well below 0.05 lbs/MMBtu[11] have been reported[12].

Various principles of the SCR technology are commonly described foremost by the SCR reactor's location within the flue gas path. Three main categories of SCR systems with one being split into two subcategories are known for fossil fuel fired utility boilers, namely:

- High-dust SCR (HDSCR) located between the boiler's economizer outlet and the air perheater inlet upstream of the ESP (pictured below). At this location typically no reheating of the flue gas is required.



- Low-dust SCR (LDSCR), which is split into two subcategories, namely:
  - Hot-side LDSCR located downstream of a hot-side ESP and upstream of the air preheater (not pictured below). At this location no reheating of the flue gas is typically required as the hot-side ESP is also upstream of the air pre-heater.
  - Cold-side LDSCR located downstream of the air preheater as well as downstream of a cold-side ESP (pictured below). At this location reheating of the flue gas is typically required as the cold-side ESP is downstream of the air preheater.

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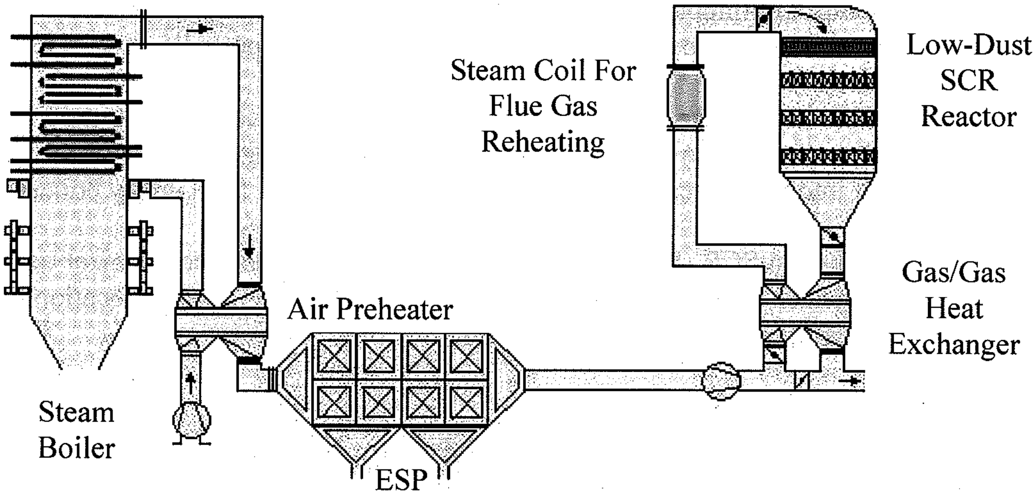
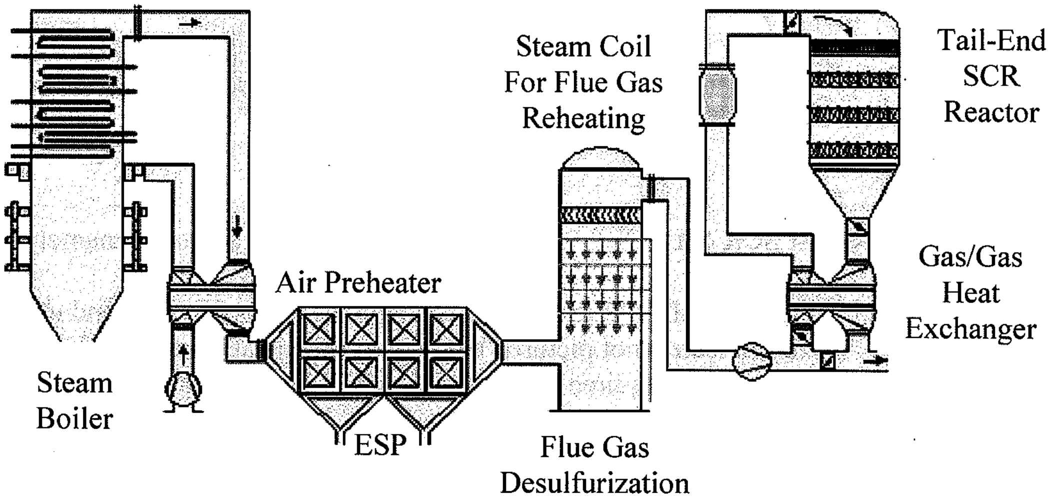
[11] MMBtu = million British thermal units.

[12] Erickson, C., S. Straight, L. Hutcheson, "Coal-Fired SCR Operating Experience with High Removal Efficiency and Low-NOx Firing Systems", Babcock Power's website: www.babcockpower.com.



- Tail-end SCR (TESCR) located downstream of a dry or wet flue gas desulfurization (FGD) system (pictured below). At this location the same type and net quantity of reheating of the flue gas is always required as in case of LDSCR located downstream of a cold-side ESP pictured above.



After the technology was initially installed in Japan, SCR began to be used in Europe, mainly in Germany during the 1980s, where legislation introduced in 1983[13] required all power plants to drastically reduce the NOx emissions by the end of the decade. As a result, the first HDSCR on a coal-fired power plant in Europe went into operation in 1985 (Altbach Power

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[13] EPA-450/3-92-004, Office of Air and Radiation, Office of Air Quality Planning and Standards, "Summary of NOx Control Technologies and their Availability and Extent of Application", February 1992.

Station Unit 5[14]), the first TESCR in Europe went into operation in 1986 (Hamburg Hafen Generating Station Unit 1[15]) and the first LDSCR went into operation in 1988 (Walsum Cogeneration Plant Unit 7[16]). By the end of the 1980s, SCRs were used in a wide variety of coal-fired power plants worldwide after Austria, Denmark, Germany, Holland and Japan had retrofitted most of their coal fired power plants with SCR systems for NOx removal. Even the first HDSCR on a lignite or brown coal fired utility boiler went into operation in Austria in 1990 (Voitsberg Power Station Unit 3[17]). By the end of the 1980s, well over 100 SCR systems had been installed in Europe on more than 30,000 MW of coal fired generating capacity with most SCRs representing retrofits of coal fired generating units[18, 19].

As reported by the Electric Power Research Institute (EPRI)[20], an institution solely funded by and dedicated to the electric utility industry, by 1989 the SCR technology was fully developed in two basic forms, namely as HDSCRs and as TESCRs. It is worth mentioning that the TESCR principle was mainly developed for the use on cyclone-fired and other wet bottom boilers because of their very high catalyst deactivation rates resulting from high arsenic levels in the flue gas in case of fly ash re-injection into the furnace for internal vitrification and no arsenic mitigation by means of limestone addition. Furthermore, TESCRs were also applied in some cases due to space constraints and/or difficult retrofit sites where the installation of a HDSCR would have caused elongated periods of downtime of the unit. In total about 40% of the SCR retrofits in Europe were TESCRs.

EPRI[21/]reports that all European SCR systems visited during a field trip in 1988 consistently met their design removal efficiencies of up to 88% in HDSCRs and TESCRs operating in coal fired units firing coals with sulfur contents up to 1.5 %wt. This overall finding was solidified by 1989 after additional years of operating experience.

EPRI reported heat rate penalties on the unit between 1 and 3% resulting from the necessity of flue gas reheating in case of cold-side LDSCR and/or TESCR. Such flue gas reheating requires the use of a gas/gas heat exchanger, in which the flue gas coming from the SCR

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[14] Fisia Babcock GmbH (formerly L&C Steinmüller GmbH) and Babcock Power, Inc. reference lists SCR systems.

[15] Ibid

[16] Ibid

[17] Reference list on CERAM's website: www.frauenthal.net.

[18] Technical Feasibility and Cost of SCR NOx Control in Utility Applications, RP 1256-8 prepared by United Engineers and Constructors, Inc. for Electric Power Research Institute (EPRI), August 1989.

[19] EPA-450/3-92-004, Office of Air and Radiation, Office of Air Quality Planning and Standards, "Summary of NOx Control Technologies and their Availability and Extent of Application", February 1992.

[20] Technical Feasibility and Cost of SCR NOx Control in Utility Applications, RP 1256-8 prepared by United Engineers and Constructors, Inc. for Electric Power Research Institute (EPRI), August 1989.

[21] Ibid

reactor outlet is used to reheat the flue gas going to the SCR reactor inlet similarly to an air preheater. These gas/gas heat exchangers can be designed as rotary type, tubular or plate type heat exchangers. All three types have been utilized successfully. Since a 100% efficient heat transfer from the outgoing to the incoming flue gas is physically impossible, a comparatively small amount of additional energy must be provided for reheating the flue gas downstream of the gas/gas heat exchanger to the SCR reactor inlet temperature. This additional energy, which is needed to overcome the temperature gradient of the gas/gas heat exchanger, amounts to an additional heating of the flue gas of typically between 45 degrees F (25 K) and no more than 90 degrees F (50 K) with amounts known as low as 18 degrees F (10 K). Flue gas reheating is most commonly accomplished in one of two ways, namely:

- In case of coal-fired power plants or when steam of sufficiently high pressure and temperature is available, a steam coil is used for flue gas reheating. The use of steam for flue gas reheating is generally the most economical and advantageous method as it neither increases the flue gas flow rate nor adds any additionally constituents (i.e. NOx) to the flue gas. Steam reheating is particularly economically advantageous in coal-fired power plants, which are "turbine limited" meaning the boiler can generate more high pressure steam at full load than the turbine needs for generating its maximum electrical output. In such a case, the surplus generated high pressure steam, which cannot be used for generating electricity, is ideally suitable for the use of steam reheating of the flue gas without or only minimal impact on the generating capacity of the unit. In this case, the heat rate penalty of the unit may be eliminated entirely.

- In case no steam or only steam of insufficient temperature and pressure is available as it is the case in many non-power plant applications, natural gas duct burners are typically used for flue gas reheating. Such flue gas reheating results in some additional operating cost for natural gas, which, however, can at least partially be offset by significantly prolonged catalyst life of typically well over 100,000 SCR operating hours, a smaller overall SCR reactor, less installed catalyst volume and a smaller catalyst pitch[22]. In some cases the additional operating costs can be completely offset by the elimination of extended unit downtime, which would be necessary for an HDSCR retrofit, and the availability of excess high pressure steam, thus making TESCR the most economical solution.

- EPRI[23] reported TESCR systems in Europe to achieve NOx removal efficiencies between 83 and 92% with cost between US$ 180 – 225 per kW and HDSCR systems to achieve NOx removal efficiencies between 65 and 88% with cost between US$ 65 – 200 per kW. Considering the fact that this was reported in 1989, in other words more than a decade before the SCR retrofit phase in the U.S. resulting from the

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[22] Sobolewski, H, H. Hartenstein, H. Rhein, "STEAG's Long Term SCR Catalyst Experience and Cost", The 2005 EPRI Workshop on Selective Catalytic Reduction, Louisville, KY, November 2005.

[23] Technical Feasibility and Cost of SCR NOx Control in Utility Applications, RP 1256-8 prepared by United Engineers and Constructors, Inc. for Electric Power Research Institute (EPRI), August 1989.

CAAA NOx SIP call[24] and considering the fact that the cost of almost all SCRs retrofitted in North America were within this range, it can be reasonably expected that the retrofit cost for TESCR will also fall approximately within the range determined by EPRI back in 1989.

All European and North American HDSCRs have achieved their targeted NOx emission rates without any major operational problems. Early design flaws mostly resulting from inadequate flow conditions and flue gas distribution problems were mostly corrected by about 1990. By early 2000 more than 23,000 MW of SCRs were in operation in Japan and more than 55,000 MW in Europe[25], of which about 40% are TESCRs. Currently, more than an estimated 250,000 MW of HDSCRs are successfully operating worldwide on utility boilers with an estimated more than 100,000 MW in North America. The balance can be found in Europe (Austria, Belgium, Denmark, Finland, France, Germany, Holland, Italy, Portugal, Spain, Sweden, Turkey, etc,) and Asia (China, Japan, Korea, Taiwan, etc.).

By 1989/1990 approximately 18,000 MW of TESCRs were in operation or near completion on coal-fired utility boilers in Europe. At the same time almost four years of extremely positive operating experience had been collected on the first TESCR, which went into operation in Hamburg in 1986. Today after more than 20 years of TESCR operating experience, catalyst lifetime in excess of 100,000 is considered normal[26].

As a result of this extremely positive long term operating experience with TESCR, this principle was generally adopted as a universally applicable SCR solution for all types and compositions of flue gases incompatible for HDSCR due to the catalyst deactivation characteristics. Incompatible conditions for HDSCR can be either due to:

- physical parameters of the flue gas, which are unacceptable, such as temperature, ash content, etc., or
- chemical composition of the flue gas, which may cause uneconomically rapid catalyst deactivation such as higher concentrations of gaseous arsenic, phosphorus, sodium, potassium, calcium, magnesium, chromium, barium, selenium, etc..

Consequently, TESCRs were installed for NOx control on a wide variety of high temperature combustion and other thermal processes including:

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[24] Call by USEPA for State Implementation Plans in 19 Eastern States in order to reduce the NOx emissions of large sources (e.g. coal fired power plants) as required by the 1990 Clean Air Act Amendments (CAAA) under Title I – Groundlevel Ozone.

[25] Sanyal, A., W. Allison, "Lessons Learned from SCR Experience of Coal-Fired Units in Japan, Europe and USA; Are These Enough?" Presented at the 2002 DOE Conference Selective Catalytic Reduction and Non Catalytic Reduction for NOx Control, Pittsburgh, PA, May 2002.

[26] Sobolewski, H, H. Hartenstein, H. Rhein, "STEAG's Long Term SCR Catalyst Experience and Cost", The 2005 EPRI Workshop on Selective Catalytic Reduction, Louisville, KY, November 2005.

- municipal solid waste incinerators (1989)
- hazardous waste incinerators (1990)
- sewage sludge incinerators (1990)
- hospital and medical waste incinerators (1990)
- crematories (1991)
- pharmaceutical waste incinerators (1992)
- refinery crackers (1994)
- glass smelters (1994)
- blast furnace and coke gas combustors (1994)
- nitric acid plants (1994)
- biomass furnaces (1994)
- construction debris and waste wood combustors (1995)
- electric arc furnaces (1996)
- ammunition and chemical weapons incinerators (1997)
- ethylene crackers (1997)
- Orimulsion boilers (1999)
- roller mills (2000)
- photovoltaic cell production (2002)
- hydrogen reformers (2003)
- steel coil heat treatment facilities (2003)
- sintering plants (2003)
- steel pickling (2005)

In short, almost every high NOx producing process imaginable was successfully retrofitted with TESCR systems making the SCR technology the most widely used secondary NOx reduction technology worldwide. As a matter of fact, in many cases, HDSCRs or LDSCRs were successfully installed and operated despite the fact that original pilot testing often suggested severe, rapid catalyst deactivation and seriously questioned the technical feasibility of either one of these two SCR principles for these applications. Examples include:

- lignite or brown coal fired boilers (HDSCR, 1990)
- cyclone fired and other wet bottom boilers with fly ash re-injection (HDSCR, 1991)
- heavy fuel oil (HDSCR, 1992)
- municipal solid waste incinerators (LDSCR, 1992)
- hazardous waste incinerators (LDSCR, 1995)
- roller mills (LDSCR, 2000)
- cement kilns (HDSCR, 2003)
- biomass (HDSCR, 2006)

Two of the most recent examples of this development in the U.S. are the ongoing HDSCR retrofits on PRB-fired utility boilers as well as at several utility boilers firing Texas lignite. Once again, initial pilot testing seemed to have suggested that catalyst deactivation through fly ash pluggage and chemical poisoning may be too rapid to make HDSCR economically viable. For example, in case of PRB-fired utility boilers, HDSCR pilot testing conducted at Dynegy's Baldwin Energy Center (Baldwin Pilot Testing) yielded results that clearly suggested that PRB caused "significant accumulations of ash on the catalyst, on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months[27]."

During HDSCR pilot testing at Luminant's Sandow Generating Station Unit 4 catalyst deactivation was determined to be about 20% after approximately 2,900 hours before increasing to approximately 50% after some 3,500 hours due to catalyst plugging[28]. Based on an extrapolation of this data a HDSCR would not likely have reached 10,000 operating hours prior to catalyst needed to be added or exchanged. For comparison purposes, typical SCR catalyst design requires an addition or exchange of catalyst during an outage when the total

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[27] Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

[28] Smith, R, J. Bennett, D. Broske, "Impacts of Texas Lignite on SCR Catalyst Life and Performance", presented at the 2007 EPRI SCR Workshop in Pensacola, Florida, November 2007.

reactor potential has reached between 60% and 75% of the original value when equipped with all new catalyst.

Yet, in both cases, at Baldwin and Sandow, HDSCR has become the NOx control method of choice. Currently, more than fifty (50) PRB-fired boilers including at least twenty two (22) cyclone-fired units have successfully operated HDSCRs without any of the problems suggested based on the Baldwin Pilot Testing results[29]. Likewise, HDSCRs are being installed at several utility units burning Texas lignite including Oak Grove 1 & 2[30], Sandow 4[31] & 5[32], Martin Lake 1, 2 & 3[33] and Limestone 3[34].

In case of a TESCR installation, the situation is dramatically less challenging resulting from the fact that the flue gas downstream of a wet scrubber, which a TESCR is exposed to, is extremely clean compared to what the catalyst is exposed to in a HDCSR upstream of the ESP. Downstream of an ESP and a wet scrubber in excess of 99% of the fly ash is removed in the ESP[35] and between 90% and 95% of SO_2 is removed in the wet scrubber[36], thus leaving very little if anything in the flue gas that is critical for catalyst deactivation.

Additionally, downstream of a wet scrubber, the flue gas has gone through its dew point after being cooled to saturation while passing through the wet scrubber. Going through the dew point of the flue gas, which is typically between 110 F (~43 °C) and 150 F (~65°C), means that all condensable catalyst poisons such as alkali and earth alkali salts, arsenic and phosphorus oxides will inevitably have condensed and, along with all other highly water soluble gaseous catalyst poisons including sodium and potassium sulfates, phosphates and carbonates, will have been mostly removed by the wet scrubber. In a wet scrubber all water soluble compounds including water soluble alkali sulfates, phosphates and carbonates as well as all residual alkali vapors are virtually quantitatively removed as a result of their extremely high water solubility.

The very small residual amounts (less than 1%) of small particles (< 5 µm) passing through the ESP consist of condensed vapors or aerosols including sulfuric acid, alkali sulfates, earth-

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[29] Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

[30] E-Mail from Randy Sadler on behalf of Cindy Khalaf, President of Argillon LLC, supplier of the SCR catalyst for Oak Grove 1 & 2, dated June 24, 2008.

[31] McIlvaine Utiltiy E-Alert #870 dated April 18, 2008.

[32] Jones, B., Introductory presentation at the Gulf Coast Power Association Spring Conference, April 2006.

[33] McIlvaine Utiltiy E-Alert #874 dated May 16, 2008.

[34] McIlvaine Utility E-Alert #871 dated April 25, 2008.

[35] Milton R. Young Station – Our Jewel on the Prairie, brochure published by Minnkota Power Cooperative and Square Butte Electric Cooperative on Minnkota's website: www.minkota.com.

[36] Ibid

alkaline oxides and silicates. These small particles often act as condensation nuclei during the rapid flue gas quenching in the inlet of the wet scrubber and are largely removed by this mechanism. Thus, their already small quantity downstream of the ESP is reduced further, typically by at least 50% across a wet scrubber. This means that compared to a HDSCR, catalyst installed in a TESCR is confronted with less than 0.5% of the particulate matter and less than 5 – 10% of the acid gases, vapors and other water soluble compounds, which cause catalyst deactivation. Consequently, the experienced catalyst deactivation rate is correspondingly slower.

It must be noted that particle bound compounds add very little to the chemical catalyst poisoning causing deactivation. Only gaseous compounds or in liquid dissociated ions of salts of these compounds are chemical catalyst poisons. However, as explained earlier, these gaseous compounds are largely removed in a wet scrubber and the remaining concentrations downstream of a wet scrubber are typically so negligible that the result is and in extraordinarily slow catalyst deactivation. Furthermore, the flue gas is being reheated in a TESCR prior to entering the catalyst, which means that these very small residual concentrations of chemical catalyst poisons including alkali and earth alkali sulfates and phosphates as well as the flue gas itself are at least 400 degrees (200 K) above their respective dew points, which virtually eliminates the possibility of these residual catalyst poisons condensing in the pores of the catalyst. In general, the condensation temperature or dew point of any compound including these gaseous catalyst poisons is a function of the flue gas temperature and the compound's concentration in the flue gas. As noted above, the residual concentrations of catalyst poisons are very small in a TESCR downstream of a wet scrubber and the difference between their dew point temperature, which is the flue gas temperature at the outlet of the wet scrubber and the TESCR operating temperature is very large due to the reheating of the flue gas. Consequently, any type penetration of these chemical catalyst poisons and subsequent condensation in the catalyst pores is at least extremely unlikely if not physically impossible at the TESCR operating conditions.

The virtually negligible residual amount of gaseous catalyst poisons entering a TESCR compared to an HDSCR results directly in an almost proportionally extended catalyst life. Based on 20 years of extraordinarily successful full scale TESCR operating experience in Europe, a catalyst life of typically well more than 100,000 hours must be considered the norm rather than the exception. Several TESCRs after wet bottom utility boilers are still in operation after 20 years with the initial fill of catalyst and no replacement, exchange or addition[37].

Additionally, the minimal concentration of catalyst poisons entering a TESCR and the resulting very slow long-term catalyst deactivation (as experienced over 20 years of operation of TESCRs) led to the reduction in operating temperatures for TESCRs as shown in the graph below, which can be found on Argillon's website[38]. Argillon, who is one of the

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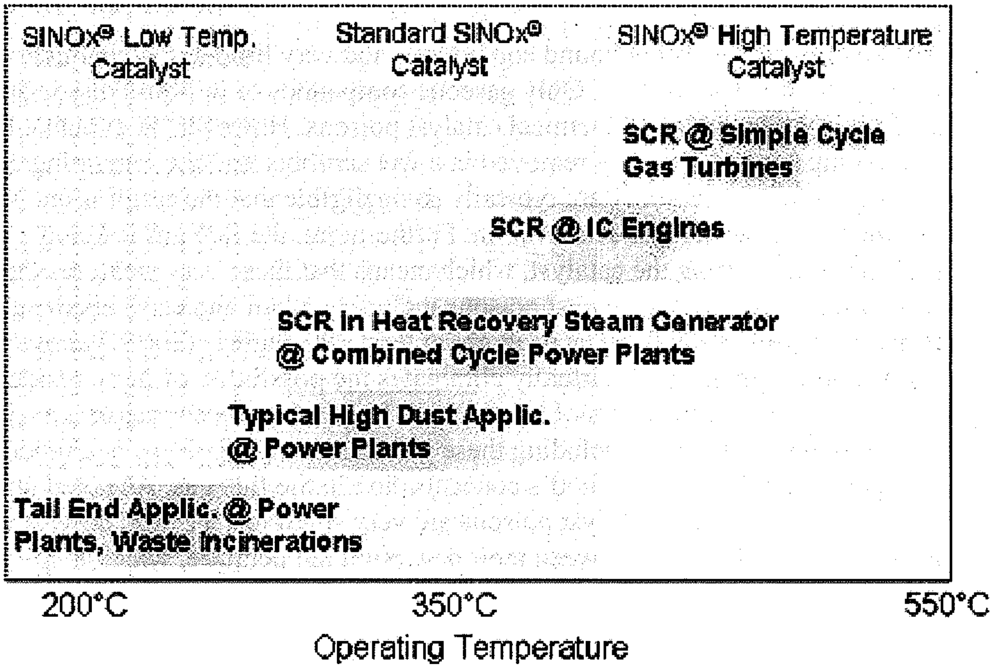
[37] Sobolewski, H, H. Hartenstein, H. Rhein, "STEAG's Long Term SCR Catalyst Experience and Cost", The 2005 EPRI Workshop on Selective Catalytic Reduction, Louisville, KY, November 2005.

[38] Argillon's website: www.argillon.com.

leading catalyst manufacturers of honeycomb as well as plate catalyst marketed under the trade name SINOx, has a wealth of experience in all types of SCR applications (HDSCR, LDSCR, TESCR) with more than 500 SCR installations worldwide[39]. Based on Argillon's extensive experience, Argillon promotes the use of TESCR in a temperature range between approximately 300 F (~150 °C) and no more than about 570 F (300 °C) as can be seen in the graph below.



As a matter of fact, for purely economic reasons and regardless of the fuel burned, no TESCR system in Europe operates today at a temperature greater than about 550 F (~290 °C). Today, the majority of TESCRs behind plants such as municipal and hazardous waste incinerators, which have an incomparably greater fuel variability and much higher concentrations of the entire spectrum of catalyst poisons (arsenic, barium, calcium, chromium, magnesium, phosphorus, potassium, selenium, sodium, thallium, etc.) than any coal-fired boiler will ever have, operate downstream of wet scrubbers and/or baghouses or activated carbon reactors (ACR) at temperatures as low as 300 F (~150 °C). These low temperature TESCR operations have been extremely successful for over a decade now with minimal to no catalyst deactivation experienced.

CERAM is another leading manufacturer of honeycomb SCR catalyst and with well over 500 SCR installations worldwide, more than 100 of which are LDSCR and TESCR installations. CERAM, arguably one of the most experienced suppliers of TESCR catalyst, fully confirms this concept of lowering the TESCR temperature. CERAM sees no need for a TESCR operating temperature of more than about 554 F (290 °C) even in case of a wet bottom boiler

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[39] Argillon's website: www.argillon.com

such as a cyclone fired unit burning the most complex and difficult fuels including North Dakota lignite[40]. As a matter of fact, the only thing that dictates the minimum SCR operating temperature are the residual SO_2 and SO_3 concentrations in the flue gas, which determine the ABS reaction equilibrium[41] and thus the probability for ABS deposition on the catalyst and in the gas/gas heat exchanger. This, however, is not an irreversible catalyst poisoning issue but rather a reversible fouling problem not related to the SCR catalyst per se but simply to the reaction chemistry between H_2O, SO_3 and NH_3 in the flue gas at various temperatures.

In summary it can be stated that the SCR technology is the most widely used secondary NOx control technology in the world. It is technically feasible and applicable to a large number of thermal processes including all types of utility boilers burning any kind of fuel. In my professional experience gained over the last 20 years with the SCR technology, neither the design of the boiler or the combustion system nor the composition of the fuel burned has ever posed an irresolvable technical obstacle, which made the application of the SCR technology in one of its principles (HDCSR, LDSCR, TESCR) technically infeasible. The only challenge is the proper selection of the appropriate type of SCR principles (HDSCR, LDSCR or TESCR) and the correct SCR process and catalyst design. This selection, however, is neither a question of technical feasibility or applicability nor of availability of the SCR technology but simply a question of economics.

6. SCR EVALUATION

In June 2008, the North Dakota Department of Health's Division of Air Quality issued a "Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2[42]", in which it determined "that SCR is not technically feasible for North Dakota lignite-fired cyclone boilers." This determination seems to rest largely on five documents provided by Minnkota Power, namely:

1. Minnkota's Best Available Control Technology Analysis Study for Milton R. Young Station Unit 1, October 2006.[43]
2. Square Butte's Best Available Control Technology Analysis Study for Milton R.

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[40] Personal conversation with John Cochran, President of CERAM Environmental, Inc., on June 25, 2008.

[41] The reaction equilibrium between ammonium sulfate ($(NH_4)_2SO_4$) and ammonium hydrogen sulfate (NH_4HSO_4), which is often incorrectly referred to as ammonium bisulfate or ABS, in the flue gas. Both, ammonium sulfate and ammonium hydrogen sulfate are products of the inevitable reaction of gaseous sulfur trioxide (SO_3) and ammonia (NH_3) contained in the flue gas upstream of the SCR catalyst.

[42] Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, Division of Air Quality, North Dakota Department of Health, 918 East Divide Avenue, Bismarck, North Dakota.

[43] NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc., Revised Final Report, October 2006, 311777.

Young Station Unit 2, October 2006.[44]

3. SCR Catalyst Performance in Flue Gases Derived From Subbituminous and Lignite Coals, A. Benson, et al.[45]

4. Application of SCR Technology to North Dakota Lignite Fuels, Power Point Presentation slides by Sargent and Lundy, LLC, May 2007.[46]

5. Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 and 2, May 2008.[47]

These five documents are seemingly reasonably recent with the first and second document dated October 2006 and the forth and fifth documents dated May 2007 and May 2008, respectively. However, the third document even though published in 2005 was already accepted for publication in mid 2004 and the actual HDSCR catalyst pilot testing at the Coyote Station (Coyote Pilot Testing) and at the Baldwin Energy Center (Baldwin Pilot Testing) that lasted at least 6 months at each plant was conducted as early as 2000/2001[48]. This is relevant, since the Coyote Pilot Testing, which was conducted following the Baldwin Pilot Testing, used the same pilot test reactor equipped with the same Haldor Topsoe catalyst that was used at the Baldwin Pilot Testing[49]. Based on the Baldwin Pilot Test results the technical feasibility of HDSCR at Baldwin's cyclone-fired Units 1 & 2 burning 100% PRB would have been at least highly questionable and a BACT determination similarly conducted as the one by the Department for the M.R. Young Station would most likely have reached the same conclusion as was reached for the M.R. Young Station, namely that the SCR is technically infeasible for retrofit at the Baldwin Energy Center. However, the full scale HDSCRs at Baldwin Units 1 & 2 were commissioned in 2002 and 2003 and have since been in service for more than 45,000 hours without any of the problems indicated during the Baldwin Pilot Testing.

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[44] NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 2 Minnkota Power Cooperative, Inc. Operating Agent for Square Butte Electric Cooperative, Owner. Revised Final Report, October 2006, 311777.

[45] Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

[46] Sargent and Lundy, LLC, "Application of SCR Technology to North Dakota Lignite Fuels", a Power Point presentation, May 2007.

[47] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

[48] E-mail from Flemming Hansen (Haldor Topsoe) dated June 30, 2008.

[49] Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

At Associated Electric's New Madrid Station Units 1 & 2, both cyclone-fired units burning 100% PRB, HDSCRs were commissioned in 1999/2000 already and have been in operation successfully since then. Numerous other cyclone-fired units burning 100% PRB were retrofitted with HDSCRs and have also been operating successfully[50, 51]. This clearly proves that the results obtained during the Baldwin Pilot Testing with this particular SCR catalyst and this particular pilot test reactor design cannot be considered representative for a full scale HDSCR installation at the same unit. Baldwin Units 1 & 2 don't use the type of Haldor Topsoe catalyst used in the Baldwin and Coyote Pilot Testing but instead use Argillon plate catalyst. New Madrid Units 1 & 2 also don't use the type of Haldor Topsoe catalyst used in the Baldwin and Coyote Pilot Testing but instead use Cormetech honeycomb catalyst. Also, the HDSCR reactors at Baldwin and New Madrid were properly designed and are adequate to meet the challenges of this application and not as ill-designed and fundamentally flawed as the Baldwin and Coyote Pilot Testing reactor and catalyst design. This fact along with the conclusion that the Coyote Pilot Testing[52] didn't provide much useful data was pointed out clearly by the Department.

Furthermore, CERAM in one of their responses explicitly stated their belief that "the information and test work presented indicate that it is certainly premature to assume that there is a fatal flaw for the use of high duct SCR behind cyclones burning North Dakota lignite. The concerns presented are similar in argument to those that where used 10 years ago against the application of PRB for high dust (SCR) applications[53]". CERAM continues stating that "concerns reported by Dr. Benson[54] regarding high sodium contents and fine fume are duly noted, but inadequate evidence is presented that this could be a fatal flaw to application of (HD)SCR considering the flawed pitch and resultant pluggage of the (Haldor Topsoe) catalyst (used) during (the) Coyote Station testing[55]". This view of CERAM was further discussed in a personal conversation with Mr. Kurt Orehovsky, Product Manager of

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[50] NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc., Revised Final Report, October 2006, 311777.

[51] NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 2 Minnkota Power Cooperative, Inc. Operating Agent for Square Butte Electric Cooperative, Owner. Revised Final Report, October 2006, 311777.

[52] Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

[53] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

[54] Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

[55] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

CERAM's SCR Catalyst Division[56]. Mr. Orehovsky clearly stated that CERAM reviewed all available data carefully and thoroughly and sees currently no reason why HDSCR would be technically infeasible at M.R. Young Station, however, only after resolving the temperature variation problem. He pointed out that CERAM would not expect any extraordinarily high catalyst deactivation or pluggage at a cyclone-fired unit burning North Dakota lignite if in fact an HDSCR system would be properly designed and operated. CERAM's extensive experience with lignite and biomass fired units equipped with HDSCR support this position.

Despite that clear statement and despite the ongoing proof in form of the success of the HDSCRs at New Madrid, Baldwin and many other cyclone-fired units burning 100% PRB, the only field data the Department relied upon concerning the expected catalyst deactivation and pluggage of an HDCSR installed at M.R. Young Units 1 and 2 is the data obtained from the ill-designed and fundamentally flawed Coyote Pilot Testing.

Admittedly, the Coyote Pilot Testing results seem to indicate worse pluggage than the Baldwin Pilot Testing results. However, it must be noted that the same pilot test reactor and the same catalyst, which had been already used (and plugged) at Baldwin was subsequently used at Coyote. The well known fact that catalyst that had been plugged and only mechanically cleaned is more likely to quickly plug again than new, unused catalyst was simply ignored. Furthermore, it is more than reasonable to expect that lignite fired units will cause a higher rate of catalyst deactivation in an HDSCR than a PRB fired unit. This fact was also proven during the Sandow 4 pilot testing[57] but is no reason for considering the SCR technology in general as technically infeasible. In case of Sandow 4 and other units burning Texas lignite HDSCR was even considered to be more economically viable than LDSCR or TESCR with the technical feasibility not even being a question.

Given the fact that the same pilot test reactor and catalyst were used for the Baldwin and subsequently for the Coyote Pilot Testing, it can be clearly stated that the reason for the pilot testing results at Coyote being worse than at Baldwin was because of the pilot test reactor and catalyst designs and the execution of the pilot testing, all of which were already inadequate for the Baldwin application but disastrous for the Coyote application. Yet, the unanswered question remains, why is it unreasonable to assume that a properly designed and operated HDSCR at M.R. Young Units 1 and 2 could be as successful as it has been and continues to be at New Madrid, Baldwin and the many other cyclone-fired units burning 100% PRB despite the fact that the results of the Baldwin Pilot Testing seemed to indicate the exact opposite? Based on this clear and indisputable evidence would not every reasonable engineer first suspect that the reason for the failure of the Coyote Pilot Testing was the ill-designed test pilot reactor and catalyst and the flawed execution of the pilot testing just as it was the case at Baldwin? However, instead of trying to answer these most important questions objectively and correctly, the Department jumped to the highly premature and speculative conclusion that the SCR technology regardless of the selected principle (HDSCR,

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[56] Personal conversation with Mr. Kurt Orehovsky in Vienna, Austria, on July 7, 2008.

[57] Smith, R, J. Bennett, D. Broske, "Impacts of Texas Lignite on SCR Catalyst Life and Performance", presented at the 2007 EPRI SCR Workshop in Pensacola, Florida, November 2007.

LDSCR or TESCR) cannot be applied successful at the M.R. Young Station.

The Department lists the following twelve (12) conclusions that result in the Department's largely speculative and unsubstantiated determination "that high dust SCR is not technically feasible at this time for both units at the M.R. Young Station", the validity of which are discussed in detail in the following sections.

6.1 Variability of Fuel Composition

Lignite from the Center Mine is highly variable in heat and ash contents and in the constituents that make up ash, which will affect SCR design and operation. This is an undisputed fact, however, not only true for lignite from the Center Mine but for all coals regardless whether it is anthracite, bituminous, sub-bituminous, lignite, brown coal etc. As a matter of fact, these listed classifications are nothing but the result of the extremely high variability of the various types of coal. Each class in itself has a high variability again, which unquestionably affects SCR design and operation. This high variability includes also the compounds sodium and potassium (as further discussed in several subsequent sections) as well as all other catalyst poisons. Bituminous and sub-bituminous coals, which are considered relatively unproblematic for HDSCR design and operation, may serve as an example for this typical variability. Bituminous and sub-bituminous coal-fired boilers constitute the vast majority of HDSCRs in the world even though the:

- The heating value ranges from less than 8,000 Btu/lb to more than 13,000 Btu/lb.
- The ash content can vary by one order of magnitude from as low as 4 %wt. to as high as 40 %wt.
- Sulfur contents also vary easily by one order of magnitude from less than 0.5%wt. in sub-bituminous to more than 5%wt in bituminous coal.
- Likewise arsenic content range over an order of magnitude from less than 3 ppm to more than 40 ppm.

The list of similarly wide ranges of concentrations and/or variability for individual constituents of bituminous and sub-bituminous coals could be extended for almost every element of the Periodic Table. However, I am not aware of one single case where this high variability of the heat and ash contents of the coals and/or of the constituents that make up the ash precluded one of the principles of the SCR technology (HDSCR, LDSCR, TESCR) from being technically feasible and applicable.

Thus, it remains unexplained why the Department's conclusion that "lignite from the Center Mine is extremely variable in heat content, ash content and in the constituents that make up the ash", leads to the determination that the SCR technology is not technically feasible. Even though the statement that "this variability will affect the design and operation of an SCR system", is only correct with respect to a HDSCR and maybe partially to a LDSCR, it is most definitely not plausible for a TESCR. In case of TESCR the preceding air pollution control equipment (ESP and wet FGD) as well as the flue gas reheating system of a TESCR, which typically includes a gas-gas heat exchanger and steam coil upstream of the SCR reactor, virtually eliminate even the most extreme variability in the fuel and its resulting flue gas composition upstream of the SCR catalyst. It is intuitively obvious that the coal's variability in heat and ash content and in the constituents that make up the ash is no longer of any relevance in case of a TESCR system after more than 99% of the ash has been removed in the upstream air pollution control equipment[58].

6.2 Results of the Coyote Pilot Testing

The Department correctly states that "the only pilot testing that has ever been conducted on a unit firing North Dakota lignite was at the Coyote Station[59]. The pilot scale SCR was plugged after 2 months and little useful data was obtained". The Department further alludes to the fact that "the pilot testing at the Coyote Station did not provide much useful data, and in hind-sight, was ill-designed for a unit combusting North Dakota lignite". Yet despite the Department's indisputably correct and valid recognition of this as well as the facts that:

- no deactivation data exists and no conclusions should be drawn from this ill-designed and highly flawed Coyote Pilot Testing;
- several SCR equipment suppliers (Alstom, Babcock Power) clearly stated that , an "(HD)SCR system could be successfully utilized on a boiler fired with Northern lignite"[60];
- several catalyst manufacturers (CERAM, Haldor Topsoe) clearly stated and that concerns reported by Dr. Benson[61] regarding high sodium contents and fine fume are duly noted, but inadequate evidence is presented that this could be a fatal flaw to application of SCR considering the flawed pitch and resultant pluggage of the (Haldor Topsoe) catalyst during Coyote Station testing"[62];

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[58] Milton R. Young Station – Our Jewel on the Prairie, brochure published by Minnkota Power Cooperative and Square Butte Electric Cooperative on Minnkota's website: www.minkota.com.

[59] Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

[60] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

[61] Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

[62] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination

- several catalyst manufacturers (CERAM, Haldor Topsoe), who have experience with high sodium and potassium containing fuels, offered industry standard type catalyst performance guarantees (NOx removal efficiency, SO_2/SO_3 conversion rate, pressure drop, NH_3 slip, catalyst lifetime)[63];

the Department still concludes that "the Coyote testing demonstrates to the Department that North Dakota lignite firing will have more severe effects (plugging and catalyst deactivation) than units firing sub-bituminous coal when the same design is employed".

This statement promotes three basic questions, namely:

a. How can the Coyote Pilot Testing demonstrate to the Department that North Dakota lignite firing will have more severe effects (plugging and catalyst deactivation) when no catalyst deactivation data exists and the pilot scale SCR reactor at the Coyote Station plugged very quickly because the reactor was ill-designed and the selected catalyst design not suitable, particularly for a unit combusting North Dakota lignite?

b. Does the Department have any additional information that may substantiate the Department's otherwise completely unfounded conclusion and that wasn't provided to the contacted vendors including Alstom, Babcock Power, CERAM and Haldor Topsoe so that they reached the essentially opposite conclusion?

c. Why does the Department imply that the same catalyst and SCR design employed for units firing sub-bituminous coal must also be used for M.R. Young Station?

As pointed out earlier, this is relevant since in the early 2000s, when the Coyote Pilot Testing[64] was conducted, the results of which provide the only catalyst relevant field data for the Department's conclusion concerning the rapid pluggage and deactivation of catalyst in a HDSCR, no long term full scale HDCSR operating experience was available from Associated Electric's New Madrid Station, which was the first one to install HDSCR on a cyclone-fired unit burning PRB. Yet, as pointed out by Burns & McDonnell, today a significant number of cyclone-fired units in the U.S. burning PRB successfully operate HDSCRs[65, 66, 67].

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for Milton R. Young Station Units 1 & 2", May 8, 2008.

[63] Ibid

[64] Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

[65] NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc., Revised Final Report, October 2006, 311777.

[66] NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 2 Minnkota Power Cooperative, Inc. Operating Agent for Square Butte Electric Cooperative, Owner. Revised Final Report, October 2006, 311777.

The Department further states that "besides catalyst deactivation, it is likely that a high-dust SCR would experience plugging problems (deposition on the catalyst surface) due primarily to the carryover of popcorn ash from the boiler". This statement is also quite puzzling, since the formation of popcorn ash is a commonly known phenomenon that has first caused catalyst pluggage in Germany in the mid 1990s[68] and is also a well known problem in the U.S. since the early 2000s. However, it has been solved successfully[69] by the use of properly designed popcorn ash removal systems[70].

The Department's statement that "the advances made in the last few years for controlling popcorn ash are not shown to be applicable to a cyclone boiler burning North Dakota lignite" is not only purely speculative but defies all common engineering sense. Various designs and types of popcorn ash screens have been installed in a wide variety of units in the U.S. and are operating successfully. I believe that no engineering company with SCR experience including Sargent and Lundy and Burns & McDonnell would seriously argue the fact that properly designed popcorn ash screens could be successfully installed at M.R. Young Station's Units 1 and 2 without additional pilot scale testing. Needless to add that in case of a LDSCR or TESCR any concern over popcorn ash would be considered absurd simply by virtue of the location of the LDSCR or TESCR in the flue gas path downstream of the ESP (LSDCR) and wet scrubber (TESCR).

Furthermore, the Department's statement that "operation of an SCR system for only 2 months between catalyst replacements is not considered successful operation of SCR technology," implies that the catalyst in a properly designed full scale HDSCR at the M.R. Young Station would have to be replaced every two (2) months. Again, no deactivation data was ever determined during or after the Coyote Pilot Testing to substantiate this claim. This forces the conclusion that the mostly useless data obtained from the ill-designed and flawed Coyote Pilot Testing was improperly and incorrectly used by the Department to speculatively extrapolate to what may or may not happen in a properly designed HDSCR system.

This bold speculative extrapolation to a catalyst life of only two (2) months between replacements in a full scale HDSCR is particularly interesting since the Department immediately contradicts its own conclusion by postulating that "without pilot testing, the life of the catalyst cannot be predicted with any reasonable certainty." Assuming this latter statement is true and further reiterating the fact that no deactivation testing from pilot testing

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[67] Sargent and Lundy, LLC, "Application of SCR Technology to North Dakota Lignite Fuels", a PowerPoint presentation, May 2007.

[68] Hartenstein, H., H. Gutberlet, L. Licata, "Utility Experience with SCR in Germany", a paper presented at the Sixteenth Annual International Pittsburgh Coal Conference, October 1999.

[69] Sargent and Lundy, LLC, "Application of SCR Technology to North Dakota Lignite Fuels", a PowerPoint Presentation, May 2007.

[70] Martin, M., M. Harrell, J, Jancauskas, H. Hartenstein, H. Sobolewski, "Large Particel Ash (LPA) Screen Retrofits at Coal-Fired Units in Indiana and Ohio", DOE-NETL Conference on SCR/SNCR, 2006.

is available, how can the Department assert that a properly designed full scale HDSCR system would operate for only two (2) months between catalyst replacements while stating at the same time that the life of the catalyst cannot be predicted without further pilot testing?

Furthermore, the Department's bold postulation of an expected catalyst life of only two (2) months between replacements is made despite the fact that two (2) experienced catalyst suppliers (Haldor Topsoe and CERAM) offered firm performance and lifetime guarantees[71] for their catalyst installed in an HDSCR of considerably more than the 10,000 hour threshold arbitrarily defined by the Department. Why the Department ignores all these facts and concludes that it can predict the expected catalyst life better than even the most experienced catalyst manufactures remains unknown.

6.3 Soluble Sodium

The Department concludes that "the combustion of (North Dakota) lignite produces soluble sodium compounds, which cause more severe catalyst deactivation than insoluble sodium compounds". Even though this statement may be generally correct, it remains unclear and unexplained, why soluble sodium compounds, which can only penetrate into the catalyst and deactivate the catalytically active vanadium pentoxide (V_2O_5) when in they are either in the gas phase or as sodium ions (Na^+) dissociated in a liquid, would be present in the gas phase or in a liquid and therefore in a mobile form.

The argument raised by Minnkota and reiterated by the Department that the formation of low temperature sodium-calcium-magnesium sulfates and phosphates poses the most significant problem for the successful operation of SCR catalysts in a HDSCR may be true with respect to catalyst deactivation. However, the simple comparison of emission rates of these compounds with the fly ash is not a correct and appropriate way to derive any meaningful prediction concerning the expected catalyst deactivation. Even though the Department correctly states that "the catalyst deactivation rate may not be directly proportional to the emission rates of the various constituents", incorrectly continues that "it does provide a means of comparison of the flue gas characteristics". Unfortunately, the Department fails to realize what was pointed out by one of the most experienced catalyst suppliers, namely that "sodium is not a poison to catalyst at SCR operating temperatures[72]." Thus, the elaborate comparison of emission factors of sodium, potassium, calcium and magnesium emission factors with the fly ash may have some academic value but is effectively meaningless for the correct prediction of catalyst deactivation, since particle bound sodium, potassium, calcium and magnesium in the fly ash are not mobile and therefore are not catalyst poisons.

Typically, sodium and potassium sulfates, so called pyrosulfate compounds, have very high

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[71] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

[72] Ibid

boiling points well above any possible SCR operating temperature. Thus, it is highly unlikely that any appreciable quantities of these pyrosulfates will be present in the SCR in the gas phase. This, however, would be necessary in order to cause severe and rapid catalyst deactivation. Therefore, under these conditions these compounds are not a major concern.

Alternatively, these pyrosulfate compounds would have to be present in a liquid so that their dissociated ions (i.e. Na^+, K^+) would be mobile in order to enter the catalyst pores and react with the catalyst's active sites. However, these compounds will only be present in the catalyst in a liquid form if either the SCR operating temperature is too low or during shut down when cooling the SCR reactor to temperatures below the moisture dew point. Since the melting point of most pyrosulfates is well above the typical HDSCR operating temperature of 650 – 750 F (343 – 400 °C) the intrusion of liquid pyrosulfates is no major concern with respect to a severe, rapid catalyst deactivation. Therefore, even catalyst suppliers state clearly that "sodium is not a poison to catalyst at SCR operating temperatures. Significant deactivation can occur if condensed moisture transports sodium residing at the surface into the catalyst pore structure during outage or layup[73]". Since the HDSCR operating temperature must be expected to be maintained at well above 650 F (343 °C) at all times, no liquid ever occurs during SCR operation not even in the inner pores as the temperature is too high even for capillary condensation. This well known fact is one of the main reasons why HDSCR operating temperatures are selected to be typically in the range between 600 F (315 °C) and 800 F (427 °C). Maintaining the required minimum SCR operating temperature at all times is an absolute requirement for all HDSCRs regardless of fuel type and/or boiler/burner configuration and has nothing to do with North Dakota lignite and/or cyclone-fired boilers.

As pointed out earlier, the condensation of moisture in the pores of the SCR catalyst typically occurs only during shut-down and subsequent cooling of an SCR reactor. Thus, reducing the number of shut-downs, which result in cooling the SCR catalyst to below the moisture dew-point, is always advantageous for all HDSCRs regardless of fuel- and/or firing type.

Given the fact that sixty (60) start-ups were reported for M.R. Young Unit 1[74] within a five (5) year period and sixty two (62) start-ups for the same period for M.R. Young Unit 2[75], it can be easily calculated that this equates to an average of approximately twelve (12) start-ups per year or roughly one (1) per month. However, in case of Unit 1 only six (6) and in case of Unit 2 only seventeen (17) were considered "cold" start-ups, which are defined as the boiler having been without fuel-firing for more than seventy two (72) hours[76]. During shut-downs

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[73] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

[74] NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc., Revised Final Report, October 2006, 311777.

[75] NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 2 Minnkota Power Cooperative, Inc. Operating Agent for Square Butte Electric Cooperative, Owner. Revised Final Report, October 2006, 311777.

[76] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Responses to NDDH and EPA

of less than seventy two (72) hours, SCR reactors are typically "buttoned up hot", which means the SCR reactor is isolated from the flue gas path during shut down by means of putting it in a bypass mode while the SCR is still at its design operating temperature. The cooling rate of such a "buttoned up hot" SCR reactor is known to be extremely slow. Unless forced cooled with ambient air no "buttoned up hot" SCR reactor loses more than approximately 50 – 100 degrees and therefore gets nowhere near the sulfuric acid or even the moisture condensation temperature in a seventy two (72) hour period.

Therefore, catalyst deactivation by means of soluble sodium compounds in the ash being dissociated into a liquid and penetrating into the catalyst pores and reacting there with the catalytically active V_2O_5 must be expected to be rather slow. Since the actually experienced catalyst deactivation rate due to this effect has never been measured, the respective conclusion postulated by the Department cannot be considered more than an unsubstantiated speculation.

6.4 Differences in Flue Gas Composition

The Department concludes that "the flue gas generated at the M.R. Young Station is different from the flue gas at any plant where SCR technology has been applied". The absoluteness of this statement, which is not even limited to power plants, is quite amazing as it indubitably implies that the Department has complete detailed knowledge not only of the flue gas composition of every other power plant in the world equipped with an SCR system but also of every other plant in the world where the SCR technology is applied. Even though theoretically possible, the lack of any data from all these other plants strongly suggests that this may be highly questionable and largely overreaching. As a matter of fact, I am sure that I could easily present to the Department several plants where the SCR technology has been applied successfully that the Department doesn't even know that these plants existed.

Furthermore, the Department states that this absolute uniqueness is "primarily due to the high ash concentration of soluble sodium compounds and the total loading of catalyst deactivation chemicals". Again, as discussed in section 6.3 and clearly pointed out by catalyst suppliers, sodium is not a catalyst poison at SCR operating temperatures[77]. The claimed uniqueness of the flue gas generated at the M.R. Young Station appears to be highly speculative and completely unproven as comparisons were only drawn to:

- bituminous coal (specifically mentioning Pennsylvania coal);
- sub-bituminous coal (specifically mentioning Wyoming PRB);

Comments Regarding SCR Technical Feasibility and Non-SCR Concerns Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007.

[77] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

- other lignites (specifically mentioning Texas lignite).

Needless to say that Pennsylvania coal is not the only bituminous coal in the world, Wyoming PRB is not the world's only sub-bituminous coal and Texas lignite is referred to as Texas lignite for the simple reason that it is somewhat unique to Texas compared to the many other types of lignites and brown coals around the world. Thus, the Department's statement in its far reaching and absolute form must either be considered extraordinarily uninformed or only correct if rigorously limited to the three specific coal types mentioned. In that sense this conclusion has little if any relevance to the question of the technical feasibility of the SCR technology to the M.R. Young Station and should be simply ignored as completely irrelevant.

6.5 Experience of Burns and McDonnell and Sargent and Lundy

The Department concludes that "both Burns and McDonnell and Sargent and Lundy have extensive experience with the design and operation of SCR systems". The fact of the matter is, however, that the SCR experience of Burns & McDonnell must be considered rather limited for a number of reasons, namely Burns & McDonnell has provided SCR related services for only seventeen (17) power plants[78]. At least ten (10) of these are not even in operation yet and only two (2) SCR projects are retrofits. Thus, Burns & McDonnell has very little experience with SCR retrofits and the only two (2) SCR retrofits, in which Burns and McDonnell was involved as Owner's Engineer, namely Hoosier Energy's Merom Station and HMPL's Henderson Station, have accumulated any appreciable long-term operating experience. However, in both of these cases, Burns & McDonnell's scope was limited to portions completely irrelevant to SCR process and catalyst design such as balance-of-plant design including foundations, electrical, controls integration, civil and contract oversight[79]. In the case of the Henderson Station, the SCR was supplied by Alstom and the catalyst by Cormetech. All process design, catalyst selection and design and all relevant process performance guarantees were provided by either Alstom or Cormetech. None were provided by Burns & McDonnell. In the case of the Merom Station, the SCR was supplied by Lurgi and the catalyst by KWH. Again, all process design, catalyst selection and design and all relevant process performance guarantees were provided by either Lurgi or KWH. None were provided by Burns & McDonnell.

Detailed design is currently being provided by Burns & McDonnell for only one (1) power plant, namely Associated Electric's Thomas Hill Units 1, 2 and 3. The SCRs are currently under construction and Burns & McDonnell lists conceptual design and studies, structural

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[78] Summary of Responses to EPA/DOH Questions on Minnkota Power's NOx BACT Analysis for Milton R. Young Units 1 & 2, Presentation by EERC, Minnkota Power, Burns & McDonnell to NDDH and U.S. EPA, May 23, 2007.

[79] Ibid

design, balance of plant design and construction management as services provided[80]. It is worth noting that again none of these services have anything to do with the SCR process or catalyst design. The only service provided by Burns & McDonnell for this one (1) SCR retrofit project at least remotely related to SCR process design was the selection of the reagent and the catalyst manufacturer. However, reagent selection is irrelevant for catalyst deactivation and/or pluggage and the SCR catalyst itself is supplied by CERAM including the design, sizing as well as all process performance guarantees[81]. Thus, the catalyst selection performed by Burns and McDonnell was nothing more than recommending CERAM as the catalyst supplier presumably on the basis of a lowest price competitive bidding process.

In summary it is worth noting that Burns & McDonnell has neither provided SCR process design and/or SCR process performance guarantees in one single case nor ever operated any SCR system. Thus, the Department's conclusion concerning Burns & McDonnell's "extensive experience with the design and operation of SCR systems" seems to be based on a surprising lack of familiarity of the true capabilities and limitations of these architect engineering (A/E) firms. Concerning the "extensive operating experience" the Department's conclusion is plain wrong and for the remainder coarsely exaggerating as no A/E ever provides any process and/or catalyst design and/or performance guarantees.

Even though Sargent and Lundy claims significantly more SCR experience than Burns & McDonnell, Sargent and Lundy has also only acted as an A/E for SCR retrofits. Sargent and Lundy lists to have been involved in approximately 27,000 MWs of SCRs as an A/E. This represents a little more than one fifth ($^1/_5$) of the SCRs retrofitted to coal-fired units in North America[82] or less than half of the 46% claimed by Sargent and Lundy. Despite Sargent and Lundy's greater involvement in SCR retrofits as an A/E compared to Burns & McDonnell, it must be noted that Sargent and Lundy has also never provided any SCR process and/or catalyst design and/or performance guarantees and never operated any SCR systems. Thus, the Department's conclusion concerning Sargent and Lundy's "extensive experience with the design and operation of SCR systems" seems to be also based on a lack of familiarity of the true capabilities and limitations of these architect engineering (A/E) firms. Concerning the "extensive operating experience" the Department's conclusion is plain wrong and for the remainder at least highly questionable as no A/E ever provides and process and/or catalyst design and/or performance guarantees.

In general it must be noted that all services, which are critical for SCR system process design and process performance guarantees, including:

- process design;

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[80] Summary of Responses to EPA/DOH Questions on Minnkota Power's NOx BACT Analysis for Milton R. Young Units 1 & 2, Presentation by EERC, Minnkota Power, Burns & McDonnell to NDDH and U.S. EPA, May 23, 2007.

[81] Reference list on CERAM's website: www.frauenthal.net.

[82] Sargent and Lundy LLC, "Application of SCR Technology to North Dakota Lignite Fuels", a PowerPoint Presentation, May 2007.

- catalyst sizing and design;
- flow modeling and SCR rector design;
- process performance guarantees;
- catalyst performance guarantees;

have never been and most likely will never be provided by neither Burns and McDonnell nor Sargent and Lundy. All these critical services are always either supplied by an SCR equipment supplier (Alstom, Babcock Power, Babcock & Wilcox, etc.) or by the catalyst manufacturer (Argillon, CERAM, Cormetech, Haldor Topsoe, Hitachi, etc.). As a matter of fact, all catalyst related performance guarantees (NOx removal efficiency or activity, SO_2/SO_3 conversion rate, catalyst life or deactivation rate, etc.) are never provided by anyone other than the catalyst manufacturers. Even the SCR equipment suppliers only pass through the catalyst performance guarantees obtained from the catalyst manufacturer to the end customer. And at least two (2) of these catalyst manufacturers, namely Haldor Topsoe and CERAM were clearly willing to provide industry standard type performance guarantees for their catalyst[83]. Notably, both of these catalyst manufacturers have extensive HDSCR experience with high sodium and potassium containing fuels such as biomass and/or lignite. It remains unclear why the Department didn't exploit the statements of these highly experienced catalyst manufacturers further but rather relied on the A/E's who have no SCR process and/or catalyst design experience, have never provided any SCR process and/or catalyst related performance guarantees and have absolutely no SCR operating experience.

6.6 Development Stage of High-Dust SCR

The Department states that "to design and install an SCR system for a cyclone-fired unit firing North Dakota lignite without obtaining additional data from bench scale would be experimentation". This conclusion is again in clear disagreement with the statement of catalyst manufacturers such as Haldor Topsoe and CERAM, who were willing to provide industry standard type catalyst performance guarantees even for HDSCR. This clearly indicates that both of these highly experienced catalyst manufacturers see no need for obtaining additional data from bench scale experimentation but feel to be in the position to design and install a HDSCR system at M.R. Young's Units 1 and 2.

Needless to say that no catalyst manufacturer and/or SCR system supplier will turn down the opportunity for additional bench scale and/or pilot testing if offered as it always effectively presents itself as a welcome possibility for risk free research paid by others. Also needless to say, every A/E, who typically charges billable manhours, will favor bench scale and/or pilot

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[83] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

testing, thus extending the life of the project and therefore the amount of manhours billable.

Furthermore, even if HDSCR would not be economically viable, LDSCR or TESCR certainly would be and are indubitably technically feasible and applicable as clearly indicated by the multitude of applications of this principle of the SCR technology to a wide range of processes (see also section 5 of this report). Why the Department essentially ignores all the statements by these catalyst manufacturers and insists stubbornly that their provided SCR catalyst design[84] is experimentation, remains a mystery.

6.7 Temperature Variations

The Department correctly states that "the temperature variation of the flue gas entering the (HD)SCR will adversely affect the performance and must be resolved for successful application of this technology". However, the large temperature variations present at these units is very unusual for coal-fired units including cyclone-fired units. It is a unit specific problem related to the very unique design of the backpass of the boiler and the air preheater rather than to cyclone-fired boilers and/or North Dakota lignite. According to the boiler supplier Babcock & Wilcox only four (4) of these type boilers including the two (2) at M.R. Young Station were ever built[85], which clearly makes this the exception rather than the rule. In fact, such large temperature variations would not be tolerable for any HDSCR installed after any type of firing system (single or opposed wall-fired, tangentially-fired, turbo-fired, cyclone-fired, etc.) burning any type of fuel (bituminous, sub-bituminous, lignite, brown, etc. coal, oil, gas, biomass, etc.). Thus, the temperature variation problem, which Babcock & Wilcox indicated can be technically resolved by incorporating the appropriate and necessary measures for the modification of the boiler's backpass and possibly the lignite pre-drying system[86], is no reason to determine that the SCR technology is technically infeasible for cyclone-fired units burning North Dakota lignite. In a worst case scenario it may make HDSCR the economically less attractive alternative compared to LDSCR or TESCR due to the very unique boiler design employed at the M.R. Young Station.

6.8 Catalyst Erosion

The Department concludes that "there are unresolved issues regarding catalyst erosion from the ash generated at the M.R. Young Station". This conclusion is not substantiated by any data and at least highly disputable based on long-term SCR operating experience in Europe. Units equipped with HDSCR systems firing up to 40% ash waste coals have been in

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[84] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

[85] E-mail from Steve Moormann (Babcock &Wilcox) to Robert Blakley (Burns & McDonnell) dated 07/18/07.

[86] Ibid

successful operation for almost two (2) decades now without any major operating problems or excessive catalyst erosion[87]. The average ash content of Center Mine North Dakota lignite, which has an average heating value of approximately 50% of bituminous coal, is less than about 8%wt[88]. Hence, approximately twice as much lignite must be burned for the same heat input compared to average bituminous coal. This, however, results still only in an equivalent average ash content of about 16%wt. of comparable bituminous coal, which is a factor of approximately 2.5 lower than the maximum ash content that HDSCRs have been exposed to successfully in Europe. As a matter of fact, bituminous coals with ash contents in the range of 12 – 15 %wt. are considered normal in Europe and pose no erosion threat to SCR catalyst whatsoever. Consequently, preventing excessive ash erosion of the catalyst is simply a matter of correct SCR design as has been proven extensively in Europe. Neither Burns & McDonnell nor Sargent and Lundy have any experience with HDSCR designs for higher ash coals or any experience with the operation of HDSCRs on high ash units.

This leads to the conclusion that the Department's concerns over seemingly unresolved issues regarding catalyst erosion appear to be the result of a simple lack of knowledge of the many HDSCRs that have been subjected to much harsher conditions for almost two (2) decades now.

6.9 Catalyst Poisoning, Blinding and Plugging

The Department correctly states that "poisoning, blinding and plugging of a catalyst are affected by the geometries and properties of the catalyst". However, subsequently, the Department concludes that "cyclone firing of Fort Union lignite and Center Mine coal results in a flue gas stream that highly accelerates poisoning, blinding and plugging (of pores) due to the rich sodium and potassium vapors, particles and ammonia sulfates (due to ammonia injection) in lignite-fired cyclone flue gas". The categorical absoluteness of this statement is impressive as it rest solely on the highly questionable results of the ill-designed Coyote Pilot Testing[89]. As already elaborated on in detail in sections 6.2 and 6.3 of this report and confirmed by the Department[90], the data of the referenced Coyote Pilot Testing is more or less useless. Despite the facts that:

- No deactivation data of the catalyst was ever determined during or after the Coyote

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[87] Sobolewski, H, H. Hartenstein, H. Rhein, "STEAG's Long Term SCR Catalyst Experience and Cost", The 2005 EPRI Workshop on Selective Catalytic Reduction, Louisville, KY, November 2005.

[88] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Responses to NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007.

[89] Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

[90] Page 7 of the Preliminary Best Available Control Technology Determination for Nitrogen Oxides for M.R. Young Station Units 1 and 2, Division of Air Quality ND Department of Health, 918 E. Divide Avenue, Bismarck, ND, June 2008.

Pilot Testing.

- The combination of the fatally flawed Coyote Pilot Testing reactor design, the inadequacy of the selected catalyst type and the extremely poor execution of the test runs caused the severe catalyst pluggage after only two (2) months rather than the flue gas composition and/or ash characteristics as pointed by highly experienced catalyst manufacturers including CERAM and Haldor Topsoe[91], who provided the catalyst for the Baldwin and Coyote Pilot Testing.

- The catalyst manufacturers most experienced with similar fuels (i.e. biomass, PRB, brown coal, etc.) clearly stated[92] that:

  - "the deactivation rate of the catalyst will be high but manageable" (Haldor Topsoe);

  - "the information and test work presented indicate that it is certainly premature to assume that there is a fatal flaw for the use of high dust SCR behind cyclones firing North Dakota lignite" (CERAM);

  - they "are willing to warrant the catalyst performance" based on industry standard terms (Haldor Topsoe);

  - "a commercial offering regarding this project" can be provided (CERAM);

the Department boldly decided that "the engineering solutions of a larger SCR reactor, more catalyst and larger pitch do not resolve the rapid plugging of catalyst pores". This conclusion is in sharp contrast to the statements provided not only by the catalyst manufacturers most experienced with similar types of fuels but also with the statements made by some of the most experienced SCR system suppliers (Alstom, Babcock Power), who "expect that an SCR system could be successfully utilized on a boiler fired with Northern lignite fuel[93]".

The Department continues stating that "there is no catalyst vendor solution to reduce or eliminate pore plugging. The chemical and physical process of pore plugging cannot be reversed, which dictates catalyst change out." This statement is simply incorrect as several well proven methods exist for successfully reducing and/or eliminating pore plugging and completely reversing sodium and potassium poisoning of the catalyst. For instance, Alstom in their correspondence with Burns & McDonnell points out several times[94] that as a result of

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[91] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Responses to NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007.

[92] Ibid

[93] Ibid

[94] Ibid

the highly efficient flue gas cleaning equipment upstream of a LDSCR or TESCR, the installation of a LDSCR or TESCR would eliminate these issues. Furthermore, Haldor Topsoe points out that "the expected poisons are mostly water soluble, therefore periodic water washing of the catalyst can be used to regain activity and to increase overall service life[95]". This is a clear reference towards the various in-situ[96], on-site[97] and off-site[98] catalyst washing, rejuvenation and regeneration processes that are commercially available and have been successfully used in the U.S. as well as in Europe for more than a decade now. These methods have proven beyond any doubt the possibility of regaining the catalyst's full initial activity for a fraction of the cost of new catalyst. They can also be applied multiple times to the same catalyst, particularly in case of sodium and potassium poisoning as well as fly ash pluggage, where simple washing either in-situ[99] or on site[100] has yielded excellent results. These various washing, rejuvenation and regeneration technologies have been utilized successfully by the U.S. utility industry since early 2003[101].

Why the Department ignores these facts and makes a statement in clear contradiction to all this evidence remains unknown.

6.10 Lack of Pilot Scale Testing Data

The Department states that "without pilot testing, the long term NOx reduction efficiency, the volume of the reactor, the catalyst pitch, life of the catalyst, or even type of the catalyst to be used cannot be predicted with a high degree of confidence." This statement is most interesting as is seems to be in clear contradiction to the Department's previous statements that:

- "Cyclone firing of Fort Union lignite and Center Mine coal results in a flue gas stream that highly accelerates poisoning, blinding and plugging (of pores) due to the rich sodium and potassium vapors, particles and ammonia sulfates (due to ammonia

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[95] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Responses to NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007.

[96] Maier, H, W. Götz, "In Situ Catalyst Regeneration – a Cost Saving Technology for SCR Operators", a paper presented at Power Gen, 2001.

[97] Nagai, Y., Y. Inatsune, I. Morita, Y. Kato, K. Yokoyama, K. Ito, P. Otte, "Rejuvenation of the SCR Catalyst at Mehrum", a paper presented at the Electric Power Conference, 2004.

[98] Hartenstein, H., H. Gutberlet, "Catalyst Regeneration – An Integral Part of Proper Catalyst Management", The 2001 EPRI Workshop on Selective Catalytic Reduction, 2001.

[99] Maier, H, J. Matschke, "Recent Experience With SCR Catalyst Regeneration", a paper presented at the DOE-NETL Conference on SCR/SNCR, 2001.

[100] www.envirgy.com/en/references/catalyst_regeneration.

[101] www.ebinger-kat.com/en/referenzen.php.

injection) in lignite-fired cyclone flue gas".

- "The engineering solutions of a larger SCR reactor, more catalyst and larger pitch do not resolve the rapid plugging of catalyst pores."
- "The pilot scale (HD)SCR that was deployed at the Coyote Station was plugged and the catalyst pores deactivated after 2 months (approx. 1,430 hours)" The Department believes successful operation is considerably more than a few thousand hours of operation."

How can the Department postulate on one hand that without further pilot testing long term NOx reduction efficiency or in other words catalyst deactivation and therefore catalyst life cannot be predicted with a high degree of confidence, while claiming on the other hand with the seemingly highest degree of confidence that:

- The flue gas composition leads to highly accelerated catalyst poisoning, blinding and plugging?
- Successful operation is considerably more than a few thousand hours based on the fact that the ill-design HDSCR pilot test reactor plugged after only two (2) months?

Likewise how can the Department postulate on one hand that such fundamental HDSCR design parameters as volume of the SCR reactor, catalyst pitch and type of catalyst cannot be predicted with a high degree of confidence, while claiming on the other hand with the seemingly highest degree of confidence that no engineering solutions of a larger SCR reactor, more catalyst volume and larger pitch exist to resolve the rapid plugging of catalyst pores? Unfortunately, the Department fails to resolve these obviously diametrically contradicting statements.

Yet, it must be noted that the Department's claims concerning the rapid catalyst poisoning, blinding and plugging as well as the claim that no engineering solutions exist to mitigate these, are solely based on the highly questionable results of the ill-designed Coyote Pilot Testing. At the same time, however, the Department states that without additional pilot testing none of these necessary predictions could be made since the Coyote Pilot Testing was ill-designed and didn't provide much useful data[102]. This contradiction further nurtures the impression that the Department either solely relies upon or completely negates the Coyote Pilot Testing results depending on what ever seems to favor the particular argument against SCR at the moment.

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[102] Preliminary Best Available Control Technology Determination for Nitrogen Oxides for M.R. Young Station Units 1 and 2, page 7, Division of Air Quality ND Department of Health, 918 E. Divide Avenue, Bismarck, ND, June 2008.

6.11 Lack of Vendor Guarantees

The Department states that "vendors cannot without further pilot testing, guarantee SCR system performance for M.R. Young Station boilers firing North Dakota lignite". This statement is simply incorrect as both CERAM and Haldor Topsoe clearly stated that they would be willing to offer industry standard type performance guarantees[103] for their catalyst for a HDSCR system installed at M.R. Young Station – see also the discussion in section 6.9 of this report.

The Department's claim that "even the most optimistic vendors don't offer true guarantees of catalyst performance", is as incorrect as the first statement. Both, Haldor Topsoe and CERAM clearly stated that they would be willing to offer industry standard type guarantees for the performance of their catalyst for a HDSCR at M.R. Young Station. The fact that the Department argues that "the guarantee is limited to the contract value" merely unveils the Department's surprising lack of familiarity with the type and extent of performance guarantees provided within the utility industry. The fact of the matter is that no equipment vendor in the utility industry ever accepts any liability for performance guarantees above and beyond the full amount of the contract value, which is exactly what was offered i.e. by Haldor Topsoe[104]. This is not only common practice in the utility industry but also a well known fact to all A/E's including Burns & McDonnell and Sargent and Lundy. If asked, none of the eight (8) participants in the SCR Vendor Query would offer an unlimited liability or even a limit of liability of more than the contract value for performance guarantees. Burns & McDonnell as well as Sargent and Lundy, who themselves never provide any type of process or system performance guarantees what so ever, are fully aware of this fact and will surely admit to it if asked.

It is worth mentioning that in case a project such as an SCR retrofit at M.R. Young Station would be carried out by an A/E such as Burns & McDonnell or Sargent and Lundy as an owner's engineer for Minnkota and/or Square Butte, the only performance guarantees the owner (in this case Minnkota and/or Square Butte) would ever receive would be the various system performance independent guarantees for the performance of the individual equipment and components supplied by the individual vendors including the one from the catalyst supplier. Each of these individual equipment and component performance guarantees would be limited to the value of and the equipment and/or component supplied by the respective vendor and simply passed through by the A/E to the owner. Thus, none of these individual performance guarantees would come even remotely close to covering the entire value of the SCR retrofit as each one would represent only a small portion of the entire project. The owner (in this case Minnkota and/or Square Butte) would have no performance guarantee for

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[103] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Responses to NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007.

[104] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

the entire SCR system and not even any kind of system performance guarantee from the A/E that all the individually purchased pieces of equipment and/or components fit together as intended so that the entire system performs as intended.

As a matter of fact, the type and extent of performance guarantees offered by the catalyst suppliers CERAM and Haldor Topsoe including the stated limitation of liability are most certainly exactly the same as were provided for each and every SCR project, in which Burns & McDonnell and Sargent and Lundy were ever involved.

If an owner seeks a true system performance guarantee that covers the entire scope of the project, no A/E is needed. As a matter of fact, an A/E is a hindrance in such a case as such true complete system performance guarantees are only offered by complete system suppliers such as Alstom, Babcock Power or Babcock & Wilcox. Contrary to an A/E, these true system suppliers are willing and able to provide the entire scope of a turn-key SCR retrofit including complete system performance guarantees for up to the value of the entire retrofit project, which is then again the value of the contract. Such a turn-key supply, however, eliminates the need for an owner to additionally pay an A/E, which is the simple reason why these types of contracts are not favored by the A/Es. Yet, the most successful SCR retrofits in the U.S. were done as turn-key installations without the use of an A/E.

6.12 Review Authority

The Department claims the review authority for this case. I do not comment on this.

6.13 Conclusions

In conclusion, it must be stated that the Department made numerous factually incorrect claims, conclusions and statements as outlined in detail above. The most significant ones include:

- The conclusion that HDSCR is not technically feasible based on the data obtained from the ill-designed HDSCR Coyote Pilot Testing that provided little useful data – see sections 6.2, 6.3 and 6.9.

- The conclusion that HDSCR is not technically feasible based on the lack of any meaningful pilot testing data because the HDSCR Coyote Pilot Testing was ill-designed and provided little useful date – see sections 6.4, 6.6, 6.8 6.10 and 6.11.

- The statement that Burns & McDonnell and Sargent and Lundy have extensive experience with the design and operation of SCR systems – see section 6.5.

- The claim that vendors cannot guarantee SCR system performance for M.R. Young Station – see section 6.11.

- The claim that LDSCR and TESCR are not technically feasible based on the data obtained from the ill-designed HDSCR Coyote Pilot Testing that provided little useful data and must be considered completely irrelevant altogether for an LDSCR and/or TESCR design and application.

It is worth pointing out that the Department contradicted its own statements numerous times, particularly concerning the quality of the data of the HDSCR Coyote Pilot Testing and the unavailability of any really useful data from said pilot testing. No explanation was offered why the HDSCR Coyote Pilot Testing data is condemned as inadequate in some cases, yet hailed as offering the absolute truth in some other cases. Depending on what seems to best fit the argument at the moment that HDSCR is not technically feasible for the M.R. Young Station, the Department seems to either solely rely on this essentially useless Coyote Pilot Testing data, which appears to be the case for the Department's conclusions concerning catalyst:

- poisoning, blinding and plugging;

- deactivation and lifetime;

or seems to complain that no reliable pilot testing data is available, which appears to be the case for the Department's conclusions concerning catalyst:

- erosion;

- sizing (type, pitch, volume);

- performance guarantees from the vendors.

The incorrectness of the Department's conclusions concerning the expected catalyst deactivation as well as the performance guarantees was pointed out by some of those, who know best, namely the catalyst manufacturers and SCR system suppliers[105].

The Department's arguments concerning fuel variability and ash composition are true for all coals and by no means unique to this application and thus of no relevance to this case. Likewise, the argument concerning unacceptable temperature variations and possible popcorn ash problems are also of no further relevance to this case as all these issues would have to and can be successfully resolved regardless of the type of combustion system (i.e. cyclone fired) and/or the type of fuel burned (i.e. North Dakota lignite).

Finally, the Department's conclusions against the technical feasibility of LDSCR and TESCR are completely unsubstantiated and erroneous. Not only does the Department fail to

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[105] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, "Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2", May 8, 2008.

correctly distinguish and separate these two (2) distinctly different types of SCR systems, it also concludes that "the (catalyst) deactivation issue for low-dust and tail-gas SCR remains as with the high-dust SCR". Deciphered in detail, this is the Department's only single argument against the application of a LDSCR or TESCR, since all other argued issues are admitted to be "not unresolvable". Unfortunately, the Department again bases its erroneous conclusion concerning LDSCR and TESCR solely on the data obtained during the ill-designed HDSCR Coyote Pilot Testing. As little if any relevance this essentially useless data may have for an HDSCR application it most certainly has absolutely no relevance for a possible LDSCR and/or TESCR application. The Department fails to recognize this.

A noticeably poor and incomplete attempt was made to provide at least some, however, not meaningful data for the flue gas and fly ash composition downstream of the ESP. This clearly suggests the lack of any meaningful data for the correct evaluation of an LDSCR. The only data provided was some sampling performed downstream of the ESP at a temperature of 300 F (149 °C), which is well below the temperature range of 650 – 750 F (343 – 400 °C) required for LDSCR operation. Therefore, the deposition data cited by the Department from Minnkota's November 9, 2007 response to comments[106] is not relevant for the flue gas conditions present in a LDSCR and even less for the flue gas conditions in a TESCR. Unquestionably, the condensation of vapors including pyrosulfates and gaseous compounds responsible for the stickiness of the ash is a function of temperature as condensation of vapors and gaseous compounds occurs progressively at lower temperatures. The Department fails to explain how data concerning the stickiness of the ash particles collected on a silicon dioxide surface at 300 F (149 °C) would have any significant relevance for the prediction of catalyst pore pluggage by ash particles at 650 – 750 F (343 – 400 °C).

Absolutely no useful data characterizing the conditions downstream of the wet FGD was provided, thus making any conclusion concerning a TESCR nothing but presumptive speculation. The only at least somewhat factual attempts to argue why catalyst deactivation downstream of a wet scrubber could be an issue is the Department's comment concerning the Minn-Dak Farmer's Coop's coal fired boilers and some convoluted data[107], which presumably obtained by means of stack testing downstream of the wet scrubber at M.R. Young Station's Unit 2.

Using the Minn-Dak boilers 7A and 7B as an example, the Department argues that "Minn-Dak had trouble complying with its particulate matter emission limit due to sodium compounds passing through the air pollution control device. In order to maintain compliance, the ash Na_2O content of the coal combusted had to be limited". The Department argues that this is sufficient support for the Department's conclusion that "alkali mineral compounds are not removed by the ESP or SO_2 scrubbing system". As a result the Department argues that "it

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[106] Response letter to EPA's October 4, 2007 letter sent from Minnkota Power Cooperative, Inc. to Mr. Terry O'Clair, Director, Division of Air Quality at the North Dakota Department of Health, dated November 9, 2007.

[107] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Responses to NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007.

appears a significant amount of sodium compounds, a catalyst poison, will enter a low-dust or tail-gas SCR system. The deactivation issue for low-dust and tail-gas SCR will remain the same as for the high-dust SCR. The research, design and pilot testing needed to develop an SCR system that will have reasonable success makes this technology also not applicable at this time."

As will be shown in detail in section 7 of this report, no research, design and/or pilot testing is needed to install a TESCR that will have complete success at M.R. Young Station. The Minn-Dak experience cited by the Department, however, is by no means of any relevance to the technical feasibility of a TESCR at M.R. Young Station, yet it seems to form the sole and only basis for the Department's reasoning that TESCR is not applicable at this time. Reviewing Minn-Dak's Air Pollution Control Title V Permit to Operate[108] and the North Dakota Department of Health's Inspection Report[109], it becomes evident that neither the particulate matter removal device nor the wet scrubber are comparable to the air pollution control equipment installed or under construction at M.R. Young Station. Minn-Dak's boilers 7A and 7B, which are two Babcock & Wilcox stoker-fired boilers burning coal, biogas and natural gas, are equipped with multi-cyclones and co-current venturi scrubbers rather than ESPs and counter-current spray towers. The coal burned was reported to be sub-bituminous coal from the Spring Creek Coal Company in Montana rather than North Dakota lignite[110]. Not only is the partitioning of the ash constituents of the coal that occurs in a cyclone-fired boiler different from that in a stoker-fired boiler[111] but also is said partitioning different for different coals. Thus, using data from a stoker-fired unit burning PRB to predict the partitioning at a cyclone-fired unit burning North Dakota lignite is simply inappropriate.

As correctly stated by the Department, Minn-Dak has a restriction on the sodium content in the coal at 2.8% Na_2O on a dry mass basis in the coal ash in order to meet the particulate emission limit of 45.5 lb/hr, which, however, equates to 0.40 lb/10^6 Btu rather than 0.10 lb/10^6 Btu as erroneously claimed by the Department. It is critically important to note that the sub-bituminous coal fired at Minn-Dak[112] has an ash content of approximately 4 – 5%, which is typical for sub-bituminous coal and not about 8 – 10% on average as North Dakota lignite. In other words, North Dakota lignite has about twice the amount of ash compared to sub-bituminous coal. Furthermore, it is important to realize that the sub-bituminous coal burned at Minn-Dak has only between 0.3% and 0.5% sulfur, which means that the uncontrolled SO_2

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[108] State of North Dakota, Department of Health, Division of Air Quality, Air Pollution Control Title V Permit to Operate, Permit Number T5-X78001 issued on 7/31/2006.

[109] North Dakota Department of Health, Inspection Report, issued on 10/27/2003.

[110] Ibid

[111] Response letter to EPA's October 4, 2007 letter sent from Minnkota Power Cooperative, Inc. to Mr. Terry O'Clair, Director, Division of Air Quality at the North Dakota Department of Health, dated November 9, 2007.

[112] State of North Dakota, Department of Health, Division of Air Quality, Air Pollution Control Title V Permit to Operate, Permit Number T5-X78001 issued on 7/31/2006.

emissions range between 0.7 lb/10^6 Btu and 1.1 lb/10^6 Btu[113], which compares very favorably to a permitted emission limit of 3.0 lb/10^6 Btu. The measured SO_2 emission rate was reported to be around 0.1 lb/10^6 Btu at a time when the uncontrolled emission rate was theoretically and not accounting for any SO_2 being captured in the fly ash only about 0.7 lb/10^6 Btu (based on the coal data included in the report), which suggests a SO_2 removal rate of no more than at the most 70%[114]. Combining this with the fact that these stoker fired units have no ESP but are equipped with only multi-cyclones as primary particulate control devices, suggests very strongly that the co-current venturi scrubbers were never intended to remove any significant amounts of SO_2 but where designed as additional particulate removal devices.

Multi-cyclones are comparatively simple devices designed for the removal of only the coarsest fly ash particles. Therefore, multi-cyclones have not been used in utility boilers for more than 40 years anymore. Due to the fact that multi-cyclones are based on the principal of centrifugal forces removing the particles, only the largest and heaviest particles can be removed. Contrary to that, ESPs electrically charge all sizes of particles, which are then removed in an electric field as a result of their electric charge. Therefore, ESPs are much more effective removal devices for particulate matter, particularly for very small particles.

Since PRB is known to generate a comparatively large fraction of very fine ash particles and since these stoker-fired units were most likely not designed for burning PRB, it is quite conceivable why the units didn't meet their particulate emission limit while burning PRB. Not being equipped with particulate control devices suitable for the removal of fine particles, limiting the sodium content in the ash serves as means to limit the amount of very small particles formed.

Co-current venturi scrubbers are particulate removal devices, which operate on the principle of inertial impaction of smaller particles on water droplets as a result of largely different velocities. Again, only the larger particles have enough mass and therefore inertia to be removed successfully. Small particles with a small mass and therefore very little inertia follow the gas stream and successfully evade impaction. Contrary to that, counter-current spray towers designed for SO_2 removal are based on the principle of offering a large amount of finely dispersed liquid for the rapid cooling of the flue gas to its saturation temperature followed by the absorption of gaseous air pollutants such as SO_2. During the rapid cooling of the flue gas with a large excess of water, the very small particles, which provide a comparatively large surface area, act as condensation nuclei and are absorbed into the scrubbing solution. Also, the flue gas residence time in a counter-current spray tower is much longer than in a co-current venturi scrubber, which further assists removing small particles.

Suggesting that the flue gas inlet composition to a TESCR downstream of an ESP and a counter-current wet flue gas desulfurization scrubber is even similar to the flue gas composition downstream of a multi-cyclone and a co-current venturi scrubber designed for

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[113] North Dakota Department of Health, Inspection Report, issued on 10/27/2003.

[114] Ibid

coarse particulate removal is truly creative. Yet, the fact of the matter remains that the Minn-Dak experience is not comparable to the situation at the M.R. Young Station due to the different:

- coal burned (PRB versus North Dakota lignite);
- combustion system design (stoker fired versus cyclone fired);
- primary particulate matter removal device (multi-cyclone versus ESP);
- wet scrubber design and purpose (co-current venturi for particulate removal versus counter-current spray tower for SO_2 removal).

Thus, the Minn-Dak experience must be considered completely meaningless and irrelevant for the possible application of a TESCR at the M.R. Young Station.

In Minnkota's April 18, 2007 response to question from the Department[115], Minnkota states that "stack sampling was conducted downstream of the ESP and wet FGD on Unit 2." However, it remains unclear whether the data provided represents samples taken downstream of the ESP or samples taken downstream of the wet scrubber. Furthermore, even if the data represents samples downstream of the wet scrubber, it is unknown whether the samples were taken downstream of the wet scrubber but upstream of the bypassing flue gas re-entering the flue gas stream to the stack or downstream of the bypass re-entry point. These questions are very relevant, since the flue gas stream downstream of the ESP and upstream of the wet scrubber is significantly different from the flue gas downstream of the wet scrubber. Likewise, the flue gas stream downstream of the wet scrubber but upstream of the bypass re-entry point is significantly different than the flue gas downstream of the bypassing flue gas re-entering the flue gas stream coming from the wet scrubber to the stack. An e-mail string between Minnkota and Burns & MacDonnell[116] seems to indicate that at least the sampling may have been done downstream of the wet scrubber and downstream of the bypass re-entry point of the flue gas for reheating. If this is confirmed than this data is completely useless for the correct characterization of the flue gas stream entering a TESCR as approximately 18% of the flue gas bypassed the wet scrubber at the time of sampling[117]. This means that the flue gas sampled clearly does not represent what would enter a TESCR as everything that is removed in a wet scrubber was still present in almost one fifth of the flue gas during sampling. Since the sampling was clearly not intended to characterize the flue gas composition entering a TESCR but intended to prove the particulate removal downstream of the ESP, this data cannot be considered relevant for any reasonable judgment concerning the technical feasibility of a TESCR.

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[115] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Responses to NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007.

[116] E-mail string from John Graves (Minnkota) to Robert Blakely (Burns & McDonnell) dated April 12, 2007.

[117] Ibid

Also, no flue gas characteristics (temperatures, velocity, composition, etc.) at the sampling point are provided. Without exact knowledge of all these important details, the provided data is useless even for any reasonable judgment concerning a LDSCR. However, even if some of this missing information would be made available, the data would still be meaningless unless the total mass flow or at least the total concentration of the various compounds in the flue gas would be provided. The provided data only offers a morphological composition analysis of the samples expressed in relative percentages of the various elements as a portion of the entire sample. No information about the absolute amount of the various compounds as well as their aggregate state was made available, which renders the data in its provided form as absolutely useless for any meaningful interpretation concerning expected catalyst deactivation rates. Why only this by itself completely useless portion of the data was provided while all information needed to make the data possibly meaningful was withheld (assuming that this information exists), remains unknown.

While the Department devotes forty (40) pages of the seventy two (72) page document to arguments why HDSCR should be considered technically not feasible, little more than two (2) pages are dedicated to LDSCR and TESCR combined. Of these two (2) pages little more than one (1) page deals with possible site constraints and flue gas reheating, both of which are correctly dismissed as being economic considerations instead of technical feasibility issues, thus leaving about only one (1) page for the combined evaluation of LDSCR and TESCR. This one (1) page states the Department's conclusion that a LDSCR and/or a TESCR are technically infeasible without presenting any relevant supporting data. The Department's conclusion rests solely on the incorrect, unsupported and unfounded claim that "the deactivation issue for low-dust and tail-gas SCR remains the same as for high-dust SCR". However, only a few paragraphs later, the Department contradicts this earlier statement by postulating that "catalyst deactivation of a low-dust or tail-gas SCR due to alkali compounds is an issue that will require extensive research, design and pilot testing to determine whether the technology can be successfully applied to units fired on North Dakota lignite". Either the Department can provide relevant supporting data for the claim that the deactivation issue in a TESCR remains the same as in a HDSCR, or such supporting data doesn't exist, in which case the claim is purely speculative and unsupported.

It is also a fact that the SCR Vendor Query conducted by Burns & McDonnell very specifically stated that it was solely directed towards HDSCR, thus ignoring LDSCR and TESCR. Why attempts by various vendors (Alstom, Babcock Power, CERAM) to also consider LDSCR and/or TESCR were seemingly ignored remains unexplained.

Thus, the final conclusion reached by the Department that HDSCR is not technically feasible is unacceptable. All the presented data, investigations, vendor information etc. most certainly don't allow the conclusion that HDSCR is not technically feasible. Concluding that HDSCR is technically infeasible is premature and unfounded.

Furthermore, the Department's conclusion that LDSCR and TESCR are both not technically feasible is clearly presumptive and speculative as this conclusion cannot be supported by any relevant data, investigation or vendor information. Additionally, it must be stated that this conclusion is wrong as the only one (1) claim of excessive catalyst deactivation made against TESCR is clearly technically not defendable.

In summary, this leads to the conclusion that the Department's statement that that SCR technology is not technically feasible for application at the M.R. Young Station's cyclone-fired units burning North Dakota lignite is incorrect. HDSCR may very well be technically feasible, LDSCR is most likely technically feasible and TESCR is most certainly technically feasible for application at the M.R. Young Station's cyclone-fired units burning North Dakota lignite. With at least one SCR principle, namely TESCR being most certainly technically feasible for the application at the M.R. Young Station, the Department's BACT analysis incorrectly eliminated the SCR technology from further consideration.

7. VENDOR QUERY TAIL-END SCR

In order to further substantiate the technical feasibility of TESCR for the M.R. Young Station, the same eight (8) vendors were contacted that also participated in the Vendor Query conducted by Burns & McDonnell[118]. Due to vacation schedules and other personal restrictions only six (6) of the eight (8) vendors contacted were able to provide written responses, while two (2) could provide only verbal responses. Also, time constraints demanded that the scope and extent of the discussion with these eight (8) vendors had to be limited to some very fundamental questions concerning TESCR.

Since catalyst deactivation seems to be the primary concern of the Department, more time was devoted to communication with the catalyst manufacturers (Argillon, CERAM, Cormetech, Haldor Tospoe, Hitachi) as they are ultimately the ones, who provide the process performance guarantees for the catalyst. Somewhat less time was devoted to the SCR equipment vendors, who ultimately also rely on the catalyst manufacturers for catalyst performance and deactivation information and guarantees. Therefore, the response of the catalyst manufacturers was considered to be most meaningful, particularly the responses of the ones with extensive TESCR experience. Again, more time was devoted to the companies with TESCR experience (Alstom, Argillon, CERAM, Babcock Power, Haldor Topsoe) compared to the ones with no TESCR experience (Babcock & Wilcox, Cormetech, Hitachi).

The following eight (8) vendors were contacted:

- SCR equipment vendors:
    - Alstom – Mr. Michael Philips was not available due to time constraints and therefore directed me to Mr. John Buschmann, SCR Product Manager at Alstom, who provided only a verbal response due to insufficient time for a

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[118] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Responses to NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007.

written response. Alstom has extensive TESCR experience.

  - Babcock Power – Dr. Clayton Erickson provided a written statement. Babcock Power has access to extensive TESCR experience and is the equipment supplier of the LDCSR downstream of a cold-side ESP under construction as WE Energies' South Oak Creek Station.

  - Babcock & Wilcox – Mr. Steve Moormann could not be reached. Instead, Mr. Donald Tonn, SCR Process Expert at Babcock & Wilcox in Barberton, OH was contacted and provided a written response. Babcock & Wilcox has no TESCR experience.

- SCR catalyst manufacturers:

  - Argillon – Mrs. Cindy Khalaf provided a written statement. Argillon has extensive TESCR experience.

  - CERAM – Mr. John Cochran provided a written statement. CERAM has extensive TESCR experience.

  - Cormetech – Mr. Scot Pritchard provided a written statement. Cormetech has no TESCR experience but some LDSCR experience.

  - Haldor Topsoe – Mr. Flemming Hansen provided a written statement. Haldor Topsoe has extensive TESCR experience.

  - Hitachi – Mr. Anthony Favale provided only a verbal response due to insufficient time for a written response. Hitachi has no TESCR experience but some LDSCR experience.

Due to the time constraints, the person named above at each of the eight (8) vendors was contacted by phone and informed about the purpose of the discussion as well as asked whether he or she would be willing to provide a brief statement in writing per e-mail. All contacted people agreed to provide a written statement. However, Messrs. John Buschmann of Alstom and Anthony Favale of Hitachi who could provide only provide a verbal response due to time constraints as the written response would have arrived after the submission of this report.

All eight (8) vendors, namely three (3) SCR system suppliers (Alstom, Babcock Power and Babcock & Wilcox) and five (5) SCR catalyst suppliers (Argillon, CERAM, Cormetech, Haldor Topsoe and Hitachi) were asked to provide answers to the following three (3) questions:

Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would <*company*>:

a. Consider a tail-end SCR technically feasible?

b. Recommend or require additional pilot testing?
c. Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

All eight (8) vendors answered the question a. with a clear "yes". None of the vendors expressed even the slightest doubts that TESCR would not be technically feasible for both units at the M.R. Young Station. All three (3) contacted SCR system suppliers and all responding five (5) SCR catalyst suppliers consider TESCR to be unquestionably technically feasible for cyclone fired units burning North Dakota lignite.

All five (5) responding catalyst manufacturers answered question b. with a clear "no", thus dismissing any need for any further pilot testing for a TESCR application at M.R. Young Station.

Likewise, the SCR system suppliers Babcock Power and Alstom also dismissed any need for any additional pilot testing for a TESCR. The only SCR system supplier, who stated that they "would require further discussion with the catalyst suppliers", was Babcock & Wilcox. This caution is simply the result of the lack of experience of Babcock & Wilcox with TESCRs. Given the fact that even though Babcock & Wilcox has a license from Hitachi for SCR catalyst but Hitachi has no experience with TESCR either, such caution is no surprise.

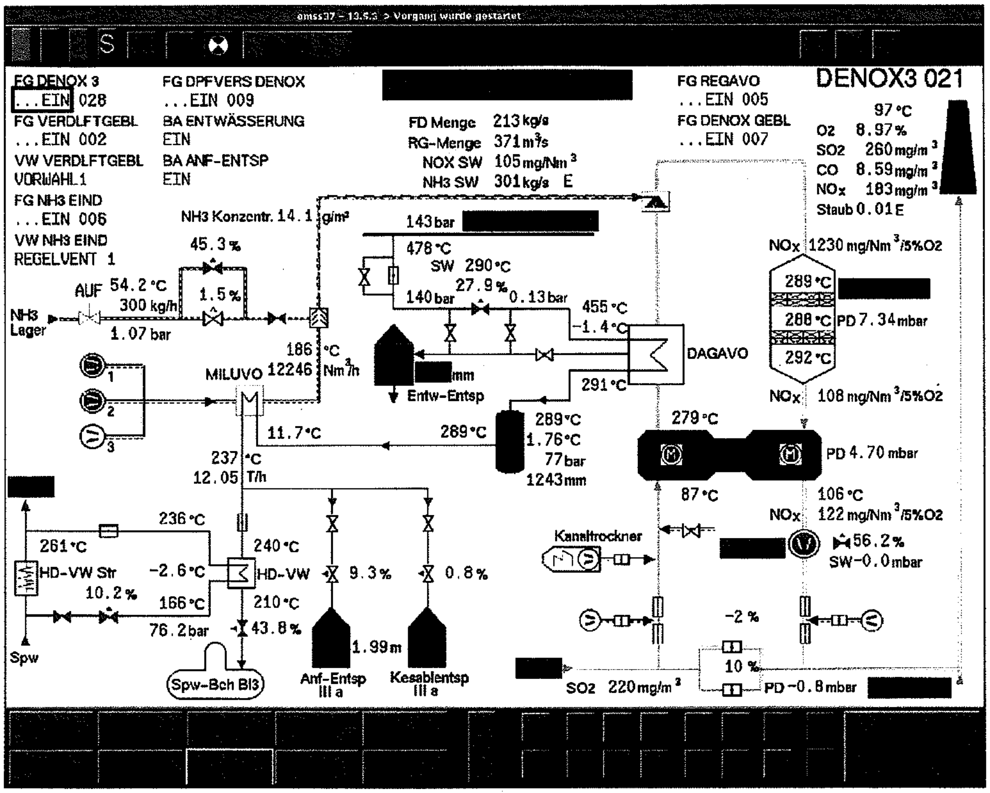
All five (5) responding catalyst suppliers and all three (3) SCR system suppliers answered question c. with a clear statement that they would provide common commercial performance guarantees. Argillon indicated 90% NOx removal efficiency at less than 2 ppmvd @ 3% O_2 NH_3 slip and greater 24,000 SCR operating hours catalyst life. Obviously, more details would have to be determined as the project would need to be defined better. Only Babcock & Wilcox stated that the commercial guarantees would have to be discussed first with the catalyst suppliers before passing them on to the buyer. Hitachi stated that they would have to see the exact flue gas composition in order to determine what commercial guarantees would be provided. Again, this can be explained by the fact that neither Babcock & Wilcox nor Hitachi has any TESCR experience and did not have time to evaluate a TESCR application for M.R. Young Station in sufficient detail.

Additionally, during the verbal discussions with all four (4) catalyst suppliers as well as all three (3) responding SCR systems suppliers, the contact persons made it very clear that their companies would not consider HDSCR as technically infeasible at this time. Particularly, all five (5) responding catalyst suppliers very adamantly stated that the existing knowledge does not support prematurely discarding HDSCR as a technically feasible possibility. All five (5) responding catalyst suppliers suggested that properly designed and executed HDSCR pilot testing would certainly be helpful to decide whether HDSCR would be more economically attractive than LDSCR or TESCR for the M.R. Young Station. The e-mail correspondence of all six (6) vendors, who responded in writing, is presented in detail in Appendix A.

8. SUMMARY

In summary, it must be concluded that TESCR is not only technically feasible but may be even the most economical SCR alternative for M.R. Young Station. As reiterated by the responding vendors, the very high removal efficiency of the ESP and wet FGD upstream of a TESCR combined with the flue gas reheating from the flue gas dew point provides flue gas conditions, which are unquestionably much more favorable for SCR catalyst than the conditions present in almost all HDSCRs. Two decades of TESCR experience in Europe have proven that TESCR can be successfully applied to the most complex processes and the most difficult flue gases. Catalyst replacement in most TESCRs has been minimal to none. Most coal-fired units equipped with TESCRs still utilize the initial catalyst fill after more than 130,000 SCR operating hours. Due to the greatly reduced mass flow of catalyst poisons to the SCR catalyst the catalyst deactivation rates in TESCRs have proven to be extremely low, in some cases barely measurable.

Additionally, minimal unit downtime for TESCR tie-in resulting in very little if any lost generation is a huge advantage for TESCRs as they can be constructed typically completely independent of and parallel to unit operation. Flue gas reheat cost is relatively low as the flue gas needs to be reheated with high pressure steam only by about 18 – 65 degrees (10 K – 35 K) and the condensate from the steam coil is typically further used for dilution air heating and subsequent feed water before returned to the condensate from the turbine.



The graph above presents a typical process flow diagram from a TESCR on a 300 MW coal-fired unit. This TESCR has operated for more than 130,000 hours for more 20 years now on the initial fill of catalyst with a continuous NOx removal efficiency in excess of 91%. As can be seen on the graph, the high pressure steam used for reheating is cooled from about 892 F (478 °C) to ultimately 410 F (210 °C) after dilution air and feedwater heating and prior to being discharged to the feedwater storage tank. Also worth noting is the small amount of only 18 degrees F (10 K) that need to be added to the flue gas by means of high pressure steam. As can be seen, the flue gas downstream of the gas-gas heat exchanger enters the steam coil with a temperature of approximately 534 F (279 °C) and enters the SCR reactor downstream of the steam coil with a temperature of only about 552 F (289 °C). This proves the high efficiency of the gas-gas heat exchanger and the small amount of high pressure steam needed for flue gas reheating, which makes this concept economically more attractive.

In the U.S. currently both 325 MW units at PSE&G's Mercer Generating Station are equipped with TESCRs with flue gas reheat downstream of the ESPs. Spray dryer absorbers followed by baghouses downstream are being added downstream of the SCRs, thus effectively converting them from TESCRs to LDSCRs. The same type SCR with flue gas reheat is currently being installed at WE Energies South Otter Creek Generating Station.

Thus, LDSCR and/or TESCR systems can neither be dismissed as being technically infeasible nor based on economic reasons. Particularly the TESCR principle was developed specifically in order to successfully adapt the SCR technology to units with the most difficult flue gas compositions and the most complex retrofit challenges. During its 22 years of extraordinarily successful operating history, the TESCR principle has not only unconditionally proven itself as one of the most viable SCR principles but certainly the most universally applicable of all SCR principles.

Appendix A: Data and Information Considered

"Alternative Control Technologies Document NO_x Emissions from Utility Boilers" March 1994. U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards. This information can be found at website address: http://www.epa.gov/ttn/catc/dir1/utboiler.pdf.

Amended SIP Permit to Operate, letter from the North Dakota Department of Health to John Graves, Minnkota Power Cooperative, dated February 5, 2002.

Ando, Jumpei, "SO_2 and NO_x Removal for Coal Fired Boilers in Japan," presented at the Seventh Symposium on Flue Gas Desulfurization, May, 1992.

Argillon's website: www.argillon.com.

Assessment of SO_2 and NO_x Emission Control Technology in Europe, Air and Energy Engineering Research Laboratory, EPA-600/2-88-013, February 1988.

Attachment 10, "Initial Design" Boiler Heat Input Rating vs "As Built" Boiler Heat Input Rating, George W. Button, January. 2001.

Attachment 11, Expert Opinion Report, Maximum Boiler Heat Input Capacity Units 1 and 2 Milton R. Young Station, Minnkota Power Cooperative, Inc. Center, N.D., 58530, Robert L. Pearson, Ph.D., PE, CH2M Hill, 100 Inverness Terrace East, Englewood, CP 80224, ca. 2001.

Benson, A. J. D. Laub, C. R. Crocker, J. H. Pavlish, „SCR catalyst performance in flue gas derived from subbituminous and lignite coals", Fuel Processing Technology 86 (2005) pages 577 – 613, 2005.

"Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume 1: Stationary Point and Area Sources, Chapter 1.1, Bituminous and Subbituminous Coal Combustion" dated July 1993.

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Appendix B: SCR Vendor Query Correspondence

1. Vendor Correspondence with SCR system suppliers

1.1 E-Mail correspondence with Clay Erickson, Babcock Power (SCR System Vendor – extensive tail-end SCR experience)

From: cerickson@babcockpower.com [mailto:cerickson@babcockpower.com]
Sent: Thursday, June 19, 2008 15:59
To: Hans Hartenstein
Cc: jlangone@babcockpower.com; tlicata@babcockpower.com
Subject: Re: Tail-end SCR

Hans,

Babcock Power has reviewed the Milton Young plant in the past, based on these reviews Babcock Power finds

- A tail-end SCR is technically and commercial feasible
- Babcock Power does not recommend or require additional pilot testing only proper flue gas characterization as with any SCR system per performed
- Will provide commercial guarantees for the SCR and catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime

Babcock Power has the largest SCR experience list in the world; from this experience we are completely confident in the application of a tail end system at Milton Young. If you have further questions please let me know.

With best regards,
Clay

Clayton Erickson, PhD
Director, Process Engineering
Babcock Power Inc.
5 Neponset Street
Worcester, MA 01606

T: 508-854-4039 F: 508-854-1177
M: 508-245-2383

From: "HansHartenstein"<Hans.Hartenstein@Evonik-EnergyServices.us>
Sent: 06/18/2008 12:16
To: <cerickson@babcockpower.com>
Subject: Tail-end SCR

Clay,

As discussed during our phone conversation today, during which you stated that Babcock Power considers a high-dust SCR principally, technically feasible even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in Babcock Power's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat) Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Babcock Power:

- Consider a tail-end SCR technically feasible?
- Recommend or require additional pilot testing?
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Given the fact that tail-end SCRs in Germany including the ones built by your licensor Fisia Babcock (most of which are on wet bottom boilers) went into operation in the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that Babcock Power / Fisia Babcock has sufficient confidence in your tail-end SCR experience to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

1.2 E-Mail Correspondence with Don Tonn, Babcock & Wilcox (SCR System Vendor – no tail-end SCR experience)

From: Tonn, Donald P [mailto:dptonn@babcock.com]
Sent: Monday, June 23, 2008 16:06
To: Hans Hartenstein
Subject: RE: Tail-end SCR

Hans:

Please note my responses to your questions in the referenced email below.

Regards,
Donald P. Tonn
Babcock & Wilcox Power Generation Group
AQCS Technology
Phone 330-860-1986
Cell 330-289-7795

From: Hans Hartenstein [mailto:Hans.Hartenstein@Evonik-EnergyServices.us]
Sent: Wednesday, June 18, 2008 13:25
To: Tonn, Donald P
Subject: Tail-end SCR

Don,

As discussed during our phone conversation today, during which you stated that Babcock & Wilcox considers a tail-end SCR (downstream of a wet scrubber including flue gas reheat) principally technically feasible for Minnkota's Milton R. Young Station, I would be interested in Babcock & Wilcox's position on the following questions. Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Babcock & Wilcox:

- Consider a tail-end SCR technically feasible? Yes
- Recommend or require additional pilot testing? Requires further discussion with catalyst suppliers.

- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be? While B&W has considered tail-end SCR systems on other projects we have not had these commercial guarantee discussions with the catalyst suppliers for the North Dakota lignite application. Before consideration of providing these guarantees a comfort level would be required after obtaining guarantees from catalyst suppliers.

Given the fact that tail-end SCRs in Germany went into operation in the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that Babcock & Wilcox has sufficient confidence in tail-end SCR systems to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

2. Vendor Correspondence with SCR Catalyst Manufacturers

2.1 E-Mail Correspondence with Cindy Khalaf, Argillon (Catalyst Manufacturer – extensive tail-end SCR experience)

From: Khalaf Cindy R [mailto:cindy.khalaf@argillon.com]
Sent: Tuesday, June 24 2008 14:15
To: Hans Hartenstein
Subject: Re: Argillon Tail-end SCR

No problem.
Regards,
Cindy

From: Hans Hartenstein <Hans.Hartenstein@Evonik-EnergyServices.us>
Sent: Tuesday, June 24, 2008, 16:45
To: Khalaf Cindy R
Subject: RE: Argillon Tail-end SCR

Cindy,

Thanks a bunch for taking the time to respond. I greatly appreciate your answer. I'll keep you posted where this thing is going.

Best regards,
Hans Hartenstein
http://www.evonik-energyservices.us

From: Sadler Randy [mailto:randy.sadler@argillon.com]
Sent: Tuesday, June 24, 2008 08:15 AM

To: Hans Hartenstein
Cc: Khalaf Cindy R
Subject: Argillon Tail-end SCR
Importance: High

On behalf of Cindy Khalaf -

Hans,

Further to our phone call, as far as I know, Argillon has more tail end experience than any other SCR catalyst manufacturer and, as you noted, we also have experience with high dust, German lignite SCRs. Argillon also won the first US lignite SCR catalyst project (Luminant Oak Grove 1 & 2) and provided commercial guarantees. These units are not in service yet. So, yes, we consider ourselves able to answer these questions competently.

Consider a tail-end SCR technically feasible?

Yes, we consider this configuration to be technically feasible. As you know, tail end SCRs are often used when there are significant catalyst poisons in a flue gas stream. A wet scrubber can remove most of these poisons, resulting in very low catalyst deactivation.

Recommend or require additional pilot testing?

For a high dust configuration, we would say definitely. For a tail-end configuration, we would say no. We would only like to see a flue gas analysis for conditions at the inlet to the SCR in order to predict deactivation rate.

Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Generally speaking, yes, we would provide guarantees for DeNOx & slip as specified (not to exceed 90% or 2 ppm), 24k hours life, SO_2 conversion rate - low but value TBD, pressure drop - value TBD. Of course we would have to see the technical specifications before being more specific. In addition, tail-end SCRs perform much longer, so depending on the application specifics, customer, etc., we may decide to extend the operating life guarantees. This is a commercial decision and will be reviewed on a case-by case basis.

If you have any more questions, please let me know.

Regards,
Cindy

Cindy R. Khalaf
Argillon LLC
President
Tel: 678.341.7520
Mobile: 770.331.9571
FAX: 678.341.7509
Email: cindy.khalaf@argillon.com
5895 Shiloh Road, Ste. 101
Alpharetta, GA 30005

From: Hans Hartenstein [mailto:Hans.Hartenstein@Evonik-EnergyServices.us]
Sent: Thursday, June 19, 2008 16:29

To: Khalaf Cindy R
Subject: Tail-end SCR

Cindy,

As discussed during our phone conversation today, during which you stated that Argillon considers a high-dust SCR principally technically, feasible based on your high-dust SCR experience with lignite fired units in Europe even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in Argillon's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat). Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Argillon:

- Consider a tail-end SCR technically feasible?
- Recommend or require additional pilot testing?
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Given the fact that tail-end SCRs in Germany including the ones equipped with Argillon catalyst went into operation in the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that Argillon has sufficient confidence in your tail-end SCR experience to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

2.2 E-Mail Correspondence with John Cochran, CERAM Environmental (Catalyst Manufacturer – extensive tail-end SCR experience)

From: John Cochran [mailto:John.Cochran@ceram-usa.com]
Sent: Wednesday, June 25, 2008 15:14
To: Hans Hartenstein
Cc: Greg Holscher; Noel Rosha; Orehovsky Kurt
Subject: RE: Request for Information

Hans,

CERAM certainly considers the use of a tail-end SCR on applications such as the Milton R. Young Station as technically feasible provided a proper design approach is used. CERAM has the experience from more than 100 tail-end and low dust applications dating from 1988 that would substantiate our opinion. For a tail-end approach we see no need for additional pilot testing. As such, we can provide full commercial guarantees for catalyst performance (activity or lifetime, conversion rate, pressure drop, etc.).

The choice between high dust and tail-end processes certainly should consider capital costs, operating costs and process risk. Based on our experience certainly process risk would favor a tail-end approach, but albeit for most circumstances at a higher "all-in" cost. Should very high retrofit factors be present for a high dust arrangement then the relative economic factors may even favor a tail-end approach.

I hope this information is useful to your evaluation. Please advise should you have any further questions or information needs. Thanks.

Best Regards,
John Cochran

CERAM Environmental, Inc.
www.frauenthal.net
913.239.9896 (phone)
913.205.5615 (cell)

From: Hans Hartenstein [mailto:Hans.Hartenstein@Evonik-EnergyServices.us]
Sent: Tuesday, June 17, 2008 7:20
To: John Cochran
Subject: Request for Information

John,

As discussed during our phone conversation today, during which you stated that CERAM considers a high-dust SCR principally technically, feasible even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in CERAM's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat) Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would CERAM:

- Consider a tail-end SCR technically feasible?
- Recommend or require additional pilot testing?
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Given the fact that tail-end SCRs in Germany including the ones equipped with CERAM catalyst (Herne 1, 2 and 3, Voerde (West) 1 and 2, Lünen 10 and 11 – all of which are wet bottom boilers) went into operation in the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that CERAM has sufficient confidence in your tail-end SCR experience to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

2.3 E-Mail Correspondence with Scot Pritchard, Cormetech (Catalyst Manufacturer – no tail-end SCR experience)

From: Pritchard, Scot G. [mailto:PritchardSG@Cormetech.com]
Sent: Thursday, June 19, 2008 17:41
To: Hans Hartenstein
Subject: RE: Tail-end SCR

Hans,

I was thinking of if you put a coupon in the tailend location and it showed something weird then you would have to do something more elaborate i.e. A slipstream with longer hours, etc. We do not anticipate this - in fact you could probably do without the coupon test as well since I don't see any reason why this system would be any different the primary tail end experience i.e. Unlikely any nasties make it through the lower temperature environment and scrubber process. The coupon is OK but I really don't expect to see much. Finally, we have not done any specific coupon tests (because slipstream has been the primary way to evaluate) so we would need to think through the best way to do it - i.e. holder, mounting arrangement, test method, hours of exposure, etc. If you already have something in mind please let us know.
Hope that helps with the clarification.

Scot

From: "Hans Hartenstein" <Hans.Hartenstein@Evonik-EnergyServices.us>
Sent: Thursday, 6/19/08 4:26 pm
To: "Pritchard, Scot G." <PritchardSG@Cormetech.com>
Subject: RE: Tail-end SCR

Scot,

Thanks for the input from Cormetech, which is greatly valued. One question for clarification purposes only, though. Coupon tests and/or flue gas analysis would only be performed in order to characterize the flue gas going into the tail-end SCR as is needed for the design of any APC equipment. Obviously, nobody could offer any performance guarantees concerning what's coming out of a tail-end SCR without knowing what's going into it. You state that in case coupon tests would show a significant accumulation of catalyst poisons, a subsequent slip stream test, which is unquestionably more accurate and representative of a full scale - in this case tail-end - SCR, would be recommended. Stating this, do I understand you right that you would recommend this slip stream testing mainly for the purpose of properly characterizing the flue gas composition at the inlet to the tail-end SCR in order to provide a reliable basis for correct catalyst design? Do I assume correctly, that you would not require extensive and long-term (12 - 24 months) pilot testing with a slip stream reactor because you have serious doubts about the principal technical feasibility of a tail-end SCR for this application? Please clarify. Thanks.

Best regards,
Hans Hartenstein

From: Pritchard, Scot G. [mailto:PritchardSG@Cormetech.com]
Sent: Thursday, June 19, 2008 12:15
To: Hans Hartenstein
Subject: RE: Tail-end SCR

Hans,

Please see my input below.

As discussed during our phone conversation today, during which you stated that Cormetech considers a high-dust SCR principally technically, feasible even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in Cormetech's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat) Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Cormetech:

- Consider a tail-end SCR technically feasible? - yes

- Recommend or require additional pilot testing? - We generally do not consider coupon testing an accurate representation of an SCR, however in order to minimize cost and provide basic screening information we would suggest the potential use of a coupon sample test. If the coupon shows significant accumulation of catalyst poisons, a subsequent slipstream type test which is more representative of a full scale SCR i.e match velocity, AVs, etc. would be recommended.
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be? Presuming the coupon test does not show anything unusual (which we do not expect to see anything unusual) we would be willing to provide commercial guarantees for a low dust application. Basic guarantees would be associated with life (this would not include specific Ko and K/Ko as guarantees - the guarantee would be an efficiency and slip guarantee at a certain number of operating hours), SO2 conversion, pressure loss.

As discussed, the high dust application needs additional due diligence testing (slipstream, ash testing, etc.) as well as the practicality of the applicable operating temperature to establish the commercial stance for a high dust application on North Dakota Lignite. We have done such work for Texas lignite as well as other coal sources and other fuels/applications in the past and would expect to be able to achieve the same for this application. The economics for any given application would be considered on a case by case basis.
Let me know if you have any questions. Also I would appreciate anything of the final document that you can share.

Thank you and regards,

Scot Pritchard
VP, Sales & Marketing
Cormetech
919-595-8708 o
919-815-2380 c

From: Hans Hartenstein [mailto:Hans.Hartenstein@Evonik-EnergyServices.us]
Sent: Thursday, June 19, 2008 11:35 AM
To: Pritchard, Scot G.
Subject: Tail-end SCR

Scot,

As discussed during our phone conversation today, during which you stated that Cormetech considers a high-dust SCR principally technically, feasible even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in Cormetech's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat) Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Cormetech:

- Consider a tail-end SCR technically feasible?
- Recommend or require additional pilot testing?
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Given the fact that tail-end SCRs in Germany (most of which are on wet bottom boilers) went into operation in the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that Cormetech has sufficient confidence in tail-end SCR systems to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

2.4 E-Mail Correspondence with Flemming Hansen, Haldor Topsoe (Catalyst Manufacturer – extensive tail-end SCR experience)

From: Flemming Hansen [mailto:FGH@topsoe.com]
Sent: Friday, June 27, 2008 12:56
To: Hans Hartenstein
Subject: RE: Tail-end SCR

Hans,
Your understanding is what I meant to say.

Thanks

Flemming G. Hansen
Manager SCR DeNOx Catalyst
Haldor Topsoe, Inc.
281-228-5120 (office)
281-228-5129 (fax)
281-684-8820 (cell)
FGH@Topsoe.com
www.topsoe.com

"Hans Hartenstein" <Hans.Hartenstein@Evonik-EnergyServices.us>
06/24/2008 04:16 PM

To "Flemming Hansen" <FGH@topsoe.com>
cc

Subject RE: Tail-end SCR

Flemming,

Thanks for your note. Just to make sure that I understand you correctly. Is it correct to state that Haldor Topsoe feels fully confident that a tail-end SCR is technically feasible and would not experience any accelerated catalyst deactivation? Therefore, you would be willing to guarantee catalyst performance (NOx removal efficiency, pressure drop, SO_2/SO_3 conversion rate and catalyst lifetime) without any need for further pilot testing. Please confirm. Thanks.

Best regards,
Hans Hartenstein

From: Flemming Hansen [mailto:FGH@topsoe.com]
Sent: Dienstag, 24. Juni 2008 16:44
To: Hans Hartenstein

Subject: Re: Tail-end SCR

Hans,

Like you describe we have had very good operating experience with SCR in the clean environment after a scrubber or bag filter. There appears to be practically no catalyst deactivation and with the low amount of particulate the catalyst pitch can be small, which both leads to a compact SCR as compared to a high dust SCR.

Based on the clean flue gas after the FGD we would not require any further testing in order to guarantee a catalyst performance.

The actual guarantees would be as normally applied in a high dust installation and depend on the catalyst volume and operating conditions. At the low operating temperature expected at the tail-end position the SO_2 oxidation will be negligible.

I hope this confirmation will have your approval.

Flemming G. Hansen
Manager SCR DeNOx Catalyst
Haldor Topsoe, Inc.
281-228-5120 (office)
281-228-5129 (fax)
281-684-8820 (cell)
FGH@Topsoe.com
www.topsoe.com

"Hans Hartenstein" <Hans.Hartenstein@Evonik-EnergyServices.us>
06/24/2008 10:24 AM

To <fgh@topsoe.com>
cc
Subject Tail-end SCR

Flemming,

As discussed during our phone conversation today, during which you stated that Haldor Topsoe considers a high-dust SCR principally technically, feasible even though not without technically resolvable challenges for Minnkota's Milton R. Young Station, I would also be interested in Haldor Topsoe's position on the technical feasibility of a tail-end SCR (downstream of a wet scrubber including flue gas reheat) Given your knowledge about the plant (cyclone-fired B&W boilers, ESP, wet scrubber) and the fuel (ND lignite), would Haldor Topsoe:

- Consider a tail-end SCR technically feasible?
- Recommend or require additional pilot testing?
- Be willing to provide commercial guarantees for catalyst performance (activity, pressure drop and SO_2/SO_3 conversion rate) and lifetime? If so what would these be?

Given the fact that tail-end SCRs in Germany including the ones equipped with your catalyst have been in operation since the late 1980s and most of them still operate on the initial fill of catalyst after almost 20 years and up to 130,000 operating hours, I would assume that Haldor Topsoe has sufficient confidence in your tail-end SCR experience to competently respond to these questions. Please let me know if you have any additional questions. Thanks.

Best regards,
Hans Hartenstein

Appendix C: Selected Papers Authored in Last Ten Years

Selected SCR related papers in English I have authored in the last ten years:

Licata, A., W. Schüttenhelm, H. Hartenstein, "Mercury and Dioxin Control for Municipal Waste Combustors", Asia-North American Waste Management Conference, Los Angeles, CA, USA 1998.

Hartenstein, H., P. Dyke, "Working Group 1 Expert Report - Sources and Technology", 1st Scientific and Evaluation Workshop on Persistent Manufactured Chemicals and By-Products from Industrial and Combustion Processes, UNEP Chemicals, Geneva, Switzerland 1999.

Bouwman, H., H. Hartenstein, "Working Group 2 Expert Report – Technology and Remediation", 4th Workshop on Policy, Social and Economic Issues Assessing Persistent Toxic Substances, UNEP Chemicals, Geneva, Switzerland 1999.

Chandler, J, J. Gallant, H. Hartenstein, "Retrofit of a WTE-Facility With SCR for NOx and PCDD/F Control Na_2S_4-Injection for Mercury Control", 7th North American Waste-To-Energy Conference, Tampa, FL, USA 1999.

Hartenstein, H., "Dioxin and Furan Inventories – National and Regional Emissions of PCDD/PCDF", UNEP Chemicals, Geneva, Switzerland 1999.

Hartenstein, H., H. Gutberlet, "Utility Experience with SCR in Germany", DOE Conference on SCR/SNCR, Pittsburgh, PA, USA 1999.

Chandler, J., J. Gallant, H. Hartenstein, A. Licata, "Retrofit of a WTE Facility with SCR for NOx and PCDD/F Control and Na_2S_4 Injection for Mercury Control", DOE Conference on SCR/SNCR, Pittsburgh, PA, USA 1999.

Schüttenhelm, W., R. Wemhöner, H. Hartenstein, K. Werner, " Reduction of PCDD/F Emissions From Iron Ore Sintering Plants – The First Full-Scale SCR Installation", 19th International Symposium on Halogenated Environmental Organic Pollutants and POPs – Dioxin 99, Venice, Italy 1999.

Gutberlet, H., H. Hartenstein, A. Licata, "SO_2 Conversion Rate of DeNOx Catalysts – Effects on Downstream Plant Components and Remedial Measures", The Mega Symposium – EPA-DOE-EPRI Combined Power Plant Air Pollution Control Symposium, Atlanta, GA, USA 1999.

Hartenstein, H.-U.; Schüttenhelm, W.; "Dioxin and Furan Reduction Technologies for Combustion and Industrial Thermal Process Facilities", Workshop on Polychlorinated Dibenzo-P-Dioxins and Polychlorinated Dibenzofurans, Pollution Control Department, Bangkok, Thailand 1999

Hartenstein, H. “UNEP’s Standardized Dioxin Release Inventory Kit – A Tool to Assist Countries in Establishing National PCDD/PCDF Release Inventories”, Sub-Regional Expert Meeting on the Reduction of Persistent Organic Pollutants (POPs) in Particular Dioxins and Furans, St. Petersburg, Russia 1999.

Hartenstein, H. “Techniques to Reduce Emissions of Dioxins And Furans From Large Sources”, Sub-Regional Expert Meeting on the Reduction of Persistent Organic Pollutants (POPs) in Particular Dioxins and Furans, St. Petersburg, Russia 1999.

Hartenstein, H., “Modern Technologies to Reduce Emissions of Dioxins and Furans from Waste Incineration”, International Symposium on Environmental Endocrine Disrupters ’99, Kobe, Japan 1999.

Fiedler, H., P. Dyke, H. Hartenstein, “Standardized Dioxin Inventory Toolkit” UNEP Chemicals, Geneva, Switzerland 2000.

Chandler, J, H. Hartenstein, “Controlling Heavy Metals and Persistent Organic Pollutants from Waste Incineration”, Internationales Symposium zur Abfallwirtschaft in Mitteleuropa, Prague, Czech Republic 2000.

Hartenstein, H., “Availability of Techniques to Reduce Non-Pesticide PTS”, STAP Brainstorming Meeting on Persistent Organic Pollutants (POPs), Bridgetown, Barbados 2000.

Hartenstein, H., “Guidance Document for the Collection, Assembly and Evaluation of Data on Sources, Environmental Levels and Impact Assessment” GEF: Regionally Based Assessment of Persistent Toxic Substances, UNEP Chemicals, Geneva, Switzerland 2000.

Hartenstein, H., “Techniques to Reduce PCDD/PCDF Emissions from Waste Incineration”, Invitational Expert PCDD/PCDF Workshop sponsored by UNEP Chemicals Switzerland, Gesellschaft für Technische Zusammenarbeit Germany and the Thai Pollution Control Department, Bangkok, Thailand 2000.

Licata, A., H. Hartenstein, “Modern Technologies to Reduce Emissions of Dioxins and Furans from Waste Incineration”, 8th Annual North American Waste To Energy Conference, Nashville, TN, USA 2000.

Hartenstein, H., “Introduction and Use of Techniques to Reduce Emissions of Dioxins and Furans – A Training Module to Complement UNEP’s Standardized Toolkit for Identification and Quantification of Dioxin and Furan Releases”, UNEP Chemicals, Geneva, Switzerland 2000.

Hartenstein, H. “Techniques to Reduce Emission of Dioxins and Furans”, UNEP Workshop on PCBs, Dioxins and Furans, Montevideo, Uruguay 2000.

Fiedler, H., P. Dyke, H. Hartenstein, “Standardized Toolkit to Establish Dioxin Inventories”, UNEP Workshop on PCBs, Dioxins and Furans, Montevideo, Uruguay 2000.

Fiedler, H., P. Dyke, H. Hartenstein, “Needs and Ways to Establish Complete and Comparable Dioxin Inventories”, 20th International Symposium on Halogenated Environmental Organic Pollutants and POPs – Dioxin 2000, Seoul, Korea 2000.

Schluttig, A., P. Servatius, H. Hartenstein, “Lifetime Extension of SCR-DeNOx Catalysts Using SCR-Tech’s High Efficiency Ultrasonic Regeneration Process”, DOE Conference on SCR/SNCR, Pittsburgh, Pa, USA 2001.

Hartenstein, H., “Final Result Evaluation Report – Thailand Dioxin Sampling Program November 20, 2000 – January 26, 2001”, Gesellschaft für Technische Zusammenarbeit, Bonn, Germany 2001.

Hartenstein, H., A. Schluttig, P. Servatius, “Lifetime Extension of SCR-DeNOx Catalysts Using SCR-Tech’s High Efficiency Ultrasonic Regeneration Process”, Coal-Gen, Chicago, Il, USA 2001.

Hartenstein, H., A. Schluttig, P. Servatius, H. Gutberlet, “Experience with Full Scale Commercial Regeneration of SCR-DeNO$_x$ Catalyst” The Mega Symposium – EPA-DOE-EPRI Combined Power Plant Air Pollution Control Symposium, Chicago, IL, USA 2001.

Hartenstein, H., H. Gutberlet, “Catalyst Regeneration – An Integral Part of Proper Catalyst Management”, The 2001 EPRI Workshop on Selective Catalytic Reduction, Baltimore, MD, USA 2001.

Hartenstein, H., “SCR Experience in Europe – Lessons Learned After 17 Years of SCR Operation”, Invitational SCR Workshop by Babcock & Wilcox, Akron, OH, USA 2002.

Bullock, D., H. Hartenstein, “O&M Cost Reduction of a Coal-Fired US Merchant Plant Through an Optimized SCR Management Strategy Involving Catalyst Regeneration”, DOE Conference on SCR/SNCR, Pittsburgh, PA, USA 2002.

Fiedler, H., P. Chareonsong, J. Mayer, H. Hartenstein, “PCDD/PCDF Emissions From Stationary Sources – First Results From Thailand”, 22nd International Symposium on Halogenated Organic & Persistent Organic Pollutants - Dioxin 2002, Barcelona, Spain 2002.

Harrison, K., E. Healy, H. Hartenstein, “Southern Company's Investigation of Catalyst Cleaning and Regeneration Options”, The 2002 EPRI Workshop on Selective Catalytic Reduction, Atlanta, GA, USA 2002.

Craig, M., H. Harrison, E. Healy, H. Hartenstein, "Catalyst Pluggage Due to Popcorn Ash – Cleaning and Regeneration Options", The Mega Symposium – EPA-DOE-EPRI Combined Power Plant Air Pollution Control Symposium, Washington, D.C., USA 2003.

Bullock, D., H. Hartenstein, "O&M Cost Reduction of a Coal-Fired US Merchant Plant Through an Optimized SCR Management Strategy Involving Catalyst Regeneration – Strategy Update Summer 2003", The Stack Emissions Symposium, Clearwater Beach, FL, USA 2003.

Bullock, D, H. Hartenstein, "Full-Scale Catalyst Regeneration Experience At The Coal-Fired Indiantown Generating Plant", DOE Conference on SCR/SNCR, Pittsburgh, PA, USA 2003.

Hartenstein, H., "Dioxin and Furan Reduction Technologies for Combustion and Industrial Thermal Process Facilities", Handbook of Environmental Chemistry- Volume 3 Anthropogenic Compounds Part O – Persistent Organic Pollutants, Springer Verlag Berlin Heidelberg New York, ISBN 3-540-43728-2, Germany 2003.

Hartenstein, H. "Performance of Commonly Used Combustion Technologies on POPs Destruction", STAP/GEF Technical Workshop on Emerging Innovative Technologies for the Destruction and Decontamination of Obsolete POPs, Washington D.C., USA 2003.

Hartenstein, H., "Control Technologies for the W. H. Sammis Plant, Stratton, Ohio" Expert Report for the US Department of Justice, Civil Action No. C-2-99-1181, Washington D.C., USA 2003.

Hartenstein, H., "Catalyst Regeneration Experience", NOx Round Table 2004 Conference and Exhibit, Akron, OH, USA 2004.

Yurkanin, T, H. Hartenstein, "O&M Cost Savings Through SCR Management and Catalyst Regeneration for the Logan Generating Plant", Electric Power 2004 Conference and Exhibit, Baltimore, MA, USA 2004.

Hartenstein, H., "Air Pollution Control Technologies for the W. H. Sammis Plant, Stratton, Ohio developed in connection with United States v. Ohio Edison Company, et al." Expert Rebuttal Report for the US Department of Justice, Civil Action No. C-2-99-1181, Washington D.C., USA 2004.

Hartenstein, H., "Incineration Technologies", World Bank Workshop Series: Issues on Waste Disposal: Workshop 1 – Hazardous Wastes, Washington D.C., USA, 2004.

Wiese, S., D. Monnin, K. Sauvageau, H. Hartenstein, "O&M Cost Optimized SCR Operation and Management at AES' Somerset Station", The Mega Symposium – Combined Air Pollution Control Symposium, Washington D.C., USA 2004.

Harrison, K, E. Healy, M. Craig, T. Harbin, L. Mays, H. Hartenstein, "Simultaneous Reduction of the SO_2 Oxidation Rate During Catalyst Washing And Regeneration", 2004 EPRI SCR Workshop, Pittsburgh, PA, USA 2004.

Hartenstein, H., "Pet Coke - Effects of Wet and Dry Scrubbing", 2005 WPCA / Dominion Particulate - Scrubber Seminar, Richmond, VA, USA 2005.

Hartenstein, H., "LPA Screens - Utilities Need a Proven Solution", WPCA News, Issue 8 fall 2005, Chicago, IL, USA 2005

Sobolewski, H, H. Hartenstein, H. Rhein, "STEAG's Long Term SCR Catalyst Experience and Cost“, The 2005 EPRI Workshop on Selective Catalytic Reduction, Louisville, KY, USA 2005.

Hartenstein, H., "LPA Screens - A Proven Solution", 2006 NOx Round Table Conference and Expo, Charlotte, NC, USA 2006

Hartenstein, H., "SCR Management Ensures SCR Performance at Minimum Operating Cost", WPCA News, Issue 9 spring 2006, Chicago, IL, USA 2006

Sobolewski, H., H. Hartenstein, M. Martin, "STEAG's Long Term SCR Catalyst Experience and Cost“, DOE-NETL Conference on SCR/SNCR, Pittsburgh, PA, USA 2006

Martin, M., M. Harrell, J, Jancauskas, H. Hartenstein, H. Sobolewski, "Large Particel Ash (LPA) Screen Retrofits at Coal-Fired Units in Indiana and Ohio“, DOE-NETL Conference on SCR/SNCR, Pittsburgh, PA, USA 2006

Hartenstein, H., "SCR Operating and Management Experience Including Catalyst Regeneration“, AES Operator's Meeting, Denver, CO, USA 2006

Hartenstein, H., "AIG Tuning – An Essential Part of SCR Management“, WPCA News, Issue 10 fall 2006, Chicago, IL, USA 2006

Rhein, H., S. Sobolewski, H. Hartenstein, M. Martin, "STEAG's Long-Term Catalyst Operating Experience and Cost", Power Plant Air Pollutant Control Mega Symposium, Baltimore, MD, USA 2006

Harrell, M., J. Jancauskas, H. Hartenstein, S. Sobolewski, M. Martin "LPA Screen Retrofits at Coal-Fired Units in Indiana and Ohio", Power Plant Air Pollutant Control Mega Symposium, Baltimore, MD, USA 2006

Rhein, H., H. Hartenstein, H. Brüggendick, "Cost Development of Single Absorber Open Spray Tower LSFO FGDs During the Last 20 Years – STEAG's Experience", Power Plant Air Pollutant Control Mega Symposium, Baltimore, MD, USA 2006.

Hartenstein, H., S. Wiese, M. Martin, “Regeneration – STEAG Process and Experience”, The 2006 EPRI Workshop on Selective Catalytic Reduction, Dearborn, MI, USA 2006

Martin, M. H. Hartenstein, “Bench Scale Testing of Catalyst – History and Protocol”, The 2006 EPRI Workshop on Selective Catalytic Reduction, Dearborn, MI, USA 2006

Hartenstein, H., “German Experience With Catalyst Regeneration”, 2007 NOx Round Table Conference and Expo, Cincinnati, OH, USA 2007

Hartenstein, H., “STEAG’s Catalyst Regeneration Process – Ten Years of Experience”, 2007 NOx Round Table Conference and Expo, Cincinnati, OH, USA 2007

Martin, M., H. Hartenstein, “Catalyst Bench Scale Testing: Guidelines and Round Robin Testing”, WPCA News, Issue 11 spring 2007, Chicago, IL, USA 2007

Elliot, P., Hartenstein, H., “Selective Separation of Mercury and Other Heavy Metals During FGD Wastewater Treatment””, 2007 APC Round Table Conference and Expo, Chattanooga, TN, USA 2007

Elliot, P., H. Hartenstein, “A Cost Effective FGD Wastewater Treatment System” WPCA News, Issue 12 fall 2007, Chicago, IL, USA 2007

Kramer, M., C. Gerlach, H. Hartenstein, “As_2O_3 and SO_3 Testing at Hoosier Energy’s Merom Generating Station”, The 2007 EPRI Workshop on Selective Catalytic Reduction, Pensacola, FL, USA 2007

Appendix D: Resume

Hans-Ulrich Hartenstein

Title:
Managing Director E&EC

Nationality:
German

Education:

University of Stuttgart	B. Sc. in Mechanical Engineering
University of Stuttgart	M.E. in Mechanical Engineering
University of Florida	M.E. in Environmental Engineering
University of Toronto	Global Executive MBA

General Experiences:

Mr. Hartenstein has been in the environmental field for over twenty years. His experience includes project development, project management and supervision, coordination and implementation of design and building projects for municipal waste-to-energy, hazardous waste incineration, and air pollution control facilities (SCR, FGD, Hg control, PCDD/PCDF control) in the power utility industry and waste-to-energy industry.

His responsibilities included project development, process engineering and management, procurement and construction supervision, start-up and commissioning, environmental and financial analysis, permitting application procedures and regulatory interfacing.

Mr. Hartenstein has been project management director of numerous air pollution control systems, one municipal waste-to-energy project, and four hazardous waste incineration projects. He has been involved in the development of eighteen environmental projects out of which seven also included permitting procedures and process design, two also included construction and one included complete start-up and commissioning.

Mr. Hartenstein has also directed development of waste management and air pollution control segments and managed a $ 61 million turnkey contract for 80 TPD hazardous waste incineration contract including a tail-end SCR. After completion of the facility Mr. Hartenstein was responsible for the initial 2 years of operation of the plant. He was also responsible for the successful negotiations of eight turn key mass burn, waste-to-energy contracts valued in excess of $ 600 million and he has successfully negotiated several international air pollution control technology licenses (SCR and FGD) among Polish, Korean, American and Japanese companies.

He has managed and supervised feasibility analysis, conceptual engineering and design, permitting final design, technology development, and project implementation and has assisted in project financial planning including assuring financing for several projects.

Since 1999 Mr. Hartenstein has been active mainly in the U.S. in the areas of SCR and FGD retrofits to fossil fuel fired electric utility generating stations. He expanded his initial focus on the design and construction of these SCR and FGD retrofits quickly into the areas of long term operation and maintenance of air pollution control equipment. His current focus is on most cost effective long term FGD and SCR management ensuring maximum performance at the lowest possible cost.

Positions Held:

• Environmental Engineer L&C Steinmüller GmbH[1]	1987 – 1989
• Senior Environmental Engineer L&C Steinmüller GmbH[1]	1989 – 1990
• Engineering Department Manager L&C Steinmüller GmbH[1]	1990 – 1992
• Senior Engineering Director L&C Steinmüller GmbH[1]	1992 – 1995
• Project Management Director L&C Steinmüller GmbH[1]	1995 – 1997
• Plant Manager RVA Böhlen RVA Böhlen GmbH	1997 – 1999
• Senior Vice President Babcock Borsig Power, Inc.[2]	2000 – 2001
• President SCR-Tech LLC	2001 – 2005
• President Evonik Energy Services LLC[3]	2006 - present
• Managing Director E&EC GmbH	1999 – present

[1] L&C Steinmüller GmbH has been acquired and renamed to Fisia Babcock GmbH

[2] Babcock Borsig Power, Inc. has been acquired and renamed Babcok Power, Inc.

[3] Steag LLC was renamed Evonik Energy Services LLC, no change in ownership

Professional Memberships

- Member of the World Pollution Control Association (WPCA)
- Invitational member of the Scientific Technical Advisory Panel (STAP) of the United Nations Environment Programme related to POPs and PTS.

Comments and Responses to NDDH Regarding U.S. EPA Region 8's July 31, 2008 Comments and Plains Justice July 30, 2008 Comments on NDDH Preliminary NOx BACT Determination for Milton R. Young Station (MRYS)

September 22, 2008

Burns & McDonnell (B&McD), and their SCR consultant, Tackticks LLC, along with the Energy & Environmental Research Center (EERC) of the University of North Dakota, have reviewed the EPA's comments (U.S. EPA, 2008), those of the Department of Justice's commenter, Hans Hartenstein (Hartenstein, 2008), and Plains Justice (Plains Justice, 2008). These are responses regarding selective catalytic reduction (SCR) technology feasibility and non-SCR concerns pertaining to the NDDH's Preliminary NO_X BACT Determination for Nitrogen Oxides for Milton R. Young Station Units 1 and 2, dated June 2008 (NDDH, 2008). We continue to believe that the administrative record fully supports a finding by the North Dakota Department of Health ("NDDH") that separated over-fire air (SOFA) in conjunction with selective non-catalytic reduction (SNCR) technology is Best Available Control Technology for electric generating units that utilize cyclone burners firing North Dakota lignite. The following sections address specific topics mentioned in the EPA's comments and other issues in greater detail.

- General Regulatory Considerations
- Corrections, Clarification and Omissions of Hartenstein and EPA's comments
- SCR Technology Review and Update
- Variability of Lignite
- Results of Coyote Pilot Testing
- Soluble Sodium
- Differences in Flue Gas Composition
- Catalyst Poisoning, Blinding, and Plugging
- Applicability of SCR Development for Texas Lignite
- SCR Catalyst Erosion
- Pilot Testing for SCR Catalyst

- Vendor Guarantees for TESCR
- Temperature Variations for HDSCR
- Burns & McDonnell's SCR Experience
- Comments by Sargent and Lundy on SCR Experience
- Comments on Hans Hartenstein's Qualifications for SCR Expert Opinions
- Fuel Switching
- Non-SCR Controls
- Conclusions

General Regulatory Considerations

In determining BACT, the limits placed on MRYS will be required for the plant's lifetime. In order for the units to run, emission rates will need to be met. Any emissions limit exceedance can result in a violation subject to significant financial penalties, injunctive relief and possible unforeseen equipment changes or plant outages. Many of the boilers referenced in EPA's report are not subject to New Source Review but some other form of regulation such as the NOx State Implementation Plan (SIP) Call program. There is a significant difference in NOx SIP and NSR. The NOx SIP Call is a seasonal (May to October) cap and trade program. Under this program, a utility's NOx emissions are capped to a level below historic emissions. The utility has the option to apply pollution controls and/or buy offsets from other utilities. Under the NOx SIP program, a problem with the pollution control equipment can be overcome by buying allowances while continuing to operate their units. NSR requires the controls be operating continuously and properly during plant operation.

1. EPA is deviating from a case-by-case BACT analysis by casting a wide net over SCR and insisting that it will work on all fuels and boiler types. Based on their comments, and those of DOJ's expert, in essence, "any problem can be overcome, SCR has been used successfully everywhere and no long term problems exist". However, as detailed later, our experts have found many instances where SCR was not used as a reduction strategy, or was unsuccessful.

In Minnkota's case, the combustion process from cyclone boilers and the North Dakota lignite makes application of SCR infeasible. Our specific combustion issue revolves around the size and type of combustion products produced in a cyclone-fired boiler when firing a high-sodium-containing lignite. The cyclone combustion process occurs at higher temperatures and different air distributions than other boiler types. Cyclone firing combustion products are partitioned between the slag that flows out of the bottom of the furnace and the flue gas containing impurities. The flue gas impurities are enriched in alkali (sodium and potassium) species relative to other boiler types. These species are known to blind and poison the SCR catalyst. The impurities of concern are vaporized during the cyclone combustion process to form a gas and upon gas cooling these gas phase impurities will condense to form aerosols or small particles that will deposit on the surface and in the pores of SCR catalysts. Once deposited, these alkali-rich materials will react with other gas phase species and deposited particles causing blinding or can react with active sites in the catalyst causing poisoning. This is well documented by Tackticks (see Appendix A) as well as by the DOJ's expert (Hartenstein). In a TESCR system, the flue gas passes through a precipitator and scrubber prior to reaching the SCR system. Large particles can be removed from the precipitator and scrubber. However, the removal of aerosols and small particulate (less than 2 microns in diameter) is dependent on the aerosol and small particle size and composition. Sodium, potassium and alkali aerosols are not easily removed from the precipitator and scrubber and no vendors will guarantee removal rates. In a TESCR application for a high-sodium lignite fired cyclone, the TESCR catalyst is likely to be exposed to appreciable concentrations of sodium, potassium and alkali concentrations. The second part of this case-by-case BACT evaluates the fuel used. North Dakota lignite is known to have a much higher levels of catalyst poisoning constituents than other lignite types. The lethal combination of the high temperature cyclone firing combustion process and high levels of catalyst poisoning constituents present in the lignite make this specific application technically infeasible.

2. Some catalyst vendors have "guaranteed catalyst operation" for the Minnkota units, according to DOJ's expert. EPA has taken a "guarantee" as a demonstration that the SCR application for North Dakota lignite is commercial. From the discussion above, EPA would lead us to

believe that the high sodium levels and the cyclone combustion processes resulting in an abundance of SCR blinding and poisoning alkali species in the flue gas are inconsequential since a vendor will provide equipment to Minnkota. However, Minnkota has to evaluate a guarantee on the long term viability of meeting an emissions limit, including catalyst maintenance and replacement requirements, and therefore we must question the vendor on numerous issues.

- **Does the vendor look at the long term compliance obligations that Minnkota will be subject to?** The vendor guarantees and contractual language will vary from project to project. For example, a vendor could guarantee a one time performance of their product and meet their obligation. However, the end user is stuck with a product that does not provide long term compliance. Some vendor language may guarantee a product for a longer period but assumes that certain operational conditions are met during that time period. If the operating conditions deviate, the vendor is no longer responsible. It is not unusual for vendors to guarantee performance then have to settle claims or change offer. Yet, Minnkota will still need to meet emission limits for the plant's lifetime.

- **The only test data (Coyote) for a cyclone boiler burning North Dakota lignite resulted in significant catalyst blinding and plugging in a short time period. How does a vendor resolve this issue?** Burns & McDonnell and EERC contacted Haldor Topsoe (HT) about this issue (B&McD and EERC, 2007). HT participated in the Coyote test that showed catalyst blinding and plugging was so severe that they could not make catalyst reactivity measurements. HT suggested that they would increase the pitch of the catalyst but had no solution for severe blinding and plugging of the catalyst pore structure. HT indicated that there were no catalyst designs available that would alleviate the severe blinding and plugging of the pore structure due to the high levels of sodium-rich aerosols present in flue derived from the cyclone-fired combustion of ND lignite.

3. EPA has claimed the Coyote pilot-scale SCR test to be completely invalid and no conclusions can be made. The Coyote test was developed by a consortium of Cormetech (catalyst vendor), Haldor Topsoe (catalyst vendor), Hitachi (SCR system provider), EPRI (research

agency), US. DOE, Alliant Energy, Otter Tail Power, Ameren, Dynegy, and Lignite Energy Council. This pilot test was intended to evaluate the fouling potential of SCR on lignite coal. DOJ's expert claims the test was fatally flawed, yet the participants in the test included vendors that design and install SCR systems as well as end-user utilities that have applied SCR on their boilers. This team was competent and, like many pilot tests, it is meant as a learning opportunity. Certainly, further testing may change some of the testing parameters, but the intent was to evaluate the system. Minnkota believes this testing was valid for its intended purpose and from this sole test, it was determined that there are significant impediments to using SCR on MRYS. The test results showed catalyst blinding and plugging due to sodium and potassium rich species. Peer reviewed literature written by many authors have verified that sodium and potassium species are fatal to the catalyst life.

Corrections, Clarifications and Omissions of Hartenstein and EPA Comments

The EPA's SCR technology comments (U.S. EPA. 2008) rely heavily on their interpretation of information mostly repeated from earlier comments to Minnkota and opinions expressed by the Department of Justice's (DOJ) commenter (Hartenstein, 2008), Many of these comments need to be clarified for the record.

1. Hartenstein implies that lignite-fired boilers are significantly represented among the 30,000 MW of SCR systems installed in Europe. This is misleading and substantially incorrect. Very few of the many SCRs retrofit in Europe were installed on lignite-fired utility boilers. Tackticks has advised that to the best of their knowledge, they are aware of SCR being originally installed at only two plants, and neither of these plants is operational today.

2. The EPA argues that NDDH's preliminary BACT Determination does not properly compare the emissions from other coal-fired boilers with high fuel sodium content to other boilers that successfully operate SCRs firing Powder River Basin (PRB) coal with high dust SCRs in the United States and are comparable to the Young Station boilers for their flyash alkali contents. The EPA ignored the Department's supporting detailed information by EERC that explains

why SCRs are not able to tolerate the higher levels of alkali species contained in flue gas such as exhausted from the MRYS boilers as compared to the PRB coal fired boilers..

3. In addition, the EPA and Hartenstein did not provide any substantial technical information that demonstrates that effective solutions to prevent or remove pore pluggage and blinding of SCR catalyst from sodium- and potassium-rich species present in the flue gas stream exhausted from a North Dakota lignite-fired cyclone boiler, whether installed in a conventional hot-side or cold-side application downstream of a wet scrubber, have been developed by catalyst vendors.

4. Hartenstein did not demonstrate he had an understanding of Center lignite characteristics and variability issues. Specifically, he did not understand how soluble sodium is used to define the abundance of organically associated sodium in lignite and how sodium will vary because of the abundance of other ash forming components in the coal. The abundance of sodium and other ash forming components vary dramatically and uniquely in North Dakota (Fort Union region) lignite coal and result in operational challenges. Hartenstein does not understand the differences between Fort Union lignite and Texas lignite. He indicates that the installations of SCR on Powder River Basin (PRB) subbituminous coal and testing on Texas lignite indicate feasibility for SCR on ND lignite even though the levels of sodium in typical PRB coal and Texas lignites are very low (0.7 to 1.5% Na_2O) as compared to 4.4 % Na_2O for Center lignite. The amount and form of alkali species in the coal along with combustion processes influence their ability to be enriched in the aerosol and fine particle fraction of the fly ash. The size and composition of the particle along with gas velocity determines their ability to penetrate and deposit on SCR catalyst passages and in pores and cause plugging, blinding, and poisoning.

5. Hartenstein did not address the issue of the partitioning of ash-forming species between the slag and fly ash components in cyclone-fired systems that result in an enrichment of sodium and other flame-volatilized species in the flue gas. These flame-volatilized species will condense homogeneously to produce abundant sodium and potassium-rich aerosols because

of the lower level of entrained solid ash particles in cyclone combustion-derived flue gases relative to pulverized coal combustion derived flue gas.

6. Hartenstein did not address the formation of aerosols and how that can impact SCR performance. The key issue for high sodium Fort Union (North Dakota lignite) coals fired in cyclone-fired boilers is the abundance of alkali-rich aerosols in the flue gas that can penetrate into the pores of SCR catalyst, causing blinding and poisoning. This is an issue for high dust and low dust / tail-end SCR applications. He appears to not be familiar with the diffusion mechanism of transport of aerosols deep into the SCR catalysts that can cause poisoning and plugging. Hartenstein appears to confuse the importance of catalyst pitch relative to pore plugging and blinding. He incorrectly suggests that catalyst pitch will solve the pore plugging and blinding problem. Using wider pitch catalyst does not eliminate the penetration of alkali-rich aerosols deep into SCR catalyst causing pore plugging and blinding problems. The impact of such aerosols that pass through the electrostatic precipitator (ESP) on the performance of low dust SCR applications was not discussed by Hartenstein. This fine ash that escapes from the ESP is finer than the bulk flyash and has a higher catalyst plugging potential due to a higher tendency to agglomerate. In addition, Hartenstein did not consider information provided on Powerspan barrier discharge reactor pilot slipstream testing that showed alkali rich accumulations downstream of the Unit 1 ESP at the MRY station.

7. Hartenstein's knowledge of gas-solid reaction mechanisms to form sulfate and pyrosulfate phase *in situ* in SCR catalysts appears to be very limited and was not adequately addressed.

8. Hartenstein did not discuss the recent literature on catalyst poisoning studies in Europe associated with cofiring high alkali (Na and K) containing biomass. This testing has showed significant poisoning of catalysts due to alkali aerosol penetration into catalysts and the subsequent reaction with catalyst active components causing poisoning.

9. Hartenstein did not offer information that more than 20,000 MW of lignite fired units in Germany were not required to install SCR in order to comply with the national regulation, or that even new lignite-fired units being installed today in Germany are not equipped with SCR

of any type. He did not state that Germany had only one cyclone-fired boiler operating with a LDSCR (Walsum Unit 7), or that the unit burns bituminous coal; nor did he advise that Voitsberg Unit 3, a boiler in Austria firing lignite coal, only ran for a short time with a high-dust SCR and was subsequently shutdown and demolished. He states that TESCR technology was "generally adopted as a universally applicable SCR solution for all types…" but failed to mention that there has never been another TESCR built after Siersdorf, (which was finished in early 1991 and has subsequently been decommissioned), in the United States or Europe. To the best of our knowledge, there is no TESCR anywhere in the world on a lignite-fired utility boiler. He cites "Ceram's extensive experience with lignite..", but fails to report that this consists of only one plant with Ceram catalyst having operated for a short period of time on lignite and a few pilot programs, so that it is dubious to say that this vendor has extensive experience on lignite fired boiler SCR plants (see Appendix A). There are numerous other instances of missing or factually incorrect information attributed to Mr. Hartenstein discussed in Appendix A.

10. Again, the EPA fails to recognize conclusively that ash chemical and physical properties of the Texas lignite (Wilcox formation) that TXU proposes to burn at the new Oak Grove powerplant where SCR is being installed (but has not yet begun operation) do not represent what is fired in North Dakota, and therefore technical feasibility and expected performance in a Texas lignite-fired pulverized coal boiler SCR application is not transferable to North Dakota lignite-fired cyclone burner units due to the significant differences in flue gas and ash chemical and physical properties. The composition of the Texas lignite fired at Martin Lake, where SCR mini-SCR pilot testing has been conducted, is typical of the composition of lignite fired at Sandow, with sodium oxide levels in the Texas lignite ash equal to 0.7%. The levels of sodium oxide in Center lignite average 4.4% and can be as high as 13% in as-fired samples. Hartenstein (2008) does not provide information on chemical composition of any fuels that are comparable to high sodium ND lignite where SCR installation have been installed and tested or successfully operated.

11. No examples were provided of on-line cleaning methods nor catalyst that would prove resistant to damage from such methods that would be effective in removing surface blinding and pore plugging deposits such as those seen in the Coyote pilot test catalyst even with the suggested edge erosion prevention measures in place. Hans Hartenstein does not address this issue in his comments. Hartenstein implies in his report (2008), that catalyst that has been poisoned by sodium compounds can be regenerated in-situ, and that this technique is well developed. There is extremely limited experience with in-situ catalyst cleaning on coal-fired units. It has never been used for blinded or chemically poisoned catalyst, but only for mechanically plugged catalyst (see Appendix A).

The following discussion will provide information on the following topics relevant to the EPA's comments: an SCR technology review and update; the variability of lignite; results of Coyote pilot testing; soluble sodium; differences in flue gas composition; catalyst poisoning, blinding and plugging; applicability of SCR development for Texas lignite; SCR catalyst erosion and cleaning; pilot testing for SCR catalyst; vendor guarantees for TESCR; temperature variations for HDSCR; Burns & McDonnell's SCR experience; comments by Sargent and Lundy on SCR experience; comments on Hans Hartenstein's qualifications for SCR expert opinions; fuel switching/blending/cleaning; non-SCR controls; and conclusions.

SCR Technology Review and Update

The literature provided by Hartenstein in his expert report (Hartenstein, 2008) did not provide any new information that would indicate the SCR technology is feasible for NO_x reduction at the MRY plant. Much of the information Hartenstein provided was reviewed earlier by the Energy & Environmental Research Center (EERC) and Burns and McDonnell. In addition, the reports provided by Hartenstein were not peer reviewed and were derived primarily from companies who have vested interests in the SCR technology and typically do not discuss problems and challenges. The reports from EPRI provided more useful information on the characteristics of the Texas lignite.

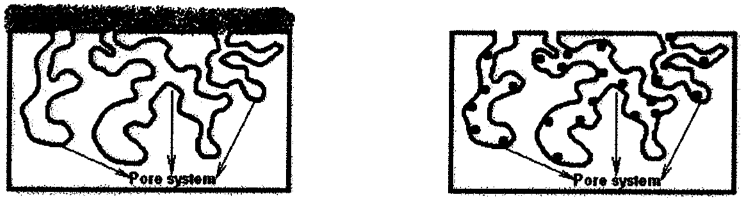
Hartenstein (2008) provided little information indicating that he is familiar with blinding and poisoning processes involving alkali (sodium and potassium). A demonstrated understanding of the blinding, plugging, and poison due to firing alkali-rich fuels is vital in determining the feasibility of SCR technologies. Much of this background information has been provided in EERC's previous comments (2007 and earlier). In addition, a significant amount of work has recently been conducted in Europe on blinding and poisoning of SCR catalysts associated with firing biomass alone and with coal. Much of the discussions are focused on the impact of alkali-rich aerosols on catalyst deactivation.

Since Hartenstein does not adequately address key mechanisms of catalyst deactivation and poisons, it is appropriate to provide a summary of the technical information. Guo (2006) who conducted testing of catalyst deactivation studies described the mechanisms of catalyst deactivation as shown in Figure 1. There are four primary types of catalyst deactivation.

- The first is channel plugging and is impacted by so called "popcorn ash" or in many cases typical of ash deposit fragments. Channel plugging is largely driven by the size of the ash materials carried back into the flue gas treatment system and can typically be controlled by the use of large particle ash screens to remove the ash, or by providing larger pitch catalyst.
- The second type is pore plugging by small fly ash particles. Small particles sometimes become lodged in the openings to the catalyst pore system and can cause plugging. These particles are typically not bonded and can be removed by various cleaning technologies.
- The third type is masking of the macrosurface by a dense phase. These phases that form are typically sulfates. The sulfates have formed as a result of in-situ sulfation of deposited alkali and alkaline earth materials.
- The fourth type is poisoning of the active sites in the catalyst. The active sites in SCR catalyst can be poisoned by the diffusion of various types of aerosols. The aerosols will diffuse into the pores and react with the active components of the catalyst.

Channel plugging: ash particles plug the monolith channel

Plugging: Microscopic blockage of catalyst pore system by small fly ash particles



Fouling/Masking: Macroscopic blockage of catalyst surface dense second-phase coating

Poisoning: Deactivation of catalyst active sites by chemical attack

Figure 1. General mechanisms of SCR catalyst deactivation (Guo, 2006).

High sodium lignites are prone to form abundant levels of aerosols when fired in a cyclone burner. Aerosols are formed as a result of the homogenous condensation of flame-volatilized species in combustion systems. During combustion of lignite, sodium, potassium, sulfur, and other components will vaporize and upon gas cooling these components will condense to form aerosols and other particles. As a result of these interactions, the resulting ash composition and mass distribution as a function of size is also shown in Figure 2. Typical ash derived from coal combustion has a bimodal to multimodal size distribution that consists of a submicron and supermicron size fraction as shown in Figure 3. The submicron component is largely a result of the condensation of flame-volatilized inorganic components. The intermediate size mode at about 2 micrometers is derived from the more refractory organically associated elements such as calcium and magnesium. The larger particles at approximately 12 to 15 μm are derived from the mineral grains present in the coal. The larger-size particles have been called the residual ash by some investigators (Sarofim and others, 1977) because these ash particles resemble, to a limited degree, the original minerals in the coal. Sodium and other flame-volatilized components are concentrated in the finer size fractions of ash as shown in Figure 4. This figure illustrates the increase in the sodium content in the finer size fractions of ash as a result of firing high sodium lignite. The sodium content of the 3rd stage (1–3 micrometer size cut) of the sampling train approached 20% Na_2O.

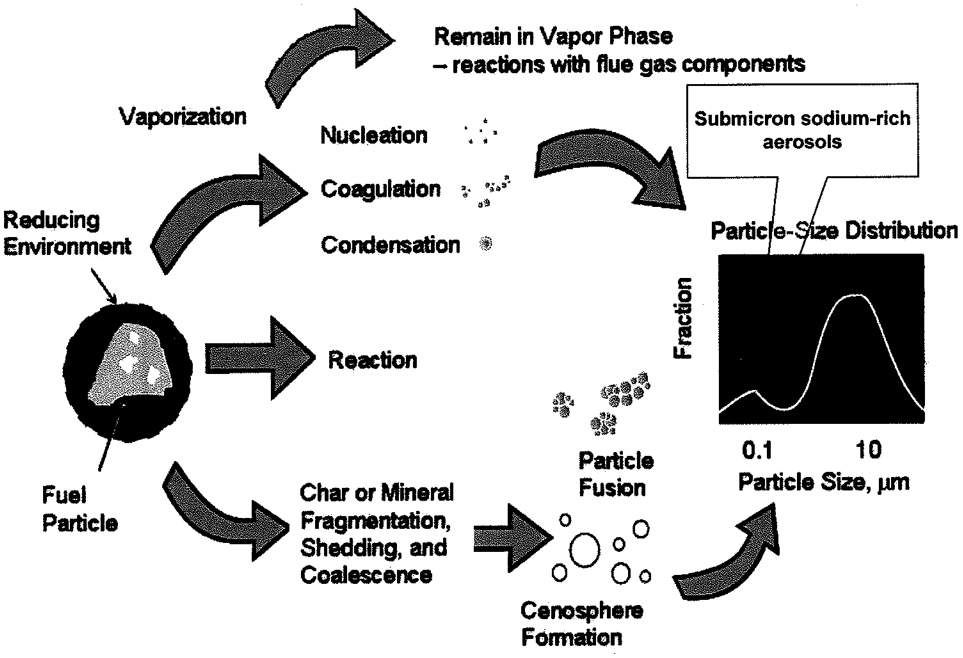


Figure 2. Transformation of inorganic components present in coal during combustion.

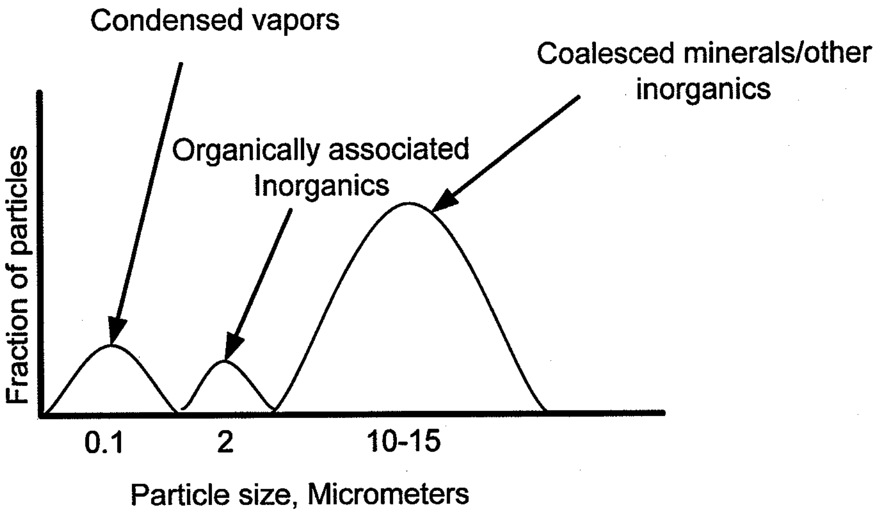


Figure 3. Final size distribution of ash particles produced upon combustion of lignitic coals (Benson and Laumb, 2007).

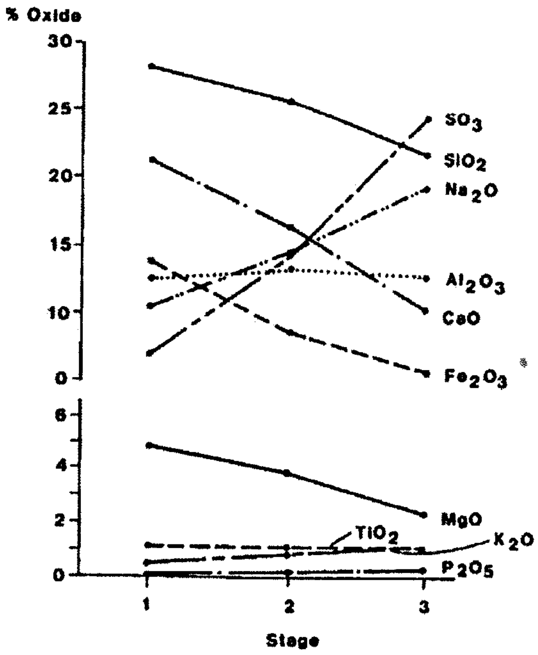


Figure 4. Composition distribution of ash particles during combustion of North Dakota Lignite (Benson and others, 1983).

The transport of intermediate ash species (i.e., inorganic vapors, liquids, and solids) is a function of the state and size of the ash species and system conditions such as gas flow patterns, gas velocity, and temperature. Several processes are involved in the transport of ash particles. These processes have been described by Raask (1985) and Rosner (1986). The primary transport mechanisms are illustrated in Figure 5. For larger particles inertial impaction and eddy impaction in turbulent regions are the dominant mechanisms. The aerosols (small particles <1 μm) and vapor-phase species are transported by the vapor phase and small particle diffusion. The inorganic materials are transported to heat-transfer and catalyst surfaces by diffusion, electrophoresis, and inertial impaction.

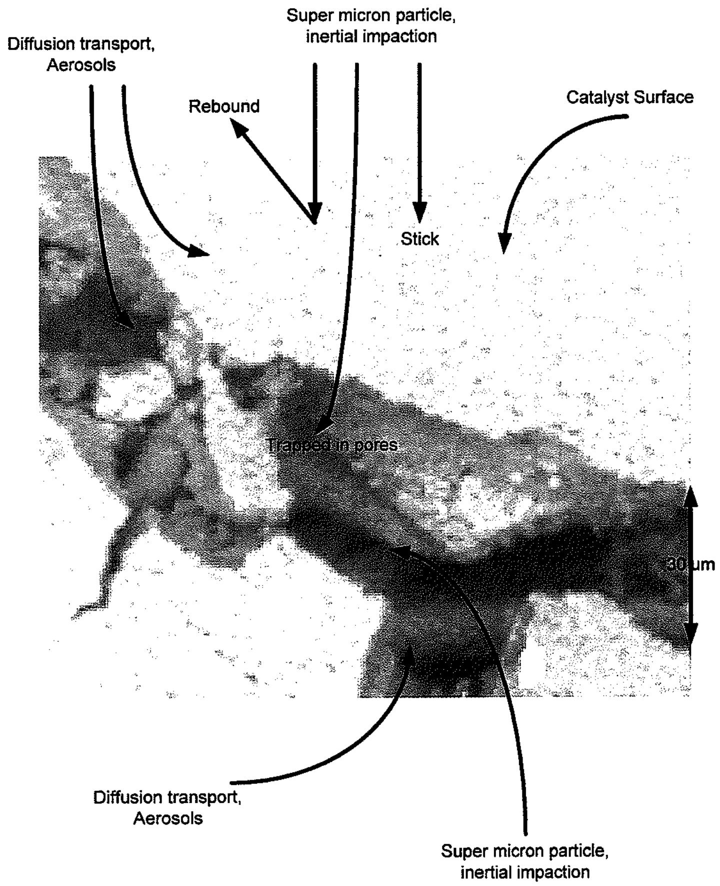
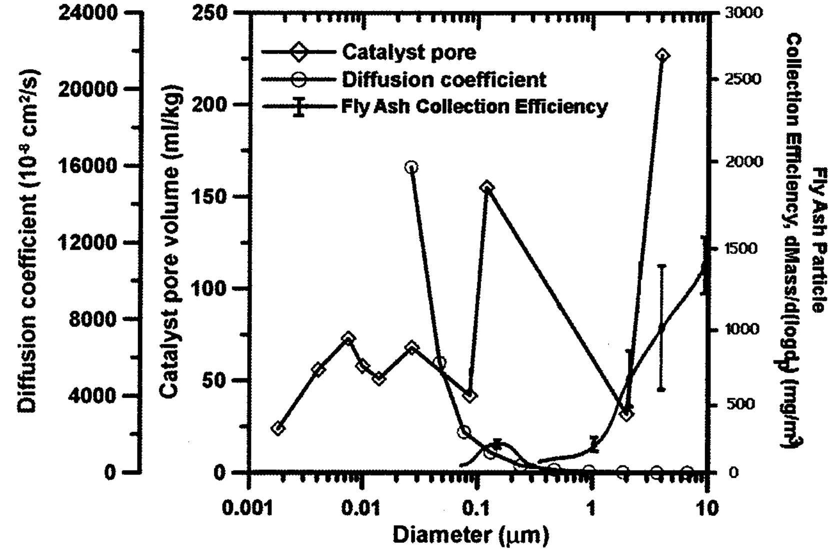
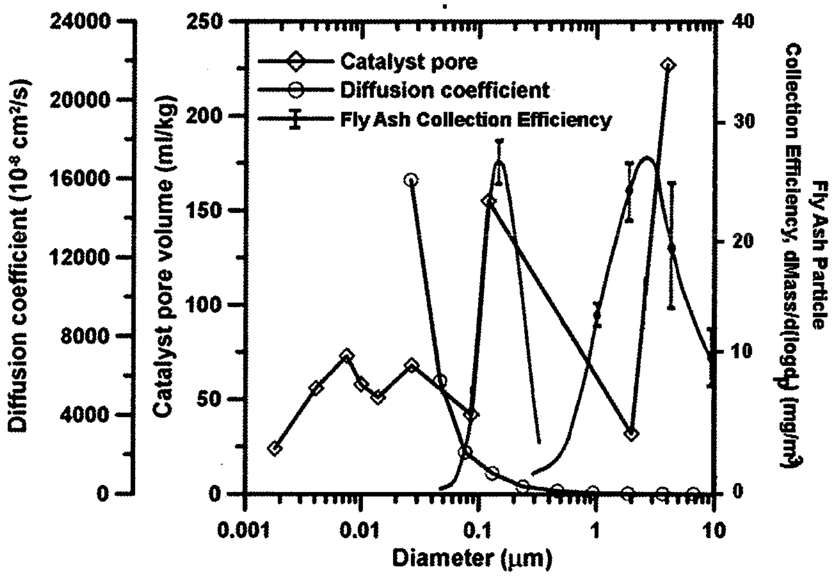


Figure 5. Scanning electron microscope secondary electron image of SCR surface structure before exposure to flue gases.

Recent work conducted by Zheng and others (2008) in a paper entitled “Deactivation of V_2O_5-WO_3-TiO_2 SCR catalyst at biomass fired power plant entitled “Elucidation of mechanisms by lab- and pilot-scale experiments” described the diffusion of aerosols and their ability to cause catalyst poisoning. Figure 6 shows a plot of the aerosol concentration as a function of size, catalyst pore size, and the diffusion coefficient with size. These result show that diffusion of the submicron aerosol is highly likely since potential for diffusion increases with the smaller size fraction of particles and that the mechanism will be active for particulate from upstream and downstream of the particulate control device such as an ESP. These efforts followed earlier studies where Zheng and others (2005) biomass-derived alkali rich aerosols caused a drop in NO_x reduction activity by 52% after about 1140 hours of operation.



a. Comparison to ESP inlet size distribution of fly ash.



b. Comparison to ESP outlet size distribution of fly ash

Figure 6. Comparison of the size distribution of the aerosol produced during combustion with the diffusion coefficient and catalyst pore size (Modified after Zheng and others (2008) with data from Linak and Wendt (1994)).

The association of alkali and alkaline earth elements in Center lignite is similar to the associations found in biomass. In both Center lignite and biomass materials the alkali and alkaline earth elements are largely organically associated. An analysis of a wood residue biomass material that is similar to lignite is shown in Table 1. The total alkali (Na_2O+K_2O)

calculated on a lb/mmBTU basis for the wood residue is 0.10. The total alkali for the average Center lignite was determined to be 0.84 lb/mmBTU. Compositions of various biomass types were compiled by Miles and others (1995) and they found the total alkali ranged from 0.06 to 1.15 lb/mmBTU. The overall chemical compositions for the biomass are listed in Tables 2 through 5 along with the water soluble alkali. Miles and others (1995) conducted chemical fractionation, a procedure that determines the abundance of alkali and other elements that is soluble (associated as soluble species and with the fuel organic fraction), on the biomass and found that the alkali were mainly organically associated.

Because of the organic association alkali species vaporize upon combustion and condense to form aerosols upon gas cooling. This vaporization of alkali during biomass combustion resulting in the formation of aerosols has been investigated by numerous researchers. One of the most recent paper is by Hindiyarti and others (2008).

Table 1. Example of a wood residue biomass composition.

	Wood Residue Biomass
Proximate Analysis, as received, wt%	
Moisture	7.30
Volatile Matter	76.82
Fixed Carbon	15.25
Ash	0.6
Ultimate Analysis, as received, wt%	
Hydrogen	6.1
Carbon	46.85
Nitrogen	0.1
Sulfur	0.1
Oxygen	46.05
Ash	0.63
Heating Value, Btu/lb	8274
Ash Composition, wt% equivalent oxide	
SiO_2	27.7
Al_2O_3	11.0
Fe_2O_3	10.0
TiO_2	0.5
P_2O_5	1.4
CaO	28.4
MgO	5.9
Na_2O	4.9
K_2O	7.6
SO_3	2.5

Lb alkali (Na_2O+K_2O)/mBtu 0.10

Table 2. Wood Fuel Blends: Alkali Deposit Investigation Samples (Miles and others 1995).

Fuel	Fuel Blend CFB-1		Fuel Blend FBC-1		Fuel Blend Grate-1		Fuel Bend CFB-3		Fuel Blend CFB-2		Fuel Blend Grate-1	
Type	Urban wood - Ag		Urban wood - Ag		Urban wood		Wood-Pit		Wood-Almond		Wood-20% Straw	
	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry
Proximate Analysis												
Fixed Carbon	12.36	19.79	13.02	16.93	12.69	15.23	11.55	18.10	12.32	15.94	15.45	16.67
Volatile Matter	47.40	75.89	62.02	80.57	66.02	79.23	48.95	76.77	59.77	77.28	69.65	75.14
Ash	2.70	4.32	1.93	2.50	4.62	5.54	3.27	5.13	5.25	6.78	7.59	8.19
Moisture	37.54	--	23.03	--	16.67	--	36.23	--	22.66	--	7.31	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ultimate Analysis												
Carbon	32.13	51.44	38.24	49.69	40.64	48.77	31.00	48.62	36.7	47.45	44.01	47.48
Hydrogen	3.54	5.67	4.51	5.87	4.8	5.76	3.68	5.78	4.28	5.53	5.38	5.81
Oxygen	23.81	38.13	32.01	41.57	32.99	39.59	25.36	39.76	30.6	39.57	35.28	38.05
Nitrogen	0.26	0.41	0.25	0.33	0.22	0.27	0.42	0.65	0.45	0.59	0.32	0.35
Sulfur	0.02	0.03	0.03	0.04	0.06	0.07	0.04	0.06	0.06	0.08	0.11	0.12
Ash	2.7	4.32	1.93	2.5	4.62	5.54	3.27	5.13	5.25	6.78	7.59	8.19
Moisture	37.54	--	23.03	--	16.67	--	36.23	--	22.66	--	7.31	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV, Btu/lb	5,506	8,815	6,449	8,379	6,967	8,361	5,388	8,450	5,281	6,829	7,492	8,083
Chlorine %	<0.01	0.01	0.04	0.05	0.05	0.06	0.02	0.03	0.02	0.03	0.12	0.13
Water Soluble Alkalis %	—											
Na_2O	0.008	0.013	0.034	0.044								
K_2O	0.097	0.155	0.132	0.172								
CaO		0.226										
Elemental Composition												
SiO_2		39.96		28.81		55.12		52.55		45.60		55.50
Al_2O_3		12.03		8.47		12.49		13.15		10.75		9.37
TiO_2		0.87		0.83		0.72		0.43		0.54		0.50
Fe_2O_3		7.43		3.28		4.51		8.18		4.06		4.77
CaO		19.23		27.99		13.53		10.06		18.96		11.04
MgO		4.30		4.49		2.93		3.27		4.22		2.55
Na_2O		1.53		3.18		3.19		5.90		3.08		2.98
K_2O		5.36		8.86		4.78		5.04		6.26		6.40
SO_3		1.74		2.00		1.92		2.10		2.06		1.80
P_2O_5		1.50		2.57		0.88		1.90		1.47		1.04
CO_2		6.05		6.07								
Undetermined				3.45		-0.07		-2.58		3.00		4.05
TOTAL		100.00		100.00		100.07		100.00		100.00		100.00
Alkali, Lb/MMBtu		0.34		0.36		0.53		0.66		0.93		0.95

Table 3. Wood Fuel Blends: Various (Miles and others 1995).

Fuel	Wood		Wood		Wood		Wood		Wood		Wood		Wood		Wood	
Type	Red Oak Sawdust		Fir Mill Waste		Furniture Waste		Hybrid Poplar		Alder/Fir Sawdust		Poplar-Coarse		Forest Residuals		Christmas Trees	
	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry
Proximate Analysis																
Fixed Carbon	11.92	13.47	6.47	17.48	11.77	13.39	11.63	12.49	9.14	19.31	11.44	12.26	6.96	13.62	12.93	20.80
Volatile Matter	76.35	86.22	30.38	82.11	72.98	83.00	78.97	84.81	36.27	76.56	80.33	86.14	42.10	82.41	46.02	73.99
Ash	0.28	0.31	0.15	0.41	3.18	3.61	2.51	2.70	1.96	4.13	1.49	1.60	2.03	3.97	3.24	5.21
Moisture	11.45	--	63.00	--	12.07	--	6.89	--	52.63	--	6.74	--	48.91	--	37.81	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ultimate Analysis																
Carbon	44.24	49.96	18.95	51.23	43.85	49.87	46.72	50.18	24.17	51.02	47.39	50.82	25.7	50.31	32.09	51.59
Hydrogen	5.24	5.92	2.21	5.98	5.2	5.91	5.64	6.06	2.75	5.8	5.49	5.89	2.35	4.59	3.47	5.58
Oxygen	38.76	43.77	15.66	42.29	35.42	40.29	37.66	40.44	18.25	38.54	38.32	41.08	20.42	39.99	22.82	36.70
Nitrogen	0.03	0.03	0.02	0.06	0.25	0.29	0.56	0.6	0.22	0.46	0.55	0.59	0.53	1.03	0.32	0.52
Sulfur	<0.01	0.01	0.01	0.03	0.03	0.03	0.02	0.02	0.02	0.05	0.02	0.02	0.06	0.11	0.25	0.40
Ash	0.28	0.31	0.15	0.41	3.18	3.61	2.51	2.7	1.96	4.13	1.49	1.6	2.03	3.97	3.24	5.21
Moisture	11.45	--	63.00	--	12.07	--	6.89	--	52.63		6.74	--	48.91	--	37.81	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV, Btu/lb	7,415	8,374	3,248	8,779	7,613	8,658	7,615	8,178	4,150	8,760	7,590	8,139	4,429	8,670	5,603	9,009
Chlorine %	<0.01	<0.01	0.07	0.19	<0.01	<0.01	0.01	0.01	<0.01	0.02	0.04	0.04	0.02	0.04		
Water Soluble Alkalis %																
Na_2O	<0.001	0.001	0.051	0.139					0.004	0.009						
K_2O	0.069	0.078	0.019	0.051					0.086	0.181						
CaO	0.017	0.019														
Elemental Composition																
SiO_2		20.97		15.17		57.62		5.90		35.36		0.88		17.78		38.89
Al_2O_3		2.99		3.96		12.23		0.84		11.54		0.31		3.55		14.74
TiO_2		0.27		0.27		0.50		0.30		0.92		0.16		0.50		0.36
Fe_2O_3		2.94		6.58		5.63		1.40		7.62		0.57		1.58		9.30
CaO		10.90		11.90		13.89		49.92		24.90		44.40		45.46		9.50
MgO		4.15		4.59		3.28		18.40		3.81		4.32		7.48		2.52
Na_2O		1.40		23.50		2.36		0.13		1.71		0.23		2.13		0.53
K_2O		22.40		7.00		3.77		9.64		5.75		20.08		8.52		7.86
SO_3		2.69		2.93		1.00		2.04		0.78		3.95		2.78		11.36
P^2O_5		1.33		2.87		0.50		1.34		1.90		0.15		7.44		2.40
CO_2/other		14.30		18.92				8.18		1.85		19.52				
Undetermined		15.66		2.31		-0.78		1.91		3.86		5.43		2.78		2.54
TOTAL		100.00		100.00		100.00		100.00		100.00		100.00		100.00		100.00
Alkali, Lb/MMBtu		0.09		0.14		0.26		0.32		0.35		0.40		0.49		0.49

Table 4. Urban Waste Fuels and Residues (Miles and others 1995).

Fuel	Wood		Wood		Wood		Waste Paper		Refuse Derived Fuel		Currency	
Type	Demolition		Land Clearing		Yard Waste		Mixed Waste Paper		Tacoma		Shredded	
	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry
Proximate Analysis												
Fixed Carbon	11.21	12.32	7.04	13.87	8.41	13.59	6.78	7.42	0.45	0.47	11.13	11.67
Volatile Matter	67.84	74.56	35.38	69.63	40.90	66.04	76.87	84.25	70.29	73.40	79.02	82.86
Ash	11.94	13.12	8.39	16.50	12.62	20.37	7.60	8.33	25.02	26.13	5.21	5.47
Moisture	9.01	--	49.19	--	38.07	--	8.75	--	4.24	--	4.64	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ultimate Analysis												
Carbon	42.13	46.3	21.5	42.32	25.72	41.54	43.79	47.99	38.02	39.70	40.90	42.89
Hydrogen	4.9	5.39	2.55	5.02	2.97	4.79	6.05	6.63	5.53	5.78	5.69	5.97
Oxygen	31.39	34.5	18.17	35.77	19.94	32.21	33.61	36.84	26.09	27.24	41.61	43.62
Nitrogen	0.52	0.57	0.17	0.33	0.53	0.85	0.13	0.14	0.77	0.80	1.67	1.75
Sulfur	0.11	0.12	0.03	0.06	0.15	0.24	0.07	0.07	0.33	0.35	0.28	0.30
Ash	11.94	13.12	8.39	16.5	12.62	20.37	7.6	8.33	25.02	26.13	5.21	5.47
Moisture	9.01	--	49.19	--	38.07	--	8.75	--	4.24	--	4.64	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV, Btu/lb	7,203	7,916	3,764	7,408	4,341	7,009	8,152	8,934	6,396	6,679	7,480	7,867
Chlorine %	0.05	0.05	0.01	0.02	0.19	0.3						
Water Soluble Alkalis %												
Na_2O			0.008	0.015							0.214	0.224
K_2O			0.095	0.187							0.123	0.129
CaO												
Elemental Composition												
SiO_2		45.91		65.77		59.65		28.10		33.81		2.99
Al_2O_3		15.55		14.84		3.06		52.56		12.71		11.92
TiO_2		2.09		0.55		0.32		4.29		1.66		24.30
Fe_2O_3		12.02		5.27		1.97		0.81		5.47		19.55
CaO		13.51		5.78		23.75		7.49		23.44		12.38
MgO		2.55		1.81		2.15		2.36		5.64		1.38
Na_2O		1.13		2.70		1.00		0.53		1.19		3.58
K_2O		2.14		2.19		2.96		0.16		0.20		1.94
SO_3		2.45		0.36		2.44		1.70		2.63		9.30
P_2O_5		0.94		0.66		1.97		0.20		0.67		0.78
CO_2/other				0.45								1.27
Undetermined		1.71		-0.38		0.73		1.80		12.58		10.61
TOTAL		100.00		100.00		100.00		100.00		100.00		100.00
Alkali, Lb/MMBtu		0.54		1.09		1.15		0.06		0.54		0.38

Table 5. Wood Fuel: Energy Crops (Miles and others 1995).

Fuel	Willow		Willow		Willow		Willow		Willow		Willow		Willow		Willow	
Type	SV1.3Yr		SV1.1Yr		SP3.1Yr		SH3-1Yr		SA22.1Yr		SA22.3Yr		SA22.Top		SA22-Butt	
	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry
Proximate Analysis																
Fixed Carbon	12.40	13.82	12.09	13.99	14.22	15.75	14.09	16.14	14.75	16.67	14.47	16.07	16.70	17.99	13.18	14.81
Volatile Matter	76.52	85.23	73.38	84.91	74.99	83.05	71.74	82.16	72.43	81.83	74.01	82.22	73.92	79.67	74.82	84.13
Ash	0.85	0.95	0.95	1.10	1.08	1.20	1.49	1.70	1.33	1.50	1.54	1.71	2.17	2.34	0.94	1.06
Moisture	10.23	--	13.58	--	9.71	--	12.68	--	11.49	--	9.98	--	7.21	--	11.06	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ultimate Analysis																
Carbon	44.07	49.09	41.43	47.94	45.41	50.29	42.65	48.85	44.03	49.75	44.92	49.9	45.86	49.42	43.53	48.95
Hydrogen	5.29	5.89	5.05	5.84	5.43	6.01	5.27	6.04	5.31	6.00	5.31	5.9	5.47	5.89	5.38	6.05
Oxygen	39.21	43.69	38.39	44.43	37.85	41.93	37.24	42.64	37.18	42.01	37.63	41.81	38.28	41.27	38.73	43.54
Nitrogen	0.32	0.35	0.55	0.63	0.45	0.5	0.62	0.71	0.58	0.65	0.55	0.61	0.89	0.96	0.32	0.36
Sulfur	0.03	0.03	0.05	0.06	0.07	0.07	0.05	0.06	0.08	0.09	0.07	0.07	0.12	0.12	0.04	0.04
Ash	0.85	0.95	0.95	1.1	1.08	1.2	1.49	1.70	1.33	1.50	1.54	1.71	2.17	2.34	0.94	1.06
Moisture	10.23	--	13.58	--	9.71	--	12.68	--	11.49	--	9.98	--	7.21	--	11.06	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV, Btu/lb	7,478	8,330	7,194	8,325	7,848	8,691	7,373	8,443	7,485	8,457	7,583	8,424	7,896	8,510	7,405	8,326
Chlorine %	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.01	<0.01	0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.01
Water Soluble Alkalis %																
$Na_2 0$	0.021	0.023	0.010	0.012	0.022	0.024	0.011	0.013	0.004	0.004	0.007	0.007	0.066	0.071	0.010	0.011
K_2O	0.113	0.126	0.147	0.012	0.245	0.271	0.243	0.278	0.270	0.305	0.242	0.269	0.466	0.503	0.145	0.163
CaO																
Elemental Composition																
SiO_2		8.08		16.76		2.83		1.11		1.89		2.35		2.05		1.82
Al_2O_3		1.39		3.01		0.12		0.09		0.16		1.41		1.97		1.48
TiO_2		0.06		0.07		0.06		0.00		0.04		0.05		0.03		0.05
Fe_2O_3		0.84		0.85		0.42		0.21		0.30		0.73		0.35		0.49
CaO		45.62		34.83		36.51		40.48		32.00		41.20		34.18		44.68
MgO		1.16		2.46		1.54		3.04		7.67		2.47		2.98		2.16
Na_2O		2.47		3.05		1.97		0.77		0.65		0.94		2.67		0.86
K_2O		13.20		12.20		19.9		13.90		22.10		15.00		18.4		15.30
SO_3		1.15		1.70		1.94		1.70		3.09		1.83		2.92		2.33
P_2O_5		10.04		10.36		12.9		8.16		11.68		7.40		7.1		7.18
CO_2/other		13.67		17.58		19.85		27.10		17.65		18.24		22.64		18.34
Undetermined		2.32		-2.87		1.96		3.44		2.77		8.38		4.71		5.31
TOTAL		100.00		100.00		100.00		100.00		100.00		100.00		100.00		100.00
Alkali, Lb/MMBtu		0.18		0.20		0.30		0.30		0.40		0.32		0.58		0.21

Hartenstein (2008) indicated that "sodium is not a poison at SCR operating temperatures." This statement is inconsistent with Hartenstein's past claims, where he makes the following statement (Hartenstein and Licata, 1996) "…elements such as sodium and potassium, are known to cause permanent irreversible disactivation of SCR catalysts." There is literature information indicating that sodium is a poison at SCR operating temperatures. The poisoning mechanisms of alkali and alkaline earth oxides on vanadia catalysts were investigated by Chen and others (1990). Their work found that the deactivation is directly related to the basicity of the poisons. The ranking of the strengths of the poisons are listed as follows: $Cs_2O > Rb_2O > K_2O > PbO > Na_2O > LiO > CaO > P_2O_5$. Figure 7 shows the activities of the catalyst with various elements added. The testing was conducted at 300°C. In addition, Guo (2006) conducted a study on the intrinsic SCR activity for NO with NH_3 reaction and found that the additions of K, Na, and Ca greatly decrease the NO reduction activity of 1% V_2O_5 – 9% WO_3/TiO_2 as illustrated in Figure 8.

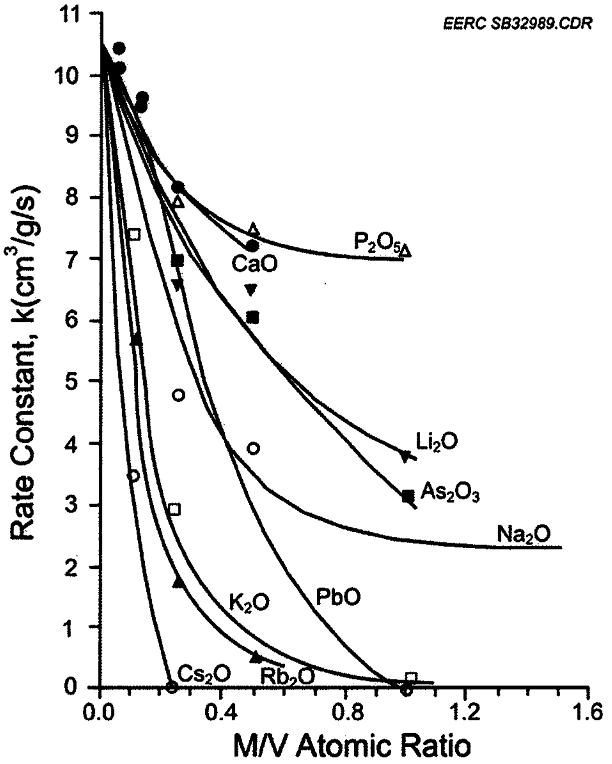


Figure 7. Rate constants for a V_2O_5/TiO_2 combined with different amount of oxide poisons (Chen and others, 1990).

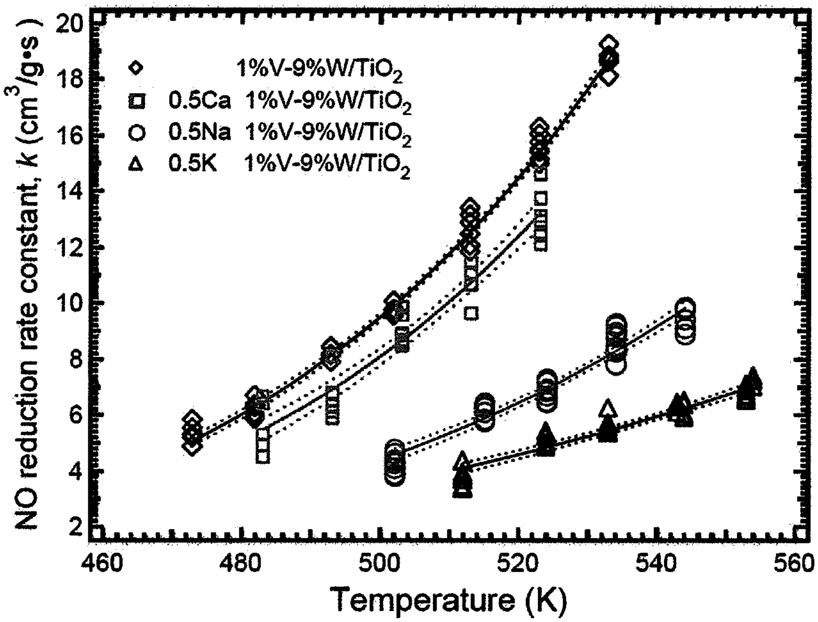


Figure 8. Impact of NO_x reduction rate constant as a result of poisoning by sodium, potassium, and calcium (Guo, 2006).

The mechanisms of catalyst deactivation due to alkali components are currently being investigated in depth. Several studies are being conducted in Europe because of poisoning of catalysts due to biomass firing and co-firing. The diffusion of alkali (Na and K) vapor has been ruled out as was correctly stated by Hartenstein (2008) because it will be in the condensed form at SCR temperatures. However, the presence of alkali aerosols does contribute to the deactivation of catalysts (Zheng and others 2008, Zheng and others 2005). The rates of deactivation in full-scale and laboratory studies were about 1% per day. They indicated that the in-situ formation of liquid potassium-vanadium-pyrosulfates could be one of the possible mechanisms. However, testing showed that the deactivation reactions also take place in the absence of SO_2 due to aerosol penetration into the catalyst.

The exact form of the alkali aerosol (hydroxide, sulfate, or other) that contributes to poisoning is not known. Zheng and others (2008) indicate the possible mechanism of deactivation occurs by the diffusion of aerosol particles rich in alkali into the catalyst pores followed by reaction with the V–OH groups producing –V–O–K (Na). These observations are consistent with the work conducted by Kling and others (2007) who investigated deactivation of SCR catalysts in three biomass and peat fired 100 MW-scale combustion systems. They found that the increased levels of sodium and potassium accumulated in the SCR catalyst was derived from the ultra fine particles (aerosols). These accumulations of aerosols resulted in decreased the NOx reduction catalytic activity as shown in Figure 9.

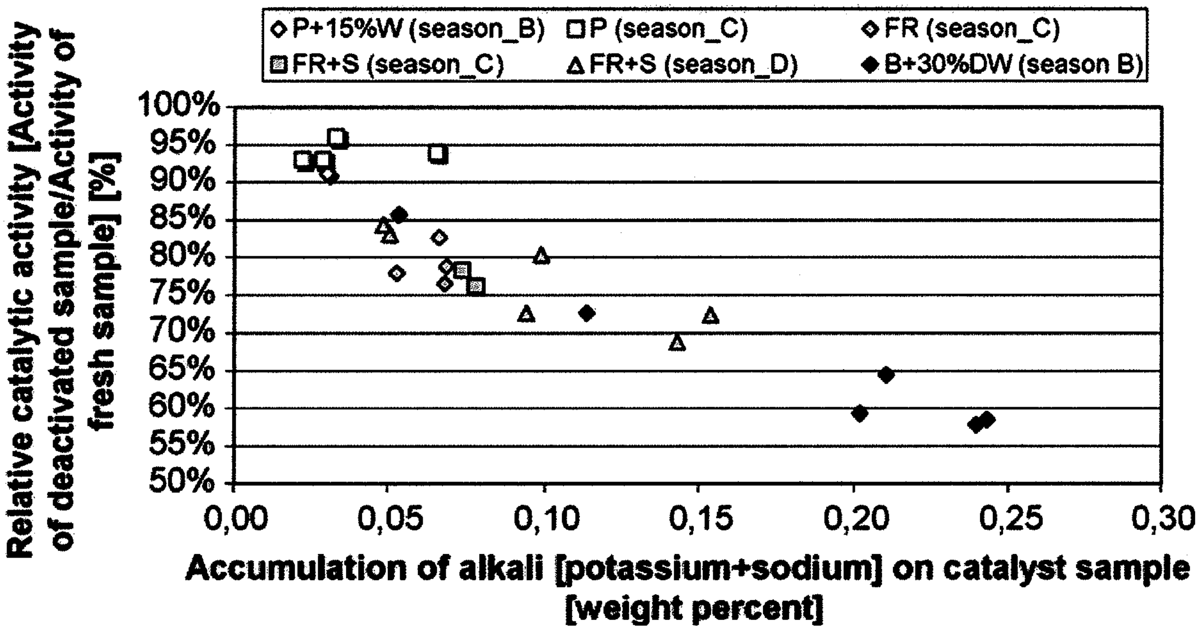


Figure 9. Reduction in catalytic activity as a function of accumulation of alkali in the catalyst (Kling and others (2007).

Recent testing conducted by Strege and others (2008) at a stoker-fired utility boiler firing a blend of biomass and Powder River Basin coal (PRB) found that the catalyst deactivation rate was about 18% per 1000 hours. The components responsible for the deactivation were sodium, potassium, and calcium sulfate-based materials. Alkali components (sodium and potassium) were found deep inside the catalyst.

Broske (2003) in an EPRI report indicated that for analysis of spent catalysts from medium sulfur bituminous (Appalachian) coal found that the concentration of sodium and potassium species accumulated to over 100 times the levels found in new catalysts. The levels reached in the catalyst were between 4000 and 6000 ppm. This is for an Appalachian coal that typically has low levels of sodium in the ash. In this particular catalyst, arsenic was found to be the primary contributor to poisoning but the alkali (sodium and potassium) also contributed.

The impact of aerosols on the performance of low dust SCR applications was not discussed by Hartenstein (2008). The impacts have been identified by Copolo and others (2003). They indicated in their paper that "The ash however, that escapes from the precipitators is finer than the ash in general ….. Although less likely to cause erosion, it does have a higher plugging potential as finer ash has been found to have a higher tendency to agglomerate." In addition, Hartenstein (2008) did not consider information provided on ash accumulations downstream of the ESP at the MRY station. Testing of Powerspan's barrier discharge reactor (Tolbert and Benson, 2008) was conducted to determine the potential application of the Powerspan technology for new power generation firing high sodium ND lignite. The barrier discharge reactor is placed downstream of particulate control systems to enable the oxidation of NO to NO_x species that will allow for capture in an ammonia-based scrubbing system. A slipstream barrier discharge reactor system was designed by Powerspan and the EERC and installed downstream of the ESP on Unit 1 at the MRY Station. The gas temperature was approximately 300°F.

The primary concern regarding the success of the Powerspan technology was that sodium-rich aerosols exiting the ESP would accumulate on the quartz rod resulting in decreased performance of the barrier discharge reactor. At two week intervals during the testing campaign, the reactor was inspected and rods were removed for analysis. The ash accumulation resulted in decreased nitrogen oxide (NO) oxidation due to accumulations of alkali and alkaline earth sulfate rich ash layer on the rods. An example of the ash accumulation on the rod after exposure to flue gases downstream of the ESP is illustrated in Figure 10. The exposed quartz rods were mounted in epoxy resin and cross-sectioned for scanning electron microscopy and x-ray microanalysis. The image in Figure 10 shows a highly bonded ash coating on the surface of the quartz rod. The red line represents the line analyzed across deposit and the quartz rod. The length of the line is 22μm. The abundance elements were determined along the red line shown in Figure 10. The levels of sodium and potassium in the bonded ash layer were greater than 10 percent.

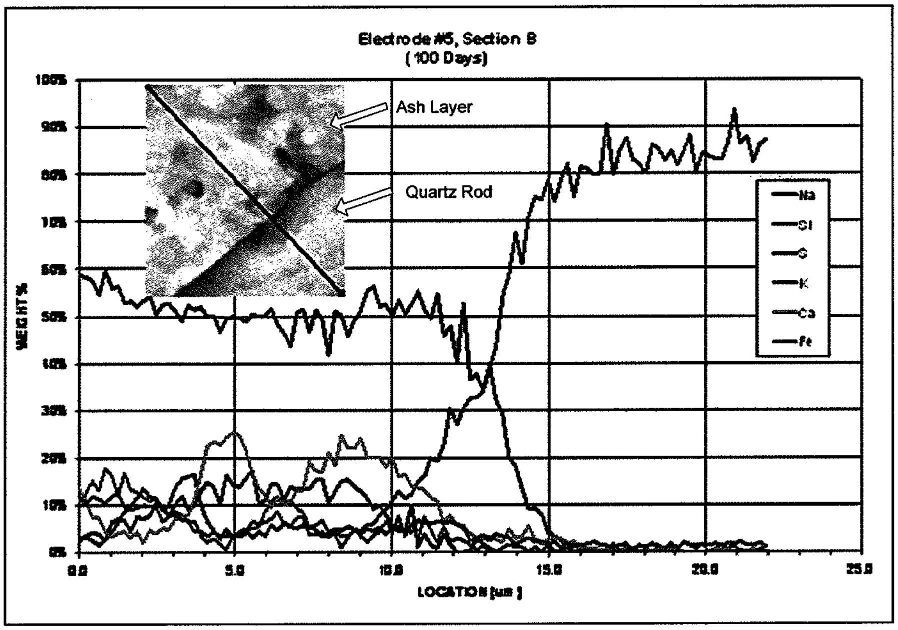
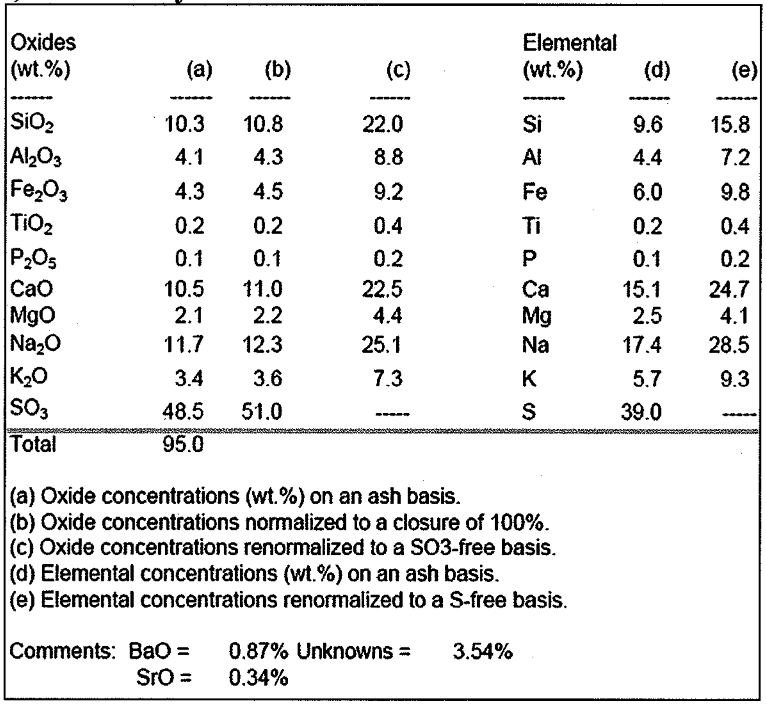


Figure 10. SEM image of quartz rod exposed to flue gas downstream of the ESP at MRY Unit 1 with element composition line scan across the deposit and quartz rod (Tolbert and Benson, 2008).

The bulk composition of ash scraped from selected quartz rods was determined by x-ray fluorescence (XRF). The rods sampled were from three electrodes that were exposed to flue gas downstream of the ESP for 20, 48, and 107 days. The bulk composition summarized in Table 6 shows significant levels of sodium, calcium, and potassium along with sulfur.

Table 6. Bulk composition of ash removed from electrode samples obtained from rod removed at 20, 48, and 107 days.



Oxides (wt.%)	(a)	(b)	(c)	Elemental (wt.%)	(d)	(e)
SiO_2	10.3	10.8	22.0	Si	9.6	15.8
Al_2O_3	4.1	4.3	8.8	Al	4.4	7.2
Fe_2O_3	4.3	4.5	9.2	Fe	6.0	9.8
TiO_2	0.2	0.2	0.4	Ti	0.2	0.4
P_2O_5	0.1	0.1	0.2	P	0.1	0.2
CaO	10.5	11.0	22.5	Ca	15.1	24.7
MgO	2.1	2.2	4.4	Mg	2.5	4.1
Na_2O	11.7	12.3	25.1	Na	17.4	28.5
K_2O	3.4	3.6	7.3	K	5.7	9.3
SO_3	48.5	51.0	-----	S	39.0	-----
Total	95.0					

(a) Oxide concentrations (wt.%) on an ash basis.
(b) Oxide concentrations normalized to a closure of 100%.
(c) Oxide concentrations renormalized to a SO3-free basis.
(d) Elemental concentrations (wt.%) on an ash basis.
(e) Elemental concentrations renormalized to a S-free basis.

Comments: BaO = 0.87% Unknowns = 3.54%
SrO = 0.34%

In the 1999 technical paper, Mr. Hartenstein (1999) and his co-authors reported SCR catalyst deactivation due to sodium at the RWE Staudinger plant in Germany. Specifically, it is reported on page 5 of the referenced paper that "...the fly ash from the German coal formed highly adhesive deposits, while the portion of South African coal contributed to the formation of a liquefied fly ash. The reason for this was determined by a chemical analysis of the fly ash. It can be seen that the content of the alkali sulfate, which adheres to the surface of the fly ash particles, favors the tendency to agglomerate. A phase analysis of the deposits revealed crystalline sodium aluminum sulfate and potassium aluminum sulfate ($NaAl(SO_4)_2$;$KAl(SO_4)_2$)."

This information supports the Department's opinion related to the formation of sodium–related deposits on the SCR catalyst that accelerate the deactivation of the catalysts. This information conflicts with Mr. Hartenstein's statement, on page A-28 of his expert report, that the "...the intrusion of liquid pyrosulfates is no major concern with respect to a severe, rapid catalyst deactivation."

Variability of Lignite

North Dakota lignite or lignite from the Fort Union Region of North America has very unique properties. The Fort Union lignite coals are unique because of the extraordinarily high levels of alkali and alkaline earth elements that are associated with the organic or combustible fraction of the coal. The constituents that are organically associated are considered ion exchangeable or soluble sodium. The association of the sodium in Fort Union lignites is similar to the association of sodium and potassium found in biomass. In addition, the coal contains mineral grains consisting of mixed clays, quartz, and sulfides that vary significantly in abundance. The form of the element influences their form in the flue gas. For example, organically associated sodium will vaporize during combustion and form an aerosol upon gas cooling, while mineral associated sodium (sodium in a clay) is less likely to vaporize and will be retained with the clay-derived particle. The sodium associated with the aerosol is much more reactive than sodium associated with a melted clay-derived particle.

The organically-associated elements are prone to vaporize during combustion. These organically associated elements will condense homogenously to form submicron sized aerosols or ultrafine particles. In addition, the organically associated elements will react with aluminosilicates producing low-viscosity (low melting point silicate-based liquids) phases and with sulfur-producing sulfates and pyrosulfate. These elements contribute to the formation of deposits on ceramic/refractory surfaces, cyclones, heat-transfer surfaces, SCR catalysts, and gas filters. Formation of these deposits will lead to operability problems, with the potential to shut down the system. Lignite composition is highly variable and, therefore, will contribute to a range of challenges. As a result of these challenges and efforts to identify problematic species, a significant database of selected North Dakota lignites, specifically Center lignite, has been developed to provide the basis for understanding the behavior of lignite and to project potential challenges. The variability of the Center mine lignite characteristics are summarized in Table 7.

Table 7. Center lignite composition (moisture, ash, sulfur, and heating value expressed on an as-received basis; and ash composition expressed as weight percent equivalent oxide of the ash produced at 750 °C).

	Moisture,%	Ash, %	Sulfur%	Btu/lb	Al_2O_3	BaO	CaO	Fe_2O_3	MgO	P_2O_5	K_2O	SiO_2	Na_2O	SO_3
Average	37.13	9.64	0.98	6578	11.68	0.52	13.15	8.90	3.99	0.12	1.33	36.04	4.40	18.39
Max	39.37	25.46*	2.55	7101	15.62	1.22	23.96	24.72	7.09	1.00	2.30	55.98	13.03	34.50
Min	33.56	4.97	0.47	5852	6.31	0.20	6.80	5.38	2.30	0.01	0.16	12.30	0.55	8.12
90th Perc.	38.10	12.51	1.29	6820	14.23	0.84	19.92	12.20	5.68	0.41	1.92	45.98	8.71	26.25
10th Perc.	35.95	7.06	0.72	6359	9.58	0.37	9.73	7.08	3.00	0.04	0.61	22.70	1.99	14.35
45th Perc.	37.17	9.33	0.90	6552	11.62	0.47	12.15	8.34	3.81	0.09	1.36	36.99	4.09	17.30
55th Perc.	37.37	9.75	0.94	6592	11.97	0.50	12.74	8.68	3.97	0.10	1.44	38.36	4.61	18.02

* *High value may be an analysis or reporting error. Sample could not be reanalyzed to verify.*

Hartenstein (2008) indicated that "I am not aware of a single case where high variability of heat and ash contents of the coals and/or of the constituents that make up the ash preclude the principles of the SCR technology from being technically feasible and applicable." Hartenstein did not indicate how he would identify a design coal for the catalyst design for high dust SCR based on the lignite characteristic. In addition, Hartenstein incorrectly assumes that over the range of fuel properties the performance of the particulate control systems will not be impacted, thus avoiding impact on a low-dust or tail-end SCR. In cases where there is high sodium and low ash contents, the abundance of aerosol particles increases dramatically. These particles can make their way through particulate control devices and can impact the performance of low dust and tail-end SCR as discussed previously.

Hartenstein (2008) does not provide information on chemical composition of the fuels that are comparable to high sodium lignite where SCR installation have been installed and tested or successfully operated. The composition of the Texas lignite fired at Martin Lake is typical of the composition of lignite fired at Sandow and is shown in Table 8. The sodium oxide levels in the Texas lignite ash is 0.7%. The levels of sodium oxide in Center lignite average 4.4% and can be as high as 13% in as-fired samples.

It is surprising that Hartenstein did not discuss his experience with German Ruhr Brown coal as described in a paper by Hartenstein and others (1999) where they found that "... the pressure drop across the catalyst layers rapidly increased...." when they fired German Ruhr coal alone. The problem was associated with the highly "adhesive" fly ash bonded with an alkali sulfate phase. They were unable to fire 100% lignite and had to rely on blending with a South African coal to reduce the problem. He also stated that "We have also learned that we had to analyze not only for sodium (Na) and potassium (K) content of the coal but also we need to know if the Na and K compounds are water-soluble. In a water soluble form, these alkaline metals are highly mobile and will migrate throughout the catalyst material reducing active sites."

Table 8. Average Texas Lignite Coal and Ash Composition (Ulvog and Wiemuth, 2003)

Proximate Analysis			Ash Analysis			Trace Constituents		
Moisture	% As Received	34.6	PO_5	%	0.2	Sb	mg/Kg	<0.5
Ash	% As Received	11.5	SiO_2	%	44.6	As	mg/Kg	<.05
Volatiles	% As Received	26.4	Fe_2O_3	%	8.5	B	mg/Kg	155.6
Fixed Carbon	% As Received	27.5	AL_2O_3	%	15.8	Cd	mg/Kg	<.05
Sulfur	% As Received	1.1	TiO_2	%	1.0	Cr	mg/Kg	11.2
BTU/Lb	% As Received	6928	Mn_2O_4	%	0.1	Cu	mg/Kg	15.3
			CaO	%	10.0	Pb	mg/Kg	<0.5
			MgO	%	2.5	Mn	mg/Kg	82.4
			K_2O	%	0.9	Hg	mg/Kg	0.0
			Na2O	%	0.7	Mo	mg/Kg	0.8
			SO_3	%	12.8	Se	mg/Kg	1.8
			SrO	%	0.1	Zn	mg/Kg	13.4
			BaO	%	0.6			
			Undetermined	%	2.2			

Results of the Coyote Pilot Testing

Hartenstein stated "The HDSCR Coyote pilot testing was ill-designed and fundamentally flawed." Hartenstein based this statement on his flawed interpretation of the Coyote testing. Hartenstein (2008) incorrectly interpreted the testing at Coyote Station as follows: "Admittedly, the Coyote Pilot Testing results seem to indicate worse pluggage than the Baldwin Pilot Testing results. However, it must be noted that the same pilot test reactor and the same catalyst, which had been already used (and plugged) at Baldwin was subsequently used at Coyote. The well known fact that catalyst that had been plugged and only mechanically cleaned is more likely to quickly plug again than new, unused catalyst was simply ignored."

Hartenstein (2008) described the reactor as being "ill-designed." The reactor system initial design was based on a design provided by Cormetech. The final design was reviewed and approved by the project team that included Cormetech, Haldor Topsoe, Hitachi, EPRI, US. DOE, Alliant Energy, Otter Tail Power, Ameren, Dynegy, and Lignite Energy Council. In addition, the selection of catalyst for the testing at Coyote was based on the recommendations of Haldor Topsoe. The testing protocols including the soot blowing media and frequency as well as all operating conditions were reviewed and approved by the aforementioned project team.

The following describes how the testing was conducted and is clearly described in Benson and others (2005).

1. The same reactor system used at Baldwin station was moved to the Coyote Station and installed.
2. The system was completely cleaned prior to operations at the Coyote Station.
3. Fresh catalyst was installed in reactor prior to testing at the Coyote Station.
4. At approximately two month intervals, the reactor was inspected and sections of the catalyst were removed for analysis, and fresh catalyst replaced the catalyst section that was removed.
5. The catalyst sections were analyzed for pore plugging and Haldor Topsoe was going to conduct activity measurements.
6. Haldor Topsoe indicated that the catalyst was too plugged to measure reactivity.

The slipstream reactors worked well at the Baldwin Station (cyclone PRB fired) and Columbia (pulverized coal tangential PRB fired) with minor to moderate fouling. The same reactor used at Baldwin was used at the Coyote Station. The pitch of the catalyst used at Coyote Station was 6mm as recommended by Hansen at Haldor Topsoe. A comparison of the first 500 hours with both systems using fresh catalysts is shown in Figures 11 and 12 for Baldwin and Coyote Station, respectively.

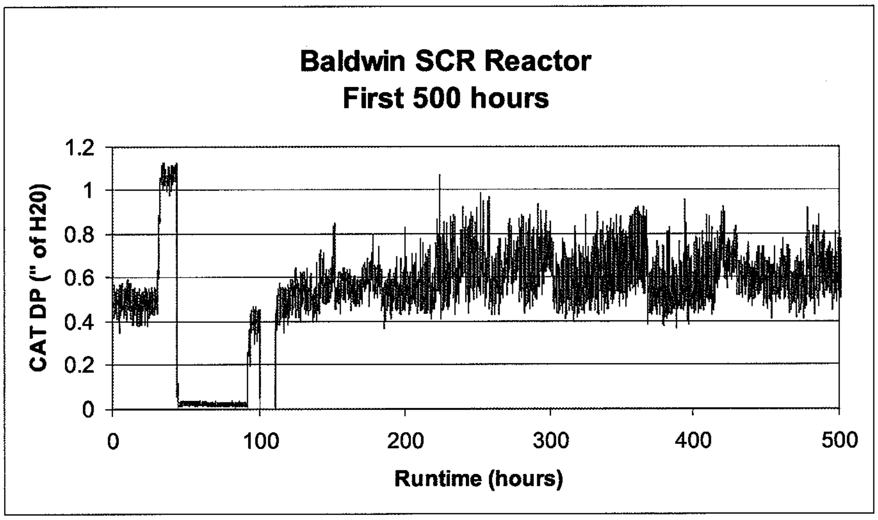


Figure 11. Pressure drop across SCR reactor during first 500 hours of testing at Baldwin

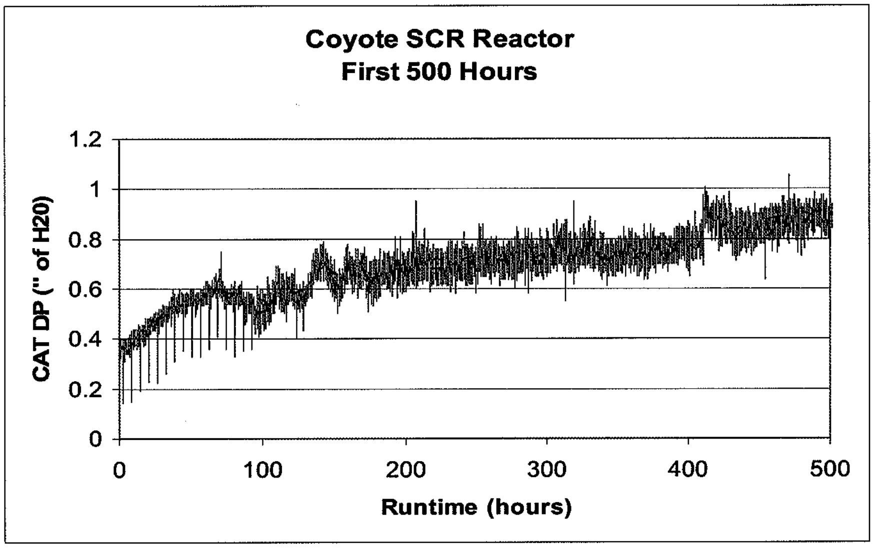


Figure 12. Pressure drop across SCR reactor during first 500 hours of testing at Coyote

Initially, at Baldwin there were some problems with start up and operation of the reactor because of plant outages. The pressure drop at the end of 500 hours averaged about 0.6 inches of water. The pressure drop for Coyote Station is shown in Figure 12, and at the end of 500 hours the pressure drop averaged about 0.85 inches of water. The plugging and blinding of the catalyst was severe.

Soluble Sodium

Soluble sodium is used to describe the form of sodium in the coal as well as forms of sodium in ash. The soluble form of sodium in coal is used to describe the abundance of sodium associated with the water soluble and organic fraction of the coal. During combustion the soluble sodium (organically associated) in the coal is much more likely to vaporize than an insoluble form. This is especially true for a cyclone-fired boiler. Upon gas cooling the alkali vapors will condense to form aerosols or sometimes called ultrafine particles. These ultrafine particles can diffuse into the pores of the catalyst and react with V-OH groups forming V-O-K(Na) rendering the site inactive (Zheng and others 2008). Hartenstein's following interpretation is inconsistent with the work by Zheng and others (2008) which is co-authored by one of the lead scientists from Haldor Topsoe.

> "Unfortunately, the Department fails to realize what was pointed out by one of the most experienced catalyst suppliers, namely that "sodium is not a poison to catalyst at SCR operating temperatures." Thus, the elaborate comparison of emission factors of sodium, potassium, calcium, and magnesium emission factors with the fly ash may have some academic value but is effectively meaningless for the correct prediction of catalyst deactivation, since particle bound sodium, potassium, calcium and magnesium in the fly ash are not mobile and therefore are not catalyst poisons."

The abundance of alkali aerosols in the flue gas as depicted by emission factor will have an impact on the rate of catalyst deactivation by the formation of aerosols that directly poison sites or produce pyrosulfates. The impact of the abundance of alkali (sodium and potassium) is clearly illustrated by the recent work conducted by (Kling and others (2007).

The formation of pyrosulfates as described earlier (EERC and Burns and McDonnell) is consistent with recent investigations of alkali poisoning of catalyst (Zheng and others 2008, Zheng and others 2005). They indicated that the in situ formation of liquid potassium-vanadium-pyrosulfates could be one of the possible mechanisms. Hartenstein (2008) states "Alternatively, these pyrosulfate compounds would have to be present in a liquid so that their dissociated ions (i.e. Na+, K+) would be mobile in order to enter the catalyst pores and react with the catalyst's active sites." He does not consider their in-situ formation as a result of the reaction of accumulated Na or K-rich aerosols with SO_3 and vanadium in the pores of the catalyst. Vanadium and iron compounds are know to catalyze the formation of pyrosulfates. Hartenstein (2008) also incorrectly states the range of melting points of the pyrosulfate phases (650 to 750°F). The melting points of selected pyrosulfates are listed in Table 9 and have a range of (535 to 1281°F).

Table 9. Melting Points of Selected Pyrosulfate Compounds

Compound	Temperature, °C	Temperature, °F
$K_3Fe(SO_4)_3$	618	1144
$K_3Al(SO_4)_3$	654	1209
$KFe(SO_4)_2$	694	1281
$Na_3Fe(SO_4)_3$	624	1155
$Na_3Al(SO_4)_3$	646	1195
$NaFe(SO_4)_2$	690	1274
$Na_2S_2O_7$	401	754
$K_2S_2O_7$	300	572
$(K_{1.5}Na_{0.5})S_2O_7$	279	535

Differences in Flue Gas Composition

The flue gas derived from the cyclone combustion of high sodium lignite contains an abundance of alkali-rich aerosols. This is well known and has been published by Benson and others (1983) as well as other investigators. The abundance of alkali rich aerosols is similar to that found in biomass combustion systems. Recently, work conducted by Zheng and other (2008) point out the importance of the aerosol particles and catalyst poisoning.

Hartenstein again makes the incorrect claim that "sodium is not a catalyst poison at SCR operating temperature" and dismisses the uniqueness of the flue gas derived from high sodium lignites. However, he provides no example of a coal fired in a boiler that produces a flue gas that is characteristic of flue gases produced from North Dakota lignite where SCR has been installed and successfully operated.

Catalyst Poisoning, Blinding and Plugging

The pores of the catalyst exposed to the alkali-rich flue gas derived from the cyclone-fired combustion of ND lignite at the Coyote pilot test were plugged. Penetration into the pores was extensive. Sulfation of the alkali components resulted in filling and plugging of the pores of the catalyst. Cyclone firing increases the abundance of alkali and other flame-volatilized species in the flue gas stream. The more refractory components end up in the slag. The alkali-rich flue gas stream is deficient in larger entrained ash particles derived from quartz and clay mineral in the flue gas stream. Upon gas cooling the alkali components will largely condense homogeneously to form alkali-rich aerosols because of the low abundance of larger ash particles for heterogeneous condensation. This results in a flue gas with higher alkali aerosol content than produced by pulverized coal fired systems.

The aerosols diffuse into the catalyst pores and are subsequently sulfated or interact with catalyst active sites resulting in plugging/blinding and deactivation, respectively. There does not appear to be a catalyst material that has shown significantly improvement over the past catalyst relative to the performance in high sodium containing system. The specific question was asked to Flemming Hansen of Haldor Topsoe (Hansen, 2007) as to whether improvements have been made in catalysts over the ones tested at Coyote Station that warrant further testing. He indicated that no formulation or design changes have been made to improve their performance in high sodium containing flue gases.

Applicability of SCR Development for Texas Lignite

EPA provided several comments regarding future application of high-dust SCR at TXU's Oak Grove facility as an example that it should not be eliminated as technically infeasible (at MRYS) on the basis of catalyst plugging and deactivation. The EPA mentioned catalyst vendors' beliefs, and an opinion by Electric Power Research Institute (EPRI) issued on September 7, 2006 and determinations by the Texas Commission on Environmental Quality. The EPA also states that "while the properties of North Dakota and Texas lignite might not be the same…" that the "same basic principle applies that the accelerated catalyst replacement requirements are a matter of economics and not technical feasibility" (U.S. EPA, 2008, Enclosure 2).

As responses to previous EPA opinions on this subject have been presented elsewhere (Minnkota, 2007A, 2007B, 2007C, 2008), the EPA fails to recognize conclusively that ash chemical and physical properties of Texas lignite (Wilcox formation) that TXU proposes to burn at the new Oak Grove powerplant do not represent what is fired in North Dakota, and its technical feasibility and expected performance in an SCR application is not transferable to North Dakota lignite-fired cyclone burner units due to the significant differences in flue gas and ash chemical and physical properties.

The EPA also fails to recognize and acknowledge that significant pilot testing has been conducted at several power plants in Texas that fire lignite supplied from various locations in Texas, and that there are no cyclone-fired boilers in Texas. The EPA has gone down the same path that tried to compare German SCR applications which lack significant cyclone boiler experience and is not currently required for lignite-fired boilers to be appropriate and comparable to North Dakota lignite-fired cyclone burner units. These are misleading statements and contrary to the presentation of the body of information submitted in support of the NDDH's preliminary BACT determination for MRYS.

SCR Catalyst Erosion and Cleaning

Various means of resolving catalyst erosion have been previously discussed in earlier comments and responses (Minnkota, 2007A and 2007B). While hardened leading catalyst surfaces may be resistant to erosion from entrained flyash, the more important issues to consider are effectiveness and damage from on-line catalyst cleaning methods. Hans Hartenstein (2008) does not address this issue in his comments.

Effective on-line cleaning of catalyst deposits seen in the Coyote pilot testing, especially with the micropores plugged with sodium-sulfur compounds, does not appear to be achievable.

No examples of on-line cleaning methods nor catalyst that would prove resistant to damage from such methods that would be effective in removing surface blinding and pore plugging deposits such as those seen in the Coyote pilot test catalyst even with the suggested edge erosion prevention measures in place have been identified. It is difficult to compare current experience with lower fouling coals with a hypothetical installation on a cyclone boiler firing North Dakota lignite, without having pilot or full-scale testing experience on the subject fuel to expected surface blinding and pore plugging deposits and cleaning operation conditions.

Hartenstein implies, on page A-36 of his report, that catalyst that has been poisoned by sodium compounds can be regenerated in-situ, and that this technique is well developed. ENBW in Germany developed this technique, but it has never had a commercial success. Regarding the contention of Hartenstein, there is extremely limited experience with in-situ catalyst cleaning on coal-fired units. It also has never been used for blinded or chemically poisoned catalyst, but only for mechanically plugged catalyst (see Appendix A).

Pilot Testing for SCR Catalyst

In many cases where SCR technology has been applied to fossil fuel-fired boilers located throughout the world burning a variety of coals and solid petroleum byproducts, extensive pilot testing programs have been performed prior to the implementation on full-scale utility boilers: Germany in the 1980's, the United States in the 1980's for low sulfur and high coals, and in Texas since year 2000 on Texas lignite. The application of SCR technology to coal-fired boiler in Germany has been almost exclusively on non-lignite fired units. Both in Germany and in the United States, it has been demonstrated that it is very difficult to solely rely on SCR catalyst suppliers' experience with similar coals and pulverized coal-fired boilers when developing SCR system designs and understanding process issues that are important to the successful deployment, operation, and maintenance of such emissions reduction technology in strict compliance with regulatory and subsequent permit requirements.

Many pilot test programs have been conducted to implement SCR technology when new and unknown process issues have been raised. There have been multiple pilot tests and research and development programs involving application of SCR technology to fossil fuel-fired utility boilers in Germany. Several are described in Appendix A by Burns & McDonnell's SCR technology consultant assisting in these responses, who participated in them.

These described pilot SCR test programs include a high dust SCR on a wet bottom boiler before the first high dust SCRs were built in Germany, and a TESCR application. The first tests determined that the catalyst deactivated rapidly, which contradicted what the catalyst suppliers believed, which was that such testing was unnecessary. The HDSCR pilot test revealed the fact that arsenic was unknown as a strong catalyst poison. Most of the German utilities decided not to retrofit wet bottom boilers that had fly ash recirculation with a HDSCR so that arsenic poisoning could be avoided (see Appendix A).

Utilities built tail-end SCRs in Germany that included a wet scrubber ahead of the reactor to avoid the arsenic poisoning problems with the catalyst. Again, pilot testing led to the discovery of a new catalyst poison (SiF_4) which caused the first catalyst layer to lose more than 50 % activity in less than 2,000 hours. This demonstrates that SCR catalysts can be severely deactivated even when boilers burn coals with a SCR configuration that were not expected to cause such problems (see Appendix A).

A recent pilot SCR test program in the Southeast United States involving eastern bituminous coal, Venezuelan coal and pet coke at a utility boiler was performed to account for the influences of the fuel on the NOx activity and SO2 oxidation rates of the catalyst. With limited worldwide experience on such a range of fuels, the Utility decided to conduct an extensive pilot program to assess impacts on the catalyst (see Appendix A). Following completion of the pilot testing, the catalyst vendors found it necessary to significantly modify and/or completely withdraw the guarantees they had offered prior to the testing.

Mr. Hartenstein and his co-authors support pilot programs for those SCR applications in which new and uncertain process considerations are encountered. In the referenced technical paper (Hartenstein, 1999), Mr. Hartenstein states: *"In principle, the reduction of NOx emissions with SCR catalysts is a mature technology, which was developed many years ago. Nevertheless, experience has shown that in many applications, special features were required that necessitate* *further optimization of the DeNOx system. In particular, standard solutions were often not possible or optimal when retrofitting existing power plants."*

In the case of Milton R Young, the uncertainty associated with the high sodium concentration and the presence of sodium aerosols in the flue gas raise serious concerns pertaining to catalyst performance. The potential application of any SCR technology at Milton R. Young suggested by the EPA and Mr. Hartenstein is not standard, and is very unique, due to the special considerations pertaining to the lignite, boiler operating temperatures, flue gas reheating, among others. Pilot testing is certainly warranted before any claims that this technology is feasible at M.R. Yong Station can be confirmed. The pilot testing must utilize new concepts and designs that alleviate the problems associated with alkali aerosols. These new concepts and designs do not appear to be currently available from the vendors.

We disagree with catalyst vendors and Mr. Hartenstein that pilot testing is not required for HDSCR, LDSCR, or TESCR prior to application to the boilers at MRYS. They have not cited any substantiated data that show successful SCR experience from coal-fired boilers with similar boiler- and fuel-specific conditions as present on North Dakota lignite-fired cyclone boilers that make this technology infeasible at Young station. The lack of evidence shown to prove that such factors have been solved such that any form of SCR technology would not require extensive pilot testing and design development for these applications is significant and important in supporting the NDDH's arguments against adopting SCR technology as BACT for MRYS boilers.

As we have stated previously, the application of emission reduction technology that requires such extensive pilot testing and design development should not be considered as available and technically feasible for the purposes of a BACT determination (U.S. EPA, 1990).

Vendor Guarantees for TESCR

Burns & McDonnell's consultant (Tackticks LLC) has significant experience in dealing with SCR system suppliers and catalyst vendors involving their initial willingness to offer guarantees and what they will actually agree to sign in the form of a contract. Mr. Hartenstein (2008) frequently states that various catalyst and SCR system vendors would be willing to offer performance guarantees for the Milton R. Young Station TESCR.

Examples of cases where SCR vendors have initially said they would guarantee performance without hesitation then subsequently changed their offer or settled a claim by the utility for failure to meet guarantees are described in Appendix A.

It is typical for vendors to do this in the absence of a detailed technical specification and contract with commercial conditions and liquidated damages. Actual performance guarantees that the SCR vendor intends to agree with for the purpose of a entering a binding contract will only be offered once all technical issues and challenges have been identified and addressed in the system specification. The vendors will not present performance guarantees for negotiation without having assessed their risk mitigation strategy. As the cost of potentially having to provide one or several levels of replacement catalyst in order to make it through the guarantee and warranty periods is significantly less than 10 percent of the total installed cost for a typical coal-fired SCR project, and the total liquidated damages should such replacement be required prematurely are only a fraction of the utility's potential actual and consequential damages, the supplier's financial exposure is decidedly much less than the buyer's (utility) should such failure to meet guarantees and warranties occur.

Temperature Variations for HDSCR

Hans Hartenstein's comments agree with the NDDH's position that such large boiler flue gas exit temperature variations, as shown in Minnkota's April 2007 response letter (Minnkota, 2007B), would not be tolerable for a high dust SCR at MRYS. Mr. Hartenstein (2008) went further to state this would not be tolerable for any HDSCR installed after any type of firing system burning any type of fuel. The ability to successfully control SCR reactor inlet temperatures in a high-dust SCR application at MRYS without impairing lignite pre-drying has not been confirmed.

The EPA's, Plains Justice's, and Hans Hartenstein's comments (2008) all assume that the SCR catalyst system suppliers (boiler original equipment manufacturers) will solve the stated temperature problems. None of the catalyst vendors queried offered to guarantee their catalyst's performance with the current situation of too low and excessively high operating temperatures on these boilers under various operating conditions. The SCR system suppliers queried did not offer any examples of successful application of proven solutions to the conditions existing at MRYS (B&McD and EERC, 2008). It is speculative and would be inappropriate to assume these challenges have been or will be solved or to expect meaningful responses from vendors knowing the nature of the conditions involved have not been resolved.

Mr. Hartenstein states, on page A-9 of the referenced opinion report (2008), that no flue gas reheating is typically required for HDSCR (and LDSCR). This is incorrect. The majority of coal-fired boilers with HDSCR technology cannot maintain minimum operating temperature over the entire load range, therefore reheating with economizer bypass, split economizer or supplementary heat input from duct burners is necessary (see Appendix A). Because of the unique arrangement of economizers in the flue gas ductwork from Minnkota's boilers, and lack of a natural gas pipeline serving the plant, this has already been dismissed in previous responses to the EPA's comments (Minnkota, 2007A, 2007B, 2007C, 2008).

Burns & McDonnell's SCR Experience

The NDDH's Preliminary NOx BACT Determination included a statement attesting to the "extensive experience with the design and operation of SCR systems" of Burns & McDonnell, which was refuted by the DOJ's commenter (Hartenstein 2008). A brief summary of Burns & McDonnell's size, years in business as an engineering firm and both general and specific areas of experience and technical expertise, particularly in regards to utility powerplant boiler NOx emissions control was presented to the NDDH and EPA in May, 2007 (B&McD and EERC, 2007).

The issue of experience with SCR systems in this response is a question of relevance. It will be helpful to first discuss what typical phases a project may go through from start to completion. These are:

- Preliminary study and investigation
- Conceptual Design

- Detailed design
- Procurement
- Fabrication and delivery
- Construction
- Commissioning
- Startup and tuning

Project execution involves all phases listed above and, depending on the project and the contracting strategy; the architectural and engineering (A&E) firm's role may involve all of the above or selected portions of the listed phases while remaining portions are delegated to other entities such as technology suppliers, system vendors, or the owner.

Is Burns & McDonnell's SCR Experience even a relevant factor at this stage of the project? Burns & McDonnell's role in this project has been to perform the BACT analysis, not to design two SCR systems for Units 1 and 2 at Milton R. Young Station. Our experience on performing BACT for utility powerplant units located in the United States is relevant and extensive. Some engineering firms only work on the environmental permitting and study aspects of pollution control and emissions reduction projects while others focus more on the implementation and construction. Burns & McDonnell has successfully worked in both areas and continues to provide these services to our clients. Mr. Hartenstein seems confused as to the role of an engineering firm and from that lack of understanding has made some irrelevant commentary.

What constitutes "SCR Experience"?

Relevant experience in various aspects of a project and specifically a retrofit air pollution control project has to be considered. Burns & McDonnell's role in an air pollution control retrofit project does not typically include the "process design" portion but there are many aspects of retrofit projects that are not specific to just an SCR retrofit project. For example, our structural engineers that are experienced at ductwork arrangement, detailed design of hot flue gas ducts, foundation design, structural steel design, consideration for wind, snow, seismic as well as component thermal expansion and movements all contribute to the project. None of those aspects are specific to SCR process design but all are relevant for SCR system design and Burns

& McDonnell has successfully provided these engineering and design efforts on many projects including SCR retrofit projects.

The specific issue discussed in the EPA's comment document on NDDH's Preliminary BACT Determination (NDDH, 2008) is in regard to SCR process design and catalyst design. In this type of retrofit emissions control project, Burns & McDonnell's role is to serve the Owner's needs and gather the data, resources, and expertise needed to execute the project. Burns & McDonnell would develop and specify the operating conditions, fuel, and flue gas parameters and values that form a basis of design which the catalyst supplier relies on, along with their expertise and proprietary knowledge of their products, to offer a proposed catalyst type, pitch and volume required to meet certain performance guarantees and warranty requirements. The catalyst supplier is in the best position to determine how they propose to meet the specified performance responsibility, understand how that offer fits their business' commercial/financial impact, and whether this may impair or enhance the long term supply of their product.

It is within Burns & McDonnell's ability to assess the relevance of the various catalyst suppliers' offers, their experience, and their level of understanding of the site, the project, the fuel and other system concerns in order to advise the owner as to which vendors are deemed qualified for bidding and executing the pertinent portions of an SCR retrofit project. Many utility owners are not comfortable with performing such technology and vendor assessments alone, nor do they maintain the in-house resources that have expertise to do such tasks to a level that significantly reduces their risk of selecting a vendor to provide a product that ultimately does not meet their requirements nor satisfy their expectations.

As has been pointed out in NDDH's Preliminary BACT Determination (NDDH, 2008) and other supporting documents (Minnkota, 2007A, 2007B, 2007C, 2008; B&McD and EERC, 2007 and 2008; Appendix A), significant concerns exist about the unique characteristics of the fuel burned, type of firing, and flue gas and ash constituents and their influence on the viability of SCR application on these units. We recognize this site-specific situation falls outside the current knowledge and experience base of the potential catalyst suppliers. Additionally, some of the significant concerns on this project have nothing to do with what the catalyst supplier can address, such as the boiler exit temperature. This concern and ways to address it are rightly placed in the boiler design firm's realm of expertise. Burns & McDonnell's role in this phase of the project is to gather, manage, and assess the technical information and advise the owner based on what these entities claim and what has been done elsewhere as well as to investigate publicly-available technical data that is relevant.

Burns & McDonnell's SCR Experience can be categorized in four distinct areas:

- Preliminary studies
- Conceptual designs and cost estimates
- Engineering management of project implementation
- Detailed design engineering duties

Each of these roles serves an important function during the overall project timeline. We can elaborate and provide more details on each category of specific experience on various projects. This is considered business proprietary information and will only be made available if needed. We do not feel this project-specific information is relevant to the current issue raised by the Hartenstein (2008), and have not included these details at this time but can if required. A summary of the roles and experience is provided below as we feel it will suffice to demonstrate our capability and viability for the role we have served thus far on this effort.

- Preliminary studies

  Burns & McDonnell has performed studies for utility clients for many years. The level of detail in what is deemed a preliminary study can be described as typically evaluating various alternatives. In a pollution control retrofit study, various compliance scenarios are evaluated in a screening analysis where technologies are reviewed with regard to several criteria: whether or not the technology is commercially available or under development, the level of experience of the technology, what suppliers are qualified, an evaluation of regulatory impact, very rough screening level cost estimates of the project, discussion of contracting alternatives, and schedule. In some cases when there is uncertainty or a range of alternatives and compliance scenarios, where more than one pollutant is involved, and more than one unit, possible variable levels of control for each pollutant, a matrix of alternatives and potential outcomes is developed to help narrow the focus of the overall strategy. Burns & McDonnell has performed many studies as described that have involved a wide range of complexity. This experience includes studies for utility clients with multiple unit sites and multiple sites covering SO_2, NOx, Hg, and particulate emissions along with some current work that includes CO_2 control as potential regulatory impacts are being assessed. Other studies have been specific single unit evaluations of SCR application only that were done to provide the owner a relative cost and impact on the utility operation. In summary, Burns & McDonnell has performed numerous studies of these types over the past thirty plus years, of which SCR technology retrofit was included in nearly every one of them over the past five years.

- Conceptual designs and cost estimates

Typically after the screening level or preliminary study has been performed, many owners need a more definitive and site specific evaluation of the retrofit project for their unit at the site. Burns & McDonnell has performed these evaluations for SCR retrofits; particulate control retrofits including new pulse jet or reverse air fabric filters; electrostatic precipitator projects including rebuilds, upgrades, conversion to fabric filter, and hot side to cold side conversions; and various SO_2 control alternatives including wet flue gas desulfurization (FGD) or semi-dry FGD, including spray dryer scrubbers, and circulating fluidized bed (CFB) dry scrubbers. FGD technology studies have included processes based on various reagents such as wet lime, wet limestone, ammonia, lime spray drying, and a few of the more developmental proprietary processes that are fairly new to the market. Also, we have performed evaluations of upgrades to existing particulate and SO_2 removal systems where upgrade and refurbishment is being evaluated along with new equipment system retrofits to look for the best solution comparing capital cost, arrangement, operating costs, outage requirements, and construction constraints. The level of detail required or desired by an Owner on this type of project can vary. Some of these projects can extend over 12 months in duration and can involve 20-30% of the design effort being complete whereas others are less detailed and can involve 4-8 months of engineering and evaluation.

The main point here is that Burns & McDonnell's experience and expertise is relevant to our role in providing BACT Analysis study reports, additional information and responses as inputs to the NDDH's BACT Determination process. It includes retrofit and new utility and industrial powerplant air pollution control projects involving SCRs and other technologies, and involves individuals who apply process design and operating knowledge, whether they exist within Burns & McDonnell or are available through technology suppliers or consultants, to the specific conditions involved. To suggest that A/E firms provide no value to clients for these projects (Hartenstein, 2008) is personal opinion not based on an informed understanding of project roles and responsibilities nor utility owner perspectives.

Comments by Sargent and Lundy on SCR Experience

On page A-31 of Mr. Hartenstein's report, Hartenstein calls into question the SCR experience of Sargent and Lundy (S&L). The following response to Mr. Hartenstein's comments has been prepared by Mr. William Depriest of S&L (Depriest, 2008):

> "S&L's involvement in the U.S. Power Industry's SCR program in the late 1990's and 2000's as presented to the NDDH in May 2007 represents NOx reduction activities associated with the NO_x SIP CALL and various projects related to NOx non-attainment areas in the U.S. These NO_X reduction programs represent the vast majority of SCR work in the U.S. during that time frame but it does not include any new unit work or any gas fired combined cycle work which we would classify in a different category of experience. Specifically, we were involved in 53 of 113 units in-service or near to in-service at the time of May 2007 to the best of our knowledge. Again, it is important to note that these NOx programs represent by-far the vast majority of SCRs in progress in the U.S. at that time and that S&L was clearly a leader in this area.
>
> In regard to Mr. Hartenstein's claims to S&L's role on these projects, I have the following comments:

- S&L provided all of the process design on the vast majority of our SCR projects. In some cases (6) we "teamed" with another entity with SCR expertise and shared in the process design role.

- S&L specified the process design criteria for the catalyst on all of our projects short of the actual formulation chemistry which is typically proprietary to the catalyst supplier.

- S&L has never made claims to either an S&L guarantee position regarding catalyst performance or direct operating experience with SCR systems."

Comments on Hans Hartenstein's Qualifications for Expert SCR Opinions

Enclosure 1 of the EPA's referenced letter (EPA, 2008) included descriptions of relevant work experience, and the resume Mr. Hans-Ulrich Hartenstein in Appendix D. Mr. Hartenstein also made numerous statements in his comments regarding the NDDH's Preliminary NOx BACT Determination attesting to his considerable technical knowledge and personal experience with the design and operation of SCR systems (Hartenstein, 2008).

According to Burns & McDonnell's consultant assisting in these responses to Mr. Hartenstein's and the EPA's comments on SCRs, Hartenstein's claimed personal experience and technical expertise on the design of German SCRs, especially of the tail-end variety, is not what it appears to be (see Appendix A). It is difficult to determine the true extent of Mr. Hartenstein's SCR technical experience, but his qualifications state that his direct involvement with SCR technology on coal-fired boilers has largely occurred since 1999 in the United States, not in Germany during the majority of the mentioned SCR retrofits. Mr. Hartenstein's involvement with SCR technology seems to be mostly business development related.

As Mr. Hartenstein states himself on page A-6 of the referenced opinion report (2008), he was not involved in SCR retrofits for utility boilers until 1993. Experience claimed with waste-to-energy LDSCR systems, which are completely different and not comparable to LDSCR systems on fossil fuel fired boilers, does not transfer effectively to the North Dakota lignite cyclone-fired units in question.

Fuel Switching

While clean fuels may be considered to meet BACT requirements, clean fuels may only be considered when the permit applicant proposes to meet BACT using clean fuels. See Pub. Law No. 101-549, § 403(d), 104 Stat. at 2631 (1990) (U.S. Senate Report of the Committee on Environment and Public Works to Accompany S. 1630 (Dec. 20, 1989) discussing the addition of "clean fuels" to the definition of BACT in the 1990 Clean Air Act Amendments).

Fuel switching/blending/cleaning was mentioned in the EPA's comments (EPA, 2008, Enclosure 2) but only fuel cleaning was questioned as a potential technique that was not fully considered in the NDDH's analysis. Fuel cleaning has typically been practiced where removal of sulfur, typically as inorganic pyrite form (FeS), is performed by simple density separation methods ("air jigging" in a classifier separate from or within coal pulverizers which reject the heavier pieces). This reduces the amount of sulfur introduced into the furnace and potentially emitted to the downstream gas cleaning equipment.

In Minnkota's NOx BACT determination case, fuel cleaning would presumably not be attempting to remove nitrogen from the fuel, for reduction of the formation into NO_X, as this would be impractical from a solid fuel. Nitrogen oxides are also created from nitrogen in the combustion air being exposed to high temperatures in the cyclone burners. So the issue of fuel cleaning is really one of trying to remove elements in the lignite besides nitrogen, for the purpose of mitigating other problems associated with those specific elements. Thus, it appears that the EPA and Plains Justice are raising this issue in trying to use fuel cleaning as an "enabling technique" so that SCR technology could be deployed without resolving the problems associated those problem elements.

Ash is included in the Center lignite supplied from the adjacent mine. Some ash comes from the mineral layers that are above and below the lignite seams as a result of the practical inability to completely separate the lignite from the burden material during mining. The remainder and majority of ash in the lignite is bound within the coal particles. Reducing the amount of bound ash in the lignite prior to introduction to the boiler would not be practical with known methods of fuel cleaning.

In cyclone boilers, ash is not normally problematic if it melts within the cyclone burner barrel and drains out to become bottom ash. In the case of North Dakota lignite-fired cyclone boilers, there is a high amount of ash that is not captured and drained from the cyclones and lower furnace as bottom ash. Thus, a higher than typical 70:30 bottom ash: flyash ratio for cyclone boilers occurs at MRYS, closer to a 50:50 split. This means that a significant amount of ash is released from the burners as flyash, where these particulates escape and become entrained in the flue gases rising up through the furnace.

As previously discussed in earlier responses, it is sodium and potassium-related elements that would cause SCR catalyst deactivation. These troublesome elements are mostly in forms where they are organically-bound within the coal particles, so simple "air jigging" classification methods are believed to be ineffective.

The arguments for coal cleaning also do not cite specific examples where minerals such as sodium and potassium have been removed economically and would not require pilot testing in order to demonstrate that the technology is developed sufficiently to be successful for this application

Non-SCR NOx Controls

Plains Justice implies that because various non-SCR NO_X reduction technologies have been demonstrated or pilot-tested on any utility boiler, the control technology would be technically feasible at MRYS. This ignores the differences in specific conditions at the MRYS boilers compared with where the technology has been demonstrated that are pertinent to whether the technology is appropriate and could be successful at MRYS.

Successful implementation of NO_X controls is highly dependent on the specific configuration and process conditions that lend themselves to be compatible within the limits of constructability, survivability, and effectiveness. Just because a control technology is "technically feasible" based on Plains Justice's interpretation of the NSR Manual (U.S. EPA, 1990) does not mean it will work effectively at MRYS to reduce NO_x emissions. Many comments by Plains Justice give the impression that they did not review Minnkota's BACT Analysis study reports (B&McD, 2006), or understand the technical reasons why such non-SCR NO_x control technologies were not evaluated for MRYS.

An example of this is Plains Justice's suggestion that injection of a fluxing agent to increase melting of solid combustion products will reduce catalyst poisoning due to a reduced amount of flyash. Superficially, this sounds plausible, but where fluxing agents have been added to coal for reduction of impact on SCR catalyst, it is due to the practice of flyash reinjection or firing of bituminous coal with low calcium-to-arsenic ratio. For the cyclone boilers firing North Dakota lignite, the fuel and its response to melting is more complex than other coals where the use of fluxing agents has been demonstrated as described. These cyclone boilers are designed specifically to melt the fuel ash in the cyclone burners as part of the combustion process. Flyash reinjection is not practiced, and arsenic is not significant in North Dakota lignite-fired cyclone boilers; however, sodium is a known catalyst poison and is present in abundance in ND lignite.

The problem with Plains Justice's argument is that the use of the fluxing agent mentioned would not prevent melting of sodium compounds which creates a fine fume that does not get captured in the molten slag. Sodium, in fact, is preferentially released from the slag that forms in the cyclone burners and lower furnace and is then exhausted where it is available to react with sulfur and calcium to foul and deactivate SCR catalysts. This is the main source of sodium that ends up in the boiler's exhausted flue gas instead of remaining in the slag. This has been explained in numerous ways by EERC in previous responses to EPA comments (Minnkota, 2007A, 2007B, 2007C, 2008; B&McD and EERC, 2007 and 2008).

Most of the "commercially available solutions" to facilitate the use of SCR that Plains Justice lists involve coal cleaning and drying or beneficiation. MRYS already has cyclone lignite drying systems, which are required for preparing the fuel for proper combustion in the cyclone burners. The arguments for coal cleaning also do not cite specific examples where minerals such as sodium and potassium have been removed economically and would not require pilot testing in order to demonstrate that the technology is developed sufficiently to be successful for this application.

Minnkota's BACT Analysis reports and previous responses to EPA comments (Minnkota, 2007A, 2007B, 2007C, 2008; B&McD, 2006; B&McD and EERC, 2007 and 2008) have explained that other non-SCR technologies, such as various forms of enhanced selective non-catalytic reduction (SNCR) with natural gas or coal reburn, low NOx burners, and flue gas recirculation are not appropriate for the operating conditions experienced inside the boilers at MRYS. Plains Justice appears to ignore the arguments previously presented regarding the expected limitations of effective NO_X reduction at MRYS with modest cyclone air-staged combustion compared with lower NO_X emissions demonstrated at Ameren's Sioux plant with deeply staged cyclones using lower furnace urea reagent injection. Oxygen-enhanced combustion, NOx adsorption from flue gases using activated coke, and various chemical treatment processes have not been demonstrated on cyclone boilers or lignite fuels, and thus would require extensive pilot or full-scale testing in order to assess their potential performance and economics. The interpretation of the NSR Manual (U.S. EPA, 1990) noting that requiring extensive pilot or full-scale demonstration of the technology is outside the BACT process beyond step 2 has already been presented in previous responses (Arfmann and others, 2007).

Conclusions

In the end, EPA's objections to NDDH's Preliminary BACT Determination may be reduced to disputing NDDH's characterization of the gas stream characteristics and the impacts of those characteristics on boiler and emissions control operations. EPA and Hartenstein suggest that these impacts can be resolved by the use of TESCR, and that TESCR technology will work at MRYS (2008). We believe their arguments are flawed because they fail to recognize the significance of these facts:

- There is no prior experience with full-scale SCR on any unit firing North Dakota lignite.
- Results from the only known example of simulating SCR catalyst exposure to high-alkali containing flue gases produced from firing North Dakota lignite in a cyclone boiler showed severe catalyst blinding and plugging due to sodium and potassium rich species

(Benson, 2005). Coyote pilot-scale SCR test was intended to evaluate the fouling potential of SCR on lignite coal results. The Coyote test was developed by a consortium of three catalyst vendors, EPRI, U.S. DOE, and other participants that design and install SCR systems as well as end-user utilities that have applied SCR on their boilers. This team was competent and Minnkota believes this testing was valid for its intended purpose. From this sole test, it was determined that there are significant impediments to using SCR on MRYS. Peer-reviewed literature written by many authors has verified that sodium and potassium species are fatal to the catalyst life.

- European SCR experience at lignite-fired utility boilers has been very limited. One HDSCR installation was at Voitsberg Unit 3 (Austria) and there were HDSCRs on three units at the Bayernwerk Schwandorf plant in Germany. These units were not cyclone-fired, the fuel burned was much lower in sodium than North Dakota lignite, and the units are no longer in operation (see Appendix A).

- There have never been, to the best of our knowledge, any tail-end SCRs applied to coal-fired utility boilers burning lignite, whether in Europe or North America (see Appendix A).

- There have not been, to the best of our knowledge, any TESCRS installed on any coal-fired utility boiler anywhere in the world since 1991, when the TESCR on the Siersdorf power station in Germany was placed into service. Siersdorf did not burn lignite, did not have a Wet FGD system, and has since been decommissioned (see Appendix A). This 17-year span since the last TESCR installation on a coal-fired utility boiler belies EPA's contention that TESCR has been universally applied and represents BACT for NOx control on a North Dakota lignite-fired cyclone boiler.

- Contrary to statements made by Mr. Hartenstein (2008), there are no currently active or planned TESCR installations in the U.S. on coal-fired utility boilers. PSEG Mercer Station does not have TESCR configuration (it is LDSCR), and the SCR systems at South Oak Creek Station for WE Energies will also be LDSCR, not TESCR as stated by Hartenstein. The change in SCR type at South Oak Creek was made due to the technical incompatibility of full scrubbing Wet FGD and the type of gas-to-gas heat exchanger

(GGH) required for TESCR. Neither of these plants burn (or will burn) high-sodium lignite (see Appendix A).

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APPENDIX A

Tackticks, LLC Report
“Comments to Enclosure 1 Hans Hartenstein’ Expert Opinion Report”

Tackticks, LLC General Company Information

Resume for Volker Rummenhohl

Resume for Robert E. Johnson

Tackticks LLC SCR Consulting and Process Engineering Reference List, June 2007

Minnkota
Milton R. Young Station
NOx BACT

Comments to Enclosure 1 Hans Hartenstein's Expert Opinion Report

Prepared for
Burns & McDonnell Engineers

by:

Tackticks, LLC
Volker Rummenhohl, Principal Author
Robert Johnson
September, 2008

Tackticks, LLC

Introduction

Mr. Volker Rummenhohl, Tackticks, LLC, has prepared the following comments to Mr. Hans Hartenstein's Expert Opinion Report pertaining to the "Feasibility of SCR Technology for NOx Control Technology for the Milton R. Young Station, Center, North Dakota (July 2008)."

The following comments address five general topics rather than a point by point rebuttal of Mr. Hartenstein's statements. These five general topics are: Mr. Hartenstein's qualifications, information not reported by Mr. Hartenstein, incorrect information presented by Mr. Hartenstein, vendor guarantees and catalyst poisons / pilot tests.

In general, Mr. Hartenstein mainly reports the opinion of third parties and not his own. In some cases where his own opinion is offered, significant materially-related information is either missing or the information he presents is incorrect. For instance, he mistakenly refers to the SCR systems at PSEG Mercer Station as tail end systems. Mr. Hartenstein does not have hands on experience with the design, commissioning, operation or maintenance of tail end SCR systems (TESCR) for coal fired boilers. He also does not have experience with design or commissioning of Low Dust SCR systems (LDSCR) for coal fired boilers.

In his report, Mr. Hartenstein focuses entirely on the catalyst and ignores problems that have occurred with the subsystems of a SCR plant.

Qualifications

As Mr. Hartenstein states himself on page A-6 of the referenced opinion report, he was not involved with SCR retrofits for utility boilers until 1993. His direct involvement with SCR technology on coal-fired boilers has largely occurred since 1999 in the United States, not in Germany during the majority of the mentioned SCR retrofits. Mr. Hartenstein's involvement with SCR technology seems to be mostly business development related. Experience claimed with waste-to-energy LDSCR systems, which are completely different and not comparable to SCR systems on fossil fuel fired boilers, does not transfer effectively to the units in question. The size is much smaller and this allows the use of different pre heat equipment. All waste-to-energy plants in Europe have either activated carbon injection or fixed bed activated carbon plants. Those take out all poisons such as all acidic components, arsenic etc. from the flue gas.

The dead line for the retrofit of SCR systems for fossil fired units was January 1, 1990 in Germany. All but one TESCR system was built and commissioned by that date. The last TESCR system was installed in 1991 at the 170 MW Siersdorf power station, firing bituminous coal, equipped with a dry circulating fluidized bed scrubber and electrostatic precipitator with natural gas-fired duct burners ahead of the TESCR reactor. Mr. Hartenstein was not involved with that project. The author was responsible for process design and commissioning for the Siersdorf power station's SCR system constructor. This power station has since been decommissioned and dismantled.

Missing information

On page A-11, Mr. Hartenstein references the high dust SCR system (HDSCR) that was installed in 1990 at the Voitsberg Power Station in Austria. This paragraph concludes with the implication that lignite-fired boilers are among the 30,000 MW of SCR systems installed in Europe. However, Mr. Hartenstein does not offer the information that more than 20,000 MW of lignite fired units in Germany were not required to install SCR in order to comply with the national regulation. These units were exempted from the regulation despite the fact that they would not achieve the required emission limit of 200 mg/Nm^3. It should be noted that high dust SCR systems were installed and operated at the lignite-fired Bayernwerk Schwandorf plant in Germany. The units fired a Czech lignite and were decommissioned in the late 1990s. Voitsberg Unit 3 and the units at the Bayernwerk Schwandorf plant in Germany, which were not cyclone-fired, have been the only SCRs ever to operate on European lignite, and the fuel they burned was much lower in sodium than contained in North Dakota lignite. To the best of my knowledge, there have been no TESCRs built nor are any currently operating anywhere in the world on lignite-fired utility boilers.

Mr. Hartenstein also did not state in his report that Germany had only one cyclone-fired (slag tap) unit with a SCR system. This unit is Walsum 7, the NOx emissions control system is a LDSCR, and the unit does not burn lignite.

Mr. Hartenstein also did not explain that the Voitsberg lignite-fired dry-bottom pulverized coal unit operated only for a very short period of time with high dust SCR, before the boiler was taken out of business and decommissioned. The power station does not exist any longer.

Mr. Hartenstein also fails to explain that on utility boilers you cannot send saturated gas from the scrubber to the gas-gas heat exchange (GGH) for the TESCR. The gypsum in the flue gas will deposit on the SCR GGH surface and lead to a fast pressure drop increase. It is extremely difficult or impossible to clean this during an outage. The FGD GGHs are frequently washed with liquid water during operation, which keeps them clean.

Mr. Hartenstein, on page A-10 of his report, displays a diagram purporting to be the configuration of a TESCR downstream of a wet FGD system. What he fails to explain is that there is no TESCR on any utility boiler anywhere in the world that uses this configuration successfully downstream of a wet FGD. For the reasons noted above, the GGH of the TESCR cannot accept the flue gas immediately from the FGD without reheat. This diagram offered by Mr. Hartenstein represents an infeasible configuration.

Mr. Hartenstein reports on page A-50 regarding the "We Energies South Otter (*sic*) Creek Generating Station" and implies that this SCR project proves the viability of TESCR. He fails to explain that for this project, which is located at the South *Oak* Creek plant, Alstom and Howden, which are the main GGH suppliers for the SCR market, both required that the flue gas be free of moisture droplets and preheated to allow the use of TESCR. Otherwise they would not offer performance guarantees. This particular project has now changed the SCR system to a LDSCR due, in part, to issues related to the GGH.

In the German TESCR installations, a rotary GGH could be used because the required FGD removal efficiency was about 80% , and the flue gas leaving the FGD could be reheated with bypass or by other means prior to entering the GGH for the TESCR. This is confirmed by the data shown in the boiler process flow diagram from an operating utility boiler plant shown by Mr. Hartenstein on page A-49 of his report. It is clearly seen that the flue gas temperature entering the GGH for the TESCR is 87 °C, or more than 30 degrees C above the saturated flue gas temperature at the FGD absorber outlet (typically 55 °C). Obviously, although not shown on his diagram, the flue gas at this plant has been reheated prior to the inlet to the TESCR GGH. The FGD systems in Germany typically use an "FGD GGH" to accomplish this reheat. However, leakage across the FGD GGH makes a rotary GGH infeasible for TESCR systems following high SO_2 removal efficiency FGD systems, as required in the U.S.

Mr. Hartenstein references several times the "ill-designed" pilot test plant that was conducted at the Coyote Station. However, he does not offer a single reason why the pilot plant was "ill-designed".

Incorrect Information

Mr. Hartenstein states, on page A-9, that no flue gas re-heating is typically required for HDSCR and LDSCR. This is incorrect. The majority of the units cannot maintain minimum operating temperature over the entire load range, therefore reheating with economizer bypass, split economizer or duct burners is necessary. Vectren installed duct burners on four units.

Denmark and the Netherlands did not have SCR by the end of the 80s, as stated by Mr. Hartenstein on page A-11.

While rotary, tubular and plate type heat exchangers have been used for re-heating flue gas, as noted by Mr. Hartenstein on page A-12, not a single coal fired unit with a LDSCR or TESCR system has a heat exchanger other than rotary. As discussed above, this poses a problem with fouling and leakage when located directly downstream of a wet scrubber without reheat.

Mr. Hartenstein states on page A-12 for turbine limited units: "In this case, the heat rate penalty of the unit may be eliminated completely". This is complete nonsense. There will still be a penalty since more heat input is necessary for the same electrical output.

Mr. Hartenstein states on page A-13 that it can reasonably be assumed that the retrofit cost today would be the same as stated in an EPRI report from 1989. The cost for rotary heat exchangers for LDSCR and TESCR are much higher today.

Further, Mr. Hartenstein states on the same page that TESCR technology was "generally adopted as a universally applicable SCR solution for all types…" There has never been another TESCR built after Siersdorf, which was finished in early 1991, in the US or Europe.

The following is an excerpt from page A-19 of Mr. Hartenstein's report concerning minimum operating temperature:

"As a matter of fact, the only thing that dictates the minimum SCR operating temperature are the residual SO_2 and SO_3 concentrations in the flue gas, which determine the ABS reaction equilibrium and thus the probability for ABS deposition on the catalyst and in the gas/gas heat exchanger. This, however, is not an irreversible catalyst poisoning issue but rather a reversible fouling problem not related to the SCR catalyst per se but simply to the reaction chemistry between H_2O, SO_3 and NH_3 in the flue gas at various temperatures."

It is factually incorrect that the temperature depends only on the SO_2 and SO_3 concentration of the flue gas. It is independent of the SO_2 concentration. Minimum operating temperature depends primarily on the SO_3, ammonia and moisture concentrations in the flue gas. Catalyst fouling is only reversible if no calcium has reacted with the ammonium bisulfate. Once that has happened it becomes irreversible.

On page A-19, Mr. Hartenstein states:

"The reaction equilibrium between ammonium sulfate ($(NH_4)2SO_4$) and ammonium hydrogen sulfate (NH_4HSO_4), which is often incorrectly referred to as ammonium bisulfate or ABS, in the flue gas. Both ammonium sulfate and ammonium hydrogen sulfate are products of the inevitable reaction of gaseous sulfur trioxide (SO_3) and ammonia (NH_3) contained in the flue gas upstream of the SCR catalyst."

Ammonium hydrogen sulfate is a different name for ammonium bisulfate.

Mr. Hartenstein discusses, on page A-22, "Ceram's extensive experience with lignite.." With only one plant with CERAM catalyst having operated for a short period of time on lignite and a few pilot programs, it is impossible to say that CERAM has extensive experience on lignite fired plants.

Mr. Hartenstein devotes an entire section to soluble sodium (Section 6.3, page A-27). He notes in the second paragraph a statement from one of the catalyst suppliers that sodium is not a catalyst poison at SCR operating temperatures.

Yet, on page 5 of the technical paper, "Utility Experience with SCR in Germany," presented at the Sixteenth Annual International Pittsburgh Coal Conference in October, 1999, Mr. Hartenstein and his co-authors reported SCR catalyst deactivation due to

sodium at the RWE Staudinger plant in Germany. Specifically, it is reported on page 5 that "…the fly ash from the German coal formed highly adhesive deposits, while the portion of South African coal contributed to the formation of a liquefied fly ash.
The reason for this was determined by a chemical analysis of the fly ash. It can be seen that the content of the alkali sulfate, which adheres to the surface of the fly ash particles, favors the tendency to agglomerate. A phase analysis of the deposits revealed crystalline sodium aluminum sulfate and potassium aluminum sulfate ($NaAl(SO_4)_2$;$KAl(SO_4)_2$)."

This information would tend to support the Department's opinion related to the formation of sodium–related deposits on the SCR catalyst and accelerate the deactivation of the catalysts. This information would also tend to conflict with Mr. Hartenstein's statement, on page A-28 of his expert report, that the "…the intrusion of liquid pyrosulfates is no major concern with respect to a severe, rapid catalyst deactivation."

Mr. Hartenstein states on page A-29:

"…of less than seventy two (72) hours, SCR reactors are typically "buttoned up hot," which means the SCR reactor is isolated from the flue gas path during shut down by means of putting it in a bypass mode while the SCR is still at its design operating temperature. The cooling rate of such a "buttoned up hot" SCR reactor is known to be extremely slow. Unless forced cooled with ambient air no "buttoned up hot" SCR reactor loses more than approximately 50-100 degrees and therefore gets nowhere near the sulfuric acid or even the moisture condensation temperature in a seventy two (72) hour period."

This is a statement, which is incorrect and must be based on the lack of practical experience. I have been involved in several measurements of cool down rates for SCR units. The rate differs in a range between five and ten degree Fahrenheit per hour depending on the quality of the dampers and the insulation, the unit size, catalyst volume installed and the ambient conditions. It must also be considered that the boiler is operated at low loads before during the shut down phase. This means the starting temperature is already very low. Almost all units are below the acid dew point after 72 hours and most of them at the water dew point.

Mr. Hartenstein takes exception to the Department's statement on page A-29, as excerpted below:

"The Department concludes that "the flue gas generated at M.R. Young Station is different from the flue at any plant where SCR technology has been applied." The absoluteness of this statement, which is not even limited to power plans, is quite amazing as it indubitably implies that the Department has complete detailed knowledge not only of the flue gas composition of every other power plant in the world equipped with an SCR system but also of every other plant in the world where the SCR technology is applied. Even though theoretically possible, the lack of any data from all these other plants

strongly suggests that this may be highly questionable and largely overreaching. As a matter of fact, I am sure that I could easily present to the Department several plants where the SCR technology has been applied successfully that the Department doesn't even know that these plants existed."

The statement of the Department can be easily supported since there is not a single SCR system in operation on a lignite fired boiler in the United States, nor in Europe, at this time.

The statements on pages A-31 and A-32 that Burns & McDonnell never has given a guarantee and never provided process design are incorrect.

On page A-32, Mr. Hartenstein states:

"As a matter of fact, all catalyst related performance guarantees (NOx removal efficiency or activity, SO_2/SO_3 conversion rate, catalyst life or deactivation rate, etc.) are never provided by anyone other than the catalyst manufacturers. Even the SCR equipment suppliers only pass through the catalyst performance guarantees obtained from the catalyst manufacturers to the end customer. And at least two (2) of these catalyst manufacturers, namely Haldor Topsoe and CERAM were clearly willing to provide industry standard type performance guarantees for their catalyst."

This statement can only be explained by a lack of involvement in the design of SCR plants. Catalyst performance guarantees are not always a pass through from the system supplier. Depending on the contract, there are a lot of other issues that are not done by the catalyst supplier. Distributions, pop-corn ash screens, control system, and analyzer system all impact the performance of the SCR catalyst but may not be guaranteed by the catalyst supplier. These are typically warranted by the system supplier.

On page A-39, Mr. Hartenstein states:

"Yet, the most successful SCR retrofits in the U.S. were done as turn-key installations without the use of an A/E."

There are certainly many examples of successful SCR projects which were executed on different contractual conditions.

Mr. Hartenstein states on page A-50 that the SCR systems at PSE&G Mercer Generating Station are TESCR. This is incorrect. Both SCR systems at this plant are LDSCR with flue gas re-heating. Mr. Hartenstein also states that the SCR systems at WE Energy South Oak Creek Station will be TESCR. This is also incorrect. South Oak Creek started out as TESCR, but technical difficulties have forced the change to a LDSCR.

Vendor Guarantees

Mr. Hartenstein frequently states that various catalyst and SCR system vendors would be willing to offer performance guarantees for the Milton R. Young Station SCR. It is typical for vendors to do this in the absence of a detailed specification and contract with commercial conditions and liquidated damages. Performance guarantees will only be offered once all technical issues and challenges have been identified and addressed in the system specification. The vendors will not present performance guarantees for negotiation without having assessed their risk mitigation strategy.

A recent example of this occurred on the retrofit of SCR systems on two units in Florida. Three catalyst vendors provided totally different sets of preliminary guarantees at the beginning of the project. All three suppliers changed their guarantees after a 2,000 hour pilot test significantly identified the effects of various fuels on the expected performance of the catalyst.

Another example occurred several years ago on three SCR units in Pennsylvania. Two catalyst suppliers (Haldor Topsoe and CERAM) provided guarantees based on their experience with similar coals, but were very surprised about the rapid deactivation of the catalyst. These companies are those most cited in Mr. Hartenstein's paper. The money the utility received in a settlement with the turn key supplier was a very small fraction of the long term operating costs absorbed by the Utility to maintain SCR system operation.

Catalyst Poisons and Pilot Projects

In many cases where SCR technology has been applied to fossil fuel-fired boilers located throughout the world burning a variety of coals and solid petroleum byproducts, extensive pilot testing programs have been performed prior to implementation on full-scale power plants: Germany in the 1980's, United States in 1980's, and in Texas since year 2002.

There are two pilot tests and one R&D program in which the author was involved with in Germany. The results of these programs emphasize the importance of understanding design and process issues for certain applications. These also demonstrated that it is very difficult to solely rely on experience with similar coals and boilers.

The first was a pilot program for a high dust SCR on a wet bottom boiler at the Franken power station in Germany. This was before the first HDSCRs were built in Germany. All catalyst suppliers said that it would be unnecessary to conduct a test program, since these companies had sufficient experience basis from the units in Japan. It turned out that the catalyst deactivated rapidly. Some catalyst types lost almost all of their activity in just 200 hours. At this time, arsenic was not known to be an issue for the catalyst because it had not been observed in the Japanese SCR systems. The pilot test revealed the fact that arsenic is a heavy catalyst poison. Most of the utilities decided not to retrofit wet bottom boilers that had fly ash recirculation with a HDSCR so that arsenic poisoning could be avoided.

The second pilot program was in the Reuter power station in Berlin. The author was involved in a pilot plant that included a wet scrubber and a TESCR. The result was that it is impossible to have saturated flue gas going to the GGH of the TESCR without drying and pre heating it. The gypsum in the flue gas plugged the TESCR GGH with no means to clean it. The temperatures are too high to clean it with liquid water as it is frequently done on the FGD GGHs.

Utilities built TESCRs in Germany to avoid the arsenic problems. Everybody thought that an indefinite catalyst lifetime could be expected. It was even more surprising to see that the first layer on which activity was measured lost more than 50 % activity in less than 2,000 hours. Again, a new catalyst poison was detected. It was SiF_4, a gaseous component which forms on the plates of the FGD rotary heat exchanger in a reaction of SiO_2, H_2SO_4 and HF. It was an R&D project of several million dollars to detect the poison, the formation mechanism and the solution. Lime was injected upstream of the FGD, which bound the sulfuric acid on the GGH plates. The capital cost of the lime system is certainly not included in the EPRI cost reports referenced by Mr. Hartenstein.

See:

German Experience Sheds Light on SCR O&M Issues, September 1992 issue of Power magazine, Coauthor. (attached).

The author also participated in a more recent pilot test program for a Southeast U.S. Utility. At this particular plant, a proposed SCR system had to be designed for three very different fuels: Eastern bituminous, Venezuelan coal and pet coke. Due to very stringent permit conditions related to NOx, NH_3 and SO_3 emissions, the SCR system and catalyst had to account for the influences of the fuel on the NOx activity and SO_2 oxidation rates of the catalyst. With limited worldwide experience on such a range of fuels, the Utility decided to conduct an extensive pilot program to assess impacts on the catalyst. All three suppliers changed their guarantees after a 2,000 hour pilot test identified significant effects of the various fuels on the expected performance of the catalyst. This SCR is not yet operational.

The EPA also fails to recognize and acknowledge that significant pilot testing has been conducted at two power plants in Texas that fire lignite supplied from various locations in Texas, and that there are no cyclone-fired boilers in Texas. The EPA has gone down the same path that tried to compare German SCR applications, which lack significant cyclone boiler experience and is not currently required for lignite-fired boilers, to be appropriate and comparable to North Dakota lignite-fired cyclone burner units. These are misleading statements and contrary to the presentation of the body of information submitted in support of the NDDH's preliminary BACT determination for MRYS.

These examples emphasize the importance of understanding the intricate process design issues that will influence SCR performance. The industry has benefitted from the many pilot test programs that have been conducted to implement SCR technology when new and unknown process issues have been raised. In the case of Milton R Young, the uncertainty associated with the high sodium concentration and the presence of sodium aerosols in the flue gas raise questions pertaining to catalyst performance. Pilot testing is certainly warranted.

Mr. Hartenstein and his co-authors support pilot programs for those SCR applications in which new and uncertain process considerations are encountered. On page 2 of the technical paper, "Utility Experience with SCR in Germany," presented at the Sixteenth Annual International Pittsburgh Coal Conference in October, 1999, Mr. Hartenstein states: *"In principle, the reduction of NOx emissions with SCR catalysts is a mature technology, which was developed many years ago. Nevertheless, experience has shown that in many applications, special features were required that necessitate further optimization of the DeNOx system. In particular, standard solutions were often not possible or optimal when retrofitting existing power plants."*

Mr. Hartenstein implies, on page A-36 of his report, that catalyst that has been poisoned by sodium compounds can be regenerated in-situ, and that this technique is well developed. Regarding the contention of Hartenstein, there is extremely limited experience with in-situ catalyst cleaning on coal-fired units. ENBW in Germany developed this technique, but it has never had a commercial success. It also has never been used for blinded or chemically poisoned catalyst, but only for mechanically plugged catalyst.

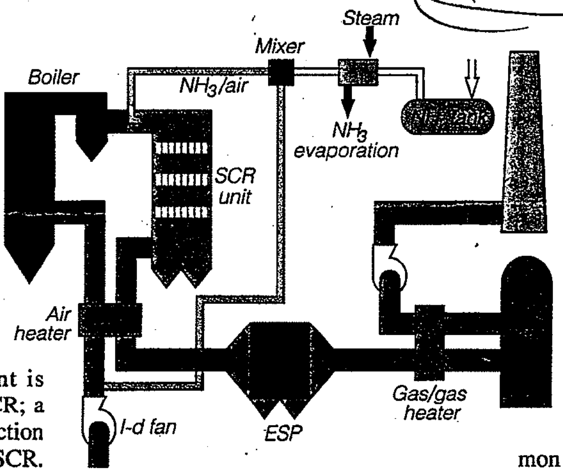
The possible application of any SCR technology at Milton R. Young is not standard, due to the special considerations pertaining to the lignite, boiler operating temperatures, flue gas reheating, among others.

c: HNH, JFM, WHP, REJ, PLC, FES, LB.

Experience sheds light on SCR O&M issues

German application of selective catalytic reduction (SCR) for controlling NO_x from coal-fired boilers is extensive. But while design of SCR units is well-known, operating and maintenance experience highlights critical issues that may not be understood by US power producers

By **Volker Rummenhohl** and **Helmut Weiler,** Steag AG, and **William Ellison,** Ellison Consultants



1. High-dust systems are located between the economizer and the air heater

Whether prompted by federal, state, or local regulations, it seems clear that new coal-fired powerplants built in the US will require high-efficiency NO_x control. SCR is perhaps the most widely applied technique worldwide for this purpose (POWER special reports, "Controlling NO_x emissions," September 1988; "Clean Air Act Amendments: The Engineering Response," June 1991). One non-utility generating (NUG) plant is being built in New Jersey with an SCR; a utility coal-fired boiler under construction in Florida provides space for a future SCR.

In Germany, SCR has been widely applied to coal-fired boilers. Thus, it is important to transfer the operation and maintenance (O&M) experience from Germany to future US installations.

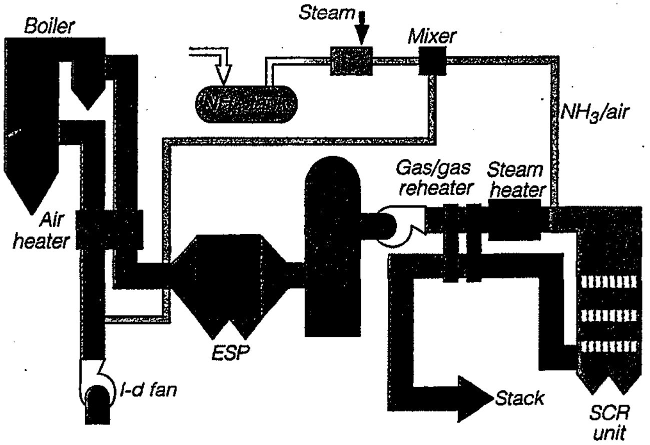
Steag AG has extensive experience with SCR (table) in a wide array of configurations, including boilers fired by ballast coal with sulfur content similar to US bituminous coals.

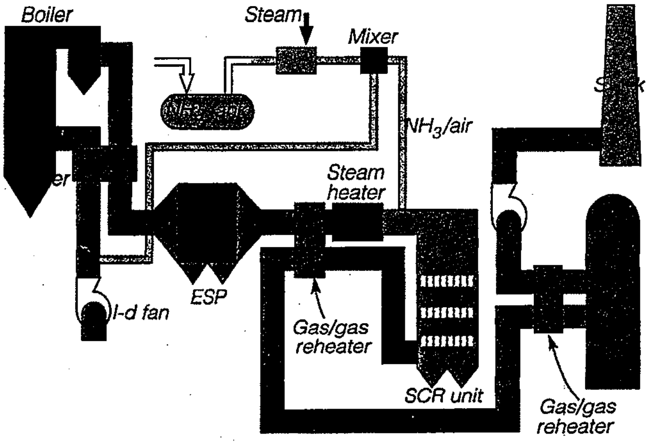
Background

In the early 1980s, the NO_x emissions limit for large coal-fired boilers was reduced to around 100 ppm. To prepare to meet the new stringent standard, Steag AG began pilot-testing SCR in the mid-1980s. Catalysts for SCR had been pioneered commercially in Japan. However, the characteristics of German powerplants were significantly different, including:

- German plants burn a wide variety of low-rank domestic coals with a high content of inerts and impurities; Japanese power stations typically burn high-quality imported coals.
- Slagging-type boilers are common in Germany, but not in Japan.
- At least 90% NO_x removal was the objective for many German plants while Japan utilities had to accomplish 80%.

All conventional pulverized-coal-fired (p-c) units in Steag's system are equipped with so-called "high-dust" SCR configurations (Fig 1), referring to placement of the SCR reactor ahead of the air heater.





For all but one slag-tap unit, the SCR unit is located in a tail-end arrangement (Fig 2), or after the flue-gas desulfurization (FGD) system. In this case, a gas-to-gas flue-gas reheater and a steam-fed heater are located between the FGD and SCR units. The steam-fed heater is used to regulate the temperature of the flue gas entering the SCR unit. This also helps optimize the reduction of NO_x emissions during startup.

Unit 7 at the Walsum station, a slag-tap unit, includes the SCR reactor after the electrostatic precipitator (ESP) but ahead of the FGD system. This is referred to as the "low-dust" configuration (Fig 3).

High-dust units

Two units, Walsum-9 and Herne-4, burn high-ash, medium-to-high-sulfur coal and exhibit high flyash concentrations entering the SCR unit. Plate-type catalysts have proved superior to honeycomb-shaped modules in resisting abrasion and fouling.

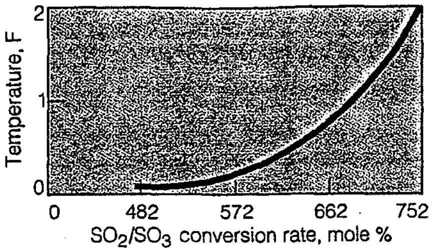
Loss of catalyst activity over time has been considerably less than originally expected for high-dust SCR units. One key factor is the fine lime content of the coal. Here's why: Catalysts also oxidize SO_2 to SO_3. Lime content of the coal neutralizes the sulfuric acid that results from this conversion. If the neutralizing capacity of the coal is not high enough, it is increased by adding limestone or other alkaline compounds to the coal or flue gas.

The first catalyst charge at Walsum-9 had to be upgraded after 27,000 hours of service. Around 25% of the original catalyst capacity had to be added at this point because ammonia slip—that amount that escapes unreacted—caused a disagreeable odor threshold in the flyash and rendered it useless for sale to the construction industry. The original design value of 5 ppm for ammonia slip was too high in Germany.

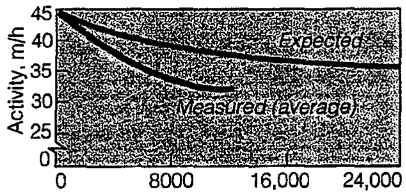
It takes very little ammonia to make ash unsalable. The odor threshold is reached when ammonia content reaches 80 mg/kg of ash—equivalent to 3 ppm, measured at the air-heater inlet, when firing ballast coal or 1.5 ppm when firing high-quality, low-ash coal.

The conversion of SO_2 to SO_3 in SCR systems requires special attention. High SO_3 levels result in corrosion of air heaters, ESPs, and FGD systems as well as the potential for the release of acid aerosols from the stack. Note that wet FGD systems designed for SO_2 removal typically cannot control sulfuric acid aerosol emissions.

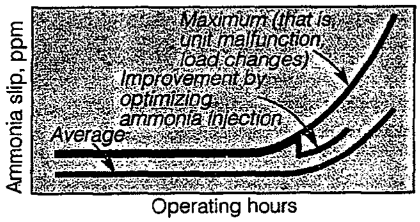
Before SCR retrofit, the German p-c-fired boilers typically operated with flue-gas temperatures at full load ranging between 700 and 715F at the economizer outlet. However, the conversion of SO_2 to SO_3 is temperature dependent (Fig 4). Thus, sootblowing schedules were modified to keep the boilers cleaner and lower flue-gas temperatures to between 660 and 690F. This action reduced SO_3 concentrations at the air-heater inlet from 80 to 40 mg/m^3. This is equivalent to from 22 to 11 ppm. Overall, however, Steag's experience is that high-dust SCR has in some units limited the boiler's operating range.



4. Conversion of SO_2 to SO_3 is highly dependent on temperature



5. Catalyst activity was found to degrade because of poisoning by SiF_4. Lime hydrate injection mitigates the degradation



6. Ammonia slip rises as catalyst ages; optimizing ammonia feed helps stem the increase

Tail-end systems

Experience with the tail-end arrangement was expected to be much better in terms of chemical and physical service life. After all, the flue gas here is low in sulfur compounds and flyash, and materials that can poison the catalyst—arsenic and other heavy metals—are removed by the FGD system upstream. Unfortunately, after only a few thousand operating hours, an extremely high fall off in catalyst activity was observed, particularly on the first layers of honeycomb modules (Fig 5).

The decline in catalyst effectiveness is attributed to the formation of a coating of silicon compounds on catalyst surfaces, generally caused by the presence of silicon fluoride (SiF_4). Sulfuric acid, which condenses onto the FGD flue-gas reheater plates, traps SiF_4 and HF. These compounds combine and later split at the clean gas side into highly corrosive hydrogen fluoride and SiF_4.

Solution to the problem proved to be the injection of lime hydrate downstream of the ESP. This compound reacts with acid gases to form calcium sulfate, calcium fluoride, and other calcium halide compounds. These solids are removed either in the FGD unit or by sootblowing after they deposit on plates in the flue-gas reheater.

Tail-end systems entail high operating expense because of the intermediate steam heating required and the added pressure drop, increasing fan power requirements. On the plus side, they do not limit boiler operation because SCR inlet temperature can be regulated by the steam heater, independent of the boiler.

Monitoring crucial

Regardless of arrangement, monitoring SCR effectiveness must go beyond catalyst activity measurements. At Steag's plants, measurements are taken from sampling systems installed between catalyst layers in addition to recommended measurements taken immediately after the SCR unit. NO_x and NH_3 measurements are taken to detect catalyst degradation early.

Note that both the absolute value of ammonia slip and range of ammonia slip within which the plant can be operated with NO_x compliance rise as the catalyst ages. Constant improvement of ammonia feed regulation has assisted in reducing ammonia slip (Fig 6). ■

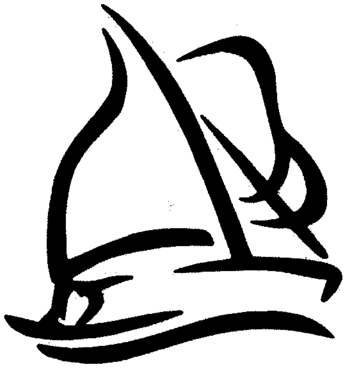
Overview of Steag powerplants using SCR

(May 1992 survey)

Station	Output, MW	Furnace type	NO_x in, mg/Nm^3	Config	SCR type	SCR start date	Operating hours
Bergkamen	747	Dry ash	800	HD[1]	HnyComb[2]	11/89	20,400
Voerde-A	710	Dry ash	950	HD	HnyComb	11/89	15,500
Voerde-B	710	Dry ash	950	HD	HnyComb	10/89	16,500
Herne-1, -2	150[5]	Slag tap	1200	TE[3]	HnyComb	10/89	16,500
Herne-3	300	Slag tap	1500	TE	HnyComb	10/89	18,200
Herne-4	500	Dry ash	400	HD	Plate	12/89	17,000
Luenen-10	150	Slag tap	1200	TE	HnyComb	11/89	16,000
Luenen-11	350	Slag tap	1400	TE	HnyComb	11/89	18,440
Walsum-9	410	Dry ash	650	HD	Plate	10/88	26,000
Walsum-7	150	Slag tap	1200	LD[4]	Plate	10/88	17,000
West-1	350	Slag tap	1400	TE	HnyComb	11/89	17,800
West-2	350	Slag tap	1400	TE	HnyComb	11/89	17,500

[1]High dust (SCR reactor ahead of air heater) [2]Honeycomb [3]Tail end (SCR reactor after FGD system) [4]Low dust (SCR reactor after particulate collector but ahead of FGD system) [5]Each unit

check Siemens list



Tackticks, LLC

General Company Information:

Principal Company Address:

Tackticks, LLC
247 Booth Meadow Lane
Durham, NC 27713

Phone #: 919 – 484 – 1500
Fax#: 919 – 484 – 1544

President: Volker Rummenhohl
vrummenhohl@tackticks.com

Regional: Robert E. Johnson
rjohnson@tackticks.com
913 – 897 – 0727

Tackticks, LLC

1.1 General Company Description

Tackticks, LLC has a broad range of engineering experience with SCR systems and related power plant operations. Tackticks, LLC was formed in 2001 by Volker Rummenhohl after working within the SCR industry for almost twenty years, first in Europe then in the US. Tackticks has been involved with SCR's using gas, coal, oil and all types of waste fuel used in boilers, simple cycle and combined cycle systems and incinerators.

The company's primary focus is optimizing process design, catalyst selection and performance of SCR systems on coal-fired boilers. The company's clients are Electric Utilities, Independent Power Producers, Architect & Engineers, OEM's and component suppliers. Tackticks has also been involved in the design of SCR systems, start ups, ammonia injection grid tuning, performance testing, trouble shooting and O & M support.

Tackticks, LLC has special experience with the design, operation and maintenance support of operating units with generation exceeding 15,000 MW. The company's services are targeted to minimize the operating costs of the SCR system, to diagnose operating problems, to enhance overall performance and to assist Clients in managing the most comprehensive catalyst strategies.

The involvement in the SCR strategy contracts enables Tackticks, LLC to be at the front of technology advancement and development.

Tackticks, LLC also currently owns seventy five percent of the flow modeling company FlowTack, LLC. FlowTack, LLC performs CFD and physical flow models for all kind of technologies. Among those technologies is of course also the SCR technology. FlowTack also designs ammonia injection grids for SCR systems.

General Description of Services

The following is a general description of Tackticks' services:

Process Design

Tackticks can assist Clients define the appropriate SCR design parameters. Historical boiler operating data will be reviewed and assessed to determine unit process data at full, mid and low loads. Tackticks can assist Clients in selecting SCR catalyst performance requirements so that the Client's NOx emission control strategy is effectively met with minimum negative impact due to ammonia slip and SO2 oxidation.

Tackticks will help define process distribution requirements so that long term performance and operational demands are met.

SCR Arrangement

Tackticks can assist Clients in determining preliminary SCR arrangements and reviewing initial design criteria. With the use of Computational Fluid Dynamics modeling, Tackticks can recommend optimal arrangements of duct configuration and flow correction devices in order to maintain appropriate flue gas velocities, velocity distribution, fly ash distribution and ammonia to NOx distribution within the SCR system.

Specification Review & Preparation

Tackticks can assist Clients by reviewing turnkey specifications with special attention paid to, but not limited to, design data, guarantees, process design, equipment, catalyst design, potential impacts on boiler and unit operation.

Tackticks can also prepare technical specifications for Clients. Our company focus is generally applied to catalyst selection, ammonia injection grid design, flow modeling and flow correction requirements, reagent system requirements and performance guarantees.

Proposal Evaluation

Tackticks has also evaluated proposals for Clients. The company's assistance in this area can range from a complete technical assessment of a proposed design and its compliance with the specification to an analysis of a specific technical issue. Tackticks will assist in the development of evaluation criteria, preparation of questions to the suppliers, and recommendation of the most qualified supplier.

SCR Troubleshooting and Optimization

Tackticks can assist Operators in solving current operational issues and suggesting improvements to the SCR system in order to enhance overall performance. Services include systems audits, ammonia injection grid tuning, catalyst testing and system inspections.

Requirements for Annual SCR Operation

Tackticks can review SCR operational procedures to ensure appropriateness for annual operation. This includes all operating sub-systems of the SCR system. Tackticks can evaluate seasonal catalyst performance and update for year-round operation. Catalyst management plans can be updated accordingly to coincide with unit outage schedules.

Volker Rummenhohl
247 Booth Meadow Lane
Durham, NC 27713-5810

Work Experience:

FlowTack, LLC
Manager
January 2004 – Present
Mr. Rummenhohl manages FlowTack, LLC a flow model and computational fluid dynamics company.

Tackticks, LLC
President
February 2001 - Present
Mr. Rummenhohl is currently the president of Tackticks, LLC, a consulting firm located in Durham, North Carolina. Tackticks provides process consulting for air quality control systems and specializes in SCR systems. Consulting work includes review of arrangement drawings, writing and reviewing air quality specifications, general process consulting, training, and support during project startup. Mr. Rummenhohl continues to consult with Black & Veatch on the evaluation and design of SCR projects.

STEAG AG
Manager, North America
September 1993 – February 2001

Mr. Rummenhohl was the Manager of STEAG AG's liaison office in Durham, North Carolina. His responsibilities include marketing and implementing the company's experience and expertise in designing, engineering, startup, commissioning, and performance testing of Selective Catalytic Reduction (SCR) systems in North America. During his time in this position, Mr. Rummenhohl has consulted for a number of U.S. utilities, architectural and engineering firms, and manufacturers, conducted seminars, and presented oral and written testimony for regulatory agencies. He was located in the United States to consult with Black & Veatch on the evaluation and design of domestic SCR projects.

STEAG AG
Division Manager, Environmental Engineering Group
January 1990 - August 1993
Duties included the maintenance and continued improvement / optimization of SCR systems for over 5,300 MW of coal fueled electric and cogeneration capacity owned and operated by STEAG. These systems have now been in operation for in excess of 600,000 cumulative hours. Additionally, Mr. Rummenhohl was responsible for the design and engineering of SCR plants. This includes the three SCR plants for the residual oil fired power station Leuna.

Lentjes AG
Project Engineer and Manager
1983 – 1990

Lentjes AG is one of Germany's largest designers, engineers, and constructors of SCR systems. In the position of project engineer and manager, Mr. Rummenhohl was involved in the design, engineering, procurement, construction, and commissioning of over $600 million of SCR systems throughout Germany. Responsibilities included supervision of the startup and commissioning of SCR retrofit systems for 2,200 MW.

University of Dortmund
1981 - 1983

Mr. Rummenhohl is a 1981 graduate engineer with an advanced degree in chemical engineering ("Diplom Ingenieur," comparable to a U.S. Master of Science degree) from the University of Dortmund. After graduation, Mr. Rummenhohl taught as an Assistant Professor for a period of two years at the University.

U.S. Technical Papers

Pre Heater Pluggage Issues, presented at the 2006 NOx Round Table, Charlotte, NC, January, 2006, Author.

Start-Up and Shutdown of SCR Systems Impact on the Lifetime of the Systems, presented at the 24th Annual Electric Utility Chemistry Workshop at the University of Illinois, May 11-13, 2004, Author.

Effective Catalyst and SCR System Management, presented at the 24th Annual Electric Utility Chemistry Workshop at the University of Illinois, May 11-13, 2004, Coauthor.

SCR Experience on High Sulfur Fuel, presented at the 2003 NOx Round Table, Birmingham, AL January 28-30, 2003, Author.

Design & Initial Start Up Results from the New Madrid SCR Retrofit Project, presented at the ICAC Forum 2000, Washington, DC March 20-24, 2000, Coauthor.

Economic Alternatives for Effective NO_x Emissions Reduction, presented at the DOE SCR and SNCR NO_x Emission Controls Conference, Pittsburgh, Pennsylvania, May 15-16, 1997, Coauthor.

Helping the Utility Compete and Comply: Lessons Learned Lead to Informed Decision-making for NO_x Emissions Reductions, presented at the PowerGen Americas Conference Anaheim, California, December 5-7, 1995, Coauthor.

Effects on Catalytic Activity and SO_2 / SO_3 Conversion of DeNO$_x$ Catalytic Converters Downstream of Oil-Fired Power Plants: Causes and Remedial Measures, presented at EPRI/EPA 1993 Joint Symposium on Stationary NO_x Control, Miami, Florida, May 24-27, 1993, Coauthor.

SNCR, SCR and Hybrid Systems Capabilities, Limitations, and Cost, presented at EPRI/EPA 1995 Joint Symposium on Stationary Combustion NO_x Control, May 16-19, 1995, Coauthor.

The Impact of SCR and SNCR Systems on Plant Equipment and Operations, presented at the ICAC NO_x Emissions Control Conference, Arlington, Virginia, November 2, 1994, Coauthor.

Relating the German DeNO$_x$ Experience to U.S. Power Plants: Lessons Learned from More Than 30,000 MW of DeNO$_x$ Retrofits, presented at the ASME Joint International Power Generation Conference, Phoenix, Arizona, October 3, 1994 Coauthor.

The Effects of Various Parameters on SCR System Cost, presented at the PowerGen Americas '93 Conference, Dallas, Texas, November 17, 1993, Coauthor.

Alternative NO$_x$ Emission Reduction System Comparison, presented at the 1993 USDOE Coal-Fired Power Plant Upgrade Conference, Warsaw, Poland, June 17, 1993, Coauthor.

German Experience Sheds Light on SCR O&M Issues, September 1992 issue of Power magazine, Coauthor.

ROBERT E. JOHNSON

PROFESSIONAL EXPERIENCE

Mar 2007 – Present **Tackticks, LLC – Durham, NC**

Air Pollution Control Consultant -- Specific focus on Selective Catalytic Reduction (SCR) technology and applications. Principal responsibilities include SCR process design analysis and recommendations, Flow Modeling Analysis, SCR performance evaluation, ammonia injection grid design and tuning, SCR system inspections.

2003 – Feb 2007 **Burns & McDonnell Engineers – Kansas City, MO**

SCR Program Manager – Responsible for promoting BMcD's SCR-related activities within the Power Industry. Provided technical consultation on in-house projects to Clients and Project Teams as well as assisting Clients with operating performance evaluations.

Major Accomplishments

- Member of the Team that secured a major SCR design engineering project from a major Midwestern Cooperative.
- Lead technical advisor for ten (10) SCR projects.

1996 – 2003 **C & I Ceramics USA – Alpharetta, GA**
(formerly Siemens Power Generation)

Vice-President, Sales – Responsible for Sales of Siemens' SCR Catalysts to the Power Industry

Major Accomplishments

- Negotiated systemwide agreements with three U.S. Utilities for the supply of SCR catalyst for SIP-related compliance projects.
- Successfully negotiated contracts with other Utilities for similar projects.
- Total Sales in excess of $300 million.

1989 – 1996 **Wahlco Environmental Systems – Leawood, Kansas**

Vice President of New Technologies – Responsible for the commercialization and market development of Wahlco's NOx emission control technology. Coordinated technology assessment and research activities.

Major Accomplishments

- Sold Wahlco's first commercial Staged NOx Reduction System on a gas-fired boiler.
- Negotiated partnerships with key participants in demonstration programs for Staged NOx Reduction System. Instrumental in selecting customers for demonstration sites; successfully negotiated first demonstration on a coal-fired boiler.

- Negotiated first commercial flue gas conditioning installations on a coal-fired cogeneration plant, a hot-side electrostatic precipitator, and the industry's first baghouse application.

1983 – 1989 **Belco Technologies Corporation – Parsippany, New Jersey**

Regional Manager – Directed air pollution control equipment sales for special projects involving new accounts and existing customers with emphasis on flue gas conditioning and microprocessor based control systems.

Major Accomplishments

- Sold Company's first flue gas conditioning system, first precipitator rebuild on a cement kiln, and first new precipitator installation on a cement kiln.
- Sold $2 million of equipment upgrades, control systems and parts.

1983 **Israel Electric Company – Independent Consultant**

1977 – 1982 **Apollo Technologies, Inc. – Regional Manager, Technical Services**

EDUCATION Bachelor of Science, Fairleigh Dickinson University, 1976
Bachelor of Arts, University of Notre Dame, 1975

Technical Papers & Presentations

"Selective Catalytic Reduction Performance Project at Public Service Electric and Gas Company's Mercer Generating Station Unit No. 2;" Wallace, Gibbons et al., presented at EPRI/EPA 1995 Joint Symposium on Stationary Combustion NOx Control, May 16-19, 1995, Kansas City Missouri

"Selective Catalytic Reduction: Successful Commercial Performance on Two U.S. Coal-Fired Boilers;" Wagner, Bullock et al; presented at EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, The Mega Symposium, August 25-29, 1997, Washington, D.C.

"SCR For a 460 MW Coal Fueled Unit: Stanton Unit 2 Design, Startup, and Operation;" Cochran, Scarlett et al; presented at EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, The Mega Symposium, August 25-29, 1997, Washington, D.C.

"Current Practices for Monitoring Ammonia Slip from SCR Processes;" Sigling, Johnson; presented at FETC 1998 Conference on SCR and SNCR for NOx Control, May, 1998, Pittsburgh, Pennsylvania

"Powder River Basin (PRB) Coal and High Arsenic Concentrations: Catalyst Specific Issues and Operating Experience;" Rigby, Hums et al.; presented at EPRI Workshop on Selective Catalytic Reduction, April 18-21, 2000, Memphis, Tennessee

"SCR Catalyst Design Issues and Operating Experience: Coals with High Arsenic Concentrations and Coals from the Powder River Basin;" Rigby, Sigling, et al; presented at The International Joint Power Generation Conference, July 23-28, 2000, Miami Beach, Florida

"U.S. Utility Coal-Fired Selective Catalytic Reduction Applications: SCR Catalyst-Specific Issues and Operating Experience;" Sigling, Johnson; presented at EPRI 2001 Workshop on Selective Catalytic Reduction, November 13-15, 2001, Baltimore, Maryland

"U.S. Utility Coal-Fired SCR Applications: SCR Catalyst-Specific Issues and Operating Experiences;" Sigling, Johnson; presented at ICAC Forum 2002, February, 2002, Houston, Texas

"SCR Catalyst Performance: New Information for U.S. Operators;" Sigling, Johnson; presented at EPRI 2002 Workshop on Selective Catalytic Reduction; October 16, 2002, Atlanta, Georgia

"Peak SCR Performance Requires Consolidated Program Management;" presented at Electric Power 2004, April 1, 2004, Baltimore, Maryland

"SCR Update for Simple Cycle Gas Turbine Applications;" presented at Power Gen International 2004, December, 2004, Orlando, Florida

"Selective Catalytic Reduction System Design Considerations;" presented at Power Gen International 2004, December, 2004, Orlando, Florida

"Selective Catalytic Reduction System Design Considerations;" presented at the 110th Plant Design and Operating Committee, January, 2005, Fort Worth, Texas

"SCR Program Management;" presented at the 110th Plant Design and Operating Committee, January, 2005, Fort Worth, Texas

"How Can You Maximize Results from Your SCR Catalyst Replacement?" presented at Burns & McDonnell 2006 Coal Symposium, April, 2006, Kansas City, Missouri

"SCR Program Management: A Powerful Program to Enhance Plant Operations;" presented at the 57th Annual Generation Conference, Association of Rural Electric Generating Cooperatives, June, 2006, Cincinnati, Ohio

"Thomas Hill Unit 3 SCR Retrofit Design Approach Avoids Increases in Draft Loss;" presented at Coal Gen 2006, August, 2006, Cincinnati, Ohio

"SCR Technology for Coal Fired Boilers: Design Considerations for Proper Performance;" presented at Power Gen Asia, September, 2006, Hong Kong

"Environmental Controls Retrofit Project at AECI Thomas Hill Energy Center;" presented at EPRI 2006 Workshop on SCR, November, 2006, Dearborn, Michigan

"Thomas Hill Unit 3 SCR Retrofit Design Approach Avoids Increases in Draft Loss;" presented at Power Gen International 2006, November, 2006, Orlando, Florida

Tackticks LLC SCR Consulting and Process Engineering Reference List

June, 2007

Plant	Size MW	Fuel	Utility/IPP	Time Service Provided	Remarks
New Madrid 1	600	PRB Coal	AECI	2001	High Dust
Stuart 1-4	4*600	Bit. Coal	Dayton Power & Light	2001 -	High Dust
Killen 2	600	Bit. Coal	Dayton Power & Light	2001 -	Low Dust/ Hot ESP
Cully 3	265	Bit. Coal	VECTREN	2001 - 2003	High Dust
Warrick 4	325	Bit. Coal	VECTREN	2001 -	High Dust
Brown 1	265	Bit. Coal	VECTREN	2002 -	High Dust
Brown 2	265	Bit. Coal	VECTREN	2001 -	High Dust
Desert Basin (Trouble Shooting)	180	Gas	Reliant Energy	2001	HRSG
Michigan City 12	540	PRB/Bit. Blend	NIPSCO	2001 - 2003	High Dust
Shafer 14	540	Bit. Coal	NIPSCO	2001 -	High Dust
Bailly 8	420	High Sulfur Coal	NIPSCO	2002 -	High Dust
Dallman 31 & 32	2 * 85	High Sulfur Coal	CWLP Springfield	2001 - 2003	High Dust
Dallman 33	150	High Sulfur Coal	CWLP Springfield	2001 - 2003	High Dust
Lambton 3 & 4	2 * 500	High Sulfur Coal	Ontario Power Generation	2001 - 2003	High Dust
Nanticoke 7 & 8	2 * 500	PRB/ Bit. Blend	Ontario Power Generation	2001 -	High Dust
E.D. Edwards 3	**365**	**Bit. Coal**	**Ameren**	**Current**	**High Dust**
Duck Creek	**440**	**Bit. Coal**	**Ameren**	**Current**	**High Dust**
Mercer 1 & 2	2 * 325	Bit. Coal	PSE&G	2002 -	Low Dust/ Cold ESP
Powerton (project delayed)	2 * 700	Bit. Coal	MidWest Gen	2001 – 2002	Low Dust/ Cold ESP
Homer City 1 & 2 (upgrades)	2 * 600	Bit. Coal	MidWest Gen	2002-2005	High Dust
Brandon Shores 1 & 2 (upgrades)	2 * 650	Bit. Coal	Constellation Energy	2002	Low Dust/ Hot ESP
Canal 1 & 2 (upgrades)	2 * 600	Oil	MIRANT	2001 -	High Dust

Plant	Size MW	Fuel	Utility/IPP	Time Service Provided	Remarks
Lovett 3,4,5	435	Bit. Coal	MIRANT	2002 -	High Dust
Harding Street	470	Bit. Coal	AES	2003-2004	High Dust
Weston	600	Bit. Coal	Wisconsin Public Service Corp.	2004 -	High Dust
Prairie State	2*750	High Sulfur Coal	Peabody Energy	2004 -	High Dust
Thoroughbred	2*750	High Sulfur Coal	Peabody Energy	2004 -	High Dust
Homer City 3 (upgrades)	**650**	**Bit. Coal**	**MidWest Gen**	**2002-2005**	**High Dust**
Thomas Hill 1,2,3	**1135**	**PRB**	**AECI**	**2005-2010**	**High Dust**
Elmer Smith PS Unit 1 (Trouble Shooting)	150	Bit. Coal	OMU	2005	High Dust
St. Johns River Power Plant	**2* 660**	**Petcoke, Bit. Coal**	**SJRPP**	**2005-2009**	**High Dust**
Northport Unit 3	150	Oil	Key Spann Energy	2005-	High Dust
La Cygne Unit 1	800	PRB	Kansas Power & Light	2005	High Dust
Sibley Unit 3	**420**	**PRB**	**Aquila**	**Current**	**High Dust**
Southwest Unit 1	**194**	**PRB**	**City Utilities Springfield MO**	**Current**	**High Dust**
Oak Creek Units 5 - 8	**1,200**	**PRB**	**WE Energy**	**Current**	**Tail End**
Trimble County Unit 2	**900**	**Bit. Coal**	**LGE Energy**	**Current**	**High Dust**
Southern Company (Various Plants)		**PRB, Bit. Coal**	**Southern Company**	**Current**	**High Dust**
Total	**> 28,300 MW**				

Bachman, Tom A.

From: Buenning.Hans@epamail.epa.gov
Sent: Tuesday, April 28, 2009 5:31 PM
To: Bachman, Tom A.
Cc: O'Clair, Terry L.; JMacLaug@ENRD.USDOJ.GOV; Rutherford.Ron@epamail.epa.gov; Morris.Brenda@epamail.epa.gov; Kodish.Jeff@epamail.epa.gov
Subject: Kling Paper

Attachments: Hans H Response to Tom Bachmann's questions 4-21-09.doc

Hans H
se to Tom Bac

Hi Tom - I have attached a document prepared by Hans Hartenstein responding to your emails of 4/15/09 & 4/16/09 on his informal "Thoughts on the Kling Paper" and accompanying calculations that I originally sent to you on 4/9/09. As you will see, Mr. Hartenstein acknowledges the mathematical errors that you cited and agrees with much of what you stated in your emails. The attached document hopefully clarifies those items that you raised and helps provide some insights on how the Kling and Crespi papers might relate to TESCR at MRYS.

Let me know if you have any questions and thanks for bringing the problems with the previous submittal to our attention.

-Hans

Hans Buenning
US EPA, Region 8 (8ENF-AT)
Air & Toxics Technical Enforcement Program
1595 Wynkoop St.
Denver, CO 80202-1129
303-312-6486

(See attached file: Hans H Response to Tom Bachmann's questions
4-21-09.doc)

Response to Tom Bachmann's questions forwarded to me by Hans Buenning via e-mails dated 4/15/09 and 4/16/09.

In his e-mail dated 4/15/09 Mr. Bachmann stated: *My calculations indicate Center lignite has an average sodium content of over 4,800 ppmd (dry basis) and over 1,600 ppmd of potassium (see attached calculations). This is over 4 times more than Mr. Hartenstein calculated. Of course this is an average and the sodium and potassium can be much higher. These values are higher than for the fuels Kling evaluated based on the sodium and potassium content. In addition, Minnkota is a cyclone boiler versus fluidized bed boilers and PC's. I note this for HDSCR. Of course, for a tail-end SCR the sodium and potassium in the flue gas will be much lower.*

In a follow up e-mail dated 4/16/09 Mr. Bachmann stated: *Just to follow up on my previous email, attached is a corrected version of Mr. Hartenstein's spreadsheet. The corrections are shown in green. He made 2 errors. First, when converting from a wet basis to dry basis he divided by the moisture content instead of one minus the moisture content. Second, when converting from percent Na_2O and K_2O for the Center lignite he was a factor of 10 off. 1.33% K_2O should be 13,300 ppm instead of 1,330 ppm and 4.4% Na_2O should be 44,000 ppm instead of 4,400 ppm. The difference in my calculations is that I converted Na_2O to Na and K_2O to K plus I used 35% moisture instead of 37.13%. I would be interested in any changes to his statements in the "Thoughts on Kling paper" document.*

I acknowledge both errors that Mr. Bachmann identified in my calculations as outlined in his follow up e-mail and agree with his calculations. I also do agree with his statement that the fuels Kling evaluated may have been lower in total sodium and potassium than Center lignite, which, however, would only be relevant for a HDSCR application. In a TESCR application at Minnkota the sodium and potassium containing concentration of particles in the relevant size range of less than 0.1 microns must be expected to be one to two orders of magnitude lower than what Kling exposed the catalyst to in his HDSCR studies. This argument will be supported with data shown below.

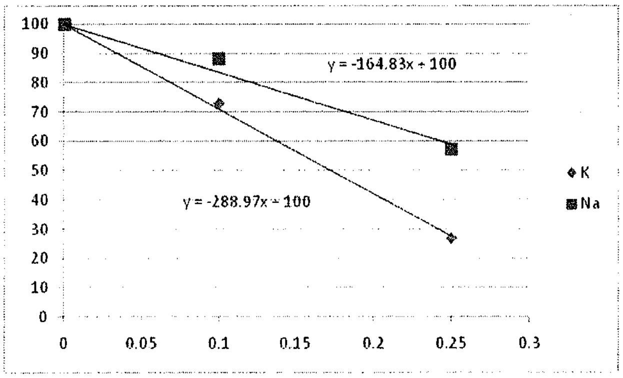
Mr. Bachmann further stated in his initial e-mail dated 4/15/09 that: *Comparison of different flue gases on a ppm/MMBtu basis is, in my opinion, not the best comparison because the amount of flue gas generated by various fuels is different on a MMBTU basis. Most researchers report the deactivation contaminants on a concentration basis (i.e. ppm or mg/Nm^3)).*

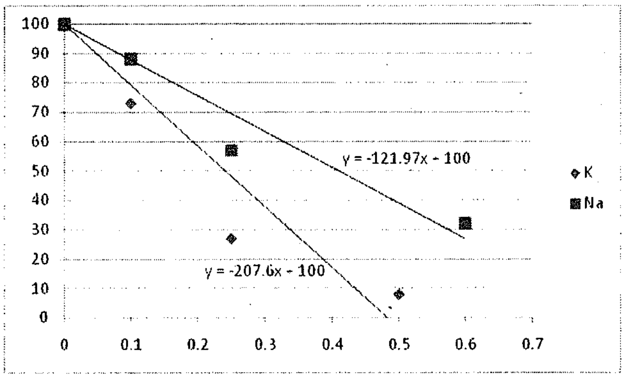
I absolutely agree with this statement and therefore all following comments are based on these units only. Not as an excuse for my error but simply as an explanation as to why I introduced the ppm/MMBtu unit may serve the fact that the Kling paper only reports potassium and sodium concentrations of particles with an aerodynamic diameter of less than 0.1 microns in flue gas concentration units in mg/Nm^3 (Table 5) rather than for all particle sizes. I merely – and certainly incorrectly – tried to quickly calculate some total sodium and potassium concentrations for Center lignite, which, however as we all agree upon, are not really relevant anyway. Mr. Bachmann confirms this by stating in his e-mail dated 4/15/09 that: *In item No. 6, Mr. Hartenstein talks about the form of the sodium and potassium and the effect on deactivation of the SCR. I agree that the form is important. He attributes the ability to inject SBS to control SO_3 to the form of the sodium injected. However, if you review the URS slide presentation, it*

Based on Figure 4 of Crespi, the slopes of the catalyst deactivations due to sodium and potassium up to a V molar ratio of about 0.25 differ by a factor of approximately 1.76. Up to a V molar ratio of about 0.5 the slopes differ by a factor of about 1.70 and past a V molar ratio of 0.5 the slopes flatten out to almost 0 past a V molar ratio of 1. In the following, the determination of these factors will be detailed.

In his e-mail dated 4/16/09 Mr. Bachmann commented: *There is no need to send the Crespi paper as I had requested if Mr. Hartenstein is referring to the paper titled "The influence of biomass burning in the design of an SCR installation". Mr. Hartenstein indicated that potassium is 1.7 times more potent as a catalyst deactivating chemical than sodium based on the Crespi paper. I believe he is referring to Figure 6 in the paper. If so, my interpretation of that figure is only that the molecular weight of potassium is 1.7 times that of sodium (39.1 versus 23.0). The x-axis indicates weight% K equivalent, not potency. The only way you can get a weight percent equivalent is using the molecular weights. If Crespi was trying to indicate a deactivation potency, I believe the formula should be K + Na/1.7; not, K+1.7*Na, since potassium is the more potent chemical.*

Even though Mr. Bachmann's statement concerning the representations on Figure 6 is absolutely correct, I based my statement of Figure 4. Coincidently, the number 1.7 appears in both cases. Extracted from Figure 4 data, the two graphs below show the approximations of the linear deactivations caused by sodium and potassium between V molar ratios of 0 and 0.25 as well as 0 and 0.5 with the equations of the best fit straight lines displayed on the graphs. As can easily be calculated the ratios of the slopes are in both cases approximately 1.7.





Based on this analysis of the data presented by Crespi, I stated that Crespi established a deactivation potency factor between potassium and sodium of approximately 1.7. In other words, potassium is 1.7 times more potent in deactivating catalyst – at least up to a V molar ratio of about 0.5 – than sodium. Therefore, it is correctly represented as 1.7K + Na or K + Na/1.7.

However, the most relevant question is really what is the concentration of sodium and potassium containing particles with an aerodynamic diameter of less than 0.1 microns in case of Minnkota downstream of their scrubber and how do these concentrations compare to the concentrations found by Kling.

don't result in any significant changes of my previous statements concerning the Kling paper and the relevance of its data for this case with respect to the technical feasibility of TESCR for Minnkota's units burning Center lignite.

Table 3 of the Kling paper represents that in the lab standard SCR catalyst deactivated 15% over a period of 1,488 hours in a HDSCR of a PC-fired 400 MW unit burning Uppsala peat + 15% wood, which is a far cry from the 40% claimed in Minnkota's Supplement for Consideration. It also needs to be born in mind that Kling points out that the deactivation of the short catalyst samples tested by Kling in the lab cannot directly be compared with the deactivation of full length catalyst in a full scale SCR reactor. Kling states that since the poisonous components accumulate at the inlet of the catalyst, the catalyst deactivation of the short samples used in the lab will be higher than what would be experienced in a full scale SCR burning the same fuel.

As outlined above, a TESCR after a Center lignite fired Minnkota unit would see even in a absolutely unrealistic worst case scenario a concentration of at least 30 times (more likely 60 – 100 times) less of the relevant combined alkali concentration in particles smaller than 0.1 microns downstream of the scrubber. A factor of 30 would result in an expected catalyst life of at least 45,000 hours. Crespi reports typical TESCR deactivation rates using biofuels at 40% after 50,000 hours – see figure below.

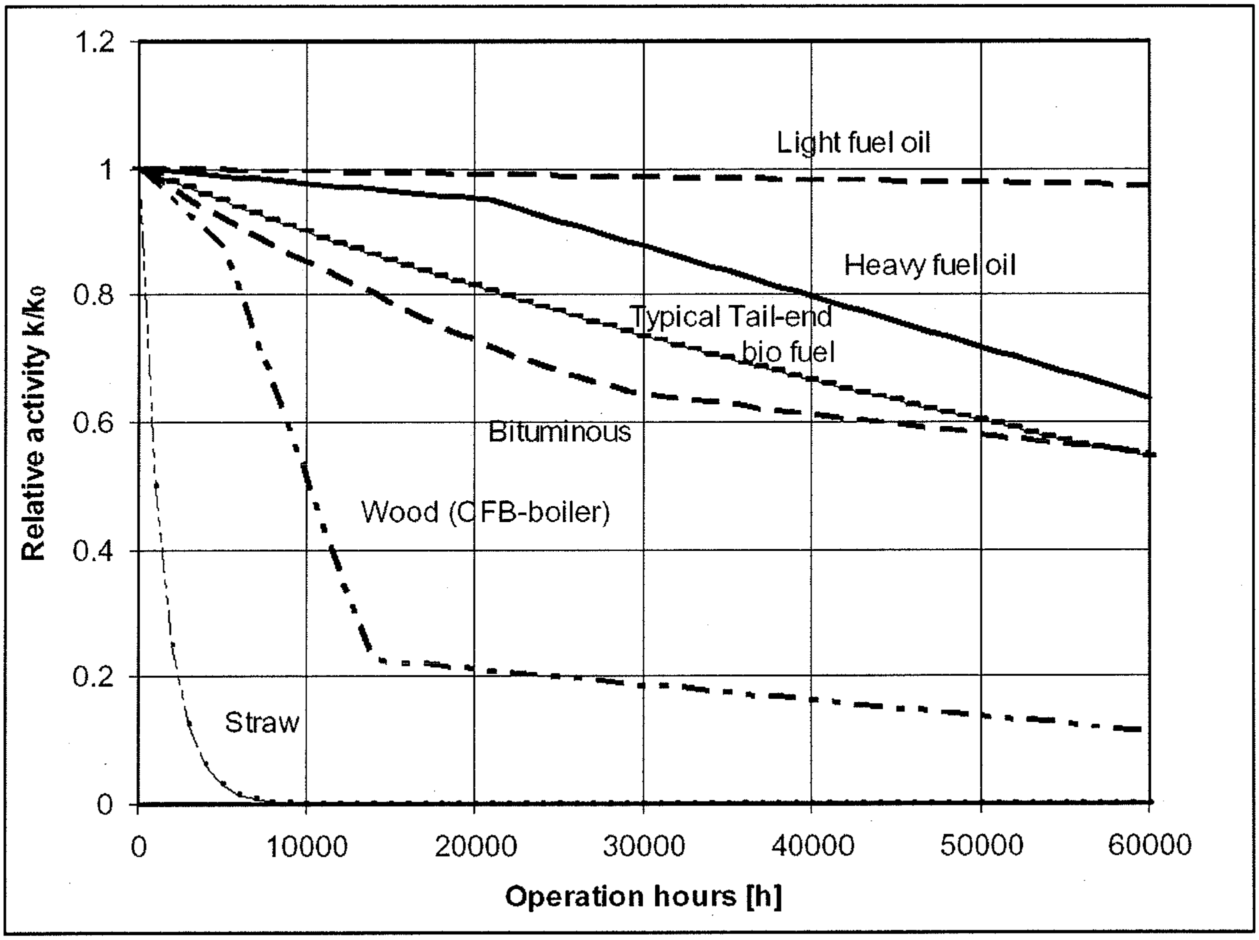


Figure 3: typical catalyst deactivation ratios for different fuel and plant configurations [6]

Minnkota Power
MPC COOPERATIVE, INC.
Your Touchstone Energy® Partner

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February 20, 2009

FEB 2009
Received
Air Quality

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue, 2nd Fl
Bismarck, ND 58501-1947

RE: Supplemental information for the North Dakota Department of Health's Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, dated June 2008

Dear Mr. O'Clair:

In response to the Department's request for additional information concerning the use of Low Dust SCRs and Tail End SCRs at Milton R. Young Station, please find enclosed the report titled "Supplemental Information for Consideration Regarding NOx BACT for M.R. Young Units 1 and 2: Technical Feasibility Issues for TESCR or LDSCR Retrofit, February 20, 2009".

Minnkota continues to believe the NDDH's preliminary BACT determination dated June 2008 to be correct and appropriate.

Should you have any questions concerning this submittal, please contact me at 701-795-4221.

Sincerely,

MINNKOTA POWER COOPERATIVE, INC.

John T. Graves

John T. Graves, P.E.
Environmental Manager

C: David Sogard

Supplemental Information for Consideration by NDDH Regarding NOx BACT for M.R. Young Units 1 and 2: Technical Feasibility Issues for TESCR or LDSCR Retrofit

prepared for

Minnkota Power Cooperative, Inc.

And

Square Butte Electric Cooperative

February 20, 2009

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri
and
Steve Benson, PhD
Department of Chemical Engineering,
University of North Dakota

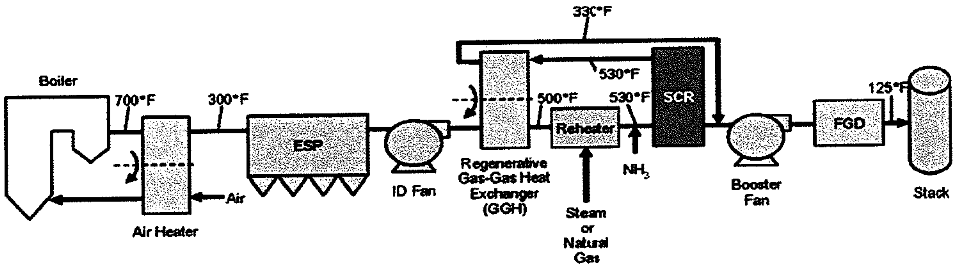
Project No. 31777

Supplemental Information for Consideration Regarding NOx BACT for M.R. Young Units 1 and 2: Technical Feasibility Issues for TESCR or LDSCR Retrofit

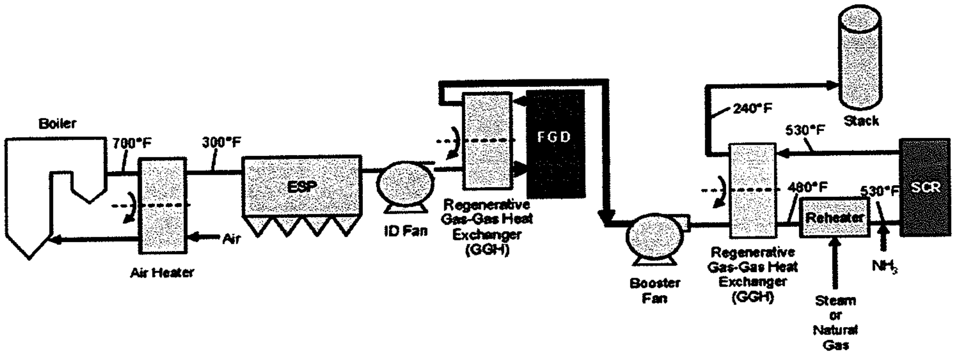
February 20, 2009

1. Purpose

Burns & McDonnell (B&McD), along with Steve Benson of the Department of Chemical Engineering at the University of North Dakota[1], have reviewed the technical literature provided by the North Dakota Department of Health (NDDH) regarding submicron particle collection and penetration for dry electrostatic precipitators (ESPs), and have prepared this document in response. The information and commentary provided herein are being submitted to NDDH for consideration relative to selective catalytic reduction (SCR) technology infeasibility for control of nitrogen oxides emitted from Milton R. Young Station Units 1 and 2. Issues related to the technical infeasibility of SCRs located in both the low-dust configuration (LDSCR) and the tail-end configuration (TESCR) are addressed. [Refer to the basic schematic diagrams below].



Low Dust



Tail End

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[1] formerly employed by Energy & Environmental Research Center (EERC) of the University of North Dakota.

We continue to believe that the administrative record fully supports a finding by the NDDH that separated over-fire air (SOFA) in conjunction with selective non-catalytic reduction (SNCR) technology is Best Available Control Technology (BACT) for NOx control for electric generating units that utilize cyclone burners firing North Dakota lignite.

2. Scope

The following sections address specific topics pertaining to the NDDH's Preliminary NO_X BACT Determination for Nitrogen Oxides for Milton R. Young Station Units 1 and 2, dated June 2008 (NDDH, 2008)

- Significance of submicron aerosol particle removal by ESPs and wet FGD
- Evaluation of submicron particle penetration data provided by NDDH
- Sodium-rich aerosol formation and penetration through ESP and FGD at M. R. Young Station firing North Dakota lignite
    - Form of sodium in Center lignite
    - Vaporization of sodium in the high temperature cyclones' combustion process
    - Condensation of sodium and concentrating in the submicron size fraction
    - Electrostatic precipitator collection efficiency
    - Aerosol capture efficiency in scrubbers
    - Powerspan testing at MRYS
    - MRYS sulfate aerosol sampling
- Determination of Sodium Loading Adversely Affecting SCR Catalyst Performance
- Alkali Aerosol Loading and Catalyst Deactivation
- Experience of ESP/FGD equipped utility plants co-firing biomass and coal with TESCR
- Relevance of recent TESCR investigations at We Energies' South Oak Creek Station
- Relevance of ongoing LDSCR installation at We Energies' South Oak Creek Station
- Relevance of existing LDSCR installation at PSEG Mercer Station
- Additional technical feasibility issues for TESCR at MRYS
- Summary and Conclusions

3. Significance of Submicron Aerosol Particle Removal by ESPs and Wet FGD

The removal percentage of submicron or aerosol particles by an ESP or any other device is not important. The key is not what is removed, but rather the quantity that is not removed. The amount (mass and number) of submicron and ultrafine particles, as well as the speciation of the particles which pass through the ESP, are extremely important. These particles have the following detrimental characteristics:

- Condensed vapor phase species concentrate in the less than 1 µm size fraction and are in the range of particle sizes where ESPs and wet flue gas desulfurization systems (FGDs) are ineffective in capturing them
- Small particles that can penetrate deep into catalyst pores
- Highly reactive, because of chemistry [rich in sodium (Na), potassium (K), sulfur (S), phosphorus (P)], which results in poisoning sites
- Highly reactive, because of physical characteristics – high surface area can react with gas phase species, which results in blinding of pores
- Highly concentrated because of the removal of larger particles by cyclone and air pollution control devices
- Highly concentrated aerosols (not diluted by large particles) that upon accumulation can efficiently bond together causing catalyst blinding and are available to poison active sites

4. Evaluation of Submicron Particle Penetration Data provided by NDDH

The NDDH provided publications on the efficiency of ESPs and scrubbers to remove particulate as well as penetration of aerosol particles through the devices. The following are some of the key conclusions that can be drawn from the review of the information described in these papers. The information provided indicates poor collection efficiency of submicron particles:

- The particulate collection efficiencies for the coarse fraction particles or particles larger than 1 to 5 µm in ESPs are generally very good (99.9%).

- For particles less than 1 µm, the collection efficiency drops off significantly.
- Particles in the finer size fractions are largely composed of condensed vapor phase species such as sodium, potassium, chlorine (Cl), and sulfur.
- Higher combustion temperatures result in more vaporization and increased levels of submicron particles.
- Emission rates downstream of ESPs described in the reports range from 4,500 to 50,000 µg/Nm^3. The particulate are dominated by aerosols rich in sodium and potassium. NOTE: The level of 22,500 µg/Nm^3 of sodium and potassium rich fly ash derived from biomass resulted in catalyst deactivation of 40 % in 1500 hours (Kling and others, 2007).

Specific observations and/or comments on each of the documents provided by NDDH are presented below:

Mohr, M., Ylatalo, S., Klippel, N., Kauppinen, E.I., Riccious, O., and Burtscher, H., Submicron Fly Ash Penetration through Electrostatic Precipitators at Two Coal Power Plants, Aerosol Science and Technology 24:191-204(1996)

Measurement of the size distribution of fine particulate (diameter less than 0.5µm) at the inlet and outlet of the ESP for two full scale pulverized coal fired power plants was conducted. The coals fired consisted of high volatile bituminous coals from South Africa and Columbia. The characteristics of these coals are summarized in Table 1. The analysis indicates very low levels of sodium as well as other alkali and alkaline earth elements [K, calcium (Ca), and magnesium (Mg)]. The potential for formation of alkali rich aerosols from these coals is extremely small because of the form of the alkali and abundance.

Table 1. Coal analysis (Mohr and others, 1996)

COAL				
Country		South Africa	Colombia	South Africa
Coal field		Klein Kopie	Eldorado	Klein Kopie
Location of burning		Plant A	Plant A	Plant B
Date		9.5.94	17.5.94	11.8.93
Proximate analysis				
Total moisture	%	9.9	13.5	7.4
dry weight bases				
Ash	%	17.1	10.2	16.2
Volatile matter	%	20.7	35.5	23
fixed carbon	%	62.2	54.2	60.9
Gross calorific value	MJ/kg	27.42	29.99	27.34
Ultimate analysis				
Carbon	%	70.3	73.4	68.4
Hydrogen	%	3.4	4.6	1.5
Nitrogen	%	1.7	1.5	3.5
Oxygen	%	7	9.4	9.9
Sulfur	%	0.43	0.81	0.5
Coal ash				
P_2O_5	%	1.2	0.3	1.2
SiO_2	%	45.3	55.7	47.7
Fe_2O_3	%	3.5	7.3	3.1
Al_2O_3	%	31.4	21.0	33.2
TiO_2	%	1.6	0.9	1.7
CaO	%	7.3	4.1	6.2
MgO	%	1.7	2.1	1.4
SO_3	%	5.4	3.1	4.8
K_2O	%	1.0	2.1	0.7
Na_2O	%	0.3	0.6	0.2
Li_2O	%	0.0	0.0	0.0

By comparison, Table 2 summarizes the average lignite properties relevant to MRYS. It can be seen that the characteristics of the MRYS coals are very different and will produce significantly different size distributions of ash than the coals fired in the plants reported by Mohr and others, 1996.

Table 2. Average Center lignite and ash composition (moisture, ash, sulfur, and heating value expressed on an as-received basis; and ash composition expressed as weight percent equivalent oxide of the ash).

	Moisture,%	Ash, %	Sulfur, %	Btu/lb	Al_2O_3	BaO	CaO	Fe_2O_3	MgO	P_2O_5	K_2O	SiO_2	Na_2O	SO_3
Average	37.13	9.64	0.98	6578	11.68	0.52	13.15	8.90	3.99	0.12	1.33	36.04	4.40	18.39

This testing has little relevance to the collection of ash in the MRY boilers for two primary reasons. The first is the firing type. The boilers are pulverized coal (PC)-fired and partitioning to the finer ash fraction will be much lower than that observed for cyclone-fired boilers. The second reason is coal type. The coals tested are bituminous coals. The ash forming components in the bituminous coals are mineral grains with no organically associated elements (Na, K, Ca and Mg). The fraction of the elements in an easily vaporizable form is much lower in the bituminous coals producing lower levels of ash in the smaller sized fractions.

Nobrega, S.W., Falaguasta, M.C.R., and Coury, J.R., A Study of a Wire-Plate Electrostatic Precipitator Operating in the Removal of Poly dispersed Particles, Brazilian Journal of Chemical Engineering, Vol 21, No. 02, pp 273-284, April-June 2004.

This paper is a laboratory and computer modeling effort that examined the performance of ESPs. The precipitators tested were small scale laboratory systems. A phosphatic concentrate was used as particulate. Computational models for predicting fine particle removal in ESPs were improved. However, the relationship to particulate collection from coal fired power systems is small.

Power Station Emissions Handbook, Cooperative Research Centre for Coal in Sustainable Development, http://www.ddsd.biz/PSE_Handbook/5/6/5/index.cfm accessed 11/24/2008.

This document states:

"Wet scrubbers can remove more than 90% for particles with diameters above 10 microns. Efficiencies for smaller particles will be significantly lower."

"The size distribution of the dust influences the overall ESP collection efficiency. Particles in the range of 0.1 to 1.0 µm are the most difficult for an ESP to collect. "

"ESP collection efficiency is particularly affected by several factors including coal ash resistivity, gas temperature, chemical composition and particle size distribution (Wu 2001)."

There is no discussion on fly ash types that are collected. Only general data is provided. Application to high sodium lignite derived coal ashes is not apparent from the website.

ICAC Institute of Clean Air Companies, Particulate controls, http://www.icac.com/i4a/pages/index.cfm?pageid=3398

This website states:

"Precipitator collection efficiencies will be somewhat lower for particles with diameters near 0.3 microns. The reason for a minimum in collection efficiency for 0.3 micron particles is that both particle charge and the resistance of the gas to particle motion both increase with particle size. Near 0.3 micron, the particle charge is low enough and the resistance to particle motion is high enough that particles are collected relatively poorly."

These conclusions indicate that aerosols can penetrate through ESPs.

Lind, T., Hokkinen, J., and Jokiniemi, J.K., Saarikoski,S., and Hillamo, R., Electrostatic Precipitator Collection efficiency and Trace Element Emissions from Co-Combustion of Biomass and Recovered Fuel in Fluidized-bed Combustion, Environmental Science and Technology, 2003, 37, 2842-2846.

This paper describes the removal efficiency of ash particles produced in a 66 megawatt (MW) biomass-fired bubbling bed fluidized bed combustion (FBC) system. Fluidized bed combustion systems operate at lower temperatures (1400 to 1600 °F) than conventional pulverized coal-fired or cyclone-fired utility boilers. The bed material in the FBC was sand. The fuel was mixture of peat and wood wastes. Fluidized bed systems typically have significant levels of entrained ash particles that provide sites for condensation of vaporized species. The particles that penetrated the ESP were found to contain mostly alkali salts (Na, K, Cl, and SO_4). The quantity of materials penetrating the ESP was 4.5 to 9 mg/Nm^3 (4,500 to 9,000 µg/Nm^3).

The 2003 paper by Lind references her earlier work on ash formation mechanisms (Lind, and others, 2000). This paper describes in detail the mechanisms of formation of the aerosol particles and that they are enriched in alkali salts (Na, K).

Ohlstrom, M., Jokiniemi, J., Hokkinen, J., Makkonen, P., and Tissari, J., Combating Particulate Emissions in Energy Generation and Industry, Tekes, VTT Technical Research Centre of Finland, 2006.

This paper also describes the concentrating of vaporized elements such as sodium and potassium in the fine (less than 1 µm) size fraction. The authors also state "higher combustion temperatures typically increase the amount of fine particle released." In addition, they discuss the fact that "Electrostatic precipitators are at their least efficient when handling particle sizes between 0.1 µm to 1 µm." They indicated in Table 8 on pg 29 of the report that the emission rates ranged from 15 to 50 mg/Nm^3 (15,000 to 50,000 µg/Nm^3) from the ESP. This paper also shows that scrubbers are extremely ineffective in removing aerosols.

5. Sodium-Rich Aerosol Formation and Penetration Through ESP and FGD at M. R. Young Station Firing North Dakota Lignite

As described above, the fly ash penetration derived from the preceding described literature is not fully relevant to MRYS due to the significant differences in the sodium content of the fuels fired and the differences in the fuel firing mechanism employed in the plants tested. The following discussion will briefly review the following topics:

- Form of sodium in Center lignite
- Vaporization of sodium in the high temperature cyclones' combustion process
- Condensation of sodium and concentrating in the submicron size fraction
- Electrostatic precipitator collection efficiency for fine particulate and relationship to ash produced from Center lignite
- Aerosol capture efficiency in scrubbers
- Powerspan testing at MRYS
- MRYS sulfate aerosol sampling.

Form of Sodium in Center Lignite

Sodium is associated with the organic matrix in Center lignite. That means the sodium is atomically dispersed in the organic matrix. The sodium is associated with a carboxylic acid groups (ion exchange sites). The carboxylic acid groups act as bonding sites for various elements such as Ba, Ca, Mg, and Sr along with minor amounts of K. Figure 1 illustrates the bonding of sodium to the organic fraction of the coal and the association of other coal impurities.

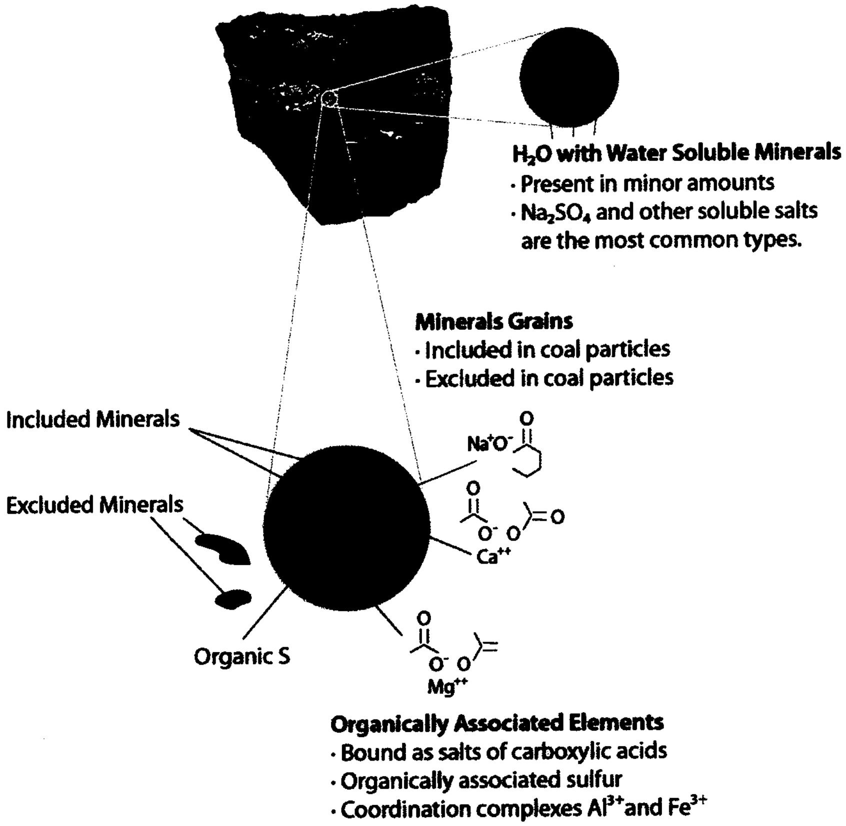


Figure 1. Form of sodium in coal (Benson and Laumb, 2008).

Vaporization of Sodium in the High Temperature Cyclones' Combustion Process

Sodium is a volatile element and is in the easily volatilized organic form in Center lignite and will be transformed into a gas upon combustion. The vaporization of sodium during the combustion of lignite is a very well known fact that has been examined by numerous investigators, including work conducted by MIT, CalTech, Sandia National Laboratory, National Energy Technology Laboratory, University of Utah, and others (see review by Lighty and others, 2000). For example, research conducted by Senior and others (2000) reported that relative to other coals, North Dakota lignite produced more vaporized ash. The actual amount vaporized for ND lignite is double the level vaporized as compared to subbituminous and lignite coals from Montana as illustrated in Figure 2.

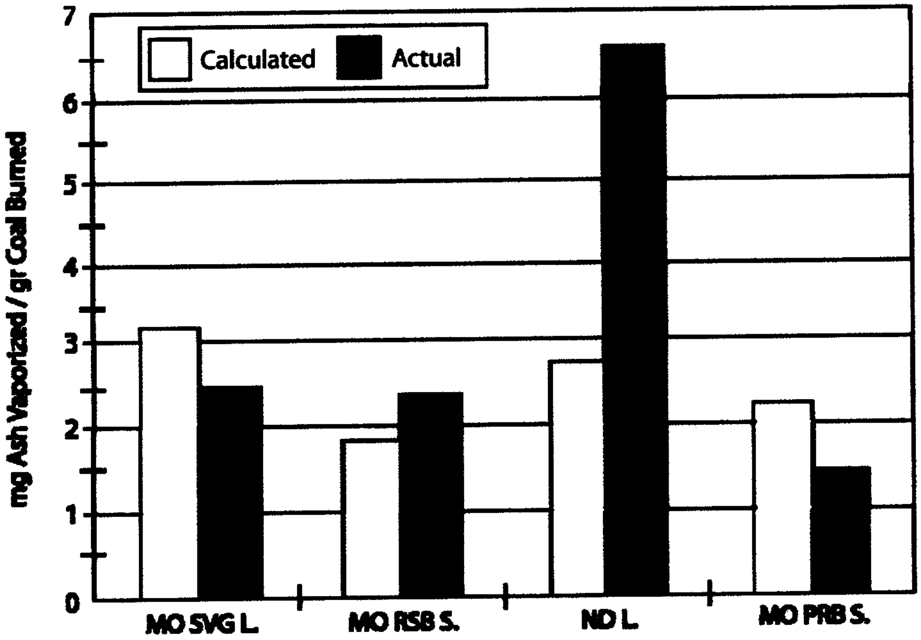


Figure 2. Ash vaporized during combustion of lignite and subbituminous coals (Senior and others, 2000).

Work conducted at the MRY plant related to the vaporization of sodium from a cyclone fired system is illustrated in Figure 3. The results show over two thirds of the sodium is not retained in the slag and is vaporized in the high sodium lower ash coals 1-3. In the low sodium high ash coals 4-5, very small amounts of the sodium was vaporized.

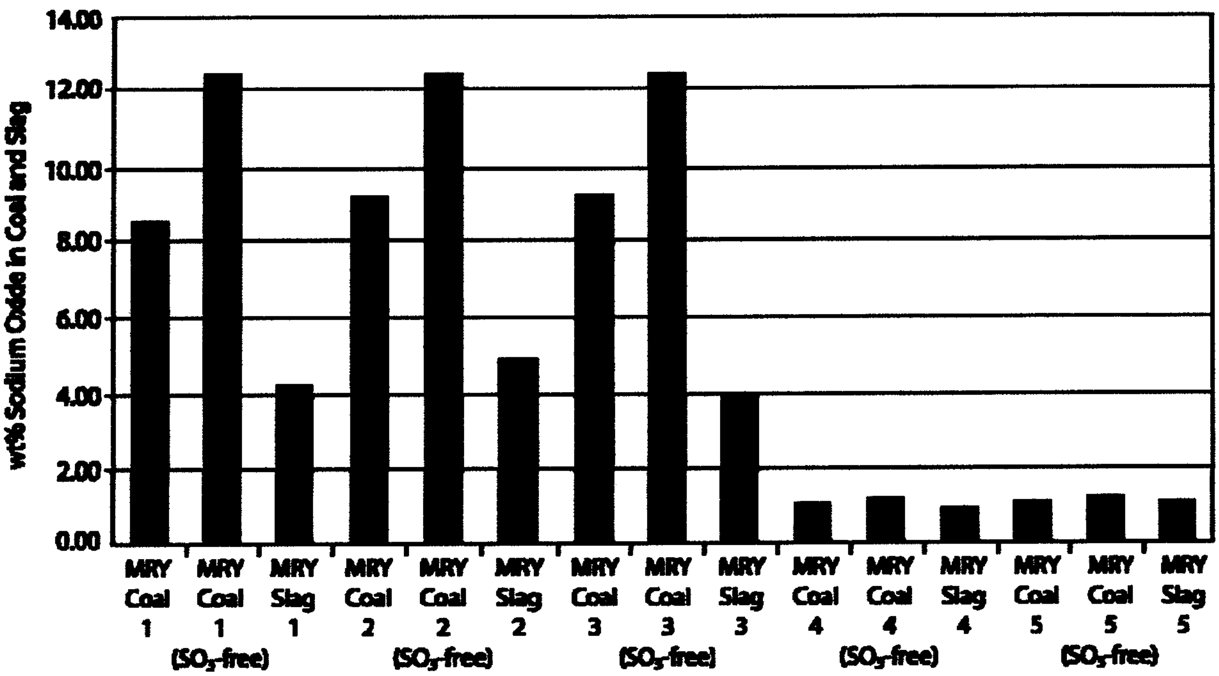


Figure 3. Comparison of sodium levels in Center lignite coal and slag samples.

Condensation of Sodium and Concentrating in the Submicron Size Fraction

EPA has evaluated the literature on particle formation during combustion and from other sources and incorporated it into an educational module that was found on the following website: (http://www.epa.gov/apti/bces/module3/formation/formate.htm). The classification of particle types shown by EPA is illustrated in Figure 4. The EPA classification is consistent with the review conducted by Lighty and others (2000). Vaporized species can condense heterogeneously on surfaces of other entrained coarse ash particles and can condense homogeneously to form the fine and ultrafine particles. The distribution of particles depicted in Figure 4 is shown on a "frequency percent particles by mass" basis. The number of particles versus size is also important. A comparison of the number of particles and particle size is summarized in Table 3. The number of aerosol particles is significant. These particles have high surface areas and are very reactive.

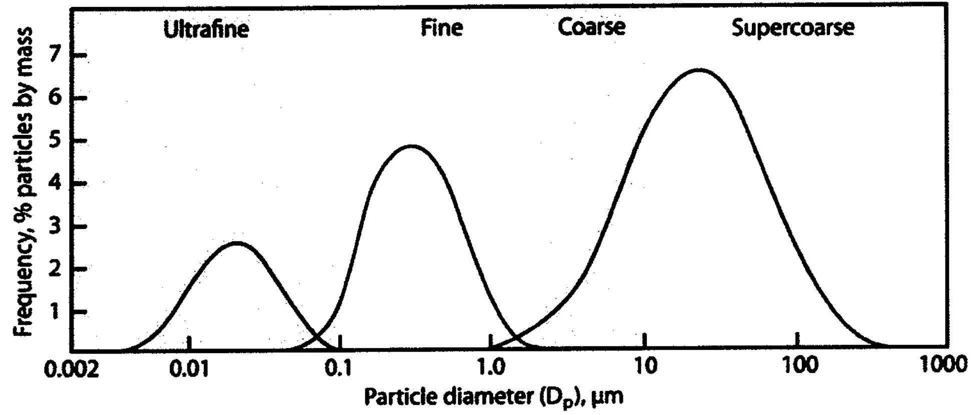
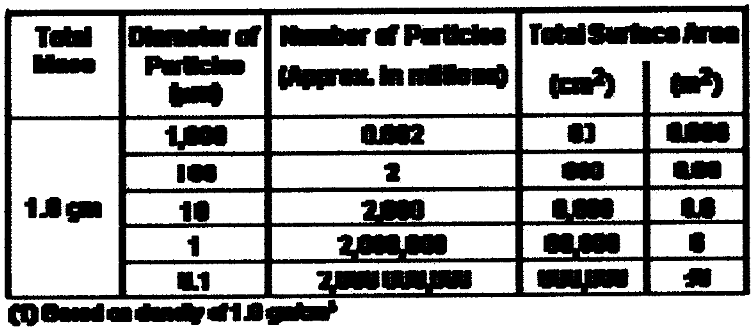


Figure 4. Particle size categories used to classify particles.
(http://www.epa.gov/apti/bces/module3/category/category.htm)

Figure 5 provides a comparison of the mass distribution and particle number distribution. As the particle size decreases the number of particles in the size fraction increases. In addition, as illustrated in Table 3, the surface area increases significantly with decreasing particle resulting in the opportunity for reactive gases such as sulfur oxides to react, forming sticky phases that bond particles together.

Table 3. Particle size, number of particles, and surface area[1]
(http://www.epa.gov/apti/bces/module3/category/category.htm)



Total Mass	Diameter of Particles (µm)	Number of Particles (Approx. in millions)	Total Surface Area (cm²)	(m²)
1.0 gm	1,000	0.002	60	0.006
	100	2	600	0.06
	10	2,000	6,000	0.6
	1	2,000,000	60,000	6
	0.1	2,000,000,000	600,000	60

(1) Based on density of 1.0 g/cm³

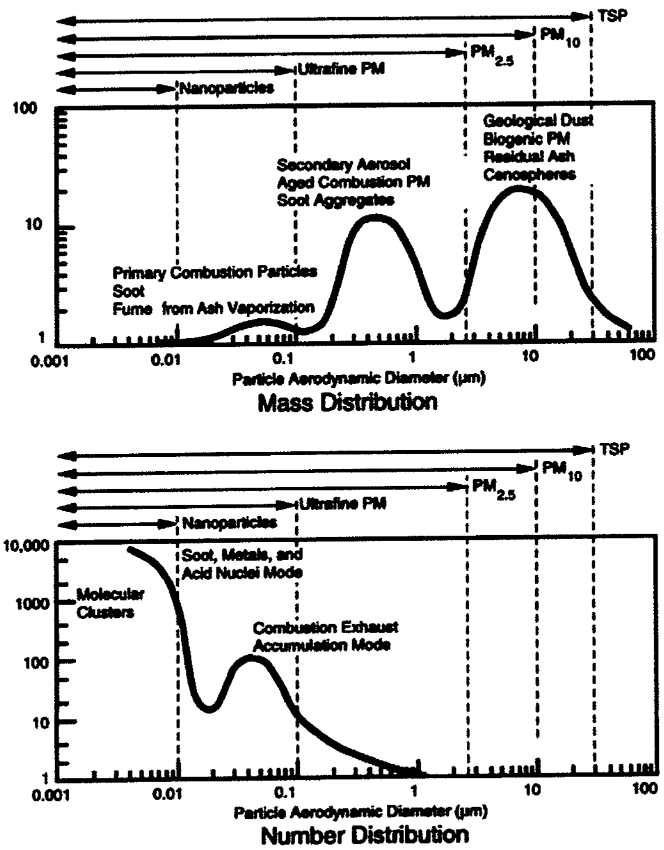


Figure 5. Comparison of Mass Distribution and Particle Number Distribution for Combustion Derived Particles and Aerosols (Lighty and others, 2000).

Particle size distributions for fly ash collected upstream and downstream of an ESP are illustrated in Figure 6. This work was conducted by Markowski and others (1980) specifically aimed at characterizing the submicron aerosol mode of fly ash formation. Figure 6B shows the penetration of fine particulate through the ESP.

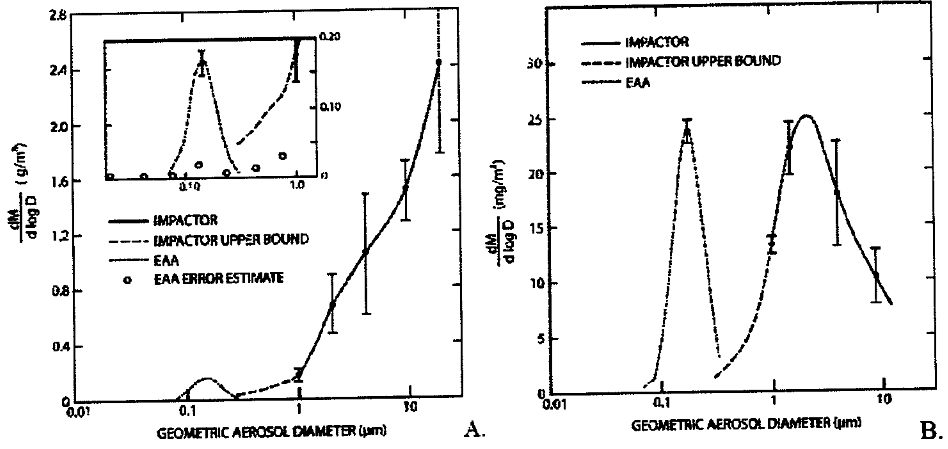


Figure 6. Typical differential mass distributions of particulate collected upstream (A) and downstream of an ESP (b) (Markowski and others, 1980).

Fly ash produced upon the combustion of high sodium lignites in a pulverized coal (PC) fired system shows significant enrichment of sodium in the smaller size fractions as shown in Figure 7. This figure illustrates the increase in the sodium content in the finer size fractions of ash as a result of firing high sodium lignite. The sodium and sulfur content of the less that 3 micrometer size fraction of the sampling train approached 20% Na_2O, and 25% SO_3. The form of the sodium is likely sodium oxide and sulfate.

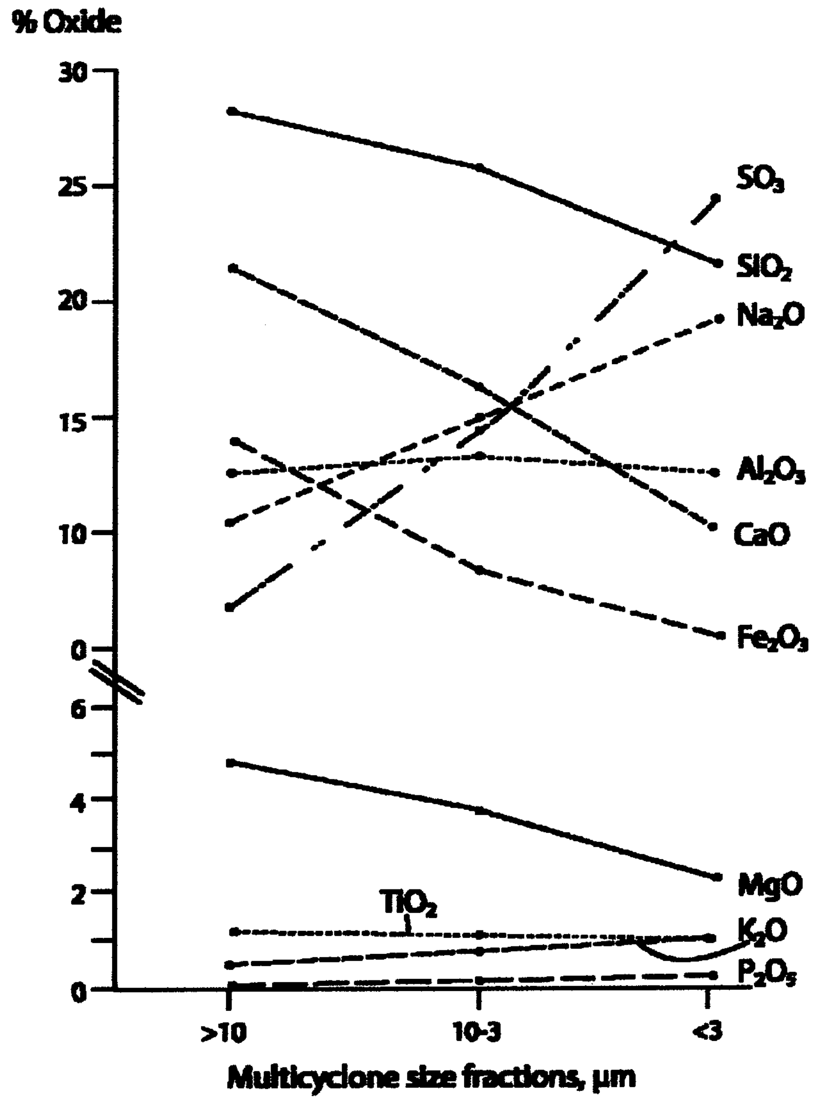


Figure 7. Composition distribution of ash particles during combustion of North Dakota Lignite (Benson and others, 1984).

Electrostatic Precipitator Collection Efficiency

The classical curve for ESP particle collection efficiency is shown in Figure 8. This curve is typical of well behaved ash materials that do not present significant problems in collection. The collection efficiency is very good for particles greater than 5 to 10µm and the collection efficiency decreases with decreasing particle size, with a minimum collection efficiency between

0.2 to 2 µm in diameter. The collection efficiencies vary significantly because of particle size and composition.

Low collection efficiency for difficult to collect particles is between 0.1 to 1 µm in particle diameter. Figure 9 provides an illustration of the range of collection efficiencies. Based on EPA education modules (http://www.epa.gov/apti/bces/module3/collect/collect.htm), no air pollution control device shows high collection efficiency in this range (0.1 to 1.0 µm) due to inherent limitations of the collection devices and particle characteristics. The following mechanisms of particle capture are impacted by the size of the particles. The impact of these mechanisms are described

- Inertial impaction and interception
- Brownian diffusion
- Gravitational settling
- Electrostatic attraction
- Thermophoresis
- Diffusiophoresis

The EPA has indicated that based on a number of studies of actual "sources stationary sources generating high concentrations of particles in the 0.1 to 0.5 micrometer range may be an especially challenging control problem. ... The gap is most noticeable in wet scrubbers and electrostatic precipitators." A generalized plot showing the range of collection efficiencies is shown in Figure 9. Overlaid on the diagram is the mass size distribution of particles collected downstream of the ESP wet FGD at the MRY plant (Markowski and others, 1983). This shows that ash produced in the MRY plant have a particle size that pass through the scrubber and that these particles are rich in sodium as previously shown in Figure 7.

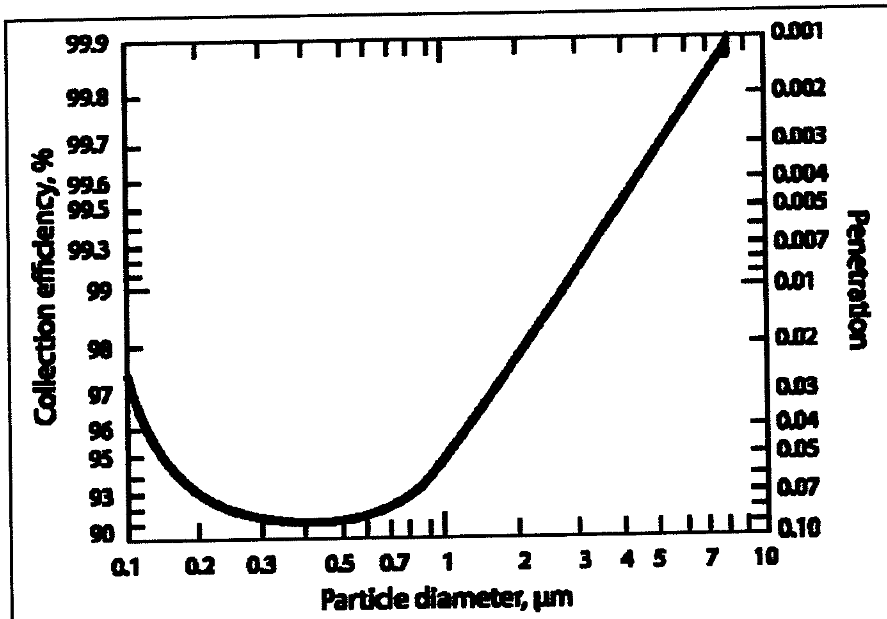


Figure 8. Typical ESP Collection efficiency curve for removal of particulate from gas streams (http://www.epa.gov/apti/bces/module3/collect/collect.htm).

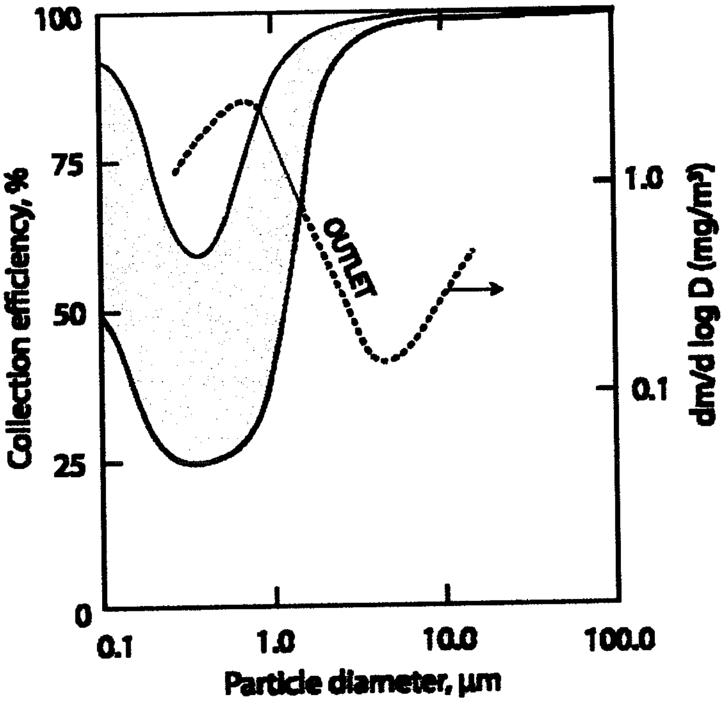


Figure 9. Particulate control efficiency for difficult to control particulate combined with the mass distribution of particulate collected downstream of the scrubber at MRYS (Markowski and others, 1983 and (http://www.epa.gov/apti/bces/module3/collect/collect.htm).

Aerosol Capture Efficiency in Scrubbers

As indicated by EPA (Woodward, 1998), scrubbers do not effectively remove particulate less than 1 µm in diameter. There is significant evidence that sodium-rich aerosols penetrate ESPs as well as scrubbers at full-scale power plants when firing high-alkali-containing fuels. An example is a biomass fired system using a tower type scrubber where the removal efficiency of the smaller size fraction of ash is low, as shown in Figure 10 (Ohlström and others, 2006).

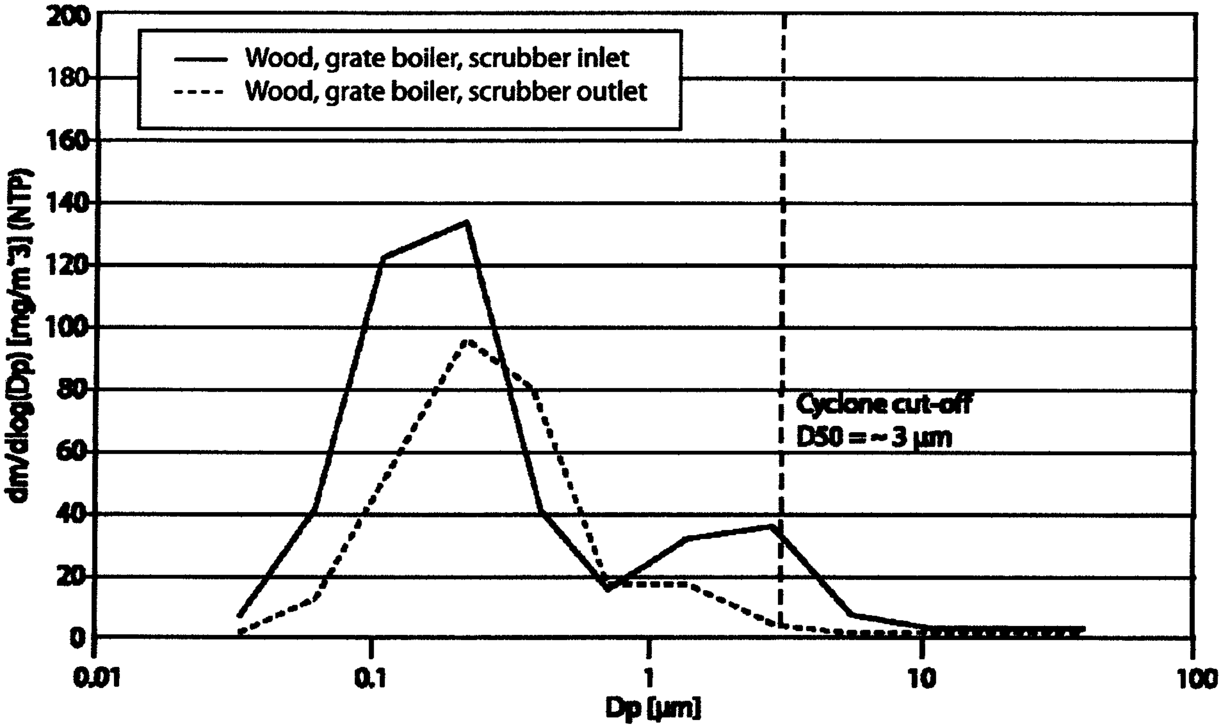


Figure 10. Removal of fine aerosols using a scrubber on a wood fired combustor (Ohlström and others, 2006).

Minnesota Power's Boswell Energy Station found that when it fired high-sodium, lower-ash northern Powder River Basin subbituminous coal (7% Na_2O in the ash), it experienced increases in opacity. Hurley and Katrinak (1992) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with a venturi wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using multicyclone followed by an impactor and a Nucleopore filter.

The sized fractions were weighed and analyzed to determine the abundance and composition of the submicron-sized fractions. The mass loadings in the various size bins are plotted in Figure 11, showing that the scrubber is quite effective in removing the larger particles. However, the scrubber is not very effective in removing the aerosols less than 1 micrometer in diameter for both the blended coal and the high sodium coal (Coal A).

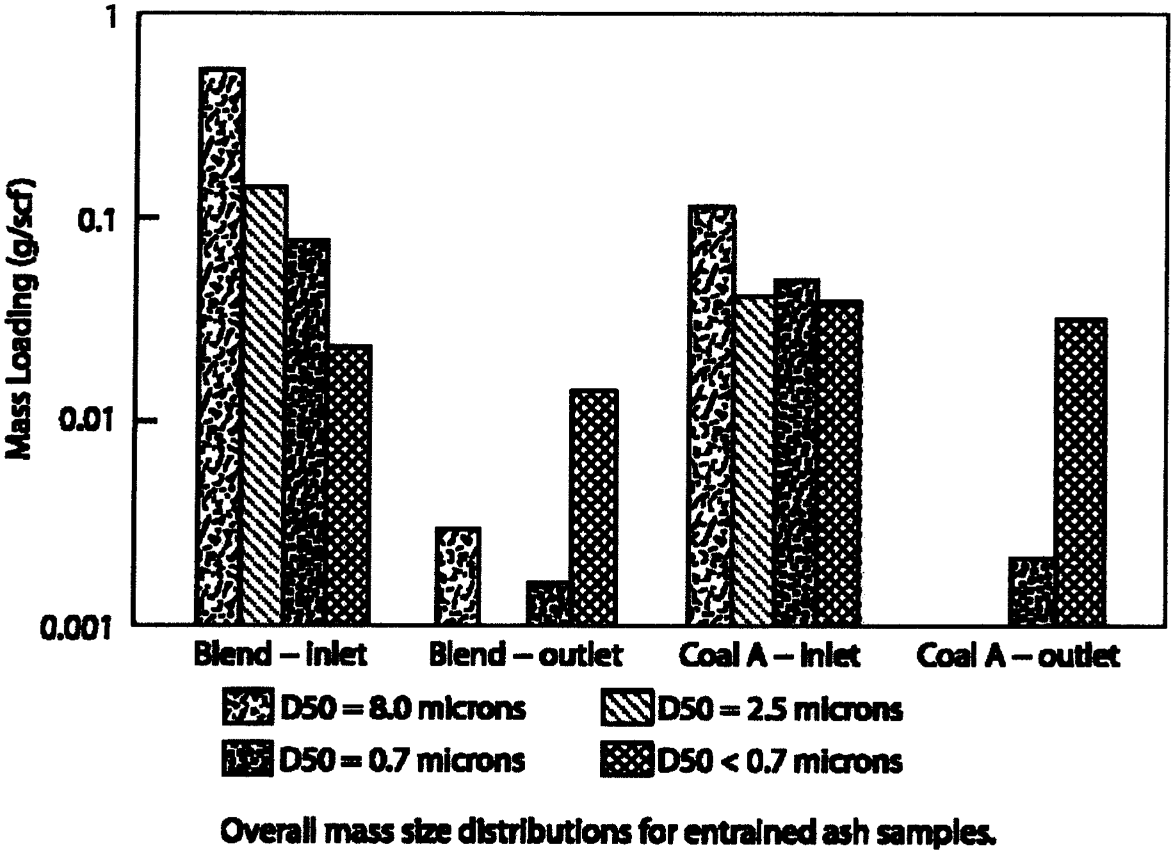


Figure 11. Mass loadings and size for particulate collected upstream and downstream of the wet venturi scrubber at Clay Boswell plant (Hurley and Katrinak, 1992)

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of the coals. Vapor-phase sodium condenses in the boiler's convective pass to form fine sodium-rich aerosols or other Na species that later react with ash particles. Pure Na_2SO_4 particles are too small to be removed by such scrubbing. Figure 12 shows the spikes of the ash material collected on Stage 10 of the impactor. This impactor accumulation represents particles of less than 0.7 to 2.5 micrometer size fraction of the submicron aerosol. The spikes are made up of submicron particulate matter, and the chemical analyses of the spikes and ash particles collected on the Nucleopore filters downstream of the impactor plates are shown in Table 4. Both samples are dominated by sodium and sulfur that are likely in the form of sodium sulfate. These sulfate materials exhibit highly cohesive tendencies.

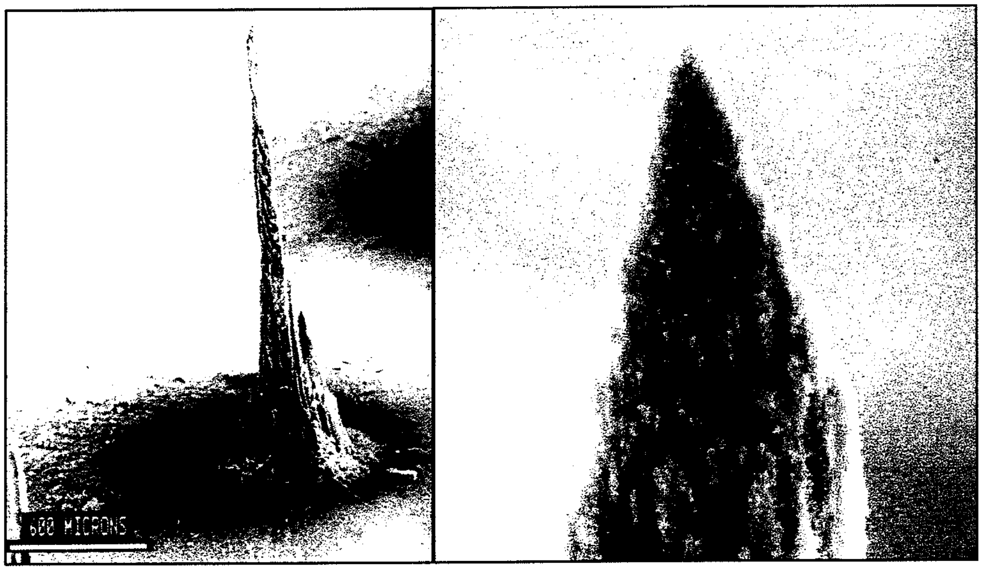
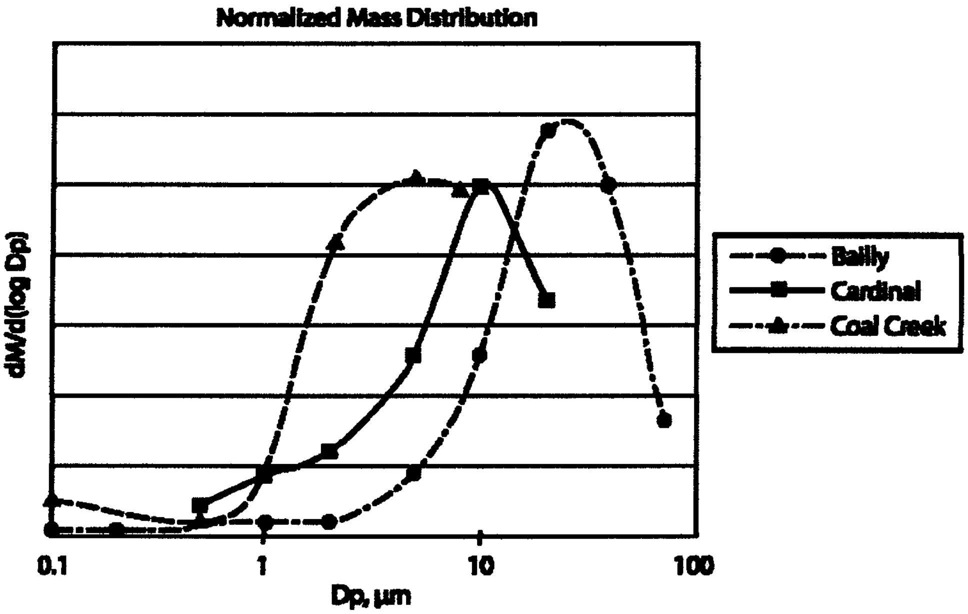


Figure 12. Scanning electron microscope images of spikes formed on impactor plates when high-sodium subbituminous coal is combusted (the picture on the right is a close-up of the spike) (Hurley and Katrinak, 1992).

Table 4. Chemical Composition of the Spike Shown in Figure 12 and the Filter (weight percent expressed as equivalent oxide).

Oxide	**100% Coal A**	
	Spike	**Filter**
Na_2O	**35.1**	17.3
MgO	1.4	7.8
Al_2O_3	2.0	9.8
SiO_2	9.1	10.6
P_2O_5	0.4	0.2
SO_3	**39.7**	28.0
K_2O	2.6	1.5
CaO	6.2	15.7
TiO_2	0.2	1.8
Cr_2O_3	1.4	0.1
Fe_2O_3	0.9	2.9
BaO	0.5	2.6

In addition to the aforementioned testing results, penetration of submicron particles through ESP and scrubbers has been reported by numerous researchers (Markowski and others, 1983, and Lighty and others, 2000). Figure 13 shows the penetration of particulate from ND lignite to be the highest of the combustion systems tested as part of the DOE field test program.



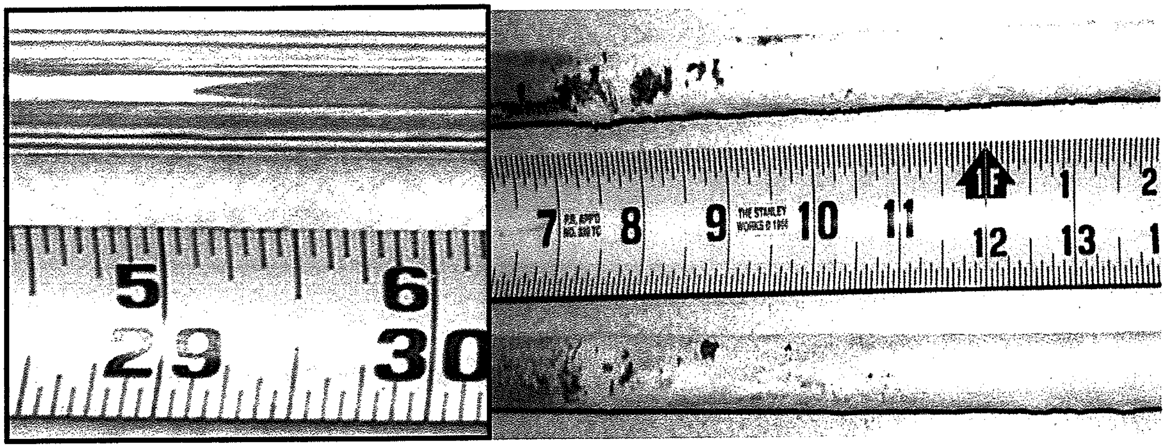
Plant	Description	Stack Emissions
Bailly	345 MW, Cyclone Burner Dry scrubber, ESP Illinois high-sulfur bituminous	60 kg/hr
Cardinal	615 MW, well-mounted cell burner ESP, no sulfur removal Pittsburgh No. 8 bituminous	100 kg/hr
Coal Creek	550 MW, tangential-fired Wet scrubber, ESP North Dakota lignite	260 kg/hr

Figure 13. Normalized differential particle mass distributions measured in the stack for a sample of coal-fired power plants using different burner and gas-cleaning technologies (Lighty and others, 2000).

Powerspan Testing at MRYS

The Powerspan slipstream electrocatalytic oxidation (ECO) reactor system was designed by Powerspan and the EERC (Tolbert and Benson, 2008). The slipstream system was installed by the EERC at Minnkota Power Company's Milton R. Young Station Unit 1 downstream of the ESP where the flue gas temperature ranged from 300°F to 350°F. The dielectric barrier discharge (DBD) reactor has quartz electrode rods inside where electric current is passed in order to generate the plasma used to oxidize nitrogen oxide (NO) to nitrogen dioxide (NO_2). The temperature of the quartz electrodes was approximately 100°F higher than the gas temperature. The system at MRYS was commissioned on July 3, 2007, and it operated for 107 days. Operational performance of the system was monitored and data were archived for post processing. A pair of electrodes was extracted and replaced on a bi-weekly basis. Each pair of electrodes was shipped to Powerspan for testing in their laboratory reactor for NO conversion testing. Tested electrodes were then shipped to the EERC for scanning electron microscopy imaging and x-ray microanalysis. Measurement of NOx conversion in the field by the slipstream system was not possible due to the nitric acid production of the DBD reactor. Aerosols passing through the ESP at MRY Unit 1 resulted in significant accumulation on Powerspan's slipstream ECO barrier discharge reactor rods resulting in significant degradation in performance.

The operational observations, performance results, and lab testing showed that the system was adversely affected by ash fouling. NOx conversion by ash covered electrodes was significantly reduced. Figure 14 visually compares a clean unexposed quartz rod to one exposed to flue gas and aerosols downstream of the ESP at MRY Unit 1. The abundance of sodium in lignite coal fired during the Powerspan testing at MRYS is shown in Figure 15. The results show sodium levels measured by the full stream elemental analyzer (FSEA) ranged from 3.5 to 6 % Na_2O in ash. Figure 16 shows the degradation in NO conversion measured during subsequent lab testing at EERC using the exposed quartz rods removed from the slipstream test ECO DBD reactor at MRYS as a result of being coated with aerosols. The NO conversion was severely impacted.



A. Clean quartz rod.

B. Dirty rod exposed to flue gas downstream of the ESP at MRYS Unit 1 for 16 days.

Figure 14. Comparison of a clean quartz rod and rod exposed to flue gas.

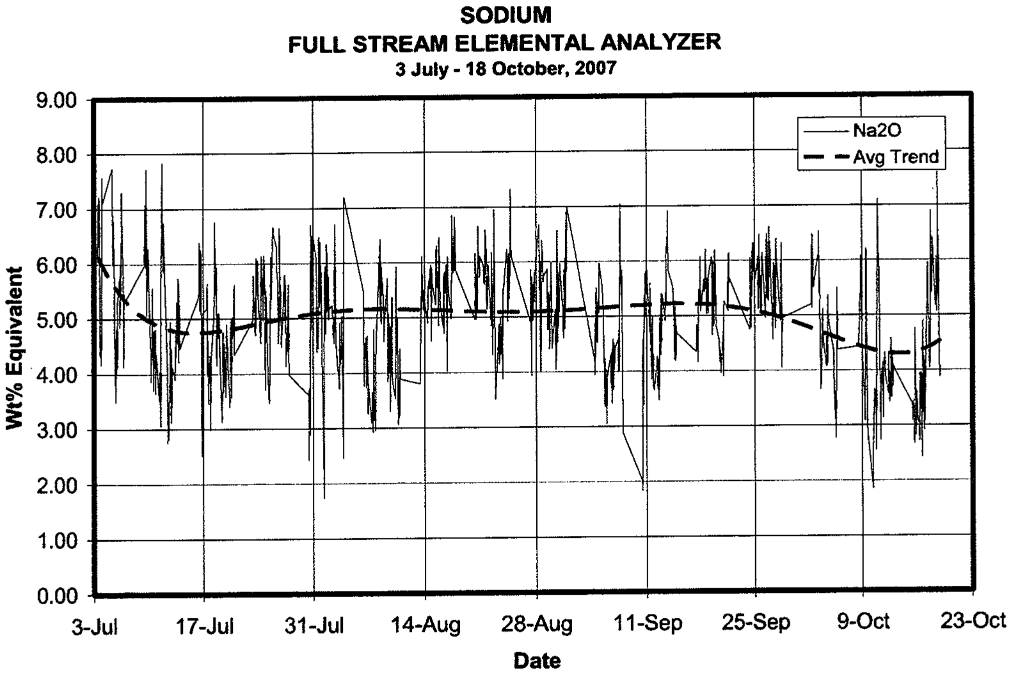
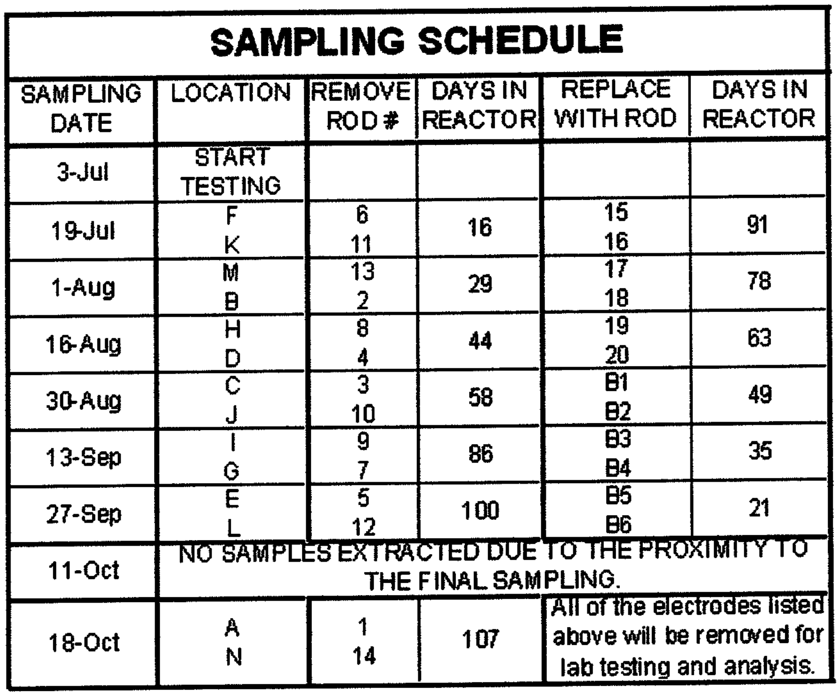


Figure 15. Sodium levels in lignite delivered during testing of the Powerspan barrier discharge reactor at MRYS Unit 1.



SAMPLING SCHEDULE

SAMPLING DATE	LOCATION	REMOVE ROD #	DAYS IN REACTOR	REPLACE WITH ROD	DAYS IN REACTOR
3-Jul	START TESTING				
19-Jul	F K	6 11	16	15 16	91
1-Aug	M B	13 2	29	17 18	78
16-Aug	H D	8 4	44	19 20	63
30-Aug	C J	3 10	58	B1 B2	49
13-Sep	I G	9 7	86	B3 B4	35
27-Sep	E L	5 12	100	B5 B6	21
11-Oct	NO SAMPLES EXTRACTED DUE TO THE PROXIMITY TO THE FINAL SAMPLING.				
18-Oct	A N	1 14	107	All of the electrodes listed above will be removed for lab testing and analysis.	

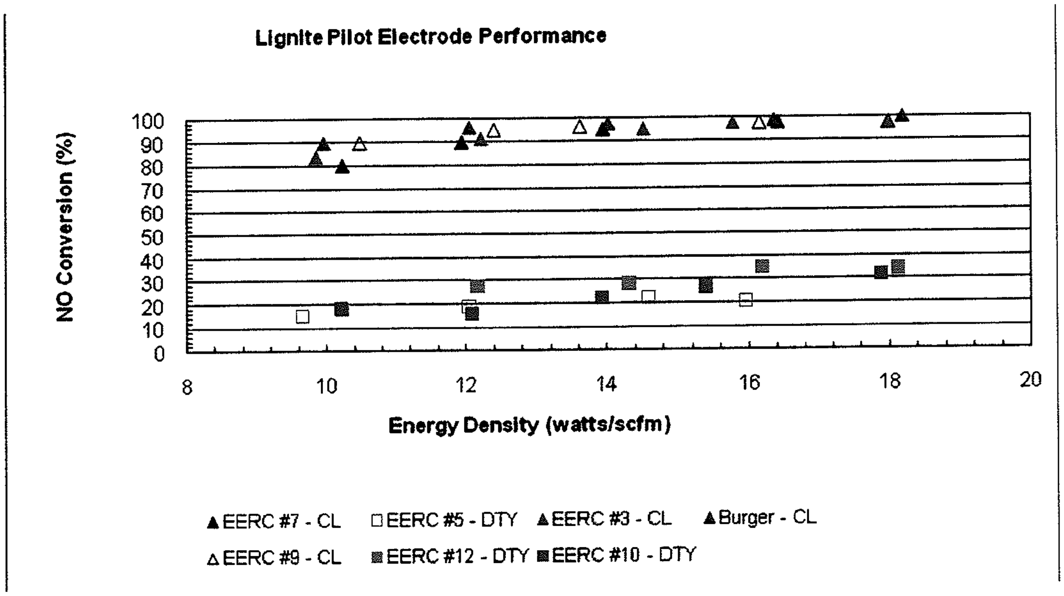


Figure 16. NO conversion for clean (CL) and dirty (DTY) for quartz tube exposed the flue gas during the MRYS testing. Burger is a slipstream pilot ECO system in Ohio used for reference.

Examination of the quartz rods removed from the slipstream ECO DBD reactor at MRYS (cross-sectioned to expose coating thickness) by EERC using scanning electron microscope equipped with an x-ray analyzer showed significant elemental sodium, sulfur, and calcium in the ash coating the tubes after only 16 days of testing. The data is reported on Figure 17. The thickness of the layer was approximately 25 µm. A sonic horn was used for in-service cleaning of the rod-tube deposits. Images of the reactor and coatings on the electrodes are shown in Figure 18.

Tag	Na	Mg	Al	Si	P	S	Cl	K	Ca	Ti	Fe	Ba
1	35.38%	0.98%	14.10%	4.68%	0.00%	35.75%	0.00%	1.42%	6.61%	0.02%	1.07%	0.00%
2	0.00%	0.00%	0.22%	98.52%	0.00%	0.00%	0.07%	0.89%	0.00%	0.30%	0.00%	0.00%
3	0.00%	0.00%	0.61%	98.11%	0.00%	0.00%	0.00%	1.05%	0.00%	0.00%	0.22%	0.00%
4	0.00%	0.00%	0.20%	98.33%	0.00%	0.00%	0.00%	1.19%	0.00%	0.00%	0.27%	0.00%
5	0.00%	0.00%	0.00%	98.70%	0.00%	0.00%	0.00%	1.24%	0.00%	0.00%	0.06%	0.00%
6	0.00%	0.00%	0.25%	97.26%	0.00%	0.00%	0.27%	1.70%	0.00%	0.00%	0.36%	0.16%
7	0.00%	0.00%	0.00%	97.93%	0.00%	0.00%	0.00%	1.55%	0.00%	0.00%	0.47%	0.05%

Figure 17. Example of SEM point analysis on electrode #11 (removed from slipstream ECO reactor at MRYS after 16 days of service).

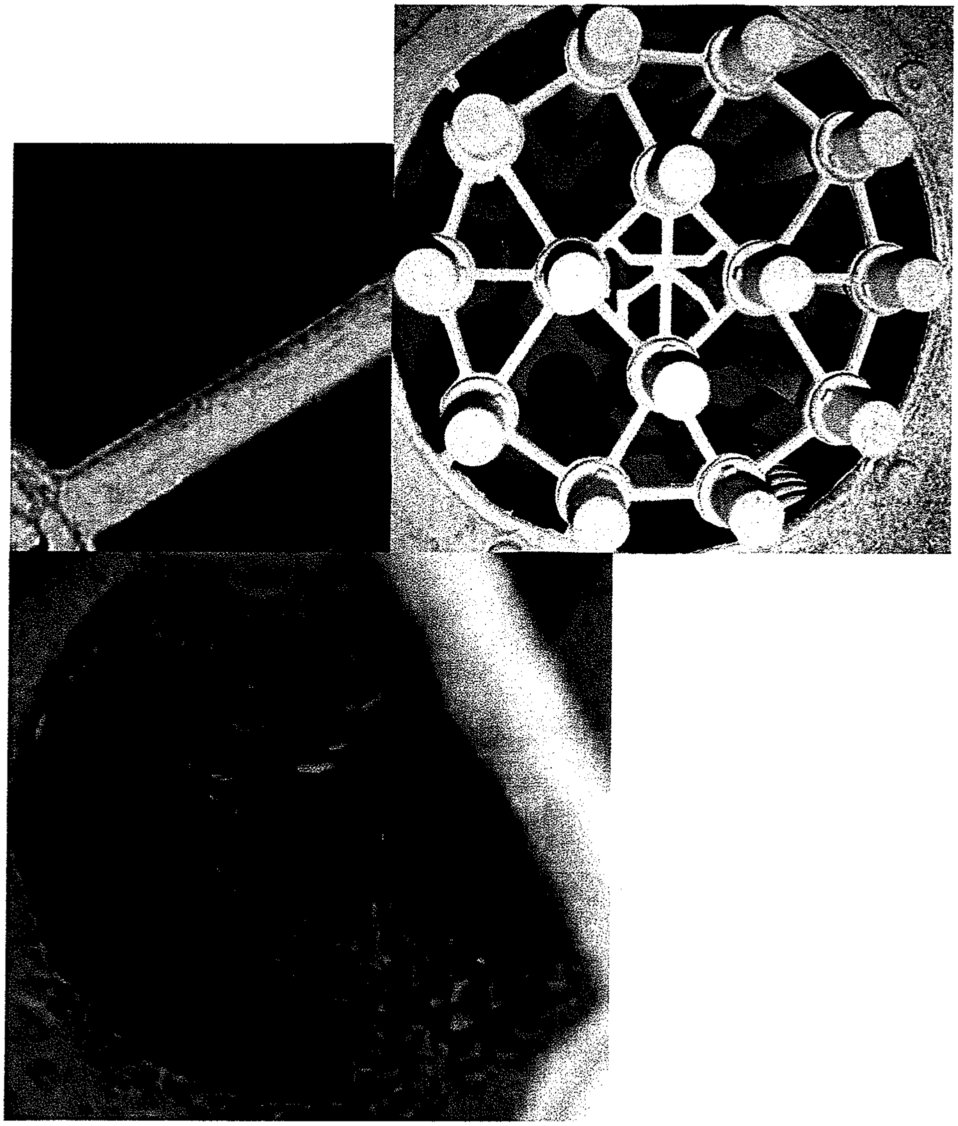


Figure 18. Images of top of slipstream ECO DBD reactor at MRYS showing ash accumulations on electrodes and reactor surfaces.

Conclusions gained by this work are:

1.) Sodium rich aerosols and small ash particles that had penetrated the ESP accumulate and become bonded on the surface of the silica electrodes despite using a sonic horn as recommended by Powerspan.

2.) Ash accumulations adversely affected the NOx conversion.

3.) The adverse impact occurs within a two week time period.

MRY Sulfate Aerosol Sampling

The penetration of aerosols through ESP and wet scrubbers is well known and has been studied since the mid 1970s (McCain and others, 1975; Ensor and others, 1975). As a result of these challenges, the quantity of total aerosols and sulfate aerosols was measured at MRYS by Markowski and others, 1983. Markowski and others (1983) collected EPA method 17 particulate samples and size segregated the particles using an impactor that aerodynamically separates particles and allows for the characterization of each fraction. The results of the EPA method 17 samples conducted over a four day period. The mass concentrations of aerosols as determined by EPA method 17 sampling are illustrated in Figure 19 for the inlet and out of the scrubber. At the inlet aerosol mass concentrations ranging from a high of over 10,000 μg/m^3 to a low of 4000 μg/m^3. Significant levels were also found at the scrubber outlet ranging from 8800 to 2500 μg/m^3. The removal efficiency varied from -25 to 66%. Markowski and other (1983) offered no explanation of the differences in the levels of aerosols measured in the flue gas and removal efficiency. They did not consider that the ash content of the coal varied significantly during the testing. Results of testing at MRYS have shown significant differences in the quantity vaporized for coals that have different ash contents (see Figure 3). The variations in ash content shown in Figure 19 reflect changing coal characteristics that resulted in differences in aerosol mass concentration.

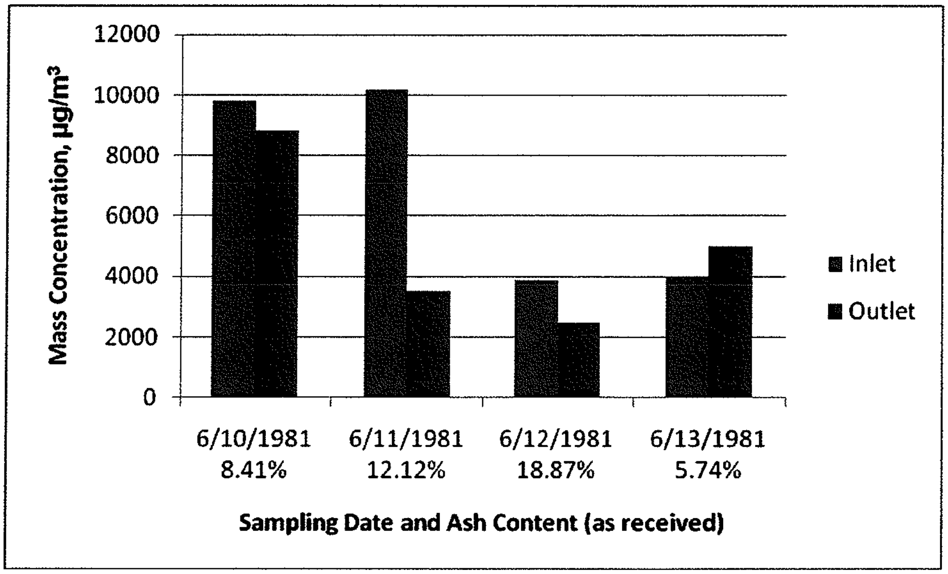


Figure 19. Mass Concentration of Aerosol Collected at MRYS Unit 2 at the Scrubber Inlet and Outlet (Markowski and others, 1983).

The results of the measurements of aerosol capture are illustrated in Figure 20. The results show that aerosols less than one micrometer in diameter are not effectively captured in the wet FGD at the MRY facility. The graph also indicates the penetration of the particles through the FGD as a function of particle size. The penetration is the outlet size distribution divided by the inlet size distribution. (Penetration = 1- efficiency). Markowski and others (1983) showed that the "metallic" sulfate aerosols (sodium sulfate) penetrated the FGD much more effectively than the larger particulate materials.

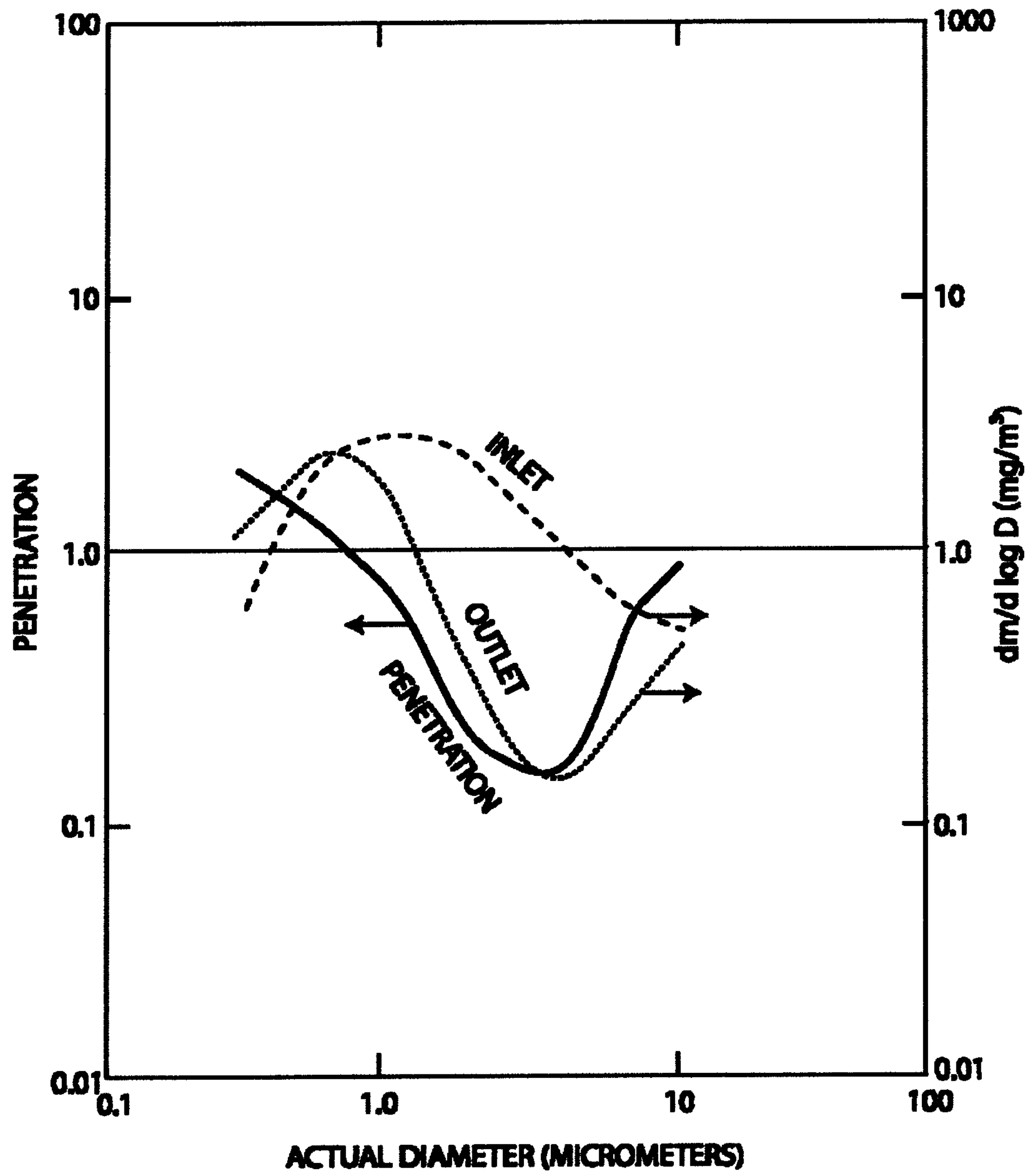


Figure 20. Penetration through the MRYS Unit 2 wet scrubber (Markowski and others, 1983).

The mass of each of the impactor size fractions for the aerosols collected at the inlet and the outlet of the wet FGD upstream and downstream of the MRYS Unit 2 scrubber are illustrated in Figure 21 and 22 with the results tabulated in Table 5. The total mass distributions are summarized in Figure 21 and the sulfate mass distribution is illustrated in Figure 22. Based on the impactor data the total mass of particulate that penetrates the scrubber is 5990 μg/m^3 (Markowski and others, 1983). These ash materials consist of a combination of sulfates and oxides of sodium, calcium, and sulfur. Much of the aerosol is present in the >14 μm size fraction. There are also significant mass in the less than 1 μm size fraction that has the potential to penetrate the pores of the catalyst. In addition, there is a significant mass in the <0.26 μm fraction. This fraction represents the ultrafine component that has been implicated as the most significant contributor to catalyst poisoning (Kling and others, 2007).

Table 5. Size segregated total and sulfate particulate collected upstream and downstream of the MRYS FGD (Markowski and others (1983).

Size, μm	Inlet Total, μg/m^3	Outlet Total, μg/m^3	Inlet Sulfate, μg/m^3	Outlet Sulfate, μg/m^3
<0.26	1910	769	436	602
0.26-0.52	401	640	164	274
0.52-1.1	883	1410	293	459
1.1-2.5	1020	265	291	69.2
2.5-6.7	337	154	173	94
6.7-14	300	367	100	103
>14	700	2390	439	46.2
Total	5550	5990	1896	1650
>1.1	2357	3176	1003	312.4
<1.1	3194	2819	893	1335
Percent				
>1.1	42.5 %	53.0 %	52.9 %	18.9 %
<1.1	57.5 %	47.1 %	47.1 %	80.9 %

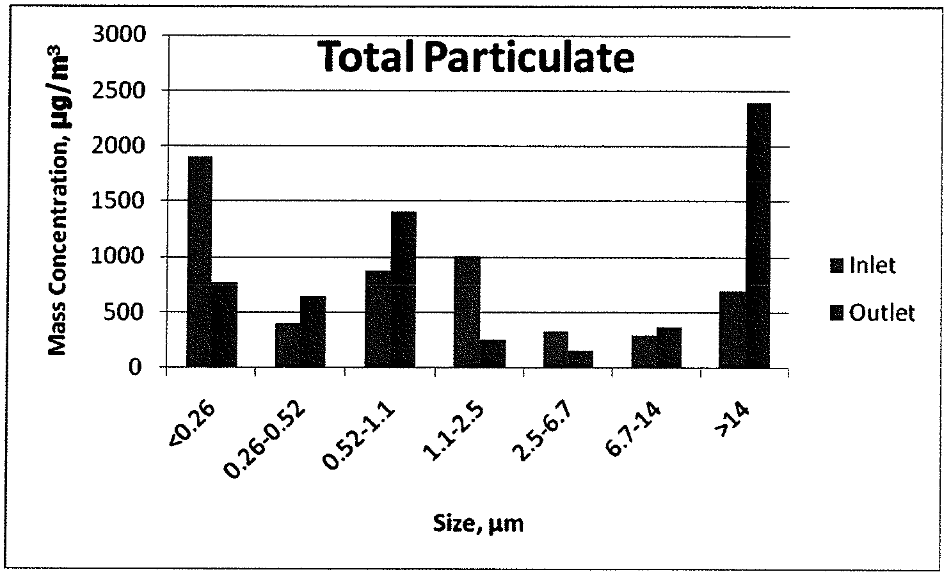


Figure 21. Total particulate removal across scrubber at MRYS.

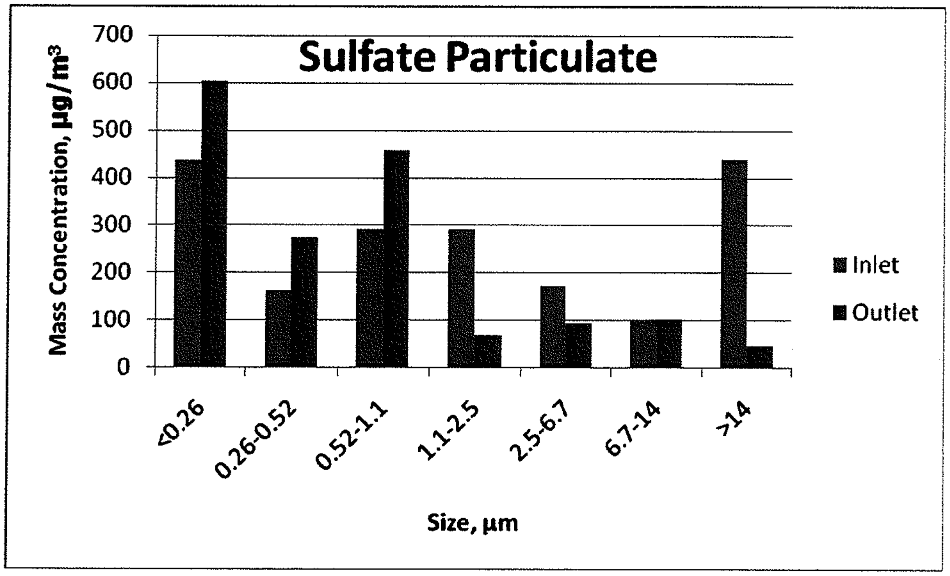


Figure 22. Sulfate particulate removal across scrubber at MRYS.

6. Determination of Sodium Loading Adversely Affecting SCR Catalyst Performance

Alkali metals such as potassium and sodium are known poisons and blinding agents for SCR catalysts used for NOx emissions control. As previously discussed (Burns & McDonnell and others, November 2008) and repeated above, there will be submicron sodium, likely in sulfate form, emitted from the dry ESPs at MRYS that will contaminate SCR catalyst located in a low-dust or tail-end configuration. The first fundamental issue is "how to estimate the amount (mass rate) of sodium and in what size range could be emitted from the boilers at MRYS, for the purposes of a BACT analysis". Because BACT analyses on existing sources are not common, we also presume them to be "studies on paper using available information". We do not consider BACT analyses as research projects requiring design of experiments, site-specific testing, and development engineering for the control technique being considered. Thus, this first issue is a significant challenge.

The second fundamental issue is "for the purposes of a BACT analysis, what rate of catalyst deactivation is likely to occur as a result of exposure to the expected particle or aerosol size range and concentration of sodium emitted from a boiler over a given period of time?"

Only by assuming that these fundamental issues can be resolved with the degree of certainty required for purposes of a BACT analysis, can such a comparison then be performed that could lead to a basis of technical feasibility of low-dust and tail-end SCR technology for MRYS.

Because most coals fired in utility boilers do not have the high sodium content of North Dakota lignite, and because cyclone boilers fire at high temperatures which promotes the emission of submicron sodium aerosols, there is not much published technical information that is available to help answer these fundamental questions. We can gain some insight into what might happen to SCR catalyst exposed to flue gas containing significant amounts of alkali salts by looking at the impact of co-firing biomass such as straw or switchgrass with coal. This is increasingly important to utilities that have chosen to pursue such a fuel mix strategy who also employ SCR technology on their boilers. We have previously commented on the high-dust SCR catalyst experience at the Avedore plant (Burns & McDonnell and others, November 2008) and the high frequency of catalyst washing performed to counteract the apparent highly negative impacts of biomass cofiring.

7. Alkali Aerosol Loading and Catalyst Deactivation

There is evidence that alkali aerosol loading in the flue gas streams results in catalyst deactivation. The total and sulfate aerosol mass loading measurements were conducted by Markowski and others (1983) at the inlet and outlet of the wet FGD scrubber at MRYS Unit 2.

The key data obtained by Markowski and others (1983) is illustrated in Figure 23 as well as the size fractionated data in Figures 21 and 22 provide information on loadings. The data provided shows a range of mass concentrations up to 8800 μg/m^3 at the outlet of the scrubber based on EPA method 17. Based on results in mass size distribution of the aerosol, 47 to 80% of the aerosols that pass through the scrubber are less than 1.1 μm. Much of this material is in the ultrafine fraction. These materials have the potential to penetrate into the catalyst, causing plugging, and can react with active components in the catalyst. There are numerous publications supporting these mechanisms. Kling and others (2007) found that the rate of catalyst deactivation was related to the accumulation of sodium and potassium on the catalyst as shown in Figure 24 and 25. The work by Kling and others (2007) is consistent with the work conducted by Khodayari, 2001 illustrated in Figure 26 where he shows that the deactivation rate is more significant for PC-fired systems as compared to fluidized beds. The work based on Kling and others (2007) when applied to PC and cyclone-fired systems will likely underestimate the degree of catalyst deactivation because of the firing methods.

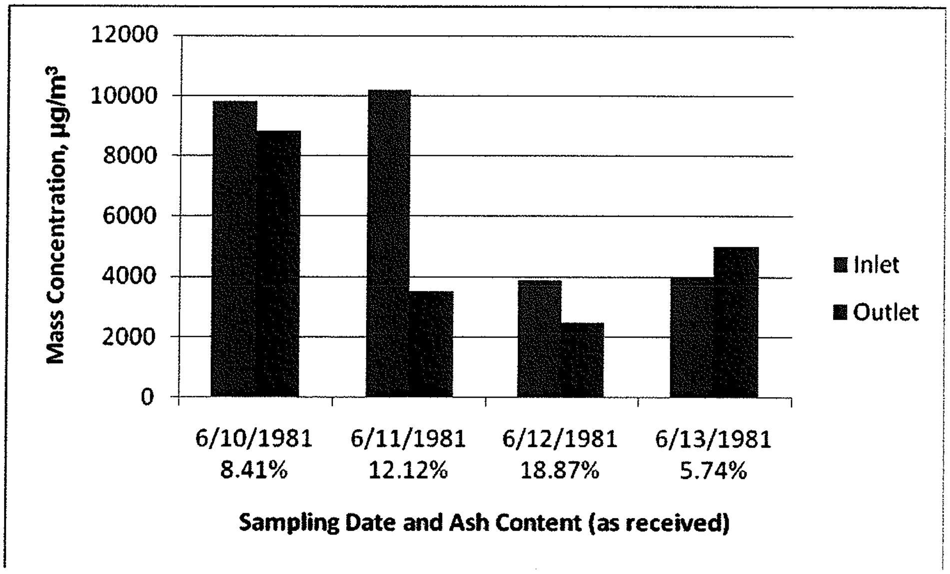


Figure 23. Mass Concentration of particulate collected at MRYS using EPA Method 17 (Markowski and others, 1983).

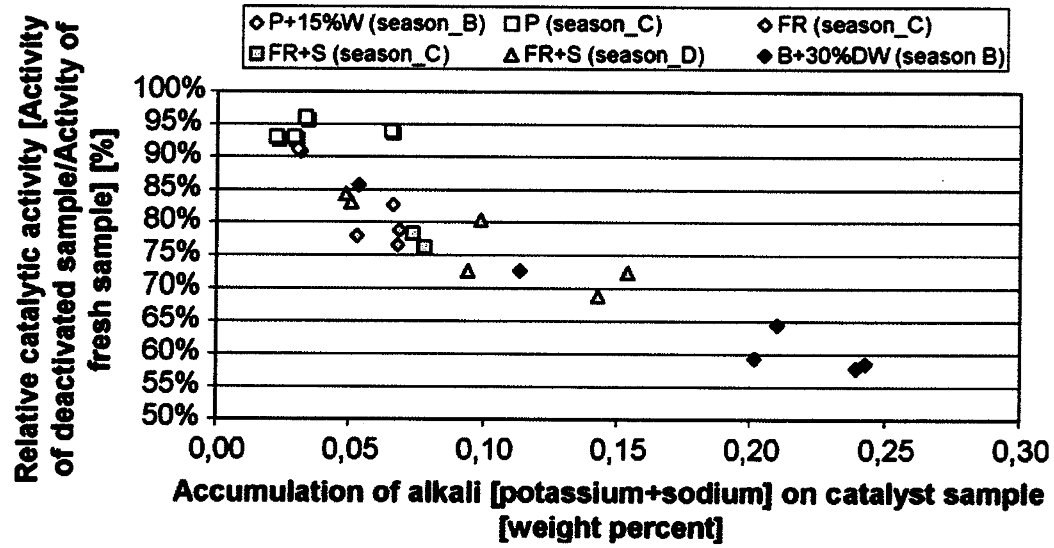


Figure 24. Catalyst deactivation compared to accumulation of potassium and sodium on the catalyst surface (Kling and others, 2007).

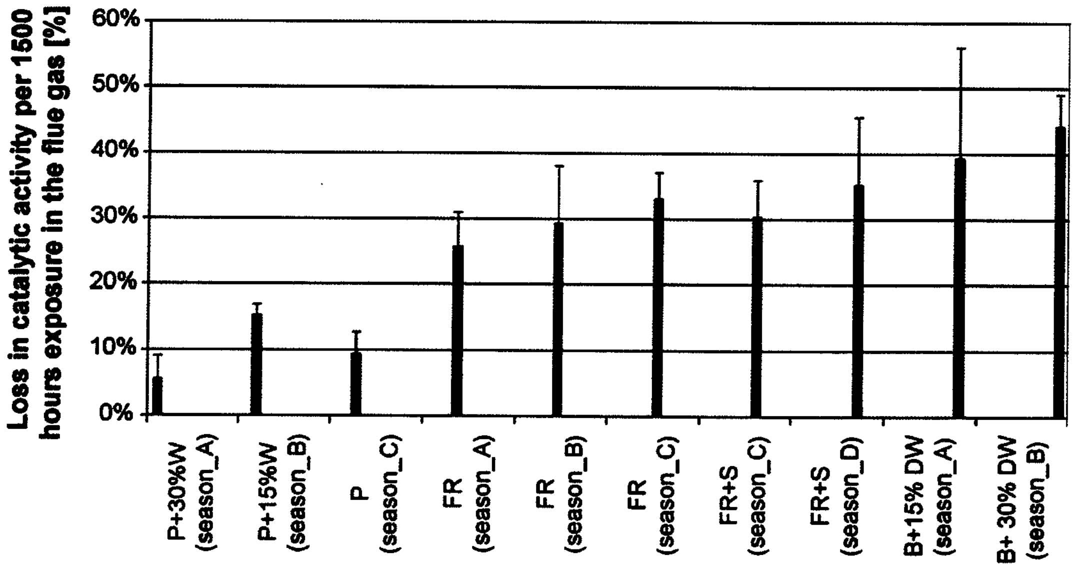


Figure 25. Loss in catalyst activity when exposed to flue gases containing vaporized Na and K when combusting biomass in a fluidized bed combustion system (Kling and others, 2007).

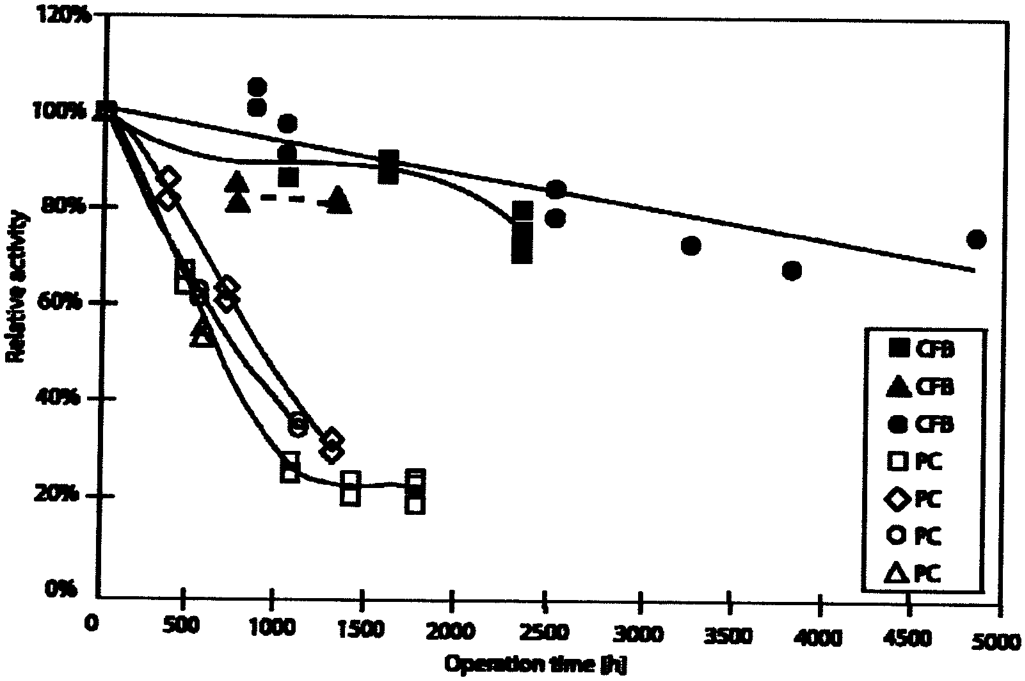


Figure 26. Comparison of poisoning of catalysts in a CFB boiler firing forest residues and in a PC firing pulverized wood (Khodayari, 2001).

There is a direct relationship to the concentration of sodium and potassium in the flue gas with accumulation on the catalyst and subsequent deactivation. The deactivation shown in Figures 24 and 25 directly relates the accumulation of sodium and potassium on the catalyst with deactivation. Deactivation rates of 40 to 55 percent (considering the error bars) was measured on catalyst that had accumulated 0.25 wt % sodium and potassium on the catalyst surface when exposed to flue gas containing 22,500 μg/m^3 sodium and potassium for only 1500 hours. The flue gas downstream of the scrubber at the MRYS Unit 2 has been shown to contain aerosols at levels of 8800 μg/m^3 with about 50% of the mass being less than 1.1 μm. The ash that exits the ESP on Unit 1 is dominated by sodium and sulfur based on the results from the Powerspan testing. The quartz elements exposed to the flue gases for 16 days (384 hours) were completely covered with sodium and sulfur rich ash (see Figure 17). These elements were exposed to cleaning using a sonic horn. The sodium and sulfur rich ash produced a dense layer on the surface of the quartz rods approximately 25 μm thick in 384 hours. The MRYS results along with research efforts conducted in Europe show that masking and poisoning of SCR catalysts from flue gases containing alkali aerosols is a significant problem that has not been overcome by SCR catalyst vendors.

8. Experience of ESP/FGD Equipped Utility Plants Co-Firing Biomass and Coal with TESCR

In previous communications to NDDH, it was stated that no recent TESCR installations had been completed on utility boilers anywhere in the world. Burns & McDonnell subsequently learned about the Amager facility currently under construction in Copenhagen, Denmark that will involve a TESCR system on a multiple fuel-fired boiler that is expected to burn combinations of pulverized coal, wood pellets, straw, and fuel oil. A technical paper written by Haldor Topsoe described the design efforts for SCRs on biomass (straw)-fired boilers (Crespi, and others, 2008) and indicated that the TESCR configuration was chosen specifically to address the concerns about catalyst poisoning due to the constituents of the straw (notably potassium). Follow-up communications were initiated by Burns & McDonnell with Haldor Topsoe, which supplied the catalyst for Amager's TESCR reactor; Alstom, which was the supplier of the SCR reactor system and the Flowpac wet FGD system (see attached project summary); and a plant engineer for the boiler's operator (Vattenfall A/S) (Burns & McDonnell personal communications, 2009). These personal communications provided the following information about this installation:

a. The boiler is wall-fired and can be fired with oil (start-up), coal and wood- and straw-pellets. Coal and bio-pellets are pulverized in mills [prior to firing in the boiler], with full flexibility from 0 to 100 % straw. It is expected to fire 100% biomass most of the time. Maximum heat input to the boiler is 350 MW during coal and oil firing and 300 MW during wood/straw pellets firing.

b. Danish regulations on emission include an emission fee (\$/ton of SO_2 or NO_x emitted), therefore the utility looks for the best compromise between low cost fuel and low emissions. The utility wants to be able to fire any mixture as specified above for the flexibility of cost and availability of both straw and coal. This is common for European customers who have to balance carbon dioxide (CO_2) emissions. When a new plant is built, the utility wants to make sure it can fire any fuel that may come on the market in the coming years without being limited by his boiler and cleaning equipment. Of the biofuels, straw is considered to be the most difficult as compared to woodchips, saw dust, paper, etc. The situation is the same in Sweden, Holland and some other countries.

c. At the planning stages of the Amager project it was expected to co-fire biomass and coal in the boiler. Now, if bio-mass fuels are not available, 100% coal will be fired. When bio-mass is fired, NOx emissions are expected to be low, so the utility is allowed to bypass the flue gas cleaning system. According to European regulations, the NOx emission limit with bio-mass is 300 mg/Nm^3 (dry 6% O_2). Both the FGD and the SCR systems will be bypassed, if NOx in the flue gas emitted from boiler is below 300 mg/Nm^3. No dampers are installed upstream of the TESCR. There is a global by-pass of both FGD and TESCR systems. The wet FGD and TESCR are mainly needed for any coal firing flue gas cleaning. When pure straw/ biomass is fired the whole wet FGD and SCR system can be bypassed, saving a lot of operating cost as both SOx and NOx will be within the limits from the authority. The client was not sure that they could get enough of straw available at an acceptable price, so the boiler had to have great fuel flexibility.

Based on this information, it appears that the Amager plant's TESCR system will typically be bypassed when the fuel firing conditions are most difficult for the SCR catalyst with regard to poisons. Consequently, Burns & McDonnell does not believe the Amager facility project under construction provides any indication that TESCR technology is technically feasible for application to MRYS.

9. Relevance of Recent TESCR investigations at We Energies' South Oak Creek Station

Recently, in response to a Consent Decree that requires the installation of SCR technology on Units 5, 6, 7 and 8 at its South Oak Creek Generating Station in Oak Creek, Wisconsin, We Energies (Wisconsin Electric) has investigated the use of TESCR technology. The investigation ultimately led to the determination that the TESCR approach would not be used. Based on information obtained by Burns & McDonnell from the engineering consultant and the technology vendor for that project (Burns & McDonnell personal communications, 2009), the decision not to use TESCR technology was based on economics. However, the fact that TESCR systems were considered to be feasible for specific application at the South Oak Creek units is not indicative that the same technology would be technically feasible for application at MRYS. This is due to the substantial differences between the South Oak Creek boilers and the MRYS boilers, as summarized in the Table below:

Table 6. Comparison of Boilers for South Oak Creek and Milton R. Young Station

	South Oak Creek	**Milton R. Young**
Fuel Type	PRB Coal (low ash, very low sulfur)	ND Lignite
FGD Design Fuel Sulfur Content, SO_2 lb/mmBtu	1.15	3.95
Firing Type	PC wall-fired (Units 5 & 6) PC tangential (Units 7 & 8) (dry bottom)	Cyclone fired (Units 1 & 2) (slagging-type, wet bottom)
Design Boiler Outlet NOx lb/mmBtu	0.15	0.51 (Unit 1 w/ASOFA) 0.49 (Unit 2 w/ASOFA)
Consent Decree NOx Limit lb/mmBtu	0.10	TBD

The significant differences in the ash characteristics, especially with regard to the sodium content, between PRB coal and North Dakota lignite have been explained in previous submittals to NDDH (Burns & McDonnell and others, 2007 and 2008). The effect that cyclone firing has on the partitioning of sodium has been explained previously, and reiterated in this document. In addition, it can be seen from the tabulation above that the SO_2 content of the flue gas will be up to four times as high at MRYS as at South Oak Creek, either before or after the FGD system. This means that the potential for deposition of ammonium bisulfate on the SCR catalyst, due to the reaction between the ammonia reagent and the SO_3 that forms within the SCR reactor when catalytic SO_2 oxidation occurs, will be proportionally much greater for the application of TESCR technology to MRYS than it would have been at South Oak Creek. Finally, it should be noted that compliance with the Consent Decree for NOx emissions in the case of South Oak Creek required only a moderate degree of emission reduction in the SCR systems, meaning that the design was not particularly challenging from a percentage reduction standpoint.

10. Relevance of Ongoing LDSCR Installation Project at We Energies' South Oak Creek Station

Following the elimination of TESCR systems from further consideration for the SCR retrofits required by the Consent Decree, We Energies is proceeding with the installation of LDSCRs at Units 5, 6, 7 and 8 at South Oak Creek. Again, as shown in Table 6, the significant differences between the fuel, firing type, sulfur content and NOx reduction requirement support the contention that installation of LDSCR systems under construction at South Oak Creek does not constitute a demonstration that LDSCR technology is technically feasible for MRYS.

11. Relevance of Existing LDSCR Installation at PSEG Mercer Station

In response to a January 2002 Consent Decree that required the installation of SCR technology on Units 1 and 2 at its coal-fired electric generating station in Mercer County, New Jersey, PSEG Fossil (PSEG) has installed and operated LDSCR systems at this site since 2004 (Unit 2) and 2005 (Unit 1). However, the fact that LDSCR was considered to be feasible for specific application at the Mercer units is not indicative that the same technology would be technically feasible for application at MRYS. This is due to the substantial differences between the Mercer boilers and the MRYS boilers, as summarized in the Table below:

Table 7. Comparison of Boilers for Mercer and Milton R. Young Station

	Mercer	**Milton R. Young**
Fuel Type	Low-sulfur bituminous coal (Venezuelan and eastern U.S. blend)	ND Lignite
Firing Type	PC wall-fired, slagging-type (wet bottom)	Cyclone fired (slagging-type, wet bottom)
Design Boiler Outlet NOx lb/mmBtu	1.40 (prior to controls) (see note below)	0.51 (Unit 1 w/ASOFA) 0.49 (Unit 2 w/ASOFA)
Consent Decree NOx Limit lb/mmBtu	0.10	TBD

Mercer has demonstrated and employed various NOx reduction techniques before LDSCR installation in 2004, primarily SNCR, with and without fuel-lean gas reburn, and in-duct SCR.

The significant differences in fuel type and firing type between these two plants would create very different flue gas characteristics of the flue gas entering the LDSCR, especially with regard to the sodium aerosol. The significant differences in the ash characteristics, especially with regard to the sodium content, between bituminous coal and North Dakota lignite have been explained in previous submittals to NDDH. The effect that cyclone firing has on the partitioning of sodium has also been explained previously, and reiterated in this document.

12. Additional Technical Feasibility Issues for TESCR at MRYS

As noted in previous submittals to NDDH (Burns & McDonnell and others, September and November, 2008), there are no existing or planned TESCRs on coal-fired utility power plants in the U.S. A review of the TESCR applications on German coal-fired power stations has indicated that these installations are configured basically as shown in the diagram on page 1 of this document. That is, flue gas from the outlet of the wet flue gas desulfurization (FGD) system absorber is reheated prior to entering the TESCR system, using a regenerative (Ljungstrom type) gas-to-gas heat exchanger (GGH) that supplies heat that was extracted from the flue gas upstream of the FGD. According to consultation with the designers of the LDSCR systems for South Oak Creek, the expected leakage through this type of heat exchanger will be at least 5.0 percent. When flue gas leaks across this "FGD GGH" from the inlet to the outlet flue gas stream, it effectively bypasses the FGD absorber, meaning that no SO_2 removal takes place from this slipstream of the total flue gas.

In the case of both MRYS Unit 1 (in the CD) and Unit 2 (in the proposed BART), NDDH has indicated that 95% SO_2 removal is required. This will preclude the use of this type of GGH, because, as leakage around the FGD system approaches five percent, it becomes ***impossible*** to achieve 95% overall SO_2 removal. This was not an issue for the German FGD systems, which were not required to achieve the same high level of SO_2 removal efficiency that is dictated by the MRYS CD and the proposed SO_2 BART.

This leakage could be avoided if the saturated flue gas from the FGD system absorber were sent directly to the "SCR GGH" upstream of the TESCR reactor as shown in the diagram on page 1. However, according to the engineering consultant who performed the evaluation of TESCR technology at South Oak Creek (as described in Section 9 above), "Saturated flue gas tends to be corrosive and there is virtually no experience with Ljungstrom GGH handling corrosive saturated gas. Saturated gas from the absorber tower carries gypsum slurry droplets, which tend to plug the cold end of the GGH with gypsum deposits that are extremely difficult to clean on-line."

Another aspect of the TESCR approach that appears infeasible at MRYS is that the flue gas would enter the new fiberglass reinforced plastic (FRP) ductwork leading to the respective chimneys, and Unit 2's FRP chimney liner, at a normal temperature above the 200°F design limit, due to the TESCR reactor's outlet temperature being above 500 °F entering the treated-side of the SCR GGH.

Based on these considerations, the only way to apply TESCR technology to the units at MRYS while providing high SO_2 removal would be to employ a flue gas reheating technology which has not been proven in the application to a TESCR system at any full scale power plant installation. This indicates that TESCR technology is technically infeasible for application to the Units at MRYS.

13. Summary and Conclusions

- Because of the unique properties of Fort Union Lignites, they produce more vaporized ash (Na and other elements) that other coals including PRB and bituminous coal.
- Higher combustion temperatures associated with cyclone firing result in more ash vaporization and increased levels of submicron fine and ultrafine aerosol particles.
- Cyclones reduce the quantity of coarse flyash particles in the flue gas available to provide sites for sodium condensation and to dilute the bonding effects of the aerosols once deposited on a surface.
- The particle collection efficiencies for fine particles less than 1 µm are poor for both ESP and wet FGD, such as those utilized at MRYS.
- The number of flue gas particles per gram increases ten times for 1 µm versus 10 µm and another ten times for 0.1 µm versus 1 µm (diameter), so the fine and ultrafine aerosols are plentiful in number because of penetration through ESPs and scrubbers. These fine particles have high surface areas, are highly reactive, and readily bond together because of high surface energies.

- Particles in the 0.1 to 1.0 μm size fractions are largely composed of condensed vapor phase species such as sodium, potassium, and sulfur.
- Sodium-rich aerosol particles present in flue gas downstream of the ESP at MRYS Unit 1 significantly impacted the performance of the Powerspan slipstream ECO barrier reactor system in less than two weeks of exposure.
- Sodium- and sulfur- rich coatings on the surface of the Powerspan quartz rods were dense, continuous, and difficult to scrape off. These sodium and sulfur rich layers were produced in only 384 hours and were 25 μm thick.
- Emission rates downstream of ESP described in the reports provided by the NDDH range from 4,500 to 50,000 μg/Nm^3. The particulate emitted are dominated fine and ultra fine aerosols rich in sodium and potassium. NOTE: The level of 22,500 μg/Nm^3 of sodium- and potassium-rich fly ash derived from biomass firing resulted in catalyst deactivation of 30 to 40 % in 1500 hours (King and others, 2007).
- These are no TESCR installations in the U.S. on utility coal-fired boilers, and there are no examples of TESCR technology being applied worldwide on any coal-fired boilers having the same high percentage SO_2 removal requirements that are applicable at MRYS. The heat exchanger technology that has been employed on other TESCR systems for bituminous coal-fired boilers located in Germany, if applied at MRYS, will preclude compliance with the established SO_2 removal requirements.
- The expected outlet temperature from the TESCR and downstream gas-to-gas heat exchangers will be too high for the fiberglass flue gas ductwork exhausting the chimneys at MRYS.
- The existing LDSCR installations in the U.S. are on units firing coals and using coal firing technology that will not produce the same high level of catalyst poisons in the flue gas as would be the case at MRYS, where both units are cyclone furnaces firing high-sodium lignite.

Conclusions

In the end, arguments regarding the technical feasibility of tail-end and low-dust SCR technology at Milton R. Young Station are reduced to disputing the characterization of the gas stream characteristics and the impacts of those characteristics on boiler and emissions control operations. Those who suggest that these impacts can be resolved by the use of LDSCR and TESCR, and that such technology will work at MRYS without failure, cannot point to relevant data showing success at other coal-fired boiler SCRs which have such high levels of sodium in the fuel and the flue gas stream.

Considering the findings and conclusions presented above and previously, low-dust and tail-end SCR technology would not be available to apply to Units 1 and 2 at MRYS without extensive long-term pilot-scale testing and design development efforts. As BACT is not the selection of a pollution reduction technology that requires such research and development in order to determine if it can be successfully deployed for full-time, full-scale operation, we believe that low-dust and tail-end SCR technology is not technically feasible at MRYS for Unit 1 and Unit 2 NOx emissions control (Arfmann and others, 2007).

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NOx BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS STUDY - SUPPLEMENTAL REPORT

for

Milton R. Young Station Unit 2

Minnkota Power Cooperative, Inc.

Operating Agent for

Square Butte Electric Cooperative

Owner

November 2009

31777

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NOx Best Available
Control Technology
Analysis Study
SUPPLEMENTAL REPORT
for
Milton R. Young Station Unit 2

prepared for

Minnkota Power Cooperative, Inc. and
Square Butte Electric Cooperative

November 2009

Project No. 31777

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

INDEX AND CERTIFICATION

Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative
Milton R. Young Station Unit 2
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Certification

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Robert D. Blakley

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4.0 SUPPLEMENTAL NOx BACT ANALYSIS CONTROLS & COSTS – MRY STATION UNIT 2

This supplement to the NO_X BACT analysis for Milton R. Young Station (MRYS) Unit 2 has been prepared in response to a request of the North Dakota Department of Health[1]. The NDDH requested completion of a "full" BACT analysis for two specific technologies that had been eliminated at step 2 of the BACT analysis process[2] in the October 2006 NO_X BACT Analysis Study report[3]. These two technologies are low-dust selective catalytic reduction (SCR) and tail-end SCR. The approach taken in this supplemental NO_X BACT Analysis Study report for MRYS Unit 2 includes ranking by control effectiveness and an impacts analysis of alternate control technologies for NO_X emissions that follows the third and fourth steps of a "top down" BACT analysis as described in the EPA's Draft New Source Review Workshop Manual[4]. The initial NO_X BACT Analysis Study for Milton R. Young Station identified potentially available NO_X control techniques and technologies, summarized in Table 3-3[5] of the October 2006 report. Commonly-applied and novel NO_X control techniques and technologies, including a technical description of the specific emission reduction processes and capabilities, were summarized in Section 3.2[6] and detailed in Appendix A1 of the October 2006 NO_X BACT Analysis Study report. This supplemental analysis report does not include the details of the technical feasibility discussion previously provided in the initial NO_X BACT Analysis Study report for MRYS Unit 2.

SCR technology is considered technically infeasible by Minnkota for application at MRYS, so this information for the hypothetical application of low-dust and tail end SCR alternatives is included for comparative purposes only. Cost estimates and emission rates shown for such hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation, operation and maintenance of the SCR equipment on this boiler are solvable. There is no available information on recently-completed similar tail-end or low-dust SCR projects on coal-fired powerplants in the United States that could be used, with adjustments, to represent total installed costs that could be expected for MRYS Unit 2. Site-specific needs and challenges identified for applying tail end and low-dust SCR technologies to Milton R. Young Station Unit 2 significantly influence the capital cost estimate for variations of these hypothetical applications of SCR alternatives. Furthermore, the

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[1] See Reference number 1, July 2009 and August 2009.
[2] As described in the EPA's Draft New Source Review Workshop Manual. See Reference number 2, October 1990.
[3] See Reference number 3, October 2006. This Supplement commences with Section 4.0, which places it at the end of the October 2006 Analysis, which ended at Section 3.5.2.
[4] As described in the EPA's Draft New Source Review Workshop Manual. Ibid Reference number 2, October 1990.
[5] Ibid Reference number 3, October 2006, page 3-5.
[6] Ibid Reference number 3, October 2006, page 3-6 through page 3-13, and pages A1-1 through A1-55.

"EPA Air Pollution Control Cost Manual" is not applicable for use in estimating control equipment costs for these hypothetical applications of SCR technologies, as the EPA Control Cost Manual states:

> "The costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements."[7]

This requirement for flue gas reheating also applies to the hypothetical application of low-dust SCR to MRYS, due to the cold-side arrangement (downstream of the electrostatic precipitator) instead of a hot-side ESP assumed in the EPA Control Cost Manual. Therefore, the equations in the EPA Control Cost Manual cannot be used for estimating either of the hypothetical application of SCR configurations for which NDDH has requested economic analyses. Thus it was necessary to prepare independent site-specific cost estimates.

The site-specific control costs estimated for application of hypothetical tail-end and low-dust SCR alternatives to MRYS Unit 2 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines[8]. Low-dust and tail end SCR technologies should be excluded from consideration for NO_X control at MRYS due to unacceptably high average and incremental cost per ton of pollutant removal based on the supplemental analysis provided herein. The October 2006 NO_X BACT Analysis Study report, and additional subsequent arguments included in responses to comments by the EPA, Department of Justice (DOJ), NDDH, and other parties[9], also present reasons for technical infeasibility of all SCR technologies considered for application at MRYS not included in this supplemental analysis report. In addition, the fact that catalyst vendors will not guarantee catalyst life on such SCR technologies without successful results from extensive pilot slipstream testing bolsters the previous submitted arguments of technical infeasibility of these NO_X control alternatives at MRYS.

4.0.1 ADDITIONAL NOx CONTROLS

The inclusion of hypothetical emissions control alternatives employing tail-end and low-dust SCR technologies in this supplemental NO_X BACT Analysis Study report does not constitute agreement by

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[7] See Reference number 10, Section 4.2, Chapter 2, page 2-41, October 2000.
[8] See Reference number 4, June, 2005.
[9] Responses submitted by Minnkota in 2007-2009.

Minnkota or Square Butte that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The rationale for rejection of all forms of SCR technology in this specific case, based on an interpretation of the EPA's Draft New Source Review Workshop Manual[10], has previously been submitted to the North Dakota Department of Health[11] and is not repeated herein. Nevertheless, this supplemental NO_X BACT Analysis Study report has been completed based on the *hypothetical assumption* that these two technologies pass the test for technical feasibility. The development of NO_X emissions control alternatives involving hypothetical application of technologies such as low-dust and tail end SCR systems at MRYS is based on preliminary plant layout design concepts that require pilot-scale slipstream SCR testing and more detailed equipment design for confirmation that all technical infeasibility issues previously raised have been, or can be, satisfactorily resolved. This supplemental analysis includes estimated capital costs and operating and maintenance (O&M) costs for four variations of alternatives involving hypothetical applications of tail-end and low-dust SCR technologies. Cost effectiveness for each hypothetically-applied SCR control technology case was plotted with previously-analyzed feasible control alternatives.

For the techniques and technologies considered for determining MRYS Unit 2 NO_X control cost-effectiveness, estimates were produced for predicted NO_X reductions that represent long-term expectations of the reduction techniques and technologies being presented in the technical analysis. Each evaluated alternative was tabulated and graphed.

It should be noted that as of October 2006, when the initial BACT Analysis Study report was completed, MRYS Unit 2 did not employ combustion-related or post-combustion NO_X emission reduction technology. However, the installation of an advanced form of a separated overfire air system (ASOFA), designed specifically for this boiler, was implemented for operation starting prior to December 31, 2007. A summary of the available alternate NO_X emission control technologies is discussed below.

4.1 RANK OF NO_X CONTROL OPTIONS BY EFFECTIVENESS

The first step[12] in this supplemental "top-down" BACT evaluation is to determine the expected control effectiveness of the hypothetical application of tail end and low-dust SCR technology alternatives, so that they may be compared and ranked relative to the technically-feasible NO_X control techniques and

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[10] Ibid Reference number 3, October 1990.
[11] See Reference number 5, November 2007.
[12] Step 3 per the NSR Manual, Ibid Reference 2, October 1990.

technologies included from the initial NO_X BACT Analysis Study report. To do this, we start with the basis for determining the NOx emissions control effectiveness, which is the historic baseline emissions expressed in pounds per million Btu of heat input from the five-year lookback period.

Unit 2 boiler's baseline pre-control emissions at Milton R. Young Station are based upon the same highest rolling 12-month average unit emission rate (lb/mmBtu) and corresponding highest rolling 12-month average gross heat input rate (mmBtu/hr) that were reported in 2001-2005:

- MRYS Unit 2's highest 12-month NO_X mass emissions averaged 0.786 lb/mmBtu at a corresponding average unit heat input rate of 4,885 mmBtu/hr and unit gross electrical output of 440 MW_g.
- During this lookback time period, Unit 2 at Milton R. Young Station was typically operated in a base-loaded manner.

4.1.1 ESTIMATING CONTROL-EFFECTIVENESS OF NO_X EMISSIONS CONTROL OPTIONS

The estimated emission control performance for NO_X control techniques and technologies included from the initial NO_X BACT Analysis Study report is assumed to be the same as previously stated in Table 3-7[13]. The expected control effectiveness of the hypothetical application of tail end and low-dust SCR technology alternatives was added to the listing of highest-performing NO_X control alternatives remaining in consideration following the initial technical infeasibility determinations. These alternatives are ranked in declining order of expected emission reduction. These combined control options refer to "advanced" separated overfire air (ASOFA), and include the expected reduction from operating with modestly air-staged cyclone furnaces and relocated lignite drying system vent ports as applied to this Milton R. Young cyclone boiler without incurring potential significant negative impacts of this technique. This level of expected NO_X reduction from ASOFA operation is approximately thirty eight percent below the pre-control baseline emissions rate of 0.786 lb/mmBtu.

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[13] Ibid Reference number 3, October 2006, page 3-18.

TABLE 4-1 – Ranked NO_X Control Options for MRY Station Unit 2 Boiler with Expected Control Performance

Alt. Label[1]	NO_X Control Alternative	Emission Rate (lb/mmBtu)	Control Percentage[2]
T2	Hypothetical Tail-End SCR w/ ASOFA – Scenario A[3]	0.049	93.8[4]
T1	Hypothetical Tail-End SCR w/ ASOFA – Scenario B[3]	0.049	93.8[4]
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[3]	0.049	93.8[4]
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[3]	0.049	93.8[4]
E	SNCR (using urea) w/ ASOFA	0.330	58.0
D	Gas Reburn with ASOFA	0.350	55.4
C	Lignite Reburn w/ ASOFA	0.360	54.2
B	Fuel Lean Gas Reburn with ASOFA	0.432	45.0
A	Advanced Separated Overfire Air (ASOFA)	0.489	37.7
-	Baseline	0.786	-

(1) - Alternative designation assigned from highest to lowest unit NOx emission rate.

(2) - Control percentages are relative to an average pre-control emission baseline of 0.786 lb/mmBtu based on annual operation at highest pre-control 12-month rolling NOx summation mass emissions divided by the 12-month heat input summation.

(3) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The emission rate shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(4) - The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.49 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate for hypothetically-applied SCR alternatives would be 0.079 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.786 lb/mmBtu.

All hypothetical applications of tail-end and low-dust SCR technology alternatives were assumed to achieve a NO_X emission level of 0.049 lb/mmBtu, which is approximately a 90% reduction from a 0.49 lb/mmBtu level representing ASOFA when operating modestly air-staged cyclone furnaces with suitable combustion controls.

Hourly mass emission rates for the baseline pre-control condition were calculated by multiplying the unit emission rate (lb/mmBtu) by the average hourly gross heat input rate (mmBtu/hr), both calculated from Unit 2’s highest 12-month NO_X mass emissions and heat inputs during the 5-year lookback period.

Equivalent annual NO_X emissions (tons) were calculated by multiplying the 12-month summation for unit operating hours during the same period as the highest NO_X emissions by the 12-month average mass emission rate (lb/hr) and dividing by 2000 lb/ton.

The annual tons for the control options were calculated by multiplying the alternative's equivalent average annual hourly mass emission rate (lb/h) by the equivalent annual unit operating hours [8,760 h/yr maximum possible operating time, adjusted by an annual uptime (availability) factor]. Scheduled and unplanned maintenance outages are expected to occur due to each hypothetically-applied SCR system. Catalyst cleaning and replacement events have been estimated, with two frequencies showing a range of possible results. Due to the variability and possible severity of fouling characteristics of gaseous and aerosol particulate emissions generated by cyclone combustion of lignite supplied from the Center mine, and the dependency of the fouling within the hypothetically-applied SCR systems on sodium, potassium, sulfur, and ammonia slip emission levels, conditions may occur during operation of the hypothetically-SCR systems that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the deposits or prevent significant catalyst deactivation. Table C.4-1 in Section 4.2.1.2.1 includes estimated unit availability and corresponding operating time and outage time due to the four hypothetical applications of SCR technology cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[14]. Based on these calculations, the estimated annual emissions for M.R. Young Station Unit 2 and the emission reduction corresponding to each technology alternative are shown in Table 4-2.

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[14] Ibid Reference number 3, October 2006, pages C3-1 through page C3-11.

TABLE 4-2 – Expected Annual NO_X Control Performance for MRY Station Unit 2 Alternatives

Alt. Label(1)	NOx Control Alternative	EMISSIONS				NOx Removal Efficiency(5) %
		Emission Rate lb/mmBtu	Hourly Emission(2) lbs/hr	Annual Emission(3) tons/yr	Emission Reduction(4) tons/yr	
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	0.049	239	936	14,857	93.8(7)
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	0.049	239	813	14,980	93.8(7)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	0.049	239	931	14,862	93.8(7)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	0.049	239	813	14,980	93.8(7)
E	SNCR (using urea) w/ ASOFA	0.330	1,612	6,421	9,372	58.0
D	Gas Reburn w/ ASOFA	0.350	1,710	6,882	8,910	55.4
C	Lignite Reburn w/ ASOFA	0.360	1,759	6,964	8,829	54.2
B	Fuel Lean Gas Reburn w/ ASOFA	0.432	2,110	8,490	7,303	45.0
A	Advanced Separated Overfire Air (ASOFA)	0.489	2,391	9,621	6,172	37.7
-	Baseline	0.786	3,839	15,793	0	-

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Hourly NO_X emission estimates (lb/hr) were calculated based upon average annual unit emission rate (lb/mmBtu) x 4,885 mmBtu/hr heat input.

(3) - Estimated annual emission tons assume an annual unit availability factor specific to each alternative; 93.9% was assumed for the baseline case. See Appendix C3 of the October 2006 NO_X BACT Analysis Study report. Hypothetically-applied tail end SCR case T2 assumes an annual unit availability factor of 89.5% (approx. 7,842 operating hours per year) and case T1 assumes an annual unit availability factor of 77.8% (approx. 6,813 operating hours per year. Hypothetically-applied low-dust SCR case L2 assumes an annual unit availability factor of 89.0% (approx. 7,801 operating hours per year) and case L1 assumes an annual unit availability factor of 77.8% (approx. 6,813 operating hours per year).

(4) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

(5) - Estimated NO_X control level percentage reductions relative to 0.786 lb/mmBtu emission baseline at 4,885 mmBtu/hr MCR heat input.

(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The emission rate shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.49 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate for hypothetically-applied SCR alternatives would be 0.079 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.786 lb/mmBtu.

4.2 NO_X CONTROLS ANALYSIS AND IMPACTS EVALUATION

The next step[15] of this supplemental "top-down" BACT analysis is to evaluate the impacts of the hypothetical application of SCR alternatives' NO_X emission controls. Energy, economic, and environmental impacts are to be considered in the control technology evaluation. The purpose of the evaluation is to determine if there are any energy, economic or environmental impacts that would eliminate the top control technologies from consideration.

This evaluation of the effectiveness of the hypothetically-applied SCR alternatives, as well as that of the other control technologies previously considered technically feasible, was performed prospectively, i.e., assuming that none of the control technologies has been implemented. This approach assumes that the hypothetical application of SCR technology cases are considered to have been added to the previous NO_X BACT Analysis Study report submitted in October, 2006. The actual costs incurred and performance achieved for an installed advanced separated overfire air system, or firm price equipment quotes with performance guarantees for SNCR alternatives, that have been determined after the submittal of the 2006 NO_X BACT Analysis Study report, have not been used to adjust the control effectiveness or cost impacts of the previously analyzed control alternatives. The approach taken in this supplemental analysis uses installed capital costs estimated in calendar year 2009 escalated to project completion forecast in 2017 adjusted to calendar year 2006 basis for the hypothetically-applied tail end SCR and low-dust SCR technology cases that have been added to the list of alternatives previously evaluated.

4.2.1 NO_X CONTROL ECONOMIC IMPACTS FOR MRY STATION UNIT 2

An evaluation was performed to determine the various cost impacts of installing previously-analyzed feasible NO_X control alternatives and hypothetical application of low-dust and tail end SCR technologies on Milton R. Young Unit 2. This evaluation includes estimated:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, design, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 4-3 through 4-11.

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[15] Step 4 per the NSR Manual, Ibid Reference 2, October 1990.

4.2.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROL ALTERNATIVES

The range of estimated capital costs to implement some of the various NO_X control technologies were derived from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. For MRY Station Unit 2, for the cases involving the use of advanced separated overfire air and SNCR alternatives, preliminary project cost estimates using vendor budgetary cost information were developed and used in place of, or to adjust, the published unit output cost factors. A discussion of the reburn alternatives' estimated capital costs was included in the 2006 NO_X BACT Analysis Study report and has not been repeated here. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

For the hypothetical application of low-dust and tail end SCR alternatives at MRYS, there is no available information on recently-completed similar projects on coal-fired powerplants in the United States that could be used, with adjustments, to properly represent total installed costs that could be expected for MRYS Unit 2. For these alternatives, site-specific detailed preliminary (conceptual) designs were developed and budgetary cost information for major equipment was obtained for the development of the estimated installed capital cost.

The unit nameplate output capacity (gross electrical output in megawatts) assumed for the installed capital cost estimate basis of the NO_X control technologies evaluated was 477 MW_g for MRY Station Unit 2[16].

A review of the unit capital cost factor range and single point factors applicable to MRY Station Unit 2 NO_X control technologies are presented in Tables 4-3SA and 4-3SF. Note that the capital cost estimates for the hypothetical application of SCR alternatives were developed separately based on two different assumptions. In one case it was assumed that all costs for the hypothetically-applied Unit 2 SCR (tail end or low-dust) system would be accounted for as if the SCR equipment were being provided for Unit 2 only. This is referred to as the "stand alone" (SA) case, and all tables showing those costs are identified with that suffix. In the other case, it was assumed that the retrofit of hypothetically-applied SCR systems was being done for both Unit 1 and Unit 2, and there are some components that could be shared between the two units. This is referred to as the "shared facilities" (SF) case, and all tables showing those costs are identified with that suffix.

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[16] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 390.

Per the EPA's NSR Manual, a BACT analysis is done on a "case-by-case basis"[17]. The "stand alone" estimated total project capital costs for the hypothetical application of SCR alternatives reflect the economic impacts incurred as a result of implementing such technologies on each individual unit at MRYS independent of what may be determined or assumed for other units at this facility or similar units at other facilities. The "shared facilities" estimated total project capital costs for the hypothetical application of SCR alternatives do not account for all economic impacts borne strictly by the unit subject to the analysis, and as such, are subsidized by the unit(s) involved with the shared facilities. In this "shared facilities" approach, a BACT would be performed more in the manner of a "case-within-a-case" instead of on a "case-by-case" basis. Additionally, BACT is not to be applied on a facility basis. Units having different characteristics, (size, etc.) may have different technologies as BACT. Therefore, each unit should be treated as a separate "stand alone" case. Although the authors believe the "stand alone "case is the proper approach to use, information for both cases has been provided.

TABLE 4-3SA – Unit Capital Cost Factors of NO_X Control Alternatives for MRY Station Unit 2 - Stand Alone SCR Projects

Alt. Label(1)	**NO_X Control Alternative**	**Range(2) ($/kW)**	**Single Point Unit Capital Cost Factor(3), ($/kW) MRYS Unit 2**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	(4)	714(4),(5)
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	(4)	714(4),(5)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	(4)	568(4),(5)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	(4)	568(4),(5)
E	SNCR (using urea) w/ ASOFA	20-35(6)	35.9(5),(6)
D	Gas Reburn w/ ASOFA	15-30(7)	74.4(5),(7),(8)
C	Lignite Reburn w/ ASOFA	30-60(7)	170.2(5),(7),(9)
B	Fuel Lean Gas Reburn w/ ASOFA	--(6)	45.7(5),(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	21.0(5)

(1) - Alternative designation has been assigned from highest to lowest unit NOx emission rate.
(2) - Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ from this due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) - Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on EPA's nameplate rating. Single point cost figures in 2006 dollars.
(4) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The single point unit capital cost factor shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical

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[17] Ibid Reference 2, October 1990, Chapter B. Introduction page B1.

infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation. Due to the site-specific nature of factors influencing cost, no comparable cost data ranges for these technologies exist in the literature. A cost range for conventional high-dust SCR technology published in the 2005 EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034[18] was $55 to $150/kW. Single point unit capital cost factors were derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 2 in 2017 dollars converted to 2006$ as described in the text.

(5) - The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(6) - Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. See Appendix C2 of the October 2006 NO_X BACT Analysis Study report for details[19].

(7) - NESCAUM 2005 Technical Paper[20]; reburn alternatives on page 2-22, overfire air on page 2-23; posted at their website. See technical references in Appendix A1 of the October 2006 NO_X BACT Analysis Study report for details.

(8) - The single point unit capital cost factor shown for a conventional or fuel-lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW or 15.7 $/kW, respectively), and that both MRYS boilers share the capital cost in proportion to their respective rated MW gross output capacities.

(9) - The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report[21], posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 75.5 $/kW. See technical references in Appendix A1 of the October 2006 BACT Analysis report for details.

TABLE 4-3SF – Unit Capital Cost Factors of NO_X Control Alternatives for MRY Station Unit 2 – Shared Facilities SCR Projects

Alt. Label(1)	NO_X Control Alternative	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3), ($/kW) MRYS Unit 2
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	(4)	671(4),(5)
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	(4)	671(4),(5)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	(4)	525(4),(5)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	(4)	525(4),(5)
E	SNCR (using urea) w/ ASOFA	20-35(6)	35.9(5),(6)
D	Gas Reburn w/ ASOFA	15-30(7)	74.4(5),(7),(8)
C	Lignite Reburn w/ ASOFA	30-60(7)	170.2(5),(7),(9)
B	Fuel Lean Gas Reburn w/ ASOFA	--(6)	45.7(5),(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	21.0(5)

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[18] See Reference number 6, March 2005, page 3-63.
[19] See Reference number 3, October 2006, pages C2-3 and C2-7.
[20] See Reference number 7, March 2005.
[21] See Reference number 8, April 2005, page 3-9.

(1) - Alternative designation has been assigned from highest to lowest unit NOx emission rate.

(2) - Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ from this due to positive or negative synergistic effects. Range based on published values or vendor proposals.

(3) - Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on EPA's nameplate rating. Single point cost figures in 2006 dollars.

(4) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The single point unit capital cost factor shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation. Due to the site-specific nature of factors influencing cost, no comparable cost data ranges for these technologies exist in the literature. A cost range for conventional high-dust SCR technology published in the 2005 EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034[22] was $55 to $150/kW. Single point unit capital cost factors were derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 2 in 2017 dollars converted to 2006$ as described in the text.

(5) - The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(6) - Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. See Appendix C2 of the October 2006 NO_X BACT Analysis Study report for details[23].

(7) - NESCAUM 2005 Technical Paper[24]; reburn alternatives on page 2-22, overfire air on page 2-23; posted at their website. See technical references in Appendix A1 of the October 2006 NO_X BACT Analysis Study report for details.

(8) - The single point unit capital cost factor shown for a conventional or fuel-lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW or 15.7 $/kW, respectively), and that both MRYS boilers share the capital cost in proportion to their respective rated MW gross output capacities.

(9) - The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report[25], posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 75.5 $/kW. See technical references in Appendix A1 of the October 2006 BACT Analysis report for details.

4.2.1.1.1 CAPITAL COST ESTIMATES FOR HYPOTHETICAL APPLICATION OF SCR NO_X CONTROL ALTERNATIVES

There is no available information on recently-completed similar tail-end or low-dust SCR projects on coal-fired powerplants in the United States that could be used, with adjustments, to represent total installed costs that could be expected for MRYS Unit 2. Site-specific needs and challenges identified for applying tail end and low-dust SCR technologies to Milton R. Young Station Unit 2 significantly influence the capital cost estimate for variations of these hypothetical alternatives. Furthermore, the "EPA Air Pollution Control Cost Manual" is not applicable for use in estimating control equipment costs for these hypothetical applications of SCR technology cases, as the EPA Control Cost Manual states:

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[22] See Reference number 6, March 2005, page 3-63.
[23] See Reference number 3, October 2006, pages C2-3 and C2-7.
[24] See Reference number 7, March 2005.
[25] See Reference number 8, April 2005, page 3-9.

> "The costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements."[26]

This requirement for flue gas reheating also applies to the hypothetical application of low-dust SCR to MRYS, due to the cold-side arrangement (downstream of the electrostatic precipitator) instead of a hot-side ESP assumed in the EPA Control Cost Manual. Therefore, the equations in the EPA Control Cost Manual cannot be used for estimating either of the hypothetical SCR configurations for which NDDH has requested economic analyses. Thus it was necessary to prepare independent site-specific cost estimates.

The installed capital costs for hypothetical application of tail end and low-dust SCR alternatives were estimated by Burns & McDonnell with inputs from an SCR system supplier with recent design experience involving these SCR configurations, equipment suppliers, and catalyst suppliers with significant European project experience in such technology. Both hypothetically-applied low-dust and tail end SCR designs for MRYS Unit 2 assume two reactor / gas reheat systems installed in parallel, each connecting to one of the two existing wet lime flue gas desulfurization absorbers also arranged in parallel configuration. Each alternative includes flue gas reheat equipment that is typical for these applications but not required for conventional high-dust/hot side SCRs. The estimated flue gas volume at a gross boiler heat input and oxygen content corresponding to unit gross nameplate output capacity determined the size of the two hypothetically-applied SCR reactors for these cases. Structures, foundations, ductwork, balance of plant equipment and materials were quantified and included with the hypothetically-applied SCR equipment, which were factored for installation costs. Escalation of project costs, including equipment, materials, engineering and labor costs, is included, along with interest during construction, due to the expected project execution duration being significantly longer than for the other alternatives. Price and scope contingencies were included to account for the uncertainties that the current preliminary design scope and pricing fully reflects what would be necessary to complete implementation of these hypothetically-applied alternatives. Total project costs were considered to be a future value from a financial perspective, which were returned to a 2009 calendar year basis using a present value factor at the 2.5% per year annual discount rate previously assumed in the 2006 NO_X BACT Analysis Study report. A ratio of regional construction cost indices for public utility construction costs between 2006 and 2009 was used to adjust the 2009 total estimated project costs to a 2006 calendar year basis for each of the hypothetically-applied SCR alternatives.

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[26] See Reference number 10, Section 4.2, Chapter 2, page 2-41, October 2000.

The estimated installed and levelized annual capital costs for the hypothetically-applied SCR systems and previously-analyzed highest-performing form of the various feasible NO_X emission reduction technologies evaluated for cost-effectiveness are shown in Table 4-4SA and Table 4-4SF. These technologies are listed in order of control effectiveness, with the highest ranked option at the top.

TABLE 4-4SA – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 2 - Stand Alone SCR Projects

Alt. Label(1)	**NOx Control Alternative**	**Installed Capital Cost(2) $1,000**	**Annualized Capital Cost(3) $1,000**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	340,733(4)	29,707(4)
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	340,733(4)	29,707(4)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	270,785(4)	23,608(4)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	270,785(4)	23,608(4)
E	SNCR w/ ASOFA	17,128	1,493
D	Gas Reburn w/ ASOFA(5)	35,490	3,094
C	Lignite Reburn w/ ASOFA(6)	81,167	7,077
B	Fuel Lean Gas Reburn w/ ASOFA(5)	21,817	1,902
A	Advanced SOFA (ASOFA)	10,008	873
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars. See Table 4-5SA for presentation of installed capital costs determined for hypothetical application of SCR alternatives.

(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.

(4) - The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The installed capital cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 2 in 2017 dollars converted to 2006$ as described in the text. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $14,988,000 for CGR and $7,494,000 for FLGR; and annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR. See footnote number 8 under Table 4-3SA.

(6) - Costs for increased PM collection capacity included in lignite reburn option are $36,013,000 for installed capital cost, and $3,140,000/yr annualized capital cost.

TABLE 4-4SF – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 2 – Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Installed Capital Cost(2) $1,000	Annualized Capital Cost(3) $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	320,279(4)	27,923(4)
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	320,279(4)	27,923(4)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	250,487(4)	21,839(4)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	250,487(4)	21,839(4)
E	SNCR w/ ASOFA	17,128	1,493
D	Gas Reburn w/ ASOFA(5)	35,490	3,094
C	Lignite Reburn w/ ASOFA(6)	81,167	7,077
B	Fuel Lean Gas Reburn w/ ASOFA(5)	21,817	1,902
A	Advanced SOFA (ASOFA)	10,008	873
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars. See Table 4-5SF for presentation of installed capital costs determined for hypothetical application of SCR alternatives.
(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.
(4) - The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The installed capital cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 2 in 2017 dollars converted to 2006$ as described in the text. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.
(5) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $14,988,000 for CGR and $7,494,000 for FLGR; and annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR. See footnote number 8 under Table 4-3SF.
(6) - Costs for increased PM collection capacity included in lignite reburn option are $36,013,000 for installed capital cost, and $3,140,000/yr annualized capital cost.

The Total Project Costs estimated for tail end and low-dust SCR technologies hypothetically-applied to MRYS Unit 2 are shown in Table 4-5SA and Table 4-5SF in 2017, 2009, and 2006 dollars.

The estimated installed capital costs for the hypothetical application of tail end or low-dust SCR system retrofits on MRYS Unit 2 include the following equipment and components:

- Two SCR reactors utilizing a "3 +1" arrangement of catalyst layers, in which three layers of catalyst are initially installed, and space for installation of a fourth layer is provided.
- Sootblowers for each catalyst layer to maintain cleanliness of catalyst
- Flue gas reheat equipment that is typical for these applications but not required for conventional high-dust/hot side SCRs. This reheat equipment includes rotary regenerative heat exchangers (gas-to-gas heaters [GGH]) and natural gas-fired duct burners.
- Underground high-pressure natural gas supply pipeline and pressure regulators and metering equipment
- Hot air recirculation and heating equipment to maintain catalyst in a warm and dry condition during standby periods
- Induced draft booster fan and dampers
- Interconnecting ductwork
- SCR bypass duct and dampers (used during times the boiler is off-line)
- Storage tanks, building, and equipment for unloading and preparation of liquid urea solution
- Circulation pumps and piping for urea solution
- Urea-to-ammonia thermal conversion with urea conversion, metering, atomization, and injection equipment
- Ammonia gas dilution/combustion air fans and burners for natural gas-firing to decompose the urea solution to ammonia
- Service and sootblowing air compressors with dryers
- Electrical motor control centers
- Controls and instrumentation
- Reinforced concrete foundations
- Active coal yard storage modifications to regain lost live capacity and handling equipment due to space consumed by the SCR reactor structures
- Installation labor, materials, and management

Addition of new electrical loads to the existing plant facilities will be required for the reagent system and new induced draft booster fan power consumption. Based on recent plant electrical distribution equipment installations, additional plant auxiliary electrical power will be available for powering the new hypothetically-applied SCR equipment. Confirmation of these concepts and cost estimates prior to any subsequent plans for implementation requires successful completion of extensive pilot-scale slipstream

testing, and more detailed plant layout and equipment design than has been performed as part of this supplemental update to the October 2006 NO_X BACT Analysis Study report.

The capital cost estimated individually for an ASOFA system retrofit on MRYS Unit 2 as previously described in the initial NO_X BACT Analysis Study report was simply arithmetically added to the hypothetical application of SCR alternatives' capital cost estimates.

TABLE 4-5SA – Estimated Capital Costs for Hypothetically-Applied SCR Alternatives - MRY Station Unit 2 - Stand Alone SCR Projects

Alt. Label(1)	**Hypothetical SCR Alternative(2)**	**Estimated BMcD Study Total Project Cost(3), 2017$ x 1000**	**Estimated BMcD Study Modified TP Cost(4), 2009$ x 1000**	**Estimated BMcD Study Adjusted TP Cost(5), 2006$ x 1000**
T2, T1	Tail End SCR	436,346	358,129	325,240
	Urea preparation and storage, building, and equipment(6)	–	6,040(6)	5,485(6)
	ASOFA	–	–	10,008
T2, T1	TOTAL	–	–	340,733(6)
L2, L1	Low-Dust SCR	342,502	281,107	255,292
	Urea preparation and storage, building, and equipment	–	6,040(6)	5,485(6)
	ASOFA	–	–	10,008
L2, L1	TOTAL	–	–	270,785(6)

(1) All SCR alternatives are assumed to have the same SCR outlet NOx emission rate.
(2) The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station.
(3) The Total Project Cost shown for each hypothetically-applied SCR system was estimated by Burns & McDonnell based on scope assumptions for installation of the SCR equipment on this boiler as described in the text, except as described in footnote 6 below. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only Does not include installed capital cost for ASOFA, as shown in Table 4-4SA.
(4) Modified Total Project Costs are converted from 2017$ to 2009$ as described in the text, except as described in footnote 6 below. Present Value factor (discounted from future value) is 0.82075.
(5) Adjusted Total Project Costs are converted from 2009$ to 2006$ as described in the text. Handy-Whitman Index of Public Utility Construction Costs ratio is 0.908.
(6) Urea preparation and storage, building, and equipment installed capital costs were estimated separately in 2009$, and then adjusted using the Handy-Whitman cost ratio of 0.908 to get 2006$. The TOTAL numbers above are the sum of the Adjusted Total Project Cost; urea preparation and storage, building, and equipment; and total Installed Capital Costs (TICC) for ASOFA alternative = estimated TICC for the hypothetically-applied SCR alternatives in Table 4-4SA.

TABLE 4-5SF – Estimated Capital Costs for Hypothetically-Applied SCR Alternatives - MRY Station Unit 2 - Shared Facilities SCR Projects

Alt. Label(1)	Hypothetical SCR Alternative(2)	Estimated BMcD Study Total Project Cost(3), 2017$ x 1000	Estimated BMcD Study Modified TP Cost(4), 2009$ x 1000	Estimated BMcD Study Adjusted TP Cost(5),(6), 2006$ x 1000
T2, T1	Tail End SCR	411,063	337,379	306,395
	Urea preparation and storage, building, and equipment(6)	–	4,268(6)	3,876(6)
	ASOFA	–	–	10,008
T2, T1	TOTAL	–	–	320,279(6)
L2, L1	Low-Dust SCR	317,429	260,529	236,603
	Urea preparation and storage, building, and equipment	–	4,268(6)	3,876(6)
	ASOFA	–	–	10,008
L2, L1	TOTAL	–	–	250,487(6)

(1) All SCR alternatives are assumed to have the same SCR outlet NOx emission rate.

(2) The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station.

(3) The Total Project Cost shown for each hypothetically-applied SCR system was estimated by Burns & McDonnell based on scope assumptions for installation of the SCR equipment on this boiler as described in the text, except as described in footnote 6 below. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. Does not include installed capital cost for ASOFA, as shown in Table 4-4SF.

(4) Modified Total Project Costs are converted from 2017$ to 2009$ as described in the text, except as described in footnote 6 below. Present Value factor (discounted from future value) is 0.82075.

(5) Adjusted Total Project Costs are converted from 2009$ to 2006$ as described in the text. Handy-Whitman Index of Public Utility Construction Costs ratio is 0.908.

(6) Urea preparation and storage, building, and equipment installed capital costs were estimated separately in 2009$, and then adjusted using the Handy-Whitman cost ratio of 0.908 to get 2006$. The TOTAL numbers above are the sum of the Adjusted Total Project Cost; urea preparation and storage, building, and equipment; and total Installed Capital Costs (TICC) for ASOFA alternative = estimated TICC for the hypothetically-applied SCR alternatives in Table 4-4SF.

4.2.1.2 O&M COST ESTIMATES FOR NO_X CONTROL ALTERNATIVES

Operational costs to implement the hypothetical application of SCR alternatives and previously-analyzed feasible NO_X control alternatives for Milton R. Young Unit 2 were estimated using preliminary conceptual designs and budgetary vendor quotes in place of, or to adjust, the OAQPS cost factors established in the EPA's Air Pollution Control Cost Manual (OAQPS) for SNCR[27] and SCR[28], and using other costs from

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[27] See Reference number 9, October 2000.

[28] See Reference number 10, October 2000.

published technical papers discussing those control technologies. Maintenance costs were estimated as percentages of installed capital costs, with additional catalyst replacement costs using budgetary vendor quotes based on preliminary conceptual designs and expected design life.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's annual O&M costs are estimates of:

- Auxiliary electrical power consumption (megawatt-hours) and incremental purchased power unit costs for operating the additional control equipment;
- Natural gas consumption and unit cost for hypothetical application of SCR alternatives' flue gas reheating and urea-to-ammonia thermal conversion systems and feasible fuel reburn alternatives;
- Reagent consumption and reagent unit cost for hypothetical application of SCR alternatives and feasible SNCR alternatives;
- Reagent dilution water consumption and unit cost for feasible SNCR alternatives.
- Catalyst removal and replacement for hypothetical application of SCR alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler and plant equipment;
- Costs for purchase of replacement electrical power expected to result from loss of unit availability, i.e., outages attributable to the control option which reduce annual net electrical generation available for distribution.

For economic evaluation purposes, a 12-month rolling average running plant capacity factor of 95.2 percent (based on a historic (demonstrated) sustainable unit output capacity of 462 MW_g) combined with a 12-month rolling average availability (uptime) of 8,229 operating hours (93.9 percent of 8760 hours per year) resulting in an equivalent annual average unit capacity factor of 89.5% was assumed for Unit 2's pre-control baseline annual operation. A 12-month rolling average heat input rate of 4,885 mmBtu/hr and a 12-month rolling average NO_X emission rate of 0.786 lb/mmBtu from pre-control maximum rolling 12 month summation of nitrogen oxides mass emissions were assumed for calculating equivalent annual average control and cost-effectiveness for MRY Station Unit 2.

Tables 4-6SA and 4-6SF show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the hypothetically-applied SCR alternative cases and the highest-performing form of previously-evaluated feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Appendix C3 of the 2006 NOx BACT Analysis Study report provides more details for the levelized annual O&M cost calculations and cost factors for the previously-analyzed feasible NO_X control alternatives[29].

TABLE 4-6SA – Estimated O&M Costs for NO_X Control Alternatives - MRY Station Unit 2 - Stand Alone SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual O&M Cost(2) $1,000	Levelized Annual O&M Cost(2),(3) $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	31,512	39,350
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	55,345	69,111
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	29,048	36,273
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	52,424	65,463
E	SNCR w/ ASOFA	8,108	10,125
D	Gas Reburn w/ ASOFA	48,688	60,798
C	Lignite Reburn w/ ASOFA(5)	9,929	12,398
B	FLGR w/ ASOFA	21,954	27,415
A	Advanced SOFA (ASOFA)	2,805	3,503
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at an average unit output (462 MWg) and assumes a 94.7% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.

(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(4) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual O&M cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimate specific to MRYS Unit 2 in 2017 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties,, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for increased PM collection capacity included in lignite reburn option are $3,358,000/yr for annual O&M cost, and $4,194,000/yr annualized O&M cost.

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[29] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

TABLE 4-6SF – Estimated O&M Costs for NO_X Control Alternatives - MRY Station Unit 2 – Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual O&M Cost(2) $1,000	Levelized Annual O&M Cost(2),(3) $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	30,898	38,583
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	54,731	68,345
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	28,439	35,512
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	51,815	64,703
E	SNCR w/ ASOFA	8,108	10,125
D	Gas Reburn w/ ASOFA	48,688	60,798
C	Lignite Reburn w/ ASOFA(5)	9,929	12,398
B	FLGR w/ ASOFA	21,954	27,415
A	Advanced SOFA (ASOFA)	2,805	3,503
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at an average unit output (462 MWg) and assumes a 94.7% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.

(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(4) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual O&M cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimate specific to MRYS Unit 2 in 2017 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties,, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for increased PM collection capacity included in lignite reburn option are $3,358,000/yr for annual O&M cost, and $4,194,000/yr annualized O&M cost.

4.2.1.2.1 O&M COST ESTIMATES FOR HYPOTHETICAL APPLICATION OF SCR NO_X CONTROL ALTERNATIVES

The hypothetical application of tail-end and low-dust SCR w/ ASOFA alternatives will involve significantly higher operating costs compared with the existing operation of MRYS Unit 2. The system uses an amine reagent in the form of concentrated aqueous urea solution, which is thermally converted to gaseous ammonia, carbon dioxide, and water vapor. The estimated unit cost of this urea was assumed to average $379/ton (delivered to the plant site via truck-tanker trailers; unit pricing based on 50% concentration as established for the 2006 NO_X BACT Analysis Study report). Consumption of urea converted to ammonia reagent was based upon recent equipment vendor budgetary proposals and SCR consultant inputs.

For the hypothetically-applied SCR cases, using the existing induced draft fans is not expected to significantly change the overall fan horsepower demand on those fans' electric motors. There will be new plant electrical power demand due to new induced draft booster fans required to overcome the estimated additional flue gas pressure drop resulting from reactor, ductwork, and gas-to-gas heat exchanger equipment assumed for the hypothetically-applied SCR systems. The additional auxiliary electric power demand for the hypothetically-applied tail end SCR systems was calculated to be 14.9 MW, using estimated annual average electrical loads of the booster fan, direct flue gas reheat burner combustion air fans, urea-to-ammonia conversion dilution/combustion air fans, and SCR sootblower and service air compressor equipment based on preliminary equipment vendor budgetary proposals developed from Burns & McDonnell ductwork sizing and designs. Estimated annual average electrical power demands for hypothetically-applied low-dust SCR systems were calculated to be 12.4 MW. Replacement of electrical power resulting from these reductions in net unit electrical output was included as a cost, assuming $35 per megawatt-hour.

Hypothetically-applied tail end and low-dust SCR equipment requiring annual maintenance includes booster fans, gas-to-gas heat exchangers, flue gas reheat duct burners, and compressor equipment. This general annual maintenance cost was estimated as 3 percent of installed capital costs.

To account for the possible range of O & M costs due to catalyst replacement, two variations (Scenario A and Scenario B) were applied. These two scenarios were used for both hypothetical applications of tail-end and low-dust SCR technology alternatives. Each scenario was based on scheduled additions and/or replacement of the exposed catalyst after a certain number of hours of operation, repeated throughout the 20 year operating span considered in the analysis. The current installed unit cost of replacement catalyst assumed for the hypothetical application of full-time tail end or low-dust SCR alternatives is $7,500 per cubic meter in 2006 dollars. The basis for development of the two scenarios is described below.

During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically-applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Based on information obtained in discussions with the catalyst vendors, the longest catalyst replacement schedule they would both agree upon as an estimated (not guaranteed) value was 16,000 hours. Both vendors indicated that actual experience could result in a shorter replacement cycle, and that the actual guarantee value could not be developed until extensive pilot testing had been completed. This led Burns & McDonnell to develop two hypothetically-applied SCR catalyst replacement scenarios to bracket possible outcomes.

Scenario A assumed a catalyst replacement schedule of 16,000 hours. Specifically for MRYS Unit 2, this scenario is based on the replacement of one catalyst layer in each reactor every 16,000 operating hours.

Scenario B assumed that the fouling of the catalyst would be severe, and that it would be necessary for Minnkota to perform catalyst maintenance at each scheduled boiler cleaning outage. The current schedule of boiler cleaning outages on Unit 2 is four times per year. Therefore, Scenario B for Unit 2 is based on the replacement of one catalyst layer in each reactor at each boiler cleaning outage. This means that each catalyst layer in the four layer SCR reactor is exposed to flue gas during approximately 12 months of operation and then is replaced. By assuming that catalyst management activities would coincide with scheduled boiler cleaning outages, Scenario B provides some minimization of the impact of catalyst replacement on unit operation.

As noted above, it is not known what the actual frequency of catalysts replacement would need to be for a hypothetically-applied tail-end or low dust SCR system operating on a cyclone-fired boiler burning North Dakota lignite, but the two scenarios described above are the catalyst replacement numbers assumed for this comparative economic analysis.

SCR catalyst replacements are additive to the general annual hypothetically-applied low-dust and tail end SCR equipment maintenance. Catalyst replacement costs are based on catalyst vendor quotation of volume of catalyst, estimated to be three layers initially (top, middle-upper and middle-lower) at 256 cubic meters per layer per reactor for two reactors in parallel. A fourth (bottom) layer at 342 cubic meters is expected to be required after initial operation of hypothetically-applied full-time tail end or low-dust SCR alternatives, as part of the catalyst replacement program. Catalyst replacement costs for the hypothetical application of SCR alternatives were estimated for the two different catalyst management scenarios described above.

Annual unit operating time will be reduced as a result of the expected outages and maintenance of the hypothetically-applied SCR equipment, including catalyst cleaning and management practices. Additional outage time of 206 hours per year was estimated to be attributable to the hypothetical application of tail end SCR Scenario A alternative (assuming 16,000 hour catalyst life), and 1,235 hours per year for the Scenario B TESCR case (assuming four layers are replaced every year) over and above the outage time assumed for ASOFA impacts. Additional outage time of 247 hours per year was estimated to be attributable to the hypothetical application of low-dust SCR Scenario A alternative, and 1,235 hours per year for the Scenario B LDSCR case over and above outage time assumed for ASOFA impacts. The expected loss of electrical power generation from these reductions in net output was included as a cost, assuming $35 per megawatt-hour for replacement power.

Table C.4-1 provides the estimated unit availability and corresponding operating time and outage time due to the four hypothetically-applied SCR technology cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[30].

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[30] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

TABLE C.4-1 – Expected Availability Reductions for MRYS Unit 2 NO_X Controls

Alt.[1]	NOx Control Alternative	Estimated Annual Average Unit Operating Time			
		Unit Availability[2]	Unit Operating Time[3], hrs/yr	Unit Outage Time[4], hrs/yr	Unit Operating Time Reduction[5], hrs/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	0.895	7,842	918	387
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	0.778	6,813	1,947	1,416
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	0.890	7,801	959	428
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	0.778	6,813	1,947	1,416
E	SNCR w/ ASOFA	0.909	7,965	795	264
D	Gas Reburn w/ ASOFA	0.919	8,048	712	181
C	Coal Reburn w/ ASOFA	0.904	7,916	844	313
B	FLGR w/ ASOFA	0.919	8,048	712	181
A	Advanced SOFA (ASOFA)	0.919	8,048	712	181
	Baseline	0.939	8,229	531	0

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.

(2) – 12-month baseline availability is assumed at 93.9 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technology.

(3) – Annual operating time is annual average availability multiplied by 8760 hrs/yr of possible uptime.

(4) – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.

(5) – Annual operating time reduction resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.

(6) – The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual unit availability factors shown for hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties,, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

Table C.4-2 includes estimated equivalent average annual unit running plant capacity ratios and unit generation reductions due to the four hypothetically-applied SCR cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[31]. These numbers assume the reduction in annual plant output is a combination of a reduction of annual operating time and capacity reductions associated with the control alternatives.

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[31] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

TABLE C.4-2 – Expected Capacity Reductions for MRYS Unit 2 NO_X Controls

Alt. Label(1)	NOx Control Alternative	Estimated Annual Average Unit Electrical Power Generation Reduction from Operating Time Reduction: Unit Running Plant Capacity Ratio(2)	Unit Generation Reduction(3) kW-hrs/yr	Unit Generation Reduction Cost(4), 1000$/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	0.924	170,167,448	5,956
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	0.924	622,740,448	21,796
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	0.929	188,270,368	6,589
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(5)	0.929	622,740,448	21,796
E	SNCR w/ ASOFA	0.951	110,176,095	3,856
D	Gas Reburn w/ ASOFA	0.943	81,416,590	2,850
C	Lignite Reburn w/ ASOFA	0.948	130,375,506	4,563
B	FLGR w/ ASOFA	0.949	81,910,024	2,867
A	Advanced SOFA (ASOFA)	0.952	75,859,855	2,655
	Baseline	0.952	0	0

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.

(2) - 12-month baseline running plant capacity ratio is assumed at 95.2 percent (= 440/462). These values reflect estimated amounts of negative annual output capacity impact expected from the implementation of the individual NOx control technique. Used only for calculation of annual power usage in Table C.4-3.

(3) - Annual electricity generation reduction is annual unit operating time reduction multiplied by the 12-month average gross output of 440 MW.

(4) - Annual electricity generation reduction cost is the annual electricity generation reduction (kW-hrs/yr) resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual unit running plant capacity ratios shown for hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Table C.4-3 includes estimated unit gross and net electrical power demands (kilowatts) and annual usage (kW-hrs per year) used to calculate unit generation reductions and replacement electrical power costs due to the four hypothetically-applied SCR cases, along with the ASOFA numbers from the referenced Appendix

C3 of the initial NO_X BACT Analysis Study report [32]. These numbers assume that the reductions of annual operating time and capacity associated with the control alternatives are also applied.

TABLE C.4-3 – Expected Auxiliary Electrical Power Demand Changes for MRYS Unit 2 NO_X Controls

		Estimated Annual Average APC NOx Equipment Auxiliary Electrical Power Demand and Usage				
Alt. Label(1)	**NOx Control Alternative**	**Gross Demand (2) kW**	**Credit(3) kW**	**Total Net Demand(4) kW**	**Power Usage(5) kW-hrs/yr**	**Power Usage Cost(6), 1000$/yr**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(7)	14,925	0	14,925	108,122,807	3,784
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(7)	14,925	0	14,925	93,941,913	3,288
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(7)	12,389	0	12,389	89,740,378	3,141
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(7)	12,389	0	12,389	78,381,807	2,743
E	SNCR w/ ASOFA	133	0	133	1,008,774	35
D	Gas Reburn w/ ASOFA	1	(228)	(227)	(1,724,428)	(60)
C	Lignite Reburn w/ ASOFA	8,342	(448)	7,894	59,217,554	2,073
B	FLGR w/ ASOFA	1	(125)	(124)	(949,051)	(33)
A	Advanced SOFA (ASOFA)	1	0	1	7,664	0.3

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) - The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of the demand for individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects. Coal reburn includes 2,484 kW for feed preparation and conveying equipment demand plus 5,857 kW for the COHPAC system addition for PM control.
(3) - The APC NOx equipment auxiliary electrical power demand credit of coal reburn alternatives is the estimated result of lower cyclone coal preparation and feeder power demand due to lower boiler cyclone coal equipment loading. Actual power demands may differ from this due to accuracy of estimates for assumed amount of operating horsepower reduction.
(4) - The total net auxiliary electrical power demand is the sum of the gross demand and credit.
(5) - The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity ratio which reflects the adjustment for any expected availability and capacity impacts from the implementation of the control technique.
(6) - The annual change in APC NOx equipment auxiliary electrical power demand electricity cost is the annual change in kW-hrs/yr for these alternatives resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.
(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated power demand shown for hypothetically-applied SCR systems are based on Burns & McDonnell estimates developed from preliminary equipment and ductwork sizing and designs with vendor budgetary proposals. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

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[32] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

Table C.4-4 includes estimated net unit electrical annual power usage (kW-hrs per year) and expected reductions in annual operating time to calculate unit generation reductions and replacement electrical power costs due to the four hypothetically-applied SCR cases, along with the ASOFA numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[33]. These numbers assume the reduction in annual plant output is a combination of a reduction of net unit generation because of electrical power usage and reductions in annual operating time and capacity associated with the control alternatives.

TABLE C.4-4 – Expected Auxiliary Electrical Power Demand and Generation Reduction Cost Changes for MRY Unit 2 NO_X Controls

		Estimated Annual Change in Unit Generation Due to APC NOx Equipment Auxiliary Power Electricity Demand and Generation Reduction			
Alt. Label(1)	**NOx Control Alternative**	**APC Electrical Power Usage(2) kW-hrs/yr**	**Unit Generation Reduction(3) kW-hrs/yr**	**Total Unit Electrical Power Generation Change(4) kW-hrs/yr**	**Total Unit Electrical Power Generation Change Cost(5) 1000$/yr**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	108,122,807	170,167,448	278,290,255	9,740
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	93,941,913	622,740,448	716,682,361	25,084
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	89,740,378	188,270,368	278,010,746	9,730
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	78,381,807	622,740,448	701,122,255	24,539
E	SNCR w/ ASOFA	1,008,774	110,176,095	111,184,869	3,891
D	Gas Reburn w/ ASOFA	(1,724,428)	81,416,590	79,692,162	2,789
C	Lignite Reburn w/ ASOFA	59,217,554	130,375,506	189,593,059	6,636
B	FLGR w/ ASOFA	(949,051)	81,910,024	80,960,972	2,834
A	Advanced SOFA (ASOFA)	7,664	75,859,855	75,867,520	2,655

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.

(2) - The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity ratio which reflects the adjustment for any expected availability and capacity impacts from the implementation of the control technique.

(3) - Annual electricity generation reduction is annual operating time reduction multiplied by the 12-month average gross output of 440 MW.

(4) - The total unit electrical power generation change is the sum of the annual change in APC NOx equipment auxiliary electrical power demand electricity usage plus the annual electricity generation reduction resulting from the implementation of the individual NOx control alternative.

(5) - The total unit electrical power generation change cost is the total generation change (kw-hrs/yr) multiplied by the incremental value of replacement electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

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[33] Ibid Reference number 2, October 2006, pages C3-1 through C3-11.

(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated power demand shown for hypothetically-applied SCR systems are based on Burns & McDonnell estimates developed from preliminary equipment and ductwork sizing and designs with vendor budgetary proposals. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

4.2.1.3 LEVELIZED TOTAL ANNUAL COST ESTIMATES FOR MRY STATION NO_X CONTROLS

A comparison of the control versus cost-effectiveness of two hypothetical SCR cases and previously-analyzed feasible NO_X control alternatives on Milton R. Young Unit 2 was made. This is summarized as shown in Tables 4-7SA and 4-7SF, Figures 4-1SA and 4-1SF, and Figures 4-2SA and 4-2SF for MRY Station Unit 2.

TABLE 4-7SA – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 2 - Stand Alone SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) $1,000	Average Control Cost(5) $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	936	14,857	69,057	4,648
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	813	14,980	98,818	6,597
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	931	14,862	59,881	4,029
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	813	14,980	89,072	5,946
E	SNCR w/ ASOFA	6,421	9,372	11,618	1,240
D	Gas Reburn w/ ASOFA	6,882	8,910	63,892(7)	7,171
C	Lignite Reburn w/ ASOFA	6,964	8,829	19,475(8)	2,206
B	FLGR w/ ASOFA	8,490	7,303	29,317(7)	4,014
A	Advanced SOFA (ASOFA)	9,621	6,172	4,376	709
	Baseline	15,793	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated annual emission tons assume an annual unit uptime availability factor specific to each alternative; 15,793 (= 0.939*8760*3,839/2000) was assumed for the baseline case.

(3) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note 3 from Tables 4-4SA and 4-6SA for annualized cost factors. Emissions are calculated from unit emission rates, control percentage,

hourly heat input, and annual hrs/yr operation compared to pre-control baseline emissions based on annual operation at baseline pre-control NOx emission rate.

(5) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are unsolvable. Costs are derived from Burns & McDonnell internal database and cost estimate specifically for MRYS Unit 2 in 2006 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR. See footnote number 8 under Table 4-3SA.

(8) - LTAC for increased PM collection capacity included in lignite reburn option are approximately $3,140,000 for annualized capital cost plus $4,194,000/yr for annualized O&M cost, for a LTAC subtotal of $7,333,000/yr.

TABLE 4-7SF – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 2 - Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) $1,000	Average Control Cost(5) $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	936	14,857	66,506	4,477
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	813	14,980	96,268	6,427
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	931	14,862	57,351	3,859
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	813	14,980	86,542	5,777
E	SNCR w/ ASOFA	6,421	9,372	11,618	1,240
D	Gas Reburn w/ ASOFA	6,882	8,910	63,892(7)	7,171
C	Lignite Reburn w/ ASOFA	6,964	8,829	19,475(8)	2,206
B	FLGR w/ ASOFA	8,490	7,303	29,317(7)	4,014
A	Advanced SOFA (ASOFA)	9,621	6,172	4,376	709
	Baseline	15,793	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated annual emission tons assume an annual unit uptime availability factor specific to each alternative; 15,793 (= 0.939*8760*3,839/2000) was assumed for the baseline case.

(3) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note 3 from Tables 4-4SF and 4-6SF for annualized cost factors. Emissions are calculated from unit emission rates, control

percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline emissions based on annual operation at baseline pre-control NOx emission rate.

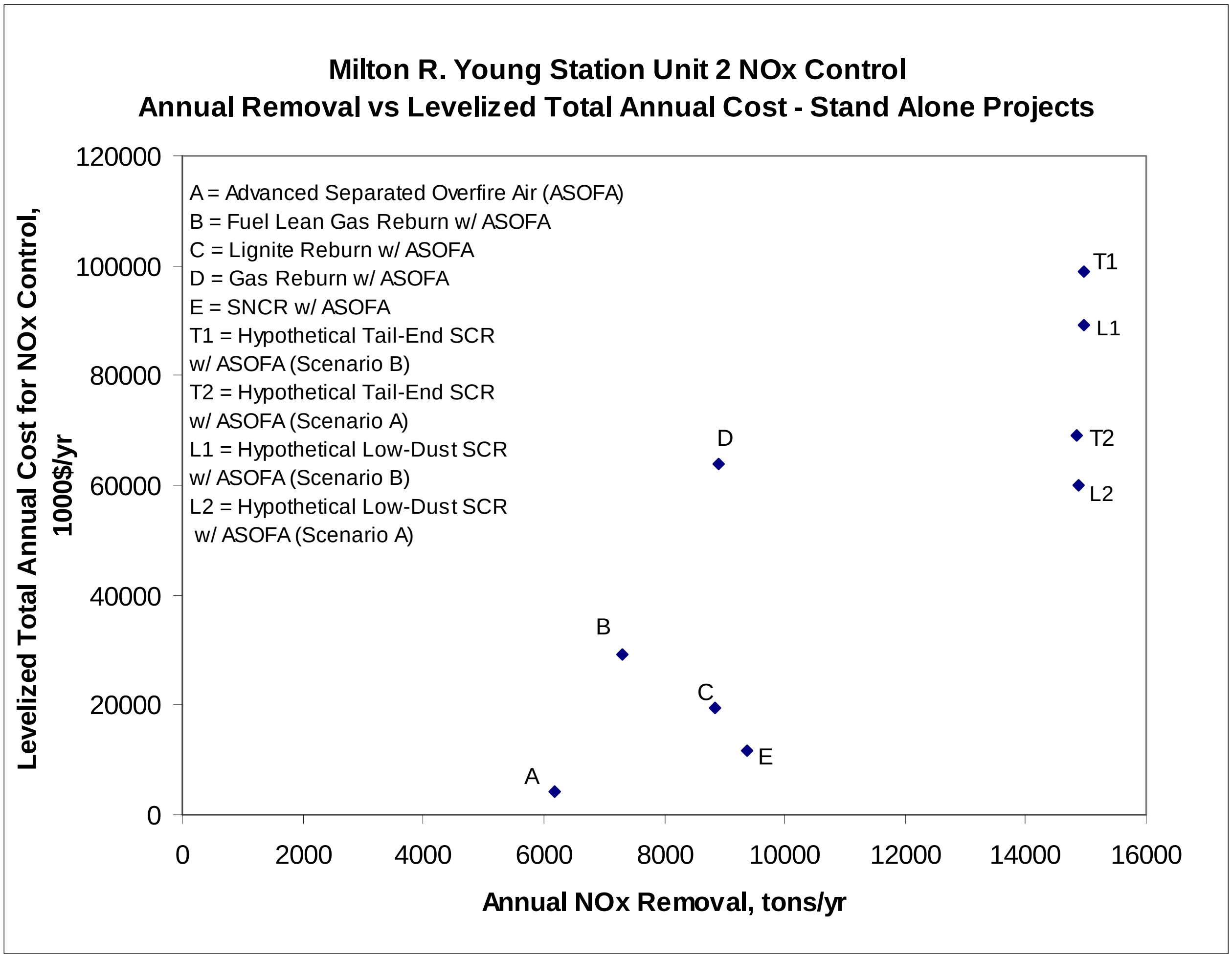
(5) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are unsolvable. Costs are derived from Burns & McDonnell internal database and cost estimate specifically for MRYS Unit 2 in 2006 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR. See footnote number 8 under Table 4-3SF.

(8) - LTAC for increased PM collection capacity included in lignite reburn option are approximately $3,140,000 for annualized capital cost plus $4,194,000/yr for annualized O&M cost, for a LTAC subtotal of $7,333,000/yr.

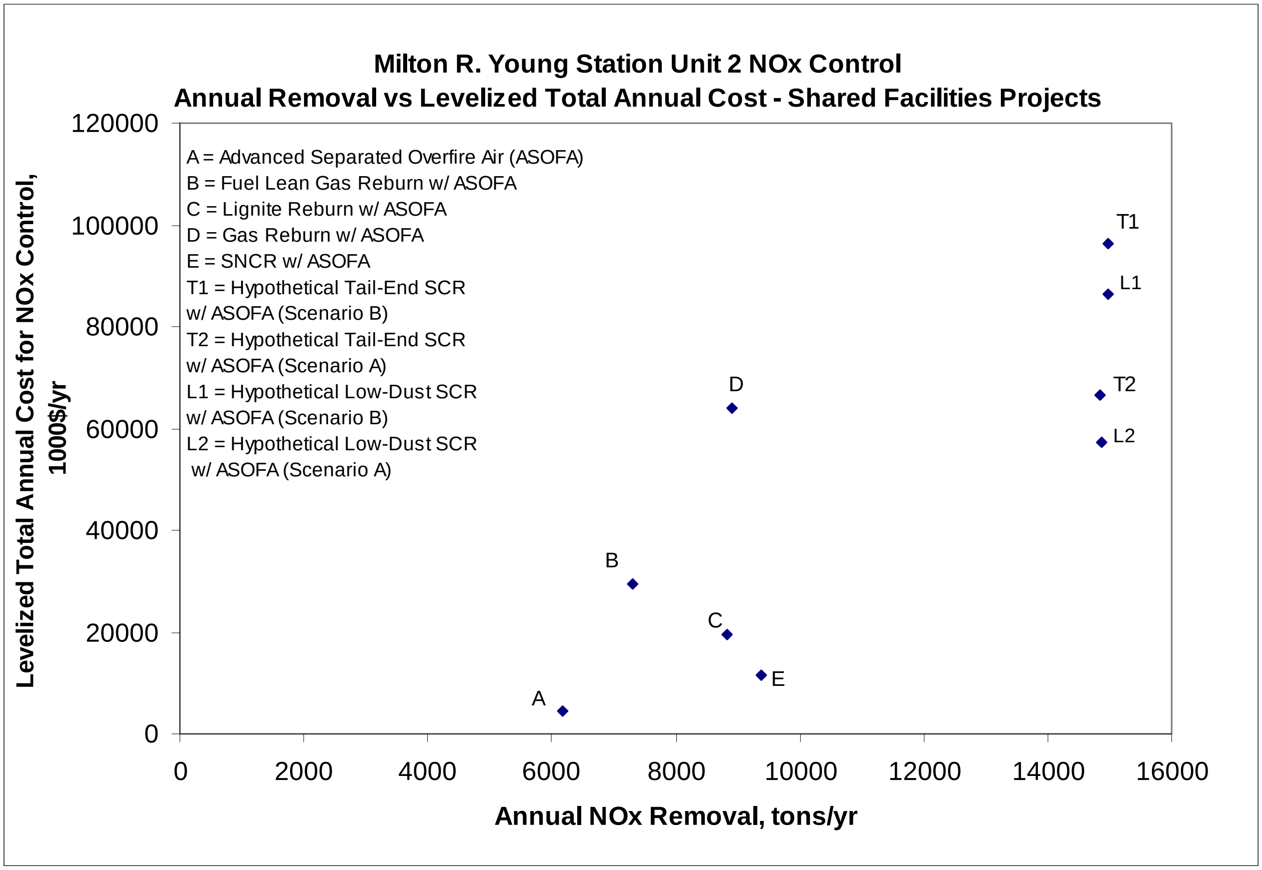
Figure 4-1SA – NO_X Control Cost Effectiveness - MRY Station Unit 2[(1)]
Stand Alone SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-7SA.

(2) - The inclusion of tail-end and low-dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Figure 4-1SF – NO_X Control Cost Effectiveness - MRY Station Unit 2(1) Shared Facilities SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-7SF.

(2) - The inclusion of tail-end and low-dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

The purpose of Figures 4-1SA and 4-1SF is to show the range of control and cost for four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives on Milton R. Young Unit 2 alternatives evaluated.

Data points for conventional gas reburn (Point D) and fuel-lean gas reburn (Point B) with advanced separated overfire air, and lignite reburn with ASOFA (Point C), in Figures 4-1SA and 4-1SF are inferior and therefore were eliminated from further control cost-effectiveness analysis.

A dominant set of control alternatives was determined by generating what is called the "envelope of least-cost alternatives". The dominant controls cost curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the annual NO_X removal tonnage versus LTAC for the various remaining BACT alternatives. Average and incremental annual costs and NO_X emission reductions for the dominant least-cost control alternatives remaining after the elimination of the obviously inferior options are listed in Tables 4-8SA and 4-8SF.

TABLE 4-8SA – Dominant Controls Cost Curve Points for NO_X Control Alternatives - MRY Station Unit 2 - Stand Alone Projects

Alt. Label[(1)]	NOx Control Alternative	Levelized Total Annual Cost[(2),(3)] ($1,000/yr)	Annual Emission Reduction[(3)] (tpy)	Incremental Levelized Total Annual Cost[(2),(4)] ($1,000/yr)	Incremental Annual Emission Reduction[(4)] (tpy)	Incremental Control Cost Effectiveness ($/ton)[(2),(4)]
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[(5)]	69,057	14,857	57,439	5,485	10,472
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[(5)]	98,818	14,980	87,200	5,608	15,550
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[(5)]	59,881	14,862	48,263	5,490	8,792
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[(5)]	89,072	14,980	77,454	5,608	13,812
E	SNCR w/ ASOFA	11,618	9,372	7,242	3,200	2,263
A	Advanced SOFA (ASOFA)	4,376	6,172	4,376	6,172	709

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Dominant controls cost curve points from lowest (ASOFA) to highest (TESCR w/ ASOFA-16,000 hrs) are labeled the same as in Table 4-7SA, and on the graphs that accompany this table (Points B, C, and D were eliminated).

(2) - All cost figures in 2006 dollars.

(3) - Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate.

(4) - Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

TABLE 4-8SF – Dominant Controls Cost Curve Points for NO_X Control Alternatives - MRY Station Unit 2 - Shared Facilities Projects

Alt. Label(1)	**NOx Control Alternative**	**Levelized Total Annual Cost(2),(3) ($1,000/yr)**	**Annual Emission Reduction(3) (tpy)**	**Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)**	**Incremental Annual Emission Reduction(4) (tpy)**	**Incremental Control Cost Effectiveness ($/ton)(2),(4)**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	66,506	14,857	54,888	5,485	10,007
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	96,268	14,980	84,650	5,608	15,096
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	57,351	14,862	45,733	5,490	8,331
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(5)	86,542	14,980	74,924	5,608	13,361
E	SNCR w/ ASOFA	11,618	9,372	7,242	3,200	2,263
A	Advanced SOFA (ASOFA)	4,376	6,172	4,376	6,172	709

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Dominant controls cost curve points from lowest (ASOFA) to highest (TESCR w/ ASOFA-16,000 hrs) are labeled the same as in Table 4-7SF, and on the graphs that accompany this table (Points B, C, and D were eliminated).

(2) - All cost figures in 2006 dollars.

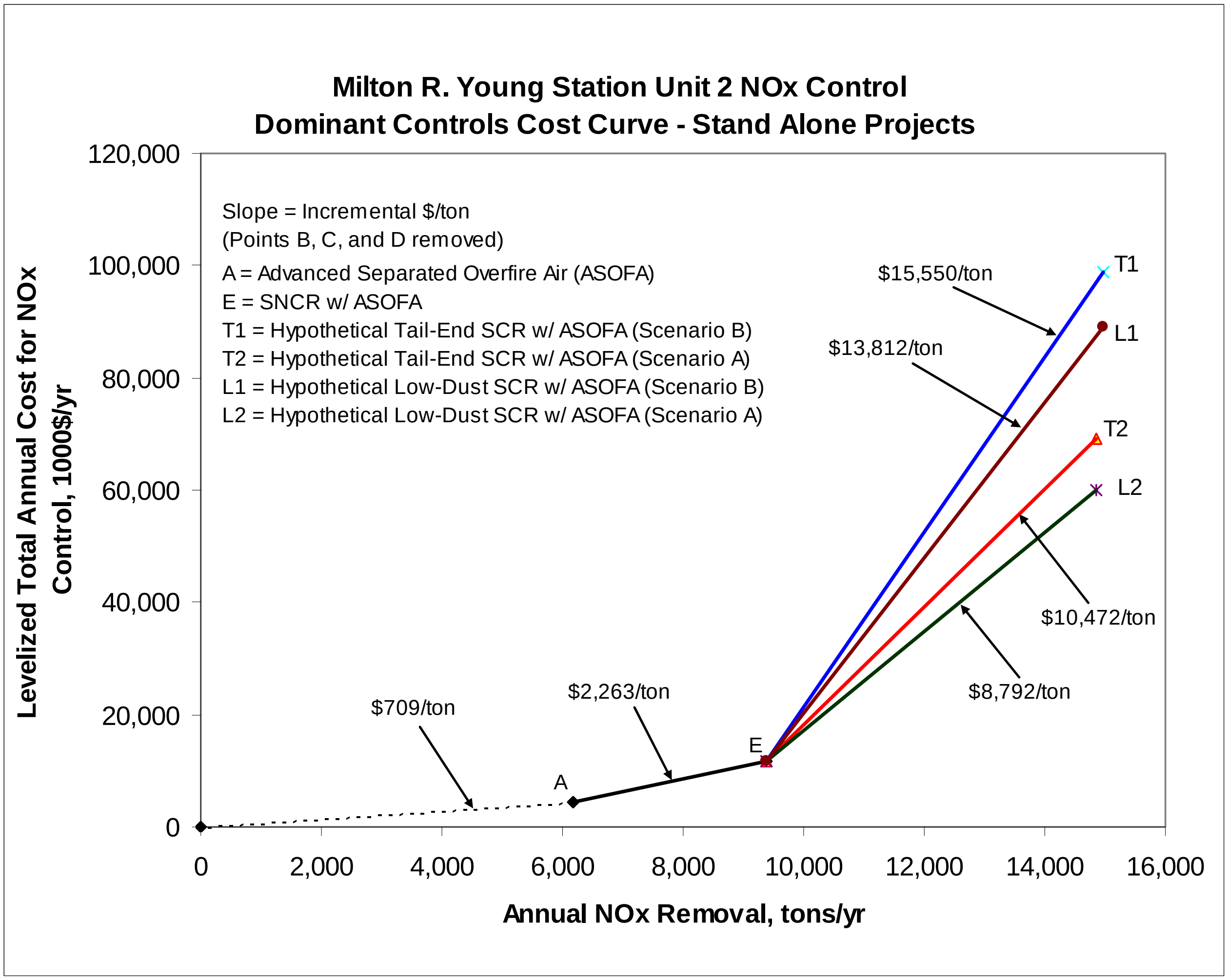
(3) - Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate.

(4) - Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Figures 4-2SA and 4-2SF contain a repetition of the levelized total annual cost and NO_X control information from Figure 4-1SA and 4-2SF for MRY Station Unit 2, with Point B (FLGR™ with ASOFA), Point C (Lignite Reburn with ASOFA) and Point D (conventional gas reburn with ASOFA) removed. This is the dominant controls cost curve for MRY Station Unit 2 NO_X emissions alternatives.

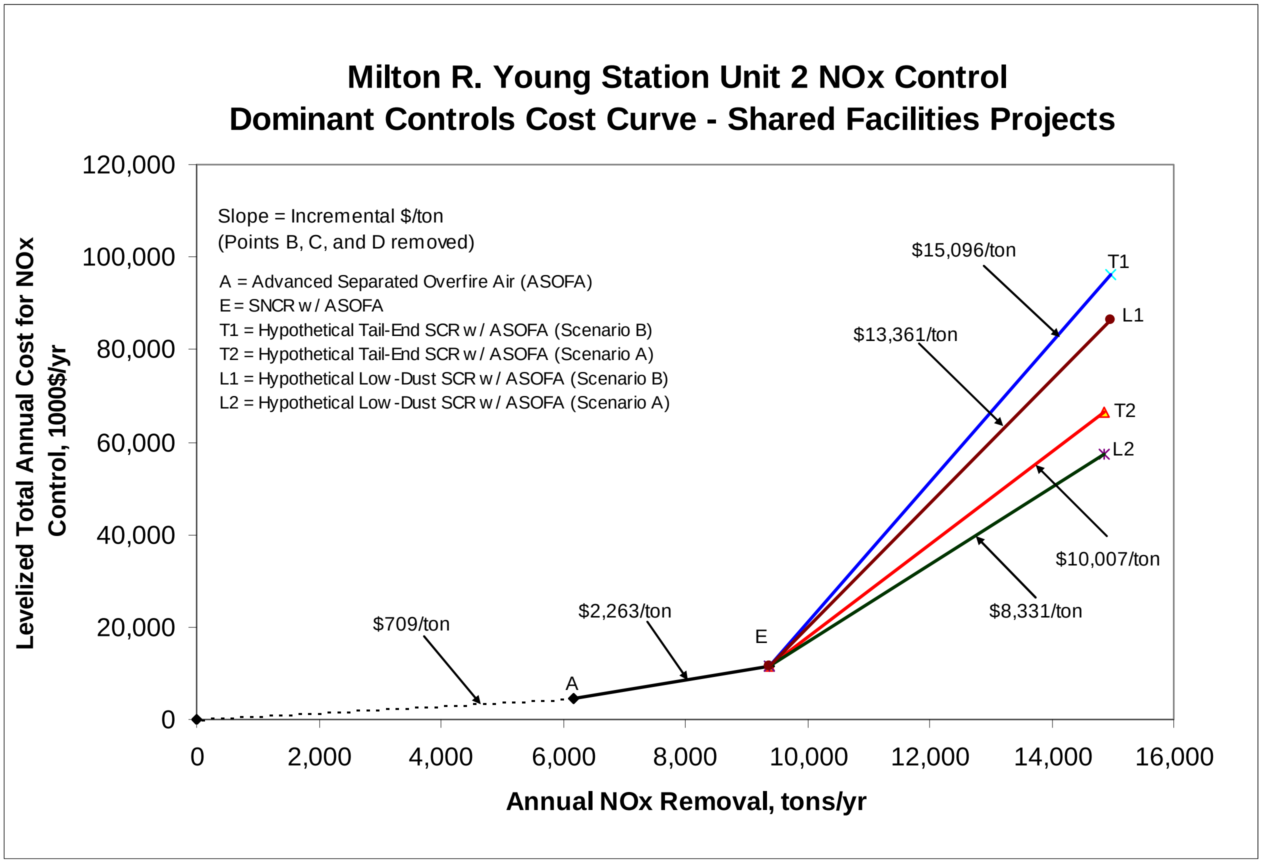
Figure 4-2SA – MRY Station Unit 2 NO_X Control Alternatives BACT Dominant Controls Cost Curve$^{(1)}$ - Stand Alone SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-8SA.

(2) - The inclusion of tail-end and low-dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

**Figure 4-2SF – MRY Station Unit 2 NO_X Control Alternatives
BACT Dominant Controls Cost Curve(1) – Shared Facilities SCR Projects**



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-8SF.

(2) - The inclusion of tail-end and low-dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

As can be seen from a review of Table 4-7SA and Table 4-7SF, the average control cost effectiveness (called the unit control cost in this report) ranges from approximately $709/ton to $7,171/ton of MRYS Unit 2's NO_X emissions removed. The unit control cost for the hypothetically-applied Scenario A Tail End SCR w/ ASOFA case was $4,648/ton and for the hypothetically-applied Scenario B Tail End SCR w/ ASOFA case was $6,597/ton (stand alone projects). The unit control cost for the hypothetically-applied Scenario A Low-Dust SCR w/ ASOFA case was $4,029/ton and for the hypothetically-applied Scenario B Low-Dust SCR w/ ASOFA case was $5,946/ton (stand alone projects). The unit control cost for the hypothetically-applied Scenario A Tail End SCR w/ ASOFA case was $4,477/ton and for the hypothetically-applied

Scenario B Tail End SCR w/ ASOFA case was $6,427/ton (shared facilities projects). The unit control cost for the hypothetically-applied Scenario A Low-Dust SCR w/ ASOFA case was $3,859/ton and for the hypothetically-applied Scenario B Low-Dust SCR w/ ASOFA case was $5,777/ton (shared facilities projects). Unit control cost for SNCR w/ ASOFA was $1,240/ton, nearly twice that of ASOFA ($709/ton). It should be noted, however, that very high estimated average control costs involve fuel lean gas reburn ($4,014/ton) and conventional gas reburn ($7,171/ton) technologies that were previously shown to be inferior options (not on the dominant controls cost curve) and thus were eliminated from further impacts analysis.

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative for MRYS Unit 2 incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control technique. The slope from zero (baseline) to ASOFA (Point A) was $709/ton; the incremental cost per ton (slope) from ASOFA (Point A) to SNCR with ASOFA (Point E) was $2,263/ton for MRYS Unit 2. The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied low-dust SCR case (Point L2, Scenario A) was $8,792/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied tail end SCR case (Point T2, Scenario A) was $10,472/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied low-dust SCR case (Point L1, Scenario B) was $13,812/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied tail end SCR case (Point T1, Scenario B) was $15,550/ton (stand alone projects). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied SCR cases were $8,331/ton (low-dust Point L2, Scenario A) and $10,007/ton (tail end Point T2, Scenario A). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied SCR cases were $13,361/ton (low-dust, Point L1, Scenario B) and $15,096/ton (tail end Point T1, Scenario B).

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. EPA's NSR Manual however, does specifically address the standard to be used when rejecting a candidate technology on the basis of adverse economic impact:

> "Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances,

> including the cost or other analyses, that show what is significantly different about the proposed source."[34]

This supplemental report for the MRYS NOx BACT Analysis has clearly established the circumstances, including the economic impacts, which would make the hypothetical application of TESCR or LDSCR to MRYS Unit 2 significantly more expensive than SCR costs normally incurred by other coal-fired steam electric generating units. The following information further supports EPA's own statements regarding the costs "normally incurred by other sources". The EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines estimated an average control cost for SCR applied to MRYS Unit 2 of $537 per ton[35]. The unadjusted unit capital cost versus capacity factor assumed by the EPA for SCR retrofits applied to cyclone boilers in the cost-effectiveness analysis used for establishing presumptive BART[36] was $100/kW. The EPA's cost-effectiveness analysis used for establishing presumptive BART stated that "applying SCR for coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton" [37]. The site-specific control costs estimated for hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 2 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines discussed above.

Also, the use of incremental cost effectiveness is warranted per the final 2005 RHR/BART Guidelines, which state "the greater the number of possible control options that exist, the more weight should be given to the incremental costs vs. average costs". Also in the final 2005 RHR/BART Guidelines, "the average cost for each [of two options, A and B]… may be deemed to be reasonable. However, the incremental cost…of the additional emissions reductions to be achieved by control B may be very great. In such an instance, it may be inappropriate to chose control B, based on its higher incremental costs, even though its average cost may be considered reasonable".[38]

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[34] Ibid Reference number 2, Section IV.D.2.c.
[35] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.
[36] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 209.
[37] See Reference number 11, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[38] Ibid Reference number 11, July 2005, FR Vol. 70 No. 128, page 39168.

TABLE 4-9SA – Estimated Emissions and Economic Impacts Summary for NO$_X$ Control Alternatives - MRY Station Unit 2 - Stand Alone SCR Projects

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 2 – Stand Alone SCR Projects

Alt. Label(1)	NOx Control Alternative	EMISSIONS(2)				NOx Removal Efficiency(2) %	ECONOMIC IMPACTS			
		Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr		Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(7)	0.049	239	936	14,857	93.8(8)	340,733	31,512	69,057(7)	4,648
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(7)	0.049	239	813	14,980	93.8(8)	340,733	55,345	98,818(7)	6,597
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(7)	0.049	239	931	14,862	93.8(8)	270,785	29,048	59,881(7)	4,029
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(7)	0.049	239	813	14,980	93.8(8)	270,785	52,424	89,072(7)	5,946
E	SNCR w/ ASOFA	0.330	1,612	6,421	9,372	58.0	17,128	8,108	11,618	1,240
D	Gas Reburn w/ ASOFA	0.350	1,710	6,882	8,910	55.4	35,490	48,688	63,892(9)	7,171
C	Lignite Reburn w/ ASOFA	0.360	1,759	6,964	8,829	54.2	81,167	9,929	19,475(9)	2,206
B	FLGR w/ ASOFA	0.432	2,110	8,490	7,303	45.0	21,817	21,954	29,317(9)	4,014
A	Advanced SOFA (ASOFA)	0.489	2,391	9,621	6,172	37.7	10,008	2,805	4,376	709
	Baseline	0.786	3,839	15,793	0	-	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO$_X$ control level reductions relative to average annual unit emission baseline of 0.786 lb/mmBtu at 4,885 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 440 MWg and assumes a 93.9% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $14,988,000 for CGR and $7,494,000 for FLGR, and annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $36,013,000 for installed capital cost.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 440 MWg and assumes a 95.2% average running plant capacity ratio compared to nominal unit gross electrical output capacity of 462 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $3,155,000/yr for annual O&M cost.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars.

(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that these technologies are technically feasible to install on Unit 2 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO$_X$ BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(8) - The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.49 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO$_X$ cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate would be 0.079 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.786 lb/mmBtu.

(9) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $3,140,000 for annualized capital cost plus $3,940,000/yr for annualized O&M cost, for a total of $7,080,000/yr.

TABLE 4-9SF – Estimated Emissions and Economic Impacts Summary for NO_X Control Alternatives - MRY Station Unit 2 – Shared Facilities SCR Projects

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 2 – Shared Facilities SCR Projects

		EMISSIONS(2)					ECONOMIC IMPACTS			
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	NOx Removal Efficiency(2) %	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(7)	0.049	239	936	14,857	93.8(8)	320,279	30,898	66,506(7)	4,477
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(7)	0.049	239	813	14,980	93.8(8)	320,279	54,731	96,268(7)	6,427
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(7)	0.049	239	931	14,862	93.8(8)	250,487	28,439	57,351(7)	3,859
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(7)	0.049	239	813	14,980	93.8(8)	250,487	51,815	86,542(7)	5,777
E	SNCR w/ ASOFA	0.330	1,612	6,421	9,372	58.0	17,128	8,108	11,618	1,240
D	Gas Reburn w/ ASOFA	0.350	1,710	6,882	8,910	55.4	35,490	48,688	63,892(9)	7,171
C	Lignite Reburn w/ ASOFA	0.360	1,759	6,964	8,829	54.2	81,167	9,929	19,475(9)	2,206
B	FLGR w/ ASOFA	0.432	2,110	8,490	7,303	45.0	21,817	21,954	29,317(9)	4,014
A	Advanced SOFA (ASOFA)	0.489	2,391	9,621	6,172	37.7	10,008	2,805	4,376	709
	Baseline	0.786	3,839	15,793	0	-	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO_X control level reductions relative to average annual unit emission baseline of 0.786 lb/mmBtu at 4,885 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 440 MWg and assumes a 93.9% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $14,988,000 for CGR and $7,494,000 for FLGR, and annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $36,013,000 for installed capital cost.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 440 MWg and assumes a 95.2% average running plant capacity ratio compared to nominal unit gross electrical output capacity of 462 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $3,155,000/yr for annual O&M cost.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars.

(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that these technologies are technically feasible to install on Unit 2 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(8) - The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.49 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate would be 0.079 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.786 lb/mmBtu.

(9) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $3,140,000 for annualized capital cost plus $3,940,000/yr for annualized O&M cost, for a total of $7,080,000/yr.

The other elements of the fourth step of a BACT analysis following economic impacts are to evaluate the following impacts of feasible emission controls:

(1) The energy impacts.
(2) The environmental impacts.

4.2.2 ENERGY IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 2

Operation of the NO_X control technologies on the dominant controls cost curve for potential application at the Milton R. Young Station impose direct impacts on the consumption of energy required for the production of electric power at the facility. The details of estimated energy usage and costs for the previously-evaluated NO_X control alternatives were described and summarized in Section 3.4.2 and Appendix C3 of the October 2006 NOx BACT Analysis Study report[39].

The hypothetical application of Tail End and Low-Dust SCR w/ ASOFA alternatives involve higher energy consumption compared with the existing operation of MRYS Unit 2. New induced draft booster fan electrical power demand is needed due to the estimated additional flue gas pressure drop resulting from hypothetical application of SCR reactor, ductwork, and gas-to-gas heat exchangers. The additional auxiliary electric power demands for the hypothetical application of TESCR and LDSCR equipment were calculated to be 14.9 MW and 12.4 MW, respectively, using estimated annual average electrical loads of the booster fan, urea-to-ammonia conversion fired heater combustion/dilution air fan, direct-fired flue gas reheat burner combustion air fan, and service and sootblowing air compressor equipment and related auxiliary equipment.

Preliminary conceptual design details were developed for these alternatives. An estimated additional 10 inches w.c. of flue gas pressure drop was assumed for each hypothetical application of low-dust SCR system, and an estimated additional 16 inches w.c. of flue gas pressure drop was assumed for the hypothetical application of tail end SCR system. Equipment and ductwork arrangements and expected severe fouling of the catalyst for the hypothetical application of SCR system ductwork, reactor, and gas-gas reheater changes may cause significantly more restrictive flow paths. Thus the electrical power usage estimated here may be too low.

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[39] Ibid Reference number 3, October 2006, pages 3-31 through 3-35, and Appendix pages C3-7 through C3-10.

The expected loss of electrical power generation from these reductions in net output was included as a cost, assuming $35 per megawatt-hour for replacement electrical power. Energy impacts of installing hypothetical applications of low-dust and tail end SCR alternatives for NO_X control were included in the O&M cost section (4.2.1.2.1) of this supplemental analysis as Tables C.4-2 through C.4-4.

Aqueous urea solution was assumed to be the preferred, readily available and transportable source of the amine reagent needed to supply ammonia to the SCR reactor catalyst for the hypothetically-applied low-dust and tail-end SCR alternatives. A urea-to-ammonia conversion system dedicated for each SCR reactor was also assumed. This conversion process will use a natural gas-fired burner that mixes the combustion products at high temperature with the injected aqueous urea solution to thermally decompose the urea, producing gaseous ammonia to supply to the reactors' ammonia injection grids. Gaseous ammonia is the required amine reagent that the catalyst in the SCR reactors uses to convert nitrogen oxides to elemental nitrogen and water vapor. Ammonia (from urea conversion) is supplied and consumed continuously on demand while the SCR NOx reduction process is in operation. Natural gas is fired continuously during the urea-to-ammonia conversion system operation.

Final reactor inlet flue gas reheat systems are required for the hypothetical applications of tail end and low-dust SCR with ASOFA alternatives. A natural gas-fired duct burner that injects high temperature combustion products directly into the flue gas discharged from each SCR gas/gas heat exchanger was assumed for raising the reactor inlet temperature to 600ºF before ammonia injection and NOx reduction can occur in each SCR reactor. Natural gas is fired continuously for flue gas reheating during SCR system operation.

TABLE 4-10 – Energy Impacts for NO_X Control Alternatives - MRY Station Unit 2

Alt. Label(1)	NOx Control Alternative(2)	Estimated Annual Natural Gas Usage for Urea-to-Ammonia Conversion’(3) (mmBtu/yr)	Estimated Annual Natural Gas Usage for SCR Inlet Reheat’(4) (mmBtu/yr)	Estimated Annual Natural Gas Usage for Reburn Fuel’(5) (mmBtu/yr)	Estimated Additional Annual Coal Burned for Urea Solution Dilution Water’(6) (mmBtu/yr)	Estimated Total Annual Natural Gas Usage and ’ Additional Annual Coal Burned (7) (mmBtu/yr)
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	49,463	754,563	0	0	804,026
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	42,975	655,591	0	0	698,566
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	49,203	710,710	0	0	759,913
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(5)	42,975	620,747	0	0	663,722
E	SNCR w/ ASOFA	0	0	0	73,986	73,986
D	Gas Reburn w/ ASOFA	0	0	6,301,740	0	6,301,740
C	Lignite Reburn w/ ASOFA	0	0	0	0	0
B	FLGR w/ ASOFA	0	0	2,610,560	0	2,610,560
A	Advanced SOFA (ASOFA)	0	0	0	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Alternatives are labeled the same as in Table 4-9.

(2) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(3) – Estimated annual natural gas usage for urea-to-ammonia conversion based on adjustments to preliminary budgetary equipment vendor proposals and process calculations. TESCR and LDSCR rate = 3.15 mmBtu/hr for each reactor x 2.

(4) – Estimated annual natural gas usage for flue gas final reheat based on adjustments to preliminary vendor process calculations. TESCR rate = 48.11 mmBtu/hr for each reactor x 2; LDSCR rate = 45.55 mmBtu/hr for each reactor x 2.

(5) – Natural gas burned for reburn alternatives is assumed to replace coal, no boiler heat rate penalty assumed. Lignite reburn is assumed to burn the same total amount of coal in the boiler as without coal reburn.

(6) - Additional coal burned is due to the urea dilution water injected directly into the boiler’s upper furnace, decreasing heat available for steam production and electricity generation, at a net loss of 900 Btu/lb of water for evaporation. See Appendix C3 in the 2006 NO_X BACT Analysis Study report for additional details.

(7) - Annual O&M costs include these values multiplied by the number of hours per year of operation and assume $7.98 per mmBtu for natural gas and $0.71 per mmBtu for coal.

4.2.3 ENVIRONMENTAL IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO$_X$ CONTROL ALTERNATIVES FOR MRY STATION UNIT 2

Operation of the NO$_X$ control technologies on the dominant controls cost curve for potential application at the Milton R. Young Station impose direct and indirect impacts on the environment. The most pronounced direct environmental impact expected from operation of any of the NO$_X$ control options considered is the reduction of ozone and improvement in atmospheric visibility (i.e. reduced visibility impairment) downwind of the facility. Environmental impacts of previously-evaluated NO$_X$ control alternatives were described and summarized in Section 3.4.3 of the October 2006 NOx BACT Analysis Study report.[40]

There would be a favorable environmental impact from potential reduction of annual unit operating time by approximately two percent due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation and by between five percent and 17 percent due to catalyst management and SCR equipment maintenance-related issues for the various low-dust and tail end SCR alternatives. The impact of fewer annual hours of operation will be to decrease the annual amount (tons) of nitrogen oxides emitted, by between approximately 0.2 percent and one percent overall compared to baseline operation. However, generation of replacement electrical power at other powerplants will negate most of these emission reductions.

Operation of the hypothetical application of SCR systems is not expected to significantly impact emissions of carbon monoxide (CO) or volatile organic compounds (VOCs). Emissions from the urea-to-ammonia conversion and flue gas reheat natural gas-fired burners are additive and included in the flue gas entering the SCR reactor in each hypothetical case.

Operation of any SCR system will normally cause a small amount of unreacted ammonia to be emitted. The amount of ammonia slip produced by an SCR depends on the reagent utilization and the location of the injection points. Higher SCR NO$_X$ reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 2 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the catalyst to form the sulfates downstream.

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[40] Ibid Reference number 3, October 2006, pages 3-35 through 3-37.

Unreacted ammonia (“slip”) from SCR operation will not be collected downstream of the hypothetically-applied tail end SCR reactors. The wet flue gas desulfurization absorbers downstream of the hypothetically-applied low-dust SCR reactors may reduce ammonia slip. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be emitted from the stack as an aerosol or condensable particulate. This has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition.

Sulfur dioxide (SO_2) formed during combustion in the boiler can combine with oxygen during passage through the hypothetical tail end and low-dust SCR catalyst to form additional sulfur trioxide (SO_3) emissions. SO_3 can subsequently combine with water (H_2O) to form sulfuric acid (H_2SO_4), usually in the form of a mist. Wet flue gas scrubbing to remove SO_2 is not highly effective in removing SO_3 created in an upstream low-dust SCR, so higher sulfate emissions will result unless a precipitating reaction with ammonia or condensation in the downstream gas-gas reheater or ductwork occurs. SO_3 and H_2SO_4 can have significant negative far-field impairment impacts on atmospheric visibility if they are above threshold concentrations and not controlled. Tail end SCRs can also cause a small amount of SO_3 to be created as the remaining SO_2 not removed by the wet lime flue gas desulfurization systems will pass through the catalyst and some will be oxidized. It is not known whether the high concentration of alkalinity in the form of sodium aerosol particles at MRYS will effectively eliminate the remaining SO_3 downstream of the hypothetically-applied low-dust and tail end SCR systems.

Catalyst from the hypothetical application of SCR reactors will require regular replacement, requiring disposal of the spent catalyst materials or chemical cleaning to remove deposits to allow reuse or regeneration. Hauling spent catalyst to a catalyst rejuvenation facility or authorized landfill may be required, producing additional liquid and solid wastes and vehicle exhaust emissions.

Because railroad service is not available to MRYS, shipments of amine reagent (concentrated urea solution) for consumption by the hypothetical application of SCR reactors will require additional truck traffic between the supply facility and plant, producing more emissions from vehicle exhaust.

4.2.4 SUMMARY OF ECONOMIC, ENERGY AND ENVIRONMENTAL IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 2

The economic, energy, and environmental impacts of each NO_X control technology on the dominant controls cost curve for potential application at the Milton R. Young Station evaluated for this study are summarized in this Section. Table 3-18 summarized the various impacts discussed in Sections 3.4.1 through 3.4.3 of the October 2006 NO_X BACT Analysis Study report[41]. The economic analysis examined the estimated capital cost of four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives and any other powerplant upgrade costs necessary to implement the alternatives. In addition, the economic analysis examined the operating and maintenance costs associated with each NO_X control technology evaluated. These costs were then combined into the levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each remaining alternative was evaluated. Four hypothetically-applied SCR cases and two previously-analyzed feasible alternatives were on the dominant controls cost curve and the latter were identified as the more cost-effective alternatives. The four hypothetically-applied SCR cases and two previously-analyzed feasible BACT NO_X control alternatives were evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 2. The results are summarized in Tables 4-11SA and 4-11SF.

The unit control cost for the hypothetically-applied SCR cases:

- Tail End SCR w/ ASOFA stand alone SCR projects cases - Scenario A was \$4,648/ton and Scenario B was \$ 6,597/ton.
- Low-Dust SCR w/ ASOFA stand alone SCR projects cases - Scenario A was \$4,029/ton and Scenario B was \$5,946/ton.
- Tail End SCR w/ ASOFA shared facilities SCR projects cases - Scenario A was \$4,477/ton and Scenario B was \$ 6,427/ton.
- Low-Dust SCR w/ ASOFA shared facilities SCR projects cases - Scenario A was \$3,859/ton and Scenario B was \$5,777/ton.

These UCCs are approximately 370 to 525 percent of the UCC for SNCR w/ ASOFA (\$1,240/ton), and approximately 645 to 920 percent of ASOFA's UCC (\$709/ton).

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[41] Ibid Reference number 3, October 2006, pages 3-20 through 3-38.

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative for MRYS Unit 2 incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control technique. The slope from zero (baseline) to ASOFA (Point A) was $709/ton; the incremental cost per ton (slope) from ASOFA (Point A) to SNCR with ASOFA (Point E) was $2,263/ton for MRYS Unit 2. The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the various hypothetically-applied SCR cases:

- Tail End SCR w/ ASOFA stand alone SCR projects cases - Scenario A was $10,472/ton and Scenario B was $15,550/ton.
- Low-Dust SCR w/ ASOFA stand alone SCR projects cases - Scenario A was $8,792/ton and Scenario B was $13,812/ton.
- Tail End SCR w/ ASOFA shared facilities SCR projects cases - Scenario A was $10,007/ton and Scenario B was $15,096/ton.
- Low-Dust SCR w/ ASOFA shared facilities SCR projects cases - Scenario A was $8,331/ton and Scenario B was $13,361/ton.

The incremental unit control cost per ton (slope) from SNCR with ASOFA to the hypothetically-applied SCR with ASOFA cases are approximately 360 to 680 percent of the incremental UCC per ton (slope) between ASOFA and SNCR with ASOFA ($2,263/ton). The incremental UCCs from SNCR with ASOFA to the hypothetically-applied SCR with ASOFA cases is between 11 and 22 times the incremental UCC for ASOFA from the pre-control baseline ($709/ton).

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. EPA's NSR Manual however, does specifically address the standard to be used when rejecting a candidate technology on the basis of adverse economic impact:

> "Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source."[42]

This supplemental report for the MRYS NOx BACT Analysis has clearly established the circumstances, including the economic impacts, which would make the hypothetical application of TESCR or LDSCR to

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[42] Ibid Reference number 2, Section IV.D.2.c.

MRYS Unit 2 significantly more expensive than SCR costs normally incurred by other coal-fired steam electric generating units. The following information further supports EPA's own statements regarding the costs "normally incurred by other sources".

The EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines was considered relevant for control cost-effectiveness comparison. The EPA's cost-effectiveness analysis used for establishing presumptive BART stated that "applying SCR for coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton" [43]. EPA's Technical Support Document estimated an average control cost for SCR applied to MRYS Unit 2 of $537 per ton[44]. The unadjusted unit capital cost factor assumed by the EPA for SCR retrofits applied to cyclone boilers in the cost-effectiveness analysis used for establishing presumptive BART[45] was $100/kW. The estimated "stand alone" and "shared facilities" installed capital costs for the hypothetically-applied low-dust SCR w/ ASOFA cases at MRYS Unit 2 are $525 to $568/kW, which are more than 500 percent of the EPA's number. The estimated "stand alone" and "shared facilities" installed capital costs for the hypothetically-applied tail end SCR w/ ASOFA cases are $671 to 714/kW, which are approximately 700 percent of the EPA's number. Also stated in the final RHR/BART Guidelines, "the average cost for each [of two options, A and B]… may be deemed to be reasonable. However, the incremental cost…of the additional emissions reductions to be achieved by control B may be very great. In such an instance, it may be inappropriate to chose control B, based on its higher incremental costs, even though its average cost may be considered reasonable".[46]

4.2.5 CONCLUSIONS

The site-specific control costs estimated for application of hypothetically-applied tail-end and low-dust SCR alternatives to MRYS Unit 2 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines discussed above.

The expected severity of catalyst blinding and pluggage from particulate matter and flue gases emitted from cyclone-fired boilers burning North Dakota lignite precludes the technical feasibility for successful application of such SCR technologies on the electric generating units (EGUs) at the Milton R. Young

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[43] See Reference number 9, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[44] Ibid Reference number 3, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.
[45] Ibid Reference number 3, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 209.
[46] Ibid Reference number 9, July 2005, FR Vol. 70 No. 128, page 39168.

Station. Not withstanding the technical discussion of SCR technology infeasibility and technical details previously provided in Appendix A1 and Appendix B[47] of the initial NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, this supplemental analysis concludes that the estimated capital and O&M costs for four variations of hypothetically-applied tail-end and low-dust SCR technology alternatives are significantly beyond the cost analysis values included in EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines[48,49]. Average control cost effectiveness for each hypothetically-applied SCR control technology case is a minimum of approximately three times the unit control costs of the previously-analyzed highest-performing feasible control alternative recommended as BACT for MRYS Unit 2 (SNCR with ASOFA). Incremental control cost effectiveness for each hypothetically-applied SCR control technology case is a minimum of approximately three times the incremental control costs of the previously-analyzed highest-performing feasible control alternative recommended as BACT for MRYS Unit 2 (SNCR with ASOFA).

There is an expected decrease in net capacity and availability to generate electrical power due to the hypothetically-applied SCR alternatives. A 5 to 17 percent decrease in the number of hours of annual operation, and approximately 3% drop in annual plant capacity (net electrical output or MW_n) during operation of the MRYS Unit 2 system are expected if the hypothetically-applied low-dust or tail end SCR alternatives were installed. There are also substantial expected negative energy impacts for each hypothetically-applied SCR control technology case. Additional auxiliary electrical power demands of approximately 12 to 15 MW will result. This estimate of electrical power usage may be too low. This higher electrical power consumption and lower electrical power generation by MRYS Unit 2 will require additional replacement electrical power to be generated elsewhere.

Natural gas is fired continuously during the urea-to-ammonia conversion system operation for each of the hypothetically-applied Tail End and Low-Dust SCR with ASOFA alternatives.

Final reactor inlet flue gas reheat systems are required for the hypothetically-applied Tail End and Low-Dust SCR with ASOFA alternatives. Natural gas is fired continuously for flue gas reheating during SCR

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[47] Ibid Reference number 2, October 2006.
[48] See Reference number 9, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[49] Ibid Reference number 3, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.

system operation for raising the reactor inlet temperature to 600ºF before ammonia injection and NOx reduction can occur in each SCR reactor.

The site-specific control costs estimated for application of hypothetically-applied tail-end and low-dust SCR alternatives to MRYS Unit 2 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines[50]. Low-dust and tail end SCR technologies should be excluded from consideration for NO_X control at MRYS due to unacceptably high average and incremental cost per ton of pollutant removal based on the supplemental analysis provided herein. Therefore the conclusions regarding NOx BACT as expressed in the original October 2006 BACT Analysis for MRYS Unit 2 are confirmed.

The economic, energy, and environmental impacts of each NO_X control technology on the dominant controls cost curve for potential application to Unit 2 at the Milton R. Young Station evaluated for this study are summarized in Tables 4-11SA and 4-11SF.

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[50] See Reference number 4, July, 2005.

TABLE 4-11SA – Summary of Supplemental BACT Analysis Impact Results for Dominant NO_X Control Alternatives - MRY Station Unit 2 - Stand Alone SCR Projects

		EMISSIONS(2)				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS	
Alt. Label(1)	**NOx Control Alternative**	**Emission Rate lb/mmBtu**	**Hourly Emission lbs/hr**	**Annual Emission tons/yr**	**Emission Reduction(2) tons/yr**	**Installed Capital Cost(3) $1,000**	**Annual O & M Cost(4) $1,000**	**Levelized Total Annualized Cost(5) $1,000**	**Average Control Cost(6) $/ton**	**Incremental Control Cost(7) $/ton**	**Incremental Aux. Power Demand(8), kW**	**Incremental Annual Aux. Power Usage + Generation Reduction(8), kW-hrs/yr**	**Non-Air Increase(9)**	**Toxic Air Increase(9)**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(10)	0.049	239	936	14,857	340,733	31,512	69,056	4,648	10,472	14,925	278,290,255	Flyash UBC, catalyst disposal	CO, NH_3, SO3
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(10)	0.049	239	813	14,980	340,733	55,345	98,818	6,597	15,550	14,925	716,682,361	Flyash UBC, catalyst disposal	CO, NH_3, SO3
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(10)	0.049	239	931	14,862	270,785	29,048	59,881	4,029	8,792	12,389	278,010,746	Flyash UBC, catalyst disposal	CO, NH_3, SO3
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(10)	0.049	239	913	14,980	270,785	52,424	89,072	5,946	13,812	12,389	701,122,255	Flyash UBC, catalyst disposal	CO, NH_3, SO3
E	SNCR w/ ASOFA	0.330	1,612	6,421	9,372	17,128	8,108	11,618	1,240	2,263	133	111,184,869	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.489	2,391	9,621	6,172	10,008	2,805	4,376	709	709	1	75,867,520	Flyash UBC	CO
	Baseline	0.786	3,839	15,793	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.786 lb/mmBtu at 4,885 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 440 MWg and assumes a 93.9% average annual availability.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 440 MWg and assumes a 95.2% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars.

(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit availability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr) compared to the pre-control baseline.

(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative compared to the pre-control baseline. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations may increase an insignificant amount with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology and the hypothetically-applied SCR technology cases.

(10) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

TABLE 4-11SF – Summary of Supplemental BACT Analysis Impact Results for Dominant NO$_X$ Control Alternatives - MRY Station Unit 2 – Shared Facilities SCR Projects

		EMISSIONS(2)				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS	
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction(2) tons/yr	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton	Incremental Control Cost(7) $/ton	Incremental Aux. Power Demand(8), kW	Incremental Annual Aux. Power Usage + Generation Reduction(8), kW-hrs/yr	Non-Air Increase(9)	Toxic Air Increase(9)
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(10)	0.049	239	936	14,857	320,279	30,898	66,506	4,477	10,007	14,925	278,290,255	Flyash UBC, catalyst disposal	CO, NH_3, SO3
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(10)	0.049	239	813	14,980	320,279	54,731	96,268	6,427	15,096	14,925	716,682,361	Flyash UBC, catalyst disposal	CO, NH_3, SO3
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(10)	0.049	239	931	14,862	250,487	28,439	57,351	3,859	8,331	12,389	278,010,746	Flyash UBC, catalyst disposal	CO, NH_3, SO3
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(10)	0.049	239	813	14,980	250,487	51,815	86,542	5,777	13,361	12,389	701,122,255	Flyash UBC, catalyst disposal	CO, NH_3, SO3
E	SNCR w/ ASOFA	0.330	1,612	6,421	9,372	17,128	8,108	11,618	1,240	2,263	133	111,184,869	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.489	2,391	9,621	6,172	10,008	2,805	4,376	709	709	1	75,867,520	Flyash UBC	CO
	Baseline	0.786	3,839	15,793	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO$_X$ control level reductions relative to average annual emission baseline of 0.786 lb/mmBtu at 4,885 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 440 MWg and assumes a 93.9% average annual availability.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 440 MWg and assumes a 95.2% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars.

(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit availability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr) compared to the pre-control baseline.

(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative compared to the pre-control baseline. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations may increase an insignificant amount with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology and the hypothetically-applied SCR technology cases.

(10) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 2 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO$_X$ BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

1. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.

2. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").

3. "BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc." and a separate "BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc." Final Report, October 2006 submitted by Minnkota to North Dakota Department of Health.

4. Technical Support Document Methodology For Developing BART NOx Presumptive Limits, Environmental Protection Agency, Clean Air Markets Division, June 15, 2005, OAR-2002-0076-0445, with Attachments, including Excel Spreadsheet OAR-2002-0076-0446 (1199 pages).

5. Comment & Response to EPA Region 8's October 4, 2007 Comment on NDDH BACT Determination at Milton R. Young Station, submitted by Minnkota to NDDH, November 9, 2007.

6. EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034, dated March, 2005, posted at their website: http://www.epa.gov/airmarkets/articles/multireport2005.pdf.

7. "Assessment of Control Technology Options for BART-Eligible Sources, Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities", dated March 2005, prepared by Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic/Northeast Visibility Union, posted at the website: http://bronze.nescaum.org/committees/haze/BART_Control_Assessment.pdf.

8. "Analysis of Combustion Controls for Reducing NO_X Emissions From Coal-fired EGU's in the WRAP Region, Draft Report", prepared for the Western Regional Air Partnership by Eastern Research Group, Inc., ERG Contract Number 30204-101, dated April 26, 2005, available at: http://www.wrapair.org/forums/ssjf/documents/eictts/NOxEGU/050426Coal-fired%20EGUs_in_WRAP_Region-draft.pdf

9. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

10. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 2 - Selective Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch2.pdf

11. Federal Register /Vol. 70, No. 128/ Wednesday, July 6, 2005 / Rules and Regulations, Part III Environmental Protection Agency 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule.

NOx BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS STUDY

- SUPPLEMENTAL REPORT

for

Milton R. Young Station Unit 1

Minnkota Power Cooperative, Inc.

November 2009

31777

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NOx Best Available
Control Technology
Analysis Study
SUPPLEMENTAL REPORT
for
Milton R. Young Station Unit 1

prepared for

Minnkota Power Cooperative, Inc.

November 2009

Project No. 31777

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

INDEX AND CERTIFICATION

Minnkota Power Cooperative, Inc.
Milton R. Young Station Unit 1
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SUPPLEMENTAL REPORT

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Certification

I hereby certify, as a Professional Engineer registered in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the laws and rules of the North Dakota State Board of Registration under Title 28 Administrative Code.

Robert D. Blakley

ROBERT D.
BLAKLEY
PE - 5658
DATE 11/12/2009

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4.0 SUPPLEMENTAL NOx BACT ANALYSIS CONTROLS & COSTS – MRY STATION UNIT 1

This supplement to the NO_X BACT analysis for Milton R. Young Station (MRYS) Unit 1 has been prepared in response to the request of the North Dakota Department of Health[1]. The NDDH requested completion of a "full" BACT analysis for two specific technologies that had been eliminated at step 2 of the BACT analysis process[2] in the October 2006 NO_X BACT Analysis Study report[3]. These two technologies are low-dust selective catalytic reduction (SCR) and tail-end SCR. The approach taken in this supplemental NO_X BACT Analysis Study report for MRYS Unit 1 includes ranking by effectiveness and providing an impacts analysis of alternate control technologies for NO_X emissions that follows the third and fourth steps of a "top down" BACT analysis as described in the EPA's Draft New Source Review Workshop Manual[4]. The initial NO_X BACT Analysis Study for Milton R. Young Station identified potentially available NO_X control techniques and technologies, summarized in Table 3-3[5] of the October 2006 report. Commonly-applied and novel NO_X control techniques and technologies, including a technical description of the specific emission reduction processes and capabilities, were summarized in Section 3.2[6] and detailed in Appendix A1 of the initial NO_X BACT Analysis Study report. This supplemental analysis report does not include the details of the technical feasibility discussion previously provided in the initial NO_X BACT Analysis Study report for MRYS Unit 1.

SCR technology is considered technically infeasible by Minnkota for application at MRYS, so this information for the hypothetical application of low-dust and tail end SCR alternatives is included for comparative purposes only. Cost estimates and emission rates shown for such hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation, operation and maintenance of the SCR equipment on this boiler are solvable. There is no available information on recently-completed similar tail-end or low-dust SCR projects on coal-fired powerplants in the United States that could be used, with adjustments, to represent total installed costs that could be expected for MRYS Unit 1. Site-specific needs and challenges identified for applying tail end and low-dust SCR technologies to Milton R. Young Station Unit 1 significantly influence the capital cost estimate for variations of these hypothetical applications of SCR alternatives. Furthermore, the

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[1] See Reference number 1, July 2009 and August 2009.
[2] As described in the EPA's Draft New Source Review Workshop Manual. See Reference number 2, October 1990.
[3] See Reference number 3, October 2006. This Supplement commences with Section 4.0, which places it at the end of the October 2006 Analysis, which ended at Section 3.5.2.
[4] As described in the EPA's Draft New Source Review Workshop Manual. Ibid Reference number 2, October 1990.
[5] Ibid Reference number 3, October 2006, page 3-5.
[6] Ibid Reference number 3, October 2006, page 3-6 through page 3-13, and pages A1-1 through A1-55.

"EPA Air Pollution Control Cost Manual" is not applicable for use in estimating control equipment costs for these hypothetical applications of SCR technologies, as the EPA Control Cost Manual states:

> "The costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements."[7]

This requirement for flue gas reheating also applies to the hypothetical application of low-dust SCR to MRYS, due to the cold-side arrangement (downstream of the electrostatic precipitator) instead of a hot-side ESP assumed in the EPA Control Cost Manual. Therefore, the equations in the EPA Control Cost Manual cannot be used for estimating either of the hypothetical applications of SCR configurations for which NDDH has requested economic analyses. Thus it was necessary to prepare independent site-specific cost estimates.

The site-specific control costs estimated for hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines[8]. Low-dust and tail end SCR technologies should be excluded from consideration for NO_X control at MRYS due to unacceptably high average and incremental cost per ton of pollutant removal based on the supplemental analysis provided herein. The October 2006 NO_X BACT Analysis Study report, and additional subsequent arguments included in responses to comments by the EPA, Department of Justice (DOJ), NDDH, and other parties[9], also present reasons for technical infeasibility of all SCR technologies considered for application at MRYS not included in this supplemental analysis report. In addition, the fact that catalyst vendors will not guarantee catalyst life on such SCR technologies without successful results from extensive pilot slipstream testing bolsters the previous submitted arguments of technical infeasibility of these NO_X control alternatives at MRYS.

4.0.1 ADDITIONAL NOx CONTROLS

The inclusion of hypothetical emissions control alternatives employing tail-end and low-dust SCR technologies in this supplemental NO_X BACT Analysis Study report does not constitute agreement by

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[7] See Reference number 10, Section 4.2, Chapter 2, page 2-41, October 2000.
[8] See Reference number 4, June, 2005.
[9] Responses submitted by Minnkota in 2007-2009.

Minnkota that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The rationale for rejection of all forms of SCR technology in this specific case, based on an interpretation of the EPA's Draft New Source Review Workshop Manual[10], has previously been submitted to the North Dakota Department of Health[11] and is not repeated herein. Nevertheless, this supplemental NO_X BACT Analysis Study report has been completed based on the *hypothetical assumption* that these two technologies pass the test for technical feasibility. The development of NO_X emissions control alternatives involving hypothetical application of technologies such as low-dust and tail end SCR systems at MRYS is based on preliminary plant layout design concepts that require pilot-scale slipstream SCR testing and more detailed equipment design for confirmation that all technical infeasibility issues previously raised have been, or can be, satisfactorily resolved. This supplemental analysis includes estimated capital costs and operating and maintenance (O&M) costs for four variations of alternatives involving hypothetical applications of tail-end and low-dust SCR technologies. Cost effectiveness for each hypothetically-applied SCR control technology case was plotted with previously-analyzed feasible control alternatives.

For the techniques and technologies considered for determining MRYS Unit 1 NO_X control cost-effectiveness, estimates were produced for predicted NO_X reductions that represent long-term expectations of the reduction techniques and technologies being presented in the technical analysis. Each evaluated alternative was tabulated and graphed.

It should be noted that as of October 2006, when the initial BACT Analysis Study report was completed, MRYS Unit 1 did not employ combustion-related or post-combustion NO_X emission reduction technology. However, the installation of an advanced form of a separated overfire air system (ASOFA), designed specifically for this boiler, is being implemented for operation starting prior to December 31, 2009. A summary of the available alternate NO_X emission control technologies is discussed below.

4.1 RANK OF NO_X CONTROL OPTIONS BY EFFECTIVENESS

The first step[12] in this supplemental "top-down" BACT evaluation is to determine the expected control effectiveness of the hypothetical application of tail end and low-dust SCR technology alternatives, so that they may be compared and ranked relative to the technically-feasible NO_X control techniques and

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[10] Ibid Reference number 2, October 1990.
[11] See Reference number 5, November 2007.
[12] Step 3 per the NSR Manual, Ibid Reference 2, October 1990.

technologies included from the initial NO_X BACT Analysis Study report. To do this, we start with the basis for determining the NOx emissions control effectiveness, which is the historic baseline emissions expressed in pounds per million Btu of heat input from the five-year lookback period.

Unit 1 boiler's baseline pre-control emissions at Milton R. Young Station are based upon the same highest rolling 12-month average unit emission rate (lb/mmBtu) and corresponding highest rolling 12-month average gross heat input rate (mmBtu/hr) that were reported in 2001-2005:

- MRYS Unit 1's highest 12-month NO_X mass emissions averaged 0.849 lb/mmBtu at a corresponding average unit heat input rate of 2,744 mmBtu/hr and unit gross electrical output of 244.5 MW_g.
- During this lookback time period, Unit 1 at Milton R. Young Station was typically operated in a base-loaded manner.

4.1.1 ESTIMATING CONTROL-EFFECTIVENESS OF NO_X EMISSIONS CONTROL OPTIONS

The estimated emission control performance for NO_X control techniques and technologies included from the initial NO_X BACT Analysis Study report is assumed to be the same as previously stated in Table 3-7[13]. The expected control effectiveness of the hypothetical application of tail end and low-dust SCR technology alternatives was added to the listing of highest-performing NO_X control alternatives remaining in consideration following the initial technical infeasibility determinations. These alternatives are ranked in declining order of expected emission reduction. These combined control options refer to "advanced" separated overfire air (ASOFA), and include the expected reduction from operating with modestly air-staged cyclone furnaces and relocated lignite drying system vent ports as applied to this Milton R. Young Station cyclone boiler without incurring potential significant negative impacts of this technique. This level of expected NO_X reduction from ASOFA operation is approximately forty percent below the pre-control baseline emissions rate of 0.849 lb/mmBtu.

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[13] Ibid Reference number 3, October 2006, page 3-18.

TABLE 4-1 – Ranked NO_X Control Options for MRY Station Unit 1 Boiler with Expected Control Performance

Alt. Label[1]	NO_X Control Alternative	Emission Rate (lb/mmBtu)	Control Percentage[2]
T2	Hypothetical Tail-End SCR w/ ASOFA – Scenario A[3]	0.053	93.8[4]
T1	Hypothetical Tail-End SCR w/ ASOFA – Scenario B[3]	0.053	93.8[4]
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[3]	0.053	93.8[4]
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[3]	0.053	93.8[4]
E	SNCR (using urea) w/ ASOFA	0.355	58.1
D	Gas Reburn with ASOFA	0.374	56.0
C	Lignite Reburn w/ ASOFA	0.385	54.6
B	Fuel Lean Gas Reburn with ASOFA	0.460	45.9
A	Advanced Separated Overfire Air (ASOFA)	0.513	39.5
-	Baseline	0.849	-

(1) - Alternative designation assigned from highest to lowest unit NOx emission rate.

(2) - Control percentages are relative to an average pre-control emission baseline of 0.849 lb/mmBtu based on annual operation at highest pre-control 12-month rolling NOx summation mass emissions divided by the 12-month heat input summation.

(3) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The emission rate shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(4) The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate for hypothetically-applied SCR alternatives would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.

All hypothetical applications of tail-end and low-dust SCR technology alternatives were assumed to achieve a NO_X emission level of 0.053 lb/mmBtu, which is approximately 90% reduction from a 0.51 lb/mmBtu level representing ASOFA when operating modestly air-staged cyclone furnaces with suitable combustion controls.

Hourly mass emission rates for the baseline pre-control condition were calculated by multiplying the unit emission rate (lb/mmBtu) by the average hourly gross heat input rate (mmBtu/hr), both calculated from Unit 1’s highest 12-month NO_X mass emissions and heat inputs during the 5-year lookback period.

Equivalent annual NO_X emissions (tons) were calculated by multiplying the 12-month summation for unit operating hours during the same period as the highest NO_X emissions by the 12-month average mass emission rate (lb/hr) and dividing by 2000 lb/ton.

The annual tons for the control options were calculated by multiplying the alternative's equivalent average annual hourly mass emission rate (lb/h) by the equivalent annual unit operating hours [8,760 h/yr maximum possible operating time, adjusted by an annual uptime (availability) factor]. Scheduled and unplanned maintenance outages are expected to occur due to each hypothetically-applied SCR system. Catalyst cleaning and replacement events have been estimated, with two frequencies showing a range of possible results. Due to the variability and possible severity of fouling characteristics of gaseous and aerosol particulate emissions generated by cyclone combustion of lignite supplied from the Center mine, and the dependency of the fouling within the hypothetically-applied SCR systems on sodium, potassium, sulfur, and ammonia slip emission levels, conditions may occur during operation of the hypothetically-applied SCR systems that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the deposits or prevent significant catalyst deactivation. Table C.4-1 in Section 4.2.1.2.1 includes estimated unit availability and corresponding operating time and outage time due to the four hypothetical applications of SCR technology cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[14]. Based on these calculations, the estimated annual emissions for M.R. Young Station Unit 1 and the emission reduction corresponding to each technology alternative are shown in Table 4-2.

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[14] Ibid Reference number 3, October 2006, pages C3-1 through page C3-11.

TABLE 4-2 – Expected Annual NO_X Control Performance for MRY Station Unit 1 Alternatives

		EMISSIONS				
Alt. Label(1)	**NOx Control Alternative**	**Emission Rate lb/mmBtu**	**Hourly Emission(2) lbs/hr**	**Annual Emission(3) tons/yr**	**Emission Reduction(4) tons/yr**	**NOx Removal Efficiency(5) %**
T2	Hypothetical Tail End SCR w/ ASOFA– Scenario A(6)	0.053	145	589	9,345	93.8(7)
T1	Hypothetical Tail End SCR w/ ASOFA– Scenario B(6)	0.053	145	536	9,398	93.8(7)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	0.053	145	586	9,348	93.8(7)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	0.053	145	533	9,401	93.8(7)
E	SNCR (using urea) w/ ASOFA	0.355	975	4,025	5,909	58.1
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6
B	Fuel Lean Gas Reburn w/ ASOFA	0.460	1,261	5,260	4,674	45.9
A	Advanced Separated Overfire Air (ASOFA)	0.513	1,409	5,874	4,060	39.5
-	Baseline	0.849	2,330	9,934	0	-

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Hourly NO_X emission estimates (lb/hr) were calculated based upon average annual unit emission rate (lb/mmBtu) x 2,744 mmBtu/hr heat input.

(3) - Estimated annual emission tons assume an annual unit availability factor specific to each alternative; 97.3% was assumed for the baseline case. See Appendix C3 of the October 2006 NO_X BACT Analysis Study report. Hypothetical application of tail end SCR case T2 assumes an annual unit availability factor of 92.8% (approx. 8,127 operating hours per year) and case T1 assumes an annual unit availability factor of 84.5% (approx. 7,402 operating hours per year). Hypothetically-applied low-dust SCR case L2 assumes an annual unit availability factor of 92.3% (approx. 8,084 operating hours per year) and case L1 assumes an annual unit availability factor of 84.0% (approx. 7,359 operating hours per year).

(4) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

(5) - Estimated NO_X control level percentage reductions relative to 0.849 lb/mmBtu emission baseline at 2,744 mmBtu/hr MCR heat input.

(6) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The emission rate shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - The stated overall control percentage includes the anticipated long-term emission reduction of approximately 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate for hypothetically-applied SCR alternatives would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.

4.2 NO_X CONTROLS ANALYSIS AND IMPACTS EVALUATION

The next step[15] of this supplemental "top-down" BACT analysis is to evaluate the impacts of the hypothetical application of SCR alternatives' NO_X emission controls. Energy, economic, and environmental impacts are to be considered in the control technology evaluation. The purpose of the evaluation is to determine if there are any energy, economic or environmental impacts that would eliminate the top control technologies from consideration.

This evaluation of the effectiveness of the hypothetically-applied SCR alternatives, as well as that of the other control technologies previously considered technically feasible, was performed prospectively, i.e., assuming that none of the control technologies has been implemented. This approach assumes that the hypothetical application of SCR technology cases are considered to have been added to the previous NO_X BACT Analysis Study report submitted in October, 2006. The actual costs incurred for an installed advanced separated overfire air system, or firm price equipment quotes with performance guarantees for SNCR alternatives, have not been used to adjust the control effectiveness or cost impacts of the previously analyzed control alternatives. The approach taken in this supplemental analysis use installed capital costs estimated in calendar year 2009 escalated to project completion forecast in 2018 adjusted to calendar year 2006 basis for the hypothetically-applied tail end SCR and low-dust SCR technology cases that have been added to the list of alternatives previously evaluated.

4.2.1 NO_X CONTROL ECONOMIC IMPACTS FOR MRY STATION UNIT 1

An evaluation was performed to determine the various cost impacts of installing previously-analyzed feasible NO_X control alternatives and the hypothetical application of low-dust and tail end SCR technologies on Milton R. Young Unit 1. This evaluation includes estimated:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, design, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 4-3 through 4-11.

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[15] Step 4 per the NSR Manual, Ibid Reference 2, October 1990.

4.2.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROL ALTERNATIVES

The range of estimated capital costs to implement some of the various NO_X control technologies were derived from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. For MRY Station Unit 1, for the cases involving the use of advanced separated overfire air and SNCR alternatives, preliminary project cost estimates using vendor budgetary cost information were developed and used in place of, or to adjust, the published unit output cost factors. A discussion of the reburn alternatives' estimated capital costs was included in the 2006 NO_X BACT Analysis Study report and has not been repeated here. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

For the hypothetical application of low-dust and tail end SCR alternatives at MRYS, there is no available information on recently-completed similar projects on coal-fired powerplants in the United States that could be used, with adjustments, to properly represent total installed costs that could be expected for MRYS Unit 1. For these alternatives, site-specific detailed preliminary (conceptual) designs were developed and budgetary cost information for major equipment was obtained for the development of the estimated installed capital cost.

The unit nameplate output capacity (gross electrical output in megawatts) assumed for the installed capital cost estimate basis of the NO_X control technologies evaluated was 257 MW_g for MRY Station Unit 1[16].

A review of the unit capital cost factor range and single point factors applicable to MRY Station Unit 1 NO_X control technologies are presented in Tables 4-3SA and 4-3SF. Note that the capital cost estimates for the hypothetical application of SCR alternatives were developed separately based on two different assumptions. In one case it was assumed that all costs for the hypothetically-applied Unit 1 SCR (tail end or low-dust) system would be accounted for as if the SCR equipment were being provided for Unit 1 only. This is referred to as the “stand alone” (SA) case, and all tables showing those costs are identified with that suffix. In the other case, it was assumed that the retrofit of hypothetically-applied SCR systems was being done for both Unit 1 and Unit 2, and there are some components that could be shared between the two units. This is referred to as the “shared facilities” (SF) case, and all tables showing those costs are identified with that suffix.

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[16] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 390.

Per the EPA's NSR Manual, a BACT analysis is done on a "case-by-case basis"[17]. The "stand alone" estimated total project capital costs for the hypothetical application of SCR alternatives reflect the economic impacts incurred as a result of implementing such technologies on each individual unit at MRYS independent of what may be determined or assumed for other units at this facility or similar units at other facilities. The "shared facilities" estimated total project capital costs for the hypothetical application of SCR alternatives do not account for all economic impacts borne strictly by the unit subject to the analysis, and, as such, are subsidized by the unit(s) involved with the shared facilities. In this "shared facilities" approach, a BACT would be performed more in the manner of a "case-within-a-case" instead of on a "case-by-case" basis. Additionally, BACT is not to be applied on a facility basis. Units having different characteristics, (size, etc.) may have different technologies as BACT. Therefore, each unit should be treated as a separate "stand alone" case. Although the authors believe the "stand alone "case is the proper approach to use, information for both cases has been provided.

TABLE 4-3SA – Unit Capital Cost Factors of NO_X Control Alternatives for MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	NO_X Control Alternative	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3), ($/kW) MRYS Unit 1
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	(4)	867(4),(5)
T1	Hypothetical Tail End SCR w/ ASOFA –Scenario B(4)	(4)	867(4),(5)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	(4)	703(4),(5)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	(4)	703(4),(5)
E	SNCR (using urea) w/ ASOFA	20-35(6)	31.6(5),(6)
D	Gas Reburn w/ ASOFA	15-30(7)	70.1(5),(7),(8)
C	Lignite Reburn w/ ASOFA	30-60(7)	181.5(5),(7),(9)
B	Fuel Lean Gas Reburn w/ ASOFA	--(6)	41.4(5),(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	16.6(5)

(1) - Alternative designation has been assigned from highest to lowest unit NOx emission rate.
(2) - Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ from this due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) - Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on EPA's nameplate rating. Single point cost figures in 2006 dollars.
(4) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The single point unit capital cost factor shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical

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[17] Ibid Reference 2, October 1990, Chapter B. Introduction page B1.

infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Due to the site-specific nature of factors influencing cost, no comparable cost data ranges for these technologies exist in the literature. A cost range for conventional high-dust SCR technology published in the 2005 EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034[18] was \$55 to \$150/kW. Single point unit capital cost factors were derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006\$ as described in the text.

(5) - The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(6) - Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. See Appendix C2 of the October 2006 NO_X BACT Analysis Study report for details[19].

(7) - NESCAUM 2005 Technical Paper[20]; reburn alternatives on page 2-22, overfire air on page 2-23; posted at their website. See technical references in Appendix A1 of the October 2006 NO_X BACT Analysis Study report for details.

(8) - The single point unit capital cost factor shown for a conventional or fuel-lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 \$/kW or 15.7 \$/kW, respectively), and that both MRYS boilers share the capital cost in proportion to their respective rated MW gross output capacities.

(9) - The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report[21], posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 91.7 \$/kW. See technical references in Appendix A1 of the October 2006 BACT Analysis report for details.

TABLE 4-3SF – Unit Capital Cost Factors of NO_X Control Alternatives for MRY Station Unit 1 – Shared Facilities SCR Projects

Alt. Label(1)	**NO_X Control Alternative**	**Range(2) (\$/kW)**	**Single Point Unit Capital Cost Factor(3), (\$/kW) MRYS Unit 1**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	(4)	706(4),(5)
T1	Hypothetical Tail End SCR w/ ASOFA –Scenario B(4)	(4)	706(4),(5)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	(4)	543(4),(5)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	(4)	543(4),(5)
E	SNCR (using urea) w/ ASOFA	20-35(6)	31.6(5),(6)
D	Gas Reburn w/ ASOFA	15-30(7)	70.1(5),(7),(8)
C	Lignite Reburn w/ ASOFA	30-60(7)	181.5(5),(7),(9)
B	Fuel Lean Gas Reburn w/ ASOFA	--(6)	41.4(5),(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	16.6(5)

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[18] See Reference number 6, March 2005, page 3-63.
[19] See Reference number 3, October 2006, pages C2-3 and C2-7.
[20] See Reference number 7, March 2005.
[21] See Reference number 8, April 2005, page 3-9.

(1) - Alternative designation has been assigned from highest to lowest unit NOx emission rate.

(2) - Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ from this due to positive or negative synergistic effects. Range based on published values or vendor proposals.

(3) - Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on EPA's nameplate rating. Single point cost figures in 2006 dollars.

(4) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The single point unit capital cost factor shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Due to the site-specific nature of factors influencing cost, no comparable cost data ranges for these technologies exist in the literature. A cost range for conventional high-dust SCR technology published in the 2005 EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034[22] was $55 to $150/kW. Single point unit capital cost factors were derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006$ as described in the text.

(5) - The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(6) - Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. See Appendix C2 of the October 2006 NO_X BACT Analysis Study report for details[23].

(7) - NESCAUM 2005 Technical Paper[24]; reburn alternatives on page 2-22, overfire air on page 2-23; posted at their website. See technical references in Appendix A1 of the October 2006 NO_X BACT Analysis Study report for details.

(8) - The single point unit capital cost factor shown for a conventional or fuel-lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW or 15.7 $/kW, respectively), and that both MRYS boilers share the capital cost in proportion to their respective rated MW gross output capacities.

(9) - The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report[25], posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 91.7 $/kW. See technical references in Appendix A1 of the October 2006 BACT Analysis report for details.

4.2.1.1.1 CAPITAL COST ESTIMATES FOR HYPOTHETICAL APPLICATION OF SCR NO_X CONTROL ALTERNATIVES

There is no available information on recently-completed similar tail-end or low-dust SCR projects on coal-fired powerplants in the United States that could be used, with adjustments, to properly represent total installed costs that could be expected for MRYS Unit 1. Site-specific needs and challenges identified for applying tail end and low-dust SCR technologies to Milton R. Young Station Unit 1 significantly influence the capital cost estimate for variations of these hypothetically-applied SCR alternatives. Furthermore, the "EPA Air Pollution Control Cost Manual" is not applicable for use in estimating control equipment costs for these hypothetical applications of SCR technology cases, as the EPA Control Cost Manual states:

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[22] See Reference number 6, March 2005, page 3-63.
[23] See Reference number 3, October 2006, pages C2-3 and C2-7.
[24] See Reference number 7, March 2005.
[25] See Reference number 8, April 2005, page 3-9.

> "The costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements."[26]

This requirement for flue gas reheating also applies to the hypothetical applications of low-dust SCR technology to MRYS, due to the cold-side arrangement (downstream of the electrostatic precipitator) instead of a hot-side ESP assumed in the EPA Control Cost Manual. Therefore, the equations in the EPA Control Cost Manual cannot be used for estimating either of the hypothetical application of SCR configurations for which NDDH has requested economic analyses. Thus it was necessary to prepare independent site-specific cost estimates.

The installed capital costs for hypothetical application of tail end and low-dust SCR alternatives were estimated by Burns & McDonnell with inputs from an SCR system supplier with recent design experience involving these SCR configurations, equipment suppliers, and catalyst suppliers with significant European project experience in such technology. Both hypothetically-applied low-dust and tail end SCR designs for MRYS Unit 1 assume one reactor / gas reheat system installed, connecting to the new wet lime flue gas desulfurization absorber currently being constructed. Each hypothetically-applied SCR alternative includes flue gas reheat equipment that is typical for these applications but not required for conventional high-dust/hot side SCR systems. The estimated flue gas volume at a gross boiler heat input and oxygen content corresponding to unit gross nameplate output capacity determined the size of the hypothetically-applied single SCR reactor for these cases. Structures, foundations, ductwork, balance of plant equipment and materials were quantified and included with the hypothetically-applied SCR equipment, which were factored for installation costs. Escalation of project costs, including equipment, materials, engineering and labor costs, is included, along with interest during construction, due to the expected project execution duration being significantly longer than for the other alternatives. Price and scope contingencies were included to account for the uncertainties that the current preliminary design scope and pricing fully reflects what would be necessary to complete implementation of these hypothetically-applied alternatives. Total project costs were considered to be a future value from a financial perspective, which were returned to a 2009 calendar year basis using a present value factor at the 2.5% per year annual discount rate previously assumed in the 2006 NO_X BACT Analysis Study report. A ratio of regional construction cost indices for public utility construction costs between 2006 and 2009 was used to adjust the 2009 total estimated project costs to a 2006 calendar year basis for each of the hypothetically-applied SCR alternatives.

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[26] See Reference number 10, Section 4.2, Chapter 2, page 2-41, October 2000.

The estimated installed and levelized annual capital costs for the hypothetically-applied SCR systems and previously-analyzed highest-performing form of the various feasible NO_X emission reduction technologies evaluated for cost-effectiveness are shown in Table 4-4SA and Table 4-4SF. These technologies are listed in order of control effectiveness, with the highest ranked option at the top.

TABLE 4-4SA – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	**NOx Control Alternative**	**Installed Capital Cost(2) \$1,000**	**Annualized Capital Cost(3) \$1,000**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	222,864(4)	19,430(4)
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	222,864(4)	19,430(4)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	180,739(4)	15,758(4)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	180,739(4)	15,758(4)
E	SNCR w/ ASOFA	8,113	707
D	Gas Reburn w/ ASOFA(5)	18,006	1,570
C	Lignite Reburn w/ ASOFA(6)	46,656	4,068
B	Fuel Lean Gas Reburn w/ ASOFA(5)	10,639	928
A	Advanced SOFA (ASOFA)	4,277	373
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. See Table 4-5SA for presentation of installed capital costs determined for hypothetical application of SCR alternatives.

(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.

(4) - The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The installed capital cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006\$ as described in the text. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of \$8,075,000 for CGR and \$4,038,000 for FLGR; and annualized capital cost of \$704,000/yr for CGR and \$352,000 for FLGR. See footnote number 8 under Table 4-3SA.

(6) - Costs for increased PM collection capacity included in lignite reburn option are \$23,561,000 for installed capital cost, and \$2,054,000/yr annualized capital cost.

TABLE 4-4SF – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Installed Capital Cost(2) $1,000	Annualized Capital Cost(3) $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	181,484(4)	15,823(4)
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	181,484(4)	15,823(4)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	139,639(4)	12,174(4)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	139,639(4)	12,174(4)
E	SNCR w/ ASOFA	8,113	707
D	Gas Reburn w/ ASOFA(5)	18,006	1,570
C	Lignite Reburn w/ ASOFA(6)	46,656	4,068
B	Fuel Lean Gas Reburn w/ ASOFA(5)	10,639	928
A	Advanced SOFA (ASOFA)	4,277	373
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. See Table 4-5SF for presentation of installed capital costs determined for hypothetical application of SCR alternatives.

(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.

(4) - The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The installed capital cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006$ as described in the text. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR; and annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SF.

(6) - Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost, and $2,054,000/yr annualized capital cost.

The Total Project Costs estimated for tail end and low-dust SCR technologies hypothetically applied to MRYS Unit 1 are shown in Table 4-5SA and Table 4-5SF in 2018, 2009, and 2006 dollars.

The estimated installed capital costs for the hypothetical application of tail end or low-dust SCR system retrofits on MRYS Unit 1 included the following equipment and components:

- One SCR reactor utilizing a “3 +1” arrangement of catalyst layers, in which three layers of catalyst are initially installed, and space for installation of a fourth layer is provided.
- Sootblowers for each catalyst layer to maintain cleanliness of catalyst
- Flue gas reheat equipment that is typical for these applications but not required for conventional high-dust/hot side SCRs. This reheat equipment includes rotary regenerative heat exchangers (gas-to-gas heaters [GGH]) and natural gas-fired duct burners.
- Underground high-pressure natural gas supply pipeline and pressure regulators and metering equipment
- Hot air recirculation and heating equipment to maintain catalyst in a warm and dry condition during standby periods
- Induced draft booster fan and dampers
- Interconnecting ductwork
- SCR bypass duct and dampers (used during times the boiler is off-line)
- Storage tanks, building, and equipment for unloading and preparation of liquid urea solution
- Circulation pumps and piping for urea solution
- Urea-to-ammonia thermal conversion with urea conversion, metering, atomization, and injection equipment
- Ammonia gas dilution/combustion air fans and burners for natural gas-firing to decompose the urea solution to ammonia
- Service and sootblowing air compressors with dryers
- Electrical motor control centers
- Controls and instrumentation
- Reinforced concrete foundations
- Active coal yard storage modifications to regain lost live capacity and handling equipment due to space consumed by the SCR reactor structures
- Installation labor, materials, and management.

Addition of new electrical loads to the existing plant facilities will be required for the reagent system and new induced draft booster fan power consumption. Based on recent plant electrical distribution equipment installations, additional plant auxiliary electrical power will be available for powering the new hypothetically-applied SCR equipment. Confirmation of these concepts and cost estimates prior to any subsequent plans for implementation requires successful completion of extensive pilot-scale slipstream

testing, and more detailed plant layout and equipment design than has been performed as part of this supplemental update to the October 2006 NO_X BACT Analysis Study report.

The capital cost estimated individually for an ASOFA system retrofit on MRYS Unit 1 as previously described in the initial NO_X BACT Analysis Study report was simply arithmetically added to the hypothetical application of SCR alternatives' capital cost estimates.

TABLE 4-5SA – Estimated Capital Costs for Hypothetically-Applied SCR Alternatives - MRY Station Unit 1
Stand Alone SCR Projects

Alt. Label(1)	**Hypothetical SCR Alternative(2)**	**Estimated BMcD Study Total Project Cost(3), 2018$ x 1000**	**Estimated BMcD Study Modified TP Cost(4), 2009$ x 1000**	**Estimated BMcD Study Adjusted TP Cost(5), 2006$ x 1000**
T2, T1	Tail End SCR	294,586	235,884	214,221
	Urea preparation and storage, building, and equipment(6)	–	4,808(6)	4,366(6)
	ASOFA	–	–	4,277
T2, T1	TOTAL	–	–	222,864(6)
L2, L1	Low-Dust SCR	236,658	189,499	172,096
	Urea preparation and storage, building, and equipment	–	4,808(6)	4,366(6)
	ASOFA	–	–	4,277
L2, L1	TOTAL	–	–	180,739(6)

(1) All SCR alternatives are assumed to have the same SCR outlet NOx emission rate.
(2) The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station.
(3) The Total Project Cost shown for each hypothetically-applied SCR system was estimated by Burns & McDonnell based on scope assumptions for installation of the SCR equipment on this boiler as described in the text, except as described in footnote 6 below. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Does not include installed capital cost for ASOFA, as shown in Table 4-4SA.
(4) Modified Total Project Costs are converted from 2018$ to 2009$ as described in the text, except as described in footnote 6 below. Present Value factor (discounted from future value) is 0.80073.
(5) Adjusted Total Project Costs are converted from 2009$ to 2006$ as described in the text. Handy-Whitman Index of Public Utility Construction Costs ratio is 0.908.
(6) Urea preparation and storage, building, and equipment installed capital costs were estimated separately in 2009$, and then adjusted using the Handy-Whitman cost ratio of 0.908 to get 2006$. The TOTAL numbers above are the sum of the Adjusted Total Project Cost; urea preparation and storage, building, and equipment; and Total Installed Capital Costs (TICC) for ASOFA alternative = estimated TICC for the hypothetically-applied SCR alternatives in Table 4-4SA.

TABLE 4-5SF – Estimated Capital Costs for Hypothetically-Applied SCR Alternatives - MRY Station Unit 1 Shared Facilities SCR Projects

Alt. Label(1)	**Hypothetical SCR Alternative(2)**	**Estimated BMcD Study Total Project Cost(3), 2018$ x 1000**	**Estimated BMcD Study Modified TP Cost(4), 2009$ x 1000**	**Estimated BMcD Study Adjusted TP Cost(5), 2006$ x 1000**
T2, T1	Tail End SCR	240,817	192,829	175,120
	Urea preparation and storage, building, and equipment(6)	–	2,298(6)	2,087(6)
	ASOFA	–	–	4,277
T2, T1	TOTAL	–	–	181,484(6)
L2, L1	Low-Dust SCR	183,274	146,753	133,275
	Urea preparation and storage, building, and equipment(6)	–	2,298(6)	2,087(6)
	ASOFA	–	–	4,277
L2, L1	TOTAL	–	–	139,639(6)

(1) All alternatives are assumed to have the same SCR outlet NOx emission rate.
(2) The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station.
(3) The Total Project Cost shown for each hypothetically-applied SCR system was estimated by Burns & McDonnell based on scope assumptions for installation of the SCR equipment on this boiler as described in the text, except as described in footnote 6 below. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO$_X$ BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Does not include installed capital cost for ASOFA, as shown in Table 4-4SF.
(4) Modified Total Project Costs are converted from 2018$ to 2009$ as described in the text, except as described in footnote 6 below. Present Value factor (discounted from future value) is 0.80073.
(5) Adjusted Total Project Costs are converted from 2009$ to 2006$ as described in the text. Handy-Whitman Index of Public Utility Construction Costs ratio is 0.908.
(6) Urea preparation and storage, building, and equipment installed capital costs were estimated separately in 2009$, and then adjusted using the Handy-Whitman cost ratio of 0.908 to get 2006$. The TOTAL numbers above are the sum of the Adjusted Total Project Cost; urea preparation and storage, building, and equipment; and Total Installed Capital Costs (TICC) for ASOFA alternative = estimated TICC for the hypothetically-applied SCR alternatives in Table 4-4SF

4.2.1.2 O&M COST ESTIMATES FOR NO$_X$ CONTROL ALTERNATIVES

Operational costs to implement the hypothetical application of SCR alternatives and previously-analyzed feasible NO$_X$ control alternatives for Milton R. Young Unit 1 were estimated using preliminary conceptual designs and budgetary vendor quotes in place of, or to adjust, the OAQPS cost factors established in the EPA's Air Pollution Control Cost Manual (OAQPS) for SNCR[27] and SCR[28], and using other costs published in technical papers discussing those control technologies. Maintenance costs were estimated as

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[27] See Reference number 9, October 2000.
[28] See Reference number 10, October 2000.

percentages of installed capital costs, with additional catalyst replacement costs using budgetary vendor quotes based on preliminary conceptual designs and expected design life.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's annual O&M costs are estimates of:

- Auxiliary electrical power consumption (megawatt-hours) and incremental purchased power unit costs for operating the additional control equipment;
- Natural gas consumption and unit cost for hypothetical application of SCR alternatives' flue gas reheating and urea-to-ammonia thermal conversion systems and feasible fuel reburn alternatives;
- Reagent consumption and reagent unit cost for hypothetical application of SCR alternatives and feasible SNCR alternatives;
- Reagent dilution water consumption and unit cost for SNCR alternatives.
- Catalyst removal and replacement for hypothetical application of SCR alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler and plant equipment;
- Costs for purchase of replacement electrical power expected to result from loss of unit availability, i.e., outages attributable to the control option which reduce annual net electrical generation available for distribution.

For economic evaluation purposes, a 12-month rolling average running plant capacity factor of 96.6 percent (based on a historic (demonstrated) sustainable unit output capacity of 253 MW_g) combined with a 12-month rolling average availability (uptime) of 8,528 operating hours (97.3 percent of 8760 hours per year) resulting in an equivalent annual average unit capacity factor of 94.1% was assumed for Unit 1's pre-control baseline annual operation. A 12-month rolling average heat input rate of 2,744 mmBtu/hr and a 12-month rolling average NO_X emission rate of 0.849 lb/mmBtu from pre-control maximum rolling 12 month summation of nitrogen oxides mass emissions were assumed for calculating equivalent annual average control and cost-effectiveness for MRY Station Unit 1.

Tables 4-6SA and 4-6SF show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the hypothetically-applied SCR alternative cases and the highest-performing form of previously-evaluated feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Appendix C3 of the 2006 NO_X BACT Analysis Study report provides more details for the levelized annual O&M cost calculations and cost factors for the previously-analyzed feasible NO_X control alternatives[29].

TABLE 4-6SA – Estimated O&M Costs for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	**NOx Control Alternative**	**Annual O&M Cost(2) $1,000**	**Levelized Annual O&M Cost(2),(3) $1,000**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	20,048	25,034
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	29,361	36,664
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	16,908	21,114
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	27,882	34,817
E	SNCR w/ ASOFA	5,417	6,764
D	Gas Reburn w/ ASOFA	28,641	35,765
C	Lignite Reburn w/ ASOFA(5)	5,862	7,320
B	FLGR w/ ASOFA	12,863	16,062
A	Advanced SOFA (ASOFA)	1,695	2,117
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at an average unit output (244.5 MWg) and assumes a 97.3% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(4) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual O&M cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specific to MRYS Unit 1 in 2018 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.
(5) - Costs for increased PM collection capacity included in lignite reburn option are $2,024,000/yr for annual O&M cost, and $2,527,000/yr annualized O&M cost.

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[29] Ibid Reference number 3, October 2006, pages C3 through 3-11.

TABLE 4-6SF – Estimated O&M Costs for NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual O&M Cost(2) $1,000	Levelized Annual O&M Cost(2),(3) $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	18,806	23,484
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	28,120	35,114
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	15,675	19,574
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	26,649	33,278
E	SNCR w/ ASOFA	5,417	6,764
D	Gas Reburn w/ ASOFA	28,641	35,765
C	Lignite Reburn w/ ASOFA(5)	5,862	7,320
B	FLGR w/ ASOFA	12,863	16,062
A	Advanced SOFA (ASOFA)	1,695	2,117
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at an average unit output (244.5 MWg) and assumes a 97.3% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.

(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(4) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual O&M cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specific to MRYS Unit 1 in 2018 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for increased PM collection capacity included in lignite reburn option are $2,024,000/yr for annual O&M cost, and $2,527,000/yr annualized O&M cost.

4.2.1.2.1 O&M COST ESTIMATES FOR HYPOTHETICAL APPLICATION OF SCR NO_X CONTROL ALTERNATIVES

The hypothetical application of tail-end and low-dust SCR w/ ASOFA alternatives will involve significantly higher operating costs compared with the existing operation of MRYS Unit 1. The system uses an amine reagent in the form of concentrated aqueous urea solution, which is thermally converted to gaseous ammonia, carbon dioxide, and water vapor. The estimated unit cost of this urea was assumed to average $379/ton (delivered to the plant site via truck-tanker trailers; unit pricing based on 50% concentration as established for the 2006 NO_X BACT Analysis Study report). Consumption of urea converted to ammonia reagent was based upon recent equipment vendor budgetary proposals and SCR consultant inputs.

For the hypothetically-applied SCR cases, using the existing induced draft fans is not expected to significantly change the overall fan horsepower demand on those fans' electric motors. There will be new plant electrical power demand due to a new induced draft booster fan required to overcome the estimated additional flue gas pressure drop resulting from reactor, ductwork, and gas-to-gas heat exchanger equipment assumed for the hypothetically-applied SCR systems. The additional auxiliary electric power demand for the hypothetically-applied tail end SCR systems was calculated to be 9.7 MW, using estimated annual average electrical loads of the booster fan, direct flue gas reheat burner combustion air fan, urea-to-ammonia conversion dilution/combustion air fan, and SCR sootblower and service air compressor equipment based on preliminary equipment vendor budgetary proposals developed from Burns & McDonnell ductwork sizing and designs. Estimated annual average electrical power demands for hypothetically-applied low-dust SCR systems were calculated to be 8.0 MW. Replacement of electrical power resulting from these reductions in net unit electrical output was included as a cost, assuming $35 per megawatt-hour.

Hypothetically-applied tail end and low-dust SCR equipment requiring annual maintenance includes booster fan, gas-to-gas heat exchangers, flue gas reheat duct burners, and compressor equipment. This general annual maintenance cost was estimated as 3 percent of installed capital costs.

To account for the possible range of O & M costs due to catalyst replacement, two variations (Scenario A and Scenario B) were applied. These two scenarios were used for both hypothetical applications of tail-end and low-dust SCR technology alternatives. Each scenario was based on scheduled additions and/or replacement of the exposed catalyst after a certain number of hours of operation, repeated throughout the 20 year operating span considered in the analysis. The installed unit cost of replacement catalyst assumed for the hypothetical application of full-time tail end or low-dust SCR alternatives is $7,500 per cubic meter in 2006 dollars. The basis for development of the two scenarios is described below.

During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically-applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Based on information obtained in discussions with the catalyst vendors, the longest catalyst replacement schedule they would both agree upon as an estimated (not guaranteed) value was 16,000 hours. Both vendors indicated that actual experience could result in a shorter replacement cycle, and that the actual guarantee value could not be developed until extensive pilot slipstream testing had been completed. This led Burns & McDonnell to develop two hypothetically-applied SCR catalyst replacement scenarios to bracket possible outcomes.

Scenario A assumed a hypothetically-applied catalyst replacement schedule of 16,000 hours. Specifically for MRYS Unit 1, this scenario is based on the replacement of one catalyst layer every 16,000 operating hours (essentially every two years of operation).

Scenario B assumed that the fouling of the catalyst would be severe, and that it would be necessary for Minnkota to perform catalyst maintenance at each scheduled boiler cleaning outage. The current schedule of boiler cleaning outages on Unit 1 is three times per year. Therefore, Scenario B for Unit 1 is based on the replacement of one catalyst layer at each boiler cleaning outage. This means that each catalyst layer in the four layer SCR reactor is exposed to flue gas during approximately 16 months of operation and then is replaced. By assuming that catalyst management activities would coincide with scheduled boiler cleaning outages, Scenario B provides some minimization of the impact of catalyst replacement on unit operation.

As noted above, it is not known what the actual frequency of catalyst replacement would need to be for a hypothetically-applied tail-end or low dust SCR system operating on a cyclone-fired boiler burning North Dakota lignite, but the two scenarios described above are the catalyst replacement numbers assumed for this comparative economic analysis.

SCR catalyst replacements are additive to the general annual hypothetically-applied low-dust and tail end SCR equipment maintenance. Catalyst replacement costs are based on catalyst vendor quotation of volume of catalyst, estimated to be three layers initially (top, middle-upper and middle-lower) at 146 cubic meters per layer per reactor for the single reactor. A fourth (bottom) layer at 195 cubic meters is expected to be required after initial operation of hypothetically-applied full-time tail end or low-dust SCR alternatives, as part of the catalyst replacement program. Catalyst replacement costs for the hypothetical application of SCR alternatives were estimated for the two different catalyst management scenarios described above.

Annual unit operating time will be reduced as a result of the expected outages and maintenance of the hypothetically-applied SCR equipment, including catalyst cleaning and management practices. Additional outage time of 213 hours per year was estimated to be attributable to the hypothetical application of tail end SCR Scenario A alternative (assuming 16,000 hour catalyst life), and 938 hours per year for Scenario B TESCR case (assuming three layers are replaced every year) over and above the hours per year of outage time assumed for ASOFA impacts. Additional outage time of 256 hours per year was estimated to be attributable to the hypothetical application of low-dust SCR Scenario A alternative, and 981 hours per year for the Scenario B LDSCR case over and above outage time assumed for ASOFA impacts. The expected loss of electrical power generation from these reductions in net output was included as a cost, assuming $35 per megawatt-hour for replacement power.

Table C.4-1 provides the estimated unit availability and corresponding operating time and outage time due to the four hypothetically-applied SCR technology cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[30].

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[30] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

TABLE C.4-1 – Expected Availability Reductions for MRYS Unit 1 NO_X Controls

Alt.[1]	NOx Control Alternative	Estimated Annual Average Unit Operating Time			
		Unit Availability[2]	Unit Operating Time[3], hrs/yr	Unit Outage Time[4], hrs/yr	Unit Operating Time Reduction[5], hrs/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	0.928	8127	633	401
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	0.845	7402	1358	1126
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	0.923	8084	676	444
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	0.840	7359	1401	1169
E	SNCR w/ ASOFA	0.942	8255	505	273
D	Gas Reburn w/ ASOFA	0.952	8340	420	188
C	Coal Reburn w/ ASOFA	0.937	8212	548	316
B	FLGR w/ ASOFA	0.952	8340	420	188
A	Advanced SOFA (ASOFA)	0.952	8340	420	188
	Baseline	0.973	8528	232	0

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.
(2) – 12-month baseline availability is assumed at 97.3 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technology.
(3) – Annual operating time is annual average availability multiplied by 8760 hrs/yr of possible uptime.
(4) – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.
(5) – Annual operating time reduction resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.
(6) – The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual unit availability factors shown for hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Table C.4-2 includes estimated equivalent average annual unit running plant capacity ratios and unit generation reductions due to the four hypothetically-applied SCR cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[31]. These numbers assume the reduction in annual plant output is a combination of a reduction of annual operating time and capacity reductions associated with the control alternatives.

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[31] Ibid Reference number 3, October 2006, pages C3-1 through C3-12.

TABLE C.4-2 – Expected Capacity Reductions for MRYS Unit 1 NO_X Controls

Alt. Label[(1)]	NOx Control Alternative	Estimated Annual Average Unit Electrical Power Generation Reduction from Operating Time Reduction: Unit Running Plant Capacity Ratio[(2)]	Unit Generation Reduction[(3)] kW-hrs/yr	Unit Generation Reduction Cost[(4)], 1000$/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[(5)]	0.937	97,976,764	3,429
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[(5)]	0.937	275,168,784	9,631
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[(5)]	0.942	108,399,824	3,794
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[(5)]	0.942	285,591,844	11,940
E	SNCR w/ ASOFA	0.965	67,660,606	2,368
D	Gas Reburn w/ ASOFA	0.957	46,120,681	1,614
C	Lignite Reburn w/ ASOFA	0.961	77,958,350	2,729
B	FLGR w/ ASOFA	0.962	46,400,200	1,624
A	Advanced SOFA (ASOFA)	0.966	46,586,546	1,631
	Baseline	0.966	0	0

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) - 12-month baseline running plant capacity ratio is assumed at 96.6 percent (= 244.4/253.0). These values reflect estimated amounts of negative annual output capacity impact expected from the implementation of the individual NOx control technique. Used only for calculation of annual power usage in Table C.4-3.
(3) - Annual electricity generation reduction is annual unit operating time reduction multiplied by the 12-month average gross output of 244.4 MW.
(4) - Annual electricity generation reduction cost is the annual electricity generation reduction (kW-hrs/yr) resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.
(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual unit running plant capacity factors shown for hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Table C.4-3 includes estimated unit gross and net electrical power demands (kilowatts) and annual usage (kW-hrs per year) used to calculate unit generation reductions and replacement electrical power costs due to the four hypothetically-applied SCR cases, along with the ASOFA numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[32]. These numbers assume that the reductions of annual operating time and capacity associated with the control alternatives are also applied.

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[32] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

TABLE C.4-3 – Expected Auxiliary Electrical Power Demand Changes for MRYS Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Alternative	Estimated Annual Average APC NOx Equipment Auxiliary Electrical Power Demand and Usage				
		Gross Demand (2) kW	Credit(3) kW	Total Net Demand(4) kW	Power Usage(5) kW-hrs/yr	Power Usage Cost(6), 1000$/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(7)	9,685	0	9,685	73,768,605	2,582
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(7)	9,685	0	9,685	67,189,753	2,352
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(7)	8,012	0	8,012	61,018,532	2,136
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(7)	8,012	0	8,012	55,548,184	1,944
E	SNCR w/ ASOFA	73.1	0	73.1	582,411	20
D	Gas Reburn w/ ASOFA	1	133	(132)	(1,054,343)	(37)
C	Lignite Reburn w/ ASOFA	4,666	261	4,405	11,905,082	1,217
B	FLGR w/ ASOFA	1	73	(72)	(578,744)	(20)
A	Advanced SOFA (ASOFA)	1	0	1	8,058	0.3

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) - The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of the demand for individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects. Coal reburn includes 1,507 kW for feed preparation and conveying equipment demand plus 3,158 kW for the COHPAC system addition for PM control.
(3) - The APC NOx equipment auxiliary electrical power demand credit of coal reburn alternatives is the estimated result of lower cyclone coal preparation and feeder power demand due to lower boiler cyclone coal equipment loading. Actual power demands may differ from this due to accuracy of estimates for assumed amount of operating horsepower reduction.
(4) - The total net auxiliary electrical power demand is the sum of the gross demand and credit.
(5) - The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity ratio which reflects the adjustment for any expected availability and capacity impacts from the implementation of the control technique.
(6) - The annual change in APC NOx equipment auxiliary electrical power demand electricity cost is the annual change in kW-hrs/yr for these alternatives resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.
(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated power demands shown for hypothetically-applied SCR systems are based on Burns & McDonnell estimates developed from preliminary equipment and ductwork sizing and designs with vendor budgetary proposals. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Table C.4-4 includes estimated net unit electrical annual power usage (kW-hrs per year) and expected reductions in annual operating time to calculate unit generation reductions due to the four hypothetically-applied SCR cases, along with the ASOFA numbers from the referenced Appendix C3 of the initial NO_X

BACT Analysis Study report[33]. These numbers assume the reduction in annual plant output is a combination of a reduction of net unit generation because of electrical power usage and reductions in annual operating time and capacity associated with the control alternatives.

TABLE C.4-4 – Expected Auxiliary Electrical Power Demand and Generation Reduction Cost Changes for MRY Unit 1 NO_X Controls

Alt. Label[(1)]	**NOx Control Alternative**	**Estimated Annual Change in Unit Generation Due to APC NOx Equipment Auxiliary Power Electricity Demand and Generation Reduction**			
		APC Electrical Power Usage[(2)] kW-hrs/yr	**Unit Generation Reduction[(3)] kW-hrs/yr**	**Total Unit Electrical Power Generation Change[(4)] kW-hrs/yr**	**Total Unit Electrical Power Generation Change Cost[(5)] 1000$/yr**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[(6)]	73,768,605	97,976,764	171,745,369	6,011
T1	Hypothetical Tail End SCR w/ ASOFA –Scenario B[(6)]	67,189,753	275,168,784	342,358,537	11,983
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[(6)]	61,018,532	108,399,824	169,418,356	5,930
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[(6)]	55,548,184	285,591,844	341,140,028	11,940
E	SNCR w/ ASOFA	582,411	67,660,606	68,243,017	2,389
D	Gas Reburn w/ ASOFA	(1,054,343)	46,120,681	45,066,338	1,577
C	Lignite Reburn w/ ASOFA	11,905,082	77,958,350	89,863,432	3,946
B	FLGR w/ ASOFA	(578,744)	46,400,200	45,821,456	1,604
A	Advanced SOFA (ASOFA)	8,058	46,586,546	46,594,605	1,631

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) - The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity ratio which reflects the adjustment for any expected availability and capacity impacts from the implementation of the control technique.
(3) - Annual electricity generation reduction is annual operating time reduction multiplied by the 12-month average gross output of 244.4 MW.
(4) - The total unit electrical power generation change is the sum of the annual change in APC NOx equipment auxiliary electrical power demand electricity usage plus the annual electricity generation reduction resulting from the implementation of the individual NOx control alternative.
(5) - The total unit electrical power generation change cost is the total generation change (kw-hrs/yr) multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.
(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated power demand shown for hypothetically-applied SCR systems are based on Burns & McDonnell estimates developed from preliminary equipment and ductwork sizing and designs with vendor budgetary proposals. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

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[33] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

4.2.1.3 LEVELIZED TOTAL ANNUAL COST ESTIMATES FOR MRY STATION NO_X CONTROLS

A comparison of the control versus cost-effectiveness of four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives on Milton R. Young Unit 1 was made. This is summarized as shown in Tables 4-7SA and 4-7SF, Figures 4-1SA and 4-1SF, and Figures 4-2SA and 4-2SF for MRY Station Unit 1.

TABLE 4-7SA – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) $1,000	Average Control Cost(5) $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	589	9,345	44,465	4,758
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	536	9,398	56,095	5,969
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	586	9,348	36,872	3,944
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	533	9,401	50,575	5,380
E	SNCR w/ ASOFA	4,025	5,909	7,472	1,265
D	Gas Reburn w/ ASOFA	4,275	5,659	37,334(7)	6,597
C	Lignite Reburn w/ ASOFA	4,343	5,591	11,388(8)	2,037
B	FLGR w/ ASOFA	5,260	4,674	16,990(7)	3,635
A	Advanced SOFA (ASOFA)	5,874	4,060	2,489	613
	Baseline	9,934	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated annual emission tons assume an annual unit uptime availability factor specific to each alternative; 9,934 (= 0.973*8760*2,330/2000) was assumed for the baseline case.

(3) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note 3 from Tables 4-4SA and 4-6SA for annualized cost factors. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline emissions based on annual operation at baseline pre-control NOx emission rate.

(5) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specifically for MRYS Unit 1 in 2006 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this

information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SA.

(8) - LTAC for increased PM collection capacity included in lignite reburn option are approximately $2,054,000 for annualized capital cost plus $2,527,000/yr for annualized O&M cost, for a LTAC subtotal of $4,581,000/yr.

TABLE 4-7SF – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 1 - Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) $1,000	Average Control Cost(5) $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	589	9,345	39,307	4,206
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	536	9,398	50,937	5,420
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	586	9,348	31,749	3,396
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	533	9,401	45,452	4,835
E	SNCR w/ ASOFA	4,025	5,909	7,472	1,265
D	Gas Reburn w/ ASOFA	4,275	5,659	37,334(7)	6,597
C	Lignite Reburn w/ ASOFA	4,343	5,591	11,388(8)	2,037
B	FLGR w/ ASOFA	5,260	4,674	16,990(7)	3,635
A	Advanced SOFA (ASOFA)	5,874	4,060	2,489	613
	Baseline	9,934	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated annual emission tons assume an annual unit uptime availability factor specific to each alternative; 9,934 (= 0.973*8760*2,330/2000) was assumed for the baseline case.

(3) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note 3 from Tables 4-4SF and 4-6SF for annualized cost factors. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline emissions based on annual operation at baseline pre-control NOx emission rate.

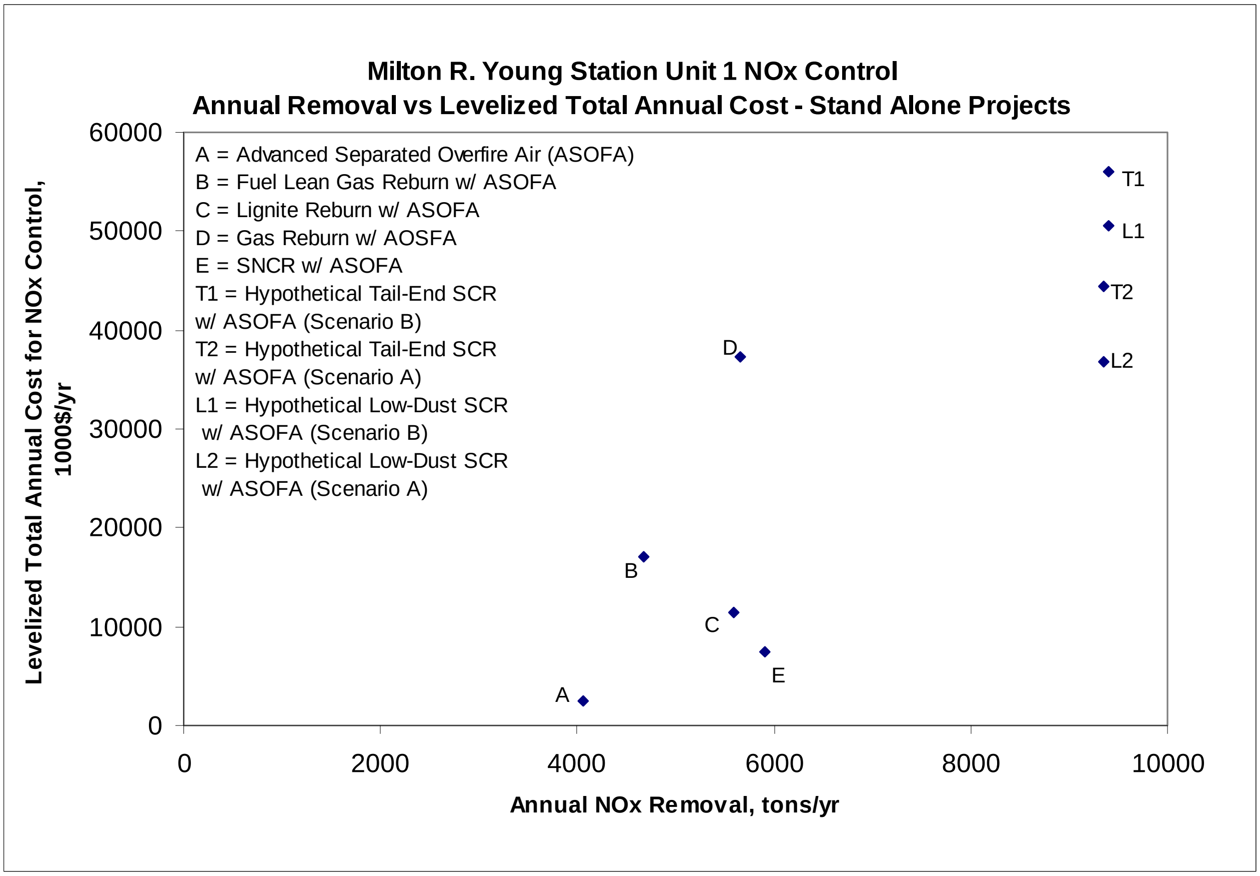
(5) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specifically for MRYS Unit 1 in 2006 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SF.

(8) - LTAC for increased PM collection capacity included in lignite reburn option are approximately $2,054,000 for annualized capital cost plus $2,527,000/yr for annualized O&M cost, for a LTAC subtotal of $4,581,000/yr.

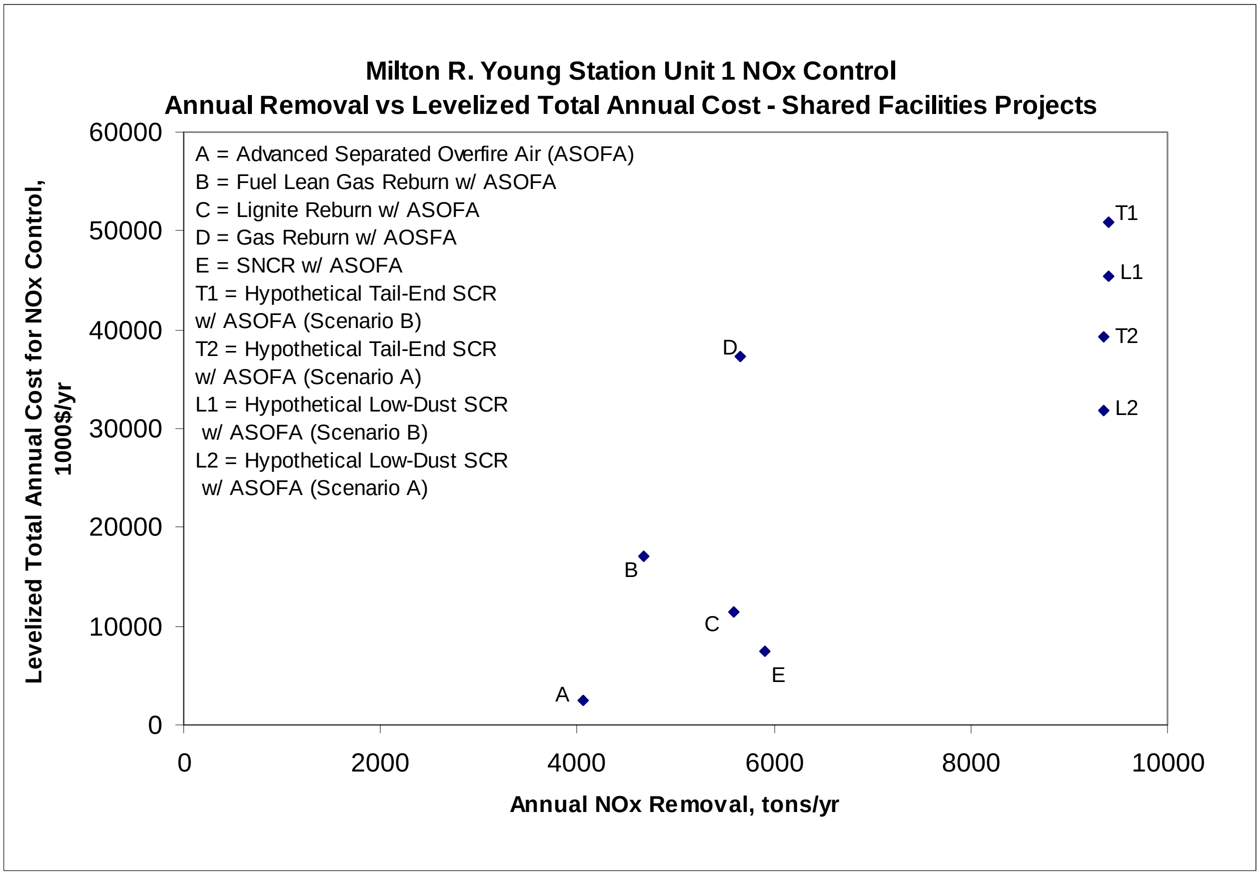
Figure 4-1SA – NO$_X$ Control Cost Effectiveness - MRY Station Unit 1(1) Stand Alone SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-7SA.

(2) - The inclusion of tail-end and low-dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO$_X$ BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Figure 4-1SF – NO_X Control Cost Effectiveness - MRY Station Unit 1(1)
Shared Facilities SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-7SF.

(2) - The inclusion of tail-end and low-dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

The purpose of Figures 4-1SA and 4-1SF is to show the range of control and cost for four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives on Milton R. Young Unit 1 alternatives evaluated.

Data points for conventional gas reburn (Point D) and fuel-lean gas reburn (Point B) with advanced separated overfire air, and lignite reburn with ASOFA (Point C), in Figures 4-1SA and 4-1SF are inferior and therefore were eliminated from further control cost-effectiveness analysis.

A dominant set of control alternatives was determined by generating what is called the “envelope of least-cost alternatives”. The dominant controls cost curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the annual NO_X removal tonnage versus LTAC for the various remaining BACT alternatives. Average and incremental annual costs and NO_X emission reductions for the dominant least-cost control alternatives remaining after the elimination of the obviously inferior options are listed in Tables 4-8SA and 4-8SF.

TABLE 4-8SA – Dominant Controls Cost Curve Points for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	NOx Control Alternative	Levelized Total Annual Cost(2),(3) ($1,000/yr)	Annual Emission Reduction(3) (tpy)	Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)	Incremental Annual Emission Reduction(4) (tpy)	Incremental Control Cost Effectiveness ($/ton)(2),(4)
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	44,465	9,345	36,993	3,437	10,765
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	56,095	9,398	48,623	3,489	13,936
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	36,872	9,348	29,400	3,440	8,547
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(5)	50,575	9,401	43,103	3,492	12,343
E	SNCR w/ ASOFA	7,472	5,909	4,982	1,849	2,694
A	Advanced SOFA (ASOFA)	2,489	4,060	2,489	4,060	613

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Dominant controls cost curve points from lowest (ASOFA) to highest (TESCR w/ ASOFA – 16,000 hrs) are labeled the same as in Table 4-7SA, and on the graphs that accompany this table (Points B, C, and D were eliminated).

(2) - All cost figures in 2006 dollars.

(3) - Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate.

(4) - Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

TABLE 4-8SF – Dominant Controls Cost Curve Points for NO_X Control Alternatives - MRY Station Unit 1 - Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Levelized Total Annual Cost(2),(3) ($1,000/yr)	Annual Emission Reduction(3) (tpy)	Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)	Incremental Annual Emission Reduction(4) (tpy)	Incremental Control Cost Effectiveness ($/ton)(2),(4)
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	39,307	9,345	31,835	3,437	9,264
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	50,937	9,398	43,465	3,489	12,458
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	31,749	9,348	24,277	3,440	7,058
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(5)	45,452	9,401	37,980	3,492	10,876
E	SNCR w/ ASOFA	7,472	5,909	4,982	1,849	2,694
A	Advanced SOFA (ASOFA)	2,489	4,060	2,489	4,060	613

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Dominant controls cost curve points from lowest (ASOFA) to highest (TESCR w/ ASOFA – 16,000 hrs) are labeled the same as in Table 4-7SF, and on the graphs that accompany this table (Points B, C, and D were eliminated).

(2) - All cost figures in 2006 dollars.

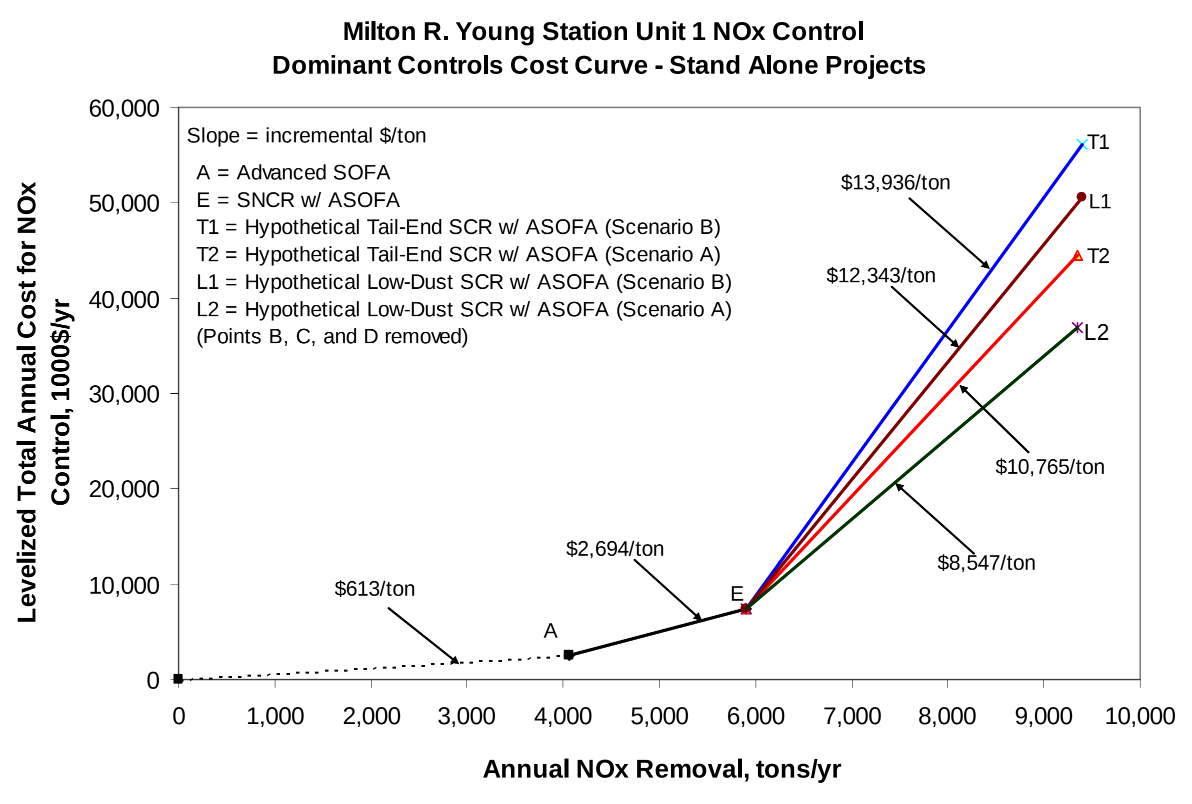
(3) - Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate.

(4) - Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Figures 4-2SA and 4-2SF contains a repetition of the levelized total annual cost and NO_X control information from Figures 4-1SA and 4-1SF for MRY Station Unit 1, with Point B (FLGR™ with ASOFA) , Point C (Lignite Reburn with ASOFA) and Point D (conventional gas reburn with ASOFA) removed. This is the dominant controls cost curve for MRY Station Unit 1 NO_X emissions alternatives.

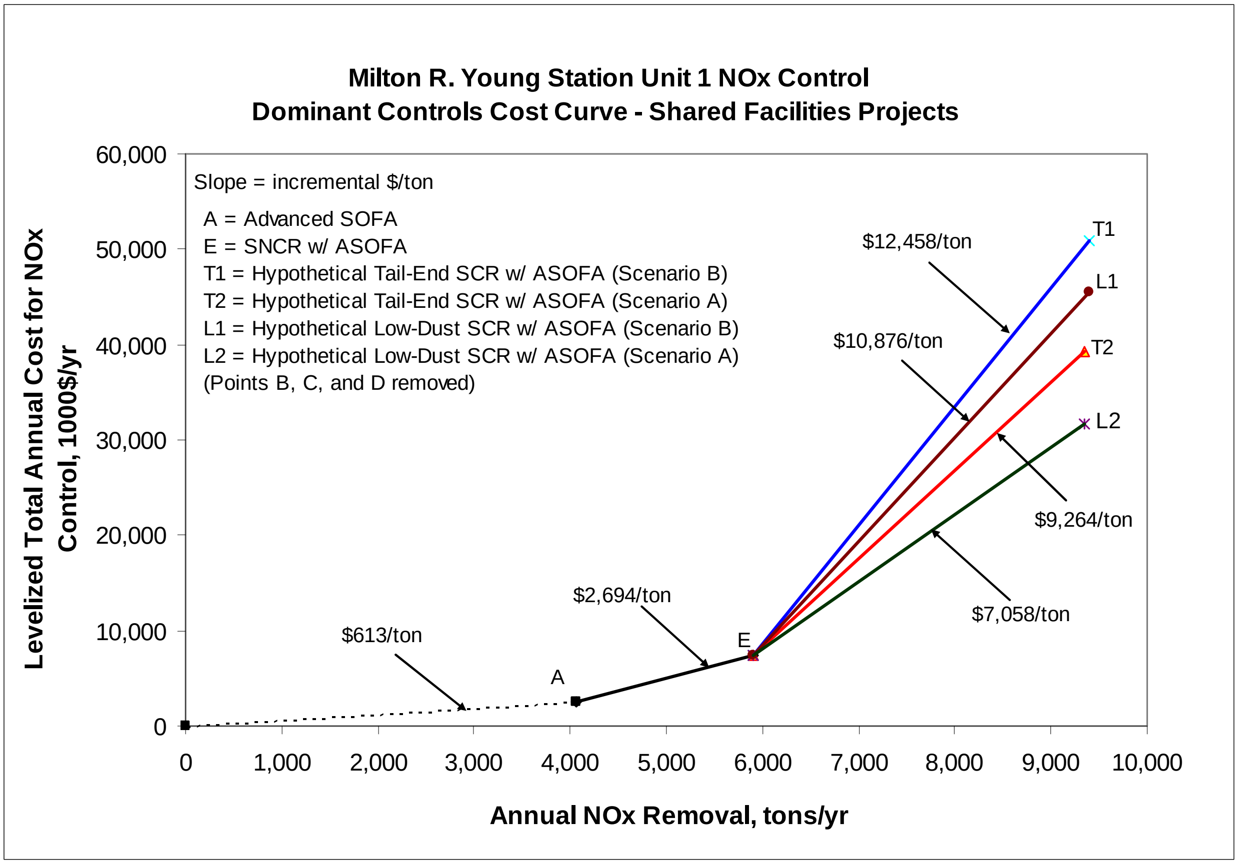
Figure 4-2SA – MRY Station Unit 1 NO_X Control Alternatives BACT Dominant Controls Cost Curve$^{(1)}$ - Stand Alone SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-8SA.

(2) - The inclusion of tail-end and low dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Figure 4-2SF – MRY Station Unit 1 NO_X Control Alternatives BACT Dominant Controls Cost Curve$^{(1)}$ – Shared Facilities SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-8SF.

(2) - The inclusion of tail-end and low dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

As can be seen from a review of Tables 4-7SA and 4-7SF, the average levelized control cost effectiveness (called the unit control cost in this report) ranges from approximately $613/ton to $6,597/ton of MRYS Unit 1's NO_X emissions removed. The unit control cost for the hypothetically-applied Scenario A Tail End SCR w/ ASOFA case was $4,758/ton and for the hypothetically-applied Scenario B Tail End SCR w/ ASOFA case was $5,969/ton (stand alone projects). The unit control cost for the hypothetically-applied Scenario A Low-Dust SCR w/ ASOFA case was $3,944/ton and for the hypothetically-applied Scenario B Low-Dust SCR w/ ASOFA case was $5,380/ton (stand alone projects). The unit control cost for the hypothetically-applied Scenario A Tail End SCR w/ ASOFA case was $4,206/ton and for the hypothetically-applied

Scenario B Tail End SCR w/ ASOFA case was $5,420/ton (shared facilities projects). The unit control cost for the hypothetically-applied Scenario A Low-Dust SCR w/ ASOFA case was $3,396/ton and for the hypothetically-applied Scenario B Low-Dust SCR w/ ASOFA case was $4,835/ton (shared facilities projects). Unit control costs for SNCR w/ ASOFA was $1,265/ton, more than twice that of ASOFA ($613/ton). It should be noted, however, that the very high estimated average control costs involve fuel lean gas reburn ($3,635/ton) and conventional gas reburn ($6,597/ton) technologies that were shown to be inferior options (not on the dominant controls cost curve) and thus were eliminated from further impacts analysis.

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative for MRYS Unit 1 incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control technique. The slope from zero (baseline) to ASOFA (Point A) was $613/ton; the incremental cost per ton (slope) from ASOFA (Point A) to SNCR with ASOFA (Point E) was $2,694/ton for MRYS Unit 1. The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied low-dust SCR case (Point L2, Scenario A) was $8,547/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied tail end SCR case (Point T2, Scenario A) was $10,765/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied low-dust SCR case (Point L1, Scenario B) was $12,343/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied tail end SCR case (Point T1, Scenario B) was $13,936/ton (stand alone projects). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied SCR cases were $7,058/ton (low-dust Point L2, Scenario A) and $9,264/ton (tail end Point T2, Scenario A). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied SCR cases were $10,876/ton (low-dust, Point L1, Scenario B) and $12,458/ton (tail end Point T1, Scenario B).

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. EPA's NSR Manual however, does specifically address the standard to be used when rejecting a candidate technology on the basis of adverse economic impact:

> "Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances,

> including the cost or other analyses, that show what is significantly different about the proposed source."[34]

This supplemental report for the MRYS NOx BACT Analysis has clearly established the circumstances, including the economic impacts, which would make the hypothetical application of TESCR or LDSCR to MRYS Unit 1 significantly more expensive than SCR costs normally incurred by other coal-fired steam electric generating units. The following information further supports EPA's own statements regarding the costs "normally incurred by other sources". The EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines estimated an average control cost for SCR applied to MRYS Unit 1 of $549 per ton[35]. The unadjusted unit capital cost versus capacity factor assumed by the EPA for SCR retrofits applied to cyclone boilers in the cost-effectiveness analysis used for establishing presumptive BART[36] was $100/kW. The EPA's cost-effectiveness analysis used for establishing presumptive BART stated that "applying SCR for coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton" [37]. The site-specific control costs estimated for hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines discussed above.

Also, the use of incremental cost effectiveness is warranted per the final 2005 RHR/BART Guidelines, which state "the greater the number of possible control options that exist, the more weight should be given to the incremental costs vs. average costs". Also in the final 2005 RHR/BART Guidelines, "the average cost for each [of two options, A and B]… may be deemed to be reasonable. However, the incremental cost…of the additional emissions reductions to be achieved by control B may be very great. In such an instance, it may be inappropriate to chose control B, based on its higher incremental costs, even though its average cost may be considered reasonable".[38]

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[34] Ibid Reference number 2, Section IV.D.2.c.
[35] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.
[36] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 209.
[37] See Reference number 11, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[38] Ibid Reference number 11, July 2005, FR Vol. 70 No. 128, page 39168.

TABLE 4-9SA – Estimated Emissions and Economic Impacts Summary for NO$_X$ Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 1 – Stand Alone SCR Projects

		EMISSIONS(2)					ECONOMIC IMPACTS			
Alt. Label(1)	**NOx Control Alternative**	**Emission Rate lb/mmBtu**	**Hourly Emission lbs/hr**	**Annual Emission tons/yr**	**Emission Reduction tons/yr**	**NOx Removal Efficiency(2) %**	**Installed Capital Cost(3) $1,000**	**Annual O & M Cost(4) $1,000**	**Levelized Total Annualized Cost(5) $1,000**	**Average Control Cost(6) $/ton**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(7)	0.053	145	589	9,345	93.8(8)	222,864	20,048	44,465	4,758
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(7)	0.053	145	536	9,398	93.8(8)	222,864	29,361	56,095	5,969
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(7)	0.053	145	586	9,348	93.8(8)	180,739	16,908	36,872	3,944
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(7)	0.053	145	533	9,401	93.8(8)	180,739	27,882	50,575	5,380
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	58.1	8,113	5,417	7,472	1,265
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0	18,006	28,641	37,334(9)	6,597
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6	46,656	5,862	11,388(9)	2,037
B	FLGR w/ ASOFA	0.460	1,261	5,260	4,674	45.9	10,639	12,863	16,990(9)	3,635
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	39.5	4,277	1,695	2,489	613
	Baseline	0.849	2,330	9,934	0	0.0	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO$_X$ control level reductions relative to average annual unit emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.45 MWg and assumes a 97.3% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.45 MWg and assumes a 96.6% average running plant capacity ratio compared to nominal unit gross electrical output capacity of 253 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $1,909,000/yr for annual O&M cost.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars.

(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO$_X$ BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(8) - The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO$_X$ cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.

(9) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $2,054,000 for annualized capital cost plus $2,384,000/yr for annualized O&M cost, for a total of $4,438,000/yr.

TABLE 4-9SF – Estimated Emissions and Economic Impacts Summary for NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 1 – Shared Facilities Projects

		EMISSIONS(2)					ECONOMIC IMPACTS			
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	NOx Removal Efficiency(2) %	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(7)	0.053	145	589	9,345	93.8(8)	181,484	18,806	39,307	4,206
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(7)	0.053	145	536	9,398	93.8(8)	181,484	28,120	50,937	5,420
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(7)	0.053	145	586	9,348	93.8(8)	139,639	15,675	31,749	3,396
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(7)	0.053	145	533	9,401	93.8(8)	139,639	26,649	45,452	4,835
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	58.1	8,113	5,417	7,472	1,265
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0	18,006	28,641	37,334(9)	6,597
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6	46,656	5,862	11,388(9)	2,037
B	FLGR w/ ASOFA	0.460	1,261	5,260	4,674	45.9	10,639	12,863	16,990(9)	3,635
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	39.5	4,277	1,695	2,489	613
	Baseline	0.849	2,330	9,934	0	0.0	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO_X control level reductions relative to average annual unit emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.45 MWg and assumes a 97.3% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.45 MWg and assumes a 96.6% average running plant capacity ratio compared to nominal unit gross electrical output capacity of 253 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $1,909,000/yr for annual O&M cost.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars.

(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(8) - The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.

(9) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $2,054,000 for annualized capital cost plus $2,384,000/yr for annualized O&M cost, for a total of $4,438,000/yr.

The other elements of the fourth step of a BACT analysis following economic impacts are to evaluate the following impacts of feasible emission controls:

(1) The energy impacts.
(2) The environmental impacts.

4.2.2 ENERGY IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 1

Operation of the NO_X control technologies on the dominant controls cost curve for potential application at the Milton R. Young Station impose direct impacts on the consumption of energy required for the production of electric power at the facility. The details of estimated energy usage and costs for the previously-evaluated NO_X control alternatives were described and summarized in Section 3.4.2 and Appendix C3 of the October 2006 NOx BACT Analysis Study report[39].

The hypothetical application of Tail End and Low-Dust SCR w/ ASOFA alternatives involve higher energy consumption compared with the existing operation of MRYS Unit 1. New induced draft booster fan electrical power demand is needed due to the estimated additional flue gas pressure drop resulting from hypothetical application of SCR reactor, ductwork, and gas-to-gas heat exchangers. The additional auxiliary electric power demand for the hypothetical application of TESCR and LDSCR equipment were calculated to be 9.7 MW and 8.0 MW, respectively, using estimated annual average electrical loads of the booster fan, urea-to-ammonia conversion fired heater combustion/dilution air fan, direct-fired flue gas reheat burner combustion air fan, and service and sootblowing air compressor equipment and related auxiliary equipment.

Preliminary conceptual design details were developed for these alternatives. An estimated additional 12 inches w.c. of flue gas pressure drop was assumed for each hypothetical application of low-dust SCR system, and an estimated additional 19 inches w.c. of flue gas pressure drop was assumed for the hypothetical application of tail end SCR system. Equipment and ductwork arrangements and expected fouling of the catalyst for the hypothetical application of SCR system ductwork, reactor, and gas-gas reheater changes may cause significantly more restrictive flow paths. Thus the electrical power usage estimated here may be too low.

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[39] Ibid Reference number 3, October 2006, pages 3-31 through 3-35, and Appendix pages C3-7 through C3-10.

The expected loss of electrical power generation from these reductions in net output was included as a cost, assuming $35 per megawatt-hour for replacement electrical power. Energy impacts of installing hypothetical application of low-dust and tail end SCR alternatives for NO_X control were included in the O&M cost section (4.2.1.2.1) of this supplemental analysis as Tables C.4-2 through C.4-4.

Aqueous urea solution was assumed to be the preferred, readily available and transportable source of the amine reagent needed to supply ammonia to the SCR reactor catalyst for the low-dust and tail-end SCR alternatives. A urea-to-ammonia conversion system dedicated for each SCR reactor was also assumed. This conversion process will use a natural gas-fired burner that mixes the combustion products at high temperature with the injected aqueous urea solution to thermally decompose the urea, producing gaseous ammonia to supply to the reactors' ammonia injection grids. Gaseous ammonia is the required amine reagent that the catalyst in the SCR reactors uses to convert nitrogen oxides to elemental nitrogen and water vapor. Ammonia (from urea conversion) is supplied and consumed continuously on demand while the SCR NO_X reduction process is in operation. Natural gas is fired continuously during the urea-to-ammonia conversion system operation.

Final reactor inlet flue gas reheat systems are required for the hypothetical application of tail end and low-dust SCR with ASOFA alternatives. A natural gas-fired duct burner that injects high temperature combustion products directly into the flue gas discharged from each SCR gas/gas heat exchanger was assumed for raising the reactor inlet temperature to 600ºF before ammonia injection and NOx reduction can occur in each SCR reactor. Natural gas is fired continuously for flue gas reheating during SCR system operation.

TABLE 4-10 – Energy Impacts for NO$_X$ Control Alternatives - MRY Station Unit 1

Alt. Label(1)	NOx Control Alternative(2)	Estimated Annual Natural Gas Usage for Urea-to-Ammonia Conversion’(3) (mmBtu/yr)	Estimated Annual Natural Gas Usage for SCR Inlet Reheat’(4) (mmBtu/yr)	Estimated Annual Natural Gas Usage for Reburn Fuel’(5) (mmBtu/yr)	Estimated Additional Annual Coal Burned for Urea Solution Dilution Water’(6) (mmBtu/yr)	Estimated Total Annual Natural Gas Usage and ’ Additional Annual Coal Burned (7) (mmBtu/yr)
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	32,580	460,090	0	0	492,670
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	29,674	419,054	0	0	448,728
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	32,409	235,290	0	0	267,699
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	29,503	214,193	0	0	243,696
E	SNCR w/ ASOFA	0	0	0	54,315	54,315
D	Gas Reburn w/ ASOFA	0	0	3,721,806	0	3,721,806
C	Lignite Reburn w/ ASOFA	0	0	0	0	0
B	FLGR w/ ASOFA	0	0	1,541,796	0	1,541,796
A	Advanced SOFA (ASOFA)	0	0	0	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Alternatives are labeled the same as in Table 4-9.

(2) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO$_X$ BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(3) – Estimated annual natural gas usage for urea-to-ammonia conversion based on adjustments to preliminary budgetary equipment vendor proposals and process calculations. TESCR and LDSCR rate = 4.27 mmBtu/hr for one reactor.

(4) – Estimated annual natural gas usage for flue gas final reheat based on adjustments to preliminary vendor process calculations. TESCR rate = 60.3 mmBtu/hr for one reactor; LDSCR rate = 31 mmBtu/hr for one reactor.

(5) – Natural gas burned for reburn alternatives is assumed to replace coal, no boiler heat rate penalty assumed. Lignite reburn is assumed to burn the same total amount of coal in the boiler as without coal reburn.

(6) - Additional coal burned is due to the urea dilution water injected directly into the boiler’s upper furnace, decreasing heat available for steam production and electricity generation, at a net loss of 900 Btu/lb of water for evaporation. See Appendix C3 in the 2006 NO$_X$ BACT Analysis Study report for additional details.

(7) - Annual O&M costs include these values multiplied by the number of hours per year of operation and assume $7.98 per mmBtu for natural gas and $0.71 per mmBtu for coal.

4.2.3 ENVIRONMENTAL IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 1

Operation of the NO_X control technologies on the dominant controls cost curve for potential application at the Milton R. Young Station would impose direct and indirect impacts on the environment. The most pronounced direct environmental impact expected from operation of any of the NO_X control options considered is the reduction of ozone and improvement in atmospheric visibility (i.e., reduced visibility impairment) downwind of the facility. Environmental impacts of previously-evaluated NO_X control alternatives were described and summarized in Section 3.4.3 of the October 2006 NOx BACT Analysis Study report.[40]

There would be a favorable environmental impact from potential reduction of annual unit operating time by approximately two percent due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation and by between five percent and 17 percent due to catalyst management and SCR equipment maintenance-related issues for the various low-dust and tail end SCR alternatives. The impact of fewer annual hours of operation will be to decrease the annual amount (tons) of nitrogen oxides emitted, by between approximately 0.2 percent and one percent overall compared to baseline operation. However, generation of replacement electrical power at other powerplants will negate most of these emission reductions.

Operation of the hypothetical application of SCR systems is not expected to significantly impact emissions of carbon monoxide (CO) or volatile organic compounds (VOCs). Emissions from the urea-to-ammonia conversion and flue gas reheat natural gas-fired burners are additive and included in the flue gas entering the SCR reactor in each hypothetical application of SCR case.

Operation of any SCR system will normally cause a small amount of unreacted ammonia to be emitted. The amount of ammonia slip produced by an SCR depends on the reagent utilization and the location of the injection points. Higher SCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 2 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate $[(NH_4)_2SO_4]$ and ammonium bisulfate $[NH_4HSO_4]$ will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the catalyst to form the sulfates downstream.

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[40] Ibid Reference number 3, October 2006, pages 3-35 through 3-37.

Unreacted ammonia (“slip”) from SCR operation will not be collected downstream of the tail end SCR reactor. The wet flue gas desulfurization absorber downstream of the low-dust SCR reactor may reduce ammonia slip. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be emitted from the stack as an aerosol or condensable particulate. This has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition.

Sulfur dioxide (SO_2) formed during combustion in the boiler can combine with oxygen during passage through the hypothetical application of tail end and low-dust SCR catalyst to form additional sulfur trioxide (SO_3) emissions. SO_3 can subsequently combine with water (H_2O) to form sulfuric acid (H_2SO_4), usually in the form of a mist. Wet flue gas scrubbing to remove SO_2 is not highly effective in removing SO_3 created in an upstream low-dust SCR, so higher sulfate emissions will result unless a precipitating reaction with ammonia or condensation in the downstream gas-gas reheater or ductwork occurs. SO_3 and H_2SO_4 can have significant negative far-field impairment impacts on atmospheric visibility if they are above threshold concentrations and not controlled. Tail end SCRs can also cause a small amount of SO_3 to be created as the remaining SO_2 not removed by the wet lime flue gas desulfurization systems will pass through the catalyst and some will be oxidized. It is not known whether the high concentration of alkalinity in the form of sodium aerosol particles will effectively eliminate the remaining SO_3 downstream of the low-dust and tail end SCR systems.

Catalyst from the hypothetical application of SCR reactors will require regular replacement, requiring disposal of the spent catalyst materials or chemical cleaning to remove deposits to allow reuse or regeneration. Hauling spent catalyst to a catalyst rejuvenation facility or an authorized landfill may be required, producing additional liquid and solid wastes and vehicle exhaust emissions.

Because railroad service is not available to MRYS, shipments of amine reagent (concentrated urea solution) for consumption by the hypothetical application of SCR reactors will require additional truck traffic between the supply facility and plant, producing more emissions from vehicle exhaust.

4.2.4 SUMMARY OF ECONOMIC, ENERGY AND ENVIRONMENTAL IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 1

The economic, energy, and environmental impacts of each NO_X control technology on the dominant controls cost curve for potential application at the Milton R. Young Station evaluated for this study are summarized in this Section. Table 3-18 summarized the various impacts discussed in Sections 3.4.1 through 3.4.3 of the October 2006 NO_X BACT Analysis Study report[41]. This supplemental economic analysis examined the estimated capital cost of four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives and any other powerplant upgrade costs necessary to implement the alternatives. In addition, the economic analysis examined the operating and maintenance costs associated with each NO_X control technology evaluated. These costs were then combined into the levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each remaining alternative was evaluated. Four hypothetically-applied SCR cases and two previously-analyzed feasible alternatives were on the dominant controls cost curve and the latter were identified as the more cost effective alternatives. The four hypothetically-applied SCR cases and two previously-analyzed feasible BACT NO_X control alternatives were evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 1. The results are summarized in Tables 4-11SA and 4-11SF.

The unit control cost for the hypothetical application of Scenario A Tail End SCR w/ ASOFA case was $4,758/ton and was $5,969/ton for the hypothetical application of Scenario B Tail End SCR w/ ASOFA case (stand alone projects). The unit control cost for the hypothetical application of Scenario A Low-Dust SCR w/ ASOFA case was $3,944/ton and was $5,380/ton for the hypothetical application of Scenario B Low-Dust SCR w/ ASOFA case (stand alone projects). The unit control cost for the hypothetical application of Scenario A Tail End SCR w/ ASOFA case was $4,206/ton and was $5,420/ton for the hypothetical application of Scenario B Tail End SCR w/ ASOFA case (shared facilities projects). The unit control cost for the hypothetical application of Scenario A Low-Dust SCR w/ ASOFA case was $3,396/ton and was $4,835/ton for the hypothetical application of Scenario B Low-Dust SCR w/ ASOFA case (shared facilities projects). Unit control cost for SNCR w/ ASOFA was $1,265/ton, more than twice that of ASOFA ($613/ton). The UCCs for the hypothetical application of SCR are approximately 270 to 470 percent of the UCC for SNCR w/ ASOFA ($1,265/ton), and approximately 550 to 970 percent of ASOFA's UCC ($613/ton).

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative for MRYS Unit 1 incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control technique. The slope from zero (baseline) to ASOFA (Point A) was $613/ton; the

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[41] Ibid Reference number 3, October 2006, pages 3-20 through 3-38.

incremental cost per ton (slope) from ASOFA (Point A) to SNCR with ASOFA (Point E) was $2,694/ton for MRYS Unit 1. The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetical application of low-dust SCR case (Point L2, Scenario A) was $8,547/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetical application of tail end SCR case (Point T2, Scenario A) was $10,765/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetical application of low-dust SCR case (Point L1, Scenario B) was $12,343/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetical application of tail end SCR case (Point T1, Scenario B) was $13,936/ton (stand alone projects). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetical application of SCR cases were $7,058/ton (low-dust Point L2, Scenario A) and $9,264/ton (tail end Point T2, Scenario A). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetical application of SCR cases were $10,876/ton (low-dust, Point L1, Scenario B) and $12,458/ton (tail end Point T1, Scenario B).

The incremental unit control cost per ton (slope) from SNCR with ASOFA to the hypothetical application of SCR with ASOFA cases are approximately 260 to 520 percent of the incremental UCC per ton (slope) between ASOFA and SNCR with ASOFA ($2,694/ton). The incremental UCCs from SNCR with ASOFA to the hypothetical application of SCR with ASOFA cases is between 11 and 23 times the incremental UCC for ASOFA from the pre-control baseline ($613/ton).

In the U.S. EPA’s NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. EPA’s NSR Manual however, does specifically address the standard to be used when rejecting a candidate technology on the basis of adverse economic impact:

> “Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source.”[42]

This supplemental report for the MRYS NOx BACT Analysis has clearly established the circumstances, including the economic impacts, which would make the hypothetical application of TESCR or LDSCR to

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[42] Ibid Reference number 2, Section IV.D.2.c.

MRYS Unit 1 significantly more expensive than SCR costs normally incurred by other coal-fired steam electric generating units. The following information further supports EPA's own statements regarding the costs "normally incurred by other sources". The EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines was considered relevant for control cost-effectiveness comparison. The EPA's cost-effectiveness analysis used for establishing presumptive BART stated that "applying SCR for coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton" [43]. EPA's technical support document estimated an average control cost for SCR applied to MRYS Unit 1 of $549 per ton[44]. The unadjusted unit capital cost factor assumed by the EPA for SCR retrofits applied to cyclone boilers in the cost-effectiveness analysis used for establishing presumptive BART[45] was $100/kW. The estimated "stand alone" and "shared facilities" installed capital costs for the hypothetical application of Low-Dust SCR w/ ASOFA cases at MRYS Unit 1 are $543 to $703/kW, which is more than 500 percent of the EPA's number. The estimated "stand alone" and "shared facilities" installed capital costs for the hypothetical application of Tail End SCR w/ ASOFA cases are $706 to $867/kW, which is more than 700 percent of the EPA's number. Also stated in the final RHR/BART Guidelines, "the average cost for each [of two options, A and B]… may be deemed to be reasonable. However, the incremental cost…of the additional emissions reductions to be achieved by control B may be very great. In such an instance, it may be inappropriate to chose control B, based on its higher incremental costs, even though its average cost may be considered reasonable".[46]

4.2.5 CONCLUSIONS

The site-specific control costs estimated for application of hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines discussed above.

The expected severity of catalyst blinding and pluggage from particulate matter and flue gases emitted from cyclone-fired boilers burning North Dakota lignite precludes the technical feasibility for successful application of such SCR technologies on the electric generating units (EGUs) at the Milton R. Young Station. Not withstanding the technical discussion of SCR technology infeasibility and technical details

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[43] See Reference number 11, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[44] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.
[45] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 209.
[46] Ibid Reference number 11, July 2005, FR Vol. 70 No. 128, page 39168.

previously provided in Appendix A1 and Appendix B[47] of the initial NO_X BACT Analysis report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, this supplemental analysis concludes that the estimated capital and O&M costs for four variations of hypothetically-applied tail-end and low-dust SCR technology alternatives are significantly beyond the normal range of costs incurred, as compared to cost analysis values included in EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines[48,49]. Average control cost effectiveness for each hypothetical application of SCR control technology case is a minimum of approximately three times the unit control costs of the previously-analyzed highest-performing feasible control alternative recommended as BACT for MRYS Unit 1 (SNCR with ASOFA). Incremental control cost effectiveness for each hypothetical application of SCR control technology case is a minimum of approximately three times the incremental control costs of the previously-analyzed highest-performing feasible control alternative recommended as BACT for MRYS Unit 1 (SNCR with ASOFA).

There is an expected decrease in capacity and availability to generate electrical power due to the hypothetical application of low-dust and tail end SCR alternatives. A five to 17 percent decrease in the number of hours of annual operation, and approximately 3% drop in annual plant capacity (net electrical output or MW_n) during operation of the MRYS Unit 1 system are expected if the hypothetical application of low-dust or tail end SCR alternatives were installed. There are also substantial expected negative energy impacts for each hypothetical application of SCR control technology case. Additional auxiliary electrical power demands of approximately 8 to 10 MW will result. This estimate of electrical power usage may be too low. This higher electrical power consumption and lower electrical power generation by MRYS Unit 1 will require additional replacement electrical power to be generated elsewhere.

Natural gas is fired continuously during the urea-to-ammonia conversion system operation for the hypothetical application of Tail End and Low-Dust SCR with ASOFA alternatives.

Final reactor inlet flue gas reheat systems are required for the hypothetical application of Tail End and Low-Dust SCR with ASOFA alternatives. Natural gas is fired continuously for flue gas reheating during SCR system operation for raising the reactor inlet temperature to 600ºF before ammonia injection and NOx reduction can occur in the SCR reactor.

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[47] Ibid Reference number 3, October 2006.
[48] See Reference number 11, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[49] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.

The site-specific control costs estimated for application of hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines[50]. SCR technologies of all three types identified in the October 2006 NO_X BACT Analysis Study report should be excluded from consideration for NO_X control at MRYS due to unacceptably high average and incremental cost per ton of pollutant removal based on the supplemental analysis provided herein. Therefore the conclusions regarding NOx BACT as expressed in the original October 2006 BACT Analysis for MRYS Unit 1 are confirmed.

The economic, energy, and environmental impacts of each NO_X control technology on the dominant controls cost curve for potential application to Unit 1 at the Milton R. Young Station evaluated for this study are summarized in Tables 4-11SA and 4-11SF.

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[50] See Reference number 4, July, 2005.

TABLE 4-11SA – Summary of Supplemental BACT Analysis Impact Results for Dominant NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

		EMISSIONS(2)				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS(9)	
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton	Incremental Control Cost(7) $/ton	Incremental Aux. Power Demand(8), kW	Incremental Annual Aux. Power Usage + Generation Reduction(8), kW-hrs/yr	Non-Air Increase	Toxic Air Increase
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(10)	0.053	145	589	9,345	222,864	20,048	44,465	4,758	10,765	9,685	171,745,369	Flyash UBC, catalyst disposal	CO, NH_3
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(10)	0.053	145	536	9,398	222,864	29,361	56,095	5,969	13,936	9,685	342,358,537	Flyash UBC, catalyst disposal	CO, NH_3
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(10)	0.053	145	586	9,348	180,739	16,908	36,872	3,944	8,547	8,012	169,418,356	Flyash UBC, catalyst disposal	CO, NH_3
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(10)	0.053	145	533	9,401	180,739	27,882	50,575	5,380	12,343	8,012	341,140,028	Flyash UBC, catalyst disposal	CO, NH_3
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	8,113	5,417	7,472	1,265	2,694	73	68,243,017	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	4,277	1,695	2,489	613	613	1	46,594,605	Flyash UBC	CO
	Baseline	0.849	2,330	9,934	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars.

(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit reliability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr) compared to the pre-control baseline.

(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative compared to the pre-control baseline. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations may increase an insignificant amount with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology and the hypothetical application of SCR technology cases.

(10) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

TABLE 4-11SF – Summary of Supplemental BACT Analysis Impact Results for Dominant NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

		EMISSIONS(2)				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS(9)	
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton	Incremental Control Cost(7) $/ton	Incremental Aux. Power Demand(8), kW	Incremental Annual Aux. Power Usage + Generation Reduction(8), kW-hrs/yr	Non-Air Increase	Toxic Air Increase
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(10)	0.053	145	589	9,345	181,484	18,806	39,307	4,206	9,264	9,685	171,745,369	Flyash UBC, catalyst disposal	CO, NH_3
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(10)	0.053	145	536	9,398	181,484	28,120	50,937	5,420	12,458	9,685	342,358,537	Flyash UBC, catalyst disposal	CO, NH_3
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(10)	0.053	145	586	9,348	139,639	15,675	31,749	3,396	7,058	8,012	169,418,356	Flyash UBC, catalyst disposal	CO, NH_3
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(10)	0.053	145	533	9,401	139,639	26,649	45,452	4,835	10,876	8,012	341,140,028	Flyash UBC, catalyst disposal	CO, NH_3
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	8,113	5,417	7,472	1,265	2,694	73	68,243,017	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	4,277	1,695	2,489	613	613	1	46,594,605	Flyash UBC	CO
	Baseline	0.849	2,330	9,934	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability.
(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars.
(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.
(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars.
(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit reliability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr) compared to the pre-control baseline.
(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative compared to the pre-control baseline. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations may increase an insignificant amount with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology and the hypothetical application of SCR cases.
(10) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

1. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.

2. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").

3. "BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc." and a separate "BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc." Final Report, October 2006 submitted by Minnkota to North Dakota Department of Health.

4. Technical Support Document Methodology For Developing BART NOx Presumptive Limits, Environmental Protection Agency, Clean Air Markets Division, June 15, 2005, OAR-2002-0076-0445, with Attachments, including Excel Spreadsheet OAR-2002-0076-0446 (1199 pages).

5. Comment & Response to EPA Region 8's October 4, 2007 Comment on NDDH BACT Determination at Milton R. Young Station, submitted by Minnkota to NDDH, November 9, 2007.

6. EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034, dated March, 2005, posted at their website: http://www.epa.gov/airmarkets/articles/multireport2005.pdf.

7. "Assessment of Control Technology Options for BART-Eligible Sources, Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities", dated March 2005, prepared by Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic/Northeast Visibility Union, posted at the website: http://bronze.nescaum.org/committees/haze/BART_Control_Assessment.pdf.

8. "Analysis of Combustion Controls for Reducing NO_X Emissions From Coal-fired EGU's in the WRAP Region, Draft Report", prepared for the Western Regional Air Partnership by Eastern Research Group, Inc., ERG Contract Number 30204-101, dated April 26, 2005, available at: http://www.wrapair.org/forums/ssjf/documents/eictts/NOxEGU/050426Coal-fired%20EGUs_in_WRAP_Region-draft.pdf

9. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

10. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 2 - Selective Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch2.pdf

11. Federal Register /Vol. 70, No. 128/ Wednesday, July 6, 2005 / Rules and Regulations, Part III Environmental Protection Agency 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule.

NOx BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS STUDY

- SUPPLEMENTAL REPORT

for

Milton R. Young Station Unit 1

Minnkota Power Cooperative, Inc.

November 2009

Revised February 2010
(refer to page TOC-3 for Index of Revisions)

31777

Minnkota Power
MPC COOPERATIVE, INC.
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SINCE 1898

NOx Best Available
Control Technology
Analysis Study
SUPPLEMENTAL REPORT
for
Milton R. Young Station Unit 1

prepared for

Minnkota Power Cooperative, Inc.

November 2009

Revised February 2010
(refer to page TOC-3 for Index of Revisions)

Project No. 31777

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

INDEX AND CERTIFICATION

Minnkota Power Cooperative, Inc.
Milton R. Young Station Unit 1
NO_X Best Available Control Technology Analysis Study
SUPPLEMENTAL REPORT

Project 31777

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Certification

I hereby certify, as a Professional Engineer registered in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the laws and rules of the North Dakota State Board of Registration under Title 28 Administrative Code.

ROBERT D. BLAKLEY
PE - 5658
DATE 2/11/2010

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4.0 SUPPLEMENTAL NOx BACT ANALYSIS CONTROLS & COSTS – MRY STATION UNIT 1

This supplement to the NO_X BACT analysis for Milton R. Young Station (MRYS) Unit 1 has been prepared in response to the request of the North Dakota Department of Health[1]. The NDDH requested completion of a "full" BACT analysis for two specific technologies that had been eliminated at step 2 of the BACT analysis process[2] in the October 2006 NO_X BACT Analysis Study report[3]. These two technologies are low-dust selective catalytic reduction (SCR) and tail-end SCR. The approach taken in this supplemental NO_X BACT Analysis Study report for MRYS Unit 1 includes ranking by effectiveness and providing an impacts analysis of alternate control technologies for NO_X emissions that follows the third and fourth steps of a "top down" BACT analysis as described in the EPA's Draft New Source Review Workshop Manual[4]. The initial NO_X BACT Analysis Study for Milton R. Young Station identified potentially available NO_X control techniques and technologies, summarized in Table 3-3[5] of the October 2006 report. Commonly-applied and novel NO_X control techniques and technologies, including a technical description of the specific emission reduction processes and capabilities, were summarized in Section 3.2[6] and detailed in Appendix A1 of the initial NO_X BACT Analysis Study report. This supplemental analysis report does not include the details of the technical feasibility discussion previously provided in the initial NO_X BACT Analysis Study report for MRYS Unit 1.

SCR technology is considered technically infeasible by Minnkota for application at MRYS, so this information for the hypothetical application of low-dust and tail end SCR alternatives is included for comparative purposes only. Cost estimates and emission rates shown for such hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation, operation and maintenance of the SCR equipment on this boiler are solvable. There is no available information on recently-completed similar tail-end or low-dust SCR projects on coal-fired powerplants in the United States that could be used, with adjustments, to represent total installed costs that could be expected for MRYS Unit 1. Site-specific needs and challenges identified for applying tail end and low-dust SCR technologies to Milton R. Young Station Unit 1 significantly influence the capital cost estimate for variations of these hypothetical applications of SCR alternatives. Furthermore, the

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[1] See Reference number 1, July 2009 and August 2009.

[2] As described in the EPA's Draft New Source Review Workshop Manual. See Reference number 2, October 1990.

[3] See Reference number 3, October 2006. This Supplement commences with Section 4.0, which places it at the end of the October 2006 Analysis, which ended at Section 3.5.2.

[4] As described in the EPA's Draft New Source Review Workshop Manual. Ibid Reference number 2, October 1990.

[5] Ibid Reference number 3, October 2006, page 3-5.

[6] Ibid Reference number 3, October 2006, page 3-6 through page 3-13, and pages A1-1 through A1-55.

"EPA Air Pollution Control Cost Manual" is not applicable for use in estimating control equipment costs for these hypothetical applications of SCR technologies, as the EPA Control Cost Manual states:

> "The costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements."[7]

This requirement for flue gas reheating also applies to the hypothetical application of low-dust SCR to MRYS, due to the cold-side arrangement (downstream of the electrostatic precipitator) instead of a hot-side ESP assumed in the EPA Control Cost Manual. Therefore, the equations in the EPA Control Cost Manual cannot be used for estimating either of the hypothetical applications of SCR configurations for which NDDH has requested economic analyses. Thus it was necessary to prepare independent site-specific cost estimates.

The site-specific control costs estimated for hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines[8]. Low-dust and tail end SCR technologies should be excluded from consideration for NO_X control at MRYS due to unacceptably high average and incremental cost per ton of pollutant removal based on the supplemental analysis provided herein. The October 2006 NO_X BACT Analysis Study report, and additional subsequent arguments included in responses to comments by the EPA, Department of Justice (DOJ), NDDH, and other parties[9], also present reasons for technical infeasibility of all SCR technologies considered for application at MRYS not included in this supplemental analysis report. In addition, the fact that catalyst vendors will not guarantee catalyst life on such SCR technologies without successful results from extensive pilot slipstream testing bolsters the previous submitted arguments of technical infeasibility of these NO_X control alternatives at MRYS.

4.0.1 ADDITIONAL NOx CONTROLS

The inclusion of hypothetical emissions control alternatives employing tail-end and low-dust SCR technologies in this supplemental NO_X BACT Analysis Study report does not constitute agreement by

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[7] See Reference number 10, Section 4.2, Chapter 2, page 2-41, October 2000.
[8] See Reference number 4, June, 2005.
[9] Responses submitted by Minnkota in 2007-2009.

Minnkota that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The rationale for rejection of all forms of SCR technology in this specific case, based on an interpretation of the EPA's Draft New Source Review Workshop Manual[10], has previously been submitted to the North Dakota Department of Health[11] and is not repeated herein. Nevertheless, this supplemental NO_X BACT Analysis Study report has been completed based on the *hypothetical assumption* that these two technologies pass the test for technical feasibility. The development of NO_X emissions control alternatives involving hypothetical application of technologies such as low-dust and tail end SCR systems at MRYS is based on preliminary plant layout design concepts that require pilot-scale slipstream SCR testing and more detailed equipment design for confirmation that all technical infeasibility issues previously raised have been, or can be, satisfactorily resolved. This supplemental analysis includes estimated capital costs and operating and maintenance (O&M) costs for four variations of alternatives involving hypothetical applications of tail-end and low-dust SCR technologies. Cost effectiveness for each hypothetically-applied SCR control technology case was plotted with previously-analyzed feasible control alternatives.

For the techniques and technologies considered for determining MRYS Unit 1 NO_X control cost-effectiveness, estimates were produced for predicted NO_X reductions that represent long-term expectations of the reduction techniques and technologies being presented in the technical analysis. Each evaluated alternative was tabulated and graphed.

It should be noted that as of October 2006, when the initial BACT Analysis Study report was completed, MRYS Unit 1 did not employ combustion-related or post-combustion NO_X emission reduction technology. However, the installation of an advanced form of a separated overfire air system (ASOFA), designed specifically for this boiler, is being implemented for operation starting prior to December 31, 2009. A summary of the available alternate NO_X emission control technologies is discussed below.

4.1 RANK OF NO_X CONTROL OPTIONS BY EFFECTIVENESS

The first step[12] in this supplemental "top-down" BACT evaluation is to determine the expected control effectiveness of the hypothetical application of tail end and low-dust SCR technology alternatives, so that they may be compared and ranked relative to the technically-feasible NO_X control techniques and

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[10] Ibid Reference number 2, October 1990.
[11] See Reference number 5, November 2007.
[12] Step 3 per the NSR Manual, Ibid Reference 2, October 1990.

technologies included from the initial NO_X BACT Analysis Study report. To do this, we start with the basis for determining the NOx emissions control effectiveness, which is the historic baseline emissions expressed in pounds per million Btu of heat input from the five-year lookback period.

Unit 1 boiler's baseline pre-control emissions at Milton R. Young Station are based upon the same highest rolling 12-month average unit emission rate (lb/mmBtu) and corresponding highest rolling 12-month average gross heat input rate (mmBtu/hr) that were reported in 2001-2005:

- MRYS Unit 1's highest 12-month NO_X mass emissions averaged 0.849 lb/mmBtu at a corresponding average unit heat input rate of 2,744 mmBtu/hr and unit gross electrical output of 244.5 MW_g.
- During this lookback time period, Unit 1 at Milton R. Young Station was typically operated in a base-loaded manner.

4.1.1 ESTIMATING CONTROL-EFFECTIVENESS OF NO_X EMISSIONS CONTROL OPTIONS

The estimated emission control performance for NO_X control techniques and technologies included from the initial NO_X BACT Analysis Study report is assumed to be the same as previously stated in Table 3-7[13]. The expected control effectiveness of the hypothetical application of tail end and low-dust SCR technology alternatives was added to the listing of highest-performing NO_X control alternatives remaining in consideration following the initial technical infeasibility determinations. These alternatives are ranked in declining order of expected emission reduction. These combined control options refer to "advanced" separated overfire air (ASOFA), and include the expected reduction from operating with modestly air-staged cyclone furnaces and relocated lignite drying system vent ports as applied to this Milton R. Young Station cyclone boiler without incurring potential significant negative impacts of this technique. This level of expected NO_X reduction from ASOFA operation is approximately forty percent below the pre-control baseline emissions rate of 0.849 lb/mmBtu.

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[13] Ibid Reference number 3, October 2006, page 3-18.

TABLE 4-1 – Ranked NO_X Control Options for MRY Station Unit 1 Boiler with Expected Control Performance

Alt. Label(1)	NO_X Control Alternative	Emission Rate (lb/mmBtu)	Control Percentage(2)
T2	Hypothetical Tail-End SCR w/ ASOFA – Scenario A(3)	0.053	93.8(4)
T1	Hypothetical Tail-End SCR w/ ASOFA – Scenario B(3)	0.053	93.8(4)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(3)	0.053	93.8(4)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(3)	0.053	93.8(4)
E	SNCR (using urea) w/ ASOFA	0.355	58.1
D	Gas Reburn with ASOFA	0.374	56.0
C	Lignite Reburn w/ ASOFA	0.385	54.6
B	Fuel Lean Gas Reburn with ASOFA	0.460	45.9
A	Advanced Separated Overfire Air (ASOFA)	0.513	39.5
-	Baseline	0.849	-

(1) - Alternative designation assigned from highest to lowest unit NOx emission rate.

(2) - Control percentages are relative to an average pre-control emission baseline of 0.849 lb/mmBtu based on annual operation at highest pre-control 12-month rolling NOx summation mass emissions divided by the 12-month heat input summation.

(3) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The emission rate shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(4) The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate for hypothetically-applied SCR alternatives would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.

All hypothetical applications of tail-end and low-dust SCR technology alternatives were assumed to achieve a NO_X emission level of 0.053 lb/mmBtu, which is approximately 90% reduction from a 0.51 lb/mmBtu level representing ASOFA when operating modestly air-staged cyclone furnaces with suitable combustion controls.

Hourly mass emission rates for the baseline pre-control condition were calculated by multiplying the unit emission rate (lb/mmBtu) by the average hourly gross heat input rate (mmBtu/hr), both calculated from Unit 1’s highest 12-month NO_X mass emissions and heat inputs during the 5-year lookback period.

Equivalent annual NO_X emissions (tons) were calculated by multiplying the 12-month summation for unit operating hours during the same period as the highest NO_X emissions by the 12-month average mass emission rate (lb/hr) and dividing by 2000 lb/ton.

The annual tons for the control options were calculated by multiplying the alternative's equivalent average annual hourly mass emission rate (lb/h) by the equivalent annual unit operating hours [8,760 h/yr maximum possible operating time, adjusted by an annual uptime (availability) factor]. Scheduled and unplanned maintenance outages are expected to occur due to each hypothetically-applied SCR system. Catalyst cleaning and replacement events have been estimated, with two frequencies showing a range of possible results. Due to the variability and possible severity of fouling characteristics of gaseous and aerosol particulate emissions generated by cyclone combustion of lignite supplied from the Center mine, and the dependency of the fouling within the hypothetically-applied SCR systems on sodium, potassium, sulfur, and ammonia slip emission levels, conditions may occur during operation of the hypothetically-applied SCR systems that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the deposits or prevent significant catalyst deactivation. Table C.4-1 in Section 4.2.1.2.1 includes estimated unit availability and corresponding operating time and outage time due to the four hypothetical applications of SCR technology cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[14]. Based on these calculations, the estimated annual emissions for M.R. Young Station Unit 1 and the emission reduction corresponding to each technology alternative are shown in Table 4-2.

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[14] Ibid Reference number 3, October 2006, pages C3-1 through page C3-11.

TABLE 4-2 – Expected Annual NO_X Control Performance for MRY Station Unit 1 Alternatives

		EMISSIONS				
Alt. Label(1)	**NOx Control Alternative**	**Emission Rate lb/mmBtu**	**Hourly Emission(2) lbs/hr**	**Annual Emission(3) tons/yr**	**Emission Reduction(4) tons/yr**	**NOx Removal Efficiency(5) %**
T2	Hypothetical Tail End SCR w/ ASOFA– Scenario A(6)	0.053	145	589	9,345	93.8(7)
T1	Hypothetical Tail End SCR w/ ASOFA– Scenario B(6)	0.053	145	536	9,398	93.8(7)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	0.053	145	586	9,348	93.8(7)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	0.053	145	533	9,401	93.8(7)
E	SNCR (using urea) w/ ASOFA	0.355	975	4,025	5,909	58.1
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6
B	Fuel Lean Gas Reburn w/ ASOFA	0.460	1,261	5,260	4,674	45.9
A	Advanced Separated Overfire Air (ASOFA)	0.513	1,409	5,874	4,060	39.5
-	Baseline	0.849	2,330	9,934	0	-

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Hourly NO_X emission estimates (lb/hr) were calculated based upon average annual unit emission rate (lb/mmBtu) x 2,744 mmBtu/hr heat input.

(3) - Estimated annual emission tons assume an annual unit availability factor specific to each alternative; 97.3% was assumed for the baseline case. See Appendix C3 of the October 2006 NO_X BACT Analysis Study report. Hypothetical application of tail end SCR case T2 assumes an annual unit availability factor of 92.8% (approx. 8,127 operating hours per year) and case T1 assumes an annual unit availability factor of 84.5% (approx. 7,402 operating hours per year). Hypothetically-applied low-dust SCR case L2 assumes an annual unit availability factor of 92.3% (approx. 8,084 operating hours per year) and case L1 assumes an annual unit availability factor of 84.0% (approx. 7,359 operating hours per year).

(4) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

(5) - Estimated NO_X control level percentage reductions relative to 0.849 lb/mmBtu emission baseline at 2,744 mmBtu/hr MCR heat input.

(6) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The emission rate shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - The stated overall control percentage includes the anticipated long-term emission reduction of approximately 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate for hypothetically-applied SCR alternatives would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.

4.2 NO_X CONTROLS ANALYSIS AND IMPACTS EVALUATION

The next step[15] of this supplemental “top-down” BACT analysis is to evaluate the impacts of the hypothetical application of SCR alternatives’ NO_X emission controls. Energy, economic, and environmental impacts are to be considered in the control technology evaluation. The purpose of the evaluation is to determine if there are any energy, economic or environmental impacts that would eliminate the top control technologies from consideration.

This evaluation of the effectiveness of the hypothetically-applied SCR alternatives, as well as that of the other control technologies previously considered technically feasible, was performed prospectively, i.e., assuming that none of the control technologies has been implemented. This approach assumes that the hypothetical application of SCR technology cases are considered to have been added to the previous NO_X BACT Analysis Study report submitted in October, 2006. The actual costs incurred for an installed advanced separated overfire air system, or firm price equipment quotes with performance guarantees for SNCR alternatives, have not been used to adjust the control effectiveness or cost impacts of the previously analyzed control alternatives. The approach taken in this supplemental analysis use installed capital costs estimated in calendar year 2009 escalated to project completion forecast in 2018 adjusted to calendar year 2006 basis for the hypothetically-applied tail end SCR and low-dust SCR technology cases that have been added to the list of alternatives previously evaluated.

4.2.1 NO_X CONTROL ECONOMIC IMPACTS FOR MRY STATION UNIT 1

An evaluation was performed to determine the various cost impacts of installing previously-analyzed feasible NO_X control alternatives and the hypothetical application of low-dust and tail end SCR technologies on Milton R. Young Unit 1. This evaluation includes estimated:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, design, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 4-3 through 4-11.

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[15] Step 4 per the NSR Manual, Ibid Reference 2, October 1990.

4.2.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROL ALTERNATIVES

The range of estimated capital costs to implement some of the various NO_X control technologies were derived from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. For MRY Station Unit 1, for the cases involving the use of advanced separated overfire air and SNCR alternatives, preliminary project cost estimates using vendor budgetary cost information were developed and used in place of, or to adjust, the published unit output cost factors. A discussion of the reburn alternatives' estimated capital costs was included in the 2006 NO_X BACT Analysis Study report and has not been repeated here. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

For the hypothetical application of low-dust and tail end SCR alternatives at MRYS, there is no available information on recently-completed similar projects on coal-fired powerplants in the United States that could be used, with adjustments, to properly represent total installed costs that could be expected for MRYS Unit 1. For these alternatives, site-specific detailed preliminary (conceptual) designs were developed and budgetary cost information for major equipment was obtained for the development of the estimated installed capital cost.

The unit nameplate output capacity (gross electrical output in megawatts) assumed for the installed capital cost estimate basis of the NO_X control technologies evaluated was 257 MW_g for MRY Station Unit 1[16].

A review of the unit capital cost factor range and single point factors applicable to MRY Station Unit 1 NO_X control technologies are presented in Tables 4-3SA and 4-3SF. Note that the capital cost estimates for the hypothetical application of SCR alternatives were developed separately based on two different assumptions. In one case it was assumed that all costs for the hypothetically-applied Unit 1 SCR (tail end or low-dust) system would be accounted for as if the SCR equipment were being provided for Unit 1 only. This is referred to as the "stand alone" (SA) case, and all tables showing those costs are identified with that suffix. In the other case, it was assumed that the retrofit of hypothetically-applied SCR systems was being done for both Unit 1 and Unit 2, and there are some components that could be shared between the two units. This is referred to as the "shared facilities" (SF) case, and all tables showing those costs are identified with that suffix.

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[16] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 390.

Per the EPA's NSR Manual, a BACT analysis is done on a "case-by-case basis"[17]. The "stand alone" estimated total project capital costs for the hypothetical application of SCR alternatives reflect the economic impacts incurred as a result of implementing such technologies on each individual unit at MRYS independent of what may be determined or assumed for other units at this facility or similar units at other facilities. The "shared facilities" estimated total project capital costs for the hypothetical application of SCR alternatives do not account for all economic impacts borne strictly by the unit subject to the analysis, and, as such, are subsidized by the unit(s) involved with the shared facilities. In this "shared facilities" approach, a BACT would be performed more in the manner of a "case-within-a-case" instead of on a "case-by-case" basis. Additionally, BACT is not to be applied on a facility basis. Units having different characteristics, (size, etc.) may have different technologies as BACT. Therefore, each unit should be treated as a separate "stand alone" case. Although the authors believe the "stand alone "case is the proper approach to use, information for both cases has been provided.

TABLE 4-3SA – Unit Capital Cost Factors of NO_X Control Alternatives for MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	**NO_X Control Alternative**	**Range(2) (\$/kW)**	**Single Point Unit Capital Cost Factor(3), (\$/kW) MRYS Unit 1**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	(4)	867(4),(5)
T1	Hypothetical Tail End SCR w/ ASOFA –Scenario B(4)	(4)	867(4),(5)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	(4)	703(4),(5)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	(4)	703(4),(5)
E	SNCR (using urea) w/ ASOFA	20-35(6)	31.6(5),(6)
D	Gas Reburn w/ ASOFA	15-30(7)	70.1(5),(7),(8)
C	Lignite Reburn w/ ASOFA	30-60(7)	181.5(5),(7),(9)
B	Fuel Lean Gas Reburn w/ ASOFA	--(6)	41.4(5),(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	16.6(5)

(1) - Alternative designation has been assigned from highest to lowest unit NOx emission rate.
(2) - Unit capital cost factors (\$/kW) of these individual technologies combined by simple addition. Actual installed costs may differ from this due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) - Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on EPA's nameplate rating. Single point cost figures in 2006 dollars.
(4) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The single point unit capital cost factor shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical

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[17] Ibid Reference 2, October 1990, Chapter B. Introduction page B1.

infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Due to the site-specific nature of factors influencing cost, no comparable cost data ranges for these technologies exist in the literature. A cost range for conventional high-dust SCR technology published in the 2005 EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034[18] was $55 to $150/kW. Single point unit capital cost factors were derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006$ as described in the text.

(5) - The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(6) - Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. See Appendix C2 of the October 2006 NO_X BACT Analysis Study report for details[19].

(7) - NESCAUM 2005 Technical Paper[20]; reburn alternatives on page 2-22, overfire air on page 2-23; posted at their website. See technical references in Appendix A1 of the October 2006 NO_X BACT Analysis Study report for details.

(8) - The single point unit capital cost factor shown for a conventional or fuel-lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW or 15.7 $/kW, respectively), and that both MRYS boilers share the capital cost in proportion to their respective rated MW gross output capacities.

(9) - The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report[21], posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 91.7 $/kW. See technical references in Appendix A1 of the October 2006 BACT Analysis report for details.

TABLE 4-3SF – Unit Capital Cost Factors of NO_X Control Alternatives for MRY Station Unit 1 – Shared Facilities SCR Projects

Alt. Label(1)	NO_X Control Alternative	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3), ($/kW) MRYS Unit 1
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	(4)	706(4),(5)
T1	Hypothetical Tail End SCR w/ ASOFA –Scenario B(4)	(4)	706(4),(5)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	(4)	543(4),(5)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	(4)	543(4),(5)
E	SNCR (using urea) w/ ASOFA	20-35(6)	31.6(5),(6)
D	Gas Reburn w/ ASOFA	15-30(7)	70.1(5),(7),(8)
C	Lignite Reburn w/ ASOFA	30-60(7)	181.5(5),(7),(9)
B	Fuel Lean Gas Reburn w/ ASOFA	--(6)	41.4(5),(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	16.6(5)

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[18] See Reference number 6, March 2005, page 3-63.
[19] See Reference number 3, October 2006, pages C2-3 and C2-7.
[20] See Reference number 7, March 2005.
[21] See Reference number 8, April 2005, page 3-9.

(1) - Alternative designation has been assigned from highest to lowest unit NOx emission rate.

(2) - Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ from this due to positive or negative synergistic effects. Range based on published values or vendor proposals.

(3) - Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on EPA's nameplate rating. Single point cost figures in 2006 dollars.

(4) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The single point unit capital cost factor shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Due to the site-specific nature of factors influencing cost, no comparable cost data ranges for these technologies exist in the literature. A cost range for conventional high-dust SCR technology published in the 2005 EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034[22] was $55 to $150/kW. Single point unit capital cost factors were derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006$ as described in the text.

(5) - The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(6) - Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. See Appendix C2 of the October 2006 NO_X BACT Analysis Study report for details[23].

(7) - NESCAUM 2005 Technical Paper[24]; reburn alternatives on page 2-22, overfire air on page 2-23; posted at their website. See technical references in Appendix A1 of the October 2006 NO_X BACT Analysis Study report for details.

(8) - The single point unit capital cost factor shown for a conventional or fuel-lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW or 15.7 $/kW, respectively), and that both MRYS boilers share the capital cost in proportion to their respective rated MW gross output capacities.

(9) - The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report[25], posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 91.7 $/kW. See technical references in Appendix A1 of the October 2006 BACT Analysis report for details.

4.2.1.1.1 CAPITAL COST ESTIMATES FOR HYPOTHETICAL APPLICATION OF SCR NO_X CONTROL ALTERNATIVES

There is no available information on recently-completed similar tail-end or low-dust SCR projects on coal-fired powerplants in the United States that could be used, with adjustments, to properly represent total installed costs that could be expected for MRYS Unit 1. Site-specific needs and challenges identified for applying tail end and low-dust SCR technologies to Milton R. Young Station Unit 1 significantly influence the capital cost estimate for variations of these hypothetically-applied SCR alternatives. Furthermore, the "EPA Air Pollution Control Cost Manual" is not applicable for use in estimating control equipment costs for these hypothetical applications of SCR technology cases, as the EPA Control Cost Manual states:

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[22] See Reference number 6, March 2005, page 3-63.

[23] See Reference number 3, October 2006, pages C2-3 and C2-7.

[24] See Reference number 7, March 2005.

[25] See Reference number 8, April 2005, page 3-9.

> "The costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements."[26]

This requirement for flue gas reheating also applies to the hypothetical applications of low-dust SCR technology to MRYS, due to the cold-side arrangement (downstream of the electrostatic precipitator) instead of a hot-side ESP assumed in the EPA Control Cost Manual. Therefore, the equations in the EPA Control Cost Manual cannot be used for estimating either of the hypothetical application of SCR configurations for which NDDH has requested economic analyses. Thus it was necessary to prepare independent site-specific cost estimates.

The installed capital costs for hypothetical application of tail end and low-dust SCR alternatives were estimated by Burns & McDonnell with inputs from an SCR system supplier with recent design experience involving these SCR configurations, equipment suppliers, and catalyst suppliers with significant European project experience in such technology. Both hypothetically-applied low-dust and tail end SCR designs for MRYS Unit 1 assume one reactor / gas reheat system installed, connecting to the new wet lime flue gas desulfurization absorber currently being constructed. Each hypothetically-applied SCR alternative includes flue gas reheat equipment that is typical for these applications but not required for conventional high-dust/hot side SCR systems. The estimated flue gas volume at a gross boiler heat input and oxygen content corresponding to unit gross nameplate output capacity determined the size of the hypothetically-applied single SCR reactor for these cases. Structures, foundations, ductwork, balance of plant equipment and materials were quantified and included with the hypothetically-applied SCR equipment, which were factored for installation costs. Escalation of project costs, including equipment, materials, engineering and labor costs, is included, along with interest during construction, due to the expected project execution duration being significantly longer than for the other alternatives. Price and scope contingencies were included to account for the uncertainties that the current preliminary design scope and pricing fully reflects what would be necessary to complete implementation of these hypothetically-applied alternatives. Total project costs were considered to be a future value from a financial perspective, which were returned to a 2009 calendar year basis using a present value factor at the 2.5% per year annual discount rate previously assumed in the 2006 NO_X BACT Analysis Study report. A ratio of regional construction cost indices for public utility construction costs between 2006 and 2009 was used to adjust the 2009 total estimated project costs to a 2006 calendar year basis for each of the hypothetically-applied SCR alternatives.

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[26] See Reference number 10, Section 4.2, Chapter 2, page 2-41, October 2000.

The estimated installed and levelized annual capital costs for the hypothetically-applied SCR systems and previously-analyzed highest-performing form of the various feasible NO_X emission reduction technologies evaluated for cost-effectiveness are shown in Table 4-4SA and Table 4-4SF. These technologies are listed in order of control effectiveness, with the highest ranked option at the top.

TABLE 4-4SA – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	**NOx Control Alternative**	**Installed Capital Cost(2) $1,000**	**Annualized Capital Cost(3) $1,000**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	222,864(4)	19,430(4)
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	222,864(4)	19,430(4)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	180,739(4)	15,758(4)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	180,739(4)	15,758(4)
E	SNCR w/ ASOFA	8,113	707
D	Gas Reburn w/ ASOFA(5)	18,006	1,570
C	Lignite Reburn w/ ASOFA(6)	46,656	4,068
B	Fuel Lean Gas Reburn w/ ASOFA(5)	10,639	928
A	Advanced SOFA (ASOFA)	4,277	373
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. See Table 4-5SA for presentation of installed capital costs determined for hypothetical application of SCR alternatives.

(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.

(4) - The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The installed capital cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006$ as described in the text. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR; and annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SA.

(6) - Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost, and $2,054,000/yr annualized capital cost.

TABLE 4-4SF – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Installed Capital Cost(2) $1,000	Annualized Capital Cost(3) $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	181,484(4)	15,823(4)
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	181,484(4)	15,823(4)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	139,639(4)	12,174(4)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	139,639(4)	12,174(4)
E	SNCR w/ ASOFA	8,113	707
D	Gas Reburn w/ ASOFA(5)	18,006	1,570
C	Lignite Reburn w/ ASOFA(6)	46,656	4,068
B	Fuel Lean Gas Reburn w/ ASOFA(5)	10,639	928
A	Advanced SOFA (ASOFA)	4,277	373
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. See Table 4-5SF for presentation of installed capital costs determined for hypothetical application of SCR alternatives.

(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.

(4) - The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The installed capital cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006$ as described in the text. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR; and annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SF.

(6) - Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost, and $2,054,000/yr annualized capital cost.

The Total Project Costs estimated for tail end and low-dust SCR technologies hypothetically applied to MRYS Unit 1 are shown in Table 4-5SA and Table 4-5SF in 2018, 2009, and 2006 dollars.

The estimated installed capital costs for the hypothetical application of tail end or low-dust SCR system retrofits on MRYS Unit 1 included the following equipment and components:

- One SCR reactor utilizing a “3 +1” arrangement of catalyst layers, in which three layers of catalyst are initially installed, and space for installation of a fourth layer is provided.
- Sootblowers for each catalyst layer to maintain cleanliness of catalyst
- Flue gas reheat equipment that is typical for these applications but not required for conventional high-dust/hot side SCRs. This reheat equipment includes rotary regenerative heat exchangers (gas-to-gas heaters [GGH]) and natural gas-fired duct burners.
- Underground high-pressure natural gas supply pipeline and pressure regulators and metering equipment
- Hot air recirculation and heating equipment to maintain catalyst in a warm and dry condition during standby periods
- Induced draft booster fan and dampers
- Interconnecting ductwork
- SCR bypass duct and dampers (used during times the boiler is off-line)
- Storage tanks, building, and equipment for unloading and preparation of liquid urea solution
- Circulation pumps and piping for urea solution
- Urea-to-ammonia thermal conversion with urea conversion, metering, atomization, and injection equipment
- Ammonia gas dilution/combustion air fans and burners for natural gas-firing to decompose the urea solution to ammonia
- Service and sootblowing air compressors with dryers
- Electrical motor control centers
- Controls and instrumentation
- Reinforced concrete foundations
- Active coal yard storage modifications to regain lost live capacity and handling equipment due to space consumed by the SCR reactor structures
- Installation labor, materials, and management.

Addition of new electrical loads to the existing plant facilities will be required for the reagent system and new induced draft booster fan power consumption. Based on recent plant electrical distribution equipment installations, additional plant auxiliary electrical power will be available for powering the new hypothetically-applied SCR equipment. Confirmation of these concepts and cost estimates prior to any subsequent plans for implementation requires successful completion of extensive pilot-scale slipstream

testing, and more detailed plant layout and equipment design than has been performed as part of this supplemental update to the October 2006 NO_X BACT Analysis Study report.

The capital cost estimated individually for an ASOFA system retrofit on MRYS Unit 1 as previously described in the initial NO_X BACT Analysis Study report was simply arithmetically added to the hypothetical application of SCR alternatives' capital cost estimates.

TABLE 4-5SA – Estimated Capital Costs for Hypothetically-Applied SCR Alternatives - MRY Station Unit 1
Stand Alone SCR Projects

Alt. Label(1)	Hypothetical SCR Alternative(2)	Estimated BMcD Study Total Project Cost(3), 2018$ x 1000	Estimated BMcD Study Modified TP Cost(4), 2009$ x 1000	Estimated BMcD Study Adjusted TP Cost(5), 2006$ x 1000
T2, T1	Tail End SCR	294,586	235,884	214,221
	Urea preparation and storage, building, and equipment(6)	–	4,808(6)	4,366(6)
	ASOFA	–	–	4,277
T2, T1	TOTAL	–	–	222,864(6)
L2, L1	Low-Dust SCR	236,658	189,499	172,096
	Urea preparation and storage, building, and equipment	–	4,808(6)	4,366(6)
	ASOFA	–	–	4,277
L2, L1	TOTAL	–	–	180,739(6)

(1) All SCR alternatives are assumed to have the same SCR outlet NOx emission rate.

(2) The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station.

(3) The Total Project Cost shown for each hypothetically-applied SCR system was estimated by Burns & McDonnell based on scope assumptions for installation of the SCR equipment on this boiler as described in the text, except as described in footnote 6 below. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Does not include installed capital cost for ASOFA, as shown in Table 4-4SA.

(4) Modified Total Project Costs are converted from 2018$ to 2009$ as described in the text, except as described in footnote 6 below. Present Value factor (discounted from future value) is 0.80073.

(5) Adjusted Total Project Costs are converted from 2009$ to 2006$ as described in the text. Handy-Whitman Index of Public Utility Construction Costs ratio is 0.908.

(6) Urea preparation and storage, building, and equipment installed capital costs were estimated separately in 2009$, and then adjusted using the Handy-Whitman cost ratio of 0.908 to get 2006$. The TOTAL numbers above are the sum of the Adjusted Total Project Cost; urea preparation and storage, building, and equipment; and Total Installed Capital Costs (TICC) for ASOFA alternative = estimated TICC for the hypothetically-applied SCR alternatives in Table 4-4SA.

TABLE 4-5SF – Estimated Capital Costs for Hypothetically-Applied SCR Alternatives - MRY Station Unit 1 Shared Facilities SCR Projects

Alt. Label(1)	Hypothetical SCR Alternative(2)	Estimated BMcD Study Total Project Cost(3), 2018$ x 1000	Estimated BMcD Study Modified TP Cost(4), 2009$ x 1000	Estimated BMcD Study Adjusted TP Cost(5), 2006$ x 1000
T2, T1	Tail End SCR	240,817	192,829	175,120
	Urea preparation and storage, building, and equipment(6)	–	2,298(6)	2,087(6)
	ASOFA	–	–	4,277
T2, T1	TOTAL	–	–	181,484(6)
L2, L1	Low-Dust SCR	183,274	146,753	133,275
	Urea preparation and storage, building, and equipment(6)	–	2,298(6)	2,087(6)
	ASOFA	–	–	4,277
L2, L1	TOTAL	–	–	139,639(6)

(1) All alternatives are assumed to have the same SCR outlet NOx emission rate.

(2) The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station.

(3) The Total Project Cost shown for each hypothetically-applied SCR system was estimated by Burns & McDonnell based on scope assumptions for installation of the SCR equipment on this boiler as described in the text, except as described in footnote 6 below. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Does not include installed capital cost for ASOFA, as shown in Table 4-4SF.

(4) Modified Total Project Costs are converted from 2018$ to 2009$ as described in the text, except as described in footnote 6 below. Present Value factor (discounted from future value) is 0.80073.

(5) Adjusted Total Project Costs are converted from 2009$ to 2006$ as described in the text. Handy-Whitman Index of Public Utility Construction Costs ratio is 0.908.

(6) Urea preparation and storage, building, and equipment installed capital costs were estimated separately in 2009$, and then adjusted using the Handy-Whitman cost ratio of 0.908 to get 2006$. The TOTAL numbers above are the sum of the Adjusted Total Project Cost; urea preparation and storage, building, and equipment; and Total Installed Capital Costs (TICC) for ASOFA alternative = estimated TICC for the hypothetically-applied SCR alternatives in Table 4-4SF

4.2.1.2 O&M COST ESTIMATES FOR NO_X CONTROL ALTERNATIVES

Operational costs to implement the hypothetical application of SCR alternatives and previously-analyzed feasible NO_X control alternatives for Milton R. Young Unit 1 were estimated using preliminary conceptual designs and budgetary vendor quotes in place of, or to adjust, the OAQPS cost factors established in the EPA's Air Pollution Control Cost Manual (OAQPS) for SNCR[27] and SCR[28], and using other costs published in technical papers discussing those control technologies. Maintenance costs were estimated as

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[27] See Reference number 9, October 2000.

[28] See Reference number 10, October 2000.

percentages of installed capital costs, with additional catalyst replacement costs using budgetary vendor quotes based on preliminary conceptual designs and expected design life.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's annual O&M costs are estimates of:

- Auxiliary electrical power consumption (megawatt-hours) and incremental purchased power unit costs for operating the additional control equipment;
- Natural gas consumption and unit cost for hypothetical application of SCR alternatives' flue gas reheating and urea-to-ammonia thermal conversion systems and feasible fuel reburn alternatives;
- Reagent consumption and reagent unit cost for hypothetical application of SCR alternatives and feasible SNCR alternatives;
- Reagent dilution water consumption and unit cost for SNCR alternatives.
- Catalyst removal and replacement for hypothetical application of SCR alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler and plant equipment;
- Costs for purchase of replacement electrical power expected to result from loss of unit availability, i.e., outages attributable to the control option which reduce annual net electrical generation available for distribution.

For economic evaluation purposes, a 12-month rolling average running plant capacity factor of 96.6 percent (based on a historic (demonstrated) sustainable unit output capacity of 253 MW_g) combined with a 12-month rolling average availability (uptime) of 8,528 operating hours (97.3 percent of 8760 hours per year) resulting in an equivalent annual average unit capacity factor of 94.1% was assumed for Unit 1's pre-control baseline annual operation. A 12-month rolling average heat input rate of 2,744 mmBtu/hr and a 12-month rolling average NO_X emission rate of 0.849 lb/mmBtu from pre-control maximum rolling 12 month summation of nitrogen oxides mass emissions were assumed for calculating equivalent annual average control and cost-effectiveness for MRY Station Unit 1.

Tables 4-6SA and 4-6SF show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the hypothetically-applied SCR alternative cases and the highest-performing form of previously-evaluated feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Appendix C3 of the 2006 NO_X BACT Analysis Study report provides more details for the levelized annual O&M cost calculations and cost factors for the previously-analyzed feasible NO_X control alternatives[29].

TABLE 4-6SA – Estimated O&M Costs for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	**NOx Control Alternative**	**Annual O&M Cost(2) $1,000**	**Levelized Annual O&M Cost(2),(3) $1,000**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	20,048	25,034
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	29,361	36,664
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	18,332	22,891
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	29,178	36,435
E	SNCR w/ ASOFA	5,417	6,764
D	Gas Reburn w/ ASOFA	28,641	35,765
C	Lignite Reburn w/ ASOFA(5)	5,862	7,320
B	FLGR w/ ASOFA	12,863	16,062
A	Advanced SOFA (ASOFA)	1,695	2,117
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at an average unit output (244.5 MWg) and assumes a 97.3% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars. Revised February, 2010.

(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor. Rev. Feb. 2010.

(4) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual O&M cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specific to MRYS Unit 1 in 2018 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for increased PM collection capacity included in lignite reburn option are $2,024,000/yr for annual O&M cost, and $2,527,000/yr annualized O&M cost.

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[29] Ibid Reference number 3, October 2006, pages C3 through 3-11.

TABLE 4-6SF – Estimated O&M Costs for NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual O&M Cost(2) $1,000	Levelized Annual O&M Cost(2),(3) $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	18,806	23,484
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	28,120	35,114
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	17,099	21,352
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	26,483	33,070
E	SNCR w/ ASOFA	5,417	6,764
D	Gas Reburn w/ ASOFA	28,641	35,765
C	Lignite Reburn w/ ASOFA(5)	5,862	7,320
B	FLGR w/ ASOFA	12,863	16,062
A	Advanced SOFA (ASOFA)	1,695	2,117
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at an average unit output (244.5 MWg) and assumes a 97.3% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars. Revised February, 2010.

(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor. Rev. Feb. 2010.

(4) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual O&M cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specific to MRYS Unit 1 in 2018 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for increased PM collection capacity included in lignite reburn option are $2,024,000/yr for annual O&M cost, and $2,527,000/yr annualized O&M cost.

4.2.1.2.1 O&M COST ESTIMATES FOR HYPOTHETICAL APPLICATION OF SCR NO_X CONTROL ALTERNATIVES

The hypothetical application of tail-end and low-dust SCR w/ ASOFA alternatives will involve significantly higher operating costs compared with the existing operation of MRYS Unit 1. The system uses an amine reagent in the form of concentrated aqueous urea solution, which is thermally converted to gaseous ammonia, carbon dioxide, and water vapor. The estimated unit cost of this urea was assumed to average $379/ton (delivered to the plant site via truck-tanker trailers; unit pricing based on 50% concentration as established for the 2006 NO_X BACT Analysis Study report). Consumption of urea converted to ammonia reagent was based upon recent equipment vendor budgetary proposals and SCR consultant inputs.

For the hypothetically-applied SCR cases, using the existing induced draft fans is not expected to significantly change the overall fan horsepower demand on those fans' electric motors. There will be new plant electrical power demand due to a new induced draft booster fan required to overcome the estimated additional flue gas pressure drop resulting from reactor, ductwork, and gas-to-gas heat exchanger equipment assumed for the hypothetically-applied SCR systems. The additional auxiliary electric power demand for the hypothetically-applied tail end SCR systems was calculated to be 9.7 MW, using estimated annual average electrical loads of the booster fan, direct flue gas reheat burner combustion air fan, urea-to-ammonia conversion dilution/combustion air fan, and SCR sootblower and service air compressor equipment based on preliminary equipment vendor budgetary proposals developed from Burns & McDonnell ductwork sizing and designs. Estimated annual average electrical power demands for hypothetically-applied low-dust SCR systems were calculated to be 8.0 MW. Replacement of electrical power resulting from these reductions in net unit electrical output was included as a cost, assuming $35 per megawatt-hour.

Hypothetically-applied tail end and low-dust SCR equipment requiring annual maintenance includes booster fan, gas-to-gas heat exchangers, flue gas reheat duct burners, and compressor equipment. This general annual maintenance cost was estimated as 3 percent of installed capital costs.

To account for the possible range of O & M costs due to catalyst replacement, two variations (Scenario A and Scenario B) were applied. These two scenarios were used for both hypothetical applications of tail-end and low-dust SCR technology alternatives. Each scenario was based on scheduled additions and/or replacement of the exposed catalyst after a certain number of hours of operation, repeated throughout the 20 year operating span considered in the analysis. The installed unit cost of replacement catalyst assumed for the hypothetical application of full-time tail end or low-dust SCR alternatives is $7,500 per cubic meter in 2006 dollars. The basis for development of the two scenarios is described below.

During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically-applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Based on information obtained in discussions with the catalyst vendors, the longest catalyst replacement schedule they would both agree upon as an estimated (not guaranteed) value was 16,000 hours. Both vendors indicated that actual experience could result in a shorter replacement cycle, and that the actual guarantee value could not be developed until extensive pilot slipstream testing had been completed. This led Burns & McDonnell to develop two hypothetically-applied SCR catalyst replacement scenarios to bracket possible outcomes.

Scenario A assumed a hypothetically-applied catalyst replacement schedule of 16,000 hours. Specifically for MRYS Unit 1, this scenario is based on the replacement of one catalyst layer every 16,000 operating hours (essentially every two years of operation).

Scenario B assumed that the fouling of the catalyst would be severe, and that it would be necessary for Minnkota to perform catalyst maintenance at each scheduled boiler cleaning outage. The current schedule of boiler cleaning outages on Unit 1 is three times per year. Therefore, Scenario B for Unit 1 is based on the replacement of one catalyst layer at each boiler cleaning outage. This means that each catalyst layer in the four layer SCR reactor is exposed to flue gas during approximately 16 months of operation and then is replaced. By assuming that catalyst management activities would coincide with scheduled boiler cleaning outages, Scenario B provides some minimization of the impact of catalyst replacement on unit operation.

As noted above, it is not known what the actual frequency of catalyst replacement would need to be for a hypothetically-applied tail-end or low dust SCR system operating on a cyclone-fired boiler burning North Dakota lignite, but the two scenarios described above are the catalyst replacement numbers assumed for this comparative economic analysis.

SCR catalyst replacements are additive to the general annual hypothetically-applied low-dust and tail end SCR equipment maintenance. Catalyst replacement costs are based on catalyst vendor quotation of volume of catalyst, estimated to be three layers initially (top, middle-upper and middle-lower) at 146 cubic meters per layer per reactor for the single reactor. A fourth (bottom) layer at 195 cubic meters is expected to be required after initial operation of hypothetically-applied full-time tail end or low-dust SCR alternatives, as part of the catalyst replacement program. Catalyst replacement costs for the hypothetical application of SCR alternatives were estimated for the two different catalyst management scenarios described above.

Annual unit operating time will be reduced as a result of the expected outages and maintenance of the hypothetically-applied SCR equipment, including catalyst cleaning and management practices. Additional outage time of 213 hours per year was estimated to be attributable to the hypothetical application of tail end SCR Scenario A alternative (assuming 16,000 hour catalyst life), and 938 hours per year for Scenario B TESCR case (assuming three layers are replaced every year) over and above the hours per year of outage time assumed for ASOFA impacts. Additional outage time of 256 hours per year was estimated to be attributable to the hypothetical application of low-dust SCR Scenario A alternative, and 981 hours per year for the Scenario B LDSCR case over and above outage time assumed for ASOFA impacts. The expected loss of electrical power generation from these reductions in net output was included as a cost, assuming $35 per megawatt-hour for replacement power.

Table C.4-1 provides the estimated unit availability and corresponding operating time and outage time due to the four hypothetically-applied SCR technology cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[30].

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[30] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

TABLE C.4-1 – Expected Availability Reductions for MRYS Unit 1 NO_X Controls

Alt.[1]	NOx Control Alternative	Estimated Annual Average Unit Operating Time			
		Unit Availability[2]	Unit Operating Time[3], hrs/yr	Unit Outage Time[4], hrs/yr	Unit Operating Time Reduction[5], hrs/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	0.928	8127	633	401
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	0.845	7402	1358	1126
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	0.923	8084	676	444
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	0.840	7359	1401	1169
E	SNCR w/ ASOFA	0.942	8255	505	273
D	Gas Reburn w/ ASOFA	0.952	8340	420	188
C	Coal Reburn w/ ASOFA	0.937	8212	548	316
B	FLGR w/ ASOFA	0.952	8340	420	188
A	Advanced SOFA (ASOFA)	0.952	8340	420	188
	Baseline	0.973	8528	232	0

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.
(2) – 12-month baseline availability is assumed at 97.3 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technology.
(3) – Annual operating time is annual average availability multiplied by 8760 hrs/yr of possible uptime.
(4) – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.
(5) – Annual operating time reduction resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.
(6) – The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual unit availability factors shown for hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Table C.4-2 includes estimated equivalent average annual unit running plant capacity ratios and unit generation reductions due to the four hypothetically-applied SCR cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[31]. These numbers assume the reduction in annual plant output is a combination of a reduction of annual operating time and capacity reductions associated with the control alternatives.

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[31] Ibid Reference number 3, October 2006, pages C3-1 through C3-12.

TABLE C.4-2 – Expected Capacity Reductions for MRYS Unit 1 NO_X Controls

Alt. Label[1]	NOx Control Alternative	Estimated Annual Average Unit Electrical Power Generation Reduction from Operating Time Reduction		
		Unit Running Plant Capacity Ratio[2]	Unit Generation Reduction[3] kW-hrs/yr	Unit Generation Reduction Cost[4], 1000$/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[5]	0.937	97,976,764	3,429
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[5]	0.937	275,168,784	9,631
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[5]	0.942	108,399,824	3,794
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[5]	0.942	285,591,844	9,996[6]
E	SNCR w/ ASOFA	0.965	67,660,606	2,368
D	Gas Reburn w/ ASOFA	0.957	46,120,681	1,614
C	Lignite Reburn w/ ASOFA	0.961	77,958,350	2,729
B	FLGR w/ ASOFA	0.962	46,400,200	1,624
A	Advanced SOFA (ASOFA)	0.966	46,586,546	1,631
	Baseline	0.966	0	0

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) - 12-month baseline running plant capacity ratio is assumed at 96.6 percent (= 244.4/253.0). These values reflect estimated amounts of negative annual output capacity impact expected from the implementation of the individual NOx control technique. Used only for calculation of annual power usage in Table C.4-3.
(3) - Annual electricity generation reduction is annual unit operating time reduction multiplied by the 12-month average gross output of 244.4 MW.
(4) - Annual electricity generation reduction cost is the annual electricity generation reduction (kW-hrs/yr) resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.
(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual unit running plant capacity factors shown for hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.
(6) Unit Generation Reduction for low-dust SCR Scenario B was $11,940,000. It should be shown as $9,996,000 instead. This does not affect economics shown in subsequent tables and graphs. Revised February, 2010.

Table C.4-3 includes estimated unit gross and net electrical power demands (kilowatts) and annual usage (kW-hrs per year) used to calculate unit generation reductions and replacement electrical power costs due to the four hypothetically-applied SCR cases, along with the ASOFA numbers from the referenced Appendix

C3 of the initial NO_X BACT Analysis Study report[32]. These numbers assume that the reductions of annual operating time and capacity associated with the control alternatives are also applied.

TABLE C.4-3 – Expected Auxiliary Electrical Power Demand Changes for MRYS Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Alternative	Estimated Annual Average APC NOx Equipment Auxiliary Electrical Power Demand and Usage				
		Gross Demand (2) kW	Credit(3) kW	Total Net Demand(4) kW	Power Usage(5) kW-hrs/yr	Power Usage Cost(6), 1000$/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(7)	9,685	0	9,685	73,768,605	2,582
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(7)	9,685	0	9,685	67,189,753	2,352
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(7)	8,012	0	8,012	61,018,532	2,136
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(7)	8,012	0	8,012	55,548,184	1,944
E	SNCR w/ ASOFA	73.1	0	73.1	582,411	20
D	Gas Reburn w/ ASOFA	1	133	(132)	(1,054,343)	(37)
C	Lignite Reburn w/ ASOFA	4,666	261	4,405	11,905,082	1,217
B	FLGR w/ ASOFA	1	73	(72)	(578,744)	(20)
A	Advanced SOFA (ASOFA)	1	0	1	8,058	0.3

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) - The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of the demand for individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects. Coal reburn includes 1,507 kW for feed preparation and conveying equipment demand plus 3,158 kW for the COHPAC system addition for PM control.
(3) - The APC NOx equipment auxiliary electrical power demand credit of coal reburn alternatives is the estimated result of lower cyclone coal preparation and feeder power demand due to lower boiler cyclone coal equipment loading. Actual power demands may differ from this due to accuracy of estimates for assumed amount of operating horsepower reduction.
(4) - The total net auxiliary electrical power demand is the sum of the gross demand and credit.
(5) - The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity ratio which reflects the adjustment for any expected availability and capacity impacts from the implementation of the control technique.
(6) - The annual change in APC NOx equipment auxiliary electrical power demand electricity cost is the annual change in kW-hrs/yr for these alternatives resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.
(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated power demands shown for hypothetically-applied SCR systems are based on Burns & McDonnell estimates developed from preliminary equipment and ductwork sizing and designs with vendor budgetary proposals. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

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[32] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

Table C.4-4 includes estimated net unit electrical annual power usage (kW-hrs per year) and expected reductions in annual operating time to calculate unit generation reductions due to the four hypothetically-applied SCR cases, along with the ASOFA numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[33]. These numbers assume the reduction in annual plant output is a combination of a reduction of net unit generation because of electrical power usage and reductions in annual operating time and capacity associated with the control alternatives.

TABLE C.4-4 – Expected Auxiliary Electrical Power Demand and Generation Reduction Cost Changes for MRY Unit 1 NO_X Controls

		Estimated Annual Change in Unit Generation Due to APC NOx Equipment Auxiliary Power Electricity Demand and Generation Reduction			
Alt. Label(1)	**NOx Control Alternative**	**APC Electrical Power Usage(2) kW-hrs/yr**	**Unit Generation Reduction(3) kW-hrs/yr**	**Total Unit Electrical Power Generation Change(4) kW-hrs/yr**	**Total Unit Electrical Power Generation Change Cost(5) 1000$/yr**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	73,768,605	97,976,764	171,745,369	6,011
T1	Hypothetical Tail End SCR w/ ASOFA –Scenario B(6)	67,189,753	275,168,784	342,358,537	11,983
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	61,018,532	108,399,824	169,418,356	5,930
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	55,548,184	285,591,844	341,140,028	11,940
E	SNCR w/ ASOFA	582,411	67,660,606	68,243,017	2,389
D	Gas Reburn w/ ASOFA	(1,054,343)	46,120,681	45,066,338	1,577
C	Lignite Reburn w/ ASOFA	11,905,082	77,958,350	89,863,432	3,946
B	FLGR w/ ASOFA	(578,744)	46,400,200	45,821,456	1,604
A	Advanced SOFA (ASOFA)	8,058	46,586,546	46,594,605	1,631

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) - The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity ratio which reflects the adjustment for any expected availability and capacity impacts from the implementation of the control technique.
(3) - Annual electricity generation reduction is annual operating time reduction multiplied by the 12-month average gross output of 244.4 MW.
(4) - The total unit electrical power generation change is the sum of the annual change in APC NOx equipment auxiliary electrical power demand electricity usage plus the annual electricity generation reduction resulting from the implementation of the individual NOx control alternative.
(5) - The total unit electrical power generation change cost is the total generation change (kw-hrs/yr) multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.
(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated power demand shown for hypothetically-

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[33] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

applied SCR systems are based on Burns & McDonnell estimates developed from preliminary equipment and ductwork sizing and designs with vendor budgetary proposals. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

4.2.1.3 LEVELIZED TOTAL ANNUAL COST ESTIMATES FOR MRY STATION NO_X CONTROLS

A comparison of the control versus cost-effectiveness of four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives on Milton R. Young Unit 1 was made. This is summarized as shown in Tables 4-7SA and 4-7SF, Figures 4-1SA and 4-1SF, and Figures 4-2SA and 4-2SF for MRY Station Unit 1.

TABLE 4-7SA – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) $1,000	Average Control Cost(5) $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	589	9,345	44,465	4,758
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	536	9,398	56,095	5,969
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	586	9,348	38,649	4,134
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	533	9,401	52,193	5,552
E	SNCR w/ ASOFA	4,025	5,909	7,472	1,265
D	Gas Reburn w/ ASOFA	4,275	5,659	37,334(7)	6,597
C	Lignite Reburn w/ ASOFA	4,343	5,591	11,388(8)	2,037
B	FLGR w/ ASOFA	5,260	4,674	16,990(7)	3,635
A	Advanced SOFA (ASOFA)	5,874	4,060	2,489	613
	Baseline	9,934	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated annual emission tons assume an annual unit uptime availability factor specific to each alternative; 9,934 (= 0.973*8760*2,330/2000) was assumed for the baseline case.

(3) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note 3 from Tables 4-4SA and 4-6SA for annualized cost factors. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline emissions based on annual operation at baseline pre-control NOx emission rate. Revised February, 2010.

(5) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars. Revised February, 2010.

(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specifically for MRYS Unit 1 in 2006 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SA.

(8) - LTAC for increased PM collection capacity included in lignite reburn option are approximately $2,054,000 for annualized capital cost plus $2,527,000/yr for annualized O&M cost, for a LTAC subtotal of $4,581,000/yr.

TABLE 4-7SF – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 1 - Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) $1,000	Average Control Cost(5) $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	589	9,345	39,307	4,206
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	536	9,398	50,937	5,420
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	586	9,348	33,526	3,586
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	533	9,401	45,244	4,813
E	SNCR w/ ASOFA	4,025	5,909	7,472	1,265
D	Gas Reburn w/ ASOFA	4,275	5,659	37,334(7)	6,597
C	Lignite Reburn w/ ASOFA	4,343	5,591	11,388(8)	2,037
B	FLGR w/ ASOFA	5,260	4,674	16,990(7)	3,635
A	Advanced SOFA (ASOFA)	5,874	4,060	2,489	613
	Baseline	9,934	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated annual emission tons assume an annual unit uptime availability factor specific to each alternative; 9,934 (= 0.973*8760*2,330/2000) was assumed for the baseline case.

(3) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative’s annual emissions (tons).

(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note 3 from Tables 4-4SF and 4-6SF for annualized cost factors. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline emissions based on annual operation at baseline pre-control NOx emission rate. Revised February, 2010.

(5) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars. Revised February, 2010.

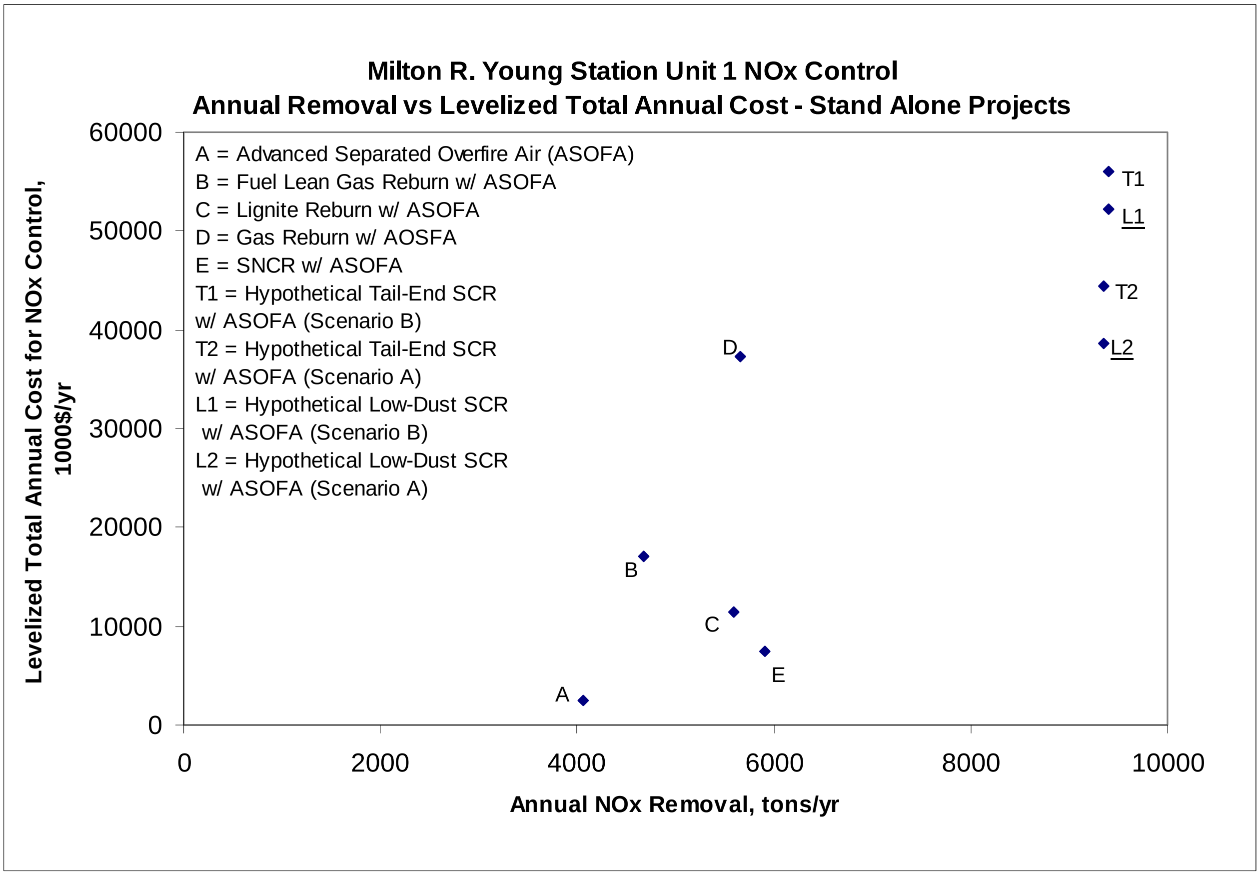
(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for

technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specifically for MRYS Unit 1 in 2006 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SF.

(8) - LTAC for increased PM collection capacity included in lignite reburn option are approximately $2,054,000 for annualized capital cost plus $2,527,000/yr for annualized O&M cost, for a LTAC subtotal of $4,581,000/yr.

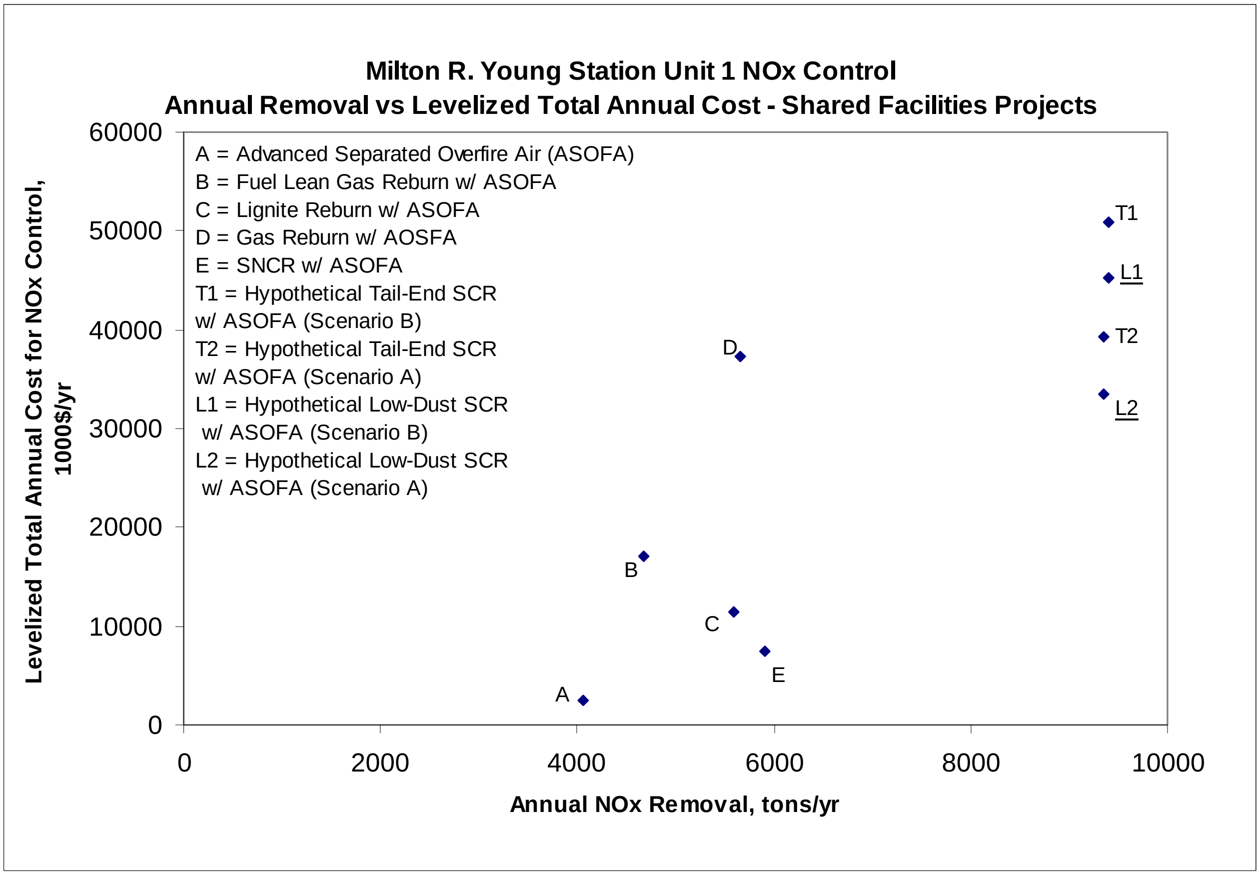
Figure 4-1SA – NO_X Control Cost Effectiveness - MRY Station Unit 1(1)
Stand Alone SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-7SA. Revised February, 2010.

(2) - The inclusion of tail-end and low-dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Figure 4-1SF – NO_X Control Cost Effectiveness - MRY Station Unit 1(1)
Shared Facilities SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-7SF. Revised February, 2010.

(2) - The inclusion of tail-end and low-dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

The purpose of Figures 4-1SA and 4-1SF is to show the range of control and cost for four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives on Milton R. Young Unit 1 alternatives evaluated.

Data points for conventional gas reburn (Point D) and fuel-lean gas reburn (Point B) with advanced separated overfire air, and lignite reburn with ASOFA (Point C), in Figures 4-1SA and 4-1SF are inferior and therefore were eliminated from further control cost-effectiveness analysis.

A dominant set of control alternatives was determined by generating what is called the "envelope of least-cost alternatives". The dominant controls cost curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the annual NO_X removal tonnage versus LTAC for the various remaining BACT alternatives. Average and incremental annual costs and NO_X emission reductions for the dominant least-cost control alternatives remaining after the elimination of the obviously inferior options are listed in Tables 4-8SA and 4-8SF.

TABLE 4-8SA – Dominant Controls Cost Curve Points for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	**NOx Control Alternative**	**Levelized Total Annual Cost(2),(3) ($1,000/yr)**	**Annual Emission Reduction(3) (tpy)**	**Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)**	**Incremental Annual Emission Reduction(4) (tpy)**	**Incremental Control Cost Effectiveness ($/ton)(2),(4)**
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	44,465	9,345	36,993	3,437	10,765
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	56,095	9,398	48,623	3,489	13,936
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	38,649	9,348	31,777	3,440	9,064
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(5)	52,193	9,401	44,721	3,492	12,806
E	SNCR w/ ASOFA	7,472	5,909	4,982	1,849	2,694
A	Advanced SOFA (ASOFA)	2,489	4,060	2,489	4,060	613

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Dominant controls cost curve points from lowest (ASOFA) to highest (TESCR w/ ASOFA – 16,000 hrs) are labeled the same as in Table 4-7SA, and on the graphs that accompany this table (Points B, C, and D were eliminated).

(2) - All cost figures in 2006 dollars. Revised February, 2010.

(3) - Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate. Revised February, 2010.

(4) - Increment based upon comparison between consecutive alternatives (points) from lowest to highest. Revised February, 2010.

(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation. Revised February, 2010.

TABLE 4-8SF – Dominant Controls Cost Curve Points for NO_X Control Alternatives - MRY Station Unit 1 - Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Levelized Total Annual Cost(2),(3) ($1,000/yr)	Annual Emission Reduction(3) (tpy)	Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)	Incremental Annual Emission Reduction(4) (tpy)	Incremental Control Cost Effectiveness ($/ton)(2),(4)
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	39,307	9,345	31,835	3,437	9,264
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	50,937	9,398	43,465	3,489	12,458
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	33,526	9,348	26,054	3,440	7,575
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(5)	45,244	9,401	37,772	3,492	10,816
E	SNCR w/ ASOFA	7,472	5,909	4,982	1,849	2,694
A	Advanced SOFA (ASOFA)	2,489	4,060	2,489	4,060	613

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Dominant controls cost curve points from lowest (ASOFA) to highest (TESCR w/ ASOFA – 16,000 hrs) are labeled the same as in Table 4-7SF, and on the graphs that accompany this table (Points B, C, and D were eliminated).

(2) - All cost figures in 2006 dollars. Revised February, 2010.

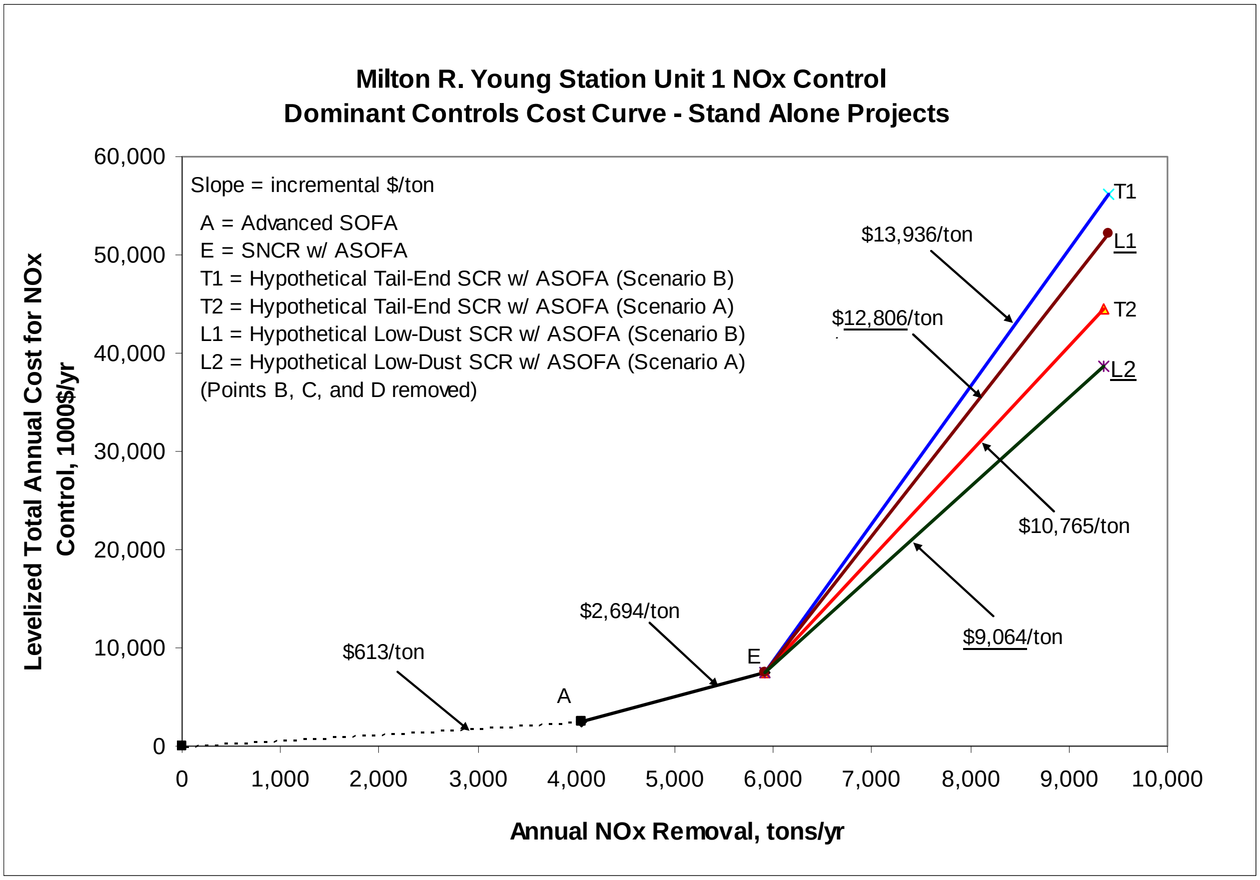
(3) - Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate. Revised February, 2010.

(4) - Increment based upon comparison between consecutive alternatives (points) from lowest to highest. Revised February, 2010.

(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation. Revised February, 2010.

Figures 4-2SA and 4-2SF contains a repetition of the levelized total annual cost and NO_X control information from Figures 4-1SA and 4-1SF for MRY Station Unit 1, with Point B (FLGR™ with ASOFA) , Point C (Lignite Reburn with ASOFA) and Point D (conventional gas reburn with ASOFA) removed. This is the dominant controls cost curve for MRY Station Unit 1 NO_X emissions alternatives.

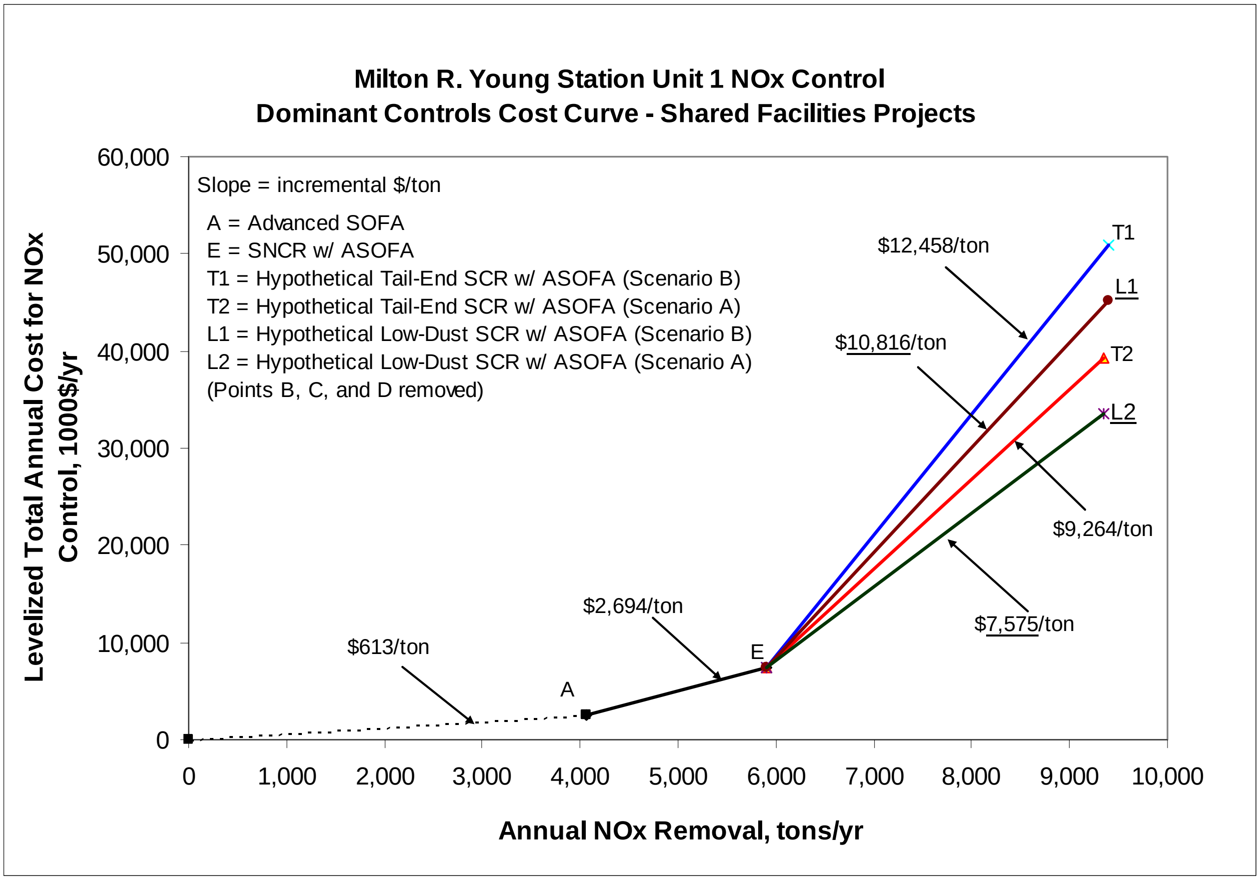
Figure 4-2SA – MRY Station Unit 1 NO_X Control Alternatives BACT Dominant Controls Cost Curve(1) - Stand Alone SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-8SA. Revised February, 2010.

(2) - The inclusion of tail-end and low dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Figure 4-2SF – MRY Station Unit 1 NO_X Control Alternatives BACT Dominant Controls Cost Curve(1) – Shared Facilities SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-8SF. Revised February, 2010.

(2) - The inclusion of tail-end and low dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

As can be seen from a review of Tables 4-7SA and 4-7SF, the average levelized control cost effectiveness (called the unit control cost in this report) ranges from approximately $613/ton to $6,597/ton of MRYS Unit 1's NO_X emissions removed. The unit control cost for the hypothetically-applied Scenario A Tail End SCR w/ ASOFA case was $4,758/ton and for the hypothetically-applied Scenario B Tail End SCR w/ ASOFA case was $5,969/ton (stand alone projects). The unit control cost for the hypothetically-applied Scenario A Low-Dust SCR w/ ASOFA case was $~~3,944~~ 4,134/ton and for the hypothetically-applied Scenario B Low-Dust SCR w/ ASOFA case was $~~5,380~~ 5,552/ton (stand alone projects). The unit control cost for the hypothetically-applied Scenario A Tail End SCR w/ ASOFA case was $4,206/ton and for the hypothetically-applied Scenario B Tail End SCR w/ ASOFA case was $5,420/ton (shared facilities projects). The unit control cost for the hypothetically-applied Scenario A Low-Dust SCR w/ ASOFA case was $~~3,396~~ 3,586/ton and for the hypothetically-applied Scenario B Low-Dust SCR w/ ASOFA case was $~~4,835~~ 4,813/ton (shared facilities projects). Unit control costs for SNCR w/ ASOFA was $1,265/ton, more than twice that of ASOFA ($613/ton). It should be noted, however, that the very high estimated average control costs involve fuel lean gas reburn ($3,635/ton) and conventional gas reburn ($6,597/ton) technologies that were shown to be inferior options (not on the dominant controls cost curve) and thus were eliminated from further impacts analysis.

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative for MRYS Unit 1 incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control technique. The slope from zero (baseline) to ASOFA (Point A) was $613/ton; the incremental cost per ton (slope) from ASOFA (Point A) to SNCR with ASOFA (Point E) was $2,694/ton for MRYS Unit 1. The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied low-dust SCR case (Point L2, Scenario A) was $~~8,547~~ 9,064/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied tail end SCR case (Point T2, Scenario A) was $10,765/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied low-dust SCR case (Point L1, Scenario B) was $~~12,343~~ 12,806/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied tail end SCR case (Point T1, Scenario B) was $13,936/ton (stand alone projects). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied SCR cases were $~~7,058~~ 7,575/ton (low-dust Point L2, Scenario A) and $9,264/ton (tail end Point T2, Scenario A). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied SCR cases were $~~10,876~~ 10,816/ton (low-dust, Point L1, Scenario B) and $12,458/ton (tail end Point T1, Scenario B).

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. EPA's NSR Manual however, does specifically address the standard to be used when rejecting a candidate technology on the basis of adverse economic impact:

> "Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology

> can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source."[34]

This supplemental report for the MRYS NOx BACT Analysis has clearly established the circumstances, including the economic impacts, which would make the hypothetical application of TESCR or LDSCR to MRYS Unit 1 significantly more expensive than SCR costs normally incurred by other coal-fired steam electric generating units. The following information further supports EPA's own statements regarding the costs "normally incurred by other sources". The EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines estimated an average control cost for SCR applied to MRYS Unit 1 of $549 per ton[35]. The unadjusted unit capital cost versus capacity factor assumed by the EPA for SCR retrofits applied to cyclone boilers in the cost-effectiveness analysis used for establishing presumptive BART[36] was $100/kW. The EPA's cost-effectiveness analysis used for establishing presumptive BART stated that "applying SCR for coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton" [37]. The site-specific control costs estimated for hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines discussed above.

Also, the use of incremental cost effectiveness is warranted per the final 2005 RHR/BART Guidelines, which state "the greater the number of possible control options that exist, the more weight should be given to the incremental costs vs. average costs". Also in the final 2005 RHR/BART Guidelines, "the average cost for each [of two options, A and B]… may be deemed to be reasonable. However, the incremental cost…of the additional emissions reductions to be achieved by control B may be very great. In such an instance, it may be inappropriate to chose control B, based on its higher incremental costs, even though its average cost may be considered reasonable".[38]

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[34] Ibid Reference number 2, Section IV.D.2.c.
[35] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.
[36] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 209.
[37] See Reference number 11, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[38] Ibid Reference number 11, July 2005, FR Vol. 70 No. 128, page 39168.

TABLE 4-9SA – Estimated Emissions and Economic Impacts Summary for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 1 – Stand Alone SCR Projects

Alt. Label[1]	NOx Control Alternative	EMISSIONS[2]				NOx Removal Efficiency[2] %	ECONOMIC IMPACTS			
		Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr		Installed Capital Cost[3] $1,000	Annual O & M Cost[4] $1,000	Levelized Total Annualized Cost[5] $1,000	Average Control Cost[6] $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[7]	0.053	145	589	9,345	93.8[8]	222,864	20,048	44,465	4,758
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[7]	0.053	145	536	9,398	93.8[8]	222,864	29,361	56,095	5,969
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[7]	0.053	145	586	9,348	93.8[8]	180,739	18,332	38,649	4,134
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[7]	0.053	145	533	9,401	93.8[8]	180,739	29,178	52,193	5,552
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	58.1	8,113	5,417	7,472	1,265
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0	18,006	28,641	37,334[9]	6,597
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6	46,656	5,862	11,388[9]	2,037
B	FLGR w/ ASOFA	0.460	1,261	5,260	4,674	45.9	10,639	12,863	16,990[9]	3,635
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	39.5	4,277	1,695	2,489	613
	Baseline	0.849	2,330	9,934	0	0.0	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO_X control level reductions relative to average annual unit emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.45 MWg and assumes a 97.3% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.45 MWg and assumes a 96.6% average running plant capacity ratio compared to nominal unit gross electrical output capacity of 253 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $1,909,000/yr for annual O&M cost. Revised February, 2010.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor. Revised February, 2010.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars. Revised February, 2010.

(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation. Revised February, 2010.

(8) - The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.

(9) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $2,054,000 for annualized capital cost plus $2,384,000/yr for annualized O&M cost, for a total of $4,438,000/yr.

TABLE 4-9SF – Estimated Emissions and Economic Impacts Summary for NO$_X$ Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 1 – Shared Facilities Projects

Alt. Label[1]	NOx Control Alternative	EMISSIONS[2]				NOx Removal Efficiency[2] %	ECONOMIC IMPACTS			
		Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr		Installed Capital Cost[3] $1,000	Annual O & M Cost[4] $1,000	Levelized Total Annualized Cost[5] $1,000	Average Control Cost[6] $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[7]	0.053	145	589	9,345	93.8[8]	181,484	18,806	39,307	4,206
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[7]	0.053	145	536	9,398	93.8[8]	181,484	28,120	50,937	5,420
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[7]	0.053	145	586	9,348	93.8[8]	139,639	17,099	33,526	3,586
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[7]	0.053	145	533	9,401	93.8[8]	139,639	26,483	45,244	4,813
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	58.1	8,113	5,417	7,472	1,265
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0	18,006	28,641	37,334[9]	6,597
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6	46,656	5,862	11,388[9]	2,037
B	FLGR w/ ASOFA	0.460	1,261	5,260	4,674	45.9	10,639	12,863	16,990[9]	3,635
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	39.5	4,277	1,695	2,489	613
	Baseline	0.849	2,330	9,934	0	0.0	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO$_X$ control level reductions relative to average annual unit emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.45 MWg and assumes a 97.3% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.45 MWg and assumes a 96.6% average running plant capacity ratio compared to nominal unit gross electrical output capacity of 253 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $1,909,000/yr for annual O&M cost. Revised February, 2010.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor. Revised February, 2010.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars. Revised February, 2010.

(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO$_X$ BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation. Revised February, 2010.

(8) - The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO$_X$ cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.

(9) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $2,054,000 for annualized capital cost plus $2,384,000/yr for annualized O&M cost, for a total of $4,438,000/yr.

The other elements of the fourth step of a BACT analysis following economic impacts are to evaluate the following impacts of feasible emission controls:

(1) The energy impacts.
(2) The environmental impacts.

4.2.2 ENERGY IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 1

Operation of the NO_X control technologies on the dominant controls cost curve for potential application at the Milton R. Young Station impose direct impacts on the consumption of energy required for the production of electric power at the facility. The details of estimated energy usage and costs for the previously-evaluated NO_X control alternatives were described and summarized in Section 3.4.2 and Appendix C3 of the October 2006 NOx BACT Analysis Study report[39].

The hypothetical application of Tail End and Low-Dust SCR w/ ASOFA alternatives involve higher energy consumption compared with the existing operation of MRYS Unit 1. New induced draft booster fan electrical power demand is needed due to the estimated additional flue gas pressure drop resulting from hypothetical application of SCR reactor, ductwork, and gas-to-gas heat exchangers. The additional auxiliary electric power demand for the hypothetical application of TESCR and LDSCR equipment were calculated to be 9.7 MW and 8.0 MW, respectively, using estimated annual average electrical loads of the booster fan, urea-to-ammonia conversion fired heater combustion/dilution air fan, direct-fired flue gas reheat burner combustion air fan, and service and sootblowing air compressor equipment and related auxiliary equipment.

Preliminary conceptual design details were developed for these alternatives. An estimated additional 12 inches w.c. of flue gas pressure drop was assumed for each hypothetical application of low-dust SCR system, and an estimated additional 19 inches w.c. of flue gas pressure drop was assumed for the hypothetical application of tail end SCR system. Equipment and ductwork arrangements and expected fouling of the catalyst for the hypothetical application of SCR system ductwork, reactor, and gas-gas reheater changes may cause significantly more restrictive flow paths. Thus the electrical power usage estimated here may be too low.

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[39] Ibid Reference number 3, October 2006, pages 3-31 through 3-35, and Appendix pages C3-7 through C3-10.

The expected loss of electrical power generation from these reductions in net output was included as a cost, assuming $35 per megawatt-hour for replacement electrical power. Energy impacts of installing hypothetical application of low-dust and tail end SCR alternatives for NO_X control were included in the O&M cost section (4.2.1.2.1) of this supplemental analysis as Tables C.4-2 through C.4-4.

Aqueous urea solution was assumed to be the preferred, readily available and transportable source of the amine reagent needed to supply ammonia to the SCR reactor catalyst for the low-dust and tail-end SCR alternatives. A urea-to-ammonia conversion system dedicated for each SCR reactor was also assumed. This conversion process will use a natural gas-fired burner that mixes the combustion products at high temperature with the injected aqueous urea solution to thermally decompose the urea, producing gaseous ammonia to supply to the reactors' ammonia injection grids. Gaseous ammonia is the required amine reagent that the catalyst in the SCR reactors uses to convert nitrogen oxides to elemental nitrogen and water vapor. Ammonia (from urea conversion) is supplied and consumed continuously on demand while the SCR NO_X reduction process is in operation. Natural gas is fired continuously during the urea-to-ammonia conversion system operation.

Final reactor inlet flue gas reheat systems are required for the hypothetical application of tail end and low-dust SCR with ASOFA alternatives. A natural gas-fired duct burner that injects high temperature combustion products directly into the flue gas discharged from each SCR gas/gas heat exchanger was assumed for raising the reactor inlet temperature to 600ºF before ammonia injection and NOx reduction can occur in each SCR reactor. Natural gas is fired continuously for flue gas reheating during SCR system operation.

TABLE 4-10 – Energy Impacts for NO_X Control Alternatives - MRY Station Unit 1

Alt. Label(1)	NOx Control Alternative(2)	Estimated Annual Natural Gas Usage for Urea-to-Ammonia Conversion’(3) (mmBtu/yr)	Estimated Annual Natural Gas Usage for SCR Inlet Reheat’(4) (mmBtu/yr)	Estimated Annual Natural Gas Usage for Reburn Fuel’(5) (mmBtu/yr)	Estimated Additional Annual Coal Burned for Urea Solution Dilution Water’(6) (mmBtu/yr)	Estimated Total Annual Natural Gas Usage and ’ Additional Annual Coal Burned (7) (mmBtu/yr)
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	32,580	460,090	0	0	492,670
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	29,674	419,054	0	0	448,728
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	32,409	413,655	0	0	446,064
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	29,503	376,566	0	0	406,069
E	SNCR w/ ASOFA	0	0	0	54,315	54,315
D	Gas Reburn w/ ASOFA	0	0	3,721,806	0	3,721,806
C	Lignite Reburn w/ ASOFA	0	0	0	0	0
B	FLGR w/ ASOFA	0	0	1,541,796	0	1,541,796
A	Advanced SOFA (ASOFA)	0	0	0	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Alternatives are labeled the same as in Table 4-9.

(2) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation. Revised February, 2010.

(3) – Estimated annual natural gas usage for urea-to-ammonia conversion based on adjustments to preliminary budgetary equipment vendor proposals and process calculations. TESCR and LDSCR rate = 4.27 mmBtu/hr for one reactor.

(4) – Estimated annual natural gas usage for flue gas final reheat based on adjustments to preliminary vendor process calculations. TESCR rate = 60.3 mmBtu/hr for one reactor; LDSCR rate = ~~31~~ 54.5 mmBtu/hr for one reactor. Rev 2/10.

(5) – Natural gas burned for reburn alternatives is assumed to replace coal, no boiler heat rate penalty assumed. Lignite reburn is assumed to burn the same total amount of coal in the boiler as without coal reburn. Revised February, 2010.

(6) - Additional coal burned is due to the urea dilution water injected directly into the boiler’s upper furnace, decreasing heat available for steam production and electricity generation, at a net loss of 900 Btu/lb of water for evaporation. See Appendix C3 in the 2006 NO_X BACT Analysis Study report for additional details.

(7) - Annual O&M costs include these values multiplied by the number of hours per year of operation and assume $7.98 per mmBtu for natural gas and $0.71 per mmBtu for coal. Revised February, 2010.

4.2.3 ENVIRONMENTAL IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 1

Operation of the NO_X control technologies on the dominant controls cost curve for potential application at the Milton R. Young Station would impose direct and indirect impacts on the environment. The most pronounced direct environmental impact expected from operation of any of the NO_X control options considered is the reduction of ozone and improvement in atmospheric visibility (i.e., reduced visibility impairment) downwind of the facility. Environmental impacts of previously-evaluated NO_X control alternatives were described and summarized in Section 3.4.3 of the October 2006 NOx BACT Analysis Study report.[40]

There would be a favorable environmental impact from potential reduction of annual unit operating time by approximately two percent due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation and by between five percent and 17 percent due to catalyst management and SCR equipment maintenance-related issues for the various low-dust and tail end SCR alternatives. The impact of fewer annual hours of operation will be to decrease the annual amount (tons) of nitrogen oxides emitted, by between approximately 0.2 percent and one percent overall compared to baseline operation. However, generation of replacement electrical power at other powerplants will negate most of these emission reductions.

Operation of the hypothetical application of SCR systems is not expected to significantly impact emissions of carbon monoxide (CO) or volatile organic compounds (VOCs). Emissions from the urea-to-ammonia conversion and flue gas reheat natural gas-fired burners are additive and included in the flue gas entering the SCR reactor in each hypothetical application of SCR case.

Operation of any SCR system will normally cause a small amount of unreacted ammonia to be emitted. The amount of ammonia slip produced by an SCR depends on the reagent utilization and the location of the injection points. Higher SCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 2 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate $[(NH_4)_2SO_4]$ and ammonium bisulfate $[NH_4HSO_4]$ will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the catalyst to form the sulfates downstream.

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[40] Ibid Reference number 3, October 2006, pages 3-35 through 3-37.

Unreacted ammonia (“slip”) from SCR operation will not be collected downstream of the tail end SCR reactor. The wet flue gas desulfurization absorber downstream of the low-dust SCR reactor may reduce ammonia slip. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be emitted from the stack as an aerosol or condensable particulate. This has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition.

Sulfur dioxide (SO_2) formed during combustion in the boiler can combine with oxygen during passage through the hypothetical application of tail end and low-dust SCR catalyst to form additional sulfur trioxide (SO_3) emissions. SO_3 can subsequently combine with water (H_2O) to form sulfuric acid (H_2SO_4), usually in the form of a mist. Wet flue gas scrubbing to remove SO_2 is not highly effective in removing SO_3 created in an upstream low-dust SCR, so higher sulfate emissions will result unless a precipitating reaction with ammonia or condensation in the downstream gas-gas reheater or ductwork occurs. SO_3 and H_2SO_4 can have significant negative far-field impairment impacts on atmospheric visibility if they are above threshold concentrations and not controlled. Tail end SCRs can also cause a small amount of SO_3 to be created as the remaining SO_2 not removed by the wet lime flue gas desulfurization systems will pass through the catalyst and some will be oxidized. It is not known whether the high concentration of alkalinity in the form of sodium aerosol particles will effectively eliminate the remaining SO_3 downstream of the low-dust and tail end SCR systems.

Catalyst from the hypothetical application of SCR reactors will require regular replacement, requiring disposal of the spent catalyst materials or chemical cleaning to remove deposits to allow reuse or regeneration. Hauling spent catalyst to a catalyst rejuvenation facility or an authorized landfill may be required, producing additional liquid and solid wastes and vehicle exhaust emissions.

Because railroad service is not available to MRYS, shipments of amine reagent (concentrated urea solution) for consumption by the hypothetical application of SCR reactors will require additional truck traffic between the supply facility and plant, producing more emissions from vehicle exhaust.

4.2.4 SUMMARY OF ECONOMIC, ENERGY AND ENVIRONMENTAL IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 1

The economic, energy, and environmental impacts of each NO_X control technology on the dominant controls cost curve for potential application at the Milton R. Young Station evaluated for this study are summarized in this Section. Table 3-18 summarized the various impacts discussed in Sections 3.4.1 through 3.4.3 of the October 2006 NO_X BACT Analysis Study report[41]. This supplemental economic analysis examined the estimated capital cost of four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives and any other powerplant upgrade costs necessary to implement the alternatives. In addition, the economic analysis examined the operating and maintenance costs associated with each NO_X control technology evaluated. These costs were then combined into the levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each remaining alternative was evaluated. Four hypothetically-applied SCR cases and two previously-analyzed feasible alternatives were on the dominant controls cost curve and the latter were identified as the more cost effective alternatives. The four hypothetically-applied SCR cases and two previously-analyzed feasible BACT NO_X control alternatives were evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 1. The results are summarized in Tables 4-11SA and 4-11SF.

The unit control cost for the hypothetical application of Scenario A Tail End SCR w/ ASOFA case was $4,758/ton and was $5,969/ton for the hypothetical application of Scenario B Tail End SCR w/ ASOFA case (stand alone projects). The unit control cost for the hypothetical application of Scenario A Low-Dust SCR w/ ASOFA case was $~~3,944~~ 4,134/ton and was $~~5,380~~ 5,552/ton for the hypothetical application of Scenario B Low-Dust SCR w/ ASOFA case (stand alone projects). The unit control cost for the hypothetical application of Scenario A Tail End SCR w/ ASOFA case was $4,206/ton and was $5,420/ton for the hypothetical application of Scenario B Tail End SCR w/ ASOFA case (shared facilities projects). The unit control cost for the hypothetical application of Scenario A Low-Dust SCR w/ ASOFA case was $~~3,396~~ 3,586/ton and was $~~4,835~~ 4,813/ton for the hypothetical application of Scenario B Low-Dust SCR w/ ASOFA case (shared facilities projects). Unit control cost for SNCR w/ ASOFA was $1,265/ton, more than twice that of ASOFA ($613/ton). The UCCs for the hypothetical application of SCR are approximately ~~270~~ 280 to 470 percent of the UCC for SNCR w/ ASOFA ($1,265/ton), and approximately ~~550~~ 580 to 970 percent of ASOFA's UCC ($613/ton).

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative for MRYS Unit 1 incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control technique. The slope from zero (baseline) to ASOFA (Point A) was $613/ton; the

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[41] Ibid Reference number 3, October 2006, pages 3-20 through 3-38.

incremental cost per ton (slope) from ASOFA (Point A) to SNCR with ASOFA (Point E) was $2,694/ton for MRYS Unit 1. The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetical application of low-dust SCR case (Point L2, Scenario A) was $~~8,547~~ 9,064/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetical application of tail end SCR case (Point T2, Scenario A) was $10,765/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetical application of low-dust SCR case (Point L1, Scenario B) was $~~12,343~~ 12,806/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetical application of tail end SCR case (Point T1, Scenario B) was $13,936/ton (stand alone projects). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetical application of SCR cases were $~~7,058~~ 7,575/ton (low-dust Point L2, Scenario A) and $9,264/ton (tail end Point T2, Scenario A). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetical application of SCR cases were $~~10,876~~ 10,816/ton (low-dust, Point L1, Scenario B) and $12,458/ton (tail end Point T1, Scenario B).

The incremental unit control cost per ton (slope) from SNCR with ASOFA to the hypothetical application of SCR with ASOFA cases are approximately ~~260~~ 280 to 520 percent of the incremental UCC per ton (slope) between ASOFA and SNCR with ASOFA ($2,694/ton). The incremental UCCs from SNCR with ASOFA to the hypothetical application of SCR with ASOFA cases is between ~~11~~ 12 and 23 times the incremental UCC for ASOFA from the pre-control baseline ($613/ton).

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. EPA's NSR Manual however, does specifically address the standard to be used when rejecting a candidate technology on the basis of adverse economic impact:

> "Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source."[42]

This supplemental report for the MRYS NOx BACT Analysis has clearly established the circumstances, including the economic impacts, which would make the hypothetical application of TESCR or LDSCR to

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[42] Ibid Reference number 2, Section IV.D.2.c.

MRYS Unit 1 significantly more expensive than SCR costs normally incurred by other coal-fired steam electric generating units. The following information further supports EPA's own statements regarding the costs "normally incurred by other sources". The EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines was considered relevant for control cost-effectiveness comparison. The EPA's cost-effectiveness analysis used for establishing presumptive BART stated that "applying SCR for coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton" [43]. EPA's technical support document estimated an average control cost for SCR applied to MRYS Unit 1 of $549 per ton[44]. The unadjusted unit capital cost factor assumed by the EPA for SCR retrofits applied to cyclone boilers in the cost-effectiveness analysis used for establishing presumptive BART[45] was $100/kW. The estimated "stand alone" and "shared facilities" installed capital costs for the hypothetical application of Low-Dust SCR w/ ASOFA cases at MRYS Unit 1 are $543 to $703/kW, which is more than 500 percent of the EPA's number. The estimated "stand alone" and "shared facilities" installed capital costs for the hypothetical application of Tail End SCR w/ ASOFA cases are $706 to $867/kW, which is more than 700 percent of the EPA's number. Also stated in the final RHR/BART Guidelines, "the average cost for each [of two options, A and B]… may be deemed to be reasonable. However, the incremental cost…of the additional emissions reductions to be achieved by control B may be very great. In such an instance, it may be inappropriate to chose control B, based on its higher incremental costs, even though its average cost may be considered reasonable".[46]

4.2.5 CONCLUSIONS

The site-specific control costs estimated for application of hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines discussed above.

The expected severity of catalyst blinding and pluggage from particulate matter and flue gases emitted from cyclone-fired boilers burning North Dakota lignite precludes the technical feasibility for successful application of such SCR technologies on the electric generating units (EGUs) at the Milton R. Young Station. Not withstanding the technical discussion of SCR technology infeasibility and technical details

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[43] See Reference number 11, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[44] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.
[45] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 209.
[46] Ibid Reference number 11, July 2005, FR Vol. 70 No. 128, page 39168.

previously provided in Appendix A1 and Appendix B[47] of the initial NO_X BACT Analysis report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, this supplemental analysis concludes that the estimated capital and O&M costs for four variations of hypothetically-applied tail-end and low-dust SCR technology alternatives are significantly beyond the normal range of costs incurred, as compared to cost analysis values included in EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines[48,49]. Average control cost effectiveness for each hypothetical application of SCR control technology case is a minimum of approximately three times the unit control costs of the previously-analyzed highest-performing feasible control alternative recommended as BACT for MRYS Unit 1 (SNCR with ASOFA). Incremental control cost effectiveness for each hypothetical application of SCR control technology case is a minimum of approximately three times the incremental control costs of the previously-analyzed highest-performing feasible control alternative recommended as BACT for MRYS Unit 1 (SNCR with ASOFA).

There is an expected decrease in capacity and availability to generate electrical power due to the hypothetical application of low-dust and tail end SCR alternatives. A five to 17 percent decrease in the number of hours of annual operation, and approximately 3% drop in annual plant capacity (net electrical output or MW_n) during operation of the MRYS Unit 1 system are expected if the hypothetical application of low-dust or tail end SCR alternatives were installed. There are also substantial expected negative energy impacts for each hypothetical application of SCR control technology case. Additional auxiliary electrical power demands of approximately 8 to 10 MW will result. This estimate of electrical power usage may be too low. This higher electrical power consumption and lower electrical power generation by MRYS Unit 1 will require additional replacement electrical power to be generated elsewhere.

Natural gas is fired continuously during the urea-to-ammonia conversion system operation for the hypothetical application of Tail End and Low-Dust SCR with ASOFA alternatives.

Final reactor inlet flue gas reheat systems are required for the hypothetical application of Tail End and Low-Dust SCR with ASOFA alternatives. Natural gas is fired continuously for flue gas reheating during SCR system operation for raising the reactor inlet temperature to ~~600ºF~~ minimum operating temperature

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[47] Ibid Reference number 3, October 2006.
[48] See Reference number 11, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[49] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.

(580ºF for low-dust, 563ºF for tail-end SCRs) before ammonia injection and NOx reduction can occur in the SCR reactor.

The site-specific control costs estimated for application of hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines[50]. SCR technologies of all three types identified in the October 2006 NO_X BACT Analysis Study report should be excluded from consideration for NO_X control at MRYS due to unacceptably high average and incremental cost per ton of pollutant removal based on the supplemental analysis provided herein. Therefore the conclusions regarding NOx BACT as expressed in the original October 2006 BACT Analysis for MRYS Unit 1 are confirmed.

The economic, energy, and environmental impacts of each NO_X control technology on the dominant controls cost curve for potential application to Unit 1 at the Milton R. Young Station evaluated for this study are summarized in Tables 4-11SA and 4-11SF.

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[50] See Reference number 4, July, 2005.

TABLE 4-11SA – Summary of Supplemental BACT Analysis Impact Results for Dominant NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

		EMISSIONS(2)				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS(9)	
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton	Incremental Control Cost(7) $/ton	Incremental Aux. Power Demand(8), kW	Incremental Annual Aux. Power Usage + Generation Reduction(8), kW-hrs/yr	Non-Air Increase	Toxic Air Increase
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(10)	0.053	145	589	9,345	222,864	20,048	44,465	4,758	10,765	9,685	171,745,369	Flyash UBC, catalyst disposal	CO, NH_3
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(10)	0.053	145	536	9,398	222,864	29,361	56,095	5,969	13,936	9,685	342,358,537	Flyash UBC, catalyst disposal	CO, NH_3
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(10)	0.053	145	586	9,348	180,739	18,332	38,649	4,134	9,064	8,012	169,418,356	Flyash UBC, catalyst disposal	CO, NH_3
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(10)	0.053	145	533	9,401	180,739	29,178	52,193	5,552	12,806	8,012	341,140,028	Flyash UBC, catalyst disposal	CO, NH_3
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	8,113	5,417	7,472	1,265	2,694	73	68,243,017	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	4,277	1,695	2,489	613	613	1	46,594,605	Flyash UBC	CO
	Baseline	0.849	2,330	9,934	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars. Revised February, 2010.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor. Revised February, 2010.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars. Revised February, 2010.

(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars. Revised February, 2010.

(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit reliability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr) compared to the pre-control baseline.

(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative compared to the pre-control baseline. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations may increase an insignificant amount with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology and the hypothetical application of SCR technology cases.

(10) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

TABLE 4-11SF – Summary of Supplemental BACT Analysis Impact Results for Dominant NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

		EMISSIONS(2)				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS(9)	
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton	Incremental Control Cost(7) $/ton	Incremental Aux. Power Demand(8), kW	Incremental Annual Aux. Power Usage + Generation Reduction(8), kW-hrs/yr	Non-Air Increase	Toxic Air Increase
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(10)	0.053	145	589	9,345	181,484	18,806	39,307	4,206	9,264	9,685	171,745,369	Flyash UBC, catalyst disposal	CO, NH_3
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(10)	0.053	145	536	9,398	181,484	28,120	50,937	5,420	12,458	9,685	342,358,537	Flyash UBC, catalyst disposal	CO, NH_3
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(10)	0.053	145	586	9,348	139,639	17,099	33,526	3,586	7,575	8,012	169,418,356	Flyash UBC, catalyst disposal	CO, NH_3
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(10)	0.053	145	533	9,401	139,639	26,483	45,244	4,813	10,816	8,012	341,140,028	Flyash UBC, catalyst disposal	CO, NH_3
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	8,113	5,417	7,472	1,265	2,694	73	68,243,017	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	4,277	1,695	2,489	613	613	1	46,594,605	Flyash UBC	CO
	Baseline	0.849	2,330	9,934	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars. Revised February, 2010.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor. Revised February, 2010.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars. Revised February, 2010.

(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars. Revised February, 2010.

(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit reliability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr) compared to the pre-control baseline.

(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative compared to the pre-control baseline. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations may increase an insignificant amount with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology and the hypothetical application of SCR cases.

(10) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

1. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.

2. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").

3. "BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc." and a separate "BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc." Final Report, October 2006 submitted by Minnkota to North Dakota Department of Health.

4. Technical Support Document Methodology For Developing BART NOx Presumptive Limits, Environmental Protection Agency, Clean Air Markets Division, June 15, 2005, OAR-2002-0076-0445, with Attachments, including Excel Spreadsheet OAR-2002-0076-0446 (1199 pages).

5. Comment & Response to EPA Region 8's October 4, 2007 Comment on NDDH BACT Determination at Milton R. Young Station, submitted by Minnkota to NDDH, November 9, 2007.

6. EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034, dated March, 2005, posted at their website: http://www.epa.gov/airmarkets/articles/multireport2005.pdf.

7. "Assessment of Control Technology Options for BART-Eligible Sources, Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities", dated March 2005, prepared by Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic/Northeast Visibility Union, posted at the website: http://bronze.nescaum.org/committees/haze/BART_Control_Assessment.pdf.

8. "Analysis of Combustion Controls for Reducing NO_X Emissions From Coal-fired EGU's in the WRAP Region, Draft Report", prepared for the Western Regional Air Partnership by Eastern Research Group, Inc., ERG Contract Number 30204-101, dated April 26, 2005, available at: http://www.wrapair.org/forums/ssjf/documents/eictts/NOxEGU/050426Coal-fired%20EGUs_in_WRAP_Region-draft.pdf

9. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

10. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 2 - Selective Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch2.pdf

11. Federal Register /Vol. 70, No. 128/ Wednesday, July 6, 2005 / Rules and Regulations, Part III Environmental Protection Agency 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule.

MINNKOTA POWER COOPERATIVE, Inc. and SQUARE BUTTE ELECTRIC COOPERATIVE

RESPONSES TO NDDH REQUEST NOx BACT ANALYSIS STUDY MILTON R. YOUNG STATION UNIT 1 and UNIT 2 REGARDING SCR ECONOMIC FEASIBILITY

December 11, 2009

Revised February 2010 (refer to page 13 for Index of Revisions)

North Dakota Department of Health's Environmental Health Section, Division of Air Quality has requested[1] that Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") provide more detailed and comprehensive cost data following their reviews of the Best Available Control Technology (BACT) Analysis Study – Supplemental reports[2] submitted on November 12, 2009 for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 at Milton R. Young Station ("MRYS"). A detailed breakdown of capital costs and operation and maintenance costs for hypothetical applications of low-dust and tail end SCR alternatives, assuming that they are technically feasible to apply at MRYS as NDDH has recently advised[3], are attached. Responses to the use of steam from the main boilers for reheat of the flue gas are provided. A comparison of control costs from relevant recent BACT Determinations versus the estimated control costs of hypothetical applications of low-dust and tail end SCR technologies at MRYS included with the November 2009 Supplemental Reports is also provided.

Burns & McDonnell (B&McD) was retained by MPC as an independent consultant to perform the referenced NO_X BACT Analysis Study[4] of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station (MRYS) in accordance with the requirements of a Consent Decree (CD)[5]. The November 2009 NO_X BACT Analysis Study Supplemental Reports were generated in response to the NDDH's request[6] to see Steps 3 and

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[1] See Reference number 1, November 25, 2009.

[2] See Reference number 2, November 12, 2009.

[3] See Reference number 3, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

[4] See Reference number 4, October 2006.

[5] See Reference number 5, April 24, 2006.

[6] Ibid Reference number 3, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

4 of the BACT analysis process[7] be performed and include low-dust and tail end SCR alternatives.

Detailed NOx BACT Analysis Study Supplemental reports' Capital and Operating & Maintenance Cost Summary:

NDDH Request: "A detailed breakdown of capital costs and operation and maintenance costs for the bulleted items on page 4-16 should be provided."[8]

BMcD Response:

The referenced "bulleted items on page 4-16" of the November 2009 NOx BACT Analysis Study Supplemental reports are intended to represent the major components (physical assets) that were identified as being required to install and operate low-dust and tail end SCRs if they were considered technically feasible for application at MRYS. Preliminary SCR Cost Estimates used as inputs to the November 2009 NO_X BACT Analysis Study Supplemental Reports were not developed based upon a direct match to each of the bulleted items included in the reports. Thus it is not possible to provide a cost breakdown in that format. In lieu of a breakout directly corresponding to the bulleted items, Burns & McDonnell has modified our cost estimate spreadsheets for the four "shared facilities" as well as the four "stand alone" hypothetical applications of SCR technologies analyzed, to reflect the cost tabulation format used in the "SCR Chapter" of the "EPA Air Pollution Control Cost Manual – Sixth Edition" (Section 4.2; Chapter 2).

Please see the attached "Shared Facilities Total Capital Investment" and "Stand Alone Total Capital Investment" cost estimate tables that follow the outline of Table 2.5 in the SCR Chapter of EPA's Control Cost Manual[9] for these hypothetical applications of SCR technologies analyzed. Note that this SCR Chapter of the EPA Control Cost Manual is intended for estimating costs of high dust SCRs, as it states on page 2-41 that "costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher

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[7] See Reference number 8, October 1990.

[8] Ibid Reference number 1, November 25, 2009.

[9] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-44, January 2002.

than the high-dust SCR systems due to flue gas heating requirements"[10]. The SCR Chapter of the Control Cost Manual also states that "the cost methodology is valid for a low-dust SCR system because the cost reductions are expected to be within the range of uncertainty for study-level costs"[11]. We also suggest that the SCR Cost Manual is not suitable for estimating the costs for the cold-side low-dust SCR arrangement analyzed in the Supplemental NOx BACT reports for MRYS because of the flue gas reheating required.

Also see attached tables of estimated "Shared Facilities Total Annual Costs" and "Stand Alone Total Annual Costs" that include the items described in pages 2-44 through 2-49 of the SCR Chapter of EPA's Control Cost Manual[12] for an SCR application. As previously mentioned, the equations in the SCR Cost Manual's cost methodology were not used for estimating annual costs of electrical power consumption, reagent usage, and catalyst replacements. Note that budgetary vendor quotes were the primary source of information used to calculate these estimated annual costs of the hypothetical applications of SCR technologies analyzed.

Use of Steam from the main boilers for reheat of flue gas (for low-dust and tail end SCR alternatives):

NDDH Request: "The use of steam from the main boilers for the flue gas reheat should also be addressed."

BMcD Response:

Natural gas-fired flue gas reheat is shown in the SCR Chapter of EPA's Control Cost Manual for an SCR application of a tail end SCR example[13], so the use of such reheat systems is not unique to Minnkota's study. MPC selected natural gas firing and rejected the use of steam for flue gas reheating for the evaluation of hypothetical applications of low-dust and tail end SCR technologies at MRYS. For the SCR cost estimate study by Burns & McDonnell, it was necessary to establish the scope conceptual design basis for estimating the costs associated with installation and operation and maintenance of the hypothetical applications of low-dust and tail

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[10] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-41, January 2002.
[11] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-41, January 2002.
[12] Ibid Reference number 9, Section 4.2, Chapter 2, pages 2-44 – 2-49, January 2002.
[13] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-21, January 2002.

end SCR technologies. Minnkota's selection of natural gas-fired flue gas reheating for these conceptual designs and cost estimates was made in order to avoid additional loss of unit electrical energy generation output capacity.

A preliminary high level conceptual review of the MRYS Unit 1 steam cycle was done by Minnkota to investigate the feasibility of using steam to achieve the estimated heat duty (was 31.1 but is now 54.5 million BTU/hr to raise flue gas temperature from ~~555°F~~ 535°F to 580°F for one reactor) required for the hypothetical application of low dust SCR technology. This preliminary review indicated that using steam for this service appeared to be feasible but would result in a unit electrical output capacity derate of ~~4-5 MW~~ 7 to 9 MW. This is because the high-temperature/high-pressure main steam extracted from the boiler for flue gas reheat system would not pass through any stages of the high/intermediate/low pressure steam turbines, so less net electrical energy would be produced.

The value of lost electrical generating capacity was not calculated, but the steady-state long term operation impact is believed to be approximately ~~50%~~ 90% or more of the total auxiliary electricity demand estimated in the November 2009 NO_X BACT Analysis Study Supplemental Reports' Table C.4-3[14] for the hypothetical application of SCR technologies at MRYS.

The preliminary concept assumed that main boiler steam (high pressure, high temperature, around 1000°F, 2500 psig) would be diverted from the steam turbine's inlet piping, and be routed for supply to the flue gas heating system. This would involve the heating steam supplied being condensed using heating coils inserted into the flue gas ductwork. The condensate liquid would then be returned to the boiler feedwater treatment system for reuse. The 7 to 9 MW (was 4-5 MW) Unit 1 derate for a hypothetical application of low-dust SCR technology does not include additional downtime due to tube leaks or other maintenance issues associated with the flue gas reheat steam system. Higher induced draft booster fan discharge pressure requirement for pressure drop is not included. Use of steam for cleaning the in-duct steam coils' exterior surfaces or the gas-to-gas heat exchanger online during operation using soot blowing is also not included in this estimate of the potential unit derate. The time required to modify the main steam

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[14] Ibid Reference 2, page 4-27.

piping and other steam turbine and boiler feedwater treatment system components in the steam cycle power generation and balance-of-plant systems and boiler flue gas systems to accommodate such suggested changes would be lengthy. The duration of an outage to implement such modifications, and value of lost electrical generating capacity, would be significant.

A similar preliminary high level conceptual review of the MRYS Unit 2's steam cycle to investigate the feasibility of using steam to achieve the estimated heat duty (2 reactors, 48.1 MMBTU/hr each to raise flue gas temperature from 535°F to 580°F) required for a hypothetical application of low-dust SCR technology was not performed. Although sizing was not evaluated for MRYS Unit 2, using a scaling factor (4-5 MW times the ratio of 96.2 divided by 31.1 MMBTU/hr heat duty values~~477 MW divided by 257 MW nameplate capacity ratings~~) to estimate Unit 2's derate compared with Unit 1's estimated derate could be applied for an approximation. This would yield a potential Unit 2 electrical generating output capacity derate on the order of magnitude of ~~8-10 MW~~ 12.4 to 15.5 MW for a hypothetical application of low-dust SCR technology. Similar impacts and issues as described for Unit 1 would be expected for Unit 2.

A similar preliminary high level conceptual review of the MRYS Unit 1's steam cycle to investigate the feasibility of using steam to achieve the estimated heat duty (1 reactor, 60.3 MMBTU/hr each to raise flue gas temperature from 520°F to 563°F) required for a hypothetical application of tail end SCR technology was not performed. Although sizing was not evaluated for this case, using a scaling factor (ratio of 60.3 divided by 31.1 heat duties) to estimate Unit 1's derate compared with Unit 1's estimated derate for a hypothetical application of low-dust SCR technology could be applied for an approximation. This would yield a potential Unit 1 electrical generating output capacity derate on the order of magnitude of 8 to 10 MW for a hypothetical application of tail end SCR technology. Similar impacts and issues as previously described for Unit 1 would be expected.

A similar preliminary high level conceptual review of the MRYS Unit 2's steam cycle to investigate the feasibility of using steam to achieve the estimated heat duty (2 reactors, 50.8

MMBTU/hr each to raise flue gas temperature from 520°F to 563°F) required for a hypothetical application of tail end SCR technology was not performed. Although sizing was not evaluated for MRYS Unit 2, using a scaling factor (ratio of 101.6 divided by 31.1 heat duties) to estimate Unit 2's derate compared with Unit 1's estimated derate could be applied for an approximation. This would yield a potential Unit 2 electrical generating output capacity derate on the order of magnitude of 13 to 16 MW for a hypothetical application of tail end SCR technology. Similar impacts and issues as described for Unit 1 would be expected for Unit 2.

These estimates of lost electrical generation outputs come from boiler main steam usage, larger induced draft fan power requirements, and potential additional downtime associated with the flue gas reheating systems. Because the MRYS units' electrical energy generation output capacity is limited by the steam energy production capacity of each boiler ("boiler limited"), there is not "free capacity margin" available to offset the megawatt losses. Minnkota also cannot increase boiler hourly heat inputs (coal firing rates) in order to compensate for the decrease in output because the increased emissions from higher firing rates are not permitted.

Additional arguments that support the decision to select natural gas firing and reject the use of steam for flue gas reheating involving hypothetical applications of low-dust and tail end SCR technologies at MRYS:

- Minnkota's previous experience with the use of steam for Unit 2's flue gas desulfurization system absorber outlet flue gas reheat (for stack plume buoyancy) was not positive and the technique was abandoned in favor of reheat via scrubber flue gas bypass. The Consent Decree does not allow Minnkota to continue the use of unscrubbed flue gas for reheating the stack gas[15].
- Boiler-turbine steam systems are complex and sensitive to steam inputs, extractions, and outlet conditions. There was insufficient time available during the SCR cost estimate study to perform a comprehensive analysis of potential performance impacts from the modifications related to the use of steam for flue gas reheat.
- High pressure/high temperature steam piping is expensive to procure and install, and requires special design to accommodate thermal growth and significant weight and

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[15] Ibid Reference number 5, April 24, 2006.

dynamic loads without overstress. There was insufficient time available during the SCR cost estimate study to perform a comprehensive analysis of potential hanger supports, pipe sizing and routing from the main steam source to the multiple points of use and return of condensate to the boiler plant.

- The deposits removed during cleaning of the in-duct steam coils fouled by particulate, aerosols, and ash products emitted from the boilers and also removed from the gas-gas heat exchanger upstream of the flue gas reheater will be entrained in the flue gas stream entering the SCR reactor. This will require a "large particle ash screen" that creates more pressure drop than the direct-fired duct burner.

Comparison of Average and Incremental Control Costs for MRYS NOx BACT (for low-dust and tail end SCR alternatives) versus recent BACT determinations:

NDDH Request: "It should be documented that the costs of SCR at the M.R. Young Station are significantly beyond the range of recent costs normally associated with BACT for coal-fired power plants (or BACT control costs in general) for the control of nitrogen oxides (NSR Manual Chapter B, Section IV.D.2.C)."

BMcD Response:

A review of available information on "costs normally associated with BACT" for control of NOx emissions from coal-fired power plants indicates that very little documentation is published. Although both the EPA's RACT BACT LAER Clearinghouse (RBLC) [http://cfpub.epa.gov/rblc/htm/bl02.cfm] and the EPA's "National Coal-Fired Utility Projects Spreadsheet" [available via http://www.epa.gov/ttn/catc/products.html#misc] include an assigned database field for entry of "Control Cost Effectiveness" in units of $/ton, neither of these sources contains much information. The assigned field where the data should be entered is blank in the vast majority of cases entered in these databases.

This dearth of data on BACT cost effectiveness was encountered by EPA Region 8 during its preparation of the "Response to Public Comments" for the Draft PSD Permit for Deseret Power Electric Cooperative's proposed 110 MW waste coal fired unit addition to the Bonanza Power Plant[16]. In seeking to defend the cost basis for its rejection of a control technology as BACT, EPA Region 8 was able to identify only 13 cases (total for all pollutants) in which control cost effectiveness data were identified in recent permit actions involving BACT.

Burns & McDonnell reviewed the cases identified by EPA Region 8 in their response for the Deseret BACT case to determine if any data on "the cost associated with BACT" was available for cases involving NOx control for coal-fired boilers. Of the 13 cases for all pollutants identified by EPA Region 8, only one case involved the rejection of the "top" NOx control

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[16] See Reference number 10, pages 29-33.

technology as BACT due to what was identified as "excessive cost". This was the case of MDU's proposed Gascoyne project in North Dakota. The inability of EPA Region 8 to identify more cases in which the permit record clearly establishes the level of NOx control costs illustrates the difficulty of this task.

Burns & McDonnell was able to identify only two other cases, both also in North Dakota, in which the permit record shows that the "top" NOx control technology for a coal-fired boiler was rejected as having an excessive "control cost effectiveness". The relevant data for these cases is tabulated below, and compared to similar information as stated in the Supplemental NO_X BACT reports prepared for MRYS Units 1 and 2.

Previous Coal-Fired Boiler NO_X BACT Determinations Based on Cost Effectiveness

State	Utility	Plant Name	Technology Considered Technically Feasible but Rejected as BACT by State Agency	Average Control Cost of Rejected Technology	Average Control Cost of Technology Accepted as BACT	Technology Recommended as BACT
ND	MDU	Gascoyne	SCR	$7545/ton	$2926/ton	SNCR
ND	South Heart Coal LLC	South Heart	SCR	$7640/ton	$1690/ton	SNCR
ND	GRE	Spiritwood	SCR	$7640/ton	$1843/ton	SNCR

As shown in the table above, for coal-fired boilers the "average cost effectiveness of BACT for NOx" as established in previous permit actions ranges from $1690/ton to $2926/ton. By comparison, the estimated cost for NOx control using SCR, which was rejected as BACT due to excessive costs in these previous cases, ranged from 2.6 to 4.5 times the control cost of the technology established as BACT using the "top down" process.

Control Cost Data from MRYS Units 1 & 2 Supplemental NOx BACT Reports

"Top" Technology Recommended to be Rejected as BACT	Average Control Cost of "Top" Technology	Average Control Cost of Technology Recommended as BACT	Technology Recommended as BACT
MRYS Unit 1 Low-Dust or Tail End SCR with ASOFA	\$3,586/ton to \$5,969/ton	\$1,265/ton	MRYS Unit 1 SNCR with ASOFA
MRYS Unit 2 Low-Dust or Tail End SCR with ASOFA	\$3,859/ton to \$6,597/ton	\$1,240/ton	MRYS Unit 2 SNCR with ASOFA

In the case of MRYS Units 1 and 2, and taking the range of control costs for SCR (TESCR and LDSCR) with ASOFA as presented in the Supplemental NO_X BACT reports (shown above), the ratio between the cost of the technology proposed for rejection on a cost basis to the cost of the technology proposed as BACT for the MRYS units is quite similar to that seen in previous permit actions. For Unit 1, the cost ratio ranges from 2.8 to 4.7. For Unit 2, the cost ratio ranges from 3.1 to 5.3. Thus it appears that the same rationale that was used to reject SCR technology as being "excessively costly on a \$/ton control cost basis" in the case of these other three North Dakota BACT determinations should also apply to the case of MRYS.

REFERENCES

1. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: BACT Cost Estimate*, dated November 25, 2009.

2. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009; and a separate NO_X BACT Analysis Study – Supplemental Report for Milton R. Young Station Unit 2 for Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, November 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009.

3. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.

4. "BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc." and a separate "BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc." Final Report, October 2006 submitted by Minnkota to North Dakota Department of Health.

5. Consent Decree filed in the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034, filed April 24, 2006.

6. ERG Memorandum to EPA Region 8 and EPA Office of Regulatory Enforcement, *Review and Critique of the Burns & McDonnell NO_X BACT Analysis for the Milton R. Young Station Operated by Minnkota Power (October 2006),* written by Roger Christman, Eastern Research Group, Inc., January 8, 2007, faxed by North Dakota Department of Health to Minnkota, January 9, 2007.

7. *EPA Region 8 Preliminary Analysis of Burns & McDonnell BACT Analysis For Nitrogen Oxide at Milton R. Young Station, Units 1 and 2 January 8, 2007* faxed by North Dakota Department of Health to Minnkota, January 9, 2007.

8. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").

9. EPA Air Pollution Control Cost Manual – Sixth Edition (EPA/452/B-02-001), January 2002.

10. *Response to Public Comments on Draft Air Pollution Control Prevention of Significant Deterioration (PSD) Permit to Construct [Permit No. PSD-OU-0002-04.00]*, U.S. EPA Region 8, August 30, 2007.

ATTACHMENTS

1. "Shared Facilities Total Capital Investment" and "Stand Alone Total Capital Investment" cost estimate tables for Low-Dust and Tail End Selective Catalytic Reduction alternatives, as supporting information regarding Unit 1 and Unit 2 at Milton R. Young Station, November, 2009, Reference number 2, NO_X Best Available Control Technology Analysis Study – Supplemental Reports for Minnkota Power Cooperative, Inc., dated December 7, 2009.

2. "Shared Facilities Total Annual Costs" and "Stand Alone Total Annual Costs" tables for Low-Dust and Tail End Selective Catalytic Reduction alternatives, as supporting information regarding Unit 1 and Unit 2 at Milton R. Young Station, November, 2009, Reference number 2, NO_X Best Available Control Technology Analysis Study – Supplemental Reports for Minnkota Power Cooperative, Inc., dated December 7, 2009.

INDEX OF REVISIONS

Strikethrough indicates text that has been deleted.

Underline indicates text that has been inserted or revised.

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Attach #1

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Capital Investment for Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis

Revised February 2010

Shared Facilities

DIRECT CAPITAL COSTS	Low Dust U1	Low Dust U2	Tail End U1	Tail End U2	Notes
(1) Purchased Capital Equipment					
(a) SCR System Equipment					
Capital Cost of SCR System	$ 29,738,389	$ 52,565,778	$ 38,796,814	$ 70,418,628	Note 1
Capital Cost of Spare Catalyst					Note 2
(b) Auxiliaries/Balance of Plant	$ 23,756,987	$ 40,894,045	$ 33,414,080	$ 52,307,775	Note 3
(c) Instruments and controls					Note 4
(d) Taxes					Note 5
(e) Freight					Note 6
PURCHASED CAPITAL EQUIPMENT COSTS - TOTAL	$ 53,495,376	$ 93,459,823	$ 72,210,894	$122,726,403	Note 7
(2) Construction Costs					
(a) Foundations and supports	$ 15,097,939	$ 28,304,959	$ 20,041,826	$ 39,631,284	Note 8
(b) Urea storage building					Note 9
(c) Electrical	$ 6,901,578	$ 13,809,256	$ 7,690,294	$ 15,296,131	Note 10
(d) Mechanical/Piping	$ 2,411,613	$ 4,718,286	$ 2,513,213	$ 4,995,255	Note 11
(e) Insulation	$ 3,195,016	$ 4,686,967	$ 5,350,536	$ 7,143,550	Note 12
(f) Painting					Note 13
DIRECT CAPITAL CONSTRUCTION COSTS - TOTAL	$ 27,606,146	$ 51,519,468	$ 35,595,868	$ 67,066,221	Note 14
DIRECT CAPITAL COSTS - TOTAL	$ 81,101,522	$144,979,291	$107,806,762	$189,792,624	Note 15
INDIRECT CAPITAL COSTS					
(3) Indirect Installation Costs					
(a) Engineering & Field Support	$ 12,165,228	$ 21,746,894	$ 16,171,014	$ 28,468,894	Note 16
(b) Construction Mgt & Indirects	$ 3,244,061	$ 5,799,172	$ 4,312,270	$ 7,591,705	Note 17
(c) Startup Expenses	$ 1,582,000	$ 2,938,000	$ 1,582,000	$ 2,938,000	Note 18
(d) Scope Contingency	$ 12,486,493	$ 21,567,604	$ 16,536,353	$ 28,151,800	Note 19
(4) Other Indirect Costs					
(a) Pricing Contingency	$ 12,486,493	$ 21,567,604	$ 16,536,353	$ 28,151,800	Note 20
INDIRECT INSTALLATION COSTS - TOTAL	$ 41,964,276	$ 73,619,274	$ 55,137,991	$ 95,302,199	Note 21
(5) Cost Escalation during Project	$ 26,772,124	$ 40,212,687	$ 35,491,483	$ 52,726,778	Note 22
(6) Interest During Construction	$ 17,441,200	$ 30,047,900	$ 23,097,900	$ 39,221,000	Note 23
(7) Natural Gas Pipeline - Installed	$ 2,362,500	$ 4,387,500	$ 2,362,500	$ 4,387,500	Note 24
(8) Owner's Costs - Other	$ 13,632,335	$ 24,182,077	$ 16,920,540	$ 29,632,862	Note 25
TOTAL CAPITAL INVESTMENT	**$183,273,957**	**$317,428,728**	**$240,817,176**	**$411,062,963**	Note 26

Shared Facilities (SF) represents estimated costs if SCR equipment is retrofitted to both boilers concurrently. This table follows outline of Table 2.5 of EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44.

Note 1: Includes costs for SCR equipment including initial catalyst, flue gas heat recovery equipment, and flue gas reheat burner equipment as well mechanical setting of this equipment.

Note 2: Does not include spare catalyst in purchased SCR equipment costs.

Note 3: Includes service air and sootblower air compressors, induced draft booster fan(s) and dampers, urea-to-ammonia conversion ~~flue gas reheat~~ equipment with natural gas-firing burners and fan(s), SCR bypass ducts and isolation dampers, interconnecting ductwork, equipment for active coal yard storage modifications, and catalyst standby heating auxiliary equipment costs as well as mechanical setting of this equipment. (Revised February 2010)

Note 4: Instrumentation and controls are included in Electrical Construction costs (see Note 10).

Note 5: Sales taxes for engineered equipment and permanent materials is not included; Taxes are included for consumable materials.

Note 6: Delivery expenses are included in equipment costs.

Note 7: Sum of SCR, Auxiliaries/Balance of Plant, and Instruments/Controls equipment costs; taxes and freight.

Note 8: Includes site excavation, structural steel, concrete, and architectural construction costs. Includes SCR bypass ducts and isolation dampers, and interconnecting ductwork construction costs.

Note 9: Estimated separately as shown in Table 4.5 SF in Supplemental BACT Control and Cost Effectiveness Analysis.

Note 10: Instrumentation and Controls, additional plant electrical distribution equipment are included in Electrical construction costs.

Note 11: Mechanical/Piping includes material and installation of all piping not provided with engineered equipment.

Note 12: Insulation includes ductwork and piping insulation.

Note 13: Painting included in structural and architectural construction costs.

Note 14: Sum of Direct Capital Construction Costs.

Note 15: Sum of Total Purchased Capital Equipment and Total Direct Capital Construction Costs; considered to be equivalent to "A" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 16: Sum of Engineering and Field Support Costs.

Note 17: Sum of Construction Management and Construction Indirects.

Note 18: Startup Costs include costs for startup engineering support.

Note 19: Scope contingency is to account for potential changes in the project scope resulting from engineering, equipment, and/or construction work which were not identified or included.

Note 20: Pricing contingency is to account for potential changes in project costs resulting from wages, productivities, equipment and/or materials costs being higher than anticipated. Note: this does not intend to cover pricing increases over time, i.e. Escalation. Considered to be equivalent to "C" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 21: Sum of Indirect Capital Installation Costs; considered to be equivalent to "D", Total Plant Costs in EPA OAQPS SCR Cost Manual Table 2.5.

Note 22: Escalation is a result of anticipated increases in costs that are due to higher costs over time.

Note 23: Interest During Construction (or Allowance for Funds During Construction) are considered to be equivalent to "E" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 24: Natural gas pipeline construction cost was assumed as an owner cost.

Note 25: Other Owner Costs include Owner personnel, insurance, pilot testing, Owner Contingency and Spare Parts.

Note 26: Total Capital Investment (TCI) is equivalent to Installed Capital Cost for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Table 4-5SF, page 4-18. The installed capital cost of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, are not included in these numbers. See Table 4-5SF.

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Capital Investment for
Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis
Revised February 2010
Stand Alone

DIRECT CAPITAL COSTS	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**	**Notes**
(1) Purchased Capital Equipment					
(a) SCR System Equipment					
Capital Cost of SCR System	$ 29,738,389	$ 52,565,778	$ 38,796,814	$ 70,418,628	Note 1
Capital Cost of Spare Catalyst					Note 2
(b) Auxiliaries/Balance of Plant	$ 34,665,617	$ 46,348,360	$ 44,322,710	$ 57,762,090	Note 3
(c) Instruments and controls					Note 4
(d) Taxes					Note 5
(e) Freight					Note 6
PURCHASED CAPITAL EQUIPMENT COSTS - TOTAL	$ 64,404,006	$ 98,914,138	$ 83,119,524	$128,180,718	Note 7
(2) Construction Costs					
(a) Foundations and supports	$ 20,120,339	$ 30,816,159	$ 25,024,641	$ 42,122,692	Note 8
(b) Urea storage building					Note 9
(c) Electrical (Revised Feb. 2010)	$ 8,399,220	$ 14,558,077	$ 9,489,326	$ 16,195,648	Note 10
(d) Mechanical/Piping	$ 4,299,227	$ 5,662,093	$ 4,400,827	$ 5,939,062	Note 11
(e) Insulation	$ 3,288,333	$ 4,733,626	$ 5,443,853	$ 7,190,209	Note 12
(f) Painting					Note 13
DIRECT CAPITAL CONSTRUCTION COSTS - TOTAL	$ 36,107,120	$ 55,769,955	$ 44,358,647	$ 71,447,611	Note 14
DIRECT CAPITAL COSTS - TOTAL	$100,511,125	$154,684,093	$127,478,171	$199,628,329	Note 15
INDIRECT CAPITAL COSTS					
(3) Indirect Installation Costs					
(a) Engineering & Field Support	$ 15,076,669	$ 23,202,614	$ 19,121,726	$ 29,944,249	Note 16
(b) Construction Mgt & Indirects	$ 4,020,445	$ 6,187,364	$ 5,099,127	$ 7,985,133	Note 17
(c) Startup Expenses	$ 1,582,000	$ 2,938,000	$ 1,582,000	$ 2,938,000	Note 18
(d) Scope Contingency	$ 15,436,040	$ 22,988,134	$ 19,529,462	$ 29,593,180	Note 19
(4) Other Indirect Costs					
(a) Pricing Contingency (Rev. 2/10)	$ 15,436,040	$ 22,988,134	$ 19,529,462	$ 29,593,180	Note 20
INDIRECT INSTALLATION COSTS - TOTAL	$ 51,551,194	$ 78,304,245	$ 64,861,776	$100,053,742	Note 21
(5) Cost Escalation during Project	$ 30,170,164	$ 42,869,269	$ 42,013,593	$ 55,436,089	Note 22
(6) Interest During Construction	$ 21,561,300	$ 32,027,100	$ 27,278,800	$ 41,228,900	Note 23
(7) Natural Gas Pipeline - Installed	$ 6,750,000	$ 6,750,000	$ 6,750,000	$ 6,750,000	Note 24
(8) Owner's Costs - Other	$ 23,114,224	$ 27,867,439	$ 26,204,034	$ 33,248,637	Note 25
TOTAL CAPITAL INVESTMENT	**$236,658,008**	**$342,502,146**	**$294,586,374**	**$436,345,697**	Note 26

Stand Alone (SA) represents estimated costs if SCR equipment is retrofitted to both boilers independently. This table follows outline of Table 2.5 of EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44.

Note 1: Includes costs for SCR equipment including initial catalyst, flue gas heat recovery equipment, and flue gas reheat burner equipment as well mechanical setting of this equipment.

Note 2: Does not include spare catalyst in purchased SCR equipment costs.

Note 3: Includes service air and sootblower air compressors, induced draft booster fan(s) and dampers, urea-to-ammonia conversion ~~flue gas reheat~~ equipment with natural gas-firing burners and fan(s), SCR bypass ducts and isolation dampers, interconnecting ductwork, equipment for active coal yard storage modifications, and catalyst standby heating auxiliary equipment costs as well as mechanical setting of this equipment. (Revised February 2010)

Note 4: Instrumentation and controls are included in Electrical Construction costs (see Note 10).

Note 5: Sales taxes for engineered equipment and permanent materials is not included; Taxes are included for consumable materials.

Note 6: Delivery expenses are included in equipment costs.

Note 7: Sum of SCR, Auxiliaries/Balance of Plant, and Instruments/Controls equipment costs; taxes and freight.

Note 8: Includes site excavation, structural steel, concrete, and architectural construction costs. Includes SCR bypass ducts and isolation dampers, and interconnecting ductwork construction costs.

Note 9: Estimated separately as shown in Table 4.5 SA in Supplemental BACT Control and Cost Effectiveness Analysis.

Note 10: Instrumentation and Controls, additional plant electrical distribution equipment are included in Electrical construction costs.

Note 11: Mechanical/Piping includes material and installation of all piping not provided with engineered equipment.

Note 12: Insulation includes ductwork and piping insulation.

Note 13: Painting included in structural and architectural construction costs.

Note 14: Sum of Direct Capital Construction Costs.

Note 15: Sum of Total Purchased Capital Equipment and Total Direct Capital Construction Costs; considered to be equivalent to "A" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 16: Sum of Engineering and Field Support Costs.

Note 17: Sum of Construction Management and Construction Indirects.

Note 18: Startup Costs include costs for startup engineering support.

Note 19: Scope contingency is to account for potential changes in the project scope resulting from engineering, equipment, and/or construction work which were not identified or included.

Note 20: Pricing contingency is to account for potential changes in project costs resulting from wages, productivities, equipment and/or materials costs being higher than anticipated. Note: this does not intend to cover pricing increases over time, i.e. Escalation. Considered to be equivalent to "C" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 21: Sum of Indirect Capital Installation Costs; considered to be equivalent to "D", Total Plant Costs in EPA OAQPS SCR Cost Manual Table 2.5.

Note 22: Escalation is a result of anticipated increases in costs that are due to higher costs over time.

Note 23: Interest During Construction (or Allowance for Funds During Construction) are considered to be equivalent to "E" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 24: Natural gas pipeline construction cost was assumed as an owner cost.

Note 25: Other Owner Costs include Owner personnel, insurance, pilot testing, Owner Contingency and Spare Parts.

Note 26: Total Capital Investment (TCI) is equivalent to Installed Capital Cost for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Table 4-5SA, page 4-17. The installed capital cost of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, are not included in these numbers. See Table 4-5SA.

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Annual Costs for
Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis

Shared Facilities

DIRECT ANNUAL COSTS	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**	**Notes**
(1) Annual Maintenance Costs	$ 4,189,181	$ 7,514,611	$ 5,444,530	$ 9,608,381	Note 1
(2) Annual Reagent Costs					Note 2
Scenario A	$ 2,710,313	$ 4,171,528	$ 2,709,417	$ 4,170,150	
Scenario B	$ 2,725,539	$ 4,204,613	$ 2,724,643	$ 4,204,613	
(3) Annual Electricity Costs					Note 3
Scenario A	$ 5,929,642	$ 9,730,376	$ 6,011,088	$ 9,740,159	
Scenario B	$ 11,939,901	$ 24,539,279	$ 11,982,549	$ 25,083,883	
(4) Annual Water Costs					Note 4
(5) Catalyst Replacement Costs					Note 5
Scenario A	$ 709,951	$ 958,131	$ 709,951	$ 963,350	Note 6
Scenario B	$ 4,387,500	$ 10,260,000	$ 4,387,500	$ 10,260,000	Note 7
(6) Natural Gas for F.G. Reheating & Urea-to-Ammonia Conversion sys.					Note 8
Scenario A	$ 2,136,238	$ 6,064,108	$ 3,931,511	$ 6,416,128	
Scenario B	$ 1,944,698	$ 5,296,499	$ 3,580,852	$ 5,574,558	Note 9
(7) Operating labor for SCR equipment and urea-to-ammonia eqpmnt					Note 10
DIRECT Annual COSTS - TOTAL					Note 11
Scenario A	$ 15,675,326	$ 28,438,754	$ 18,806,498	$ 30,898,167	
Scenario B	$ 25,186,819	$ 51,815,002	$ 28,120,074	$ 54,731,434	
INDIRECT Annual COSTS					
(8) Annual Costs from Capital Recovery	$ 12,174,396	$ 21,838,601	$ 15,822,632	$ 27,923,414	Note 12
(9) Administrative overhead, insurance and property taxes for SCRs and aux.					Note 13
INDIRECT Annual COSTS - TOTAL	$ 12,174,396	$ 21,838,601	$ 15,822,632	$ 27,923,414	
TOTAL ANNUAL COSTS					Note 14
Scenario A	$ 27,849,722	$ 50,277,355	$ 34,629,130	$ 58,821,580	
Scenario B	$ 37,361,215	$ 73,653,603	$ 43,942,706	$ 82,654,848	
LEVELIZED TOTAL ANNUALIZED COSTS					Note 15
Scenario A	$ 31,748,616	$ 57,350,872	$ 39,306,834	$ 66,506,822	
Scenario B	$ 43,625,884	$ 86,541,448	$ 50,936,958	$ 96,268,092	

Shared Facilities (SF) represents estimated costs if SCR equipment is retrofitted to both boilers concurrently.
This table includes values that are identified in the EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44 through 2-49 but use calculated and vendor-quoted values instead of the formulas provided in the OAQPS manual
Total Annual Costs consist of direct costs, indirect costs, and recovery credits (if any). Direct Annual Costs and variable and semi-variable costs that are proportional to the quantity of flue gas processed by the control system. Indirect Annual Costs are fixed costs incurred independent of control operation, and include capital recovery costs, insurance, administrative charges, and overhead (payroll and plant).
Note 1: Annual maintenance was assumed to be 3% of installed capital cost of the SCR equipment and auxiliary equipment related to the SCR systems, not including catalyst replacement costs. Maint. costs for ASOFA are included.
Note 2: Annual reagent costs are for "Scenario A" and "Scenario B" operation and related chemical usage based on receiving 50% aqueous urea solution, assumed to be $379.29 per ton in 2006$.
Note 3: Annual electricity costs are for "Scenario A" and "Scenario B" operation and related electricity consumption and lost generation, assumed to be $35/MW-hr in 2006$. See Tables C.4-1 through C.4-4 in the November 2009 NOx BACT Analysis Study Supplemental Reports for details.
Note 4: Annual water costs were not calculated, but may be more than zero, if concentrated liquid urea liquor (70% concentration) is purchased, which must be diluted to 50% concentration for storage.
Note 5: Annual catalyst replacement costs are for "Scenario A" and "Scenario B" operation, and are assumed to be based on $7,500 per cubic meter in 2006$.
Note 6: Annual catalyst replacement costs for "Scenario A" are assumed to be based one layer per reactor every two years (approx. 16,000 operating hours), and follows the EPA OAQPS SCR Cost Manual for annualizing the purchase cost using Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 assuming 6% per year annual interest rate. Tail end SCRs were assumed to have 10 layers replaced during the 20-year economic evaluation period, and 12 layers for Low-dust SCRs, but the annual catalyst replacement costs for U2 used in the November 2009 NOx BACT Analysis Study Supplemental Report underestimate the cost per layer due to assuming regular depth layers instead of deep layers recommended by vendor.
Note 7: Annual catalyst replacement costs for "Scenario B" are assumed to be based three layers per reactor every year (approx. 2,667 operating hours) for U1 and four layers per reactor per year (approx. 2,000 operating hours) for U2. There were no adjustments for annualizing the purchase cost (Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 of the EPA OAQPS SCR Cost Manual were not used). U1 Low-dust and Tail end SCRs were assumed to have 60 layers replaced during the 20-year economic evaluation period, and 80 layers for U2's Tail end SCRs.
Note 8: Annual costs of natural gas firing for flue gas reheating and urea-to-ammonia conversion system operation for "Scenario A" and "Scenario B" are assumed to be based on $7.98 per million BTU in 2006$.
Note 9: Annual costs of natural gas firing for "Scenario B" are lower than "Scenario A" due to fewer annual hours of operation resulting from additional catalyst replacements.
Note 10: Annual costs of operating labor for SCR equipment, flue gas reheating, and urea-to-ammonia systems were assumed to be zero, but this may underestimate actual requirements.
Note 11: Total Direct Annual Costs are the sum of maintenance, reagent, electricity, catalyst replacements, and natural gas for Scenario A and Scenario B operations. This may underestimate actual requirements.
Note 12: Annual Costs from capital recovery are the same for Scenario A and Scenario B operations. See Appendix C in the 2006 NOx BACT Analysis Study reports for details. The capital recovery factor used to calculate the annual costs is 0.087185. Capital recovery costs for ASOFA are included.
Note 13: Annual costs of increases in administrative overhead, insurance premiums, and property taxes for SCR equipment and related auxiliaries were assumed to be zero, but this may underestimate actual requirements.
Note 14: Total Annual Costs are the sum of increases in Direct Costs and Indirect Costs for SCR equipment and related auxiliaries. These values may underestimate actual requirements.
Note 15: Levelized Total Annualized Costs are TDC multiplied by the levelization factor (1.24873) plus the Total Indirect Annual Costs (capital recovery). See Appendix C in the 2006 NOx BACT Analysis Study Reports for details. These values may underestimate actual requirements.

These numbers are the same Levelized Total Annualized Costs for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Tables 4-6SF, 4-7SF, 4-8SF, and 4-9SF. The capital recovery costs of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, based on the installed capital costs shown in Tables 4-4SF and 4-5SF, are included in these numbers.

Attach #2

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Annual Costs for
Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis

Stand Alone

DIRECT ANNUAL COSTS	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**	**Notes**
(1) Annual Maintenance Costs	$ 5,422,167	$ 8,123,552	$ 6,685,918	$ 10,222,003	Note 1
(2) Annual Reagent Costs					Note 2
Scenario A	$ 2,710,313	$ 4,171,528	$ 2,709,417	$ 4,170,150	
Scenario B	$ 2,725,539	$ 4,204,613	$ 2,724,643	$ 4,204,613	
(3) Annual Electricity Costs					Note 3
Scenario A	$ 5,929,642	$ 9,730,376	$ 6,011,088	$ 9,740,159	
Scenario B	$ 11,939,901	$ 24,539,279	$ 11,982,549	$ 25,083,883	
(4) Annual Water Costs					Note 4
(5) Catalyst Replacement Costs					Note 5
Scenario A	$ 709,951	$ 958,131	$ 709,951	$ 963,350	Note 6
Scenario B	$ 5,850,000	$ 10,260,000	$ 4,387,500	$ 10,260,000	Note 7
(6) Natural Gas for F.G. Reheating & Urea-to-Ammonia Conversion sys.					Note 8
Scenario A	$ 2,136,238	$ 6,064,108	$ 3,931,511	$ 6,416,128	
Scenario B	$ 1,944,698	$ 5,296,499	$ 3,580,852	$ 5,574,558	Note 9
(7) Operating labor for SCR equipment and urea-to-ammonia eqpmnt					Note 10
DIRECT Annual COSTS - TOTAL					Note 11
Scenario A	$ 16,908,311	$ 29,047,696	$ 20,047,886	$ 31,511,788	
Scenario B	$ 27,882,304	$ 52,423,943	$ 29,361,462	$ 55,345,056	
INDIRECT Annual COSTS					
(8) Annual Costs from Capital Recovery	$ 15,757,639	$ 23,608,277	$ 19,430,293	$ 29,706,692	Note 12
(9) Administrative overhead, insurance and property taxes for SCRs and aux.					Note 13
INDIRECT Annual COSTS - TOTAL	$ 15,757,639	$ 23,608,277	$ 19,430,239	$ 29,706,692	
TOTAL ANNUAL COSTS					Note 14
Scenario A	$ 32,665,951	$ 52,655,972	$ 39,478,179	$ 61,218,481	
Scenario B	$ 43,639,944	$ 76,032,220	$ 48,791,755	$ 85,051,748	
LEVELIZED TOTAL ANNUALIZED COSTS					Note 15
Scenario A	$ 36,871,522	$ 59,880,950	$ 44,464,651	$ 69,056,347	
Scenario B	$ 50,575,055	$ 89,071,526	$ 56,094,775	$ 98,817,617	

Stand Alone (SA) represents estimated costs if SCR equipment is retrofitted to both boilers independently.

This table includes values that are identified in the EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44 through 2-49 but use calculated and vendor-quoted values instead of the formulas provided in the OAQPS manual

Total Annual Costs consist of direct costs, indirect costs, and recovery credits (if any). Direct Annual Costs and variable and semi-variable costs that are proportional to the quantity of flue gas processed by the control system. Indirect Annual Costs are fixed costs incurred independent of control operation, and include capital recovery costs, insurance, administrative charges, and overhead (payroll and plant).

Note 1: Annual maintenance was assumed to be 3% of installed capital cost of the SCR equipment and auxiliary equipment related to the SCR systems, not including catalyst replacement costs. Maint. costs for ASOFA are included.

Note 2: Annual reagent costs are for "Scenario A" and "Scenario B" operation and related chemical usage based on receiving 50% aqueous urea solution, assumed to be $379.29 per ton in 2006$.

Note 3: Annual electricity costs are for "Scenario A" and "Scenario B" operation and related electricity consumption and lost generation, assumed to be $35/MW-hr in 2006$. See Tables C.4-1 through C.4-4 in the November 2009 NOx BACT Analysis Study Supplemental Reports for details.

Note 4: Annual water costs were not calculated, but may be more than zero, if concentrated liquid urea liquor (70% concentration) is purchased, which must be diluted to 50% concentration for storage.

Note 5: Annual catalyst replacement costs are for "Scenario A" and "Scenario B" operation, and are assumed to be based on $7,500 per cubic meter in 2006$.

Note 6: Annual catalyst replacement costs for "Scenario A" are assumed to be based one layer per reactor every two years (approx. 16,000 operating hours), and follows the EPA OAQPS SCR Cost Manual for annualizing the purchase cost using Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 assuming 6% per year annual interest rate. Tail end SCRs were assumed to have 10 layers replaced during the 20-year economic evaluation period, and 12 layers for Low-dust SCRs, but the annual catalyst replacement costs for U2 used in the November 2009 NOx BACT Analysis Study Supplemental Report underestimate the cost per layer due to assuming regular depth layers instead of deep layers recommended by vendor.

Note 7: Annual catalyst replacement costs for "Scenario B" are assumed to be based three layers per reactor every year (approx. 2,667 operating hours) for U1 and four layers per reactor per year (approx. 2,000 operating hours) for U2. There were no adjustments for annualizing the purchase cost (Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 of the EPA OAQPS SCR Cost Manual were not used). U1 Low-dust and Tail end SCRs were assumed to have 60 layers replaced during the 20-year economic evaluation period, and 80 layers for U2's Tail end SCRs.

Note 8: Annual costs of natural gas firing for flue gas reheating and urea-to-ammonia conversion system operation for "Scenario A" and "Scenario B" are assumed to be based on $7.98 per million BTU in 2006$.

Note 9: Annual costs of natural gas firing for "Scenario B" are lower than "Scenario A" due to fewer annual hours of operation resulting from additional catalyst replacements.

Note 10: Annual costs of operating labor for SCR equipment, flue gas reheating, and urea-to-ammonia systems were assumed to be zero, but this may underestimate actual requirements.

Note 11: Total Direct Annual Costs are the sum of maintenance, reagent, electricity, catalyst replacements, and natural gas for Scenario A and Scenario B operations. This may underestimate actual requirements.

Note 12: Annual Costs from capital recovery are the same for Scenario A and Scenario B operations. See Appendix C in the 2006 NOx BACT Analysis Study reports for details. The capital recovery factor used to calculate the annual costs is 0.087185. Capital recovery costs for ASOFA are included.

Note 13: Annual costs of increases in administrative overhead, insurance premiums, and property taxes for SCR equipment and related auxiliaries were assumed to be zero, but this may underestimate actual requirements.

Note 14: Total Annual Costs are the sum of increases in Direct Costs and Indirect Costs for SCR equipment and related auxiliaries. These values may underestimate actual requirements.

Note 15: Levelized Total Annualized Costs are TDC multiplied by the levelization factor (1.24873) plus the Total Indirect Annual Costs (capital recovery). See Appendix C in the 2006 NOx BACT Analysis Study Reports for details. These values may underestimate actual requirements.

These numbers are the same Levelized Total Annualized Costs for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Tables 4-6SA, 4-7SA, 4-8SA, and 4-9SA. The capital recovery costs of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, based on the installed capital costs shown in Tables 4-4SA and 4-5SA, are included in these numbers.

MINNKOTA POWER COOPERATIVE, Inc. and SQUARE BUTTE ELECTRIC COOPERATIVE

FOLLOWUP RESPONSES TO PRESENTATION and NDDH REQUEST FOR ADDITIONAL INFORMATION SUPPLEMENTAL NOx BACT ANALYSIS STUDY MILTON R. YOUNG STATION UNIT 1 and UNIT 2 REGARDING SCR ECONOMIC FEASIBILITY

February 11, 2010

North Dakota Department of Health's Environmental Health Section, Division of Air Quality has requested[1] that Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") provide additional information clarifying the written response submitted December 11, 2009[2] that provided detailed and comprehensive cost data following the NDDH's and U.S. EPA's reviews of the Best Available Control Technology (BACT) Analysis Study – Supplemental Reports[3] submitted on November 12, 2009 for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 at Milton R. Young Station (MRYS).

Burns & McDonnell (B&McD) was retained by MPC as an independent consultant to perform the referenced 2006 NO_X BACT Analysis Study[4] of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station in accordance with the requirements of a Consent Decree (CD)[5]. Burns & McDonnell also performed the November 2009 Supplemental NO_X BACT Analysis Study and generated the referenced reports for each MRYS boiler in response to the NDDH's request[6] to see Steps 3 and 4 of the BACT analysis process[7] include low-dust and tail end SCR alternatives, assuming that they are technically feasible to apply at MRYS as NDDH has recently advised[8].

Information supplementing the previously-provided detailed breakdown of capital costs and operation and maintenance costs for hypothetical applications of low-dust and tail end SCR alternatives, and their subsequent presentation to NDDH, are attached.

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[1] See Reference number 1, January 11, 2010.

[2] See Reference number 2, December 11, 2009.

[3] See Reference number 3, November 12, 2009.

[4] See Reference number 4, October 2006.

[5] See Reference number 5, April 24, 2006.

[6] See Reference number 6, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

[7] See Reference number 7, October 1990.

[8] Ibid Reference number 6, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

NOx BACT Analysis Study Supplemental Reports:

NDDH Request #1: How were the SCR reactors sized and the catalyst volume determined and what target NOx control efficiency was used to size the catalyst? How was the cost of the catalyst determined?

BMcD Response:

The same SCR system supplier that is providing the low-dust SCR equipment for the WE Energies South Oak Creek project in Wisconsin was asked to provide a budgetary equipment proposal for both low-dust and tail end SCR arrangements for each unit at MRYS. A lignite coal analysis (proximate, ultimate, and coal ash) and process design basis (boiler fuel heat input rates, excess air percentages, flue gas volumetric flows, temperatures and gas species contents) were included with the request. An assumed inlet and outlet NOx concentration was also provided, with a nominal 85% reduction from 0.5 lb/mmBtu requested. This SCR system supplier sized the SCR reactor, the SCR gas-to-gas heat exchange equipment (SCR GGH), and related ductwork. The initial catalyst charge for each reactor was included in the lump-sum equipment price proposal. The SCR system supplier did not disclose the specific volume of catalyst to be provided nor the specific manufacturer or type of catalyst (i.e. honeycomb, plate, etc.). Due to the proprietary nature of this SCR conceptual design and budgetary equipment pricing effort, this work was performed by the SCR system supplier with the understanding that it was confidential. Refer to Burns & McDonnell’s response to NDDH Request #7 for additional information.

Two SCR catalyst suppliers provided budgetary replacement catalyst quotes, including catalyst volume, catalyst pitch, catalyst type, and arrangement of catalyst modules, based on preliminary process design provided by an SCR process design consultant. The design used for these catalyst supplier proposals was based on 90% overall NOx reduction across the SCR system. The catalyst suppliers also provided cost proposals for the replacement catalyst. One supplier provided a cost of replacement catalysts in terms of $\$/m^3$. Due to the proprietary nature of this SCR reactor sizing and budgetary catalyst pricing effort, this work was performed by the SCR catalyst suppliers with the understanding that it was confidential. Refer to Burns & McDonnell’s response to NDDH Request #7 for additional information.

NDDH Request #2: Anhydrous ammonia appears to be a less expensive reagent than urea for the SCR system due to local availability. A justification must be supplied for electing urea over anhydrous ammonia.

BMcD Response:

Aqueous urea solution was selected because of health and safety issues related to the use of ammonia, including site constraints involving over-the-road transport, on-site unloading and storage. MRYS does not have rail access, and is adjacent to a lake used for condenser cooling water and process water supplies. Public access to the lake is allowed. Anhydrous ammonia and aqueous ammonia are classified as hazardous chemicals per Clean Air Act Section 112 (r). This requires extensive emergency planning. Transport and handling of ammonia is restricted by the United States Department of Homeland Security and the Department of Transportation through the Rail Security Act. The U.S. EPA has determined that a toxic radius of a spill to be between 5 and 7 miles for anhydrous ammonia and 1 to 2 miles for aqueous ammonia[9].

NDDH Request #3: Support must be provided for the catalyst cleaning/replacement outage periods. This should include an explanation of the method used to estimate the outage time and clarification whether the outage time includes the regular outage period.

BMcD Response:

Burns & McDonnell and Minnkota queried SCR catalyst suppliers, process design consultants, utility construction and maintenance contractors, and utility personnel at U.S. coal-fired plants with operating SCRs to provide input into the estimation of time associated with catalyst installation into the empty (spare) layer of the reactor, and to remove dirty catalyst and install fresh catalyst in its place. The responses indicated that there is a broad range of experiences based on limited amounts of user and vendor data on this issue. The range of experience is due to the site-specific conditions and design-specific features of the reactor catalyst access doors' locations and sizes, module arrangement, hoisting equipment, staging areas and platforms, labor availability and familiarity. The general lack of data is due to the relative newness of many SCR installations currently operating at coal-fired powerplants in the United States that have not accumulated significant operating time and so have not required significant numbers of catalyst changeouts.

Catalyst replacement activities by current coal-fired powerplant users are typically scheduled during major boiler outages that are 18-36 months apart. The SCR catalyst changeout is usually not a schedule-critical activity during such outages. The catalyst changeout time required depends on how many modules are involved, and whether a single shift of personnel or multiple shifts per day are engaged in the work.

For the hypothetical application of low-dust and tail end SCR technologies at MRYS, most of the catalyst changeouts were assumed to coincide with boiler fireside cleaning outages, which are historically approximately 4 days in duration, three or four times per year, depending on the boiler involved. Because of the use of high pressure water to remove boiler deposits during these cleanings, the air exhausted from the boilers through the flue gas ductwork to the chimneys during these times contains moisture and particulate.

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[9] See Reference 8.

Catalyst vendors have advised that this air stream is not suitable for passing through an SCR reactor filled with catalyst. This will require an SCR reactor bypass to be provided for use during these outages.

Before catalyst changeout operations can begin, the large volume of catalyst and supporting structural steel must be cooled down sufficiently to allow personnel to safely enter the reactor to gain access to remove any ash accumulations. The means and equipment required to remove the catalyst depends on the specific reactor design and module arrangements. The specific time and equipment requirements for catalyst changeouts are normally developed after the specific reactor and module details are established.

The SCR Cost Estimate study assumed that reactor isolation dampers and reactor maintenance bypass ductwork dampers would be required to avoid contamination of the catalyst by the air/water/particulate stream, and allow the reactors to be cooled while being isolated from the normal flue gas path to the chimney. The time estimated for catalyst installation into the empty (spare) layer of the reactor was 16 shifts, which, assuming two shifts per day, would be 8 days. The time estimated to remove dirty catalyst and install fresh catalyst in its place was 24 shifts, which, assuming two shifts per day, would be 12 days. The time assumed for reactor cooldown was previously estimated as 48-60 hours, which would elapse during the first half of the boiler cleaning process[10]. After the fresh catalyst is in place, and the reactor access doors closed, the entire volume of fresh and dirty catalyst remaining in the reactor must then be heated to above the moisture dewpoint to avoid possible moisture condensation during boiler startup. This would involve use of the supplemental catalyst outage heating system, not the flue gas reheat system nor flue gas from the boiler. Burns & McDonnell estimated that post catalyst changeout outage time will extend approximately 36-48 hours until the boilers are ready to begin the startup process to return to service.

The November 2009 Supplemental NOx BACT Analysis study assumed 1168 total hours and 1126 total hours of outage time per year associated with MRYS Unit 1’s hypothetical application of low-dust and tail end SCR technologies (Scenario “B”), respectively. This is 980 hours and 938 hours of outage time in addition to the 188 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming three catalyst layer changeout outages per year for Unit 1, this works out to be approximately 13 extra days per outage. Unit 2’s Scenario “B” assumed 1415 total hours of outage time for either hypothetical application of low-dust and tail end SCR technologies. This is 1234 hours of outage time in addition to the 181 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming four catalyst changeout outages per year for Unit 2, this works out to be approximately 13 extra days per outage.

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[10] See Reference 9, March 15, 2007, pages 12-14.

The November 2009 Supplemental NOx BACT Analysis study assumed 401 total hours and 443 total hours of outage time per year associated with MRYS Unit 1's, and 387 total hours and 428 total hours of outage time per year for Unit 2's, hypothetical application of tail end and low-dust SCR technologies (Scenario "A"), respectively. This is 213 or 256 hours of Unit 1 outage time and 206 or 247 hours of Unit 2 outage time in addition to the 181 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming one catalyst changeout outage every two years for each Unit 1 and Unit 2, this works out to be approximately between 8.6 and 10.7 extra days per outage, depending on the boiler and SCR technology studied.

The catalyst changeout outage times assumed in the November 2009 Supplemental NOx BACT Analysis study for MRYS Unit 1 and the similar study for MRYS Unit 2 are expected to be extensions to the boiler cleaning outages. Note that the estimated annual number of days for catalyst changeout outages is in addition to outage times included in the Advanced Separated Overfire Air alternative, which is also relative to baseline operation which include downtime for boiler cleanings. We believe the outage durations and frequency are reasonable assumptions to use for the purposes of showing possible economic outcomes that could result from the hypothetical application of low-dust and tail end SCR technologies at MRYS.

NDDH Request #4: The indirect capital costs associated with the project appear to be high. A detailed explanation of the estimation method must be supplied.

BMcD Response:

Burns & McDonnell used standard estimating practices to estimate direct, installation, and indirect capital costs for MRYS Unit 1's and Unit 2's hypothetical application of low-dust and tail end SCR technologies. To establish the context of estimated indirect costs, we note that several major assumptions were used by Burns & McDonnell in developing the capital cost estimates of the hypothetical applications of low-dust and tail end SCRs at Milton R. Young Station. These assumptions include the following:

- A multiple (parallel prime) contracting approach was selected (as opposed to single "turnkey" or Engineer-Procure-Construct contract). Although this approach may increase the project execution risk to the Owner, the execution risk is considered manageable. This contracting approach was recommended because it allows early award of major equipment procurements to allow detailed design engineering to proceed expeditiously to meet the project schedule, and offers the greatest flexibility for the Owner (Minnkota) to be involved in key decisions regarding design.
- Project will be executed to achieve completion in 2016 for Unit 2 and 2017 for Unit 1. It was assumed that the project will be executed with skilled workforce resources sufficient to meet the target project execution schedule while minimizing overtime. No additional overtime is included to accommodate a compressed work schedule.

Indirect Costs:

- Escalation based on historical data and Burns & McDonnell experience was assumed to average 5% per year for equipment, 9% per year for materials and 5% per year for labor. See additional general description of escalation included below.
- Contingency was calculated at 20% overall (10% for pricing and 10% for scope). Contingency was applied to Total Direct Capital Costs plus Indirect Capital Costs such as Engineering and Field Support, Construction Management and related indirects, Startup Expenses, and Cost Escalation during Project Execution. Owner Contingency was estimated at 7%. See additional general description of contingency included below.
- A performance bond is included for all subcontract work at the rate of 1.5% of the estimated project contract costs.
- Sales tax on construction consumables is included. No other tax is included.
- Owner will provide a builder's risk policy for the project. Cost for this is included in the estimate of Owner's costs.
- Interest During Construction (IDC) is included in the Owner's costs at 6% per year, assuming project execution-based monthly expenditures.

Escalation:

An estimate for escalation of project costs has been included in the capital cost estimate. Escalation of construction labor, materials, and indirects was estimated based on historical data and Burns & McDonnell experience.

Escalation of construction labor was estimated to be approximately 5% annually throughout the project. This estimate of escalation was based on the average increase in craft labor costs for the United States combined with known union labor contract costs in the next few years. The average annual escalation of union contracts for skilled and common labor rates over the last ten years in North Dakota has been approximately 5.0% per year.

Escalation of equipment and materials is included in the project estimate at a rate of 5% per year for equipment and 9% per year for materials. Since January 2004, steel pricing experienced rapid escalation equating to a nearly a 100% increase in rebar and structural steel costs, then dropped in late 2008 and early 2009. Within the past 6 months, steel prices have again started to rise. Pipe and electrical commodities have also seen a high overall escalation during this time, followed by a decline in late 2008. Due to this volatility, equipment and material suppliers have been providing pricing with short bid validity.

Contingency:

This project involves a significant amount of retrofit work in the existing plant. The SCR Cost Estimate study did not perform a thorough review of existing conditions and interfaces with the new work. It is anticipated that the scope of work will increase as unknown conditions are discovered during project execution. A contingency of 20% of the overall project costs is included in the project cost. Of this 20%, 10% covers accuracy of the pricing of the equipment and materials (commodities), and 10% covers omissions from the defined project scope. This contingency is not intended to cover changes in the general project scope (i.e. addition of buildings, addition of redundant equipment, addition of systems, etc.) nor major shifts in market conditions that could result in significant increases in contractor margins, major shortages of qualified labor, significant increases in escalation, or major changes in the cost of money (interest rate on loans).

In addition to the project contingency, an additional owner contingency is included to cover owner general project scope additions. Based upon the amount of preliminary design and project definition completed, a 7% scope contingency to cover such potential changes is included. However, this contingency level depends on the probability of additional scope and is typically determined by the Owner (Minnkota).

NDDH Request #5: Support must be supplied for the cost of natural gas and electricity.

BMcD Response:

Burns & McDonnell used estimated long-term average natural gas unit cost for the economics of conventional and fuel-lean gas reburn alternatives' annual operating costs included in the 2006 NOx BACT Analysis Study reports for MRYS Unit 1 and Unit 2. The annual cost of auxiliary power consumed by air pollution control equipment and the value of electric generator output not able to be sold ("lost") due to inability to produce electricity during outages related to the air pollution control equipment associated with particular control alternatives were also calculated. The long-term average unit costs for natural gas and electricity were provided by Minnkota. Burns & McDonnell's recent review of the forecast power industry's natural gas unit cost forecasts from 2006 confirm that the number used in the original NOx BACT Analysis Study calculations and reports submitted in October 2006 are reasonable, given the uncertainty and variability that is common with such forecasts.

In the November 2009 Supplemental NOx BACT Analysis study reports, Burns & McDonnell assumed the economics of hypothetical application of low-dust and tail end SCR technologies at MRYS should be also based on the same unit costs used for the 2006 NOx BACT Analysis study reports.

NDDH Request #6: More details, including calculations, must be supplied to justify the pressure drops and parasitic loads associated with the SCR configurations.

BMcD Response:
Burns & McDonnell used estimated flue gas pressure drops provided by the SCR supplier for the SCR reactor, and gas-to-gas heat exchangers (GGH), in the development of new induced draft booster fans' performance requirements and the alternatives' economics of hypothetical application of low-dust and tail end SCR technologies at MRYS for Unit 1 and Unit 2 in the November 2009 Supplemental NOx BACT Analysis study reports. The estimated flue gas pressure drops of the flue gas ductwork, which would be incurred upstream and downstream of the low-dust and tail end SCR reactors and GGHs, were calculated using a proprietary spreadsheet.

For low dust SCR cases, new ductwork would be connected downstream of the existing induced draft fans' outlets and a new booster fan for each reactor would follow the GGH outlet after the SCR reactor, discharging to the existing flue gas desulfurization (FGD) system absorber inlet duct[11].

In tail end SCR cases, new duct connections downstream of the existing induced draft fans' outlets would divert flue gas before the FGD absorbers' inlet ducts, through the hot side of the FGD GGH then back to the FGD absorber inlet duct. Additional duct connections downstream of the existing FGD absorbers' outlet ducts would reroute flue gas through the cold side of the FGD GGH, then to the cold side of the main (SCR) GGH upstream of the flue gas reheat section in the SCR reactor. After the reactor, flue gas would pass through the hot side of the main (SCR) GGH, continue to the new induced draft booster fans, and be discharged back to new duct connections near the existing inlets to the chimneys[12].

Horsepower required to drive the fans to produce pressure needed to overcome the cumulative ductwork and SCR equipment pressure losses for full load (maximum continuous rating) and "test block" flue gas flows was calculated from budgetary booster fan equipment quotes, which included preliminary pressure rise versus flow and mechanical efficiency curves, from two fan vendors. The horsepower required for the volumetric gas flow and pressure rise was then converted into electrical kilovolt-amperes (kVA) and kilowatts (kW) in order to calculate auxiliary power loads. An annual average load factor was applied, which was then multiplied by the assumed hours of annual operation to determine the annual megawatt-hours (MW-h) of consumed auxiliary power due to the SCRs' induced draft booster fans.

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[11] See attached sketch for low-dust SCR equipment and ductwork conceptual arrangement.
[12] See attached sketch for tail end SCR equipment and ductwork conceptual arrangement.

The parasitic loads associated with the SCR alternatives studied were determined by identifying known power-consuming auxiliary equipment serving the new air pollution control equipment. Estimates of design horsepower or kVA, based on vendor quotes or similar projects where information is available, were generated. Conversion to kW along with application of an annual average load factor resulted in estimated average annual auxiliary power loads, which were summed together to establish the total parasitic load. Annual megawatt-hours (MW-h) of consumed auxiliary power due to the various SCR cases studied were calculated by multiplying the total parasitic load by the assumed hours of annual operation.

The table below provides the results of these calculations.

Pressure Drop and Fan Power Calculation Results

Parameter	U1 LD	U1 TE	U2 LD	U2 TE
FGD GGH (hot side) pressure drop, in. w.g.	--	2.7	--	1.87
FGD GGH (cold side) pressure drop, in. w.g.	--	2.7	--	1.87
SCR GGH (cold side) pressure drop, in. w.g.	2.3	2.7	1.74	1.98
SCR reactor/catalyst press. drop, in. w.g.	2.0	2.0	2.0	2.0
SCR GGH (hot side) pressure drop, in. w.g.	2.3	2.7	1.74	1.98
SCR flue gas ducts/dampers/connections pressure drop, in. w.g.	5.4	6.2	4.5	6.3
Booster Fan Static Pressure Rise / Total Pressure[1] (Inches W.G.)	12.0 / 13.51	19.0 / 21.33	10.0 / 11.50	16.0 / 18.23
Booster Fan Motor Horsepower[2]	5000	7000	3500	5000
Load kVA / Demand kVA[3]	5000 /4500	7000 /6300	3500 /3150	5000 /4500
Quantity of Fans, capacity per fan, each case	One (1) x 100%		Two (2) x 50%	

1- Booster fan static pressure rise is the sum of the duct and SCR equipment pressure drops. Total fan pressure includes fan static pressure rise plus additional pressure rise required to overcome pressure drops within the fan equipment. These numbers do not include additional fan capacity (margin) above the amount required for full load (maximum continuous rating or MCR) operation, which allows for factors that reduce actual performance over sustained periods of running. Static pressure rise and Total pressure numbers are preliminary; final design may require values higher or lower than those shown.

2- Motor horsepower is greater than fan mechanical horsepower, and is based on available size larger than "Test Block" horsepower. Mechanical horsepower takes into account fan mechanical efficiency at the stated operating condition. Fans are sized based on mechanical efficiency and additional capacity (margin) above the MCR condition, referred to as "Test Block". The test block flow margin is 15% per fan, the test block pressure rise margin is 32.25% (1.15^2) above MCR values stated above. Test block fan mechanical efficiency is approximately 0.8. Fan Mechanical Horsepower = flue gas volumetric flow (actual cubic feet per minute) multiplied by pressure rise in inches w.g. divided by (6536 x efficiency). Fan efficiency varies with flow and pressure rise; values based on estimates/vendor quotes for full load (maximum continuous rating or MCR) conditions.

3- Horsepower (motor rating) is approximately equal to Connected Load kVA; Connected Load kVA x Estimated Annual Average Demand factor = Demand Load kVA.

Hypothetical applications of low-dust and tail end SCR technologies included estimates of auxiliary electrical power usage. It is important to note that some alternatives identified between 88 and 109 electricity-consuming items supplying or serving each SCR reactor system. Several pieces of auxiliary equipment with significant electrical power loads were included. These are: sootblowing air compressors with dryers; instrument/service air compressors with dryers; seal air fans for SCR reactor inlet and outlet flue gas isolation dampers; SCR flue gas reheat burner combustion air fans; drive gearboxes for rotary gas/gas heat exchangers; urea-to-ammonia dilution air/combustion air fans; auxiliary equipment service building ventilation/heating/lighting; and urea feed pumps. The instrument/service air and sootblowing air compressors are significant but necessary to supply dry compressed air used by equipment dedicated to control, maintain, and provide catalyst cleaning media for the SCR systems.

NDDH Request #7: All vendor correspondence related to SCR reactor sizing, catalyst volume, NOx control efficiency, catalyst cost, catalyst replacement schedule, and catalyst guarantees should be provided. This includes the original requests submitted to vendors and analyst [catalyst] suppliers by Minnkota and its consultants. This must also include the description of the gas stream that was supplied to the vendors.

BMcD Response:
Information responsive to this request by Minnkota, Burns & McDonnell and the SCR system supplier and SCR process design consultant, catalyst vendors, and flue gas particulate characterization consultant is being submitted (see Enclosures). Documents that include information considered as “trade secrets” per the NDDH’s Air Pollution Control rules are being submitted and marked “confidential” (see Enclosures).

Minnkota developed agreements with the catalyst suppliers and flue gas particulate characterization consultant engaged in this effort, and has a general services agreement with Burns & McDonnell, which covers work done by the SCR system supplier and SCR process design consultant. Information provided under Enclosure C is considered non-confidential, and includes information for which no claim is being made for confidentiality, along with an index and summary of the information submitted which is suitable for release to the public. Enclosure D includes documents claimed to contain trade secrets which are requested to be treated as confidential, along with an affidavit stating how and why the information fulfills the conditions of confidentiality per the NDDH’s Air Pollution Control rules describing this confidentiality procedure.

NDDH Request #8: Data must be provided for the temperature gradient of the regenerative heat exchanger to justify the reheat calculations. This must be provided for the both LDSCR and TESCR. The 600ºF temperature for the reheated flue gas must be justified.

BMcD Response:

The preliminary design temperatures for the hypothetical applications of low-dust and tail end SCR technologies shown in the table below were calculated by the SCR process consultant. The temperature data tabulated below for the Unit 1 low dust (LD) case include corrections identified by the SCR process consultant as described further in the response to NDDH Request #11.b. The SCR system supplier, which provided pricing of SCR equipment, including GGHs for low-dust and tail end SCRs, did not provide estimates of the GGHs' process performance.

SCR Process Design Temperatures

Parameter	U1 LD	U1 TE	U2 LD	U2 TE
FGD GGH (hot side) inlet temperature, ºF	--	335	--	331
FGD GGH (hot side) outlet / FGD Absorber Inlet temperature, ºF	--	(1)	--	(1)
FGD GGH (cold side) inlet/ FGD Absorber Outlet temperature, ºF	--	142	--	143
FGD GGH (cold side) outlet temperature, ºF	--	150	--	151
SCR GGH (cold side) inlet temperature, ºF	335	150	331	151
SCR GGH (cold side) outlet temperature, ºF	535	520	535	520
Flue Gas Reheat Burner outlet / SCR Ammonia Injection Grid/Reactor inlet temperature, ºF	580	563	580	563
SCR GGH (hot side) outlet temperature, ºF	380	199	380	197
FGD Absorber Outlet temperature, ºF	142	142	143	143

1- The temperature of the FGD GGH hot side outlet (discharges to FGD Absorber Inlet) was not provided by the SCR process consultant. It would be less than 330ºF.

As can be seen in the table above, the flue gas is reheated by natural gas to either 580ºF for low-dust SCR cases or 563ºF for tail end SCR cases. Natural gas heat input rates used in the November 2009 Supplemental NOx BACT Analysis study reports assumed these flue gas temperatures. These preliminary process design temperatures have not been confirmed pending final design by the gas/gas heat exchanger manufacturer. The catalyst vendors recommended that the catalyst be designed for (able to withstand continuous exposure to) 600ºF service operating temperature. The capacity of the reheat burner equipment was not specifically provided by the SCR system supplier, but was expected to be capable of raising the flue gas up to the recommended service temperature.

NDDH Request #9: A comparison of the SCR costs at M.R.Young Station versus PSE&G Mercer Station and We Energies Oak Creek Station should be provided or an explanation why such a comparison is not possible or inappropriate. We recognize that each plant has unique characteristics and there will be some design differences from plant-to-plant, but those differences should not necessarily dismiss making general comparison of costs unless there are unique or extenuating circumstances which would preclude a general cost comparison.

BMcD Response:

A BACT analysis is performed on a case-by-case, site-specific basis. It is inappropriate to compare the capital costs associated with the low-dust SCR installation at Mercer Station, or at South Oak Creek Station, against those developed for the hypothetical applications of low-dust and tail end SCR technologies at MRYS. Site conditions, boiler firing type, type and characteristics of fuels burned and resulting flue gas emissions and ash produced, and the limited amount of NOx reduction required for those referenced low-dust SCR cases that were not required to represent BACT, make the comparison not relevant to MRYS.

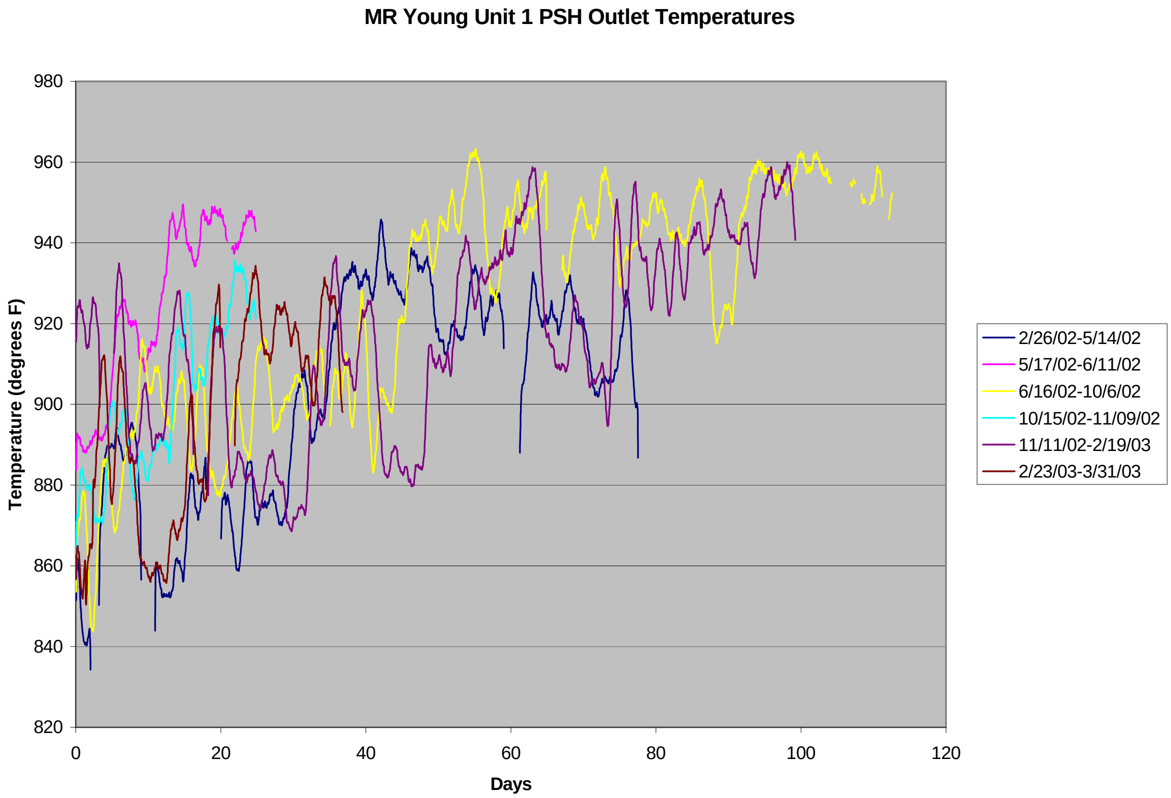
NDDH Request #10: Provide additional clarification and technical justification regarding Minnkota's determination that the units at MRYS are boiler limited and cannot generate additional steam for flue gas reheating purposes.

BMcD Response:

The steam turbine-generators at MRYS have a given output (gross megawatts) based on steam pressures, temperatures and flow rates related to the boilers. Removing high pressure/high temperature steam to use for flue gas reheating will directly cause a reduction in electrical output. This output reduction cannot be compensated for by increased boiler steam generation without unreasonable consequences. The boilers generate steam based upon their fuel heat input (firing) rates and capacities to absorb the heat created from the fuel combustion. The efficiency of converting fuel heat to steam to megawatts (heat rate or Btu per gross kilowatt) is limited by many factors. Fuel characteristics and boiler capacity are factors that impact heat rate (efficiency) that are not easily changed in the positive direction. The current fuel quality coming from the adjacent mine is not within the original design parameters of the boilers.

Because of the firing type (cyclone) and characteristics of North Dakota lignite burned and resulting flue gas emissions and ash produced at MRYS, the amount of fouling of the heat-absorbing surfaces within the boiler system is severe. These fouling conditions cause high exit flue gas temperatures that eventually reach the maximum limit recommended for maintaining the integrity of the air preheaters. This is indicated by the time-temperature graphs previously provided[13] and repeated below. The rate of boiler surface fouling increases significantly as more coal is fired, especially at maximum sustainable firing rates.

Due to the sticky character of the ash deposits, an “arsenal” of sootblower and water lance equipment is employed by Minnkota in an attempt to reduce the rate of fouling accumulations during boiler operations and remove these deposits during frequent boiler outages. These boiler cleaning outages occur every three to four months depending on the specific unit and the fuel quality delivered during the period. If the firing rate is increased to generate more steam for other heating purposes, the frequency of the cleaning outages must be increased. If the accumulated deposits are not removed, the frequency of the cleaning outages must be increased or the firing rates must be reduced and thus reduce the steam and electrical output of the boilers and steam turbine-generators. There is not “excess steam available for flue gas reheating” that would allow Minnkota to avoid reduced annual power generation.



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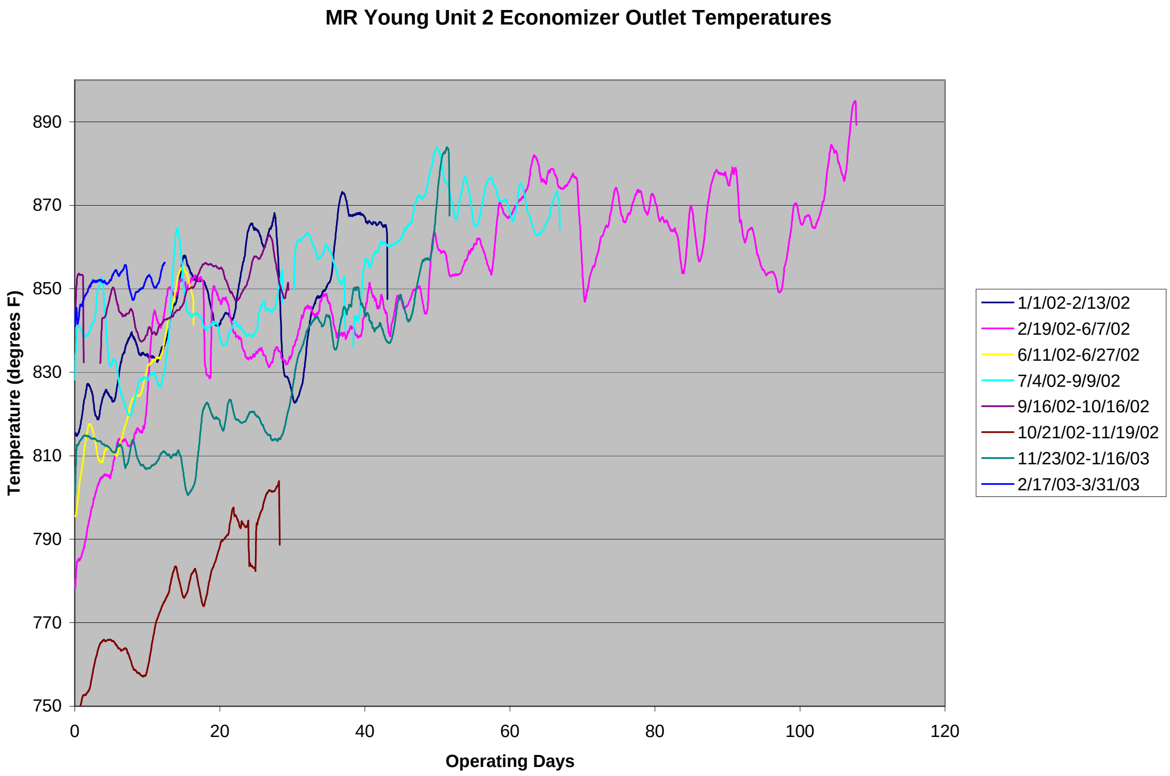
[13] See Reference number 11, April 18, 2007, pages 13-17.


MR Young Unit 2 Economizer Outlet Temperatures
Temperature (degrees F)
890
870
850
830
810
790
770
750
0
20
40
60
80
100
120
Operating Days
1/1/02-2/13/02
2/19/02-6/7/02
6/11/02-6/27/02
7/4/02-9/9/02
9/16/02-10/16/02
10/21/02-11/19/02
11/23/02-1/16/03
2/17/03-3/31/03

NDDH Request #11: There appear to be several discrepancies in the documents that must be addressed including:

a. **The catalyst volume for Unit 2 (p. 4-23) is listed as 256 m^3 per reactor or 512 m^3 per layer. This is 4-5 times more than Unit 1 yet Unit 2 is not twice as large. Please verify the Unit 2 catalyst volume.**

At page 4-23, the words “per reactor” should be deleted from the sentence describing Unit 2’s catalyst volume. This will be shown on an “Errata Sheet” attached to this document.

For Unit 2, the total initial volume was 768 cubic meters for three layers, or 256 cubic meters per layer, based on catalyst vendor input. Subsequent installation of 342 cubic meters for the fourth layer was assumed, also based on catalyst vendor input. Total initial volume plus first fill of spare layer equaling 1110 cubic meters is for two SCR reactors for each case studied for Unit 2. The correct catalyst volumes were used in the annual operating and maintenance cost calculations that are a portion of the levelized total annual costs for NOx control alternatives provided in the referenced November 2009 Supplemental NOx BACT Analysis study reports.

The conceptual design of Unit 1 Low-Dust SCR Reactor, and Tail End SCR Reactor as provided by the catalyst supplier included in each layer a total of 104 catalyst modules (8 x 13 arrangement). There is one SCR reactor for each case studied for Unit 1. The conceptual design of Unit 2 Low-Dust SCR Reactor, and Tail End SCR Reactor included in each layer a total of 91 catalyst modules per reactor (7 x 13 arrangement). There are two SCR reactors for each case studied for Unit 2.

b. **The reheat for Unit 2 for TESCR is listed as 48.11 MMBtu/hr per reactor and for LDSCR is 45.55 MMBtu/hr per reactor. The differential between TESCR and LDSCR is much less than for Unit 1 (60.3 MMBtu/hr and 31 MMBtu/hr).**
Please explain this difference.

The preliminary process design calculations were reviewed for the hypothetical applications of low-dust and tail end SCR technologies for Unit 1 and Unit 2. It was determined from this review that the temperature rise for the Unit 1 LDSCR flue gas reheat system was incorrectly assumed to be 25 degrees F instead of 25 degrees C (equivalent to 45 degrees F). The corrected 45 degrees F temperature rise for the Unit 1 LDSCR flue gas reheat system is shown in the table included with the response to NDDH Request #8. The correct natural gas heat input rate for Unit 1’s low-dust SCR cases is 54.5 MMBtu/hr (instead of 31 MMBtu/hr).

The discovery of the underestimate of Unit 1’s low-dust SCR flue gas reheat fuel requires revision to the MRYS Unit 1 November 2009 Supplemental NOx BACT Analysis study report for “Scenario A” and “Scenario B” cases. A revised version of the referenced November 2009 MRYS Unit 1 Supplemental NOx BACT Analysis Study report document and the December 2009 response document is being submitted with the corrected numbers and recalculated control costs (see Enclosures). The flue gas reheat fuel rates and costs assumed for the hypothetical applications of Unit 1’s tail end and Unit 2’s low-dust and tail end SCR alternatives included in the November 2009 Supplemental NOx BACT Analysis study reports will not change.

The temperature rise for the Unit 1 TESCR, Unit 2 LDSCR, and Unit 2 TESCR flue gas reheat systems are also shown in the table included with the response to NDDH Request #8. These are all preliminary numbers that would require confirmation after final cold-side outlet design temperatures are established by the FGD and SCR gas/gas heat exchanger manufacturer.

c. The capital costs for the “stand alone” SCR (p.3 of attachments to December 11, 2009 submittal) do not total correctly. Please check the numbers and revise the documents as necessary.

The numbers for “Pricing Contingency” shown in the table that provided “Estimates of Total Capital Investment for Low Dust and Tail End Selective Catalytic Reduction Alternatives Best Available Control Technology – Supplemental Analysis Stand Alone” cases submitted on December 11, 2009 were incorrect. They should match the “Scope Contingency” numbers above the “Pricing Contingency” line in the table. A revised version of the referenced document is being submitted containing the table with corrected data (see Enclosures).

d. The flue gas reheat burners and fans appear to be included in both “SCR system equipment” and “Auxiliaries” cost estimates (see p.4 of attachments to December 11, 2009 submittal, footnotes 1 and 3). Please check this and revise the documents as necessary.

There are two systems of natural gas-fired burners associated with each alternative studied for hypothetical application of low-dust and tail end SCR technologies in the November 2009 Supplemental NOx BACT Analysis study reports. The “flue gas reheat burner equipment” is correctly included as part of the “Purchased Capital Equipment SCR System Equipment” item (1) (a) under “Direct Capital Costs” denoted by footnote number1 in both tables of “Estimates of Total Capital Investment” for “Shared Facilities” and “Stand Alone” as submitted on December 11, 2009. Item (1) (b) “Auxiliaries/Balance of Plant” of both tables has footnote number 3. This footnote should be revised to read as follows: "Includes service air and sootblower air compressors, induced draft booster fan(s) and dampers, urea-to-ammonia conversion ~~flue gas reheat~~ equipment with natural gas-firing burners and fan(s), SCR bypass ducts and isolation dampers, interconnecting ductwork, equipment for active coal yard storage modifications, and catalyst standby heating auxiliary equipment costs as well as mechanical setting of this equipment". A revised version of the referenced document with the corrected footnotes is being submitted (see Enclosures).

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REFERENCES

1. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter from Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: SCR Cost Estimate,* January 11, 2010.

2. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH Request NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, December 2009, submitted by Minnkota to North Dakota Department of Health on December 11, 2009.

3. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009; and a separate NO_X BACT Analysis Study – Supplemental Report for Milton R. Young Station Unit 2 for Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, November 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009.

4. "BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc." and a separate "BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc." Final Report, October 2006 submitted by Minnkota to North Dakota Department of Health.

5. Consent Decree filed in the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034, filed April 24, 2006.

6. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.

7. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").

8. Technical Information (brochure) FT-9200-AP involving anhydrous and aqueous ammonia versus urea for SCRs available from Fuel Tech's website www.ftek.com, dated November 17, 2008.

9. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to EPA Comments NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Technical Feasibility, March 15, 2007. [with regard to two documents: ERG Memorandum to EPA Region 8 and EPA Office of Regulatory Enforcement, *Review and Critique of the Burns & McDonnell NO_X BACT Analysis for the Milton R. Young Station Operated by Minnkota Power (October 2006),* written by Roger Christman, Eastern Research Group, Inc., January 8, 2007, faxed by North Dakota Department of Health to Minnkota, January 9, 2007. *EPA Region 8 Preliminary Analysis of Burns & McDonnell*

BACT Analysis For Nitrogen Oxide at Milton R. Young Station, Units 1 and 2 January 8, 2007 faxed by North Dakota Department of Health to Minnkota, January 9, 2007.]

10. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns, Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007. [with regard to two documents: North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: BACT Determination Milton R. Young Station*, dated February 1, 2007, with enclosure from United States Environmental Protection Agency Region 8, letter to Terry O'Clair, North Dakota Department of Health Division of Air Quality, *Re: Transmittal of EPA Non-SCR concerns and additional information required for Minnkota BACT Analysis Study*, dated January 26, 2007.]

ATTACHMENTS

1. Conceptual design sketch, for hypothetical application of Low Dust SCR technology to MRYS Unit 1 and Unit 2, Burns & McDonnell, 2009.

2. Conceptual design sketch, for hypothetical application of Tail End SCR technology to MRYS Unit 1 and Unit 2, Burns & McDonnell, 2009.

3. ERRATA Sheet:

    a. Corrections to Reference number 3 of this document "NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 2, Minnkota Power Cooperative, Inc. Operating Agent for Square Butte Electric Cooperative, Owner" November, 2009; (February, 2010).

ENCLOSURES:

A. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH Request NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, December 2009, submitted by Minnkota to North Dakota Department of Health on December 11, 2009, revised February, 2010.

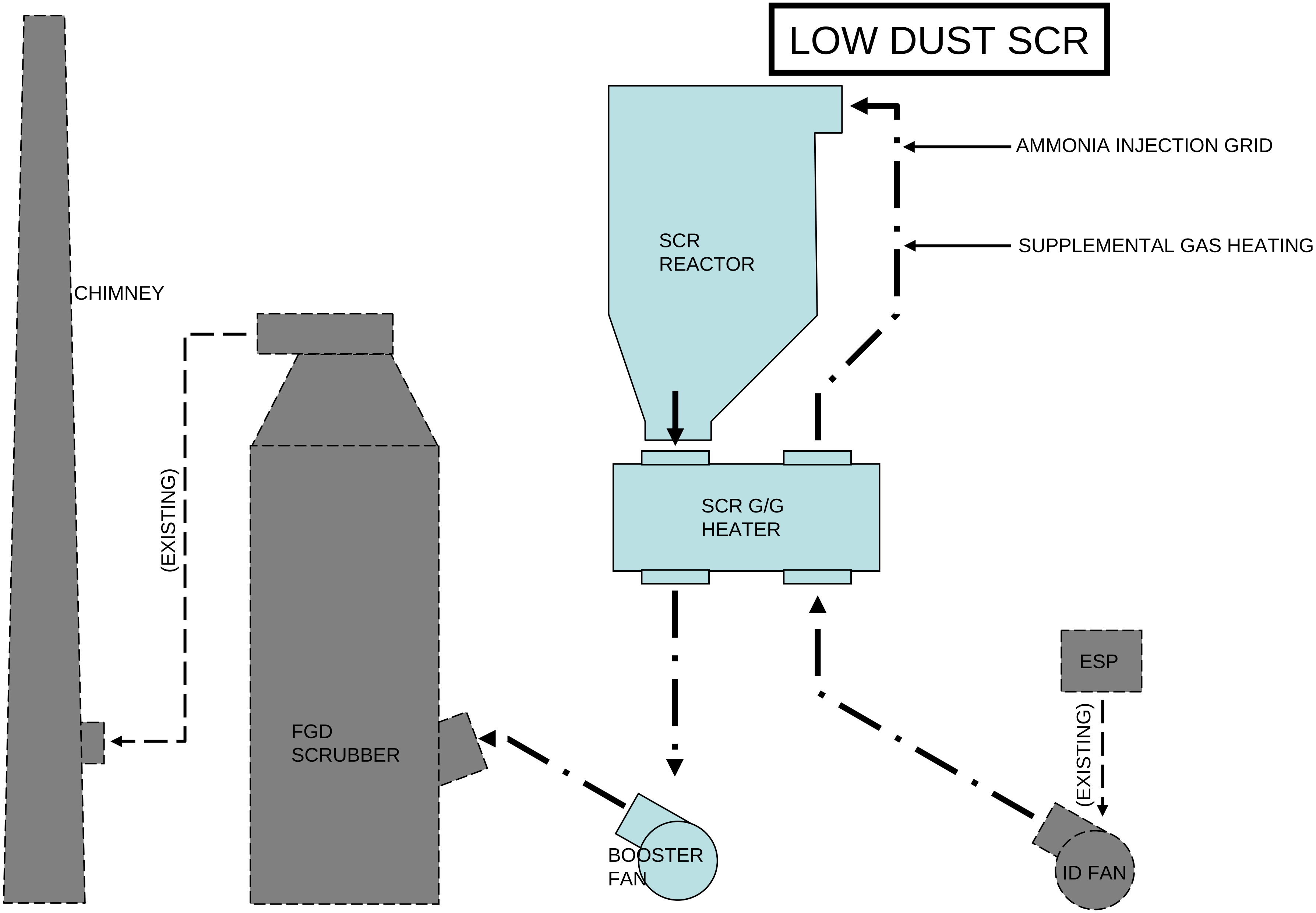
B. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009, revised February, 2010.

C. Non-confidential information related to response to NDDH Request #7 of this document (Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NOx BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, February 2010).

D. Confidential information related to response to NDDH Request #7 of this document (Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NOx BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, February 2010).

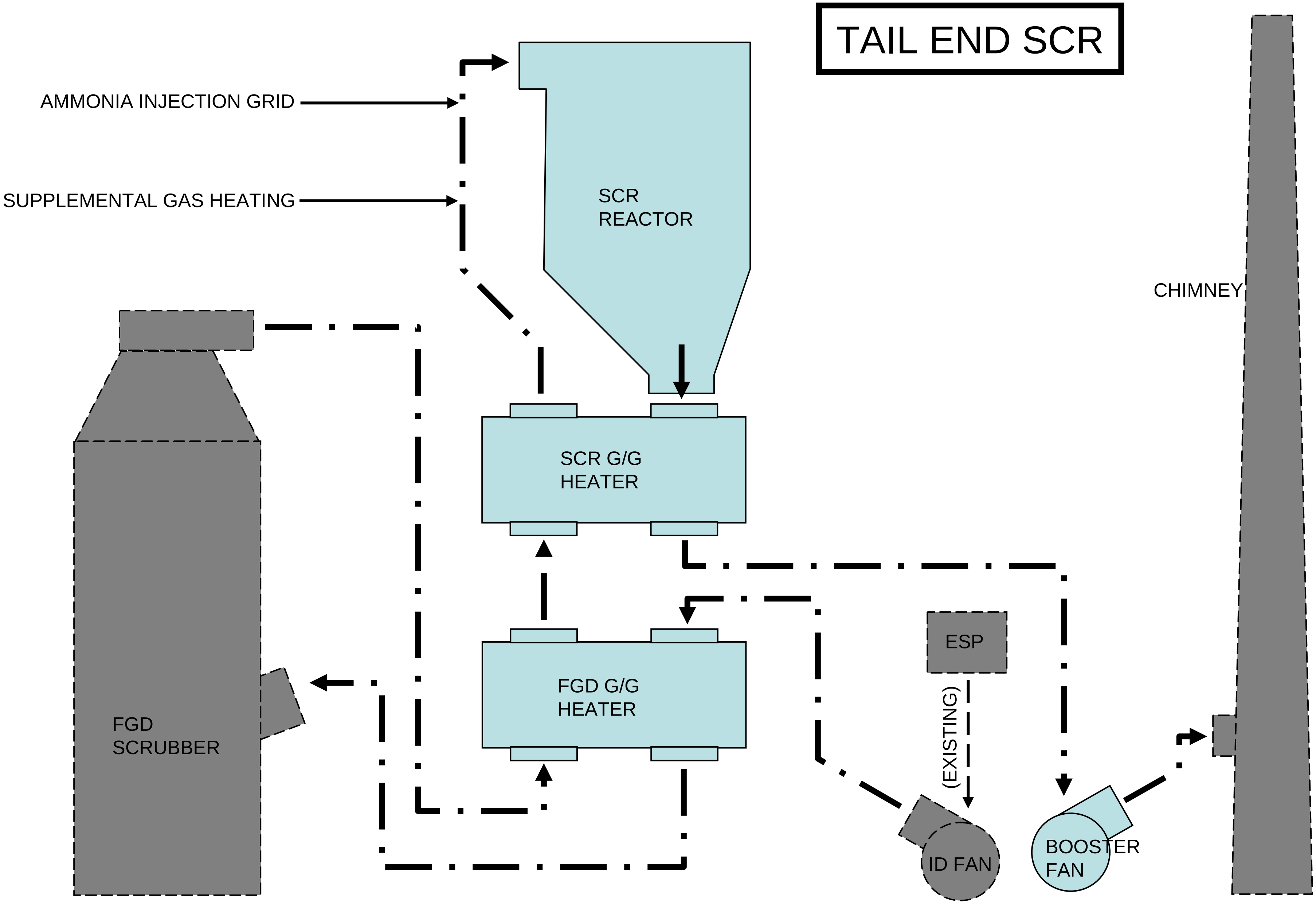
SKETCH SK - FD1

LOW DUST SCR



SKETCH SK – FD2

TAIL END SCR



ERRATA – MRYS Unit 2 Supplemental NOx BACT Analysis Study Report (November 2009)

Unit 2 Supplemental NOx BACT Analysis Study Report November 2009, page 4-23:

The second sentence of the paragraph should be revised to delete the words “per reactor”:

> SCR catalyst replacements are additive to the general annual hypothetically-applied low-dust and tail end SCR equipment maintenance. Catalyst replacement costs are based on catalyst vendor quotation of volume of catalyst, estimated to be three layers initially (top, middle-upper and middle-lower) at 256 cubic meters per layer ~~per reactor~~ for two reactors in parallel. A fourth (bottom) layer at 342 cubic meters is expected to be required after initial operation of hypothetically-applied full-time tail end or low-dust SCR alternatives, as part of the catalyst replacement program. Catalyst replacement costs for the hypothetical application of SCR alternatives were estimated for the two different catalyst management scenarios described above.

From: Blakley, Robert

Sent: Tuesday, January 06, 2009 1:31 PM

To: 'Robert Johnson'; Volker Rummenhohl

Cc: Weilert, Carl; Voss, Steve

Subject: RE: Hypothetical TE-SCR Cost Estimate

Volker & Bob –

We have been asked by one of our northern Midwest clients to perform a BACT cost-effectiveness analysis assuming that a custom tail-end SCR system could be retrofit on each of two coal-fired boilers.

We need help in developing capital cost and O&M cost estimates for retrofitting TESCR to existing units that use dry ESPs with lime-based wet FGD systems upstream. The normal operating and maintenance costs will be based on less than maximum design boiler heat input and flue gas flow conditions upon which the TESCRs would be designed for.

We will need advice as to what assumptions would be included in the process design for flue gas reheat, amount of catalyst, unit catalyst cost, frequency of catalyst replacement or washing, length of time periodic catalyst changeout, flue gas pressure drop from scrubber outlet to chimney inlet, and NOx reduction and ammonia consumption performance targets.

We will need the above estimates in a very short time period – before the end of January, with preliminary numbers by mid-January.

We would also like to get some idea as to the amount of calendar months required for implementation: scoping, vendor identification, investigation, design, procurement, construction, startup and commissioning, and outage time required for the initial installation tie-ins.

We can provide data for fuel, boiler heat input, NOx emissions and excess air/flue gas volume from the boiler outlet, sulfur dioxide removal by the wet FGD scrubber, and particulate loading.

If you have a spreadsheet, I can fill-in, or we can give you what we have as mentioned above.

We will work out the contractual agreement as we proceed, if that is okay.

Let me know how we can get this going.

Bob Blakley

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Wednesday, January 07, 2009 8:50 AM
To: Blakley, Robert; Volker Rummenhohl
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimate

Bob,
Volker and I can support you on this. We can quickly run a mass balance once we get the process data.
I will be at Burns & McDonnell tomorrow; perhaps we can get together briefly to discuss.
Thanks, Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, January 06, 2009 1:31 PM
To: Robert Johnson; Volker Rummenhohl
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimate

Volker & Bob –

We have been asked by one of our northern Midwest clients to perform a BACT cost-effectiveness analysis assuming that a custom tail-end SCR system could be retrofit on each of two coal-fired boilers.

We need help in developing capital cost and O&M cost estimates for retrofitting TESCR to existing units that use dry ESPs with lime-based wet FGD systems upstream. The normal operating and maintenance costs will be based on less than maximum design boiler heat input and flue gas flow conditions upon which the TESCRs would be designed for.

We will need advice as to what assumptions would be included in the process design for flue gas reheat, amount of catalyst, unit catalyst cost, frequency of catalyst replacement or washing, length of time periodic catalyst changeout, flue gas pressure drop from scrubber outlet to chimney inlet, and NOx reduction and ammonia consumption performance targets.

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Let me know how we can get this going.

Bob Blakley

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Monday, January 12, 2009 12:03 PM
To: Blakley, Robert; Volker Rummenhohl
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimate

Bob,
In order to run the mass balance for the TE SCR, we need the following process data:
Flue gas volumetric flow rate
Flue gas mass flow rate
Flue gas composition downstream of the FGD system
Flue gas temperature
NOx reduction requirements
Maximum SO2 oxidation rate

Once we get started, we'll let you know if we need anything else.

From this, we can estimate reheat requirements, catalyst volume, pressure drop, NH3 consumption.

Best Regards, Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, January 06, 2009 1:31 PM
To: Robert Johnson; Volker Rummenhohl
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimate

Volker & Bob –

We have been asked by one of our northern Midwest clients to perform a BACT cost-effectiveness analysis assuming that a custom tail-end SCR system could be retrofit on each of two coal-fired boilers.

We need help in developing capital cost and O&M cost estimates for retrofitting TESCR to existing units that use dry ESPs with lime-based wet FGD systems upstream. The normal operating and maintenance costs will be based on less than maximum design boiler heat input and flue gas flow conditions upon which the TESCRs would be designed for.

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If you have a spreadsheet, I can fill-in, or we can give you what we have as mentioned above.

We will work out the contractual agreement as we proceed, if that is okay.

Let me know how we can get this going.

Bob Blakley

From: Blakley, Robert
Sent: Tuesday, January 13, 2009 11:17 AM
To: 'Robert Johnson'; 'Volker Rummenhohl'
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimates

Volker & Bob –

One process parameter I did not mention that should be considered in the TESCR system design basis is the outlet gas temperature going to the stack, after the GGH on the back-end of the TESCR.

The new chimney that is being constructed for Unit 2 will have a fiberglass-reinforced plastic liner for the flue gas, and we have advised the chimney vendor that the design temperature range is 130 to 200 degrees F (continuous), with a maximum excursion to 350 degrees F for 15 consecutive minutes (transient condition due to FGD system malfunction).

The existing chimney being retrofit for Unit 1 currently has a metal liner that may receive added corrosion protection using alloy metal "wallpaper" lining or borosilicate glass block that is capable of sustained operation up to 200 degrees F, with higher excursions for short durations, similar to Unit 2's case.

Please advise a time-frame when you think that you will have a preliminary design basis and cost numbers.

Bob Blakley

From: Robert Johnson [RJohnson@ftek.com]
Sent: Friday, January 16, 2009 1:54 PM
To: Blakley, Robert
Subject: RE: Hypothetical TE-SCR Cost Estimates

Bob,
Volker and I have run our initial mass balance, but we need some more time over the weekend to review it.
I will send you comments on Monday.
Thanks, Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Thursday, January 15, 2009 9:47 AM
To: Robert Johnson; Volker Rummenhohl
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimates

Bob & Volker –

We need review of our assumed TESCR catalyst replacement plan, saved as an Excel spreadsheet <MRYS TESCR Catalyst Mgt (BMcD draft 1-15-09).xls> at the new ft site:

[redacted]

As part of the BACT cost effectiveness analysis, we also need to know what to assume for catalyst volume per layer, and unit cost (labor & materials) assumed to be required per replacement layer.

Thanks,

Bob Blakley

Assumed TESCR Catalyst Replacement Schedule (assuming wet ESP / low frequency)				Assumed TE SCR catalyst (85% removal) without wet ESP upstream replacement schedule every 8000 hours (1 year)		
starting Jan.	Year	Layer	# of layers	# of layers	Layer	3 new layers from initial onset, Fall 2014 major outage
2015	0		0	1	add bottom	new, add after 1 year in Fall 2015 outage
2016	1		0	1	replace top	after 2 yrs, add new layer in Fall 2016 outage
2017	2	add bottom	1	1	replace mid-upper	after 3 yrs, add new layer in Fall 2017 outage
2018	3		0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2018 outage
2019	4		0	1	replace bottom	after 4 yrs, add new layer in Fall 2019 outage
2020	5	replace top	1	2	replace top, mid-upper	after 2 yrs & 3 yrs, add new layers in Fall 2020 outage
2021	6		0	0	clean only	
2022	7		0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2022 outage
2023	8	replace mid	1	2	replace bottom, mid-upper	after 4 yrs & 3 yrs, add new layers in Fall 2023 outage
2024	9		0	1	replace top	after 2 yrs, add new layer in Fall 2024 outage
2025	10		0	0	clean only	
2026	11	replace bottom	1	3	replace top, mid-upper, mid lower	after 2 yrs, 3 yrs & 4 yrs, add new layers in Fall 2026 outage
2027	12		0	1	replace bottom	after 4 yrs, add new layer in Fall 2027 outage
2028	13		0	1	replace top	after 2 yrs, add new layer in Fall 2028 outage
2029	14	replace top	1	1	replace mid-upper	after 3 yrs, add new layer in Fall 2029 outage
2030	15		0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2030 outage
2031	16		0	1	replace bottom	after 4 yrs, add new layer in Fall 2031 outage
2032	17	replace mid	1	2	replace top, mid-upper	after 2 yrs & 3 yrs, add new layers in Fall 2032 outage
2033	18		0	0	clean only	
2034	19		0	3	replace top, mid-upper, mid lower	after 2 yrs, 3 yrs & 4 yrs, add new layers in Fall 2034 outage
2035	20	replace bottom	1	1	replace bottom	after 4 yrs, add new layer in Fall 2035 outage
		total	7	28		
		avg per yr	0.35	1.40		

Assumed TESCR catalyst Replacement Schedule (assuming wet ESP / low frequency)				Assumed TE SCR catalyst (85% removal) without wet ESP upstream replacement schedule every 8000 hours (1 year)		
starting Jan.	Year	Layer	# of layers	# of layers	Layer	3 new layers from initial onset, Fall 2013 major outage
2014	0		0	1	add bottom	new, add after 1 year in Fall 2014 outage
2015	1	add bottom	0	1	replace top	after 2 yrs, add new layer in Fall 2015 outage
2016	2		1	1	replace mid-upper	after 3 yrs, add new layer in Fall 2016 outage
2017	3	replace top	0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2017 outage
2018	4		0	1	replace bottom	after 4 yrs, add new layer in Fall 2018 outage
2019	5	replace mid	1	2	replace top, mid-upper	after 2 yrs & 3 yrs, add new layers in Fall 2019 outage
2020	6		0	0	clean only	
2021	7		0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2021 outage
2022	8		1	2	replace bottom, mid-upper	after 4 yrs & 3 yrs, add new layers in Fall 2022 outage
2023	9		0	1	replace top	after 2 yrs, add new layer in Fall 2023 outage
2024	10		0	0	clean only	
2025	11	replace bottom	1	3	replace top, mid-upper, mid lower	after 2 yrs, 3 yrs & 4 yrs, add new layers in Fall 2025 outage
2026	12		0	1	replace bottom	after 4 yrs, add new layer in Fall 2026 outage
2027	13		0	1	replace top	after 2 yrs, add new layer in Fall 2027 outage
2028	14	replace top	1	1	replace mid-upper	after 3 yrs, add new layer in Fall 2028 outage
2029	15		0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2029 outage
2030	16		0	1	replace bottom	after 4 yrs, add new layer in Fall 2030 outage
2031	17	replace mid	1	2	replace top, mid-upper	after 2 yrs & 3 yrs, add new layers in Fall 2031 outage
2032	18		0	0	clean only	
2033	19		0	3	replace top, mid-upper, mid lower	after 2 yrs, 3 yrs & 4 yrs, add new layers in Fall 2033 outage
2034	20	replace bottom	1	1	replace bottom	after 4 yrs, add new layer in Fall 2034 outage
		total	7	28		
		avg per yr	0.35	1.40		

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Friday, January 23, 2009 9:58 AM
To: Robert Johnson; Volker Rummenhohl
Cc: Weilert, Carl; Blackwood, Dave; Voss, Steve
Subject: RE: Mass Balance for Hypothetical SCR Installation

Bob & Volker –

Several items to discuss and consider:

1. The U2 FGD absorber vessels (two in parallel configuration) are not designed for 14.5 in. w.g. internal pressure; I believe they have a much lower limit; operationally it is around 4 in. w.g., but I do not know the exact design value. We are looking into hiring a company that can perform a finite element analysis of the absorber vessels, but that will not be started for several months from now. I assume this means that a booster fan will be needed after the FGD GGH, upstream of the SCR GGH, to overcome the pressure drops across the GGHs.
2. We have assumed (and Minnkota is directing us to do so) that the source of heat for the final reheating of the flue gas downstream of the SCR GGH and upstream of the reactors should be fired natural gas or propane, not steam. So the effluent of the direct-fired burner(s) and the associated NOx emissions also must be accounted for in the reactor design and NOx removal. Conservatively, burners should be assumed to be supplied with ambient air for combustion and emit 0.1 lb/mmBtu (per million BTU), unless this is not feasible or there are other reasons to change this assumption.
3. I don’t know if this makes a difference, but Minnkota is expecting to store liquid urea concentrate (40-50% solution) on-site as the NOx removal reagent, and so some sort of conversion process will be needed to supply ammonia to the reactors. The plant site does not have direct rail access, so all consumable materials have to be transported by tanker trailer to be offloaded near the U2 boiler building.

We will need a similar preliminary mass balance for a low-dust SCR configuration for Unit 2, as well as both low-dust and tail-end SCRs for Unit 1.

We can arrange a phone conference for Monday to discuss. Carl will be back late tonight. We also need the numbers on catalyst volume and changeout frequency and costs.
Dave Blackwood is leading the scope definition and cost estimating effort from our Development Engineering department here in our Energy group.

We appreciate the information and will continue to work on this in a parallel-path effort. We can discuss this on Monday. Please let us know your availability for a phone conference or visit.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Friday, January 23, 2009 8:10 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Mass Balance for Hypothetical SCR Installation

Bob,
Attached are a Mass Balance and PFD for a Hypothetical Tail End SCR for your review.
Please note:
1. 2 SCR reactors will be required for the installation;
2. The PFD denotes flue gas mass flow in kg/hr and temperature in degrees C. You can identify the specific process stream (noted in blue) and see this information converted into lb/hr and degrees F on the Mass Balance sheet.

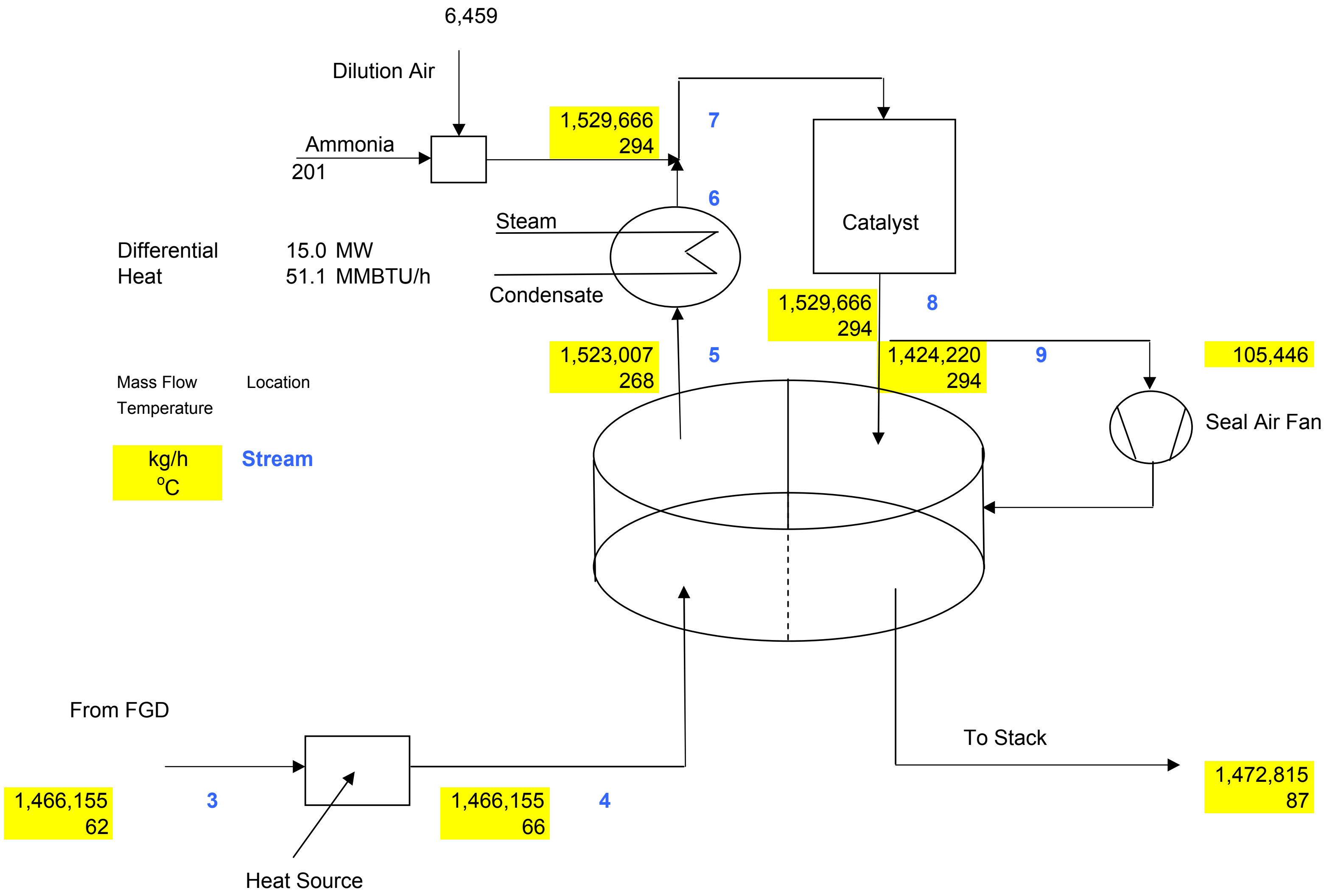
We are still evaluating this and will provide more information later today.
Thanks, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727
<<22Jan09_TailEnd_PFDRev1.pdf>> <<22Jan09_TailEnd_MBRev1.pdf>>

MRY 2		Input Data FGD Outlet	3 FGD Outlet	4 GGH inlet	5 GGH outlet	6 Steam HE out	7 Reactor inlet	8 Reactor outlet	9 GGH treated inlet	10 Booster fan in	11 Booster fan out	14 Ammonia	15 Dilution Air	17 Purge+Scavange	14 Reacted		
Volumetric flow rate vol.	Nm^3/h		1,180,582	1,180,582	1,226,360	1,226,360	1,231,634	1,231,766	1,146,942	1,186,234	1,186,234	263	4,997	84,927		Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		744,304	744,304	773,165	773,165	776,490	776,573	723,096	747,868	747,868	166	3,150	53,543		scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		820,913	820,913	1,394,069	1,469,126	1,474,667	1,485,560	1,384,940	917,742	917,742					acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,466,155	1,466,155	1,523,007	1,523,007	1,529,666	1,529,666	1,424,220	1,472,815	1,472,815	201	6,459	105,446	201	kg/h	Mass Flow
Mass Flow	lb/hour		3,229,416	3,229,416	3,354,640	3,354,640	3,369,309	3,369,309	3,137,049	3,244,085	3,244,085	442	14,227	232,260	442	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	515	565	562	562	562	188	188					Degree F	Temperature
Temperature	Degree C		62	66	268	296	294	294	294	87	87					Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0						Pressure
Composition																	Composition
Nitrogen	Vol-parts		0.6346	0.6346	0.6346	0.6346	0.6351	0.6354	0.6354	0.6352	0.6352		0.7809		0.2999	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1063	0.1063	0.1063	0.1063	0.1058	0.1058	0.1058	0.1058	0.1058		0.0003			Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0496	0.0496	0.0497	0.0497	0.0503	0.0502	0.0502	0.0501	0.0501		0.2095			Vol-parts	Oxygen
Moisture	Vol-parts		0.2091	0.2091	0.2091	0.2091	0.2082	0.2085	0.2085	0.2088	0.2088				0.7001	Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001					Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000					Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0093				
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		Total
Volumetric Flow			0														Volumetric Flow
Nitrogen	Nm^3/h		749,220	749,220	778,316	778,316	782,218	782,610	728,717	753,514	753,514		3,902	53,947	64	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		125,507	125,507	130,345	130,345	130,347	130,347	121,371	125,508	125,508		1	8,986		Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		58,606	58,606	60,904	60,904	61,951	61,820	57,563	59,391	59,391		1,047	4,252		Nm^3/h	Oxygen
Moisture	Nm^3/h		246,863	246,863	256,419	256,419	256,419	256,811	239,126	247,646	247,646		0	17,730	150	Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		79	79	82	82	82	81	75	78	78		0	6		Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	1	1	1	1		0	0			
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen dioxide	Nm^3/h		307	307	306	306	306	45	41	46	46		0	3		Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	49	49	45	46	46		46	3			
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3		0	0			
Total	Nm^3/h		1,180,582	1,180,582	1,226,374	1,226,374	1,231,634	1,231,766	1,146,942	1,186,234	1,186,234		4,997	84,927	214	Nm^3/h	Total
Mass Flow																	Mass Flow
Nitrogen	kg/h	1,873,285	936,643	936,643	973,016	973,016	977,894	978,385	911,010	942,010	942,010		4,878	67,442	80	kg/h	Nitrogen
Carbon di oxide	kg/h	492,954	246,477	246,477	255,979	255,979	255,982	255,982	238,354	246,480	246,480		3	17,647		kg/h	Carbon di oxide
Oxygen	kg/h	167,370	83,685	83,685	86,967	86,967	88,461	88,275	82,196	84,807	84,807		1,495	6,072		kg/h	Oxygen
Moisture	kg/h	396,920	198,460	198,460	206,142	206,142	206,142	206,457	192,240	199,090	199,090		0	14,254	120	kg/h	Moisture
Sulfur di oxide	kg/h	450	225	225	234	234	234	231	215	223	223		0	16		kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	3	3	3	3		0	0			
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen di oxide	kg/h	1,261	631	631	628	628	628	91	85	95	95		0	7		kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	87	87	81	83	83		83	6			
Ammonia	kg/h		0	0	0	0	201	2	2	2	2	201	0	0			
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35		0	3			
Total	kg/h	2,932,310	1,466,155	1,466,155	1,523,007	1,523,007	1,529,666	1,529,550	1,424,220	1,472,827	1,472,827	201	6,459	105,446	201	kg/h	Total
Nitrogen	lb/h		2,063,089	2,063,089	2,143,208	2,143,208	2,153,953	2,155,033	2,006,630	2,074,912	2,074,912	0	10,745	148,552	177	lb/h	Nitrogen
Carbon di oxide	lb/h		542,901	542,901	563,831	563,831	563,837	563,837	525,009	542,907	542,907	0	6	38,869	0	lb/h	Carbon di oxide
Oxygen	lb/h		184,328	184,328	191,556	191,556	194,849	194,438	181,048	186,800	186,800	0	3,293	13,374	0	lb/h	Oxygen
Moisture	lb/h		437,137	437,137	454,057	454,057	454,057	454,752	423,436	438,523	438,523	0	0	31,396	265	lb/h	Moisture
Sulfur di oxide	lb/h		496	496	514	514	514	510	474	491	491	0	0	35	0	lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	6	6	6	6		0	0			
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,384	1,384	202	188	208	208	0	0	15	0	lb/h	Nitrogen di oxide
Argon	lb/h		0	0	9	9	191	191	178	182	182		182	13			
Ammonia	lb/h		0	0	0	0	442	5	5	5	5		0	0			
Particulate	lb/h		77	77	80	80	80	80		77	77		0	6			
Total	lb/h		3,229,416	3,229,416	3,354,640	3,354,640	3,369,309	3,369,054	3,136,975	3,244,113	3,244,113	0	14,227	232,260	442	lb/h	Total
Composition																	Composition
Nitrogen	Mass-parts		0.639	0.639	0.639	0.639	0.639	0.640	0.640	0.640	0.640		0.755	0.640		Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.168	0.168	0.168	0.168	0.167	0.167	0.167	0.167	0.167		0.000	0.167		Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.057	0.058	0.058	0.058	0.058	0.058		0.231	0.058		Mass-parts	Oxygen
Moisture	Mass-parts		0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.135		0.000	0.135		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000		Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000		Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.013	0.000			
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	0.987	1.000	0.000	Mass-parts	Total

MRY 2		Input Data FGD Outlet	3 FGD Outlet	4 GGH inlet	5 GGH outlet	6 Steam HE out	7 Reactor inlet	8 Reactor outlet	9 GGH treated inlet	10 Booster fan in	11 Booster fan out	14 Ammonia	15 Dilution Air	17 Purge+Scavange	14 Reacted		
Density	kg/Nm^3		1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242						
Cp	kJ/kgK		1.118792829	1.1197279	1.1779222	1.186904869	1.1863618	1.186361804	1.186361804	1.12492337	1.12492337					kJ/kgK	Cp
Heat Content	MW		28.098	29.895	133.689	148.655	148.397	148.397	138.167	39.834	39.834					MW	Heat Content
	MMBTU/hr		95.899	102.032	456.280	507.360	506.478	506.478	471.565	135.953	135.953						
NO_2	lbs/hour		1388.7665	1388.7665	1384.0485	1384.0485	1384.0485	201.5056	187.6292	208.3150	208.3150			14.9		lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3580	628.3580	628.3580	91.4835	85.1837	94.5750	94.5750			6.8		kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	306.1	306.1	44.6	41.5	46.1	46.1			3.3			
NO + NO_2 @ actual O_2	PPM		260.2	260.2	249.6	249.6	248.5	36.2	36.2	38.8	38.8			38.8			
NO + NO_2 @ 3 % O_2	PPM		292.0	292.0	280.2	280.2	280.1	40.8	40.8	43.7	43.7						
						NO2 Balance Check											
Eta NOx		0.850	0.8500			kg/h	lbs/hr										
Eta NOx reactor			0.8544			-0.9	-2										
SO2/SO3 Conversion Rate	%	1.00%															
						Diff. heat hot side		Diff. heat cold side		0.663477551							
Ammonia slip	PPM	2				MW		MW									
						14.966		11.736									
Temperature Diff. Hot Side	F	50															
						-2											

MRY 2 Tail End SCR Process Flow Diagram



From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Saturday, February 07, 2009 5:25 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Hypothetical Case_Tail End SCR

Bob,
Attached are the latest Mass Balances and PFDs for the Steam and Nat Gas reheat cases. We revised the Steam case from the version previously sent.

We will be working on the Low Dust case as soon as we thoroughly review the revised spreadsheet you sent. We were both out of town last week.

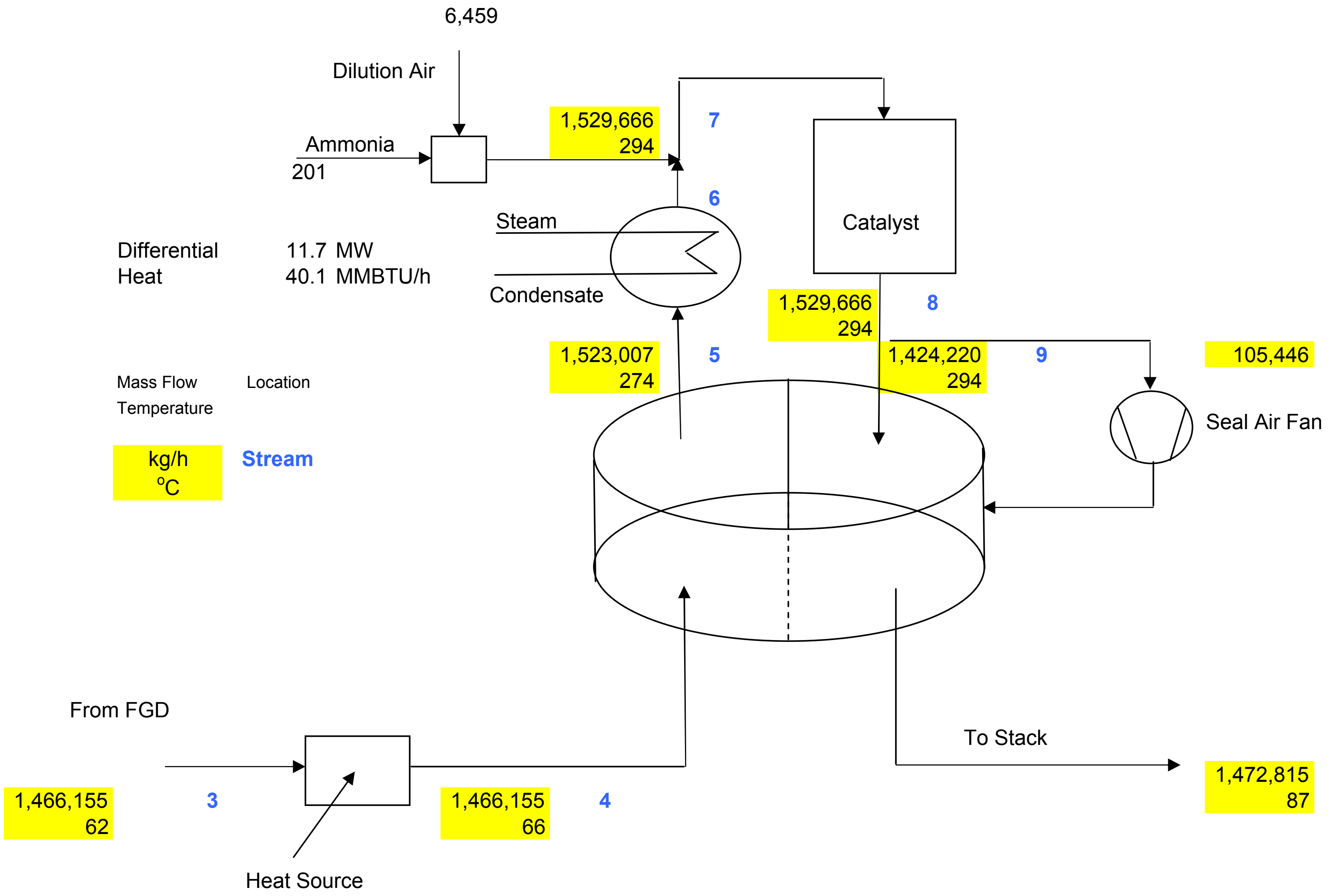
Let us know if you have any questions.
Thanks, Bob

Robert E. Johnson

Fuel Tech, Inc

(913) 897 0727
<<6Feb09_PFD_natgas_downstream_FGD.pdf>> <<6Feb09_MassBalance_MRY2TailEnd_Rev0.pdf>>
<<6Feb09_MRY2TailEnd_Rev0_natgas_downstrm_FGD.pdf>> <<6Feb09_PFD_MRY2TailEnd_Rev0.pdf>>

MRY 2 Tail End SCR Process Flow Diagram



MRY 2		Input Data FGD Outlet	3 FGD Outlet	4 GGH inlet	5 GGH outlet	6 Burner out	7 Reactor inlet	8 Reactor outlet	9 GGH treated inlet	10 Booster fan in	11 Booster fan out	12 Natural Gas	13 Combustion Air	14 Ammonia	15 Dilution Air	17 Purge+Scavange	12+13 Burner Flue Gas	14 Reacted		
Volumetric flow rate vol.	Nm^3/h		1,180,582	1,180,582	1,226,360	1,243,637	1,248,897	1,249,034	1,164,200	1,186,234	1,186,234	1,240	16,030	263	4,997	84,927	17,270		Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		744,304	744,304	773,165	784,057	787,374	787,460	733,976	747,868	747,868	781	10,106	166	3,150	53,543	10,888		scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		820,913	820,913	1,401,624	1,485,058	1,494,932	1,505,978	1,405,398	929,352	929,352								acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,466,155	1,466,155	1,523,007	1,544,383	1,551,042	1,551,042	1,445,597	1,494,191	1,494,191	966	20,410	201	6,459	105,446	21,376	201	kg/h	Mass Flow
Mass Flow	lb/hour		3,229,416	3,229,416	3,354,640	3,401,724	3,416,393	3,416,393	3,184,133	3,291,169	3,291,169	2,129	44,956	442	14,227	232,260	47,084	442	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	520	562	562	562	562	196	196								Degree F	Temperature
Temperature	Degree C		62	66	271	294	294	294	294	91	91								Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0									Pressure
Composition																				Composition
Nitrogen	Vol-parts		0.6346	0.6346	0.6346	0.6365	0.6370	0.6372	0.6372	0.6352	0.6352		0.7900		0.7809		0.7705	0.2999	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1063	0.1063	0.1063	0.1058	0.1053	0.1053	0.1053	0.1058	0.1058				0.0003		0.0703		Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0496	0.0496	0.0497	0.0492	0.0498	0.0497	0.0497	0.0501	0.0501		0.2100		0.2095		0.0147		Vol-parts	Oxygen
Moisture	Vol-parts		0.2091	0.2091	0.2091	0.2082	0.2073	0.2076	0.2076	0.2088	0.2088						0.1445	0.7001	Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001						0.0000		Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000			
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000			
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000		Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0093		0.0000			
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000			
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		Total
Volumetric Flow			0																	Volumetric Flow
Nitrogen	Nm^3/h		749,220	749,220	778,316	791,614	795,516	795,913	741,855	753,514	753,514		12,664		3,902	53,947	13,306	64	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		125,507	125,507	130,345	131,559	131,561	131,561	122,625	125,508	125,508				1	8,986	1,214		Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		58,606	58,606	60,904	61,158	62,205	62,072	57,856	59,391	59,391		3,366		1,047	4,252	254		Nm^3/h	Oxygen
Moisture	Nm^3/h		246,863	246,863	256,419	258,913	258,913	259,309	241,697	247,646	247,646				0	17,730	2,496	150	Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		79	79	82	82	82	81	75	78	78				0	6	0		Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	1	1	1	1				0	0	0			
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0			
Nitrogen dioxide	Nm^3/h		307	307	306	310	310	45	42	47	46				0	3	0		Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	49	49	45	46	46				46	3	0			
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3				0	0	0			
Total	Nm^3/h		1,180,582	1,180,582	1,226,374	1,243,637	1,248,897	1,249,034	1,164,200	1,186,235	1,186,234		16,030		4,997	84,927	17,270	214	Nm^3/h	Total
Mass Flow																				Mass Flow
Nitrogen	kg/h	1,873,285	936,643	936,643	973,016	989,641	994,519	995,015	927,435	942,010	942,010		15,832		4,878	67,442	16,625	80	kg/h	Nitrogen
Carbon di oxide	kg/h	492,954	246,477	246,477	255,979	258,363	258,366	258,366	240,818	246,480	246,480				3	17,647	2,384		kg/h	Carbon di oxide
Oxygen	kg/h	167,370	83,685	83,685	86,967	87,329	88,824	88,635	82,615	84,807	84,807		4,807		1,495	6,072	363		kg/h	Oxygen
Moisture	kg/h	396,920	198,460	198,460	206,142	208,147	208,147	208,466	194,307	199,090	199,090				0	14,254	2,005	120	kg/h	Moisture
Sulfur di oxide	kg/h	450	225	225	234	234	234	231	216	223	223				0	16			kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	3	3	3	3				0	0				
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0				
Nitrogen di oxide	kg/h	1,261	631	631	628	636	636	93	86	96	95				0	7	7		kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	87	87	81	83	83				83	6				
Ammonia	kg/h		0	0	0	0	201	2	2	2	2			201	0	0				
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35				0	3				
Total	kg/h	2,932,310	1,466,155	1,466,155	1,523,007	1,544,390	1,551,050	1,550,935	1,445,597	1,472,828	1,472,827		20,639	201	6,459	105,446	21,383	201	kg/h	Total
Nitrogen	lb/h		2,063,089	2,063,089	2,143,208	2,179,826	2,190,571	2,191,664	2,042,808	2,074,912	2,074,912		34,872	0	10,745	148,552	36,619	177	lb/h	Nitrogen
Carbon di oxide	lb/h		542,901	542,901	563,831	569,082	569,088	569,088	530,436	542,907	542,907			0	6	38,869	5,251	0	lb/h	Carbon di oxide
Oxygen	lb/h		184,328	184,328	191,556	192,355	195,648	195,232	181,972	186,800	186,800		10,588	0	3,293	13,374	799	0	lb/h	Oxygen
Moisture	lb/h		437,137	437,137	454,057	458,473	458,473	459,175	427,989	438,523	438,523			0	0	31,396	4,416	265	lb/h	Moisture
Sulfur di oxide	lb/h		496	496	514	514	514	510	475	491	491			0	0	35		0	lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	6	6	6	6				0	0				
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0				
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,400	1,400	204	190	211	208			0	0	15	16	0	lb/h	Nitrogen di oxide
Argon	lb/h		0	0	9	9	191	191	178	182	182				182	13				
Ammonia	lb/h		0	0	0	0	442	5	5	5	5				0	0				
Particulate	lb/h		77	77	80	80	80	80		77	77				0	6				
Total	lb/h		3,229,416	3,229,416	3,354,640	3,401,740	3,416,409	3,416,156	3,184,059	3,244,115	3,244,113		45,460	0	14,227	232,260	47,100	442	lb/h	Total
Composition																				Composition
Nitrogen	Mass-parts		0.639	0.639	0.639	0.641	0.641	0.642	0.642	0.640	0.640		0.767		0.755	0.640	0.777		Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.168	0.168	0.168	0.167	0.167	0.167	0.167	0.167	0.167		0.000		0.000	0.167	0.111		Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.058	0.058		0.233		0.231	0.058	0.017		Mass-parts	Oxygen
Moisture	Mass-parts		0.135	0.135	0.135	0.135	0.134	0.134	0.134	0.135	0.135		0.000		0.000	0.135	0.094		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000		Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000			
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000			
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000		Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.013	0.000	0.000			
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000			
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000			
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.987	1.000	1.000	0.000	Mass-parts	Total
Density	kg/Nm^3		1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242									
Cp	kJ/kgK		1.118792829	1.1197279	1.1788636	1.186311771	1.18631177	1.186311771	1.186311771	1.126080331	1.126080331								kJ/kgK	Cp
Heat Content	MW		28.098	29.895	135.259	149.740	150.386	150.386	140.162	42.580	42.580	14.009							MW	Heat Content
	MMBTU/hr		95.899	102.032	461.638	511.062	513.266	513.266	478.372	145.324	145.324	47.813								
NO$_2$	lbs/hour		1388.7665	1388.7665	1384.0485	1399.8458	1399.8458	203.8055	189.9632	210.6149	208.3150					14.9			lbs/hour	NO$_2$

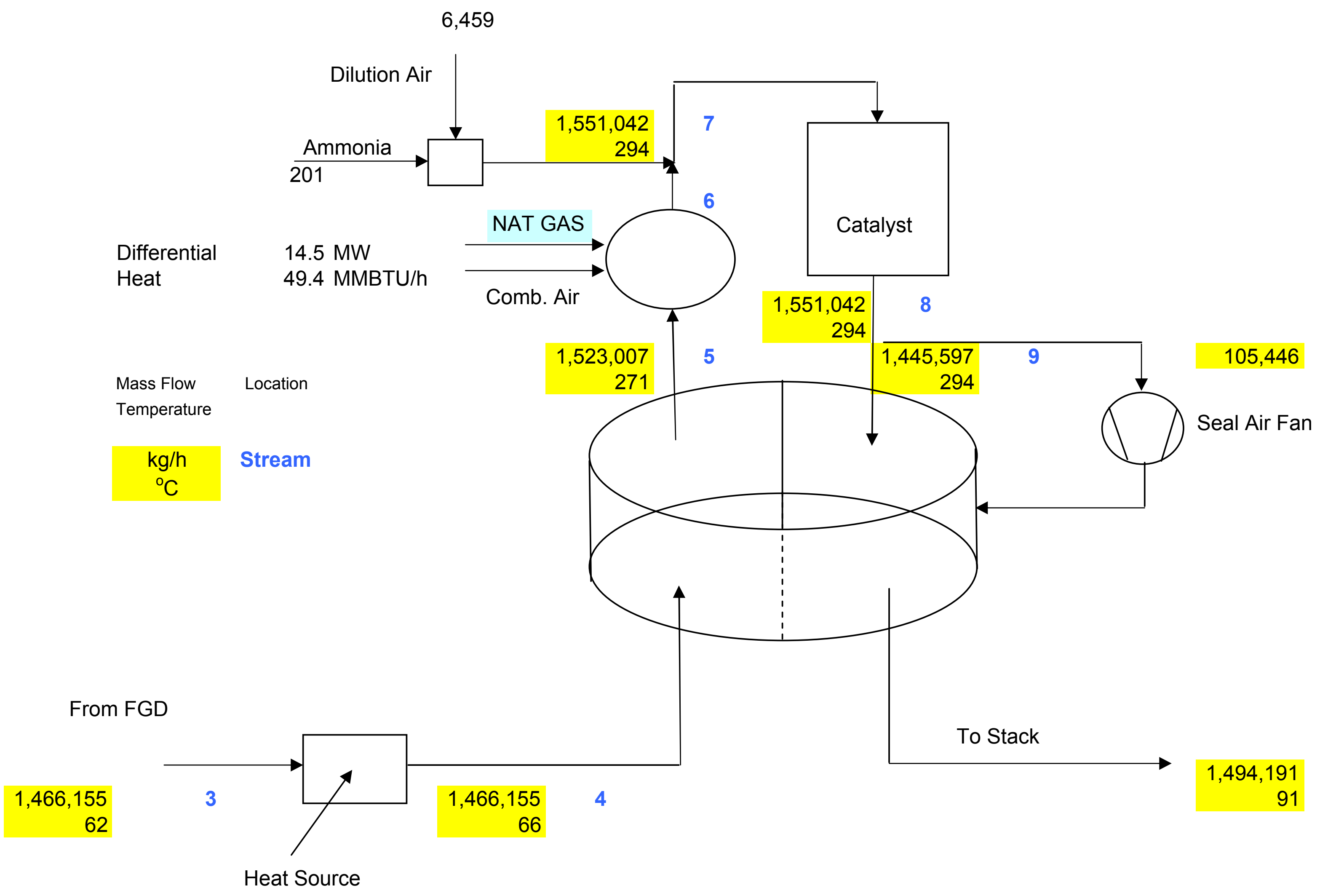
MRY 2		Input Data FGD Outlet	3 FGD Outlet	4 GGH inlet	5 GGH outlet	6 Burner out	7 Reactor inlet	8 Reactor outlet	9 GGH treated inlet	10 Booster fan in	11 Booster fan out	12 Natural Gas	13 Combustion Air	14 Ammonia	15 Dilution Air	17 Purge+Scavange	12+13 Burner Flue Gas	14 Reacted		
NO_2	kg/h		630.5000	630.5000	628.3580	635.5300	635.5300	92.5277	86.2433	95.6192	94.5750					6.8			kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	309.6	309.6	45.1	42.0	46.6	46.1					3.3				
NO + NO_2 @ actual O_2	PPM		260.2	260.2	249.6	249.0	247.9	36.1	36.1	39.3	38.8					38.8				
NO + NO_2 @ 3 % O_2	PPM		292.0	292.0	280.2	278.6	278.6	40.5	40.5	44.2	43.7									

						NO2 Balance Check				
Eta NOx		0.850	0.8500			kg/h	lbs/hr			
Eta NOx reactor			0.8544			0.1	0			
SO2/SO3 Conversion Rate	%	1.00%								
						Diff. heat hot side	Diff. heat cold side			0.663477551
Ammonia slip	PPM	2				MW	MW			
						14.481	14.481			
Temperature Diff. Hot Side	F	50								

MRY 2		Input Data FGD Outlet	3 FGD Outlet	4 GGH inlet	5 GGH outlet	6 Steam HE out	7 Reactor inlet	8 Reactor outlet	9 GGH treated inlet	10 Booster fan in	11 Booster fan out	14 Ammonia	15 Dilution Air	17 Purge+Scavange	14 Reacted		
Volumetric flow rate vol.	Nm^3/h		1,180,582	1,180,582	1,226,360	1,226,360	1,231,634	1,231,766	1,146,942	1,186,234	1,186,234	263	4,997	84,927		Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		744,304	744,304	773,165	773,165	776,490	776,573	723,096	747,868	747,868	166	3,150	53,543		scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		820,913	820,913	1,409,601	1,469,126	1,474,667	1,485,560	1,384,940	917,742	917,742					acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,466,155	1,466,155	1,523,007	1,523,007	1,529,666	1,529,666	1,424,220	1,472,815	1,472,815	201	6,459	105,446	201	kg/h	Mass Flow
Mass Flow	lb/hour		3,229,416	3,229,416	3,354,640	3,354,640	3,369,309	3,369,309	3,137,049	3,244,085	3,244,085	442	14,227	232,260	442	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	526	565	562	562	562	188	188					Degree F	Temperature
Temperature	Degree C		62	66	274	296	294	294	294	87	87					Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0						Pressure
Composition																	Composition
Nitrogen	Vol-parts		0.6346	0.6346	0.6346	0.6346	0.6351	0.6354	0.6354	0.6352	0.6352		0.7809		0.2999	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1063	0.1063	0.1063	0.1063	0.1058	0.1058	0.1058	0.1058	0.1058		0.0003			Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0496	0.0496	0.0497	0.0497	0.0503	0.0502	0.0502	0.0501	0.0501		0.2095			Vol-parts	Oxygen
Moisture	Vol-parts		0.2091	0.2091	0.2091	0.2091	0.2082	0.2085	0.2085	0.2088	0.2088				0.7001	Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001					Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000					Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0093				
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		Total
Volumetric Flow			0														Volumetric Flow
Nitrogen	Nm^3/h		749,220	749,220	778,316	778,316	782,218	782,610	728,717	753,514	753,514		3,902	53,947	64	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		125,507	125,507	130,345	130,345	130,347	130,347	121,371	125,508	125,508		1	8,986		Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		58,606	58,606	60,904	60,904	61,951	61,820	57,563	59,391	59,391		1,047	4,252		Nm^3/h	Oxygen
Moisture	Nm^3/h		246,863	246,863	256,419	256,419	256,419	256,811	239,126	247,646	247,646		0	17,730	150	Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		79	79	82	82	82	81	75	78	78		0	6		Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	1	1	1	1		0	0			
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen dioxide	Nm^3/h		307	307	306	306	306	45	41	46	46		0	3		Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	49	49	45	46	46		46	3			
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3		0	0			
Total	Nm^3/h		1,180,582	1,180,582	1,226,374	1,226,374	1,231,634	1,231,766	1,146,942	1,186,234	1,186,234		4,997	84,927	214	Nm^3/h	Total
Mass Flow																	Mass Flow
Nitrogen	kg/h	1,873,285	936,643	936,643	973,016	973,016	977,894	978,385	911,010	942,010	942,010		4,878	67,442	80	kg/h	Nitrogen
Carbon di oxide	kg/h	492,954	246,477	246,477	255,979	255,979	255,982	255,982	238,354	246,480	246,480		3	17,647		kg/h	Carbon di oxide
Oxygen	kg/h	167,370	83,685	83,685	86,967	86,967	88,461	88,275	82,196	84,807	84,807		1,495	6,072		kg/h	Oxygen
Moisture	kg/h	396,920	198,460	198,460	206,142	206,142	206,142	206,457	192,240	199,090	199,090		0	14,254	120	kg/h	Moisture
Sulfur di oxide	kg/h	450	225	225	234	234	234	231	215	223	223		0	16		kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	3	3	3	3		0	0			
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen di oxide	kg/h	1,261	631	631	628	628	628	91	85	95	95		0	7		kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	87	87	81	83	83		83	6			
Ammonia	kg/h		0	0	0	0	201	2	2	2	2	201	0	0			
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35		0	3			
Total	kg/h	2,932,310	1,466,155	1,466,155	1,523,007	1,523,007	1,529,666	1,529,550	1,424,220	1,472,827	1,472,827	201	6,459	105,446	201	kg/h	Total
Nitrogen	lb/h		2,063,089	2,063,089	2,143,208	2,143,208	2,153,953	2,155,033	2,006,630	2,074,912	2,074,912	0	10,745	148,552	177	lb/h	Nitrogen
Carbon di oxide	lb/h		542,901	542,901	563,831	563,831	563,837	563,837	525,009	542,907	542,907	0	6	38,869	0	lb/h	Carbon di oxide
Oxygen	lb/h		184,328	184,328	191,556	191,556	194,849	194,438	181,048	186,800	186,800	0	3,293	13,374	0	lb/h	Oxygen
Moisture	lb/h		437,137	437,137	454,057	454,057	454,057	454,752	423,436	438,523	438,523	0	0	31,396	265	lb/h	Moisture
Sulfur di oxide	lb/h		496	496	514	514	514	510	474	491	491	0	0	35	0	lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	6	6	6	6		0	0			
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,384	1,384	202	188	208	208	0	0	15	0	lb/h	Nitrogen di oxide
Argon	lb/h		0	0	9	9	191	191	178	182	182		182	13			
Ammonia	lb/h		0	0	0	0	442	5	5	5	5		0	0			
Particulate	lb/h		77	77	80	80	80	80		77	77		0	6			
Total	lb/h		3,229,416	3,229,416	3,354,640	3,354,640	3,369,309	3,369,054	3,136,975	3,244,113	3,244,113	0	14,227	232,260	442	lb/h	Total
Composition																	Composition
Nitrogen	Mass-parts		0.639	0.639	0.639	0.639	0.639	0.640	0.640	0.640	0.640		0.755	0.640		Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.168	0.168	0.168	0.168	0.167	0.167	0.167	0.167	0.167		0.000	0.167		Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.057	0.058	0.058	0.058	0.058	0.058		0.231	0.058		Mass-parts	Oxygen
Moisture	Mass-parts		0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.135		0.000	0.135		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000		Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000		Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.013	0.000			
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	0.987	1.000	0.000	Mass-parts	Total

MRY 2		Input Data FGD Outlet	3 FGD Outlet	4 GGH inlet	5 GGH outlet	6 Steam HE out	7 Reactor inlet	8 Reactor outlet	9 GGH treated inlet	10 Booster fan in	11 Booster fan out	14 Ammonia	15 Dilution Air	17 Purge+Scavange	14 Reacted		
Density	kg/Nm^3		1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242						
Cp	kJ/kgK		1.118792829	1.1197279	1.1798596	1.186904869	1.1863618	1.186361804	1.186361804	1.12492337	1.12492337					kJ/kgK	Cp
Heat Content	MW		28.098	29.895	136.919	148.655	148.397	148.397	138.167	39.834	39.834					MW	Heat Content
	MMBTU/hr		95.899	102.032	467.305	507.360	506.478	506.478	471.565	135.953	135.953						
NO_2	lbs/hour		1388.7665	1388.7665	1384.0485	1384.0485	1384.0485	201.5056	187.6292	208.3150	208.3150			14.9		lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3580	628.3580	628.3580	91.4835	85.1837	94.5750	94.5750			6.8		kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	306.1	306.1	44.6	41.5	46.1	46.1			3.3			
NO + NO_2 @ actual O_2	PPM		260.2	260.2	249.6	249.6	248.5	36.2	36.2	38.8	38.8			38.8			
NO + NO_2 @ 3 % O_2	PPM		292.0	292.0	280.2	280.2	280.1	40.8	40.8	43.7	43.7						
						NO2 Balance Check											
Eta NOx		0.850	0.8500			kg/h	lbs/hr										
Eta NOx reactor			0.8544			-0.9	-2										
SO2/SO3 Conversion Rate	%	1.00%															
						Diff. heat hot side		Diff. heat cold side		0.663477551							
Ammonia slip	PPM	2				MW		MW									
						11.736		11.736									
Temperature Diff. Hot Side	F	50															
						-2											

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



Blakley, Robert

From: Blakley, Robert

Sent: Monday, February 09, 2009 5:30 PM

To: 'Robert Johnson'

Cc: 'Volker Rummenhohl'; Weilert, Carl; Voss, Steve; Bryant, Ronald; Blackwood, Dave

Subject: RE: Hypothetical Case_Tail End SCR

Bob & Volker –

We will review your recent mass balances for Unit 2.

Do you expect there to be a FGD GGH and booster fan downstream of the existing U2 wet lime FGD absorbers, upstream of the TESCR GGH? We expect the existing ID fans, or their replacements, will control boiler draft, so the TESCR will need a booster fan to overcome the GGH, reactor, and GGH treated side pressure drops.

As mentioned previously, I believe the typical FGD outlet pressure on U2's existing scrubbers is around 3-3.5 in. w.c., with 330-340 degF inlet gas entering the towers, at full load conditions (approx. 4800 mmBtu/hr boiler heat input). The absorber vessels are not rated to operate beyond around 4 in. w.c., which we are attempting to confirm.

The 5,158 mmBtu/hr heat input rate in the design basis is for short term, maximum output operation, for the plant's reserve capacity rating.

I also need to know the equation for converting ACFM or SCFM to normal cubic meters (Nm3). We're trying to calculate particulate and sodium loading expected to enter the LDSCR and TESCR reactors, in terms of milligrams or micrograms per Nm3.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Saturday, February 07, 2009 5:25 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Hypothetical Case_Tail End SCR

Bob,
Attached are the latest Mass Balances and PFDs for the Steam and Nat Gas reheat cases. We revised the Steam case from the version previously sent.

We will be working on the Low Dust case as soon as we thoroughly review the revised spreadsheet you sent. We were both out of town last week.

Let us know if you have any questions.
Thanks, Bob

Robert E. Johnson

Fuel Tech, Inc

(913) 897 0727

<<6Feb09_PFD_natgas_downstream_FGD.pdf>> <<6Feb09_MassBalance_MRY2TailEnd_Rev0.pdf>>
<<6Feb09_MRY2TailEnd_Rev0_natgas_downstrm_FGD.pdf>> <<6Feb09_PFD_MRY2TailEnd_Rev0.pdf>>

Blakley, Robert

From: Blakley, Robert
Sent: Tuesday, March 03, 2009 12:26 PM
To: 'Robert Johnson'
Cc: 'Volker Rummenhohl'; Bryant, Ronald; Blackwood, Dave
Subject: RE: Hypothetical Case_Tail End SCR

Bob & Volker -

One of the decisions from the SCR cost estimate study kickoff meeting with Minnkota last Thursday, February 26 was to assume natural gas firing for supplemental flue gas heating for both LD and TESCR cases for MRYS Unit 1 and Unit 2. Minnkota has established this as their reheat source they prefer.

In addition, Minnkota directed BMcD to assume urea for the ammonia source. Our understanding is that this may slightly affect the SCR mass balances when the urea is converted to ammonia before being injected into the flue gas stream because of the CO2 and water that will be driven off. The urea solution will be stored at 50% concentration on-site prior to feeding.

Please consider these decisions so that you can revise the preliminary mass balances for the LD and TESCR cases for MRYS Unit 1 and Unit 2 and provide estimated reactor sizing.

We would like to get the revised mass balances within 1 week and the preliminary reactor sizing by mid-March if possible. I don't know what the latter entails, so advise an alternate time table if this is more complicated than I realize.

Please advise if question arise.

Thanks,

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<<6Feb09_MRY2TailEnd_Rev0_natgas_downstrm_FGD.pdf>> <<6Feb09_PFD_MRY2TailEnd_Rev0.pdf>>

Blakley, Robert

From: Blakley, Robert
Sent: Friday, March 06, 2009 12:10 PM
To: 'Robert Johnson'
Cc: 'Volker Rummenhohl'; Bryant, Ronald; Blackwood, Dave; Voss, Steve
Subject: RE: Hypothetical Case_Tail End SCR

Bob –

I don't envision Minnkota having ammonia storage tanks in addition to the concentrated urea storage tanks, if the urea-to-ammonia conversion isn't "on demand".
I assume either a FT "Ultra" system or the hydrolyzer approach would satisfy that requirement.

My guess is since Minnkota has chosen natural gas-fired final reheat for the flue gas ahead of the SCR reactor for either LD or TE SCR cases as the energy source, rather than steam, they would probably go with the Fuel Tech version that uses fuel to decompose the urea rather than a hydrolyzer that uses steam.

I suppose it may depend on how much heat is required and what steam conditions are involved for the hydrolyzer. I am not familiar with that process but I'm sure we could check into that from another SCR project is needed.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Friday, March 06, 2009 11:59 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: RE: Hypothetical Case_Tail End SCR

Bob,
Thanks. We will revise the mass balances, but it will probably take until next Friday.
Has Minnkota determined the type of urea system? one requires steam for the hydrolysis and Fuel Tech's requires a combustion fuel. in this case, we would use the natural gas. Our system will affect the mass balance due to additional NOx, and byproducts such as H_2O and CO_2. We wouldn't account for trace byproducts.

The reactor size is easier, but mid-March is fine as a deadline.

Just to confirm, you need 4 mass balances: LD and TE for both MRYS 1 and 2.

Best Regards,
Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, March 03, 2009 12:26 PM
To: Robert Johnson
Cc: Volker Rummenhohl; Bryant, Ronald; Blackwood, Dave
Subject: RE: Hypothetical Case_Tail End SCR

Bob & Volker -

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Blakley, Robert

From: Blakley, Robert
Sent: Friday, March 06, 2009 12:25 PM
To: 'Robert Johnson'
Cc: 'Volker Rummenhohl'; Bryant, Ronald; Blackwood, Dave; Voss, Steve
Subject: RE: Hypothetical Case_Tail End SCR

Bob –

I checked on the Seminole SCR project – it appears to use 125 psig saturated steam for the heat source in the urea-to-ammonia conversion process, and electric resistance heat tracing on the urea and ammonia lines.

Oh, and I am confirming that we need information on four cases:
U1 LD and TESCR; and
U2 LD and TESCR.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Friday, March 06, 2009 12:13 PM
To: Blakley, Robert
Cc: Volker Rummenhohl; Bryant, Ronald; Blackwood, Dave; Voss, Steve
Subject: RE: Hypothetical Case_Tail End SCR

Bob,
Thanks.
FYI: the Wahlco hydrolyzer system is being used on the Seminole and Crystal River SCR projects.
Regards, Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Friday, March 06, 2009 12:10 PM
To: Robert Johnson
Cc: Volker Rummenhohl; Bryant, Ronald; Blackwood, Dave; Voss, Steve
Subject: RE: Hypothetical Case_Tail End SCR

Bob –

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Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Friday, March 06, 2009 11:59 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: RE: Hypothetical Case_Tail End SCR

Bob,
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Best Regards,
Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, March 03, 2009 12:26 PM
To: Robert Johnson
Cc: Volker Rummenhohl; Bryant, Ronald; Blackwood, Dave
Subject: RE: Hypothetical Case_Tail End SCR

Bob & Volker -

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Thanks,

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Saturday, February 07, 2009 5:25 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Hypothetical Case_Tail End SCR

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Robert E. Johnson

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From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Thu 3/12/2009 8:59 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 12Mar09_Preliminary Information

Bob,
Attached are preliminary mass balances and PFDs for the LD and TE hypothetical cases. We have updated these to reflect natural gas firing to control temperatures to the SCR inlet. We have also based these on the use of Fuel Tech's ULTRA system for decomposing urea to ammonia. You will see the various inputs on the PFDs.

Also, we have prepared a table with preliminary reactor sizes. For all 4 cases, we have assumed 2 reactors per unit.
But, for Unit 1, 1 large reactor would also be possible for both cases. This is possible since the mass flow rate of the flue gas is less than 2,000,000 kg/hr.

Please let us know if we can clarify anything.

Best Regards, Bob

Robert E. Johnson

Fuel Tech, Inc

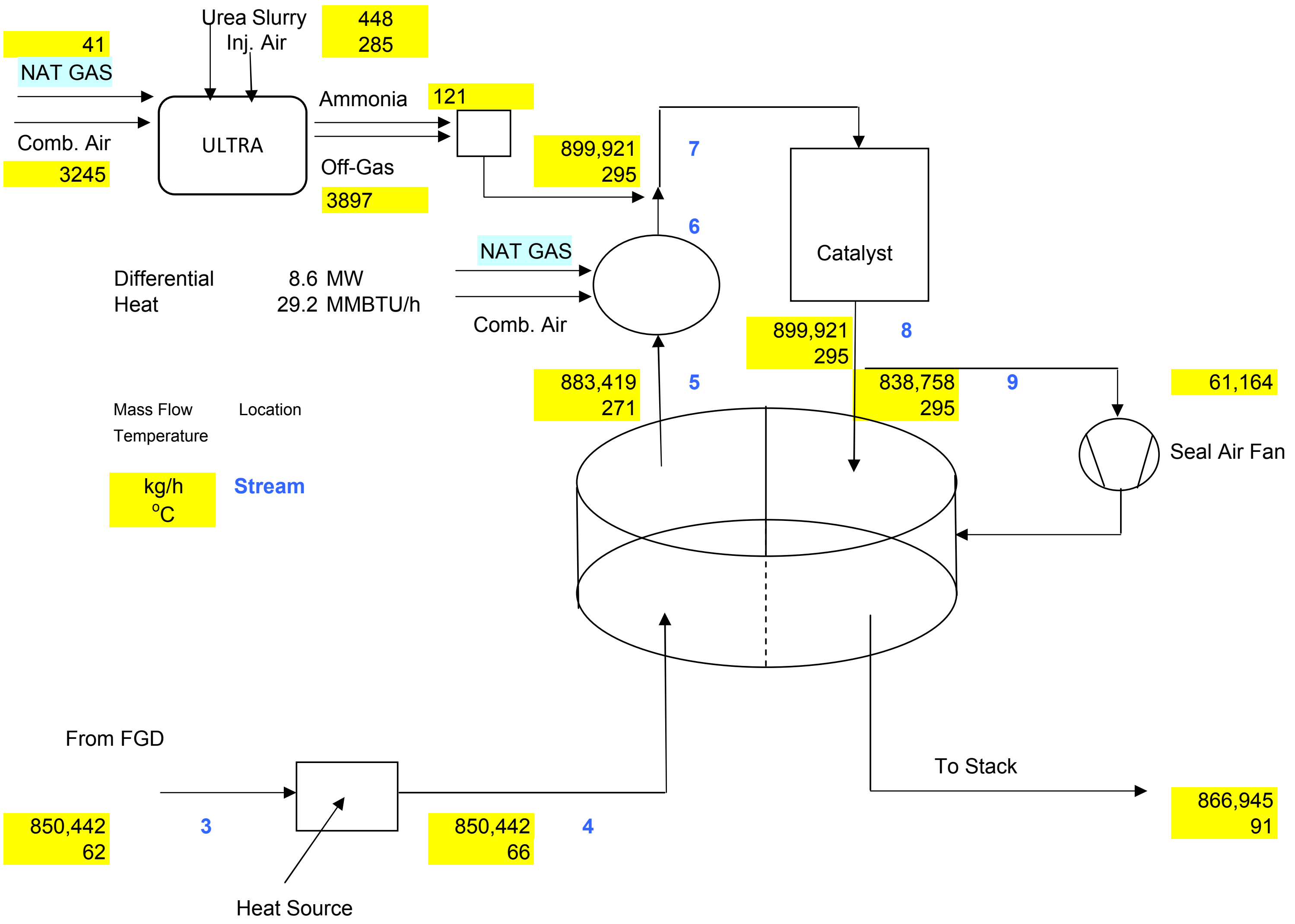
(913) 897 0727

<<10Mar09_MRY2LowDust_PFD_Rev0_natgas.pdf>> <<9Mar09_MRY2TailEnd_Mass Balance_Rev0_natgas.pdf>>
<<9Mar09_MRY2TailEnd_PFD_Rev0_natgas.pdf>> <<10Mar09_Hypothetical SCR_Reactor Arrangement_Summary.pdf>>
<<10Mar09_MRY1LowDust_MassBalance_Rev0_natgas.pdf>> <<10Mar09_MRY1LowDust_PFD_Rev0_natgas.pdf>>
<<10Mar09_MRY1TailEnd_MassBalance_Rev0_natgas.pdf>> <<10Mar09_MRY1TailEnd_PFD_Rev0_natgas.pdf>>
<<10Mar09_MRY2LowDust_Mass BalanceRev0_natgas.pdf>>

MRY 2		Input Data ESP Outlet	3 ESP Outlet	4 GGH inlet	5 GGH outlet	6 Burner out	7 Reactor inlet	8 Reactor outlet	9 GGH treated inlet	10 Booster fan in	11 Booster fan out	12 Natural Gas	13 Combustion Air	14 Ammonia	15 ULTRA Off-Gas	17 Purge+Scavange	12+13 Burner Flue Gas	14 Reacted	18 ULTRA Natural Gas	19 ULTRA Combustion Air	20 ULTRA Urea Slurry	21 ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		1,072,689	1,072,689	1,114,284	1,129,869	1,135,150	1,135,286	1,058,149	1,078,363	1,078,363	1,117	14,446	263	5,018	77,189	15,563		86	4,135		293	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		676,283	676,283	702,506	712,332	715,661	715,747	667,116	679,859	679,859	704	9,107	166	3,164	48,664	9,812		54	2,607		185	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		978,672	978,672	1,273,531	1,351,693	1,361,282	1,371,355	1,279,731	1,082,007	1,082,007												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,374,291	1,374,291	1,427,580	1,446,843	1,453,355	1,453,355	1,354,516	1,400,066	1,400,066	871	18,392	201	6,312	98,839	19,263	201	67	5,324	744	378	kg/h	Mass Flow
Mass Flow	lb/hour		3,027,072	3,027,072	3,144,449	3,186,879	3,201,223	3,201,223	2,983,516	3,083,845	3,083,845	1,918	40,512	442	13,902	217,707	42,430	442	148	11,726	1,638	832	lb/hour	Mass Flow
Temperature	Degree F	331	331	331	520	564	564	564	564	380	380												Degree F	Temperature
Temperature	Degree C		166	166	271	295	295	295	295	193	193												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6879	0.6879	0.6879	0.6890	0.6888	0.6891	0.6891	0.6878	0.6878		0.7900		0.6790		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1156	0.1156	0.1156	0.1150	0.1146	0.1146	0.1146	0.1152	0.1152				0.0467		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0525	0.0525	0.0525	0.0520	0.0524	0.0523	0.0523	0.0527	0.0527		0.2100		0.1422		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.1422	0.1422	0.1423	0.1423	0.1422	0.1425	0.1425	0.1428	0.1428				0.1240		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0015	0.0015	0.0015	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		737,868	737,868	766,494	778,477	781,884	782,281	729,129	741,666	741,666		11,412		3,407	53,088	11,991	64		3,267		232	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		124,008	124,008	128,799	129,893	130,127	130,127	121,286	124,243	124,243				234	8,893	1,094						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		56,358	56,358	58,552	58,781	59,495	59,363	55,329	56,810	56,810		3,034		714	4,066	229			868		62	Nm^3/h	Oxygen
Moisture	Nm^3/h		152,571	152,571	158,521	160,768	161,390	161,787	150,794	153,977	153,977				622	11,022	2,249	150					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		1,578	1,578	1,638	1,638	1,638	1,622	1,512	1,562	1,562				0	112	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	1	1	1	17	15	16	16				0	1	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		307	307	306	309	309	45	42	47	46				0	3	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	42	42	40	40	40				40	3	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		1,072,689	1,072,689	1,114,312	1,129,869	1,135,150	1,135,286	1,058,149	1,078,363	1,078,363		14,446		5,018	77,189	15,563	214		4,135		293	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,844,900	922,450	922,450	958,237	973,218	977,478	977,973	911,525	927,199	927,199		14,267		4,259	66,369	14,982	80		4,084		290	kg/h	Nitrogen
Carbon di oxide	kg/h	487,068	243,534	243,534	252,943	255,091	255,551	255,551	238,188	243,994	243,994				460	17,465	2,148						kg/h	Carbon di oxide
Oxygen	kg/h	160,950	80,475	80,475	83,609	83,935	84,955	84,766	79,007	81,121	81,121		4,332		1,019	5,807	327			1,240		88	kg/h	Oxygen
Moisture	kg/h	245,312	122,656	122,656	127,439	129,246	129,746	130,065	121,227	123,786	123,786				500	8,861	1,807	120			372		kg/h	Moisture
Sulfur di oxide	kg/h	9,020	4,510	4,510	4,682	4,682	4,682	4,636	4,321	4,465	4,465				0	320							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	3	3	3	59	55	56	56				0	4							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	1,261	631	631	628	635	635	92	86	96	95				0	7	6						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	76	76	71	72	72				72	5							kg/h	Argon
Ammonia	kg/h		0	0	0	0	201	2	2	2	2			201	0	0							kg/h	Ammonia
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35				0	3							kg/h	Particulate
Urea	kg/h																				372		kg/h	Urea
Total	kg/h	2,748,581	1,374,291	1,374,291	1,427,580	1,446,850	1,453,362	1,453,257	1,354,516	1,380,827	1,380,826		18,599	201	6,312	98,839	19,270	201		5,324	744	378	kg/h	Total
Nitrogen	lb/h		2,031,828	2,031,828	2,110,654	2,143,653	2,153,035	2,154,126	2,007,764	2,042,288	2,042,288		31,425	0	9,382	146,186	32,999	177		8,995		638	lb/h	Nitrogen
Carbon di oxide	lb/h		536,419	536,419	557,143	561,875	562,889	562,889	524,643	537,433	537,433			0	1,014	38,469	4,732	0					lb/h	Carbon di oxide
Oxygen	lb/h		177,258	177,258	184,160	184,880	187,125	186,709	174,023	178,682	178,682		9,541	0	2,245	12,790	720	0		2,731		194	lb/h	Oxygen
Moisture	lb/h		270,167	270,167	280,703	284,682	285,784	286,486	267,021	272,656	272,656			0	1,102	19,517	3,979	265			819		lb/h	Moisture
Sulfur di oxide	lb/h		9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835	9,835			0	0	704		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	6	6	6	130	121	124	124				0	9							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,398	1,398	204	190	210	208			0	0	15	14	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	8	8	167	167	156	159	159				159	11							lb/h	Argon
Ammonia	lb/h		0	0	0	0	442	5	4	5	5				0	0							lb/h	Ammonia
Particulate	lb/h		77	77	80	80	80	80		77	77				0	6							lb/h	Particulate
Urea	lb/h																				819		lb/h	Urea
Total	lb/h		3,027,072	3,027,072	3,144,449	3,186,893	3,201,237	3,201,008	2,983,441	3,041,469	3,041,467		40,967	0	13,902	217,707	42,444	442		11,726	1,638	832	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.671	0.671	0.671	0.673	0.673	0.673	0.673	0.671	0.671		0.767		0.675	0.671	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.177	0.177	0.177	0.176	0.176	0.176	0.176	0.177	0.177		0.000		0.073	0.177	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.059	0.059	0.059	0.058	0.058	0.058	0.058	0.059	0.059		0.233		0.161	0.059	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.090	0.090		0.000		0.079	0.090	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003		0.000		0.000	0.003	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.281	1.281	1.281	1.281	1.280	1.280	1.280	1.280	1.280													
Cp	kJ/kgK		1.104243094	1.1042431	1.1351465	1.142572233	1.14257223	1.142572233	1.142572233	1.111950928	1.111950928												kJ/kgK	Cp
Heat Content	MW		70.023	70.023	122.082	135.591	136.201	136.201	126.938	83.598	83.598	12.624							0.976				MW	Heat Content
	MMBTU/hr		238.988	238.988	416.667	462.771	464.854	464.854	433.241	285.319	285.319	43.087							3.331					
NO_2	lbs/hour		1388.7665	1388.7665	1384.0464	1398.2822	1398.2822	203.5779	189.7458	210.3873	208.3150					14.9							lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3571	634.8201	634.8201	92.4244	86.1446	95.5158	94.5750					6.8							kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	309.3	309.3	45.0	42.0	46.5	46.1					3.3								
NO + NO_2 @ actual O_2	PPM		286.3	286.3	274.7	273.7	272.4	39.7	39.7	43.2	42.7					42.7								
NO + NO_2 @ 3 % O_2	PPM		327.3	327.3	314.1	311.9	311.2	45.3	45.3	49.4	48.9													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 2	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

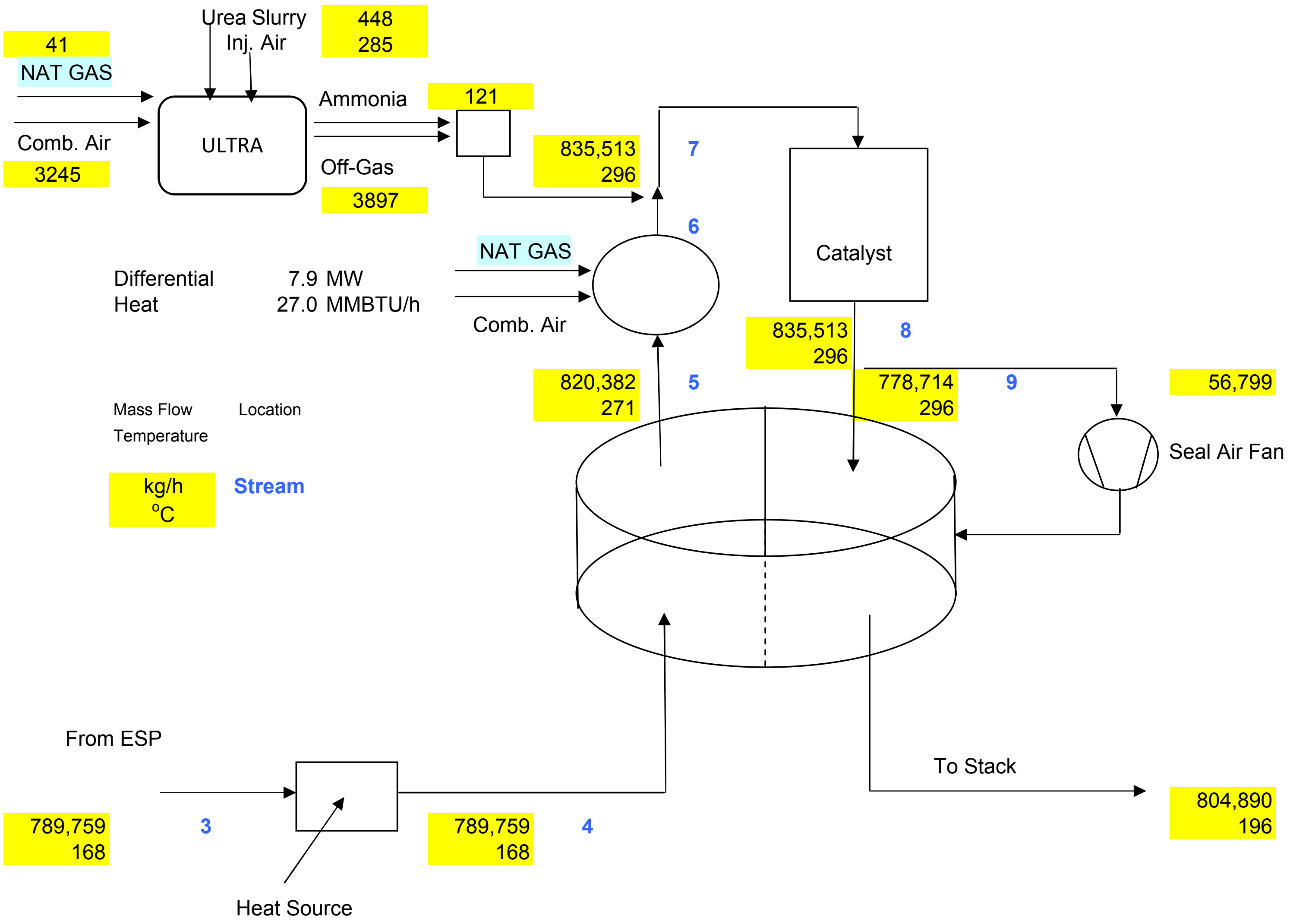
MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 1		Input Data FGD Outlet	3 FGD Outlet	4 GGH inlet	5 GGH outlet	6 Burner out	7 Reactor inlet	8 Reactor outlet	9 GGH treated inlet	10 Booster fan in	11 Booster fan out	12 Natural Gas	13 Combustion Air	14 Ammonia	15 ULTRA Off-Gas	17 Purge+Scavange	12+13 Burner Flue Gas	14 Reacted	18 ULTRA Natural Gas	19 ULTRA Combustion Air	20 ULTRA Urea Slurry	21 ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		688,272	688,272	714,960	725,054	728,310	728,392	678,935	691,763	691,763	724	9,363	158	3,097	49,517	10,087		52	2,521		221	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		433,924	433,924	450,750	457,114	459,167	459,218	428,038	436,126	436,126	456	5,903	100	1,953	31,218	6,359		33	1,589		140	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		478,587	478,587	817,138	866,311	872,297	878,746	820,075	541,960	541,960												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		850,442	850,442	883,419	895,904	899,921	899,921	838,758	866,945	866,945	564	11,921	121	3,897	61,164	12,485	121	41	3,245	448	285	kg/h	Mass Flow
Mass Flow	lb/hour		1,873,220	1,873,220	1,945,856	1,973,356	1,982,206	1,982,206	1,847,484	1,909,570	1,909,570	1,243	26,257	266	8,584	134,722	27,500	266	90	7,148	986	628	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	520	562	562	562	562	196	196												Degree F	Temperature
Temperature	Degree C		62	66	271	295	295	295	295	91	91												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6258	0.6258	0.6258	0.6278	0.6279	0.6281	0.6281	0.6260	0.6260		0.7900		0.6810		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1045	0.1045	0.1045	0.1040	0.1037	0.1037	0.1037	0.1041	0.1041				0.0458		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0493	0.0493	0.0494	0.0489	0.0493	0.0491	0.0491	0.0495	0.0495		0.2100		0.1432		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.2201	0.2201	0.2201	0.2190	0.2186	0.2189	0.2189	0.2202	0.2202				0.1220		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		430,691	430,691	447,407	455,173	457,283	457,521	426,456	433,036	433,036		7,397		2,109	30,997	7,771	39		1,991		175	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		71,902	71,902	74,681	75,390	75,532	75,532	70,403	72,044	72,044				142	5,157	709						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		33,964	33,964	35,288	35,436	35,880	35,800	33,369	34,251	34,251		1,966		444	2,452	148			529		47	Nm^3/h	Oxygen
Moisture	Nm^3/h		151,484	151,484	157,364	158,821	159,199	159,437	148,612	152,332	152,332				378	10,904	1,458	90					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		45	45	47	47	47	46	43	45	45				0	3	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		185	185	184	186	186	27	25	28	28				0	2	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	1	1	26	26	24	25	25				25	2	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	158	2	2	2	2				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		688,272	688,272	714,971	725,054	728,310	728,392	678,935	691,763	691,763		9,363		3,097	49,517	10,087	129		2,521		221	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,076,862	538,431	538,431	559,328	569,038	571,675	571,973	533,137	541,362	541,362		9,247		2,637	38,751	9,710	48		2,489		219	kg/h	Nitrogen
Carbon di oxide	kg/h	282,412	141,206	141,206	146,662	148,055	148,333	148,333	138,262	141,485	141,485				279	10,128	1,392						kg/h	Carbon di oxide
Oxygen	kg/h	96,998	48,499	48,499	50,388	50,600	51,234	51,120	47,649	48,908	48,908		2,808		633	3,501	212			756		66	kg/h	Oxygen
Moisture	kg/h	243,564	121,782	121,782	126,509	127,680	127,984	128,176	119,473	122,464	122,464				304	8,766	1,171	72			224		kg/h	Moisture
Sulfur di oxide	kg/h	258	129	129	134	134	134	133	124	128	128				0	9							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	2	2	2	2				0	0							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	758	379	379	378	382	382	56	52	57	57				0	4	4						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	2	2	47	47	44	44	44				44	3							kg/h	Argon
Ammonia	kg/h		0	0	0	0	121	1	1	1	1			121	0	0							kg/h	Ammonia
Particulate	kg/h	32	16	16	17	17	17	17	15	16	16				0	1							kg/h	Particulate
Urea	kg/h																				224		kg/h	Urea
Total	kg/h	1,700,884	850,442	850,442	883,419	895,908	899,926	899,857	838,758	854,468	854,467		12,054	121	3,897	61,164	12,489	121		3,245	448	285	kg/h	Total
Nitrogen	lb/h		1,185,971	1,185,971	1,232,000	1,253,388	1,259,196	1,259,852	1,174,310	1,192,428	1,192,428		20,367	0	5,808	85,355	21,387	106		5,483		482	lb/h	Nitrogen
Carbon di oxide	lb/h		311,026	311,026	323,044	326,111	326,725	326,725	304,541	311,640	311,640			0	614	22,308	3,067	0					lb/h	Carbon di oxide
Oxygen	lb/h		106,826	106,826	110,988	111,454	112,849	112,599	104,954	107,727	107,727		6,184	0	1,395	7,711	467	0		1,665		146	lb/h	Oxygen
Moisture	lb/h		268,242	268,242	278,655	281,234	281,903	282,325	263,156	269,745	269,745			0	669	19,309	2,579	159			493		lb/h	Moisture
Sulfur di oxide	lb/h		284	284	295	295	295	292	272	281	281			0	0	20		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	4	3	4	4				0	0							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		835	835	832	841	841	122	114	127	125			0	0	9	9	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	5	5	103	103	96	98	98				98	7							lb/h	Argon
Ammonia	lb/h		0	0	0	0	266	3	3	3	3				0	0							lb/h	Ammonia
Particulate	lb/h		35	35	37	37	37	37		35	35				0	3							lb/h	Particulate
Urea	lb/h																				493		lb/h	Urea
Total	lb/h		1,873,220	1,873,220	1,945,856	1,973,365	1,982,215	1,982,063	1,847,450	1,882,088	1,882,087		26,552	0	8,584	134,722	27,509	266		7,148	986	628	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.633	0.633	0.633	0.635	0.635	0.636	0.636	0.634	0.634		0.767		0.677	0.634	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.166	0.166	0.166	0.165	0.165	0.165	0.165	0.166	0.166		0.000		0.072	0.166	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.056	0.057	0.057	0.057	0.057	0.057		0.233		0.163	0.057	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.143	0.143	0.143	0.143	0.142	0.142	0.142	0.143	0.143		0.000		0.078	0.143	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.236	1.236	1.236	1.236	1.236	1.235	1.235	1.235	1.235													
Cp	kJ/kgK		1.125693116	1.1266306	1.1861124	1.193726213	1.19372621	1.193726213	1.193726213	1.133004044	1.133004044												kJ/kgK	Cp
Heat Content	MW		16.399	17.448	78.939	87.506	87.899	87.899	81.925	24.857	24.857	8.182							0.592				MW	Heat Content
	MMBTU/hr		55.969	59.548	269.419	298.659	299.998	299.998	279.608	84.837	84.837	27.926							2.022					
NO$_2$	lbs/hour		834.8018	834.8018	831.9646	841.1912	841.1912	122.4702	114.1547	126.5634	125.2203					9.0							lbs/hour	NO$_2$
NO$_2$	kg/h		379.0000	379.0000	377.7119	381.9008	381.9008	55.6015	51.8262	57.4598	56.8500					4.1							kg/h	NO$_2$
NO$_2$	Nm^3 / hour		184.6	184.6	184.0	186.1	186.1	27.1	25.2	28.0	27.7					2.0								
NO + NO$_2$ @ actual O$_2$	PPM		268.3	268.3	257.4	256.6	255.5	37.2	37.2	40.5	40.0					40.0								
NO + NO$_2$ @ 3 % O$_2$	PPM		300.6	300.6	288.4	286.7	286.1	41.6	41.6	45.4	44.9													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 1	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 1		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		616,442	616,442	640,345	649,337	652,592	652,674	608,347	619,933	619,933	644	8,334	158	3,097	44,359	8,979		52	2,521		221	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		388,639	388,639	403,709	409,378	411,430	411,482	383,536	390,840	390,840	406	5,254	100	1,953	27,966	5,661		33	1,589		140	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		565,259	565,259	731,859	777,489	783,269	789,069	736,373	624,992	624,992												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		789,759	789,759	820,382	831,496	835,513	835,513	778,714	804,890	804,890	502	10,611	121	3,897	56,799	11,114	121	41	3,245	448	285	kg/h	Mass Flow
Mass Flow	lb/hour		1,739,556	1,739,556	1,807,009	1,831,488	1,840,338	1,840,338	1,715,229	1,772,885	1,772,885	1,107	23,373	265	8,584	125,109	24,479	265	90	7,148	986	628	lb/hour	Mass Flow
Temperature	Degree F	335	335	335	520	564	564	564	564	384	384												Degree F	Temperature
Temperature	Degree C		168	168	271	296	296	296	296	196	196												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6881	0.6881	0.6881	0.6893	0.6890	0.6893	0.6893	0.6880	0.6880		0.7900		0.6810		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1152	0.1152	0.1152	0.1146	0.1143	0.1142	0.1142	0.1148	0.1148				0.0458		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0530	0.0530	0.0530	0.0525	0.0529	0.0528	0.0528	0.0532	0.0532		0.2100		0.1432		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.1419	0.1419	0.1419	0.1419	0.1418	0.1421	0.1421	0.1424	0.1424				0.1220		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0015	0.0015	0.0015	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		424,187	424,187	440,644	447,558	449,667	449,905	419,350	426,532	426,532		6,584		2,109	30,520	6,918	39		1,991		175	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		71,044	71,044	73,788	74,419	74,561	74,561	69,497	71,186	71,186				142	5,094	631						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		32,677	32,677	33,950	34,082	34,525	34,446	32,106	32,963	32,963		1,750		444	2,359	132			529		47	Nm^3/h	Oxygen
Moisture	Nm^3/h		87,446	87,446	90,856	92,153	92,531	92,769	86,468	88,294	88,294				378	6,318	1,298	90					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		904	904	938	938	938	929	866	895	895				0	64	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	9	9	9	9				0	1	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		185	185	184	186	186	27	25	28	28				0	2	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	1	1	26	26	24	25	25				25	2	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	158	2	2	2	2				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		616,442	616,442	640,362	649,337	652,592	652,674	608,347	619,933	619,933		8,334		3,097	44,359	8,979	129		2,521		221	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,060,600	530,300	530,300	550,874	559,517	562,154	562,452	524,253	533,231	533,231		8,231		2,637	38,155	8,643	48		2,489		219	kg/h	Nitrogen
Carbon di oxide	kg/h	279,040	139,520	139,520	144,909	146,148	146,427	146,427	136,482	139,799	139,799				279	10,003	1,239						kg/h	Carbon di oxide
Oxygen	kg/h	93,320	46,660	46,660	48,478	48,666	49,300	49,186	45,846	47,069	47,069		2,499		633	3,368	189			756		66	kg/h	Oxygen
Moisture	kg/h	140,600	70,300	70,300	73,042	74,084	74,388	74,579	69,514	70,982	70,982				304	5,079	1,042	72			224		kg/h	Moisture
Sulfur di oxide	kg/h	5,167	2,584	2,584	2,682	2,682	2,682	2,656	2,476	2,558	2,558				0	183							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	2	2	2	34	32	32	32				0	2							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	758	379	379	378	381	381	56	52	57	57				0	4	4						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	2	2	47	47	44	44	44				44	3							kg/h	Argon
Ammonia	kg/h		0	0	0	0	121	1	1	1	1			121	0	0							kg/h	Ammonia
Particulate	kg/h	32	16	16	17	17	17	17	15	16	16				0	1							kg/h	Particulate
Urea	kg/h																				224		kg/h	Urea
Total	kg/h	1,579,517	789,759	789,759	820,382	831,499	835,517	835,454	778,714	793,790	793,790		10,730	121	3,897	56,799	11,117	121		3,245	448	285	kg/h	Total
Nitrogen	lb/h		1,168,062	1,168,062	1,213,379	1,232,417	1,238,225	1,238,880	1,154,742	1,174,518	1,174,518		18,130	0	5,808	84,042	19,038	106		5,483		482	lb/h	Nitrogen
Carbon di oxide	lb/h		307,313	307,313	319,182	321,912	322,526	322,526	300,622	307,927	307,927			0	614	22,034	2,730	0					lb/h	Carbon di oxide
Oxygen	lb/h		102,775	102,775	106,779	107,195	108,590	108,340	100,982	103,677	103,677		5,505	0	1,395	7,419	415	0		1,665		146	lb/h	Oxygen
Moisture	lb/h		154,846	154,846	160,885	163,181	163,850	164,272	153,115	156,348	156,348			0	669	11,187	2,296	159			493		lb/h	Moisture
Sulfur di oxide	lb/h		5,691	5,691	5,907	5,907	5,907	5,850	5,453	5,634	5,634			0	0	403		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	4	4	4	75	70	71	71				0	5							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		835	835	832	840	840	122	114	126	125			0	0	9	8	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	5	5	103	103	96	98	98				98	7							lb/h	Argon
Ammonia	lb/h		0	0	0	0	266	3	3	3	3				0	0							lb/h	Ammonia
Particulate	lb/h		35	35	37	37	37	37		35	35				0	3							lb/h	Particulate
Urea	lb/h																				493		lb/h	Urea
Total	lb/h		1,739,556	1,739,556	1,807,009	1,831,497	1,840,346	1,840,207	1,715,195	1,748,437	1,748,436		23,635	0	8,584	125,109	24,487	265		7,148	986	628	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.671	0.671	0.671	0.673	0.673	0.673	0.673	0.672	0.672		0.767		0.677	0.672	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.177	0.177	0.177	0.176	0.175	0.175	0.175	0.176	0.176		0.000		0.072	0.176	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059		0.233		0.163	0.059	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.089		0.000		0.078	0.089	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003		0.000		0.000	0.003	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.281	1.281	1.281	1.281	1.280	1.280	1.280	1.280	1.280													
Cp	kJ/kgK		1.104654151	1.1046542	1.1349059	1.142477377	1.14247738	1.142477377	1.142477377	1.11237214	1.11237214												kJ/kgK	Cp
Heat Content	MW		40.793	40.793	70.142	78.046	78.423	78.423	73.092	48.631	48.631	7.283							0.592				MW	Heat Content
	MMBTU/hr		139.227	139.227	239.394	266.372	267.659	267.659	249.463	165.977	165.977	24.858							2.022					
NO_2	lbs/hour		834.8018	834.8018	831.9623	840.1753	840.1753	122.3223	114.0148	126.4155	125.2203					9.0							lbs/hour	NO_2
NO_2	kg/h		379.0000	379.0000	377.7109	381.4396	381.4396	55.5343	51.7627	57.3926	56.8500					4.1							kg/h	NO_2
NO_2	Nm^3 / hour		184.6	184.6	184.0	185.8	185.8	27.1	25.2	28.0	27.7					2.0								
NO + NO_2 @ actual O_2	PPM		299.5	299.5	287.4	286.2	284.8	41.5	41.5	45.1	44.7					44.7								
NO + NO_2 @ 3 % O_2	PPM		343.4	343.4	329.5	327.0	326.3	47.5	47.5	51.8	51.3													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 1	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

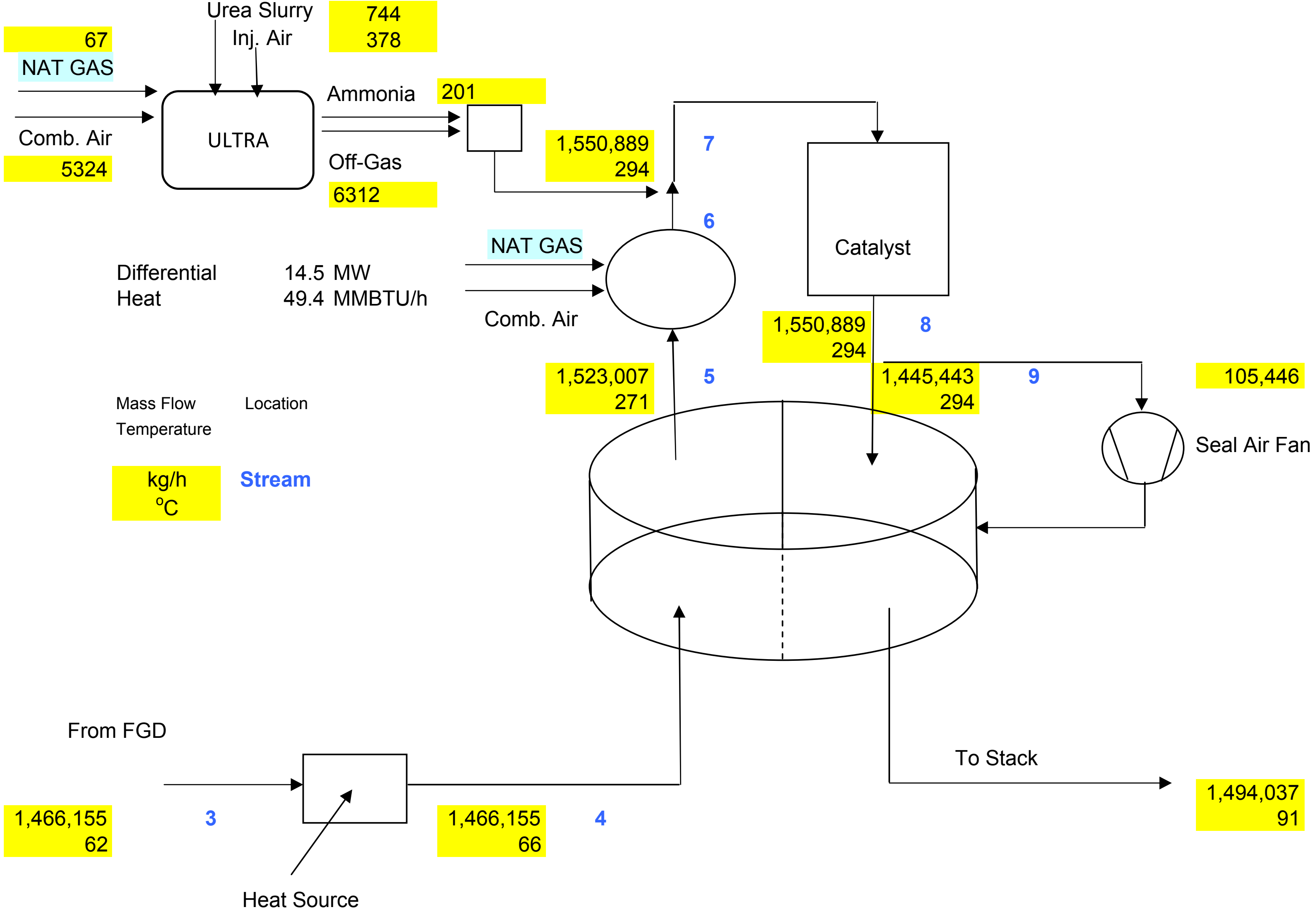
Burns & McDonnell

Client: **Confidential**

Subject: **Hypothetical SCR Reactor Arrangements**

	Unit 1	**Unit 1**	**Unit 2**	**Unit 2**
SCR	**Low Dust**	**Tail End**	**Low Dust**	**Tail End**
Flue Gas Flow (lb/hr)	1,815,800 Per reactor	1,993,400 Per reactor	3,159,000 Per reactor	3,369,300 Per reactor
Nm^3/hr	643,500	731,800	1,119,560	1,231,630
Flue Gas Temperature	630F	600F	630	600
# Reactors	2	2	2	2
Reactor				
# modules	45 (5 * 9)	45 (5 * 9)	84 (7 * 12)	77 (7 * 11)
Dimensions per reactor (approx)	10,085 mm * 9,210 mm	10,085 mm * 9,210 mm	14,025 mm * 12,200 mm	14,025 mm * 11,200 mm
	33’ * 30’	33’ * 30’	46’ * 40’	46’ * 37’
Module Layers	2 + 1	2 + 1	2 + 1	2 + 1
Initial Volume (m^3)	132	160	249	249

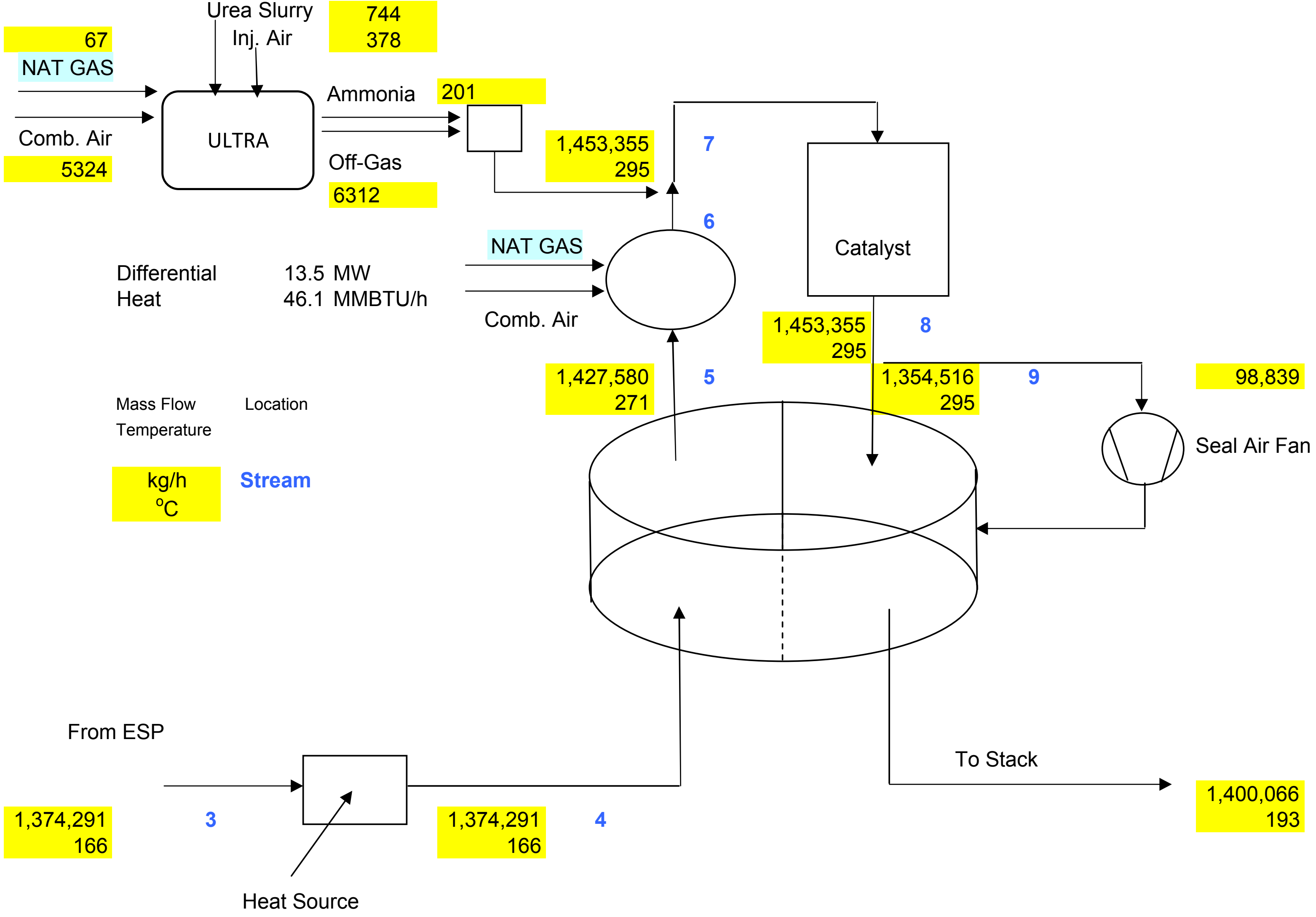
MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 2		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		1,180,582	1,180,582	1,226,360	1,243,639	1,248,920	1,249,057	1,164,213	1,186,256	1,186,256	1,239	16,026	263	5,018	84,937	17,265		86	4,135		293	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		744,304	744,304	773,165	784,058	787,388	787,474	733,984	747,881	747,881	781	10,103	166	3,164	53,549	10,885		54	2,607		185	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		820,913	820,913	1,401,624	1,485,060	1,494,958	1,506,005	1,405,413	929,368	929,368												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,466,155	1,466,155	1,523,007	1,544,376	1,550,889	1,550,889	1,445,443	1,494,037	1,494,037	966	20,404	201	6,312	105,446	21,370	201	67	5,324	744	378	kg/h	Mass Flow
Mass Flow	lb/hour		3,229,416	3,229,416	3,354,640	3,401,710	3,416,054	3,416,054	3,183,794	3,290,830	3,290,830	2,128	44,942	442	13,902	232,260	47,070	442	148	11,726	1,638	832	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	520	562	562	562	562	196	196												Degree F	Temperature
Temperature	Degree C		62	66	271	294	294	294	294	91	91												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6346	0.6346	0.6346	0.6365	0.6365	0.6368	0.6368	0.6348	0.6348		0.7900		0.6790		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1063	0.1063	0.1063	0.1058	0.1055	0.1055	0.1055	0.1060	0.1060				0.0467		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0496	0.0496	0.0496	0.0492	0.0495	0.0494	0.0494	0.0498	0.0498		0.2100		0.1422		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.2091	0.2091	0.2091	0.2082	0.2078	0.2081	0.2081	0.2093	0.2093				0.1240		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		749,220	749,220	778,295	791,589	794,996	795,393	741,365	753,019	753,019		12,660		3,407	53,917	13,302	64		3,267		232	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		125,507	125,507	130,357	131,571	131,805	131,805	122,852	125,741	125,741				234	9,003	1,214						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		58,606	58,606	60,888	61,142	61,855	61,723	57,530	59,058	59,058		3,365		714	4,229	254			868		62	Nm^3/h	Oxygen
Moisture	Nm^3/h		246,863	246,863	256,451	258,944	259,566	259,963	242,305	248,269	248,269				622	17,776	2,495	150					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		79	79	82	82	82	81	75	78	78				0	6	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	1	1	1	1				0	0	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		307	307	306	310	310	45	42	47	46				0	3	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	42	42	40	40	40				40	3	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		1,180,582	1,180,582	1,226,381	1,243,639	1,248,920	1,249,057	1,164,213	1,186,256	1,186,256		16,026		5,018	84,937	17,265	214		4,135		293	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,873,285	936,643	936,643	972,990	989,610	993,870	994,366	926,822	941,391	941,391		15,827		4,259	67,405	16,620	80		4,084		290	kg/h	Nitrogen
Carbon di oxide	kg/h	492,954	246,477	246,477	256,003	258,386	258,847	258,847	241,264	246,937	246,937				460	17,681	2,383						kg/h	Carbon di oxide
Oxygen	kg/h	167,370	83,685	83,685	86,943	87,306	88,325	88,136	82,150	84,331	84,331		4,806		1,019	6,038	363			1,240		88	kg/h	Oxygen
Moisture	kg/h	396,920	198,460	198,460	206,168	208,172	208,672	208,991	194,795	199,590	199,590				500	14,291	2,004	120			372		kg/h	Moisture
Sulfur di oxide	kg/h	450	225	225	234	234	234	231	216	223	223				0	16							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	3	3	3	3				0	0							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	1,261	631	631	628	636	636	93	86	96	95				0	7	7						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	76	76	71	72	72				72	5							kg/h	Argon
Ammonia	kg/h		0	0	0	0	201	2	2	2	2			201	0	0							kg/h	Ammonia
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35				0	3							kg/h	Particulate
Urea	kg/h																				372		kg/h	Urea
Total	kg/h	2,932,310	1,466,155	1,466,155	1,523,007	1,544,383	1,550,896	1,550,781	1,445,443	1,472,681	1,472,680		20,633	201	6,312	105,446	21,377	201		5,324	744	378	kg/h	Total
Nitrogen	lb/h		2,063,089	2,063,089	2,143,151	2,179,758	2,189,140	2,190,232	2,041,459	2,073,549	2,073,549		34,862	0	9,382	148,469	36,607	177		8,995		638	lb/h	Nitrogen
Carbon di oxide	lb/h		542,901	542,901	563,883	569,133	570,147	570,147	531,419	543,915	543,915			0	1,014	38,945	5,249	0					lb/h	Carbon di oxide
Oxygen	lb/h		184,328	184,328	191,505	192,304	194,549	194,133	180,947	185,752	185,752		10,585	0	2,245	13,300	799	0		2,731		194	lb/h	Oxygen
Moisture	lb/h		437,137	437,137	454,114	458,528	459,630	460,333	429,064	439,625	439,625			0	1,102	31,478	4,414	265			819		lb/h	Moisture
Sulfur di oxide	lb/h		496	496	514	514	514	510	475	491	491			0	0	35		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	6	6	6	6				0	0							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,400	1,400	204	190	211	208			0	0	15	16	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	8	8	167	167	156	159	159				159	11							lb/h	Argon
Ammonia	lb/h		0	0	0	0	442	5	5	5	5				0	0							lb/h	Ammonia
Particulate	lb/h		77	77	80	80	80	80		77	77				0	6							lb/h	Particulate
Urea	lb/h																				819		lb/h	Urea
Total	lb/h		3,229,416	3,229,416	3,354,640	3,401,726	3,416,070	3,415,817	3,183,720	3,243,791	3,243,788		45,446	0	13,902	232,260	47,086	442		11,726	1,638	832	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.639	0.639	0.639	0.641	0.641	0.641	0.641	0.639	0.639		0.767		0.675	0.639	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.168	0.168	0.168	0.167	0.167	0.167	0.167	0.168	0.168		0.000		0.073	0.168	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057		0.233		0.161	0.057	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.136	0.136		0.000		0.079	0.136	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.241	1.241													
Cp	kJ/kgK		1.118792829	1.1197279	1.1788636	1.186311705	1.18631171	1.186311705	1.186311705	1.126080331	1.126080331												kJ/kgK	Cp
Heat Content	MW		28.098	29.895	135.259	149.739	150.371	150.371	140.147	42.575	42.575	14.005							0.976				MW	Heat Content
	MMBTU/hr		95.899	102.032	461.638	511.060	513.215	513.215	478.321	145.309	145.309	47.799							3.331					
NO_2	lbs/hour		1388.7665	1388.7665	1384.0495	1399.8420	1399.8420	203.8050	189.9613	210.6144	208.3150					14.9							lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3585	635.5283	635.5283	92.5275	86.2425	95.6189	94.5750					6.8							kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	309.6	309.6	45.1	42.0	46.6	46.1					3.3								
NO + NO_2 @ actual O_2	PPM		260.2	260.2	249.6	249.0	247.9	36.1	36.1	39.3	38.8					38.8								
NO + NO_2 @ 3 % O_2	PPM		292.0	292.0	280.2	278.6	278.1	40.5	40.5	44.1	43.6													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 2	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.1	0															

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



Bowman, Chris

From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR
Attachments: Lignite fuel analysis (1-09).pdf; MRY - Flue Gas Conditions.pdf

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
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cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

General Information:
Unit 1, 257 MWg, cyclone-fired, subcritical, SCR COD December 2010
Unit 2, 477 MWg, cyclone-fired, subcritical, SCR COD December 2011
Fuel: Each unit burns 100% North Dakota Lignite.
Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:

- SCR system w/ gas bypass for maintenance (approx. 12.5% of total gas volume)
- Reactor housing
- Catalyst
- Associated flues and internal flow distribution devices
- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger

- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:

- Ductwork to and from SCR
- Structural support steel
- Foundations
- Electrical equipment and controls
- Air compressors
- ID Fans and/or booster fans
- Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):

- Unit 1: 2,995 / 2,744 MMBtu/hr
- Unit 2: 5,158 / 4,885 MMBtu/hr

Information required as soon as possible (estimated):

- Equipment dimensions and layout requirements
- Heat exchanger weights
- Pressure loss for each piece of equipment
- Ammonia consumption, slip rates, and natural gas consumption

We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

Thank you for your continued assistance and please call if you have any questions.

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
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Please note this effort is currently confidential and should be treated accordingly. Additionally, we do not want any technical papers written and/or published until Burns & McDonnell and Minnkota give written permission.

PROXIMATE ANALYSIS (ASTM, as rec'd)		
Moisture - Enter below in Ultimate Analysis		
Volatile Matter	wt%	**26.07**
Fixed Carbon	wt%	**27.00**
Ash - Enter below in Ultimate Analysis		
		100.00
COAL ULTIMATE ANALYSIS (ASTM, as rec'd)		
Moisture	wt%	**37.75**
Carbon	wt%	**38.56**
Hydrogen	wt%	**2.69**
Nitrogen	wt%	**0.58**
Chlorine	wt%	**0.00**
Sulfur	wt%	**1.30**
Ash	wt%	**9.18**
Oxygen	wt%	**9.94**
TOTAL	wt%	100.00
Modified Mott Spooner HHV (Btu/lb) - ***calc***	Btu/lb	6,767
	lbs SO2/mmBtu	3.847
COAL ASH ANALYSIS (ASTM, as rec'd)		
SiO2	wt%	**27.89**
Al2O3	wt%	**9.78**
TiO2	wt%	**0.40**
Fe2O3	wt%	**9.61**
CaO	wt%	**16.48**
MgO	wt%	**4.70**
Na2O	wt%	**5.50**
K2O	wt%	**0.95**
P2O5	wt%	**0.19**
SO3	wt%	**22.25**
Other Unaccounted for	wt%	**2.25**
TOTAL	wt%	100.00
Hg concentration in Coal	ppm, dry	**0.11**
	lbs Hg/TBtu	10.119

modified U1 FGD design spec

Coal 7, Lignite: 6,767 Btu, 1.3% S, 9.18% ash

Flue Gas Condition		**Low Dust SCR**		**Tail End SCR**	
		Unit 1	Unit 2	Unit 1	Unit 2
Location		ESP Outlet	ESP Outlet	FGD Outlet	FGD Outlet
Volumetric flow rate vol.	scfm	388,639	676,283	433,924	744,304
Volumetric flow rate vol.	acfm	565,259	978,672	478,587	820,913
Mass Flow	lb/h	1,739,556	3,027,072	1,873,220	3,229,416
Temperature	Degree F	335	331	143	143
Mass Flow					
Nitrogen	lb/h	1,168,062	2,031,828	1,185,971	2,063,089
Carbon dioxide	lb/h	307,313	536,419	311,026	542,901
Oxygen	lb/h	102,775	177,258	106,826	184,328
Moisture	lb/h	154,846	270,167	268,242	437,137
Sulfur dioxide	lb/h	5,691	9,934	284	496
Sulfur trioxide	lb/h	0	0	0	0
Nitrogen oxide	lb/h	0	0	0	0
Nitrogen dioxide	lb/h	835	1,389	835	1,389
Argon	lb/h	0	0	0	0
Ammonia	lb/h	0	0	0	0
Particulate	lb/h	35	77	35	77
Urea	lb/h				
Total	lb/h	1,739,556	3,027,072	1,873,220	3,229,416

Bowman, Chris

From: Bowman, Chris
Sent: Monday, March 30, 2009 3:43 PM
To: 'MGialanella@babcockpower.com'
Cc: 'bbasile@babcockpower.com'; Blackwood, Dave
Subject: RE: Low Dust/Tail End SCR

Mario,

To clarify our conversation about gas to gas heat exchangers (GGH), it is our understanding that for the tail end SCR arrangements a GGH is needed to heat the WFGD outlet air above the saturation temp to avoid acid mist condensation in the SCR GGH.

Due to SO2 emission limits required, the GGH at the WFGD cannot exceed more than a 2% leakage. If this is cannot be achieved then we would require a “no-leak” type GGH at the FGD, possibly one using a heat transfer fluid in a closed-loop or a direct-fired NG burner. Based on your experience with these projects we will default to your assumption as to which type of GGH would be most economically prudent

The use of steam as a heating source, such as a steam coil, is not an option for this site. Thanks,

Christopher Bowman
Development Engineer
Burns & McDonnell
Direct: 816-333-9400 x5693
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com
Proud to be one of FORTUNE’s 100 Best Companies To Work For

From: Bowman, Chris
Sent: Monday, March 30, 2009 9:40 AM
To: 'MGialanella@babcockpower.com'
Cc: 'bbasile@babcockpower.com'
Subject: RE: Low Dust/Tail End SCR

Mario,

As mentioned in the phone call today, if you could please provide the information in the following time frame it would be appreciated:

April 10th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

Thanks,

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Development Engineer
cbowman@burnsmcd.com
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From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

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From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

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Fuel: Each unit burns 100% North Dakota Lignite.
Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:

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- Reactor housing
- Catalyst
- Associated flues and internal flow distribution devices
- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger
- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:

  - Ductwork to and from SCR
  - Structural support steel
  - Foundations
  - Electrical equipment and controls
  - Air compressors
  - ID Fans and/or booster fans
  - Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):

  - Unit 1: 2,995 / 2,744 MMBtu/hr
  - Unit 2: 5,158 / 4,885 MMBtu/hr

Information required as soon as possible (estimated):

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We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

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From: JWaller@babcockpower.com
Sent: Wednesday, April 01, 2009 2:26 PM
To: Bowman, Chris
Cc: MGialanella@babcockpower.com; mjasinski@babcockpower.com; cerickson@babcockpower.com
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Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

Jack:

Please review the requested dates and advise if we can meet them.

Thanks,

Mario

[IMAGE]

Mario Gialanella
Business Development Manager
Babcock Power Environmental Inc.
172 Highgrove Drive
Suwanee, GA 30024

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M: 678 761 4395

mgialanella@babcockpower.com
http://www.babcockpower.com

----- Forwarded by Mario Gialanella/babcockpower on 03/30/2009 11:21 AM -----

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Ammonia Reagent: 50% Urea solution
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- Associated interconnecting piping
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Provided by others:

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- Structural support steel
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[IMAGE] Think before you print.

http://www.babcockpower.com

BabcockPower
ENVIRONMENTAL

Bowman, Chris

From: JWaller@babcockpower.com

Sent: Thursday, April 02, 2009 11:15 AM

To: Bowman, Chris

Cc: cerickson@babcockpower.com; MGialanella@babcockpower.com; mjasinski@babcockpower.com

Subject: RE: Low Dust/Tail End SCR

Attachments: MRY - Flue Gas Conditions Comparison.pdf

Chris,

I've included a summary table below that compares the flue gas conditions we get form our combustion program vs. the table in the RFQ below giving the heat input for U2 and the coal HHV. As you can see they don't match up well, so we'll need some clarification.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

"Bowman, Chris" <cbowman@burnsmcd.com>

04/01/2009 03:33 PM

To <JWaller@babcockpower.com>
cc <MGialanella@babcockpower.com>, <mjasinski@babcockpower.com>, <cerickson@babcockpower.com>
Subject RE: Low Dust/Tail End SCR

April 17th will be fine. Thank you for the update.

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[IMAGE]

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Minnkota Power MRY Station Unit 2
Flue gas provided vs calculated

Compound	Combustion	MRY	Percent
	lb/hr	lb/hr	Difference
N2	3345292.8	2031828	39.26307461
O2	126407.22	178724	41.38749807
CO2	1076954	536419	50.1910947
H2O	515478.52	270167	47.58908637
SO2	19466.024	9934	48.96749297
SO3	416.52491	0	100
TOTAL	5084015.1	3027072	-67.95157493

Bowman, Chris

From: Bowman, Chris
Sent: Tuesday, April 07, 2009 10:03 AM
To: 'JWaller@babcockpower.com'
Cc: cerickson@babcockpower.com; MGialanella@babcockpower.com; mjasinski@babcockpower.com; Blackwood, Dave
Subject: RE: Low Dust/Tail End SCR
Attachments: MRY - Flue Gas Conditions (r2).pdf

To clarify the discrepancy in the flue gas numbers, our numbers were based on the flow to each SCR reactor assuming 2 SCR reactors per unit. Therefore it showed half of the total estimated flow per unit. Attached is an updated flue gas analysis with the total numbers for each unit. Thank you for requesting clarification.

To further explain our numbers we assumed the following in calculations:

Heat Input (MMBtu/hr): Unit 1: 2,955, Unit 2: 5,158
Net Plant Heat Rate (Btu/kWhr): Unit 1: 11,498, Unit 2: 10,813
Percent Excess Air in Boiler: Unit 1: 119%, Unit 2: 128%
Air Heater Leakage: Unit 1: 16%, Unit 2: 8.5%

Please contact me with any questions.

Christopher Bowman
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[IMAGE]

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Estimated Total Gas Flow Per Unit

Flue Gas Condition		**Low Dust SCR**		**Tail End SCR**	
		Unit 1	Unit 2	Unit 1	Unit 2
Location		ESP Outlet	ESP Outlet	FGD Outlet	FGD Outlet
Volumetric flow rate vol.	scfm	777,278	1,352,566	867,848	1,488,608
Volumetric flow rate vol.	acfm	1,130,518	1,957,344	957,174	1,641,826
Mass Flow	lb/h	3,479,114	6,054,144	3,746,438	6,458,834
Temperature	Degree F	335	331	143	143
Mass Flow					
Nitrogen	lb/h	2,336,124	4,063,656	2,371,942	4,126,178
Carbon dioxide	lb/h	614,626	1,072,838	622,052	1,085,802
Oxygen	lb/h	205,550	354,516	213,652	368,656
Moisture	lb/h	309,692	540,334	536,484	874,274
Sulfur dioxide	lb/h	11,382	19,868	568	992
Sulfur trioxide	lb/h	0	0	0	0
Nitrogen oxide	lb/h	0	0	0	0
Nitrogen dioxide	lb/h	1,670	2,778	1,670	2,778
Argon	lb/h	0	0	0	0
Ammonia	lb/h	0	0	0	0
Particulate	lb/h	70	154	70	154
Urea	lb/h				
Total	lb/h	3,479,114	6,054,144	3,746,438	6,458,834

Bowman, Chris

From: JWaller@babcockpower.com
Sent: Thursday, April 09, 2009 12:23 PM
To: Bowman, Chris
Cc: cerickson@babcockpower.com; Blackwood, Dave; MGialanella@babcockpower.com; mjasinski@babcockpower.com
Subject: RE: Low Dust/Tail End SCR
Attachments: MRY - Flue Gas Conditions (r2).pdf

Chris,

RE: Tail-end SCR

How much leakage can the unit(s) accept across the FGD heat recovery GGH? This would ultimately affect the SO2 removal efficiency of the absorber(s). The leakage specification greatly affects the overall cost.

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

"Bowman, Chris" <cbowman@burnsmcd.com>

04/07/2009 11:03 AM

To <JWaller@babcockpower.com>
cc <cerickson@babcockpower.com>, <MGialanella@babcockpower.com>, <mjasinski@babcockpower.com>, "Blackwood, Dave" <dblackwood@burnsmcd.com>
Subject RE: Low Dust/Tail End SCR

To clarify the discrepancy in the flue gas numbers, our numbers were based on the flow to each SCR reactor assuming 2 SCR reactors per unit. Therefore it showed half of the total estimated flow per unit. Attached is an updated flue gas analysis with the total numbers for each unit. Thank you for requesting clarification.

To further explain our numbers we assumed the following in calculations:

Heat Input (MMBtu/hr): Unit 1: 2,955, Unit 2: 5,158
Net Plant Heat Rate (Btu/kWhr): Unit 1: 11,498, Unit 2: 10,813
Percent Excess Air in Boiler: Unit 1: 119%, Unit 2: 128%
Air Heater Leakage: Unit 1: 16%, Unit 2: 8.5%

Please contact me with any questions.

Christopher Bowman
Development Engineer

cbowman@burnsmcd.com
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From: JWaller@babcockpower.com [mailto:JWaller@babcockpower.com]
Sent: Thursday, April 02, 2009 11:15 AM
To: Bowman, Chris
Cc: cerickson@babcockpower.com; MGialanella@babcockpower.com; mjasinski@babcockpower.com
Subject: RE: Low Dust/Tail End SCR

Chris,

I've included a summary table below that compares the flue gas conditions we get form our combustion program vs. the table in the RFQ below giving the heat input for U2 and the coal HHV. As you can see they don't match up well, so we'll need some clarification.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

"Bowman, Chris" <cbowman@burnsmcd.com>

04/01/2009 03:33 PM

To <JWaller@babcockpower.com>
cc <MGialanella@babcockpower.com>, <mjasinski@babcockpower.com>, <cerickson@babcockpower.com>
Subject RE: Low Dust/Tail End SCR

April 17th will be fine. Thank you for the update.

Christopher Bowman
Development Engineer
Burns & McDonnell
Direct: 816-333-9400 x5693
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: JWaller@babcockpower.com [mailto:JWaller@babcockpower.com]
Sent: Wednesday, April 01, 2009 2:26 PM
To: Bowman, Chris
Cc: MGialanella@babcockpower.com; mjasinski@babcockpower.com; cerickson@babcockpower.com
Subject: Fw: Low Dust/Tail End SCR

Chris,

We can meet the following dates for the information you requested:

April 17th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

We will try to improve the April 17th date.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

Jack:

Please review the requested dates and advise if we can meet them.

Thanks,

Mario

[IMAGE]

Mario Gialanella
Business Development Manager
Babcock Power Environmental Inc.
172 Highgrove Drive
Suwanee, GA 30024

T: 678 965 5805 F:
M: 678 761 4395

mgialanella@babcockpower.com
http://www.babcockpower.com

----- Forwarded by Mario Gialanella/babcockpower on 03/30/2009 11:21 AM -----

"Bowman, Chris" <cbowman@burnsmcd.com>

03/30/2009 10:40 AM

To <MGialanella@babcockpower.com>
cc <bbasile@babcockpower.com>
Subject RE: Low Dust/Tail End SCR

Mario,

As mentioned in the phone call today, if you could please provide the information in the following time frame it would be appreciated:

April 10th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

Thanks,

Christopher Bowman
Development Engineer
cbowman@burnsmcd.com
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From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

General Information:
Unit 1, 257 MWg, cyclone-fired, subcritical, SCR COD December 2010
Unit 2, 477 MWg, cyclone-fired, subcritical, SCR COD December 2011
Fuel: Each unit burns 100% North Dakota Lignite.
Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:

- SCR system w/ gas bypass for maintenance (approx. 12.5% of total gas volume)
- Reactor housing
- Catalyst
- Associated flues and internal flow distribution devices
- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger
- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:

- Ductwork to and from SCR
- Structural support steel
- Foundations
- Electrical equipment and controls
- Air compressors
- ID Fans and/or booster fans
- Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):

- Unit 1: 2,995 / 2,744 MMBtu/hr
- Unit 2: 5,158 / 4,885 MMBtu/hr

<u>Information required as soon as possible (estimated):</u>

- Equipment dimensions and layout requirements
- Heat exchanger weights
- Pressure loss for each piece of equipment
- Ammonia consumption, slip rates, and natural gas consumption

We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

Thank you for your continued assistance and please call if you have any questions.

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
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Please note this effort is currently confidential and should be treated accordingly. Additionally, we do not want any technical papers written and/or published until Burns & McDonnell and Minnkota give written permission.

http://www.babcockpower.com

BabcockPower
ENVIRONMENTAL

Estimated Total Gas Flow Per Unit

Flue Gas Condition		**Low Dust SCR**		**Tail End SCR**	
		Unit 1	Unit 2	Unit 1	Unit 2
Location		ESP Outlet	ESP Outlet	FGD Outlet	FGD Outlet
Volumetric flow rate vol.	scfm	777,278	1,352,566	867,848	1,488,608
Volumetric flow rate vol.	acfm	1,130,518	1,957,344	957,174	1,641,826
Mass Flow	lb/h	3,479,114	6,054,144	3,746,438	6,458,834
Temperature	Degree F	335	331	143	143
Mass Flow					
Nitrogen	lb/h	2,336,124	4,063,656	2,371,942	4,126,178
Carbon dioxide	lb/h	614,626	1,072,838	622,052	1,085,802
Oxygen	lb/h	205,550	354,516	213,652	368,656
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Sulfur dioxide	lb/h	11,382	19,868	568	992
Sulfur trioxide	lb/h	0	0	0	0
Nitrogen oxide	lb/h	0	0	0	0
Nitrogen dioxide	lb/h	1,670	2,778	1,670	2,778
Argon	lb/h	0	0	0	0
Ammonia	lb/h	0	0	0	0
Particulate	lb/h	70	154	70	154
Urea	lb/h				
Total	lb/h	3,479,114	6,054,144	3,746,438	6,458,834

Bowman, Chris

From: Bowman, Chris
Sent: Thursday, April 09, 2009 1:15 PM
To: 'JWaller@babcockpower.com'; cerickson@babcockpower.com; MGialanella@babcockpower.com; mjasinski@babcockpower.com
Cc: Blackwood, Dave
Subject: FW: Low Dust/Tail End SCR

In regards to FGD GGH leakage, see below:

From: Bowman, Chris
Sent: Monday, March 30, 2009 3:43 PM
To: 'MGialanella@babcockpower.com'
Cc: 'bbasile@babcockpower.com'; Blackwood, Dave
Subject: RE: Low Dust/Tail End SCR

Mario,

To clarify our conversation about gas to gas heat exchangers (GGH), it is our understanding that for the tail end SCR arrangements a GGH is needed to heat the WFGD outlet air above the saturation temp to avoid acid mist condensation in the SCR GGH.

Due to SO2 emission limits required, the GGH at the WFGD cannot exceed more than a 2% leakage. If this is cannot be achieved then we would require a “no-leak” type GGH at the FGD, possibly one using a heat transfer fluid in a closed-loop or a direct-fired NG burner. Based on your experience with these projects we will default to your assumption as to which type of GGH would be most economically prudent

The use of steam as a heating source, such as a steam coil, is not an option for this site. Thanks,

Christopher Bowman
Development Engineer
Burns & McDonnell
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Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com
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From: Bowman, Chris
Sent: Monday, March 30, 2009 9:40 AM
To: 'MGialanella@babcockpower.com'
Cc: 'bbasile@babcockpower.com'
Subject: RE: Low Dust/Tail End SCR

Mario,

As mentioned in the phone call today, if you could please provide the information in the following time frame it would be appreciated:

April 10th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

Thanks,

Christopher Bowman
Development Engineer
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

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Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:
- ○ SCR system w/ gas bypass for maintenance (approx. 12.5% of total gas volume)
- ○ Reactor housing
- ○ Catalyst
- ○ Associated flues and internal flow distribution devices

- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger
- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:

- Ductwork to and from SCR
- Structural support steel
- Foundations
- Electrical equipment and controls
- Air compressors
- ID Fans and/or booster fans
- Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):

- Unit 1: 2,995 / 2,744 MMBtu/hr
- Unit 2: 5,158 / 4,885 MMBtu/hr

Information required as soon as possible (estimated):

- Equipment dimensions and layout requirements
- Heat exchanger weights
- Pressure loss for each piece of equipment
- Ammonia consumption, slip rates, and natural gas consumption

We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

Thank you for your continued assistance and please call if you have any questions.

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

Please note this effort is currently confidential and should be treated accordingly. Additionally, we do not want any technical papers written and/or published until Burns & McDonnell and Minnkota give written permission.

Bowman, Chris

From: JWaller@babcockpower.com
Sent: Tuesday, April 28, 2009 3:36 PM
To: Bowman, Chris
Cc: Blackwood, Dave; MGialanella@babcockpower.com; mjasinski@babcockpower.com
Subject: RE: Low Dust/Tail End SCR
Attachments: Design Info 4-28-09.xls

Chris,

Attached is the additional information you requested.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

RILEYPower
A Babcock Power Inc. Company

Minnkota Power - Milton R. Young Power Station

	Differential Pressure (iwc)	Ammonia (lbs/hr)	Slip (ppm)	Natural Gas (lbs/hr)
Unit 1 Low Dust				
SCR	2.0	500	2.0	1050
GGH (Untreated Gas)	2.3			
GGH (Treated Gas)	2.3			
Unit 2 Low Dust				
SCR	2.0	860	2.0	1780
GGH (Untreated Gas)	1.74			
GGH (Treated Gas)	1.74			
Unit 1 Tail End				
FGD - GGH (Untreated Gas)	2.7			
FGD - GGH (Treated Gas)	2.7			
SCR	2.0	500	2.0	1150
SCR - GGH (Untreated Gas)	2.67			
SCR - GGH (Treated Gas)	2.67			
Unit 2 Tail End				
FGD - GGH (Untreated Gas)	1.87			
FGD - GGH (Treated Gas)	1.87			
SCR	2.0	860	2.0	2120
SCR - GGH (Untreated Gas)	1.98			
SCR - GGH (Treated Gas)	1.98			

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Monday, August 03, 2009 8:24 AM
To: Blakley, Robert
Cc: TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

It was nice talking with you this morning. We will plan on meeting with you and the folks from Minnkota and the University of North Dakota on Monday afternoon August 10th in our office's in Houston, Texas. Our address is: 17629 El Camino Real, Houston, TX 77058, Suite 300. Please let me know what time we should expect you as you are able to firm thing up.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

From: Blakley, Robert
Sent: Monday, August 03, 2009 5:18 PM
To: Wayne Jones
Cc: TNW@topsoe.com; Bryant, Ronald; 51684
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Wayne -

Thank you for your willingness to meet with Minnkota, Burns & McDonnell, and University of North Dakota on Monday afternoon, August 10th.

The purpose of this visit is to introduce the members of the project team, and to discuss Haldor Topsoe's experience with SCR catalyst and how it may relate to this application. One of our objectives for this project is to establish expected catalyst volumes and deactivation rates for exposure to flue gases produced by cyclone boilers firing North Dakota lignite at Milton R. Young Station as part of a cost study for low dust and tail end SCR technologies.

The current plans for the trip and visit are as follows:

We will fly on Minnkota's turboprop aircraft departing from near Kansas City, Missouri in the morning, arriving around noon at the Hobby airport (alternate: Ellington field, which is closer to HT's office).

We expect to arrive at Haldor Topsoe's office shortly after 1 pm, allowing for travel from the airport and a quick lunch on the way. We will confirm the estimated arrival time prior to departure.

The meeting is anticipated to take approximately 2 hours, so we expect to depart between 3:00 and 3:30 pm to return to the airport. We will fly back to Kansas City late Monday afternoon.

We currently expect 7 people to visit and participate in this discussion:
> Ron Bryant, Burns & McDonnell project manager for Minnkota air pollution control projects
> Carl Weilert, Burns & McDonnell principal engineer for powerplant air pollution control projects
> Robert Blakley, Burns & McDonnell project engineer for Minnkota's NOx reduction program
> Luther Kvernen, Minnkota Vice President of Generation, Grand Forks, North Dakota headquarters
> John Graves, Minnkota Environmental Manager, Grand Forks, North Dakota headquarters
> Andy Freidt, Minnkota Permit and Compliance Engineer, Milton R. Young Station, Center, North Dakota
> Steven Benson, PhD, Professor, Department of Chemical Engineering at University of North Dakota, Grand Forks, ND, and President, Microbeam Technologies, Inc.

You advised this morning (Monday, 8/3) that you will be out of the office until mid-day Thursday, 8/6. We will confirm any updates in schedules and arrangements Thursday afternoon or Friday morning.

If you have any questions, please advise.

Thanks,

Bob Blakley

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Monday, August 03, 2009 8:24 AM
To: Blakley, Robert
Cc: TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

It was nice talking with you this morning. We will plan on meeting with you and the folks from Minnkota and the University of North Dakota on Monday afternoon August 10th in our office's in Houston, Texas. Our address is: 17629 El Camino Real, Houston, TX 77058, Suite 300. Please let me know what time we should expect you as you are able to firm thing up.

Regards,
Wayne

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Sales Manager, Power Generation
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281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

From: Bryant, Ronald
Sent: Wednesday, August 05, 2009 1:11 PM
To: 'Wayne Jones'
Cc: 51684; 'TNW@topsoe.com'; Blakley, Robert
Subject: Agenda

Wayne

Attached is a draft agenda from Minnkota Power for our meeting next Monday. Let us know if you have any comments.

Thanks
Ron Bryant

From: Blakley, Robert
Sent: Wednesday, August 05, 2009 1:05 PM
To: Wayne Jones
Cc: 51684; Bryant, Ronald; TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Wayne -

Does Haldor Topsoe have a digital projector that Minnkota can hook up to a laptop PC to use during the discussion?

If not, we can bring one.

Bob Blakley

From: Blakley, Robert
Sent: Wednesday, August 05, 2009 6:53 AM
To: 'Wayne Jones'
Cc: 51684; Bryant, Ronald; TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Thanks, Wayne. We'll check on the rental car availability. Minnkota's pilot is pretty good at finding out those details.

Bob Blakley

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Tuesday, August 04, 2009 6:18 PM
To: Blakley, Robert
Cc: 51684; Bryant, Ronald; TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

Sounds good. Please confirm that rental cars are easily available at Ellington (Southwest Svs.). I will let you know in a day or two on a restaurant where we can meet. Several good locations are within 10 minutes of Ellington Field.

Thanks,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
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wsj@topsoe.com
www.HaldorTopsoe.com

"Blakley, Robert" <rblakley@burnsmcd.com>

08/04/2009 04:40 PM

To "Wayne Jones" <WSJ@topsoe.com>

cc <TNW@topsoe.com>, "51684" <51684@burnsmcd.com>, "Bryant, Ronald" <rbryant@burnsmcd.com>

Subject RE: FW: Comments to SCR Technology at MRYS Units 1&2

Wayne -

Minnkota, BMcD, and UND accept your lunch invitation and suggestion for the local airport.

Minnkota's pilot will plan on flying and landing at Ellington field, Southwest Airport Services. Minnkota will arrange for local transportation at Ellington field.

Just let me know where you'll be meeting us for lunch, and we will plan on arriving there shortly after noon on Monday, August 10th.

We will advise on the agenda in the next day or two.

Bob Blakley

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Monday, August 03, 2009 10:12 PM
To: Blakley, Robert
Cc: TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

Ellington Field is closer, about 10-15 minutes away. Since you are flying a private plane you can probably use Southwest

Services who is the main flying service at Ellington.

Also Nate and I would like to take y'all to lunch if possible. We can talk later in the week and work out the details.

Thanks,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
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281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
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"Blakley, Robert" <rblakley@burnsmcd.com>

08/03/2009 05:18 PM

To "Wayne Jones" <WSJ@topsoe.com>
cc <TNW@topsoe.com>, "Bryant, Ronald" <rbryant@burnsmcd.com>, "51684" <51684@burnsmcd.com>

Subject RE: FW: Comments to SCR Technology at MRYS Units 1&2

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From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Monday, August 03, 2009 8:24 AM
To: Blakley, Robert
Cc: TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

It was nice talking with you this morning. We will plan on meeting with you and the folks from Minnkota and the University of North Dakota on Monday afternoon August 10th in our office's in Houston, Texas. Our address is: 17629 El Camino Real, Houston, TX 77058, Suite 300. Please let me know what time we should expect you as you are able to firm thing up.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
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281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

DRAFT #2 – HALDOR TOPSOE

MINNKOTA – MRY STATION SCR COST STUDY MEETING

Monday, August 10, 2009
1:00 PM
Meeting Location: Haldor Topsoe, Inc., Houston, Texas

Meeting Participants:

Haldor Topsoe, Inc.

- Wayne Jones, Sales Manager, Power Generation (Houston)
- Nathan White, Senior Account Executive (Houston)
-

Minnkota Power Cooperative, Inc.

- Luther Kvernen, Vice President - Generation (Grand Forks Headquarters)
- John Graves, Environmental Manager (Grand Forks Headquarters)
- Andy Freidt, Permit and Compliance Engineer (MRY Station)

University of North Dakota and Microbeam Technologies

- Steven Benson, PhD, Professor, Department of Chemical Engineering at University of North Dakota and President, Microbeam Technologies, Inc

Burns & McDonnell

- Ron Bryant, Burns & McDonnell project manager for Minnkota air pollution control projects
- Carl Weilert, Burns & McDonnell principal engineer for powerplant air pollution control projects
- Robert Blakley, Burns & McDonnell project engineer for Minnkota's NOx reduction program

Meeting Purpose:

1. To develop a common understanding of the purpose, unique challenges and status of Minnkota's cost study for low dust and tail end SCR technologies.
2. Discuss Haldor Topsoe's experience with SCR catalyst and how it may relate to the application of high sodium and potassium aerosols associated with the combustion of ND lignite in cyclone fired boilers.

AGENDA

1. Introductions

2. Review Meeting Purpose and Agenda

3. Minnkota/MRY Station Background – Luther Kvernen (10 minutes)

- Organization
- SCR cost study

4. ND Lignite (Center Mine) Characteristics – Steve Benson (10 minutes)

5. SCR cost study – Burns & McDonnell (designate) (10 minutes)

- Impact of catalyst volumes and deactivation rates
    - ➢ Input requirements to provide reasonable cost estimates

6. Haldor Topsoe Background – ___________ (10 minutes)

- Organization
- Experience with SCR catalyst for this type of application

7. Identify specific questions/concerns -- All

8. Exploration of opportunities – All

9. Action items

10. Other

From: Nate White [mailto:TNW@topsoe.com]
Sent: Wednesday, August 05, 2009 8:38 PM
To: Bryant, Ronald
Cc: 51684; Blakley, Robert; Wayne Jones
Subject: Re: Agenda

Hello Ron,

One change to your agenda. I am no longer a Senior Account Executive. I am Director, Business Development. We re-organized the SCR/DeNOx Catalyst & Technology side of HTI back in February, 2009. We will explain our new organization and responsibilities to you when we see you Monday.

Best regards,
Nathan White
Director, Business Development
SCR/DeNOx Catalyst & Technology
Fort Mill, SC Office - (803) 835-0571
Houston, TX Office - (281) 228-5127
Cell - (281) 684-8809
tnw@topsoe.com

"Bryant, Ronald"
<rbryant@burnsmcd.com>

08/05/2009 01:11 PM

To "Wayne Jones" <WSJ@topsoe.com>
cc "51684" <51684@burnsmcd.com>, <TNW@topsoe.com>, "Blakley, Robert" <rblakley@burnsmcd.com>
Subject Agenda

Wayne

Attached is a draft agenda from Minnkota Power for our meeting next Monday. Let us know if you have any comments.

Thanks
Ron Bryant

DRAFT #2 – HALDOR TOPSOE

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- Impact of catalyst volumes and deactivation rates
    - Input requirements to provide reasonable cost estimates

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- Organization
- Experience with SCR catalyst for this type of application

7. Identify specific questions/concerns -- All

8. Exploration of opportunities – All

9. Action items

10. Other

Bryant, Ronald

From: Bryant, Ronald

Sent: Friday, August 07, 2009 2:56 PM

To: 'Noel Rosha'

Cc: 'James Ferrigan'; Blakley, Robert; 'Greg Holscher'; 51684

Subject: Minnkota PFDs and Mass Balances

Attachments: 10Mar09_MRY2LowDust_PFD_Rev0_natgas.pdf; 9Mar09_MRY2TailEnd_Mass Balance_Rev0_natgas.pdf; 9Mar09_MRY2TailEnd_PFD_Rev0_natgas.pdf; 10Mar09_Hypothetical SCR_Reactor Arrangement_Summary.pdf; 10Mar09_MRY1LowDust_MassBalance_Rev0_natgas.pdf; 10Mar09_MRY1LowDust_PFD_Rev0_natgas.pdf; 10Mar09_MRY1TailEnd_MassBalance_Rev0_natgas.pdf; 10Mar09_MRY1TailEnd_PFD_Rev0_natgas.pdf; 10Mar09_MRY2LowDust_Mass BalanceRev0_natgas.pdf

Attachments this time.

From: Bryant, Ronald
Sent: Friday, August 07, 2009 2:55 PM
To: Noel Rosha
Cc: James Ferrigan; Blakley, Robert; Greg Holscher; 51684
Subject:

Noel

Attached are preliminary PFDs and mass balances requested for the low dust and tail end SCRs at the Milton R Young Station.

Ron

Burns & McDonnell

Client: **Confidential**

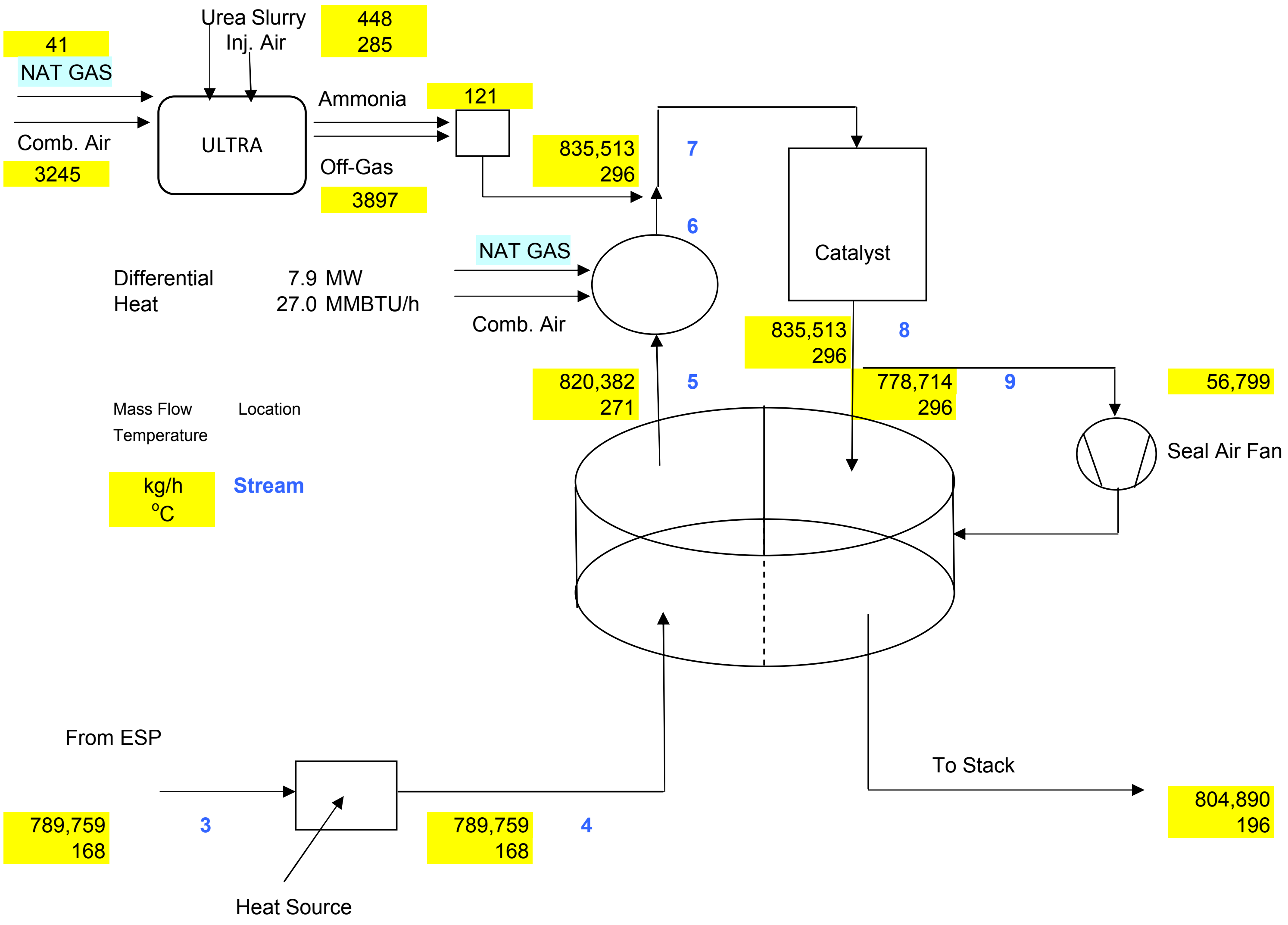
Subject: **Hypothetical SCR Reactor Arrangements**

	Unit 1	**Unit 1**	**Unit 2**	**Unit 2**
SCR	**Low Dust**	**Tail End**	**Low Dust**	**Tail End**
Flue Gas Flow (lb/hr)	1,815,800 Per reactor	1,993,400 Per reactor	3,159,000 Per reactor	3,369,300 Per reactor
Nm^3/hr	643,500	731,800	1,119,560	1,231,630
Flue Gas Temperature	630F	600F	630	600
# Reactors	2	2	2	2
Reactor				
# modules	45 (5 * 9)	45 (5 * 9)	84 (7 * 12)	77 (7 * 11)
Dimensions per reactor (approx)	10,085 mm * 9,210 mm	10,085 mm * 9,210 mm	14,025 mm * 12,200 mm	14,025 mm * 11,200 mm
	33' * 30'	33' * 30'	46' * 40'	46' * 37'
Module Layers	2 + 1	2 + 1	2 + 1	2 + 1
Initial Volume (m^3)	132	160	249	249

MRY 1		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		616,442	616,442	640,345	649,337	652,592	652,674	608,347	619,933	619,933	644	8,334	158	3,097	44,359	8,979		52	2,521		221	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		388,639	388,639	403,709	409,378	411,430	411,482	383,536	390,840	390,840	406	5,254	100	1,953	27,966	5,661		33	1,589		140	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		565,259	565,259	731,859	777,489	783,269	789,069	736,373	624,992	624,992												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		789,759	789,759	820,382	831,496	835,513	835,513	778,714	804,890	804,890	502	10,611	121	3,897	56,799	11,114	121	41	3,245	448	285	kg/h	Mass Flow
Mass Flow	lb/hour		1,739,556	1,739,556	1,807,009	1,831,488	1,840,338	1,840,338	1,715,229	1,772,885	1,772,885	1,107	23,373	265	8,584	125,109	24,479	265	90	7,148	986	628	lb/hour	Mass Flow
Temperature	Degree F	335	335	335	520	564	564	564	564	384	384												Degree F	Temperature
Temperature	Degree C		168	168	271	296	296	296	296	196	196												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6881	0.6881	0.6881	0.6893	0.6890	0.6893	0.6893	0.6880	0.6880		0.7900		0.6810		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1152	0.1152	0.1152	0.1146	0.1143	0.1142	0.1142	0.1148	0.1148				0.0458		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0530	0.0530	0.0530	0.0525	0.0529	0.0528	0.0528	0.0532	0.0532		0.2100		0.1432		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.1419	0.1419	0.1419	0.1419	0.1418	0.1421	0.1421	0.1424	0.1424				0.1220		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0015	0.0015	0.0015	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		424,187	424,187	440,644	447,558	449,667	449,905	419,350	426,532	426,532		6,584		2,109	30,520	6,918	39		1,991		175	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		71,044	71,044	73,788	74,419	74,561	74,561	69,497	71,186	71,186				142	5,094	631						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		32,677	32,677	33,950	34,082	34,525	34,446	32,106	32,963	32,963		1,750		444	2,359	132			529		47	Nm^3/h	Oxygen
Moisture	Nm^3/h		87,446	87,446	90,856	92,153	92,531	92,769	86,468	88,294	88,294				378	6,318	1,298	90					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		904	904	938	938	938	929	866	895	895				0	64	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	9	9	9	9				0	1	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		185	185	184	186	186	27	25	28	28				0	2	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	1	1	26	26	24	25	25				25	2	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	158	2	2	2	2				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		616,442	616,442	640,362	649,337	652,592	652,674	608,347	619,933	619,933		8,334		3,097	44,359	8,979	129		2,521		221	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,060,600	530,300	530,300	550,874	559,517	562,154	562,452	524,253	533,231	533,231		8,231		2,637	38,155	8,643	48		2,489		219	kg/h	Nitrogen
Carbon di oxide	kg/h	279,040	139,520	139,520	144,909	146,148	146,427	146,427	136,482	139,799	139,799				279	10,003	1,239						kg/h	Carbon di oxide
Oxygen	kg/h	93,320	46,660	46,660	48,478	48,666	49,300	49,186	45,846	47,069	47,069		2,499		633	3,368	189			756		66	kg/h	Oxygen
Moisture	kg/h	140,600	70,300	70,300	73,042	74,084	74,388	74,579	69,514	70,982	70,982				304	5,079	1,042	72			224		kg/h	Moisture
Sulfur di oxide	kg/h	5,167	2,584	2,584	2,682	2,682	2,682	2,656	2,476	2,558	2,558				0	183							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	2	2	2	34	32	32	32				0	2							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	758	379	379	378	381	381	56	52	57	57				0	4	4						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	2	2	47	47	44	44	44				44	3							kg/h	Argon
Ammonia	kg/h		0	0	0	0	121	1	1	1	1			121	0	0							kg/h	Ammonia
Particulate	kg/h	32	16	16	17	17	17	17	15	16	16				0	1							kg/h	Particulate
Urea	kg/h																				224		kg/h	Urea
Total	kg/h	1,579,517	789,759	789,759	820,382	831,499	835,517	835,454	778,714	793,790	793,790		10,730	121	3,897	56,799	11,117	121		3,245	448	285	kg/h	Total
Nitrogen	lb/h		1,168,062	1,168,062	1,213,379	1,232,417	1,238,225	1,238,880	1,154,742	1,174,518	1,174,518		18,130	0	5,808	84,042	19,038	106		5,483		482	lb/h	Nitrogen
Carbon di oxide	lb/h		307,313	307,313	319,182	321,912	322,526	322,526	300,622	307,927	307,927			0	614	22,034	2,730	0					lb/h	Carbon di oxide
Oxygen	lb/h		102,775	102,775	106,779	107,195	108,590	108,340	100,982	103,677	103,677		5,505	0	1,395	7,419	415	0		1,665		146	lb/h	Oxygen
Moisture	lb/h		154,846	154,846	160,885	163,181	163,850	164,272	153,115	156,348	156,348			0	669	11,187	2,296	159			493		lb/h	Moisture
Sulfur di oxide	lb/h		5,691	5,691	5,907	5,907	5,907	5,850	5,453	5,634	5,634			0	0	403		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	4	4	4	75	70	71	71				0	5							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		835	835	832	840	840	122	114	126	125			0	0	9	8	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	5	5	103	103	96	98	98				98	7							lb/h	Argon
Ammonia	lb/h		0	0	0	0	266	3	3	3	3				0	0							lb/h	Ammonia
Particulate	lb/h		35	35	37	37	37	37		35	35				0	3							lb/h	Particulate
Urea	lb/h																				493		lb/h	Urea
Total	lb/h		1,739,556	1,739,556	1,807,009	1,831,497	1,840,346	1,840,207	1,715,195	1,748,437	1,748,436		23,635	0	8,584	125,109	24,487	265		7,148	986	628	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.671	0.671	0.671	0.673	0.673	0.673	0.673	0.672	0.672		0.767		0.677	0.672	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.177	0.177	0.177	0.176	0.175	0.175	0.175	0.176	0.176		0.000		0.072	0.176	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059		0.233		0.163	0.059	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.089		0.000		0.078	0.089	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003		0.000		0.000	0.003	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.281	1.281	1.281	1.281	1.280	1.280	1.280	1.280	1.280													
Cp	kJ/kgK		1.104654151	1.1046542	1.1349059	1.142477377	1.14247738	1.142477377	1.142477377	1.11237214	1.11237214												kJ/kgK	Cp
Heat Content	MW		40.793	40.793	70.142	78.046	78.423	78.423	73.092	48.631	48.631	7.283							0.592				MW	Heat Content
	MMBTU/hr		139.227	139.227	239.394	266.372	267.659	267.659	249.463	165.977	165.977	24.858							2.022					
NO$_2$	lbs/hour		834.8018	834.8018	831.9623	840.1753	840.1753	122.3223	114.0148	126.4155	125.2203					9.0							lbs/hour	NO$_2$
NO$_2$	kg/h		379.0000	379.0000	377.7109	381.4396	381.4396	55.5343	51.7627	57.3926	56.8500					4.1							kg/h	NO$_2$
NO$_2$	Nm^3 / hour		184.6	184.6	184.0	185.8	185.8	27.1	25.2	28.0	27.7					2.0								
NO + NO$_2$ @ actual O$_2$	PPM		299.5	299.5	287.4	286.2	284.8	41.5	41.5	45.1	44.7					44.7								
NO + NO$_2$ @ 3 % O$_2$	PPM		343.4	343.4	329.5	327.0	326.3	47.5	47.5	51.8	51.3													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 1	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

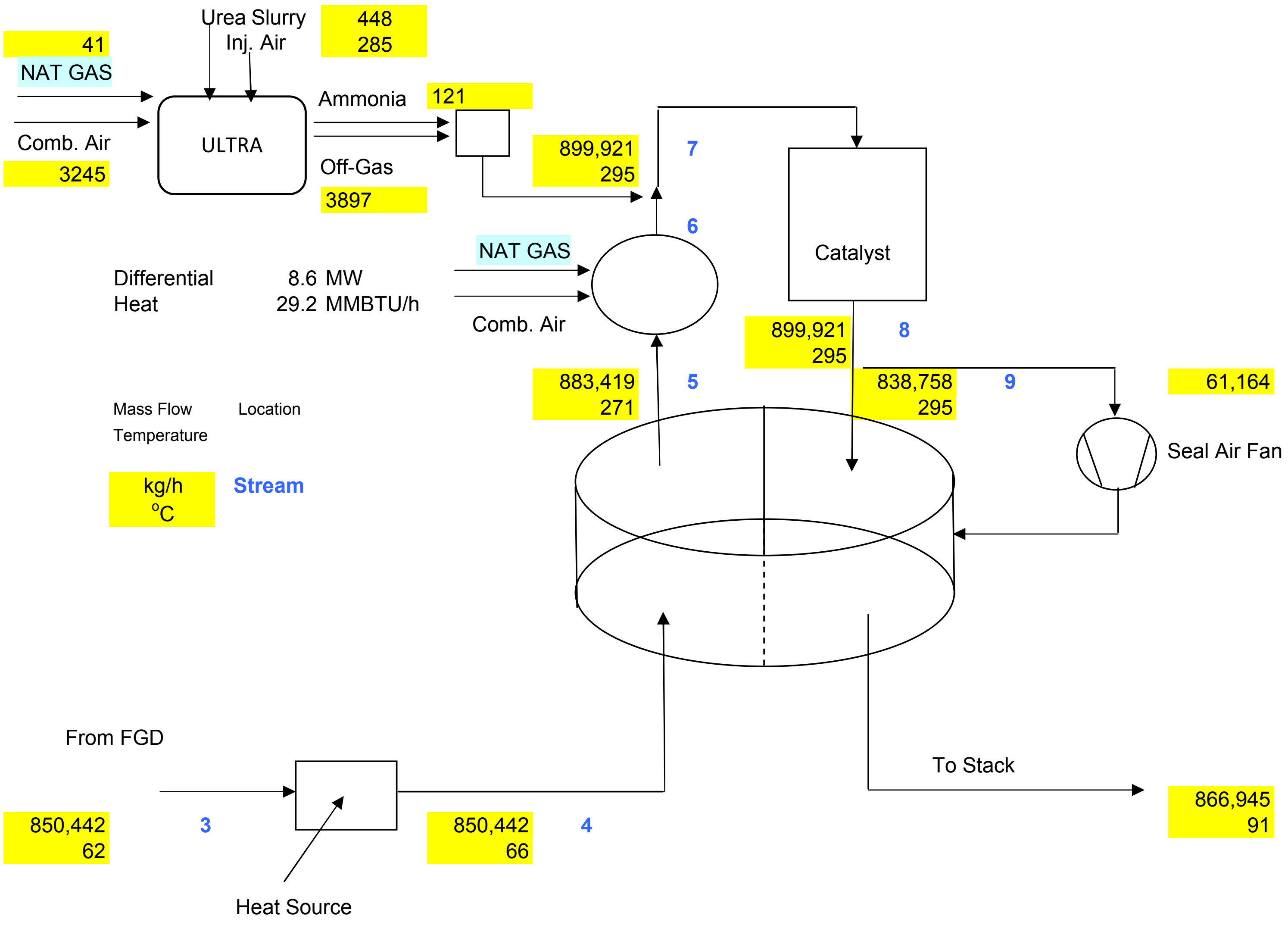
MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 1		Input Data FGD Outlet	3 FGD Outlet	4 GGH inlet	5 GGH outlet	6 Burner out	7 Reactor inlet	8 Reactor outlet	9 GGH treated inlet	10 Booster fan in	11 Booster fan out	12 Natural Gas	13 Combustion Air	14 Ammonia	15 ULTRA Off-Gas	17 Purge+Scavange	12+13 Burner Flue Gas	14 Reacted	18 ULTRA Natural Gas	19 ULTRA Combustion Air	20 ULTRA Urea Slurry	21 ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		688,272	688,272	714,960	725,054	728,310	728,392	678,935	691,763	691,763	724	9,363	158	3,097	49,517	10,087		52	2,521		221	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		433,924	433,924	450,750	457,114	459,167	459,218	428,038	436,126	436,126	456	5,903	100	1,953	31,218	6,359		33	1,589		140	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		478,587	478,587	817,138	866,311	872,297	878,746	820,075	541,960	541,960												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		850,442	850,442	883,419	895,904	899,921	899,921	838,758	866,945	866,945	564	11,921	121	3,897	61,164	12,485	121	41	3,245	448	285	kg/h	Mass Flow
Mass Flow	lb/hour		1,873,220	1,873,220	1,945,856	1,973,356	1,982,206	1,982,206	1,847,484	1,909,570	1,909,570	1,243	26,257	266	8,584	134,722	27,500	266	90	7,148	986	628	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	520	562	562	562	562	196	196												Degree F	Temperature
Temperature	Degree C		62	66	271	295	295	295	295	91	91												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6258	0.6258	0.6258	0.6278	0.6279	0.6281	0.6281	0.6260	0.6260		0.7900		0.6810		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1045	0.1045	0.1045	0.1040	0.1037	0.1037	0.1037	0.1041	0.1041				0.0458		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0493	0.0493	0.0494	0.0489	0.0493	0.0491	0.0491	0.0495	0.0495		0.2100		0.1432		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.2201	0.2201	0.2201	0.2190	0.2186	0.2189	0.2189	0.2202	0.2202				0.1220		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		430,691	430,691	447,407	455,173	457,283	457,521	426,456	433,036	433,036		7,397		2,109	30,997	7,771	39		1,991		175	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		71,902	71,902	74,681	75,390	75,532	75,532	70,403	72,044	72,044				142	5,157	709						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		33,964	33,964	35,288	35,436	35,880	35,800	33,369	34,251	34,251		1,966		444	2,452	148			529		47	Nm^3/h	Oxygen
Moisture	Nm^3/h		151,484	151,484	157,364	158,821	159,199	159,437	148,612	152,332	152,332				378	10,904	1,458	90					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		45	45	47	47	47	46	43	45	45				0	3	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		185	185	184	186	186	27	25	28	28				0	2	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	1	1	26	26	24	25	25				25	2	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	158	2	2	2	2				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		688,272	688,272	714,971	725,054	728,310	728,392	678,935	691,763	691,763		9,363		3,097	49,517	10,087	129		2,521		221	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,076,862	538,431	538,431	559,328	569,038	571,675	571,973	533,137	541,362	541,362		9,247		2,637	38,751	9,710	48		2,489		219	kg/h	Nitrogen
Carbon di oxide	kg/h	282,412	141,206	141,206	146,662	148,055	148,333	148,333	138,262	141,485	141,485				279	10,128	1,392						kg/h	Carbon di oxide
Oxygen	kg/h	96,998	48,499	48,499	50,388	50,600	51,234	51,120	47,649	48,908	48,908		2,808		633	3,501	212			756		66	kg/h	Oxygen
Moisture	kg/h	243,564	121,782	121,782	126,509	127,680	127,984	128,176	119,473	122,464	122,464				304	8,766	1,171	72			224		kg/h	Moisture
Sulfur di oxide	kg/h	258	129	129	134	134	134	133	124	128	128				0	9							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	2	2	2	2				0	0							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	758	379	379	378	382	382	56	52	57	57				0	4	4						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	2	2	47	47	44	44	44				44	3							kg/h	Argon
Ammonia	kg/h		0	0	0	0	121	1	1	1	1			121	0	0							kg/h	Ammonia
Particulate	kg/h	32	16	16	17	17	17	17	15	16	16				0	1							kg/h	Particulate
Urea	kg/h																				224		kg/h	Urea
Total	kg/h	1,700,884	850,442	850,442	883,419	895,908	899,926	899,857	838,758	854,468	854,467		12,054	121	3,897	61,164	12,489	121		3,245	448	285	kg/h	Total
Nitrogen	lb/h		1,185,971	1,185,971	1,232,000	1,253,388	1,259,196	1,259,852	1,174,310	1,192,428	1,192,428		20,367	0	5,808	85,355	21,387	106		5,483		482	lb/h	Nitrogen
Carbon di oxide	lb/h		311,026	311,026	323,044	326,111	326,725	326,725	304,541	311,640	311,640			0	614	22,308	3,067	0					lb/h	Carbon di oxide
Oxygen	lb/h		106,826	106,826	110,988	111,454	112,849	112,599	104,954	107,727	107,727		6,184	0	1,395	7,711	467	0		1,665		146	lb/h	Oxygen
Moisture	lb/h		268,242	268,242	278,655	281,234	281,903	282,325	263,156	269,745	269,745			0	669	19,309	2,579	159			493		lb/h	Moisture
Sulfur di oxide	lb/h		284	284	295	295	295	292	272	281	281			0	0	20		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	4	3	4	4				0	0							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		835	835	832	841	841	122	114	127	125			0	0	9	9	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	5	5	103	103	96	98	98				98	7							lb/h	Argon
Ammonia	lb/h		0	0	0	0	266	3	3	3	3				0	0							lb/h	Ammonia
Particulate	lb/h		35	35	37	37	37	37		35	35				0	3							lb/h	Particulate
Urea	lb/h																				493		lb/h	Urea
Total	lb/h		1,873,220	1,873,220	1,945,856	1,973,365	1,982,215	1,982,063	1,847,450	1,882,088	1,882,087		26,552	0	8,584	134,722	27,509	266		7,148	986	628	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.633	0.633	0.633	0.635	0.635	0.636	0.636	0.634	0.634		0.767		0.677	0.634	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.166	0.166	0.166	0.165	0.165	0.165	0.165	0.166	0.166		0.000		0.072	0.166	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.056	0.057	0.057	0.057	0.057	0.057		0.233		0.163	0.057	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.143	0.143	0.143	0.143	0.142	0.142	0.142	0.143	0.143		0.000		0.078	0.143	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.236	1.236	1.236	1.236	1.236	1.235	1.235	1.235	1.235													
Cp	kJ/kgK		1.125693116	1.1266306	1.1861124	1.193726213	1.19372621	1.193726213	1.193726213	1.133004044	1.133004044												kJ/kgK	Cp
Heat Content	MW		16.399	17.448	78.939	87.506	87.899	87.899	81.925	24.857	24.857	8.182							0.592				MW	Heat Content
	MMBTU/hr		55.969	59.548	269.419	298.659	299.998	299.998	279.608	84.837	84.837	27.926							2.022					
NO$_2$	lbs/hour		834.8018	834.8018	831.9646	841.1912	841.1912	122.4702	114.1547	126.5634	125.2203					9.0							lbs/hour	NO$_2$
NO$_2$	kg/h		379.0000	379.0000	377.7119	381.9008	381.9008	55.6015	51.8262	57.4598	56.8500					4.1							kg/h	NO$_2$
NO$_2$	Nm^3 / hour		184.6	184.6	184.0	186.1	186.1	27.1	25.2	28.0	27.7					2.0								
NO + NO$_2$ @ actual O$_2$	PPM		268.3	268.3	257.4	256.6	255.5	37.2	37.2	40.5	40.0					40.0								
NO + NO$_2$ @ 3 % O$_2$	PPM		300.6	300.6	288.4	286.7	286.1	41.6	41.6	45.4	44.9													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 1	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

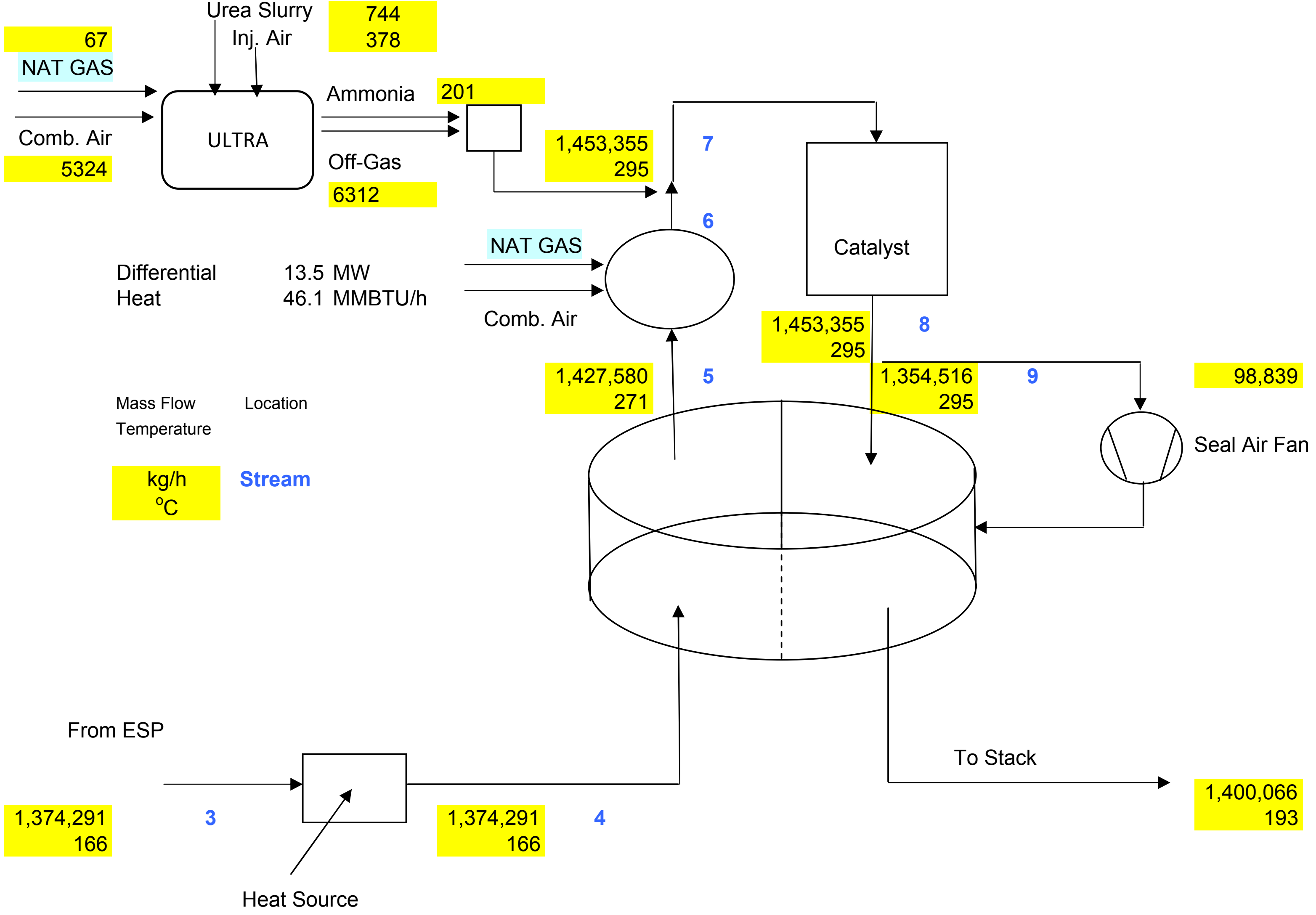
MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 2		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		1,072,689	1,072,689	1,114,284	1,129,869	1,135,150	1,135,286	1,058,149	1,078,363	1,078,363	1,117	14,446	263	5,018	77,189	15,563		86	4,135		293	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		676,283	676,283	702,506	712,332	715,661	715,747	667,116	679,859	679,859	704	9,107	166	3,164	48,664	9,812		54	2,607		185	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		978,672	978,672	1,273,531	1,351,693	1,361,282	1,371,355	1,279,731	1,082,007	1,082,007												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,374,291	1,374,291	1,427,580	1,446,843	1,453,355	1,453,355	1,354,516	1,400,066	1,400,066	871	18,392	201	6,312	98,839	19,263	201	67	5,324	744	378	kg/h	Mass Flow
Mass Flow	lb/hour		3,027,072	3,027,072	3,144,449	3,186,879	3,201,223	3,201,223	2,983,516	3,083,845	3,083,845	1,918	40,512	442	13,902	217,707	42,430	442	148	11,726	1,638	832	lb/hour	Mass Flow
Temperature	Degree F	331	331	331	520	564	564	564	564	380	380												Degree F	Temperature
Temperature	Degree C		166	166	271	295	295	295	295	193	193												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6879	0.6879	0.6879	0.6890	0.6888	0.6891	0.6891	0.6878	0.6878		0.7900		0.6790		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1156	0.1156	0.1156	0.1150	0.1146	0.1146	0.1146	0.1152	0.1152				0.0467		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0525	0.0525	0.0525	0.0520	0.0524	0.0523	0.0523	0.0527	0.0527		0.2100		0.1422		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.1422	0.1422	0.1423	0.1423	0.1422	0.1425	0.1425	0.1428	0.1428				0.1240		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0015	0.0015	0.0015	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		737,868	737,868	766,494	778,477	781,884	782,281	729,129	741,666	741,666		11,412		3,407	53,088	11,991	64		3,267		232	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		124,008	124,008	128,799	129,893	130,127	130,127	121,286	124,243	124,243				234	8,893	1,094						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		56,358	56,358	58,552	58,781	59,495	59,363	55,329	56,810	56,810		3,034		714	4,066	229			868		62	Nm^3/h	Oxygen
Moisture	Nm^3/h		152,571	152,571	158,521	160,768	161,390	161,787	150,794	153,977	153,977				622	11,022	2,249	150					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		1,578	1,578	1,638	1,638	1,638	1,622	1,512	1,562	1,562				0	112	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	1	1	1	17	15	16	16				0	1	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		307	307	306	309	309	45	42	47	46				0	3	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	42	42	40	40	40				40	3	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		1,072,689	1,072,689	1,114,312	1,129,869	1,135,150	1,135,286	1,058,149	1,078,363	1,078,363		14,446		5,018	77,189	15,563	214		4,135		293	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,844,900	922,450	922,450	958,237	973,218	977,478	977,973	911,525	927,199	927,199		14,267		4,259	66,369	14,982	80		4,084		290	kg/h	Nitrogen
Carbon di oxide	kg/h	487,068	243,534	243,534	252,943	255,091	255,551	255,551	238,188	243,994	243,994				460	17,465	2,148						kg/h	Carbon di oxide
Oxygen	kg/h	160,950	80,475	80,475	83,609	83,935	84,955	84,766	79,007	81,121	81,121		4,332		1,019	5,807	327			1,240		88	kg/h	Oxygen
Moisture	kg/h	245,312	122,656	122,656	127,439	129,246	129,746	130,065	121,227	123,786	123,786				500	8,861	1,807	120			372		kg/h	Moisture
Sulfur di oxide	kg/h	9,020	4,510	4,510	4,682	4,682	4,682	4,636	4,321	4,465	4,465				0	320							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	3	3	3	59	55	56	56				0	4							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	1,261	631	631	628	635	635	92	86	96	95				0	7	6						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	76	76	71	72	72				72	5							kg/h	Argon
Ammonia	kg/h		0	0	0	0	201	2	2	2	2			201	0	0							kg/h	Ammonia
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35				0	3							kg/h	Particulate
Urea	kg/h																				372		kg/h	Urea
Total	kg/h	2,748,581	1,374,291	1,374,291	1,427,580	1,446,850	1,453,362	1,453,257	1,354,516	1,380,827	1,380,826		18,599	201	6,312	98,839	19,270	201		5,324	744	378	kg/h	Total
Nitrogen	lb/h		2,031,828	2,031,828	2,110,654	2,143,653	2,153,035	2,154,126	2,007,764	2,042,288	2,042,288		31,425	0	9,382	146,186	32,999	177		8,995		638	lb/h	Nitrogen
Carbon di oxide	lb/h		536,419	536,419	557,143	561,875	562,889	562,889	524,643	537,433	537,433			0	1,014	38,469	4,732	0					lb/h	Carbon di oxide
Oxygen	lb/h		177,258	177,258	184,160	184,880	187,125	186,709	174,023	178,682	178,682		9,541	0	2,245	12,790	720	0		2,731		194	lb/h	Oxygen
Moisture	lb/h		270,167	270,167	280,703	284,682	285,784	286,486	267,021	272,656	272,656			0	1,102	19,517	3,979	265			819		lb/h	Moisture
Sulfur di oxide	lb/h		9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835	9,835			0	0	704		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	6	6	6	130	121	124	124				0	9							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,398	1,398	204	190	210	208			0	0	15	14	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	8	8	167	167	156	159	159				159	11							lb/h	Argon
Ammonia	lb/h		0	0	0	0	442	5	4	5	5				0	0							lb/h	Ammonia
Particulate	lb/h		77	77	80	80	80	80		77	77				0	6							lb/h	Particulate
Urea	lb/h																				819		lb/h	Urea
Total	lb/h		3,027,072	3,027,072	3,144,449	3,186,893	3,201,237	3,201,008	2,983,441	3,041,469	3,041,467		40,967	0	13,902	217,707	42,444	442		11,726	1,638	832	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.671	0.671	0.671	0.673	0.673	0.673	0.673	0.671	0.671		0.767		0.675	0.671	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.177	0.177	0.177	0.176	0.176	0.176	0.176	0.177	0.177		0.000		0.073	0.177	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.059	0.059	0.059	0.058	0.058	0.058	0.058	0.059	0.059		0.233		0.161	0.059	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.090	0.090		0.000		0.079	0.090	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003		0.000		0.000	0.003	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.281	1.281	1.281	1.281	1.280	1.280	1.280	1.280	1.280													
Cp	kJ/kgK		1.104243094	1.1042431	1.1351465	1.142572233	1.14257223	1.142572233	1.142572233	1.111950928	1.111950928												kJ/kgK	Cp
Heat Content	MW		70.023	70.023	122.082	135.591	136.201	136.201	126.938	83.598	83.598	12.624							0.976				MW	Heat Content
	MMBTU/hr		238.988	238.988	416.667	462.771	464.854	464.854	433.241	285.319	285.319	43.087							3.331					
NO_2	lbs/hour		1388.7665	1388.7665	1384.0464	1398.2822	1398.2822	203.5779	189.7458	210.3873	208.3150					14.9							lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3571	634.8201	634.8201	92.4244	86.1446	95.5158	94.5750					6.8							kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	309.3	309.3	45.0	42.0	46.5	46.1					3.3								
NO + NO_2 @ actual O_2	PPM		286.3	286.3	274.7	273.7	272.4	39.7	39.7	43.2	42.7					42.7								
NO + NO_2 @ 3 % O_2	PPM		327.3	327.3	314.1	311.9	311.2	45.3	45.3	49.4	48.9													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 2	Input Data ESP Outlet	3 ESP Outlet	4 GGH inlet	5 GGH outlet	6 Burner out	7 Reactor inlet	8 Reactor outlet	9 GGH treated inlet	10 Booster fan in	11 Booster fan out	12 Natural Gas	13 Combustion Air	14 Ammonia	15 ULTRA Off-Gas	17 Purge+Scavange	12+13 Burner Flue Gas	14 Reacted	18 ULTRA Natural Gas	19 ULTRA Combustion Air	20 ULTRA Urea Slurry	21 ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

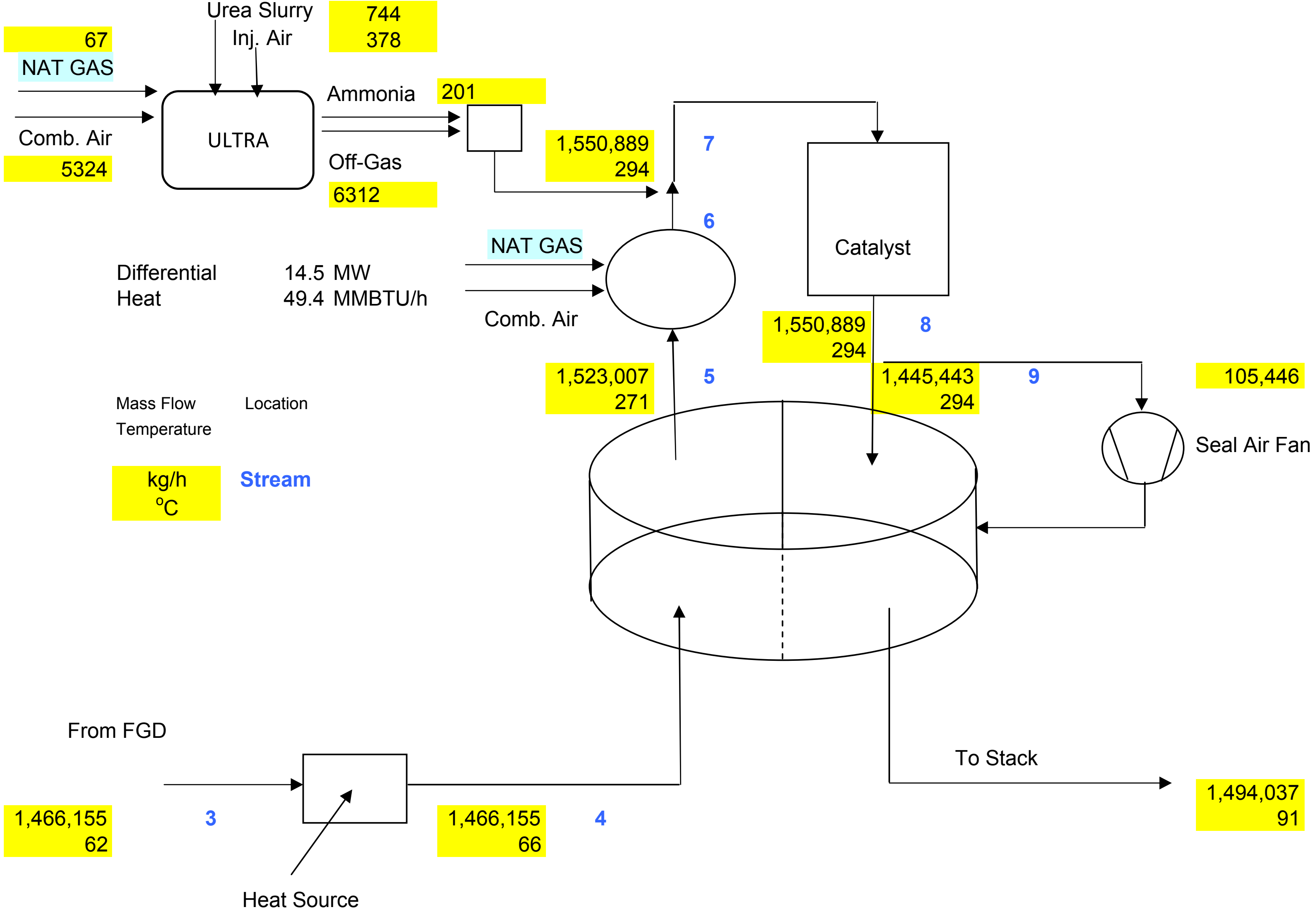
MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 2		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		1,180,582	1,180,582	1,226,360	1,243,639	1,248,920	1,249,057	1,164,213	1,186,256	1,186,256	1,239	16,026	263	5,018	84,937	17,265		86	4,135		293	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		744,304	744,304	773,165	784,058	787,388	787,474	733,984	747,881	747,881	781	10,103	166	3,164	53,549	10,885		54	2,607		185	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		820,913	820,913	1,401,624	1,485,060	1,494,958	1,506,005	1,405,413	929,368	929,368												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,466,155	1,466,155	1,523,007	1,544,376	1,550,889	1,550,889	1,445,443	1,494,037	1,494,037	966	20,404	201	6,312	105,446	21,370	201	67	5,324	744	378	kg/h	Mass Flow
Mass Flow	lb/hour		3,229,416	3,229,416	3,354,640	3,401,710	3,416,054	3,416,054	3,183,794	3,290,830	3,290,830	2,128	44,942	442	13,902	232,260	47,070	442	148	11,726	1,638	832	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	520	562	562	562	562	196	196												Degree F	Temperature
Temperature	Degree C		62	66	271	294	294	294	294	91	91												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6346	0.6346	0.6346	0.6365	0.6365	0.6368	0.6368	0.6348	0.6348		0.7900		0.6790		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1063	0.1063	0.1063	0.1058	0.1055	0.1055	0.1055	0.1060	0.1060				0.0467		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0496	0.0496	0.0496	0.0492	0.0495	0.0494	0.0494	0.0498	0.0498		0.2100		0.1422		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.2091	0.2091	0.2091	0.2082	0.2078	0.2081	0.2081	0.2093	0.2093				0.1240		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		749,220	749,220	778,295	791,589	794,996	795,393	741,365	753,019	753,019		12,660		3,407	53,917	13,302	64		3,267		232	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		125,507	125,507	130,357	131,571	131,805	131,805	122,852	125,741	125,741				234	9,003	1,214						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		58,606	58,606	60,888	61,142	61,855	61,723	57,530	59,058	59,058		3,365		714	4,229	254			868		62	Nm^3/h	Oxygen
Moisture	Nm^3/h		246,863	246,863	256,451	258,944	259,566	259,963	242,305	248,269	248,269				622	17,776	2,495	150					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		79	79	82	82	82	81	75	78	78				0	6	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	1	1	1	1				0	0	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		307	307	306	310	310	45	42	47	46				0	3	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	42	42	40	40	40				40	3	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		1,180,582	1,180,582	1,226,381	1,243,639	1,248,920	1,249,057	1,164,213	1,186,256	1,186,256		16,026		5,018	84,937	17,265	214		4,135		293	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,873,285	936,643	936,643	972,990	989,610	993,870	994,366	926,822	941,391	941,391		15,827		4,259	67,405	16,620	80		4,084		290	kg/h	Nitrogen
Carbon di oxide	kg/h	492,954	246,477	246,477	256,003	258,386	258,847	258,847	241,264	246,937	246,937				460	17,681	2,383						kg/h	Carbon di oxide
Oxygen	kg/h	167,370	83,685	83,685	86,943	87,306	88,325	88,136	82,150	84,331	84,331		4,806		1,019	6,038	363			1,240		88	kg/h	Oxygen
Moisture	kg/h	396,920	198,460	198,460	206,168	208,172	208,672	208,991	194,795	199,590	199,590				500	14,291	2,004	120			372		kg/h	Moisture
Sulfur di oxide	kg/h	450	225	225	234	234	234	231	216	223	223				0	16							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	3	3	3	3				0	0							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	1,261	631	631	628	636	636	93	86	96	95				0	7	7						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	76	76	71	72	72				72	5							kg/h	Argon
Ammonia	kg/h		0	0	0	0	201	2	2	2	2			201	0	0							kg/h	Ammonia
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35				0	3							kg/h	Particulate
Urea	kg/h																				372		kg/h	Urea
Total	kg/h	2,932,310	1,466,155	1,466,155	1,523,007	1,544,383	1,550,896	1,550,781	1,445,443	1,472,681	1,472,680		20,633	201	6,312	105,446	21,377	201		5,324	744	378	kg/h	Total
Nitrogen	lb/h		2,063,089	2,063,089	2,143,151	2,179,758	2,189,140	2,190,232	2,041,459	2,073,549	2,073,549		34,862	0	9,382	148,469	36,607	177		8,995		638	lb/h	Nitrogen
Carbon di oxide	lb/h		542,901	542,901	563,883	569,133	570,147	570,147	531,419	543,915	543,915			0	1,014	38,945	5,249	0					lb/h	Carbon di oxide
Oxygen	lb/h		184,328	184,328	191,505	192,304	194,549	194,133	180,947	185,752	185,752		10,585	0	2,245	13,300	799	0		2,731		194	lb/h	Oxygen
Moisture	lb/h		437,137	437,137	454,114	458,528	459,630	460,333	429,064	439,625	439,625			0	1,102	31,478	4,414	265			819		lb/h	Moisture
Sulfur di oxide	lb/h		496	496	514	514	514	510	475	491	491			0	0	35		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	6	6	6	6				0	0							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,400	1,400	204	190	211	208			0	0	15	16	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	8	8	167	167	156	159	159				159	11							lb/h	Argon
Ammonia	lb/h		0	0	0	0	442	5	5	5	5				0	0							lb/h	Ammonia
Particulate	lb/h		77	77	80	80	80	80		77	77				0	6							lb/h	Particulate
Urea	lb/h																				819		lb/h	Urea
Total	lb/h		3,229,416	3,229,416	3,354,640	3,401,726	3,416,070	3,415,817	3,183,720	3,243,791	3,243,788		45,446	0	13,902	232,260	47,086	442		11,726	1,638	832	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.639	0.639	0.639	0.641	0.641	0.641	0.641	0.639	0.639		0.767		0.675	0.639	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.168	0.168	0.168	0.167	0.167	0.167	0.167	0.168	0.168		0.000		0.073	0.168	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057		0.233		0.161	0.057	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.136	0.136		0.000		0.079	0.136	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.241	1.241													
Cp	kJ/kgK		1.118792829	1.1197279	1.1788636	1.186311705	1.18631171	1.186311705	1.186311705	1.126080331	1.126080331												kJ/kgK	Cp
Heat Content	MW		28.098	29.895	135.259	149.739	150.371	150.371	140.147	42.575	42.575	14.005							0.976				MW	Heat Content
	MMBTU/hr		95.899	102.032	461.638	511.060	513.215	513.215	478.321	145.309	145.309	47.799							3.331					
NO_2	lbs/hour		1388.7665	1388.7665	1384.0495	1399.8420	1399.8420	203.8050	189.9613	210.6144	208.3150					14.9							lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3585	635.5283	635.5283	92.5275	86.2425	95.6189	94.5750					6.8							kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	309.6	309.6	45.1	42.0	46.6	46.1					3.3								
NO + NO_2 @ actual O_2	PPM		260.2	260.2	249.6	249.0	247.9	36.1	36.1	39.3	38.8					38.8								
NO + NO_2 @ 3 % O_2	PPM		292.0	292.0	280.2	278.6	278.1	40.5	40.5	44.1	43.6													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 2	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.1	0															

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



Blakley, Robert

From: Bryant, Ronald

Sent: Friday, August 07, 2009 3:05 PM

To: 'Wayne Jones'; Nate White; Luther Kvernen (lkvernen@minnkota.com); John Graves; Andy Freidt; sbenson@undeerc.org; Weilert, Carl; Blakley, Robert

Cc: 51684

Subject: Revised Agenda for Monday Meeting

Attachments: SCR Economic Study Catalyst Meeting Agenda August 10 2009 Rev3.docx

Attached is the revised agenda for our meeting Monday afternoon.

Ron

MINNKOTA – MRY STATION SCR COST STUDY MEETING

Monday, August 10, 2009
1:00 PM
Meeting Location: Haldor Topsoe, Inc., Houston, Texas

Meeting Participants:

Haldor Topsoe, Inc.
- Wayne Jones, Sales Manager, Power Generation (Houston)
- Nathan White, Director, Business Development (Houston)

Minnkota Power Cooperative, Inc.
- Luther Kvernen, Vice President - Generation (Grand Forks Headquarters)
- John Graves, Environmental Manager (Grand Forks Headquarters)
- Andy Freidt, Permit and Compliance Engineer (MRY Station)

University of North Dakota and Microbeam Technologies
- Steven Benson, PhD, Professor, Department of Chemical Engineering at University of North Dakota and President, Microbeam Technologies, Inc

Burns & McDonnell
- Ron Bryant, Burns & McDonnell project manager for Minnkota air pollution control projects
- Carl Weilert, Burns & McDonnell principal engineer for powerplant air pollution control projects
- Robert Blakley, Burns & McDonnell project engineer for Minnkota's NOx reduction program

Meeting Purpose:

1. To develop a common understanding of the purpose, unique challenges and status of Minnkota's cost study for low dust and tail end SCR technologies.
2. Discuss Haldor Topsoe's experience with SCR catalyst and how it may relate to the application of high sodium and potassium aerosols associated with the combustion of ND lignite in cyclone fired boilers.

AGENDA

1. Introductions

2. Review Meeting Purpose and Agenda

3. Minnkota/MRY Station Background – Luther Kvernen (10 minutes)
- Organization
- SCR cost study

4. ND Lignite (Center Mine) Characteristics – Steve Benson (10 minutes)

5. SCR cost study – Burns & McDonnell (10 minutes)
- Impact of catalyst volumes and deactivation rates
    - Input requirements to provide reasonable cost estimates

6. Haldor Topsoe Background – (10 minutes)
- Organization
- Experience with SCR catalyst for this type of application

7. Identify specific questions/concerns – All

8. Exploration of opportunities – All

9. Action items

10. Other

Bryant, Ronald

From: Bryant, Ronald

Sent: Friday, August 07, 2009 3:13 PM

To: 'Noel Rosha'; Greg Holscher; James Ferrigan; Luther Kvernen (lkvernen@minnkota.com); John Graves; Andy Freidt; sbenson@undeerc.org; Weilert, Carl; Blakley, Robert

Cc: 51684

Subject: Revised Agenda for Tuesday Meeting

Attachments: SCR Economic Study Catalyst Meeting Agenda August 11 2009 Rev3.docx

Attached is the revised agenda for our 9:00 AM meeting Tuesday morning at Burns & McDonnell offices.

Ron

MINNKOTA – MRY STATION SCR COST STUDY MEETING

Tuesday, August 11, 2009
9:00 AM
Meeting Location: Burns & McDonnell with CERAM Environmental, Inc.

Meeting Participants:

CERAM Environmental, Inc.

- Noel Rosha, Senior Applications Engineer (Kansas City)
- Dr. Greg Holscher, Senior Applications Engineer (Kansas City)
- Jim Ferrigan, CRF Environmental, Inc. Sales Representative (Kansas City)

Minnkota Power Cooperative, Inc.

- Luther Kvernen, Vice President - Generation (Grand Forks Headquarters)
- John Graves, Environmental Manager (Grand Forks Headquarters)
- Andy Freidt, Permit and Compliance Engineer (MRY Station)

University of North Dakota and Microbeam Technologies

- Steven Benson, PhD, Professor, Department of Chemical Engineering at University of North Dakota and President, Microbeam Technologies, Inc

Burns & McDonnell

- Ron Bryant, Burns & McDonnell project manager for Minnkota air pollution control projects
- Carl Weilert, Burns & McDonnell principal engineer for powerplant air pollution control projects
- Robert Blakley, Burns & McDonnell project engineer for Minnkota's NOx reduction program

Meeting Purpose:

1. To develop a common understanding of the purpose, unique challenges and status of Minnkota's cost study for low dust and tail end SCR technologies.
2. Discuss CERAM Environmental, Inc. experience with SCR catalyst and how it may relate to the application of high sodium and potassium aerosols associated with the combustion of ND lignite in cyclone fired boilers.

AGENDA

1. Introductions

2. Review Meeting Purpose and Agenda

3. Minnkota/MRY Station Background – Luther Kvernen (10 minutes)
   - Organization
   - SCR cost study

4. ND Lignite (Center Mine) Characteristics – Steve Benson (10 minutes)

5. SCR cost study – Burns & McDonnell (10 minutes)
- Impact of catalyst volumes and deactivation rates
    - Input requirements to provide reasonable cost estimates

6. CERAM Environmental Inc. – (10 minutes)
- Organization
- Experience with SCR catalyst for this type of application

7. Identify specific questions/concerns – All

8. Exploration of opportunities – All

9. Action items

10. Other

Bryant, Ronald

From: Noel Rosha [Noel.Rosha@ceram-usa.com]
Sent: Thursday, August 13, 2009 11:18 AM
To: Bryant, Ronald
Cc: James Ferrigan; Greg Holscher; John Cochran
Subject: Minnkota MR Young Presentation
Attachments: Low Dust & Tail End 2009 Reference List.pdf; Minnkota MR Young Presentation at B&McD 090811.pdf

Ron,

Attached, please find a copy of our presentation from the meeting with Minnkota this week. I have also included our low dust/tail end experience list. Thanks again for the opportunity to meet with everyone to discuss this unique project.

Best regards

Noel Rosha, P.E.
Applications Engineer

CERAM Environmental, Inc.
Phone: 913-239-9896
Mobile: 913-638-9672

Low Dust Tail End Reference List as of April 2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
1	**SMVA Munster**	AEE	Wehreswissensch. Institut	DEU	chem. weapon, cumbustion, Tail end	4 m^3	1997
2	**BMC Moerdijk**	AEE	BMC Moerdijk BV	NLD	Chicken litter, Tail end	20 m^3	2007
3	**Sulcis 3**	ENEL	ENEL	ITA	Coal / Oil, Tail end	127 m^3	1999
4	**Killen**	Black & Veatch	Dayton Power & Light	USA	Coal, Low dust	326 m^3	2002
5	**Killen Unit 2**	Dayton Power & Light	Dayton Power & Light	USA	Coal, Low Dust, Additional delivery	164 m^3	2008
6	**Karlsruhe**	DBA	EnBW	DEU	Coal, Tail end	60 m^3	1988
7	**Herne 1, 2, 3**	KWH	STEAG	DEU	Coal, Tail end	501 m^3	1989
8	**Voerde West I/II**	KWH	STEAG	DEU	Coal, Tail end	535 m^3	1989
9	**Lünen 11**	KWH	STEAG	DEU	Coal, Tail end	243 m^3	1989
10	**Lünen 10**	KWH	STEAG	DEU	Coal, Tail end	94 m^3	1989
11	**STEAG Repl., 1 layer**	STEAG	STEAG	DEU	Coal, Tail End	46 m^3	1991
12	**Lünen 11**	BASF	STEAG	DEU	Coal, Tail end	80 m^3	1994
13	**Ibbenbüren**	BASF	Preussag / RWE	DEU	Coal, Tail end	143 m^3	1994
14	**Elenac - Werk Wesseling Unit 20-24**	BASF	Elenac GmbH	DEU	Ethylencracker, Tail end	51 m^3	2001
15	**Elenac - Werk Wesseling**	BASF	Elenac GmbH	DEU	Ethylencracker, Tail end, Additional delivery	8 m^3	2001
16	**UMEA Biomasse**	ELEX	Umea Energi AB	SWE	Fresh wood, Peat, Low dust	89 m^3	2008
17	**BASF Residue Incin. N800**	BASF	BASF	DEU	Hazardous waste, Low dust	233 m^3	1995
18	**BASF N806**	BASF	BASF	DEU	Hazardous waste, Low dust	24 m^3	1997
19	**MVA Constanti**	BASF	AE-Energietechnik	ESP	Hazardous waste, Low dust	29 m^3	1998
20	**BASF N806**	BASF	BASF	DEU	Hazardous waste, Low dust	8 m^3	1999
21	**BASF N810**	BASF	BASF	DEU	Hazardous waste, Low dust, Additional delivery	29 m^3	2001

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
22	**MVA Constanti**	BASF		ESP	Hazardous waste, Low dust, Additional delivery	10 m^3	2003
23	**Bayer Dormagen**	BASF	Lentjes	DEU	Hazardous waste, Tail end	32 m^3	1994
24	**Schwarzheide**	BASF	Integral	DEU	Hazardous waste, Tail end	29 m^3	1995
25	**SMVA Ostrava**	AE-Energietechnik		CZE	Hazardous waste, Tail end	9 m^3	1999
26	**Ostrava**	SPOVO	SPOVO	CZE	Hazardous waste, Tail end, Low temp. Additional delivery	3 m^3	2005
27	**Bayer Antwerpen**	BASF	Bayer AG	BEL	Industrial waste, Tail end	13 m^3	2002
28	**Deparia**	Deparia Engineering S.r.l.		ITA	Low Sulfur Oil, Diesel engine	7 m^3	2001
29	**KVA Thurgau**	AEE	Verband KVA Thurgau	CHE	Municipal and industrial waste, Tail end	33 m^3	1996
30	**MVA Zistersdorf**	BASF	Von Roll	AUT	Municipal Waste Tail end	41 m^3	2008
31	**KVA Basel**	BASF		CHE	Municipal waste, Low dust	58 m^3	1998
32	**Genf Linie 5, 6, 3**	BASF	SIG / AE-Energietechnik	CHE	Municipal waste, Low dust	139 m^3	2000/01
33	**ICDI Charleroi**	HRC		BEL	Municipal waste, Low dust	7 m^3	2004
34	**KVA Basel**	BASF		CHE	Municipal waste, Low dust	29 m^3	2004
35	**MVA Prag Linie 1-4 Prague-Malešice**	BASF	Pražske služby	CZE	Municipal Waste, Low Dust	236 m^3	2007
36	**Kuri MSWI**	SPECO	SPECO	KOR	Municipal Waste, Low Dust	18 m^3	2009
37	**Genf Linie 5**	BASF	CTU	CHE	Municipal waste, Low dust, Additional delivery	55 m^3	2002
38	**Genf Linie 5**	BASF	SIG	CHE	Municipal waste, Low dust, Additional delivery	72 m^3	2006
39	**Genf Linie 6**	BASF	SIG / CTU	CHE	Municipal waste, Low dust, Additional delivery	72 m^3	2004
40	**Genf**	BASF	Usine de Cheneviers	CHE	Municipal Waste, Low Dust, Additional delivery	72 m^3	2008
41	**MVA Spittelau**	SGP	Heizbetriebe Wien	AUT	Municipal waste, Tail end	39 m^3	1989
42	**MVA Spittelau Dioxin**	SGP	Heizbetriebe Wien	AUT	Municipal waste, Tail end	22 m^3	1991

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
43	**MVA Flötzersteig**	AEE	Heizbetriebe Wien	AUT	Municipal waste, Tail end	52 m^3	1992
44	**Nijmegen**	BASF	KRC	NLD	Municipal waste, Tail end	35 m^3	1994
45	**MVA Mannheim K1-3**	BASF	EVT	DEU	Municipal waste, Tail end	86 m^3	1994
46	**MVA Essen Karnap**	BASF	EVT	DEU	Municipal waste, Tail end	140 m^3	1994
47	**MVA Wels**	AEE	WAV	AUT	Municipal waste, Tail end	20 m^3	1995
48	**MVA Leudelingen**	BASF		LUX	Municipal waste, Tail end	16 m^3	1995
49	**KVA St. Gallen**	BASF	AEE	CHE	Municipal waste, Tail end	11 m^3	1996
50	**MVA Flingern**	BASF		DEU	Municipal waste, Tail end	106 m^3	1996
51	**MVA Mannheim IV**	BASF		DEU	Municipal waste, Tail end	46 m^3	1997
52	**MVA Buchs**	BASF	AE	CHE	Municipal waste, Tail end	54 m^3	1998
53	**Creteil**	BASF	ELEX	FRA	Municipal waste, Tail end	48 m^3	2001
54	**HIMTEC**	BASF		ITA	Municipal waste, Tail end	5 m^3	2001
55	**MVA Bamberg**	BASF		DEU	Municipal waste, Tail end	7 m^3	2001
56	**Halmstads Renhallnings AB**	BASF	BBP Environment	SWE	Municipal waste, Tail end	19 m^3	2002
57	**KVA Turgi**	BASF	GV Region Baden-Brugg	CHE	Municipal waste, Tail end	11 m^3	2002
58	**GMVA Oberhausen**	BASF		DEU	Municipal waste, Tail end	19 m^3	2002
59	**MVA Malmö**	BASF	LAB	SWE	Municipal waste, Tail end	30 m^3	2002
60	**Colleferro Unit 1 & 2**	Mosca Servizi Amb.	Termokimik	ITA	Municipal waste, Tail end	36 m^3	2004
61	**WAV II Wels**	LAB GmbH	Energie AG Oberösterreich	AUT	Municipal waste, Tail end	41 m^3	2005
62	**Saint Ouen Unit 1-3**	BASF	LAB / SYCTOM	FRA	Municipal waste, Tail end	219 m^3	2005
63	**Brest**	Mosca Servizi Amb.	Termokimik	FRA	Municipal waste, Tail end	14 m^3	2005

Low Dust Tail End Reference List as of April 2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
64	**MSWI Bordeaux**	BASF	ASTRIA / HRC	FRA	Municipal waste, Tail end	85 m³	2005
65	**CVDU Nice**	BASF	LAB	FRA	Municipal waste, Tail end	157 m³	2005
66	**Rennes**	BASF	Von Roll	FRA	Municipal waste, Tail end	23 m³	2005
67	**Nantes**	BASF	Von Roll	FRA	Municipal waste, Tail end	34 m³	2005
68	**Coueron / Nantes**	BASF	LAB	FRA	Municipal waste, Tail end	12 m³	2005
69	**Chaumont**	HRC	SHMVD Chaumont	FRA	Municipal waste, Tail end	13 m³	2005
70	**CENON**	Hamon	UIOM de Cenon	FRA	Municipal waste, Tail end	20 m³	2006
71	**Dunkerque**	BASF	Dunkerque Grand Littoral / Von Roll	FRA	Municipal waste, Tail end	9 m³	2007
72	**MVA Twence**	BASF	LAB	NLD	Municipal Waste, Tail end	50 m³	2007
73	**MVA Marseille**	BASF	LAB	FRA	Municipal Waste, Tail end	29 m³	2007
74	**Borsodchem NYRT**	BASF		HUN	Municipal Waste, Tail end	15 m³	2008
75	**Bazenheid**	ELEX	Bazenheid	CHE	Municipal Waste, Tail end	51 m³	2008
76	**Mida Crotone**	Hafner	Mida S.r.l.	ITA	Municipal Waste, Tail end	7 m³	2008
77	**MVA Dürnrohr Linie 3**	Envirgy	AVN	AUT	Municipal Waste, Tail end	35 m³	2009
78	**Mallorca P 3095**	BASF	TIRME SA	ESP	Municipal Waste, Tail end	45 m³	2009
79	**MSW Giubiasco**	BASF	Von Roll	DEU	Municipal Waste, Tail end	30 m³	2009
80	**KVA Thurgau**	BASF	CTU	CHE	Municipal waste, Tail end, Additional delivery	8 m³	2002
81	**Nijmegen**	BASF		NLD	Municipal waste, Tail end, Additional delivery	6 m³	2002
82	**Nijmegen Line 2**	BASF		NLD	Municipal waste, Tail end, Additional delivery	11 m³	2003
83	**KVA St. Gallen**	BASF		CHE	Municipal waste, Tail end, Additional delivery	9 m³	2003
84	**MVA Malmö**	BASF	LAB	SWE	Municipal waste, Tail end, Additional delivery	22 m³	2005

Low Dust Tail End Reference List as of April 2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
85	**Kimhae**	BASF	SPECO	KOR	Municipal waste, Tail end, Additional delivery	5 m^3	2005
86	**Kimhae**	BASF	SPECO	KOR	Municipal waste, Tail end, Additional delivery	5 m^3	2006
87	**CO-Catalyst Rotterdam**	AE-Energietechnik	AVR	NLD	Municipal waste, Tail end, CO Oxidation	6 m^3	2001
88	**T.A. Lauta**	AE	STEAG	DEU	Municipal waste, Tail end, Low temp.	47 m^3	2003
89	**Tirmadrid**	Integral		ESP	Municipal waste, Tail end, Low temp.	133 m^3	2005
90	**Ferrara**	Alstom	Hera	ITA	Municipal waste, Tail end, Low temp.	54 m^3	2006
91	**MVA Pfaffenau**	Integral	WKU / Envirgy	AUT	Municipal waste, Tail end, Low temp.	68 m^3	2007
92	**Issy-les-Moulineaux**	BASF	SYCTOM / Von Roll	FRA	Municipal waste, Tail end, Low temp.	163 m^3	2007
93	**Forli**	Alstom	Hera	ITA	Municipal waste, Tail end, Low temp.	44 m^3	2007
94	**Ferrara**	Alstom	HERA	ITA	Municipal waste, Tail end, Low temp. Additional Delivery	44 m^3	2008
95	**MVA Flötzersteig**	Integral	Fernwärme Wien	AUT	Municipal waste, Tail end, Low temperature	71 m^3	2006
96	**AMSA Silla 2**	Termokimik	AMSA	ITA	Municipal Waste, Tail end, Low temperature	171 m^3	2007
97	**Rimini**	Alstom	HERA	ITA	Municipal Waste, Tail end, Low temperature	44 m^3	2008
98	**TBA Arnoldstein**	AEE	KRV	AUT	Municipal waste, Tail end, Low temp.	14 m^3	2003
99	**MSW Reims**	Hamon	Hamon	FRA	Municipal waste, Tail end, Low temp.	31 m^3	2009
100	**MSW Antibes**	Hamon	Veolia	FRA	Municipal Waste, Tail end	37 m^3	2007
101	**Techwin**	BASF		KOR	Plywood plant, Tail end	7 m^3	2005
102	**Constanti**	BASF		ESP	Residue, Low dust, Additional delivery	20 m^3	2005
103	**Constanti**	BASF		ESP	Residue, Low dust, Additional delivery	10 m^3	2007
104	**Constanti**	BASF	Gestio De Residus Especials De Catalunya, S.A.	ESP	Residue, Low dust, Additional delivery	10 m^3	2007
105	**Constanti**	BASF		ESP	Residue, Low dust, Additional delivery	3 m^3	2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
106	**SMVA Lonza**	AEE	Lonza AG	CHE	Residue, Tail end	25 m^3	1995
107	**CZ Süd**	BASF	BASF	DEU	Residue, Tail end	3 m^3	1996
108	**DOMO Caproleuna**	BASF		DEU	Residue, Tail end	3 m^3	2003
109	**Recycling Komb. Rotterdam**	BASF	Steuler	NLD	Residue, Tail end	13 m^3	2005
110	**BASF CZ Süd**	BASF	BASF	DEU	Residue, Tail end, Additional delivery	3 m^3	2005
111	**Sammel SCR Simmering**	Envirgy	Fernwärme Wien	AUT	Sludge, Hazardous Waste, Tail end, Low temp.	125 m^3	2005
112	**Hot Strip Mill - Oven 23**	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	12 m^3	2003
113	**Hot Strip Mill - Oven 24**	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	12 m^3	2003
114	**Hot Strip Mill - Oven 23**	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	12 m^3	2006
115	**Hot Strip Mill Oven 22**	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp.	37 m^3	2000
116	**Hot Strip Mill Oven 21**	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp.	37 m^3	2002
117	**Hot Strip Mill Oven 22**	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp., Additional del.	39 m^3	2002
118	**Charlottenburg**	Steinmüller	BEW	DEU	Tail end	198 m^3	1989
119	**MVA Burgkirchen**	SHL	ZAS	DEU	Waste, Tail end	24 m^3	1993
120	**München Nord**	BASF	Stadtwerke München	DEU	Waste, Tail end	49 m^3	1993
121	**Colombes**	Integral		FRA	Waste, Tail end	20 m^3	1996
122	**MVA Lenzing**	Integral		AUT	Waste, Tail end	29 m^3	1997
123	**Dalmine**	Integral		ITA	Waste, Tail end	13 m^3	2000
124	**MVA Fribourg**	BASF		CHE	Waste, Tail end	33 m^3	2001
125	**Nimes**	Integral		FRA	Waste, Tail end	9 m^3	2003
126	**Le Havre**	Integral		FRA	Waste, Tail end	13 m^3	2003

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
127	**TRV Niklasdorf**	AEE		AUT	Waste, Tail end	12 m³	2003
128	**Steuler**	BASF	Steuler	DEU	Waste, Tail end	6 m³	2005
129	**Sangju**	BASF	David Chemical	KOR	Waste, Tail end, Additional delivery	3 m³	2005
130	**MSW Ludres**	Hamon	Nancy Energie	FRA	Waste, Tail end, Low temperature	40 m³	2006
	TOTAL AMOUNT					**6946 m³**	

Presentation to
Minnkota / Burns & McDonnell
August 11, 2009

CERAM Environmental, Inc.

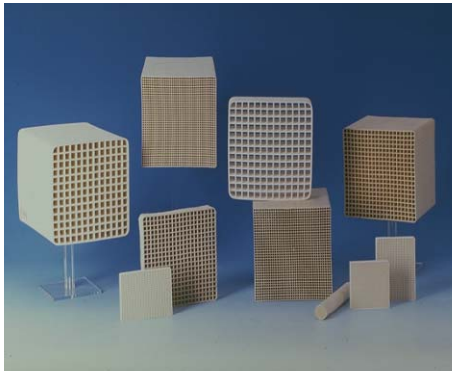
Presentation Topics

- Corporate Overview and Organization
- North Dakota Lignite Coal Analysis
- Low Dust & Tail End Catalyst Designs

CERAM ENVIRONMENTAL, INC.

CERAM Products

- DeNOx Catalyst
- Oxidation Catalyst
- Diesel Truck DeNOx Catalyst
- Heat Storage Media (RTOs)
- Casting Filters
- Specialized Porcelain and Ceramic Products



All CERAM Catalyst is Made in Our Frauental, Austria Plant (Porzellanfabrik Frauenthal, GmbH) Founded in 1921

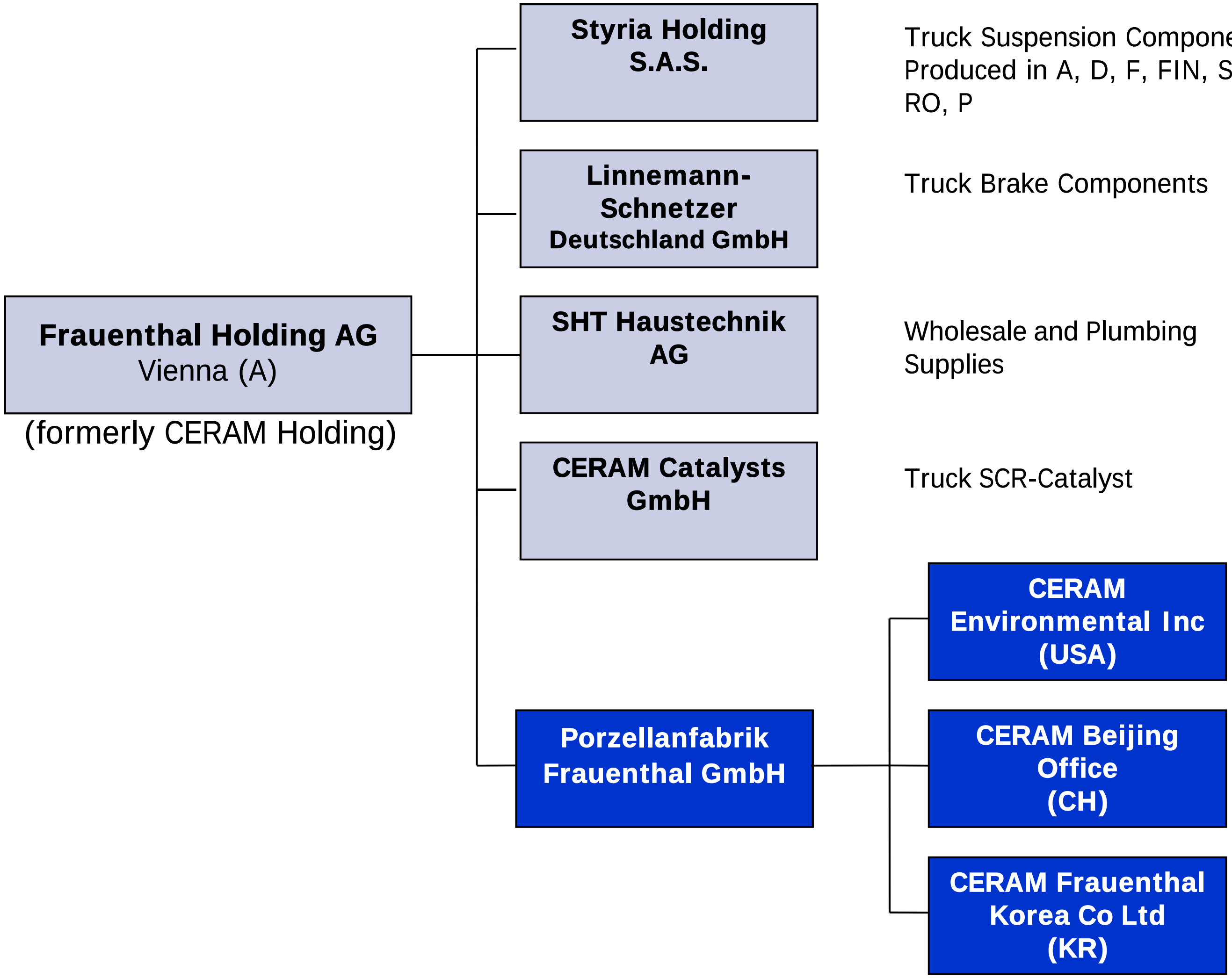
CERAM
ENVIRONMENTAL, INC.

CERAM Environmental Inc.

- U.S. Based Subsidiary Founded by John Cochran in 2000
- 100% Owned by Porzellanfabrik Frauenthal
- Single Point Project Coordination
  - Flow Modeling, Delivery, Training, Startup, Guarantee Administration
- Comprehensive Direct Services
  - Flow Modeling Administration
  - AIG Tuning
  - Reactor Inspections
  - Catalyst Testing
  - SCR Operations Assessments and Troubleshooting
  - Catalyst Management and SCR Operations Planning

CERAM ENVIRONMENTAL, INC.

Structure of the Frauenthal Group



Frauenthal Holding AG
Vienna (A)

(formerly CERAM Holding)

Styria Holding S.A.S.

Truck Suspension Components
Produced in A, D, F, FIN, SL, RO, P

Linnemann-Schnetzer Deutschland GmbH

Truck Brake Components

SHT Haustechnik AG

Wholesale and Plumbing Supplies

CERAM Catalysts GmbH

Truck SCR-Catalyst

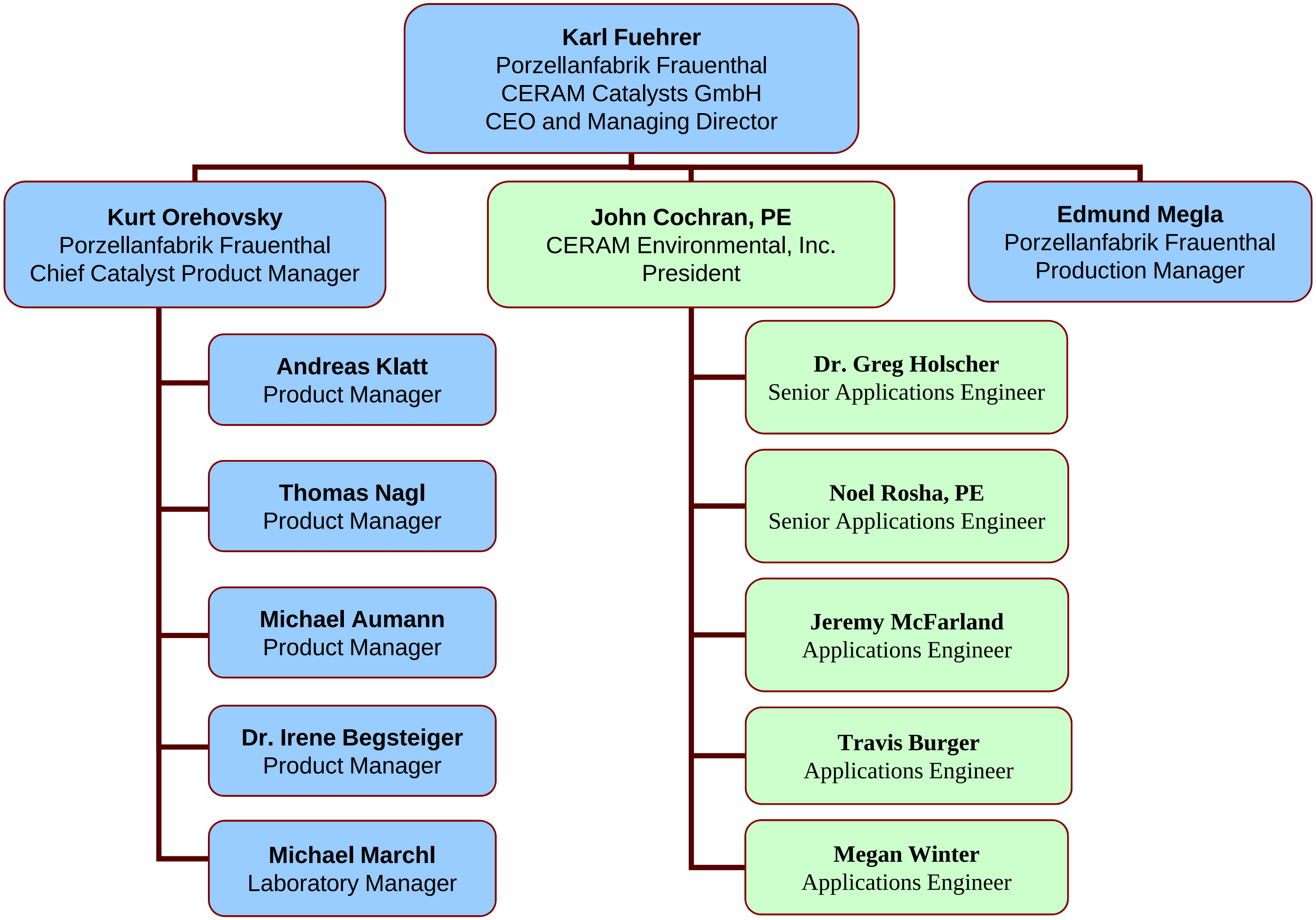
Porzellanfabrik Frauenthal GmbH

- **CERAM Environmental Inc (USA)**
- **CERAM Beijing Office (CH)**
- **CERAM Frauenthal Korea Co Ltd (KR)**

Catalyst
Heat Storage Media
Casting Filters

CERAM
ENVIRONMENTAL, INC.

CERAM Organization



Karl Fuehrer
Porzellanfabrik Frauenthal
CERAM Catalysts GmbH
CEO and Managing Director

Kurt Orehovsky
Porzellanfabrik Frauenthal
Chief Catalyst Product Manager

Andreas Klatt
Product Manager

Thomas Nagl
Product Manager

Michael Aumann
Product Manager

Dr. Irene Begsteiger
Product Manager

Michael Marchl
Laboratory Manager

John Cochran, PE
CERAM Environmental, Inc.
President

Dr. Greg Holscher
Senior Applications Engineer

Noel Rosha, PE
Senior Applications Engineer

Jeremy McFarland
Applications Engineer

Travis Burger
Applications Engineer

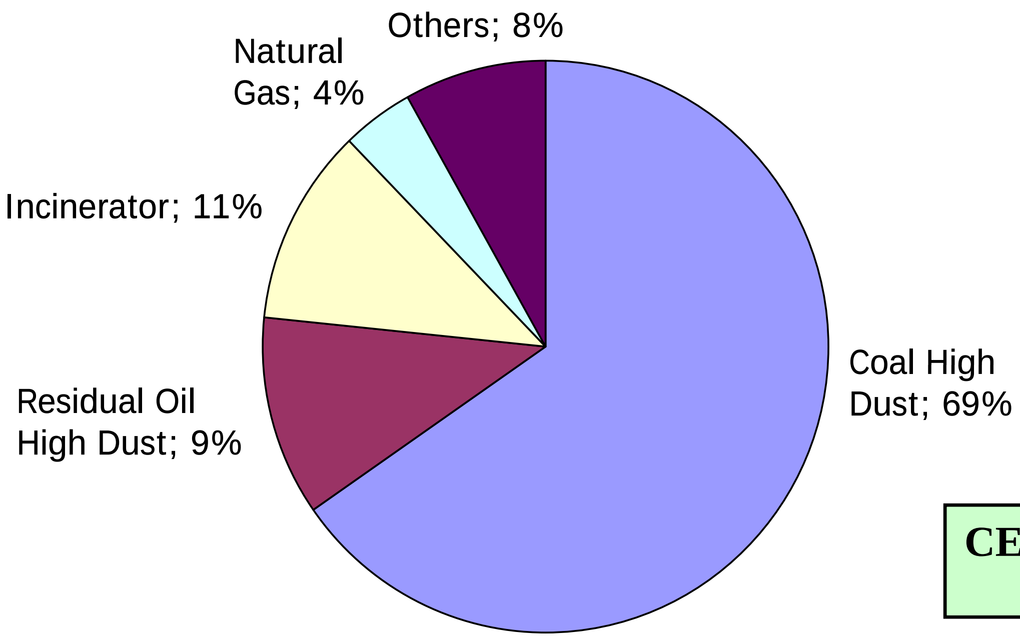
Megan Winter
Applications Engineer

Edmund Megla
Porzellanfabrik Frauenthal
Production Manager

CERAM
ENVIRONMENTAL, INC.

CERAM Has Completed More Than 400 Dirty Fuel Based SCR Catalyst Supply Projects

- Bituminous Coal
- Sub-Bituminous Coal
- Brown (Lignite) Coal
- Distillate Fuel Oil
- Residual Fuel Oil
- Biomass
- Petroleum Coke
- Orimulsion
- Synthesis Gas
- Chemical Weapons
- Wood, Wood Waste and Peat
- Municipal Solid Waste
- Refuse Derived Fuel
- Industrial, Hospital, and Hazardous Waste Incinerators
- Ethylene Crackers, HNO3, and FCC Units
- Blast Furnace and Coke Oven Gas
- Steel Production and Pickling
- Glass Production Plants
- Natural Gas



CERAM's Experience Portfolio Focus' on Dirty Gas Applications

CERAM
ENVIRONMENTAL, INC.

CERAM SCR/Catalyst/AQC Experience
"Boiler to Stack" Perspective

Name/Affiliation	**Catalyst Applications**	**SCR System Design**	**SCR System Startups**	**Other Experience**	**Previous Affiliations**
John Cochran CERAM Environmental	8 Years	7 Years 11 Units	2 Units	19 Years (FGD/ESP/CEM)	Black & Veatch
Dr. Greg Holscher CERAM Environmental	7 Years (+PhD re catalyst)		6 Units	3 Years (ESP/Baghouse/CEM)	Black & Veatch
Noel Rosha CERAM Environmental	5 Years		1 Unit	4 Years (Boilers, Draft Systems, Utility Engineer)	Black & Veatch
Jeremy McFarland CERAM Environmental	4 Years			3 Years (Field Services)	Black & Veatch
Kurt Orehovsky CERAM-Frauenthal	17 Years	7 Years 12 Units	10 Units		Uhde
Thomas Nagl CERAM-Frauenthal	9 Years	13 Years 10 Units	15 Units		Austrian Energy (Babcock Borsig)
Michael Aumann CERAM-Frauenthal	8 Years	15 Years 20 Units		10 Years (FGD/ESP)	Austrian Energy (Babcock Borsig)
Andreas Klatt CERAM-Frauenthal	17 Years				Siemens/Argillon
Total	**73 Years**	**42 Years** **53 Units**	**34 Units**		

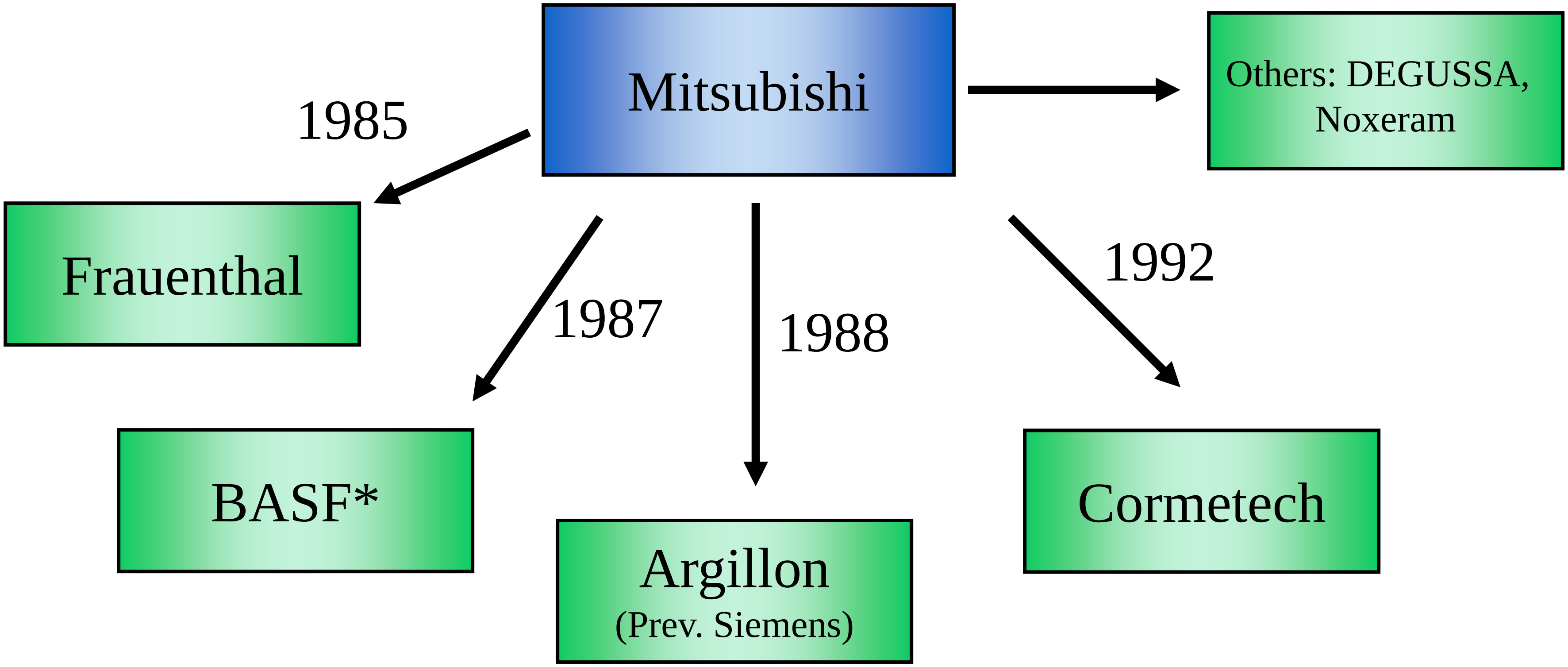
Mitsubishi Catalyst License

Mitsubishi

Information Provided to Licensees:

- Production Know How
- Two Catalyst Geometries (Pitch and Wall Thickness)
  - 7.5 mm (Coal and Oil)
  - 4.2 mm (Gas)
- Three Catalyst Recipes (Coal and High Sulfur Oil, Medium Sulfur Oil, Gas)

Mitsubishi Catalyst Licensees



Mitsubishi

1985

Frauenthal

1987

BASF*

1988

Argillon
(Prev. Siemens)

1992

Cormetech

Others: DEGUSSA, Noxeram

CERAM's or Other European Licensee's Application Experience is **Not** Exchanged with Mitsubishi

*BASF Curtailed Catalyst Production in 1992 and Began Exclusive Distribution of CERAM Catalyst

CERAM Catalyst Innovations

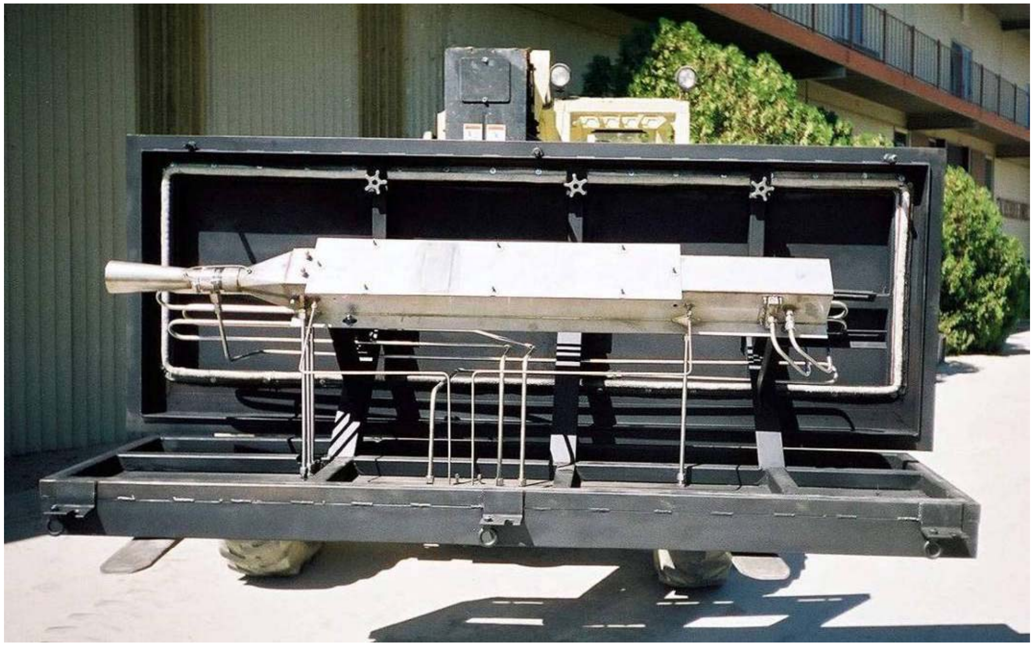
CERAM

- More Than 30 Geometries
  - 1.7 mm Pitch to 11.3 mm Pitch
  - 0.3 to 1.4 mm Wall Thickness
- No Standard Formulations – Site Specifics Fully Accommodated
  - More Than 200 Chemical Formulations
- Widest Temperature Range in Industry (300 to 1,050 F)
- Lowest Oxidation/Highest Activity Catalyst in Industry
- Industry Leading Mechanical Life
  - >120,000 Operating Hours (Coal High Dust)
  - Up to 5 Regenerations/Rejuvenations (Coal High Dust)
- Diesel Truck DeNOx Catalyst

CoPilot® Catalyst Test Reactor

- Patented In-Situ Self Contained Catalyst Testing Apparatus
- In-Situ Reactor Allows for Catalyst Exposure to Actual Flue Gas Conditions Present
  - Fly Ash
  - Temperature
- Modulated Gas Flow Velocity to Match SCR Reactor Conditions
- Allows On-Line Insertion and Removal From Flue Gas – No Outage Required for Access

PROVEN ON 8 REFERENCES

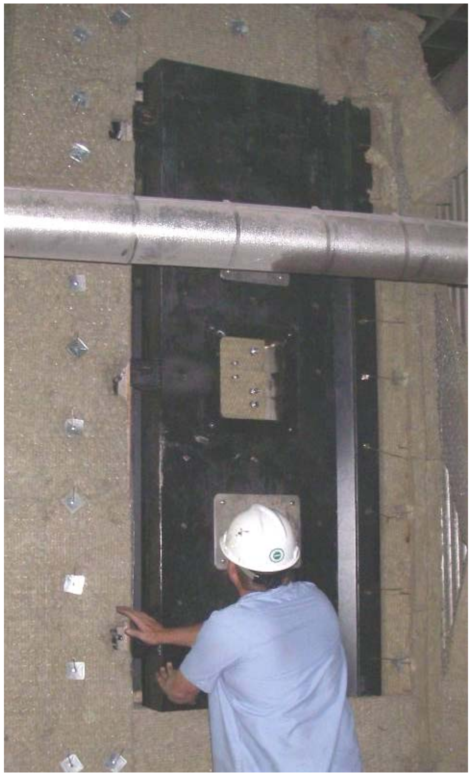


CERAM ENVIRONMENTAL, INC.

Door Operation

1. Open Door

2. Remove/Install Element



3. Close Door

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ENVIRONMENTAL, INC.

CERAM Catalyst Designs for ND Lignite Ash

- High Sodium Concentrations in Ash
  - Sodium Aerosols are a Known Catalyst Poison
  - Critical to Consider Sodium Aerosols Present Downstream of ESP and Wet FGD
  - May Require Special Layup Protection
- Presence of Potassium in Ash
  - Similar to Biomass Applications, can be Accounted for in Catalyst Design Margin
- Presence of Pyrosulfates (Sodium, Iron, and Sulfur)
  - Can Cause Increase in SO_2 to SO_3 Conversion Rate Over Time
  - Concern Reduced with Low Dust or Tail End SCR
  - Can be Accounted for In Catalyst Design Margin

CERAM
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CERAM Catalyst Design for Low Dust SCR

Parameter	**Units**	**M.R. Young Unit 1**	**M.R. Young Unit 2**
Temperature	F	564	564
Catalyst Length	mm	1,275	1,180
Catalyst Pitch / Wall Thickness*	mm	4.9 (30 cell) / 0.55	4.9 (30 cell) / 0.55
Number of Reactors	-	2	2
Catalyst Modules/Layer	-	45 (5 x 9)	84 (7 x 12)
Catalyst Layers	-	2 + 1 Spare	2 + 1 Spare
NO_x Inlet / Outlet	ppmvd ref O_2	326 / 47.5	311 / 45.3
Pressure Drop (2 layers clean)	in. w.g.	3.0	2.6
SO_2/SO_3 Oxidation Rate	%	0.5%	0.5%
Minimum NH_3 Inject Temperature	F	540	540
Volume Per Reactor	m^3	186	321.5
Total Vol. (2 Reactors)	m^3	372	643

* Designed Mechanically for Regeneration/Rejuvenation

CERAM Catalyst Design for Tail End SCR

Parameter	**Units**	**M.R. Young Unit 1**	**M.R. Young Unit 2**
Temperature	F	562	562
Catalyst Length	mm	785	780
Catalyst Pitch / Wall Thickness*	mm	4.2 (35 cell) / 0.55	4.2 (35 cell) / 0.55
Number of Reactors	-	2	2
Catalyst Modules/Layer	-	45 (5 x 9)	77 (7 x 11)
Catalyst Layers	-	2 + 1 Spare	2 + 1 Spare
NO_x Inlet / Outlet	ppmvd ref O_2	286 / 41.6	278 / 40.5
Pressure Drop (2 layers clean)	in. w.g.	3.2	3.2
SO_2/SO_3 Oxidation Rate	%	0.6%	0.6%
Minimum NH_3 Inject Temperature	F	513	513
Volume Per Reactor	m^3	114.5	195
Total Vol. (2 Reactors)	m^3	229	390

* Designed Mechanically for Regeneration/Rejuvenation

CERAM
ENVIRONMENTAL, INC.

CERAM's Comprehensive Catalyst and SCR System Management Services (CATLife®) Program

CATLife® Services

- AIG Tuning
- Catalyst Management Planning
- System Troubleshooting
- Reactor Inspections
- Catalyst Testing
- Increase NOx Removal
- DCS Data Performance Reporting
- System Planning and Upgrades
- Fuel Change Assessments
- Catalyst Rejuvenation
- Cleaning/ Regeneration Assessments
- Used Catalyst Brokering
- Catalyst Disposal
- Regeneration Procurement

CERAM
ENVIRONMENTAL, INC.

Bryant, Ronald

From: Wayne Jones [WSJ@topsoe.com]
Sent: Tuesday, August 18, 2009 3:14 PM
To: Bryant, Ronald
Cc: TNW@topsoe.com
Subject: RE: Update
Attachments: Scope of work and responsibility; Without Remedies 8-12-09.doc

Ron,

Please find attached the information you requested concerning our typical SCR system scope of work and our capabilities. Please review and let me know if you have any questions.

Still waiting on information about the start-up procedure for Amager and our comments to the NDA.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

"Bryant, Ronald" <rbryant@burnsmcd.com>

08/17/2009 05:20 PM

To "Wayne Jones" <WSJ@topsoe.com>
cc
Subject RE: Update

Thanks for the update Wayne.

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Monday, August 17, 2009 4:42 PM
To: Bryant, Ronald
Cc: TNW@topsoe.com

Subject: Update

Ron,

I have finished the requested document defining HTI "typical" scope of work on similar projects. I should have that to you tomorrow. I'm shooting for our response to the NDA on Wednesday. I have a request in for any information available with respect to the start up of Amager Plant

Thanks,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
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www.HaldorTopsoe.com

SCR Process Engineering Package
Scope of Work, Responsibilities, Battery Limits and Guarantees

8-14-2009

Haldor Topsoe, Inc. (HTI) has the capability of simply providing SCR catalyst in elements or modules or providing the catalyst along with a comprehensive process engineering package. For coal fired applications, HTI prefers to provide both the catalyst and process engineering package. This structure provides single point responsibility for the client and allows HTI to utilize our vast amount of experience to design a well integrated SCR system from the economizer outlet to the air heater inlet.

Please find a description below of what will be called HTI's "preferred" scope of work when process engineering tasks are included in our scope. With any project where more than one company is involved in the engineering, optimal points exist where it makes the most sense to draw battery limits where one company hands off responsibility to another. I will define these battery limits in detail.

While the primary engineering firm (AE) investigates available space, foundation constraints and structural steel and support requirements for the ducts, flues and reactor box. HTI will assist in the sizing of the reactor to provide the optimal gas velocity for the specific application. In addition, HTI will review preliminary ductwork layout drawings provided by AE to determine if any fatal flaws might exist with regard to meeting or exceeding all required flue gas conditions at the AIG. HTI does this review in coordination with and with the assistance of the flow modeling company, contracted by HTI and also includes an evaluation of the proposed ductwork configuration focusing on conditions that might create ash fallout issues in the ductwork or reactor.

HTI will also develop and provide recommended minimum requirements for all flow criteria that must be validated in the physical flow model paying particular attention to any characteristics of a specific application that might impact SCR system performance. For example, if very high NOx removal is required special attention might be given to NH_3 to NOx maldistribution at the catalyst face while if the fuels are very erosive and contain a high percentage of ash then gas velocity and angle of entry of the flue gas at the catalyst face might be emphasized.

Once the general arrangement is determined, a preliminary CFD model will be produced in parallel with the construction of a 1/12 scale physical model. HTI will work with the flow modeler throughout the construction and initial testing of the model. If early test results indicate problems with the initial ductwork design HTI will work with the AE and flow modeler to make necessary revisions while considering cost and constructability impacts.

Early in the process a decision will be made whether to use HTI's proprietary "Star Mixer" and AIG system or a Sulzer static mixer and their AIG design. If the HTI mixer is used then HTI will provide drawings for both the mixer and AIG assembly that contain all the detail necessary to generate fabrication drawings. In this case, HTI will also provide the design drawings for the support hardware necessary to install the "Star Mixers" and AIG inside the duct. The AE will be responsible for the procurement of the "Star Mixer", AIG and attachment hardware. The AE will also be responsible for designing the nozzle and flange assembly at the duct wall that will provide the penetration and support for the AIG lance to the duct wall. The battery limit on the AIG drawing is at the AIG lance pipe flange just outside the duct work lagging and everything upstream of that point is the responsibility of the AE.

If a Sulzer mixer is selected, then HTI will take on the responsibility of specifying and procuring both the flow model mixers (1/12 scale) and full scale mixers as well as the Sulzer designed AIG. Sulzer will design and supply all attachment and support hardware required for both the AIG assembly and static mixers.

As apart of the flow model effort, drawings will be provided for all flow conditioning devices including, if required, the large particle ash (LPA) screens. The drawings will provide all required information and dimensions to support the generation of fabrication drawings by the AE including location and orientation of the flow conditioning devices within the duct or reactor. The AE will be responsible for the detail design and support of all flow conditioning devices located either in the ductwork or reactor as well as the procurement of all flow conditioning devices except the Sulzer static mixers, attachment hardware and associated AIG assembly, as described above.

In some cases both the HTI "Star Mixer" and Sulzer mixer will be tried in the flow model. Based on preliminary results a final selection will then be made. At that time all remaining physical flow and CFD modeling will be preformed using only the selected mixer and AIG system.

Below is a list of deliverables typically provided with the process engineering package from HTI. Additions or deletions from the list are possible to meet the exact requirements of a particular project:

- Process flow diagram
- Engineering deliverable schedule
- Manufacturing schedule
- Quality program description
- Flow modeling including physical and CFD modeling services and final report
- Specification for catalyst cleaning system equipment
- Review of all engineering drawings related to the SCR system
- Drawings for all flow control devices including LPA screen and rectifier grid (attachment drawings and hardware, by AE)

- Drawings for "Star Mixer", attachment hardware and associated AIG system, issued by HTI

(or)

- Drawings for Sulzer static mixer, attachment hardware and associated AIG system, issued by Sulzer through HTI

- License for use of the “Star Mixer” and AIG system
- SCR catalyst module drawings
- SCR catalyst bed dust deflection and module sealing system drawings
- SCR catalyst module lifting yoke drawings
- Catalyst arrangement plan
- Operating procedures for installation of catalyst and operations of the SCR
- Operating procedure for handling and storage of the catalyst
- Special tools list
- Performance test procedure
- Performance curves

HTI can also provide, if required, the following scope of services.

- P&ID, preliminary
- SCR ammonia control system specification
- Ammonia system specification

The following are the process guarantees that HTI typically provides as a part of the process design package.

- SCR system pressure drop from the economizer outlet to the air heater inlet. More specifically the pressure drop includes all ductwork and reactor box included in the physical flow model. A target pressure drop will be provided prior to the completion of the physical flow model followed by the actual pressure drop guarantee after the model is complete.
- Flue gas velocity maldistribution at the AIG, at the catalyst face, and air heater inlet
- Flue gas temperature maldistribution at the AIG and catalyst face
- NH_3 to NOx maldistribution at the AIG and catalyst face
- Flue gas angle of entry at the catalyst face
- Minimize ash deposition as per the physical flow model
- Catalyst life
- NOx removal efficiency
- Ammonia slip
- Ammonia usage
- SO_2 oxidation rate
- Mercury oxidation rate

Bryant, Ronald

From: Wayne Jones [WSJ@topsoe.com]

Sent: Wednesday, August 19, 2009 9:19 AM

To: Bryant, Ronald

Cc: lkvernen@minnkota.com; Blakley, Robert; TNW@topsoe.com

Subject: Fw: Startup procedure for Amager Unit 1

Attachments: AMV1 Start-up meeting July 2008.pdf

Ron,

Please find a powerpoint presentation below discussing the proposed startup procedure for Amager 1. They plan to use heated air to preheat the SCR prior to the introduction of flue gas. The stream/gas heater will be used to preheat the air. Let me know if you have any questions.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

----- Forwarded by WSJ/houadm/hti on 08/19/2009 09:15 AM -----

trs/CAT/RVN/Haldor Topsoe@HTAS

08/19/2009 04:04 AM

To Wayne Jones@hti

cc Hans Jensen-Holm [HAJH]@htas, Nate White@hti

Subject Re: Startup procedure for Amager Unit 2Link

Wayne,

Condensing of water during start-up is definitely a serious problem with the high content of Na in the ash.

In Amager 2 this problem is solved by a steam-gas heater, please refer to page 6 in the attached file. The plant is preheated by air and the steam-gas heater just before the SCR gives a "dry" heating of the gas.

Best regards
Torben

Wayne Jones@hti

18-08-2009 22:58

Phone: 281-228-5136

Location: Houston

To Hans Jensen-Holm [HAJH]@htas, Torben Slabiak [TRS]@htas

cc Nate White@hti

Subject Startup procedure for Amager Unit 2

Gentlemen,

We have been discussing with Minnkota Power the possibility of installing a SCR either downstream of a cold ESP or wet scrubber on a North Dakota lignite fired cyclone boiler. As you may recall, this fuel contains a high level of alkali material (as high as 6-9% Na) in the fuel. The fuel also has very high levels of CaO (~20%). The concern is that the high CaO coupled with the high Na will produce a very fine and extremely sticky fly ash. My understanding is that Amager 2 has a tail end SCR. We were discussing possible operational issues surrounding the startup of Amager due to the high levels of alkali poisons in the biomass fuel and whether a full/partial bypass around the SCR may have been installed.

The flue gas on the lignite unit will be reheated using NG or other heat source. During startup if the reactor and catalyst are cold and covered with fly ash the initial flue gas entering the SCR will be rather cool and upon hitting the surface of the catalyst and catalyst modules water is likely to condense on the surface providing a path for the Na to enter the catalyst pore structure. We assumed that Amager might have a similar issue and may have installed a bypass to allow for the heat up of the flue gas before passing it through the reactor.

Any ideas or comments are appreciated.

Thanks,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

AMV1 Start-up of flue gas cleaning

Meeting with API and HTAS 16.07.2008

Henrik Rostgaard

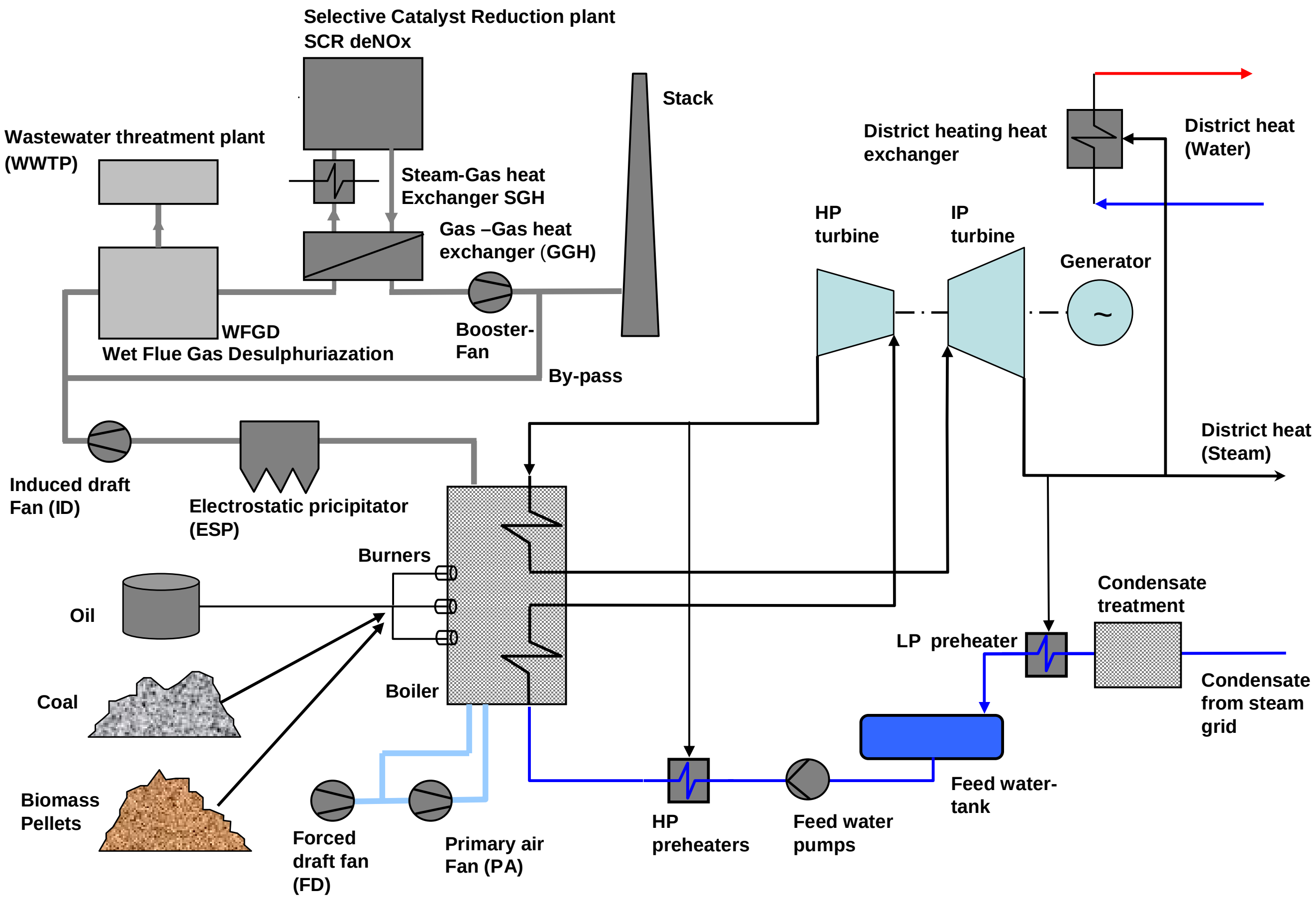
Chemistry & Materials

VATTENFALL

Agenda

1) Presentation
2) Introduction
3) Start and stop of Flue Gas Cleaning
4) Stand still
5) Experience from start up unit 3
6) Discussion and comments from API and HTAS
7) Miscellaneous

Introduction to Amager Power Station unit 1



VATTENFALL

Introduction – fuels and Flue Gas Cleaning

Fuels		
Biomass	–	Flue gas cleaning is not necessary
Coal/biomass	–	Flue gas cleaning will be used
Coal	–	Flue gas cleaning will be used
Oil	–	Only for start-up, but flue gas cleaning will be used if coal-firing is planned

Start and stop of flue gas cleaning

1) Start-cases

Cold start of boiler

Hot start

Shift from biomass to coal

2) Stop-cases

Stop of boiler

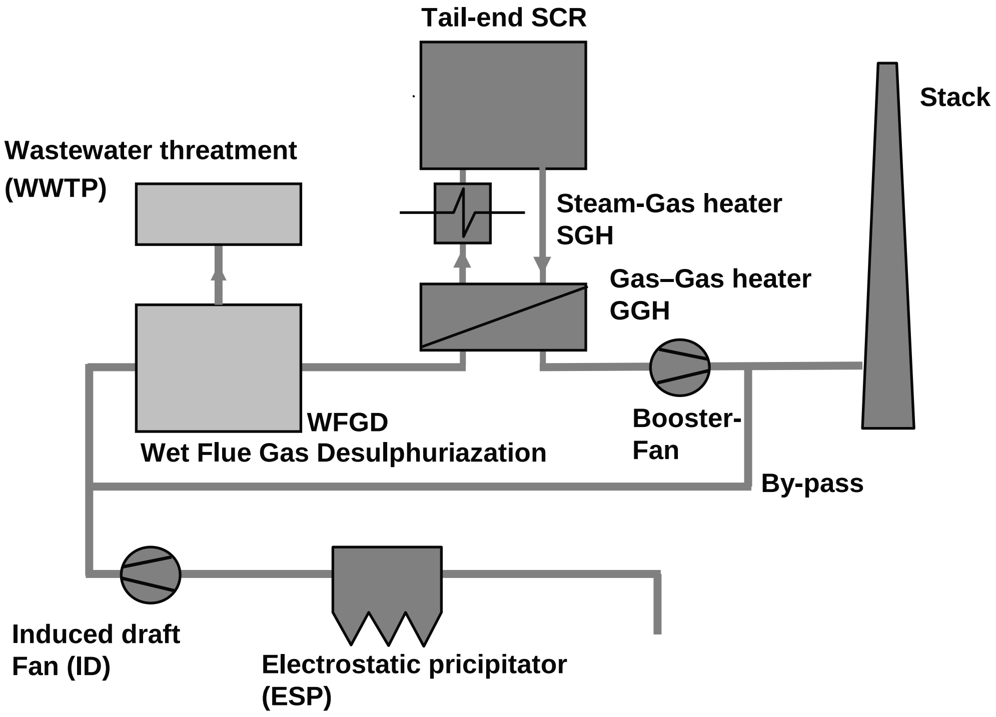
Shift from coal to biomass

3) Stand-still

During biomass-firing

During overhaul and summer-stop

Flue gas cleaning AMV1



Tail-end SCR

Stack

Wastewater threatment (WWTP)

Steam-Gas heater SGH

Gas–Gas heater GGH

WFGD
Wet Flue Gas Desulphuriazation

Booster-Fan

By-pass

Induced draft Fan (ID)

Electrostatic pricipitator (ESP)

Cold start

Boiler, ESP, flue gas ducts, FGD and SCR are pre-heated with air

Heating air before FGD below 45 degree C

Air from the boiler will pass through FGD to the gas/gas heater, steam/gas heater and SCR.

The scrubber liquid is mixed by the hydrocyclone pumps, but the oxidation air is not injected.

The steam/gas heater is operated to give a temperature increase of the SCR of 50 degree C or more pr. hour.

Cold start

Heating air before FGD above 45 degree C

- Oxidation air is injected to start circulation of the scrubber slurry
- SGH is operated to give a temperature increase of the SCR of 50 degree C or more pr. hour.
- When the temperature of the heating air is 110 degree C before FGD <u>and</u> 65 degree C after SCR, the first oilburner will be ignited.
- Subsequently more oilburners will be ignited and the switch to coal-firing will be done as quick as possible.

Cold start

- During both steps the bypass duct will be closed.
- GGH will always be colder than the SCR.
- The above mentioned procedure will ensure that the temperature of the SCR always is above the water dew point.

Hot start

As second part of cold start

Shift from bio-mass to coal

The procedure for the boiler is not finalized:

Maybe a complete stop is necessary – maybe not.

If a complete stop is not needed, preheating of SCR will not be possible, but GGH will always be colder than SCR.

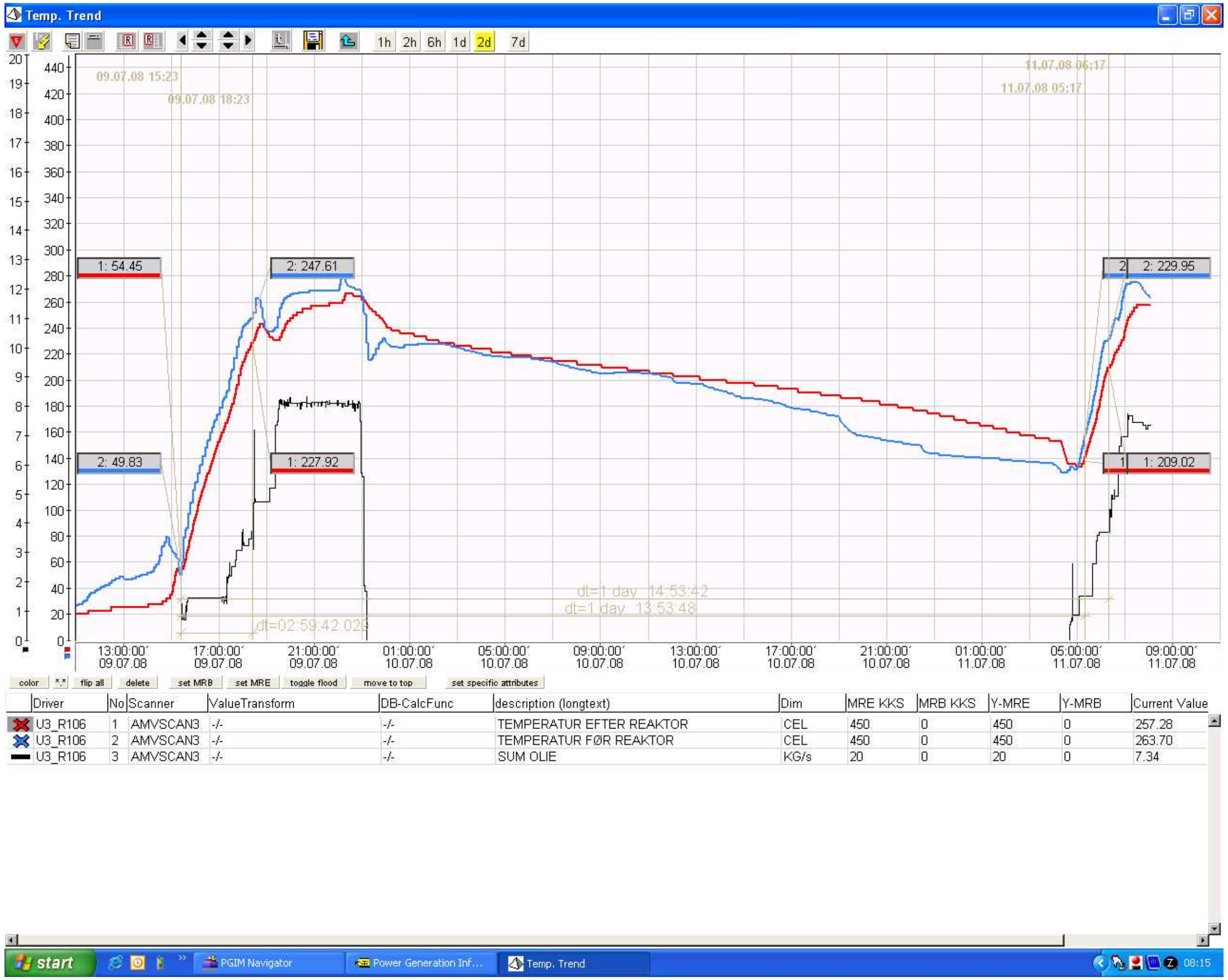
Stops and standstill

Stop of boiler
No problem – flue gas cleaning will be flushed with air during stop procedure

Shift from coal to biomass
Flue gas cleaning could be left with ”old” flue gas during bypass operation of the boiler.

Stand-still
During biomass-firing – Possibly 3 x 1 month
During overhaul and summer-stop – 3 months

Start up unit 3 on 09.07.2008



	Driver	No	Scanner	ValueTransform	DB-CalcFunc	description (longtext)	Dim	MRE KKS	MRB KKS	Y-MRE	Y-MRB	Current Value
🟥	U3_R106	1	AMVSCAN3	-/-	-/-	TEMPERATUR EFTER REAKTOR	CEL	450	0	450	0	257.28
✕	U3_R106	2	AMVSCAN3	-/-	-/-	TEMPERATUR FØR REAKTOR	CEL	450	0	450	0	263.70
▬	U3_R106	3	AMVSCAN3	-/-	-/-	SUM OLIE	KG/s	20	0	20	0	7.34

Thank you!

Comments and questions?

Bryant, Ronald

From: Bryant, Ronald

Sent: Wednesday, August 26, 2009 4:26 PM

To: Wayne Jones

Cc: 'lkvernen@minnkota.com'; John Graves; Craig Bleth (cbleth@minnkota.com); Gerry Pfau (gpfau@minnkota.com); Andy Freidt; Weilert, Carl; Blakley, Robert; sbenson@undeerc.org; 51684

Subject: Minnkota SCR Catalyst Recommendations

Attachments: Scope of Services 26Aug09.doc; Report 1084 - Particulate - FINAL 8-20-09.pdf; MRY SCR Vendor Query (4-18-07) - Abbreviated.pdf

Wayne

Minnkota Power is requesting recommendations on SCR catalyst design for low-dust and tail-end applications as discussed in your offices on August 10.

Attached are the following documents for your consideration:

1. Scope of Services 26Aug09
2. Report 1084 - Particulate - FINAL 8-20-09
3. MRY SCR Vendor Query (4-18-07) – Abbreviated

The first document summarizes items Minnkota Power is requesting in support of the required BACT.

The second document is flue gas testing data performed at the Milton R. Young Station. This information should be treated confidential.

The third document includes some basic boiler operating parameters and was extracted from the MRY SCR Vendor Query originally transmitted in April of 2007.

Please contact us if you need any additional information or would like to discuss the project.

Thank you for your assistance.
Ron Bryant
816-822-3023

Scope of Services
SCR Catalyst Recommendations

Minnkota Power Cooperative
Milton R Young Station
August 26, 2009

1. Minnkota Power Cooperative (MPC) operates two coal-fired electric generating units at the Milton R. Young Station. Both units are Babcock & Wilcox balanced-draft cyclone fired boilers burning 100% North Dakota lignite coal supplied from an adjacent mine. Unit 1 has a gross design output capacity of 257 MW and was initially placed into commercial service in 1970. Unit 2 has a gross original design output capacity of 477 MW and was initially put into service in 1977. The units are located approximately 40 miles northwest of Bismarck, ND.

2. MPC is performing a SCR cost estimate for both units as part of a NO_X BACT Study required by the North Dakota Department of Health. Because of the unique characteristics of North Dakota lignite, MPC is requesting assistant with SCR catalyst selection and sizing.

3. The scope of services MPC is requesting includes the following for both low dust and tail end SCR applications for both units:

    a. Size the reactors to provide the optimal gas velocity and NO_X reduction for the specific applications.

    b. Provide anticipated guarantees for NO_X reduction for the specific applications. Nominal anticipated NO_X concentration entering the reactors is 0.5 lb/million Btu. Nominal desired maximum NO_X concentration exiting the reactors is 0.05 lb/million Btu.

    c. Provide anticipated guarantees for ammonia usage and ammonia slip for the specific applications. The maximum ammonia slip should not exceed 5 ppm.

    d. Provide anticipated guarantees for catalyst deactivation rate and life (number of operating hours between catalyst replacement). It is desired to have a 3 year interval between catalyst layer change-out. If a 3 year interval is not achievable, provide the longest interval the catalyst vendor is able to guarantee.

    e. Provide budgetary pricing for the recommended catalyst.

    f. Review preliminary ductwork layout drawings to determine if any fatal flaws are apparent.

4. Additional design parameters and flue gas testing results are included as an attachment. It is the intent that Dr. Steve Benson and other team members will discuss the test data and related implications of the catalyst selection and design with the catalyst supplier.

5. Please provide requested items by September 18, 2009.

MICROBEAM
TECHNOLOGIES, INC.
www.microbeam.com

FINAL REPORT:

ASSESSMENT OF PARTICULATE CHARACTERISTICS UPSTREAM AND DOWNSTREAM OF ESP AND WET FGD

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EXECUTIVE SUMMARY

Particulate sampling was conducted at Minnkota Power Cooperative's Milton R. Young plant to determine the particulate size and composition distribution of samples collected upstream of the ESP, upstream of the wet scrubber, and downstream of the wet scrubber. Emphasis was placed on determining the fate of sodium, potassium, and calcium since these elements can cause significant plugging and deposition problem.

During the testing, operating conditions of the plant were constant and there was no gas bypass. The coal fired during the testing remained relatively consistent. The as-received ash content ranged from 7.73 to 7.89%. Sodium oxide content of the ash ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing (a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels). Sampling upstream of the ESP and scrubber were conducted using a combination multicylones and impactors. The cyclones collected sized fractions of larger particles (greater than one to five microns) and the impactor collected the sub-micron particulate. Sampling downstream of the scrubber was conducted with a single cyclone followed by a 13-stage advanced impactor. In addition, the submicron particle number concentration was measured using a scanning mobility particle sizer (SMPS).

The results of the particulate mass information indicated a high loading at the ESP inlet of 4.96×10^6 µg/dscm, a scrubber inlet loading of 1.1×10^4 µg/dscm, and a scrubber outlet loading of 1.08×10^4 µg/dscm. These results show very little overall removal of the submicron particulate across the wet scrubber system. A significant fraction of the particulate was removed by the ESP, with a removal efficiency of 99.76%.

The size distribution of the particulate collected upstream of the ESP and upstream of the scrubber was multi-modal as summarized below:

- Upstream of the ESP there were at least three modes – a larger mode at 40 to 50 µm, a second mode at just under 10 µm, and third mode at about 1 µm. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite. The intermediate-sized particles are typically derived from small minerals and organically associated elements. The smaller mode (about one-micron and smaller) contains fine particles and condensed vapor phase species.
- Upstream of the scrubber there were two distinct modes – a larger mode between 8 to 10 µm and another mode centered at about 1 to 2 µm in diameter. The smaller mode is typically condensed vapor phase and small particles.
- Downstream of the scrubber, the primary mode centered at about 0.5 to 0.7 µm, and another possible mode occurred at 3 µm and larger.
- Particle number distributions were as follows:
  - Inlet to the ESP – between 1×10^7 to 10^8 particles per dry normal cubic centimeter (dncc);
  - Inlet to the scrubber is 10^5 particles/dncc;
  - Outlet of the scrubber 7×10^5 particles/dncc.

- Particle number distributions into the nanometer scale (1 µm = 1000 nm) was found to be as high as 10^5 particles/dncc.

Particle composition distributions of the particulate were determined for each of the major elements. The results were reported as µg/dscm of the element as illustrated in the Appendix and in the figures in the text.

- Upstream of the ESP the composition trends for sodium, potassium, calcium and sulfur showed greater concentrations of these elements in the particles that are smaller than 10 µm, with a significant increase in concentration in the flue gas at a particle size of less than 2 µm. There is another increase at 0.1 µm.
- Upstream of the scrubber the compositional trends for sodium, potassium, calcium and sulfur show higher levels at the 1 µm level. The ESP was effective in removing larger-sized particles, as well as some of the 0.1 µm particles. However, in the intermediate 1 µm particles, the ESP is not as effective in removing the particles.
- Downstream of the scrubber the composition size distribution determined for sodium, potassium, calcium and sulfur showed significant levels of sodium and sulfur in size fraction finer than 1 µm. The DLPI sampling system provides very accurate sizing data in the submicron size range. Other elements such as aluminum, silicon and iron show a significant depletion below 1 µm.

Comparison of the characteristics of the particles in terms of mass and composition indicate that, at the time of the testing, the total average mass of the particulate was about 10,800 µg/dscm. The particulate consisted mainly of sodium, potassium, and sulfur. The total quantity of sodium and potassium exiting was between 2000 to 3000 µg/dscm.

INTRODUCTION AND BACKGROUND

Microbeam Technologies, Inc. (MTI) teamed with Energy & Environmental Research Center (EERC) and the Chemical Engineering Department at the University of North Dakota (UND-ChE) to determine the abundance and composition of particulate materials produced at Unit #2 of Minnkota Power Cooperative's Milton R. Young Station (MRY), equipped with an electrostatic precipitator (ESP) and a wet flue gas desulfurization (FGD) system.

Very small particles or aerosols are produced upon combustion of all fuels. These particles have diameters less than ten microns, and in many cases less than one micron. They are formed during the combustion process - when the fuel is exposed to high temperatures and gaseous environments, impurities within the fuel are vaporized. When the gas is cooled, the vaporized species condense to form the small particles or aerosols.

Abundance and composition of the aerosols vary depending upon the fuel type and the combustion system. High-temperature combustion systems, such as cyclone-fired systems, produce higher levels of vaporized species than other combustion system types. Fuels (such as biomass or lignite) that contain high levels of alkali (sodium and potassium) and alkaline earth elements (calcium and magnesium) are especially likely to produce abundant aerosols in the cooler regions of combustion systems, such as air pollution control systems.

Collection of aerosol particles finer than five- to ten-microns in electrostatic precipitators and scrubbers is difficult because physical processes used by these technologies to capture particles are very limited in the one-tenth to five-micron size range. Detailed discussion of the processes can be found in the appendix of this report.

This report contains the results of analyses performed on coal and ash samples collected during field testing at MRY Unit 2. The work was performed to determine the properties (including size, mass, and composition) of particulates collected upstream and downstream electrostatic precipitator and wet FGD.

GOALS AND OBJECTIVES

Objectives of the project were as follows: 1) obtain representative, size-segregated samples of particulate material, including super- and sub-micron particulate, from three locations; 2) perform analyses on these samples to determine the size, mass, and composition distribution; and 3) provide an assessment of the probable impact of particulate inorganic species on the performance of NO_x reduction technologies.

SAMPLE COLLECTION AND CHARACTERIZATION

Sampling

Particulate material in the flue gas was collected and measured upstream and downstream of the MRY electrostatic precipitator, also denoted as the "air heater inlet" and at the wet flue gas desulfurization (FGD) or "scrubber inlet". Multi-cyclone samples were taken at the locations during the impactor testing. Sampling at the ESP inlet and scrubber inlet were conducted at single port locations and traversed for depth. The sampling at the ESP inlet was performed using two different ports; the total sampling time was divided equally between the selected sampling depths. The sampling depths, along with a summary of sampling activities, are summarized in **Table 1**. Sampling locations are shown on a simplified schematic in **Figure 1**.

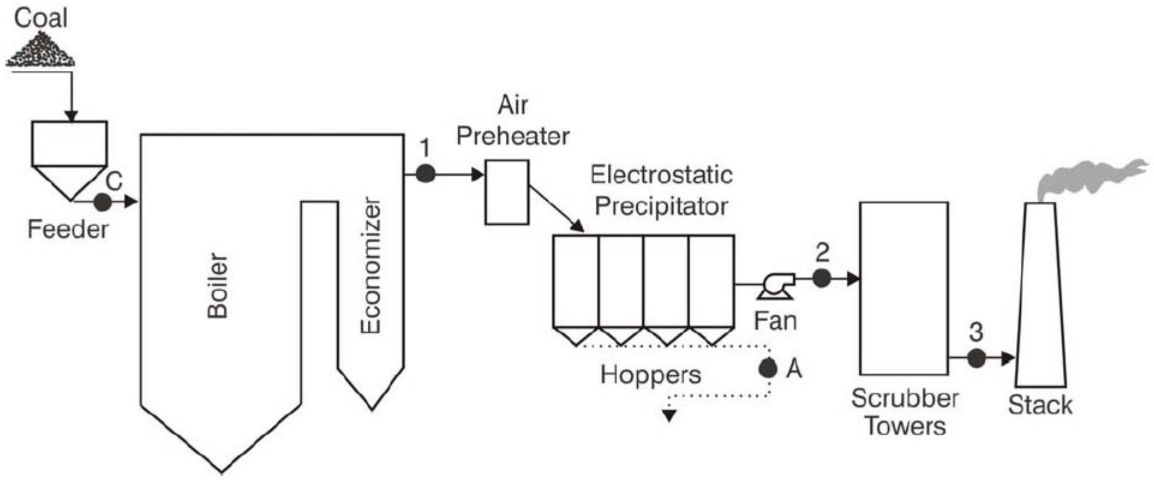


Figure 1. Location of sampling points at MRY Unit 2.

Table 1. Summary of sampling activities at MRY Unit 2.

Test	Location	Date	Start Time	End Time	Duration (minutes)	Sampling Depth (inches)	Notes
IMP/MC Test #1	ESP inlet	3/17/2009	15:40	16:23	43	56,112,161	Figure 1 – point 1
IMP/MC Test #5	ESP inlet	3/19/2009	13:37	13:49	12	56,112,168	Figure 1 – point 1
IMP/MC Test #2	ESP outlet/B scrubber inlet	3/16/2009	16:35	18:13	98	48,102,161	Figure 1 – point 2
IMP/MC Test #3	ESP outlet/B scrubber inlet	3/17/2009	13:47	15:47	120	48,102,161	Figure 1 – point 2
IMP/MC Test #4	ESP outlet/B scrubber inlet	3/18/2009	13:00	15:00	120	48,102,161	Figure 1 – point 2
IMP/MC Test #6	ESP outlet/B scrubber inlet	3/19/2009	12:20	14:20	120	48,102,161	Figure 1 – point 2
SMPS	B Scrubber outlet	3/18/2009			240	~84	Figure 1 – point D
SMPC	B Scrubber outlet	3/19/2009			240	~84	Figure 1 – point D
Dekati "SEM"	B Scrubber outlet	3/18/2009	16:30	17:30	60		*Not weighed* Figure 1 – point D
Dekati Run #1	B Scrubber outlet	3/18/2009	22:00	23:15	75		Figure 1 – point D
Dekati Run #2	B Scrubber outlet	3/19/2009	13:00	16:00	180		Figure 1 – point D

Sample	Location	Date	Time Collected	Notes
ESP ash sample	3B1 - row 1	3/19/2009	14:00	Figure 1 – point A
ESP ash sample	3B2 - row 2	3/19/2009	14:00	Figure 1 – point A
ESP ash sample	3B3 - row 3	3/19/2009	14:00	Figure 1 – point A
ESP ash sample	3B4 - row 4	3/19/2009	14:00	Figure 1 – point A
Coal sample	Feeder 1	3/16/2009	17:05	Figure 1 – point C
Coal sample	Feeder 6	3/16/2009	17:10	Figure 1 – point C
Coal sample	Feeder 7	3/16/2009	17:15	Figure 1 – point C
Coal sample	Feeder 12	3/16/2009	17:00	Figure 1 – point C
Coal sample	Feeder 1	3/17/2009	14:40	*Labeled 13:40 - Assumed to be 14:40* Figure 1 – point C

Sample	Location	Date	Time Collected	Notes
Coal sample	Feeder 6	3/17/2009	14:50	Figure 1 – point C
Coal sample	Feeder 7	3/17/2009	14:55	Figure 1 – point C
Coal sample	Feeder 12	3/17/2009	14:30	Figure 1 – point C
Coal sample	Feeder 1	3/17/2009	17:55	Figure 1 – point C
Coal sample	Feeder 6	3/17/2009	18:00	Figure 1 – point C
Coal sample	Feeder 7	3/17/2009	18:30	Figure 1 – point C
Coal sample	Feeder 12	3/17/2009	17:50	Figure 1 – point C
Coal sample	Feeder 1	3/18/2009	14:10	Figure 1 – point C
Coal sample	Feeder 6	3/18/2009	16:25	Figure 1 – point C
Coal sample	Feeder 7	3/18/2009	16:15	Figure 1 – point C
Coal sample	Feeder 12	3/18/2009	14:00	Figure 1 – point C
Coal sample	Feeder 1	3/18/2009	19:50	Figure 1 – point C
Coal sample	Feeder 6	3/18/2009	19:45	Figure 1 – point C
Coal sample	Feeder 7	3/18/2009	19:45	Figure 1 – point C
Coal sample	Feeder 12	3/18/2009	19:50	Figure 1 – point C
Coal sample	Feeder 1	3/19/2009	14:15	Figure 1 – point C
Coal sample	Feeder 6	3/19/2009	14:30	Figure 1 – point C
Coal sample	Feeder 7	3/19/2009	14:20	Figure 1 – point C
Coal sample	Feeder 12	3/19/2009	14:10	Figure 1 – point C

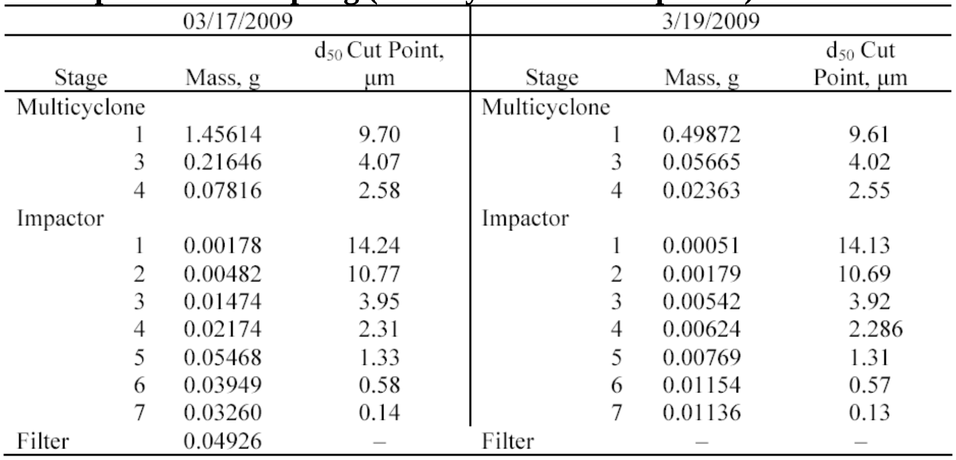
Multicyclone Sampling

Size-fractionated fly ash samples were collected with a Southern Research Institute multi-staged multi-cyclone placed in the duct work at the air heater inlet (ESP inlet). The multicyclone consists of five cyclones, with decreasing d50 cut points, placed in series. The d50 particle size for each test is determined by the temperature and gas flow rate through the cyclone. For the testing at the MRY station, three of the five cyclone stages were used, along with the impactor, to collect selected coarser and finer fractions simultaneously. Size cut data for the multicyclone sampling performed at the air heater inlet are shown in **Table 2**.

Impactor Sampling

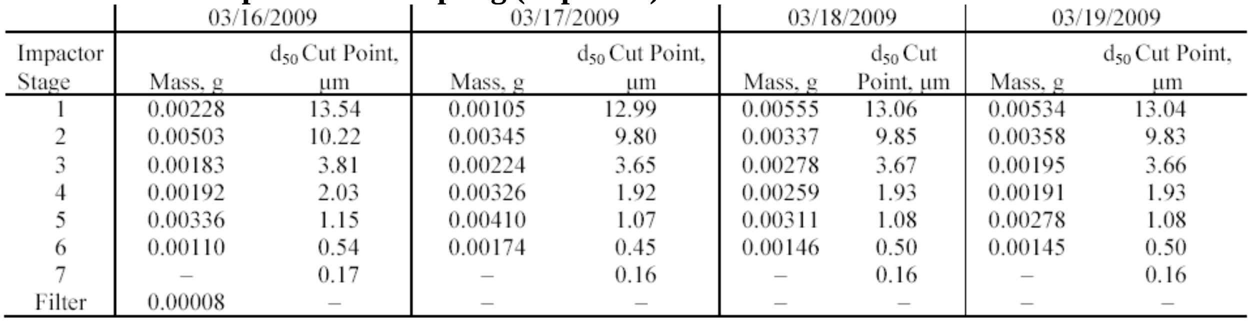
Size-fractionated fly ash samples were collected with a University of Washington seven-stage impactor placed in the gas stream behind the three multi-cyclone stages at the ESP inlet, and was used without multi-cyclone stages at the ESP outlet/scrubber inlet sampling location. The impactor is a round hole, multiple jet-type impactor with seven stages and a backup filter. Each stage has a decreasing d50 cut point. The d50 particle sizes for each test are determined by temperature and gas flow rate through the impactor. Cut points for the impactor at the air heater inlet are shown in **Table 2**. Cut points for the impactor at the scrubber inlet are shown in **Table 3**.

Table 2. D50 cut points for sampling (multicyclone and impactor) at the air heater inlet.



03/17/2009			3/19/2009		
Stage	Mass, g	d_{50} Cut Point, µm	Stage	Mass, g	d_{50} Cut Point, µm
Multicyclone			Multicyclone		
1	1.45614	9.70	1	0.49872	9.61
3	0.21646	4.07	3	0.05665	4.02
4	0.07816	2.58	4	0.02363	2.55
Impactor			Impactor		
1	0.00178	14.24	1	0.00051	14.13
2	0.00482	10.77	2	0.00179	10.69
3	0.01474	3.95	3	0.00542	3.92
4	0.02174	2.31	4	0.00624	2.286
5	0.05468	1.33	5	0.00769	1.31
6	0.03949	0.58	6	0.01154	0.57
7	0.03260	0.14	7	0.01136	0.13
Filter	0.04926	–	Filter	–	–

Table 3. D50 cut points for sampling (impactor) at the B scrubber inlet.



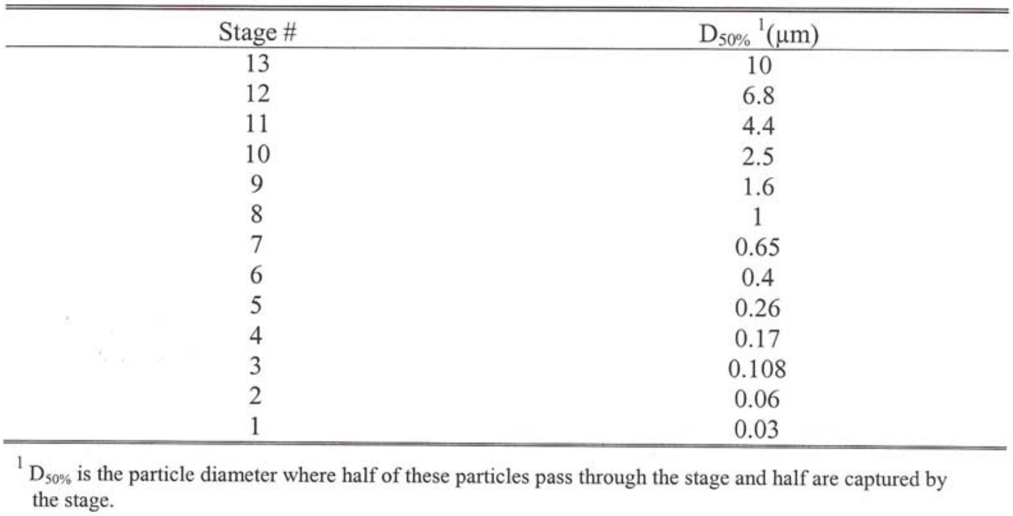
	03/16/2009		03/17/2009		03/18/2009		03/19/2009	
Impactor Stage	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm
1	0.00228	13.54	0.00105	12.99	0.00555	13.06	0.00534	13.04
2	0.00503	10.22	0.00345	9.80	0.00337	9.85	0.00358	9.83
3	0.00183	3.81	0.00224	3.65	0.00278	3.67	0.00195	3.66
4	0.00192	2.03	0.00326	1.92	0.00259	1.93	0.00191	1.93
5	0.00336	1.15	0.00410	1.07	0.00311	1.08	0.00278	1.08
6	0.00110	0.54	0.00174	0.45	0.00146	0.50	0.00145	0.50
7	–	0.17	–	0.16	–	0.16	–	0.16
Filter	0.00008	–	–	–	–	–	–	–

DLPI Sampling

The Dekati Low Pressure Impactor (DLPI) is a state-of-the-art 13-stage cascade impactor for measuring gravimetric particle size distribution of very small particles. It size-classified particles from 10 microns (µm) to 30 nm, and a filter stage accessory enables collection of particles smaller than 30 nm in diameter. **Figure 2** shows the impactor and stages. The d50 cut points for sampling with the DLPI are shown in **Table 4**.

Figure 2. Dekati Low-Pressure Impactor.

Table 4. D50 cut points for sampling (Dekati Low Pressure Impactor) at the B scrubber outlet.



Stage #	$D_{50\%}$ [1](μm)
13	10
12	6.8
11	4.4
10	2.5
9	1.6
8	1
7	0.65
6	0.4
5	0.26
4	0.17
3	0.108
2	0.06
1	0.03

[1] $D_{50\%}$ is the particle diameter where half of these particles pass through the stage and half are captured by the stage.

SMPS Sampling

Sampling at the scrubber outlet was conducted utilizing the scanning mobility particle scanning (SMPS) system that consists of an electrostatic classifier (EC), a condensation particle counter (CPC), and data analysis center (DAC). A schematic of the system is shown in **Figure 3**. The EC classifies the particles, and the concentration is measured by the CPC. The DAC includes a personal computer with custom software, which controls individual instruments and performs data reduction. The components of the SMPS system, particularly the CPC, function normally at about 35°C (95°F). However, the EC does not appear to be too sensitive to temperature conditions.

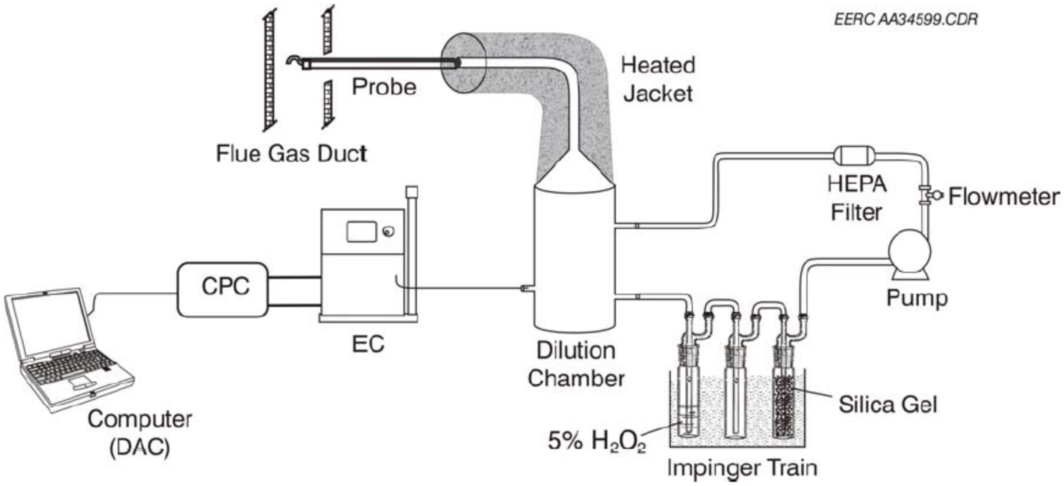


Figure 3. Schematic of the scanning mobility particle scanning (SMPS) system used at the B scrubber outlet.

The procedure for making particulate measurements with the SMPS system is conceptually simple, although manipulating the entire system is quite complex. Typically, flue gas enters the dilution chamber and is mixed with excess air fed through an external pump and at the flow rate of about 45–50 liters per minute (lpm). Dilution air from the pump passes through a HEPA filter to remove any particles that may be in the air. Part of the dilution air is sucked back from the dilution chamber and passed through an impinger train; the wet impinger contains about 250 milliliters (mL) of a 5% hydrogen peroxide (H_2O_2) solution, and the air is dried by passing it through a silica gel flask. The air from the flask is circulated through the pump back to the dilution chamber, and the recirculation process continues for the duration of the measurement. At the bottom of the dilution chamber, a ¼-inch line extracts a sample of the diluted flue gas and delivers it to the EC. The flow rates and pressure drop used in the EC are shown in **Table 5**.

Table 5. Electrostatic classifier (EC) flow meter set points.

Parameter	Monodisperse Air	Sheath Air	Excess Air
Flow Rate, lpm	0.3	3	3
Output, volts	2.305	2.735	2.627
Pressure Drop, cm H_2O	9	N/A*	N/A

* Not applicable.

Measurement does not begin until the CPC is running normally and flow is stable. At a typical working temperature of about 35°C (95°F), indicator lights are checked to ensure all parts are functioning properly (including the liquid level, laser, optics, pump flow, condenser, and saturator). The liquid used in running the CPC is n-butyl alcohol (n-butanol).

Analysis

Table 6 contains a full list of the samples collected and analyses performed. Samples collected were analyzed to determine chemical composition. Scanning electron microscopy with x-ray elemental analysis was performed on the ash samples. Information gained from this method included images and point and area (average) analyses. This type of analysis is called "morphology" because it combines image analysis for features of interest with chemical analysis.

The multicyclone samples were analyzed using bulk chemical anlaysis at EERC. The bulk analysis involved microwave digestion of the ash followed by inductively-coupled plasma-mass spectrometry (ICP-MS). Concentrations of the major elements sodium, potassium, phosphorus, calcium, magnesium and iron were determined.

The coal samples collected during the tests were composited for standard ASTM tests (proximate and ash composition or "mineral ash" analysis) and for computer-controlled scanning electron microscopy (CCSEM) analysis, which provides information on mineral types, abundance, and sizes within the coal.

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-083	3/17/2009	IMP/MC Test #1 - Cyclone nozzle	ESP inlet (A/H inlet)	None
09-084	3/17/2009	IMP/MC Test #1 - Cyclone #1	ESP inlet (A/H inlet)	Morphology
09-085	3/17/2009	IMP/MC Test #1 - Cyclone #3	ESP inlet (A/H inlet)	Morphology
09-086	3/17/2009	IMP/MC Test #1 - Cyclone #4	ESP inlet (A/H inlet)	Morphology
09-087	3/17/2009	IMP/MC Test #1 - Impactor Stage 1	ESP inlet (A/H inlet)	Morphology
09-088	3/17/2009	IMP/MC Test #1 - Impactor Stage 2	ESP inlet (A/H inlet)	Morphology
09-089	3/17/2009	IMP/MC Test #1 - Impactor Stage 3	ESP inlet (A/H inlet)	Morphology
09-090	3/17/2009	IMP/MC Test #1 - Impactor Stage 4	ESP inlet (A/H inlet)	Morphology
09-091	3/17/2009	IMP/MC Test #1 - Impactor Stage 5	ESP inlet (A/H inlet)	Morphology
09-092	3/17/2009	IMP/MC Test #1 - Impactor Stage 6	ESP inlet (A/H inlet)	Morphology
09-093	3/17/2009	IMP/MC Test #1 - Impactor Stage 7	ESP inlet (A/H inlet)	Morphology
09-094	3/17/2009	IMP/MC Test #1 - Impactor outlet (backup filter)	ESP inlet (A/H inlet)	Morphology
09-097	3/18/2009	Dekati Run #1 - Stage 1	Scrubber outlet	Morphology
09-098	3/18/2009	Dekati Run #1 - Stage 2	Scrubber outlet	Morphology
09-099	3/18/2009	Dekati Run #1 - Stage 3	Scrubber outlet	Morphology
09-100	3/18/2009	Dekati Run #1 - Stage 4	Scrubber outlet	Morphology
09-101	3/18/2009	Dekati Run #1 - Stage 5	Scrubber outlet	Morphology
09-102	3/18/2009	Dekati Run #1 - Stage 6	Scrubber outlet	Morphology
09-103	3/18/2009	Dekati Run #1 - Stage 7	Scrubber outlet	Morphology
09-104	3/18/2009	Dekati Run #1 - Stage 8	Scrubber outlet	Morphology
09-105	3/18/2009	Dekati Run #1 - Stage 9	Scrubber outlet	Morphology
09-106	3/18/2009	Dekati Run #1 - Stage 10	Scrubber outlet	Morphology
09-107	3/18/2009	Dekati Run #1 - Stage 11	Scrubber outlet	Morphology
09-108	3/18/2009	Dekati Run #1 - Stage 12	Scrubber outlet	Morphology
09-109	3/18/2009	Dekati Run #1 - Stage 13	Scrubber outlet	Morphology
09-110	3/18/2009	Dekati "SEM" - Stage 1	Scrubber outlet	None
09-111	3/18/2009	Dekati "SEM" - Stage 2	Scrubber outlet	None
09-112	3/18/2009	Dekati "SEM" - Stage 3	Scrubber outlet	None
09-113	3/18/2009	Dekati "SEM" - Stage 4	Scrubber outlet	None
09-114	3/18/2009	Dekati "SEM" - Stage 5	Scrubber outlet	None
09-115	3/18/2009	Dekati "SEM" - Stage 6	Scrubber outlet	None
09-116	3/18/2009	Dekati "SEM" - Stage 7	Scrubber outlet	None
09-117	3/18/2009	Dekati "SEM" - Stage 8	Scrubber outlet	None

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-118	3/18/2009	Dekati "SEM" - Stage 9	Scrubber outlet	None
09-119	3/18/2009	Dekati "SEM" - Stage 10	Scrubber outlet	None
09-120	3/18/2009	Dekati "SEM" - Stage 11	Scrubber outlet	None
09-121	3/18/2009	Dekati "SEM" - Stage 12	Scrubber outlet	None
09-122	3/18/2009	Dekati "SEM" - Stage 13	Scrubber outlet	None
09-123	3/19/2009	Dekati Run #2 - Stage 1	Scrubber outlet	Morphology
09-124	3/19/2009	Dekati Run #2 - Stage 2	Scrubber outlet	Morphology
09-125	3/19/2009	Dekati Run #2 - Stage 3	Scrubber outlet	Morphology
09-126	3/19/2009	Dekati Run #2 - Stage 4	Scrubber outlet	Morphology
09-127	3/19/2009	Dekati Run #2 - Stage 5	Scrubber outlet	Morphology
09-128	3/19/2009	Dekati Run #2 - Stage 6	Scrubber outlet	Morphology
09-129	3/19/2009	Dekati Run #2 - Stage 7	Scrubber outlet	Morphology
09-130	3/19/2009	Dekati Run #2 - Stage 8	Scrubber outlet	Morphology
09-131	3/19/2009	Dekati Run #2 - Stage 9	Scrubber outlet	Morphology
09-132	3/19/2009	Dekati Run #2 - Stage 10	Scrubber outlet	Morphology
09-133	3/19/2009	Dekati Run #2 - Stage 11	Scrubber outlet	Morphology
09-134	3/19/2009	Dekati Run #2 - Stage 12	Scrubber outlet	Morphology
09-135	3/19/2009	Dekati Run #2 - Stage 13	Scrubber outlet	Morphology
09-136	3/18/2009	IMP Test #4 - Inlet nozzle	ESP outlet/scrubber inlet	Morphology
09-137	3/18/2009	IMP Test #4 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-138	3/18/2009	IMP Test #4 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-139	3/18/2009	IMP Test #4 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-140	3/18/2009	IMP Test #4 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-141	3/18/2009	IMP Test #4 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-142	3/18/2009	IMP Test #4 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-143	3/18/2009	IMP Test #4 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-144	3/18/2009	IMP Test #4 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-145	3/19/2009	IMP/MC Test #5 - Impactor stage 1	ESP inlet (A/H inlet)	Morphology
09-146	3/19/2009	IMP/MC Test #5 - Impactor stage 2	ESP inlet (A/H inlet)	Morphology
09-147	3/19/2009	IMP/MC Test #5 - Impactor stage 3	ESP inlet (A/H inlet)	Morphology
09-148	3/19/2009	IMP/MC Test #5 - Impactor stage 4	ESP inlet (A/H inlet)	Morphology
09-149	3/19/2009	IMP/MC Test #5 - Impactor stage 5	ESP inlet (A/H inlet)	Morphology
09-150	3/19/2009	IMP/MC Test #5 - Impactor stage 6	ESP inlet (A/H inlet)	Morphology
09-151	3/19/2009	IMP/MC Test #5 - Impactor stage 7	ESP inlet (A/H inlet)	Morphology
09-152	3/19/2009	IMP Test #5 - Impactor outlet (backup filter)	ESP inlet (A/H inlet)	Morphology
09-153	3/19/2009	IMP Test #6 - Inlet nozzle	ESP outlet/scrubber inlet	Morphology
09-154	3/19/2009	IMP Test #6 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-155	3/19/2009	IMP Test #6 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-156	3/19/2009	IMP Test #6 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-157	3/19/2009	IMP Test #6 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-158	3/19/2009	IMP Test #6 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-159	3/19/2009	IMP Test #6 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-160	3/19/2009	IMP Test #6 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-161	3/19/2009	IMP Test #6 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-162	3/19/2009	IMP Test #5 - Film from stage 1	ESP outlet/scrubber inlet	Morphology
09-163	3/18/2009	IMP Test #4 - Film from stage 2 (bottom of jets)	ESP outlet/scrubber inlet	None

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-164	3/18/2009	IMP Test #4 - Film from stage 3 (bottom of jets)	ESP outlet/scrubber inlet	None
09-165	3/18/2009	IMP Test #4 - Film from stage 4 (bottom of jets)	ESP outlet/scrubber inlet	None
09-166	3/18/2009	IMP Test #4 - Film from stage 5 (bottom of jets)	ESP outlet/scrubber inlet	None
09-167	3/19/2009	IMP Test #6 - Film from stage 4 (back of jets)	ESP outlet/scrubber inlet	Morphology
09-168	3/19/2009	IMP/MC Test #5 - Cyclone stage 6	ESP inlet (A/H inlet)	Morphology
09-169	3/19/2009	IMP/MC Test #5 - Cyclone stage 7	ESP inlet (A/H inlet)	Morphology
09-170	3/19/2009	IMP/MC Test #5 - Cyclone #1	ESP inlet (A/H inlet)	Morphology
09-171	3/19/2009	IMP/MC Test #5 - Cyclone #3	ESP inlet (A/H inlet)	Morphology
09-172	3/19/2009	IMP/MC Test #5 - Cyclone #4	ESP inlet (A/H inlet)	Morphology
09-173	3/19/2009	IMP/MC Test #5 - Cyclone nozzle	ESP inlet (A/H inlet)	Morphology
09-174	3/19/2009	ESP Ash - Row 1 3B1	ESP	None
09-175	3/19/2009	ESP Ash - Row 2 3B2	ESP	None
09-176	3/19/2009	ESP Ash - Row 3 3B3	ESP	None
09-177	3/19/2009	ESP Ash - Row 4 3B4	ESP	None
09-178	3/16/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-179	3/17/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-180	3/18/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-181	3/19/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-184	3/16/2009	IMP Test #2 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-185	3/16/2009	IMP Test #2 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-186	3/16/2009	IMP Test #2 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-187	3/16/2009	IMP Test #2 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-188	3/16/2009	IMP Test #2 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-189	3/16/2009	IMP Test #2 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-190	3/16/2009	IMP Test #2 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-191	3/16/2009	IMP Test #2 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-192	3/16/2009	IMP Test #2 - Impactor nozzle	ESP outlet/scrubber inlet	None
09-193	3/17/2009	IMP Test #3 - Impactor stage 1	ESP outlet/scrubber inlet	None
09-194	3/17/2009	IMP Test #3 - Impactor stage 2	ESP outlet/scrubber inlet	None
09-195	3/17/2009	IMP Test #3 - Impactor stage 3	ESP outlet/scrubber inlet	None
09-196	3/17/2009	IMP Test #3 - Impactor stage 4	ESP outlet/scrubber inlet	None
09-197	3/17/2009	IMP Test #3 - Impactor stage 5	ESP outlet/scrubber inlet	None
09-198	3/17/2009	IMP Test #3 - Impactor stage 6	ESP outlet/scrubber inlet	None
09-199	3/17/2009	IMP Test #3 - Impactor stage 7	ESP outlet/scrubber inlet	None
09-200	3/17/2009	IMP Test #3 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	None
09-201	3/17/2009	IMP Test #3 - Impactor nozzle	ESP outlet/scrubber inlet	None

RESULTS AND DISCUSSION

Coal Analysis and Plant Operating Conditions during Testing

The coal samples for each day were composited to form one larger sample; the four resulting composite coal samples were subjected to proximate and ash composition analyses. The results of the analyses are shown in **Table 7**. The coal was relatively consistent over the time period sampled. The as-received ash content ranged from 7.73 to 7.89%. Sodium content ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing as a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels.

Table 7. Proximate and ash composition analyses for four composite coal samples taken from MRY coal feeders on March 16 through 19, 2009.

	MTI 09-178 3/16/09 Composite		**MTI 09-179 3/17/09 Composite**		**MTI 09-208 3/18/09 Composite**		**MTI 09-209 3/19/09 Composite**	
Proximate (wt% in coal)	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*
Total moisture	37.58		37.24		37.23		36.10	
Ash	7.89	12.64	7.85	12.51	7.84	12.49	7.73	12.10
Volatile matter	24.80	39.73	25.15	40.07	25.22	40.18	25.81	40.39
Fixed carbon	29.73	47.63	29.76	47.42	29.71	47.33	30.36	47.51
Heating value (BTU/lb)	6732	10785	6784	10810	6701	10676	6851	10721
Total sulfur	0.90	1.44	1.00	1.59	0.65	1.04	0.77	1.21
Ash Composition (wt% in ash)								
SiO2		26.92		26.08		34.46		31.06
Al2O3		8.78		8.81		11.61		10.63
TiO2		0.39		0.36		0.44		0.39
Fe2O3		11.17		12.96		7.75		8.49
CaO		15.23		14.99		14.01		15.26
MgO		4.55		4.38		4.37		4.70
K2O		1.24		1.55		1.68		1.46
Na2O		7.22		7.57		7.31		7.24
SO3		19.50		18.70		14.88		16.92
P2O5		0.45		0.40		0.33		0.47
SrO		0.45		0.43		0.41		0.44
BaO		0.72		0.55		0.61		0.63
MnO2		0.09		0.08		0.08		0.08
SiO2/Al2O3		***3.07***		***2.96***		***2.97***		***2.92***
Base/Acid		***1.09***		***1.18***		***0.76***		***0.88***

Figures 4 and **5** show the overall coal flow rate, along with the ash quantity and base-to-acid ratio determined with the Full-Stream Elemental Analyzer (FSEA) during the test period. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and feeding coal to the cyclones. These data show a decrease in the base-to-acid ratio during the testing period. This was observed in the analysis of the four daily composite samples.

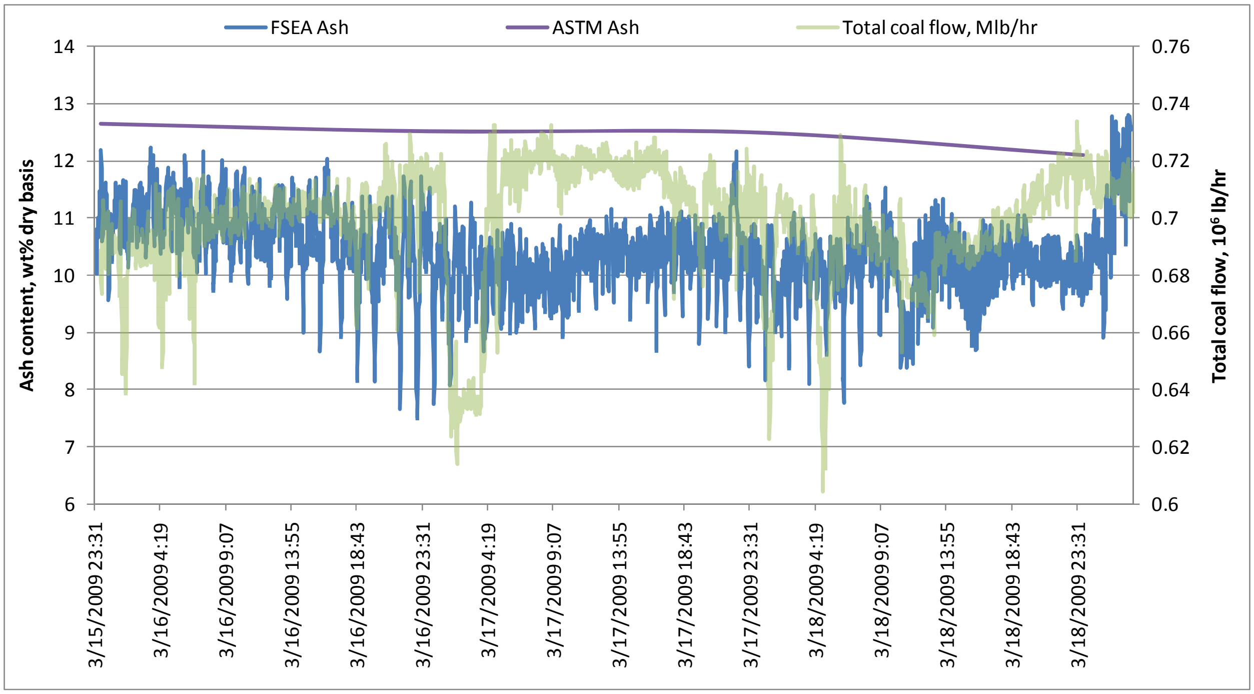


Figure 4. Coal belt flow and fuel ash quantity (determined with FSEA and by ASTM method on composite coal samples) during the testing. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and estimated fuel fed to the cyclones.

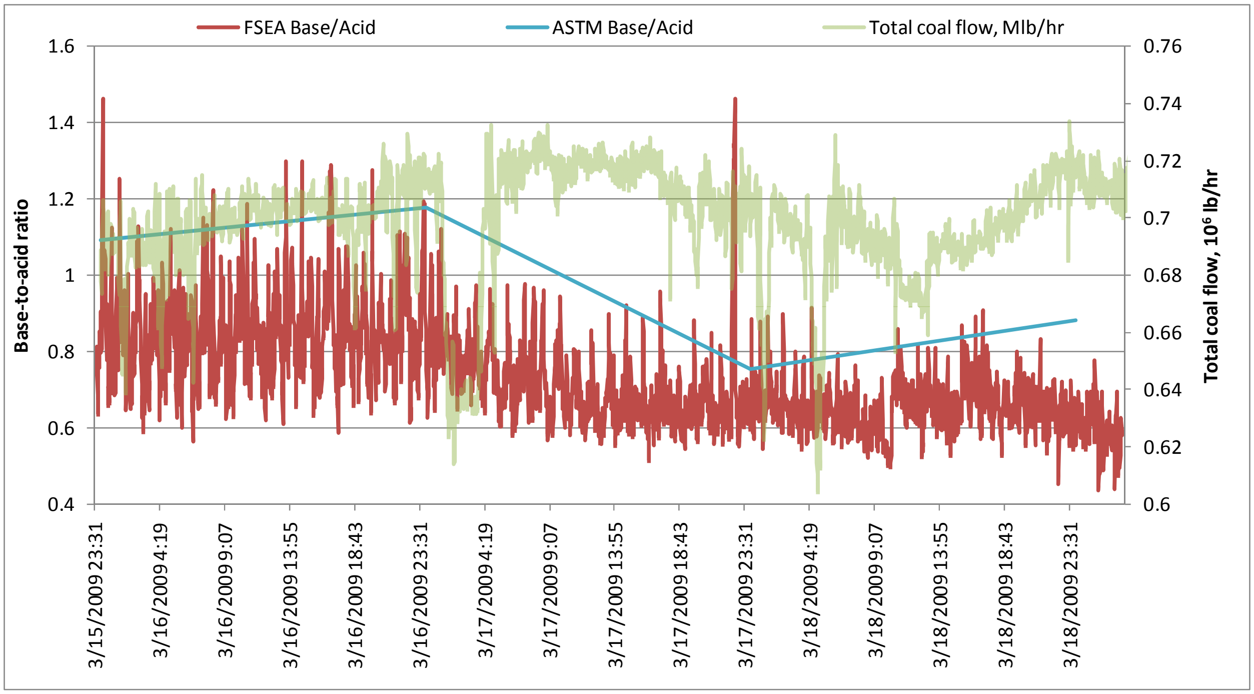


Figure 5. Coal belt flow and base-to-acid ratio (determined with FSEA and by ASTM ash composition analyses performed on composite coal samples) during the testing. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and estimated fuel fed to the cyclones.

Particulate Mass and Number Distribution

Mass Distribution as Function of Location

The total mass loadings obtained with the multicyclone and impactors are illustrated in **Figure 6**. The results show a high average loading of 4.96x10^6 micrograms per dry standard cubic meter (µg/dscm) at the ESP inlet, and average scrubber inlet and outlet loadings of 1.1x10^4 µg/dscm and 1.08x10^4 µg/dscm, respectively. Significant removal of particulate occurred across the ESP, with removal efficiency of 99.76%. These results show that very little removal of particulate material has occurred across the wet scrubber system. This is consistent with past work conducted by Markowski and others (1983) (a literature review is contained in **Appendix B** of this report). The results are also summarized in **Table 8**.

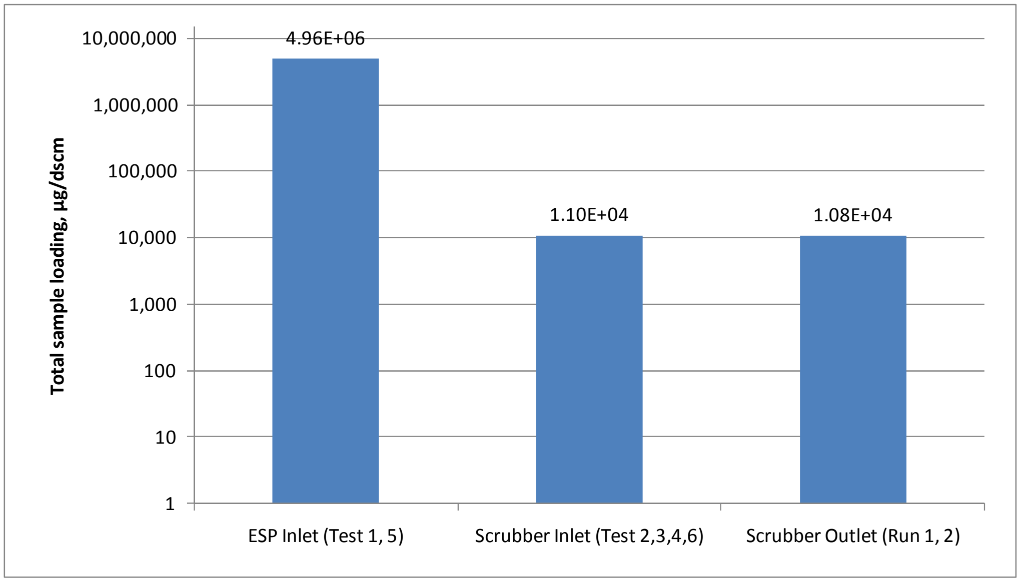


Figure 6. Total mass loadings at ESP inlet, wet scrubber inlet, and wet scrubber outlet.

Table 8. Total mass loadings for all testing conducted at ESP inlet, wet scrubber inlet, and wet scrubber outlet.

Location	Date	Test #	Sampler type	Sampler loading mg/dscm	µg/dscm	Total loading µg/dscm
ESP inlet	3/17/2009	Test 1	Impactor	5.25E+02	5.25E+05	
ESP inlet	3/17/2009	Test 1	Cyclone	4.19E+03	4.19E+06	4.72E+06
Scrubber inlet	3/16/2009	Test 2	Impactor	1.25E+01	1.25E+04	1.25E+04
Scrubber inlet	3/17/2009	Test 3	Impactor	9.77E+00	9.77E+03	9.77E+03
Scrubber inlet	3/18/2009	Test 4	Impactor	1.15E+01	1.15E+04	1.15E+04
ESP inlet	3/19/2009	Test 5	Impactor	3.73E+02	3.73E+05	
ESP inlet	3/19/2009	Test 5	Cyclone	4.84E+03	4.84E+06	5.21E+06
Scrubber inlet	3/19/2009	Test 6	Impactor	1.03E+01	1.03E+04	1.03E+04
Scrubber outlet	3/18/2009	Run 1	Dekati Impactor		9109.506	9.11E+03
Scrubber outlet	3/19/2009	Run 2	Dekati Impactor		12560.87	1.26E+04

Particulate Mass Loading as a Function of Size

Sampling at the ESP inlet was conducted using both the multicyclone and the impactor. The cyclones are designed to capture larger-size particles and the impactor collects small particles. **Figure 7** shows the mass size distributions for the cyclone and impactor. The size distribution of the particulate at the ESP inlet is multimodal. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite minerals. The intermediate-sized particles are typically derived from small minerals and organically associated elements. Particles less than a micron in diameter and finer are condensed vapor phase species.

The sample collected on 3/17/09 show a multimodal size distribution, with a mode occurring at one to three microns, and another mode at 0.1 μm. The sample collected on 3/19/09 also has a multimodal distribution, with a shift in the finer mode from 0.1 μm to about 0.5 μm. This shift may be due to the change in fuel composition (the coal sample collected on 3/17/09 had a higher base-to-acid ratio as compared to the coal collected on 3/19/09).

The mass size distribution of the particulate collected upstream of the scrubber is illustrated in **Figure 8**. Sampling was conducted at this location on all four days of the period. The results show a bimodal distribution of particles with a mode between one to two microns and another mode between seven and eleven microns. A general trend of decreasing abundance of the modes during the testing is observed. The change in abundance is likely due to changes in coal ash composition. Coals sampled on 3/16 and 3/17 had higher base-to-acid ratios; coals on 3/18 and 3/19 had lower ratios.

The mass size distribution of the scrubber outlet particulate is illustrated in **Figure 9**. The size distribution shows a main mode at about 0.8 μm and possibly a minor larger mode of 2 μm. The particle size distribution is shifted to finer particles downstream of the scrubber and the smaller particle size mode appears to dominate the size distribution. The samples were collected on 3/18 and 3/19, when the coals fired had lower base-to-acid ratios.

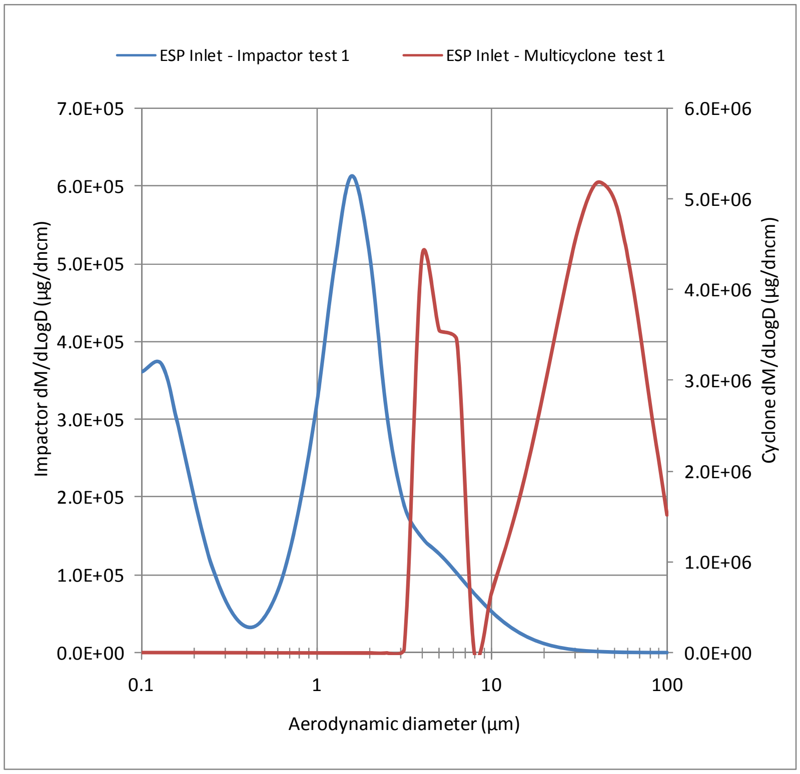


Figure 7a. Multicyclone and impactor data collected at ESP inlet on 3/17/09.

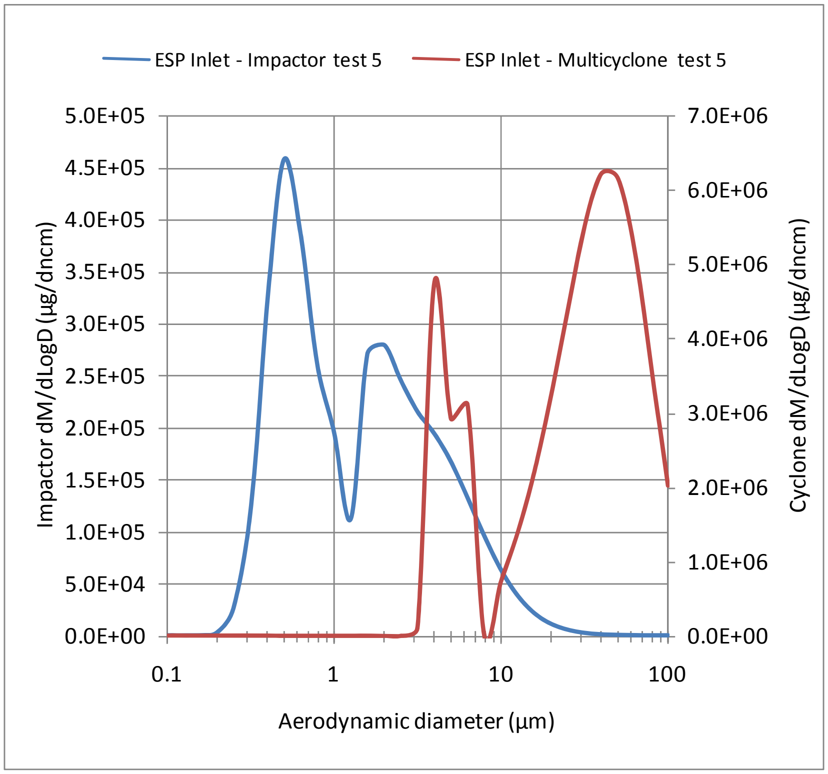


Figure 7b. Multicyclone and impactor data collected at ESP inlet on 3/19/09.

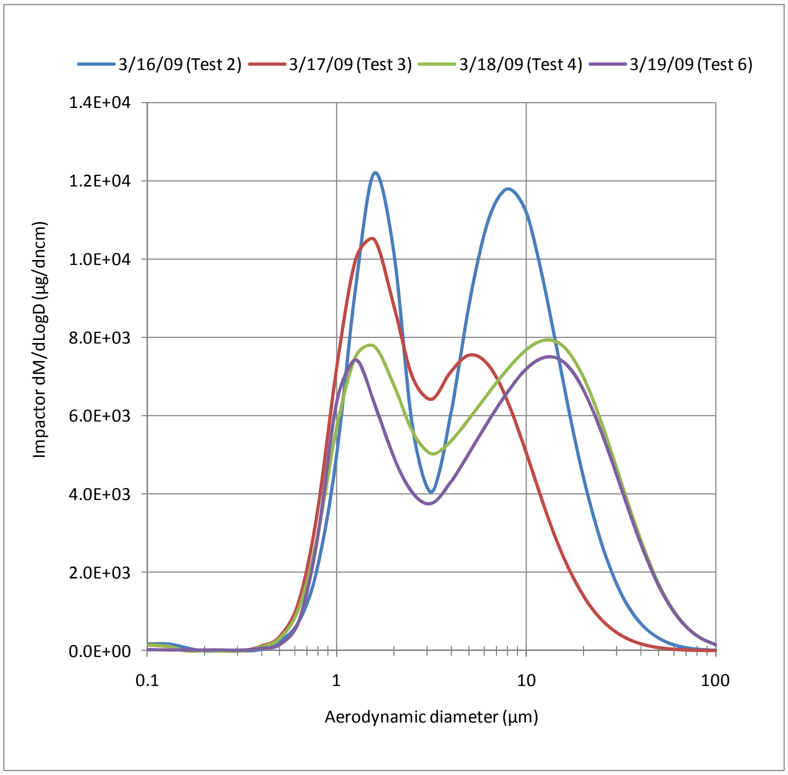


Figure 8. Mass versus size distribution of ash collected downstream of the ESP at the scrubber inlet.

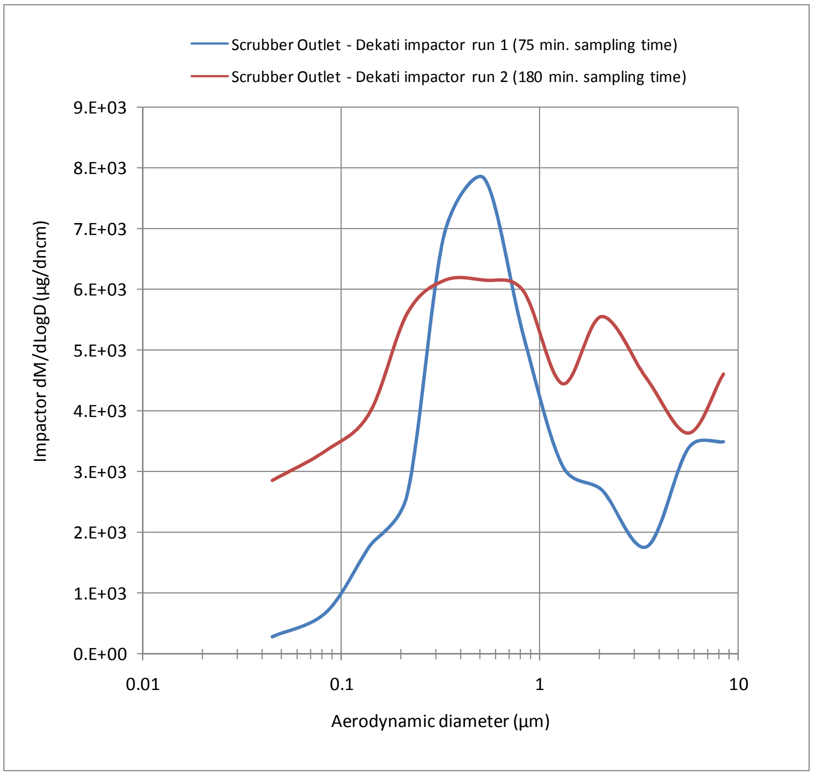


Figure 9. Mass distribution of particulate collected downstream of scrubber.

Particle Number Size Distribution

The number distributions for the particles are shown in **Figures 10** through **12** for the ESP inlet, scrubber inlet, and scrubber outlet. This information is shown as the number of particles per dry normal cubic centimeters (*not* cubic meters ash summarized above). This is the convention used by researchers.

The number of particle increases significantly with decreasing particles size. **Figure 10** shows the number of particles for the scrubber inlet. The ESP inlet sample had the highest number of particles in the smallest size fraction. The number of particles in the smallest size fraction at the scrubber inlet and outlet are similar – the slight increase in number at the scrubber outlet is likely to differences in sampling methods.

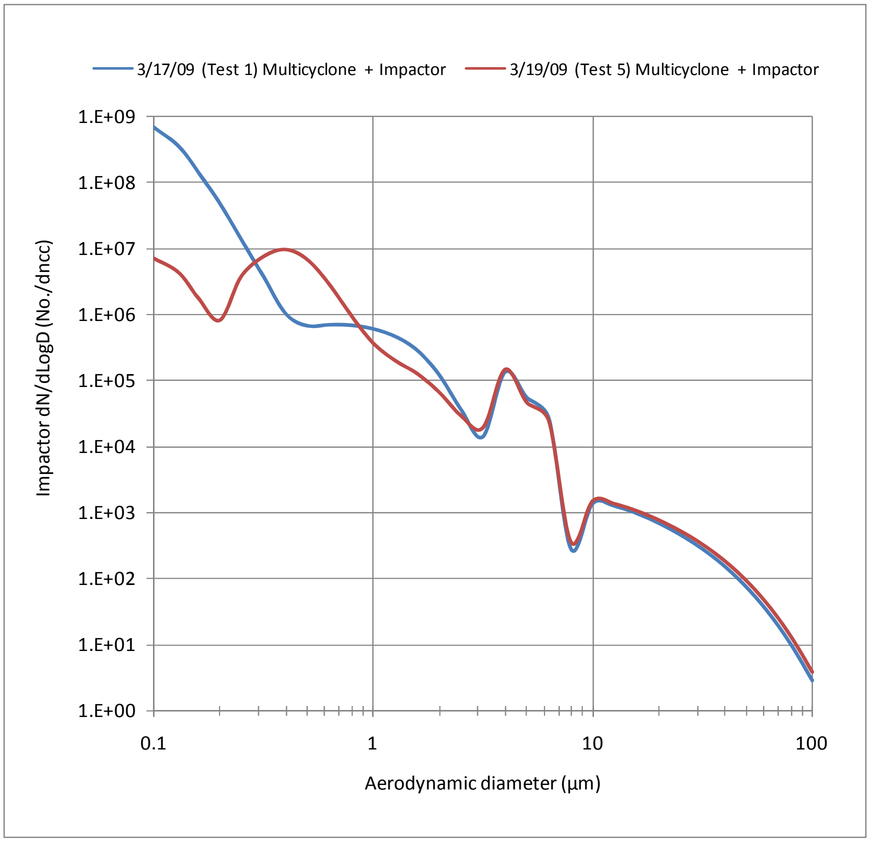


Figure 10. Number of particles as a function of size at the ESP Inlet.

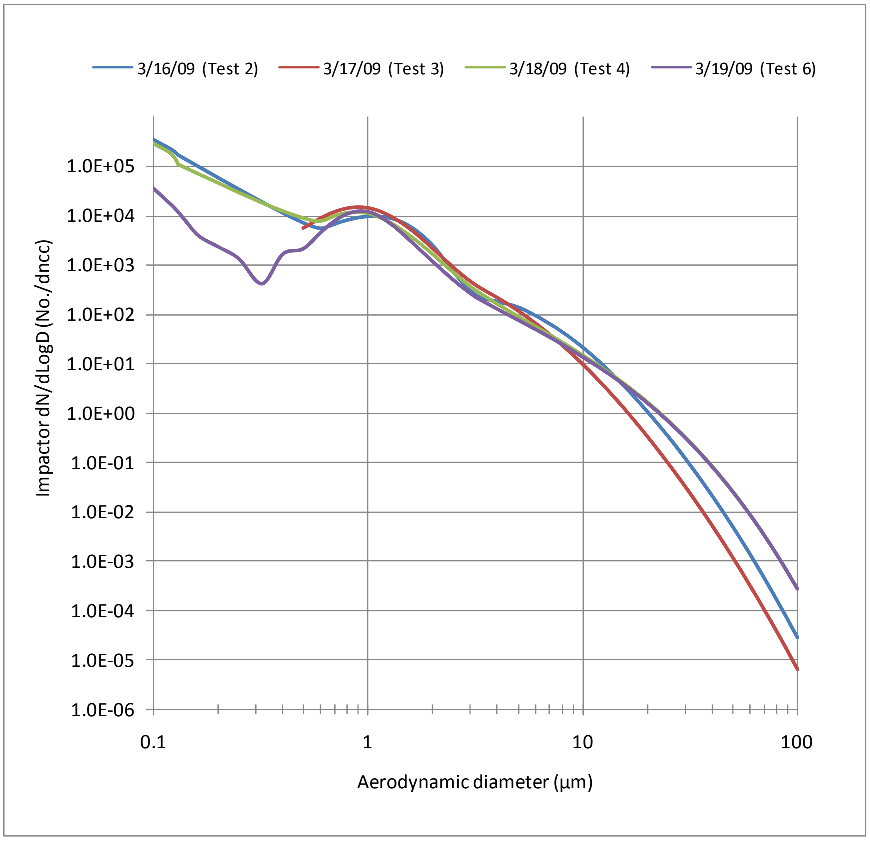


Figure 11. Number of particles as a function of size at the scrubber inlet.

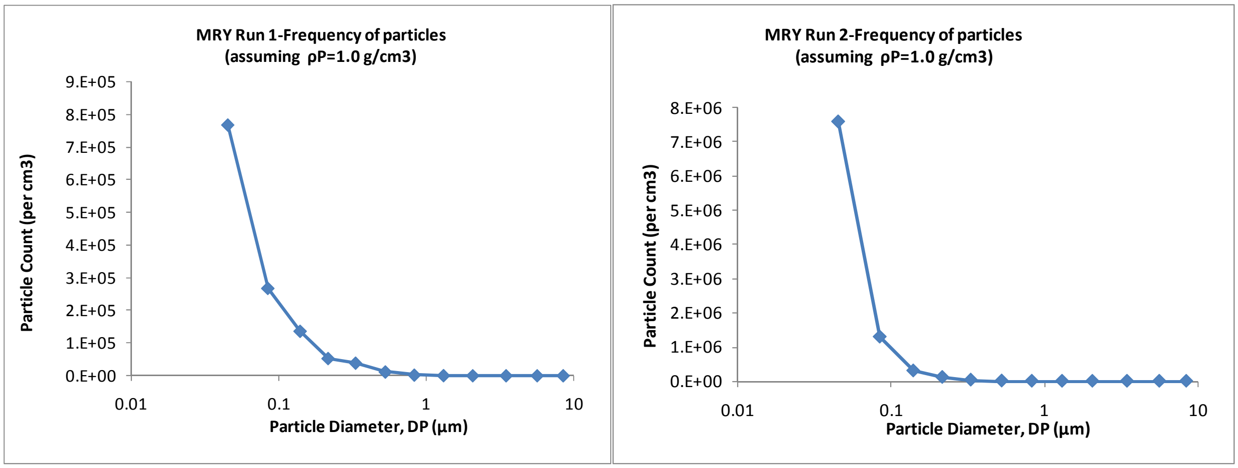


Figure 12. Number of particles as a function of size at the scrubber outlet.

Scanning Mobility Particle Scanning (SMPS)

Number-based concentration data obtained by the SMPS system at the scrubber outlet is shown in **Figures 13** and **14**. The data shown are for the on one good data set obtained during the sampling trip. A summary of the conditions at the sampling site that limited the ability of the SMPS to gain reliable data is listed in the Appendix.

The SMPS reports size data on a nanometer (nm) scale, not a micrometer (µm) scale. There are 1,000 nm in one micron. The data shown was obtained from a 10-sample test run, each 60 seconds apart, and includes two scans per sample: 60 seconds for the up scan and 30 seconds for the down scan. The scan window of the instrument covers a particle range of 16.5–605 nm (0.0165–0.605 µm).

Plots of the concentration versus particle diameter are given in **Figure 13** for number basis and in **Figure 14** for the mass basis. The number of particles observed using the SMPS is larger than that observed for the impactors but it is generally consistent the impactor data.

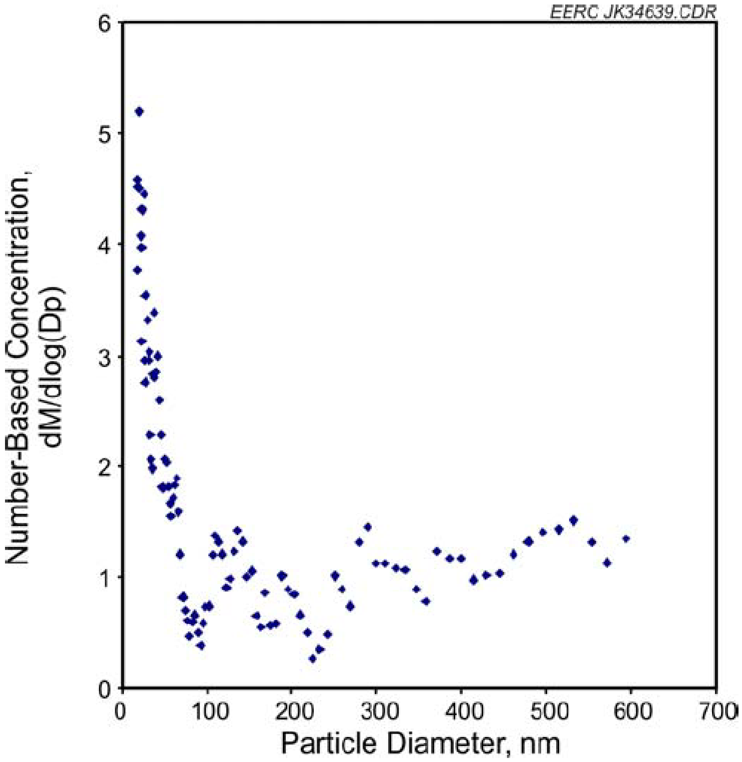


Figure 13. Plot of number-based particle concentration as a function of particle diameter (nanometers).

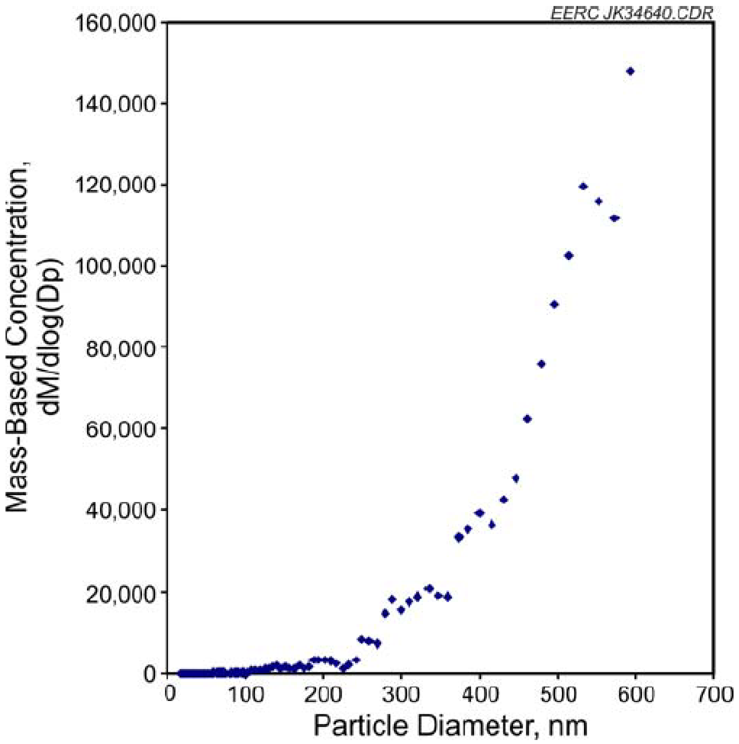


Figure 14. Plot of mass-based particle concentration as a function of particle diameter (nanometers).

Bulk Composition of Ash Materials

The composition of the size fractions of ash materials collected using the multicyclone are summarized for the element of interest specifically the Na, K, Ca, and S. These elements produce very small particles upon combustion. Data is available in the appendix that includes the major elements determined. The trends for the ESP inlet are shown in **Figure 15** for sodium, potassium, calcium and sulfur, and in **Figure 16** for silicon, aluminum, magnesium and iron. The results show concentrating of the elements in the particles that are less than 10 μm in diameter.

Figure 17 shows the trend for the ESP inlet cyclone samples (cyclones 1, 3 and 4) for sodium, potassium, calcium and sulfur and **Figure 18** shows the trends for silicon, aluminum, magnesium and iron for the ESP inlet cyclone samples.

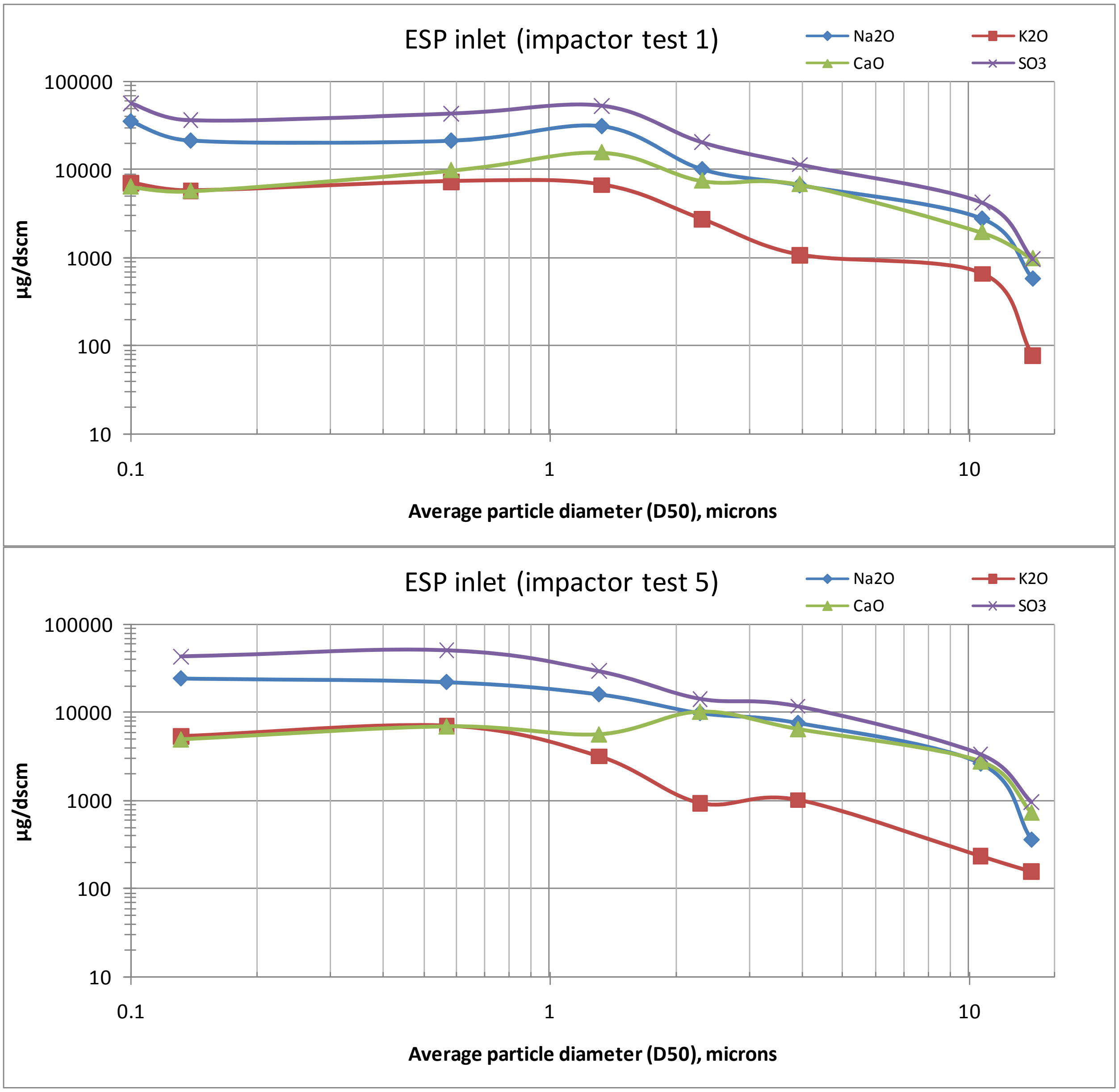
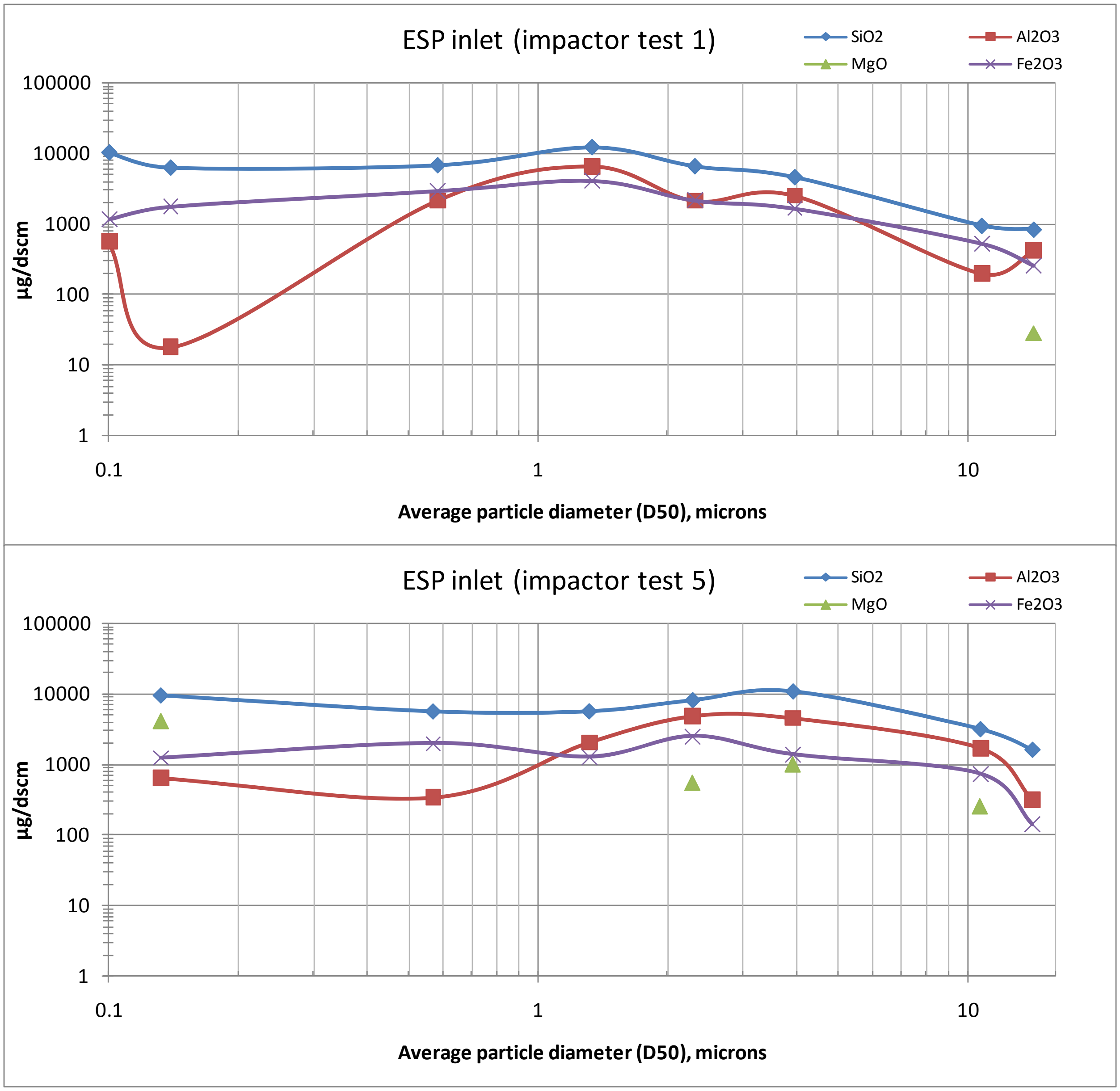


Figure 15. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter for ESP inlet (impactor) samples.


ESP inlet (impactor test 1)

ESP inlet (impactor test 5)

Figure 16. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter for ESP inlet (impactor) samples.

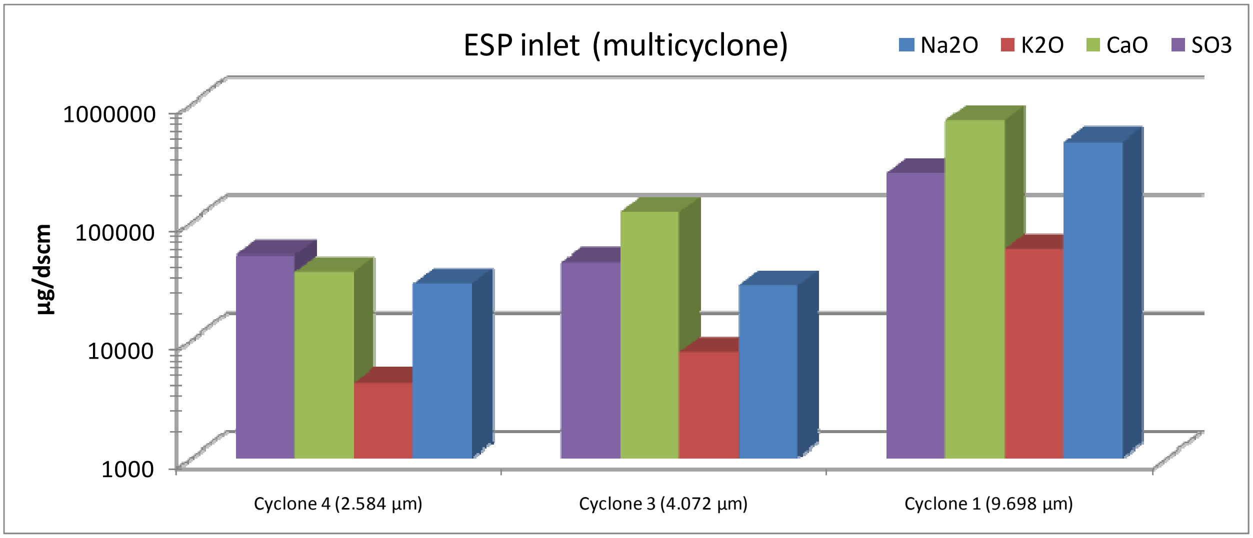


Figure 17. Sodium, potassium, calcium and sulfur concentrations for ESP inlet cyclone samples.

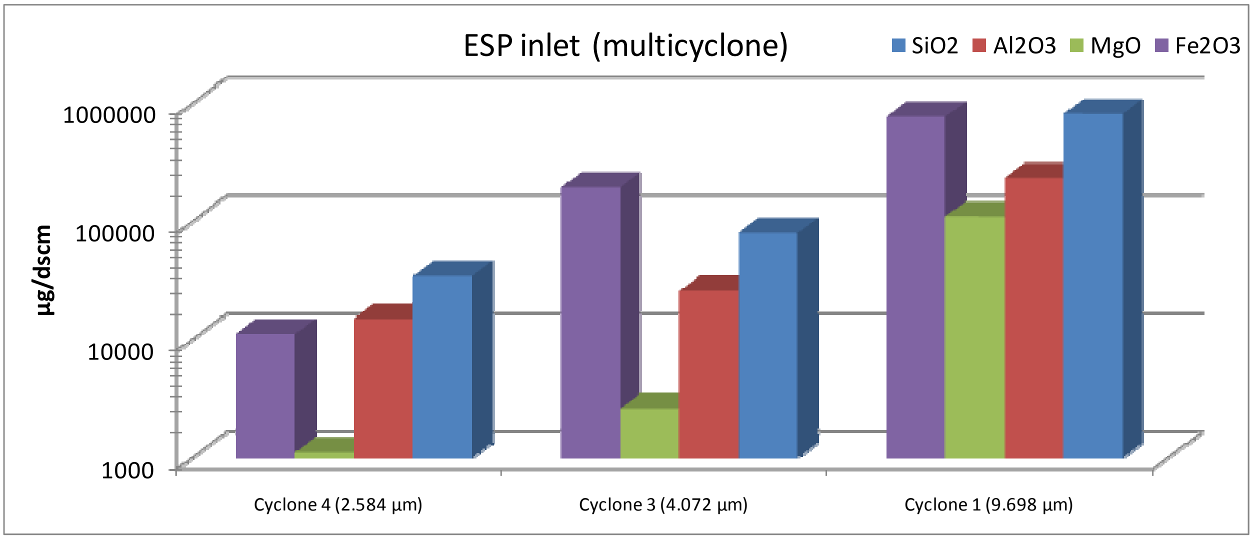
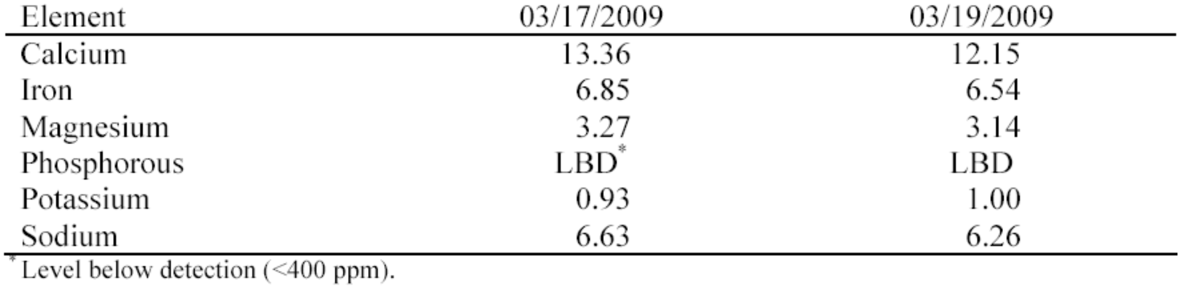


Figure 18. Silicon, aluminum, magnesium and iron concentrations for ESP inlet cyclone samples.

Analysis using digestion and inductively coupled plasma–mass spectrometry was performed to determine the concentrations of selected major elements (Ca, Fe, Mg, P, K, and Na) in the ash collected in the multicyclone stages. Table 9 lists the composition of selected elements based on the total sample collected in the multicyclone. Table 10 displays the fraction of each element, based on the total percent found in Table 9, by each cyclone stage. The largest concentrations of the selected elements were found in the first cyclone stage. The nozzle sample is material collected within the nozzle before the first multicyclone stage. This material is not size-fractionated.

The concentrations of the cyclone ash analyzed with ICP-MS cannot be compared well with the ash analyzed using SEM, as the ICP-MS samples were not analyzed for all major elements (including silicon, aluminum and sulfur).

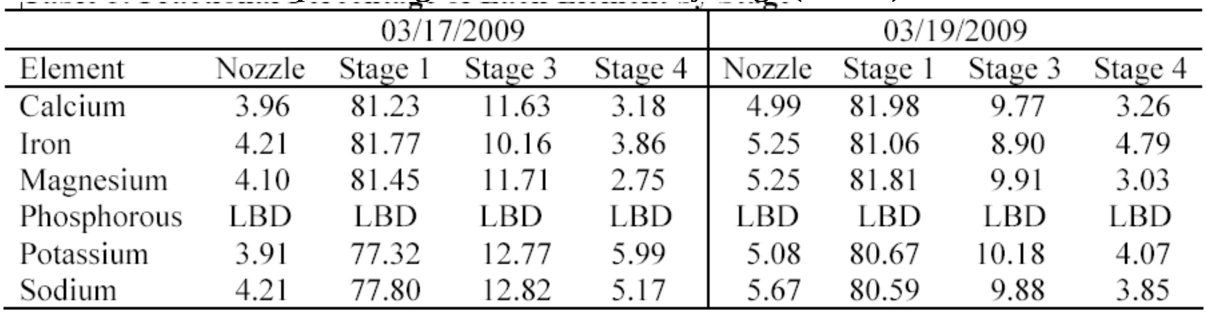
Table 9. Percentage of each element in the total multicyclone sample (EERC).



Element	03/17/2009	03/19/2009
Calcium	13.36	12.15
Iron	6.85	6.54
Magnesium	3.27	3.14
Phosphorous	LBD*	LBD
Potassium	0.93	1.00
Sodium	6.63	6.26

* Level below detection (<400 ppm).

Table 10. Fractional percentage of each element by stage (EERC).



	03/17/2009				03/19/2009			
Element	Nozzle	Stage 1	Stage 3	Stage 4	Nozzle	Stage 1	Stage 3	Stage 4
Calcium	3.96	81.23	11.63	3.18	4.99	81.98	9.77	3.26
Iron	4.21	81.77	10.16	3.86	5.25	81.06	8.90	4.79
Magnesium	4.10	81.45	11.71	2.75	5.25	81.81	9.91	3.03
Phosphorous	LBD	LBD	LBD	LBD	LBD	LBD	LBD	LBD
Potassium	3.91	77.32	12.77	5.99	5.08	80.67	10.18	4.07
Sodium	4.21	77.80	12.82	5.17	5.67	80.59	9.88	3.85

The distribution of sodium, potassium, calcium and sulfur is illustrated in **Figure 19** and the distribution of silicon, aluminum, magnesium and iron is shown in **Figure 20**. The results show higher levels of sodium, potassium and sulfur at the one-micron level. The ESP was effective in removing larger-sized particles as well as some of the 0.1-µm particles. However, in the intermediate one-micron particle range the ESP is not as effective in removing the particles. This is a characteristic of all ESPs.

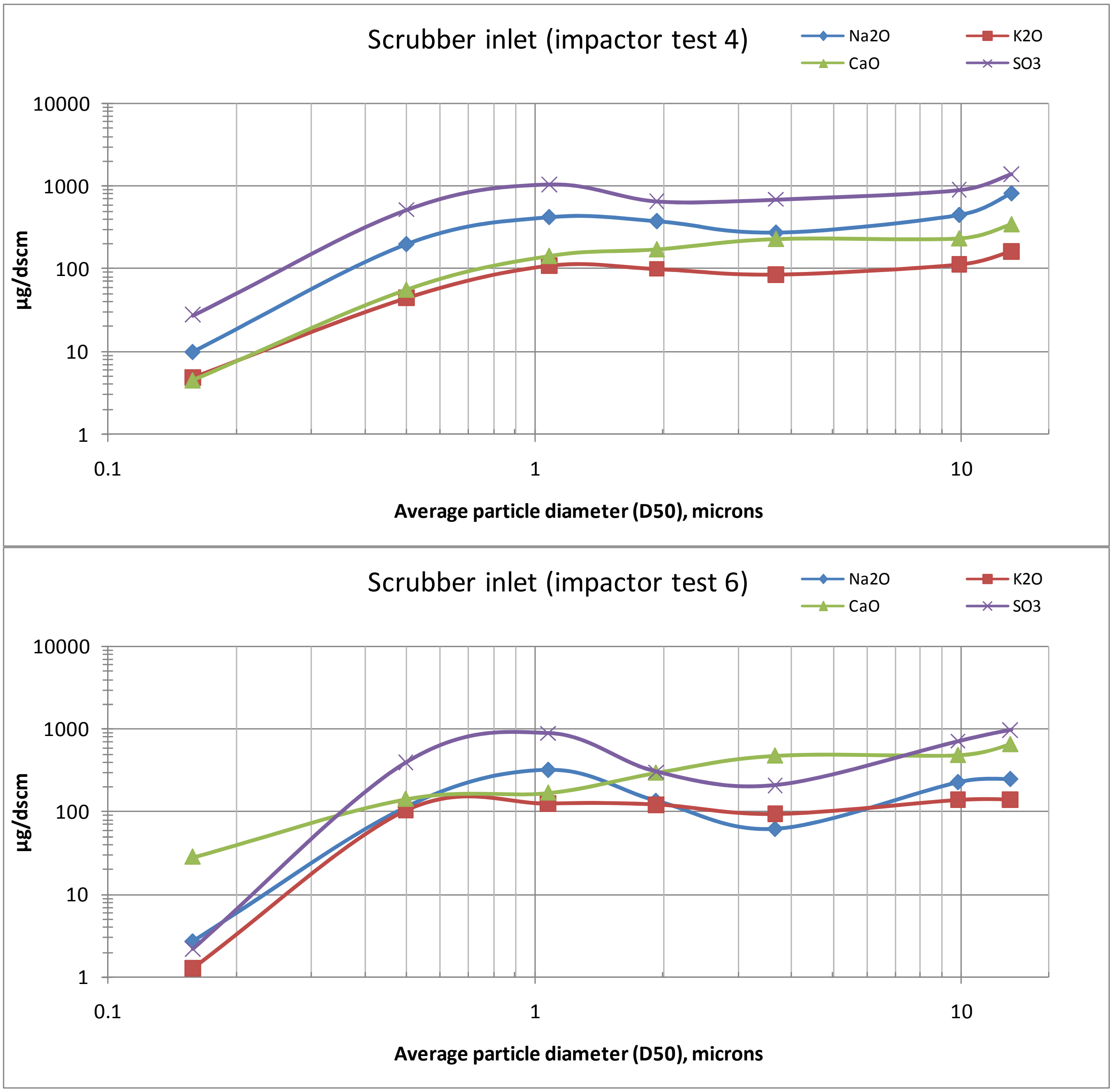


Figure 19. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter in scrubber inlet samples.

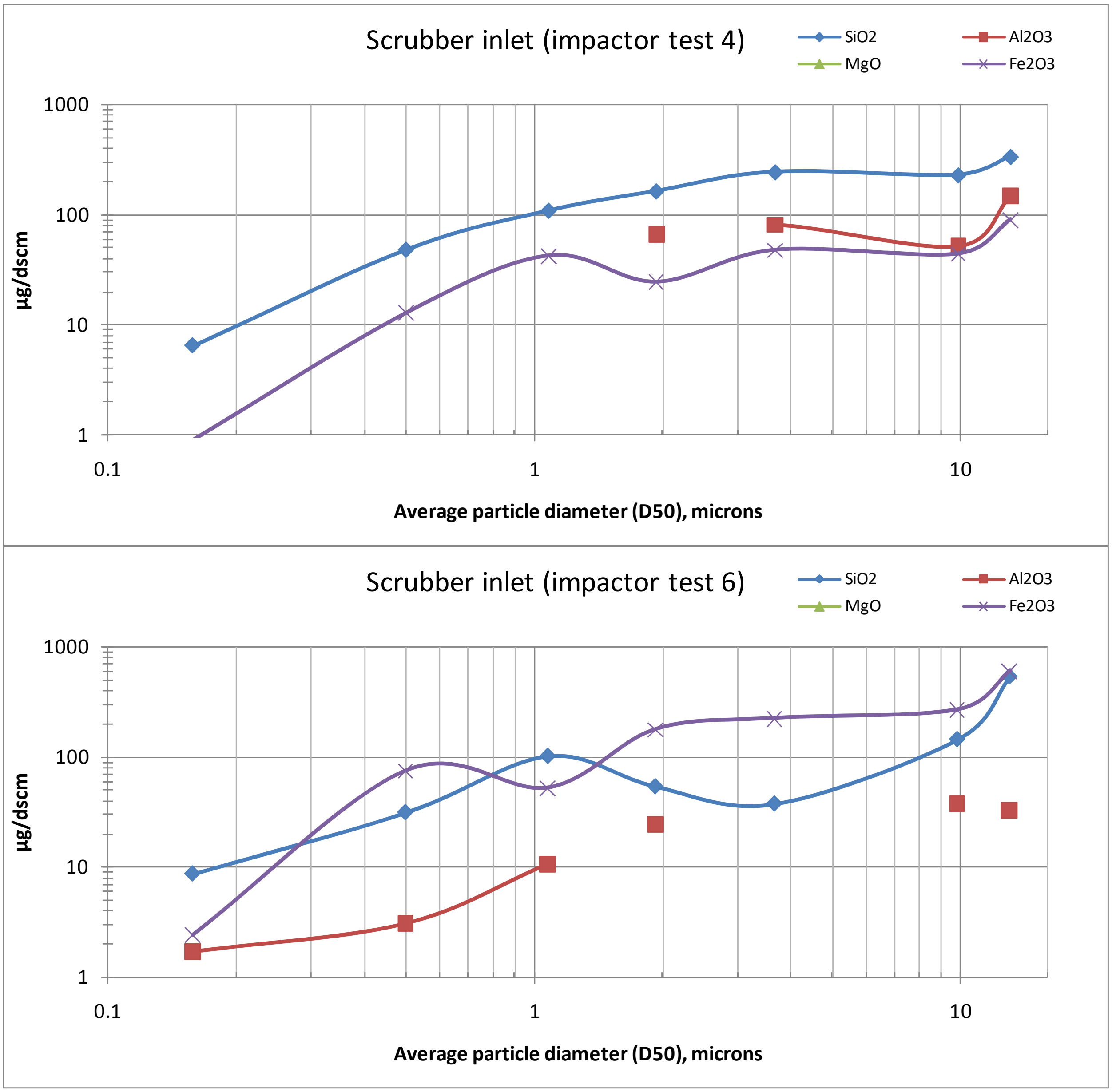


Figure 20. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter in scrubber inlet samples.

The composition size distribution determined for sodium, potassium, calcium and sulfur downstream of the scrubber is illustrated in Figure 21. The results show a significant level of sodium and sulfur in the less than 1 µm size fraction. The DLPI sampling system provides very accurate sizing data in the submicron size range. The results show a maximum for sodium and sulfur at about 0.3 µm.

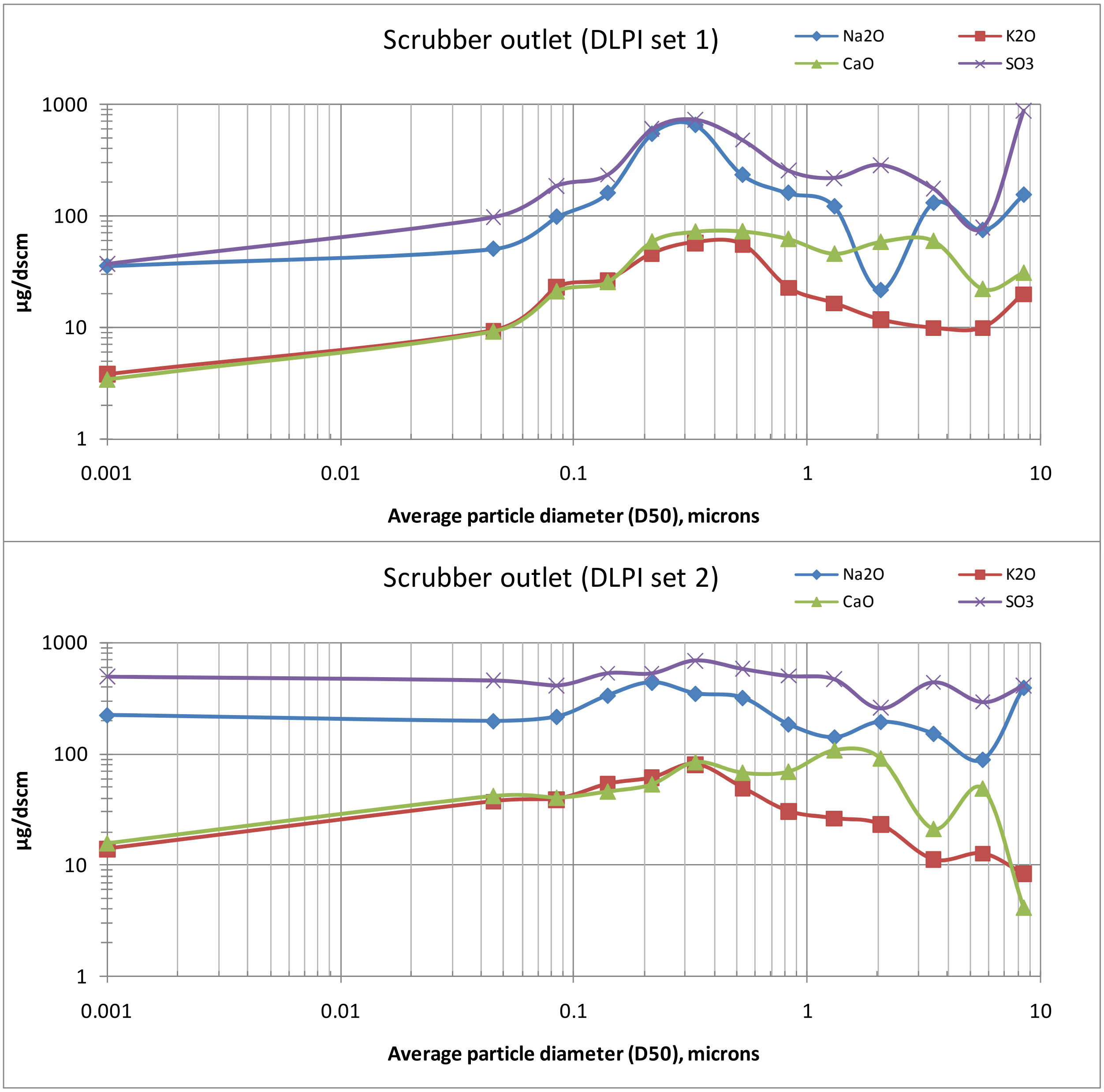


Figure 21. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter in scrubber outlet samples.

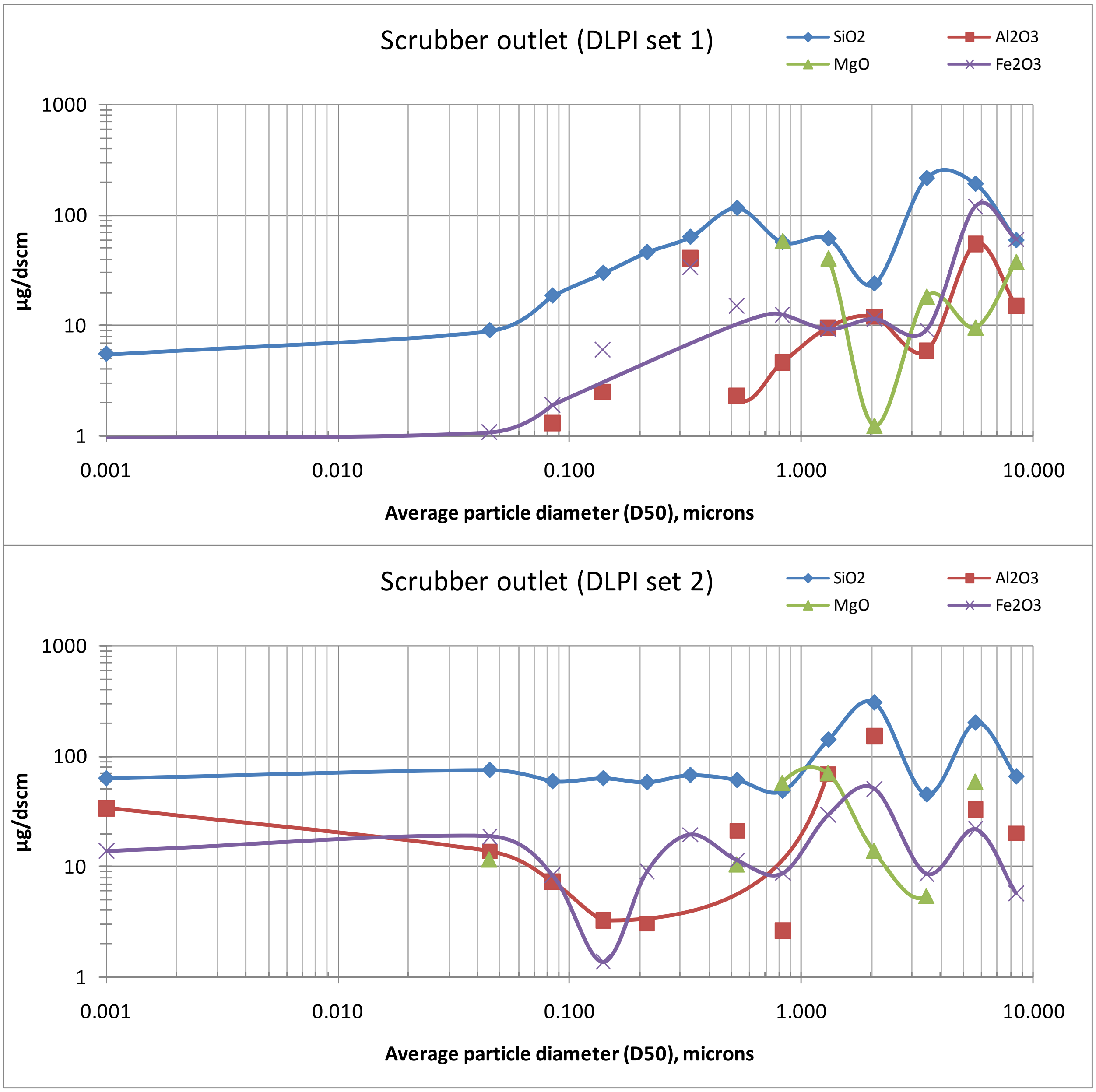


Figure 22. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter in scrubber outlet samples.

Comparison of the mass of the particles in terms of composition is shown in **Figure 23**. The results show that sodium and potassium are reduced across the ESP. However, no reduction of sodium and potassium was observed across the scrubber. This is consistent with other scrubbers operating globally.

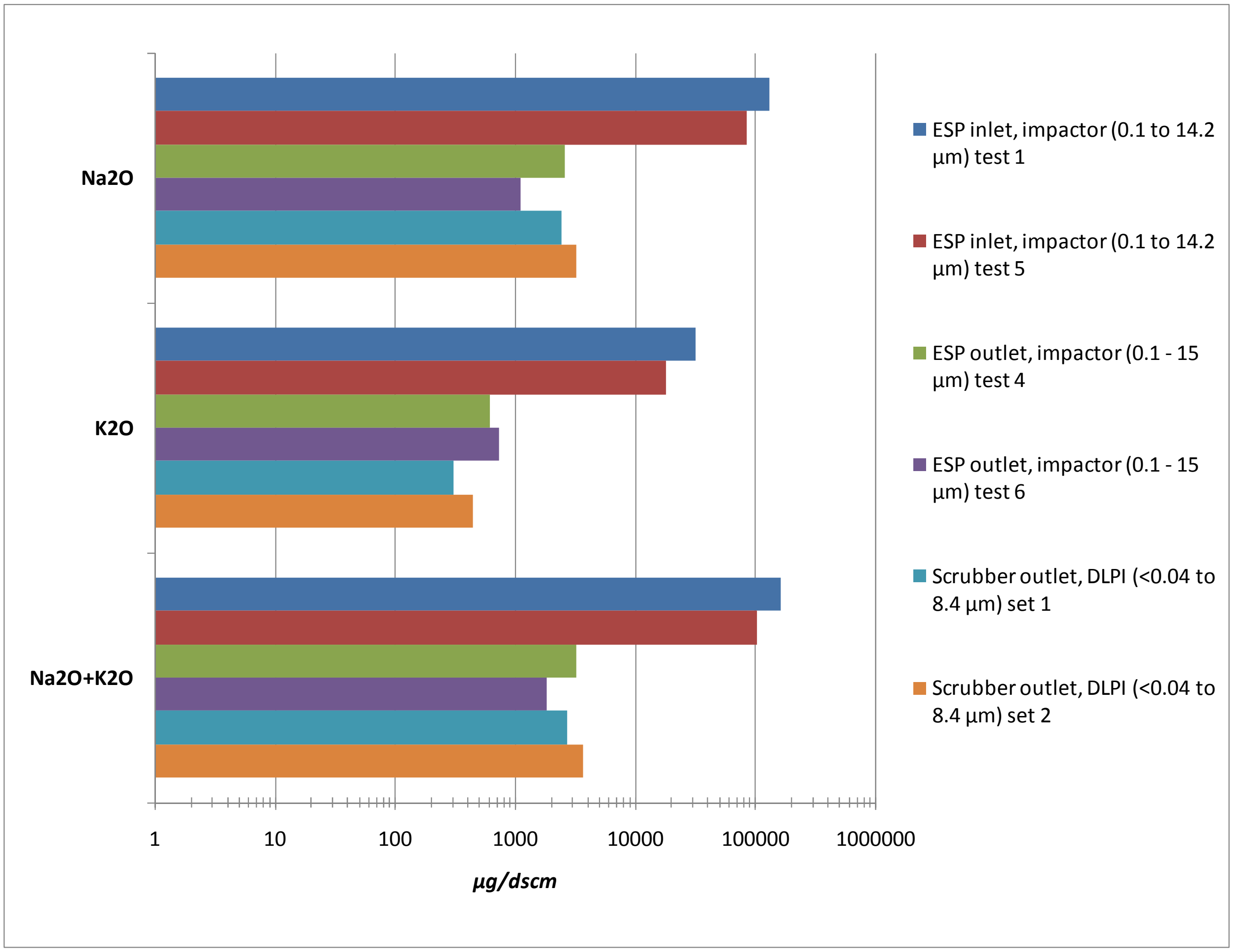


Figure 23. Mass of sodium and potassium oxide in the flue gas upstream and downstream of air pollution control devices at MRY.

SUMMARY AND CONCLUSIONS

Particulate sampling was conducted at Minnkota Power Cooperative's Milton R. Young plant to determine the particulate size and composition distribution of samples collected upstream of the ESP, upstream of the wet scrubber, and downstream of the wet scrubber. Emphasis was placed on determining the fate of sodium, potassium, and calcium since these elements can cause significant plugging and deposition problem.

During the testing, operating conditions of the plant were constant and there was no gas bypass. The coal fired during the testing remained relatively consistent. The as-received ash content ranged from 7.73 to 7.89%. Sodium oxide content of the ash ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing (a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels). Sampling upstream of the ESP and scrubber were conducted using a combination multicylones and impactors. The cyclones collected sized fractions of larger particles (greater than one to five microns) and the impactor collected the sub-micron particulate. Sampling downstream of the scrubber was conducted with a single cyclone followed by a 13-stage advanced impactor. In addition, the submicron particle number concentration was measured using a scanning mobility particle sizer (SMPS).

The results of the particulate mass information indicated a high loading at the ESP inlet of 4.96×10^6 µg/dscm, a scrubber inlet loading of 1.1×10^4 µg/dscm, and a scrubber outlet loading of 1.08×10^4 µg/dscm. These results show very little overall removal of the submicron particulate across the wet scrubber system. A significant fraction of the particulate was removed by the ESP, with a removal efficiency of 99.76%.

The size distribution of the particulate collected upstream of the ESP and upstream of the scrubber was multi-modal as summarized below:

- Upstream of the ESP there were at least three modes – a larger mode at 40 to 50 µm, a second mode at just under 10 µm, and third mode at about 1 µm. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite. The intermediate-sized particles are typically derived from small minerals and organically associated elements. The smaller mode (about one-micron and smaller) contains fine particles and condensed vapor phase species.
- Upstream of the scrubber there were two distinct modes – a larger mode between 8 to 10 µm and another mode centered at about 1 to 2 µm in diameter. The smaller mode is typically condensed vapor phase and small particles.
- Downstream of the scrubber, the primary mode centered at about 0.5 to 0.7 µm, and another possible mode occurred at 3 µm and larger.
- Particle number distributions were as follows:
    - Inlet to the ESP – between 1×10^7 to 10^8 particles per dry normal cubic centimeter (dncc);
    - Inlet to the scrubber is 10^5 particles/dncc;
    - Outlet of the scrubber 7×10^5 particles/dncc.
- Particle number distributions into the nanometer scale (1 µm = 1000 nm) was found to be as high as 10^5 particles/dncc.

Particle composition distributions of the particulate were determined for each of the major elements. The results were reported as µg/dscm of the element as illustrated in the Appendix and in the figures in the text.

- Upstream of the ESP the composition trends for sodium, potassium, calcium and sulfur showed greater concentrations of these elements in the particles that are smaller than 10 µm, with a significant increase in concentration in the flue gas at a particle size of less than 2 µm. There is another increase at 0.1 µm.
- Upstream of the scrubber the compositional trends for sodium, potassium, calcium and sulfur show higher levels at the 1 µm level. The ESP was effective in removing larger-sized particles, as well as some of the 0.1 µm particles. However, in the intermediate 1 µm particles, the ESP is not as effective in removing the particles.
- Downstream of the scrubber the composition size distribution determined for sodium, potassium, calcium and sulfur showed significant levels of sodium and sulfur in size fraction finer than 1 µm. The DLPI sampling system provides very accurate sizing data in the submicron size range. Other elements such as aluminum, silicon and iron show a significant depletion below 1 µm.

Comparison of the characteristics of the particles in terms of mass and composition indicate that, at the time of the testing, the total average mass of the particulate was about 10,800 µg/dscm. The particulate consisted mainly of sodium, potassium, and sulfur. The total quantity of sodium and potassium exiting was between 2000 to 3000 µg/dscm.

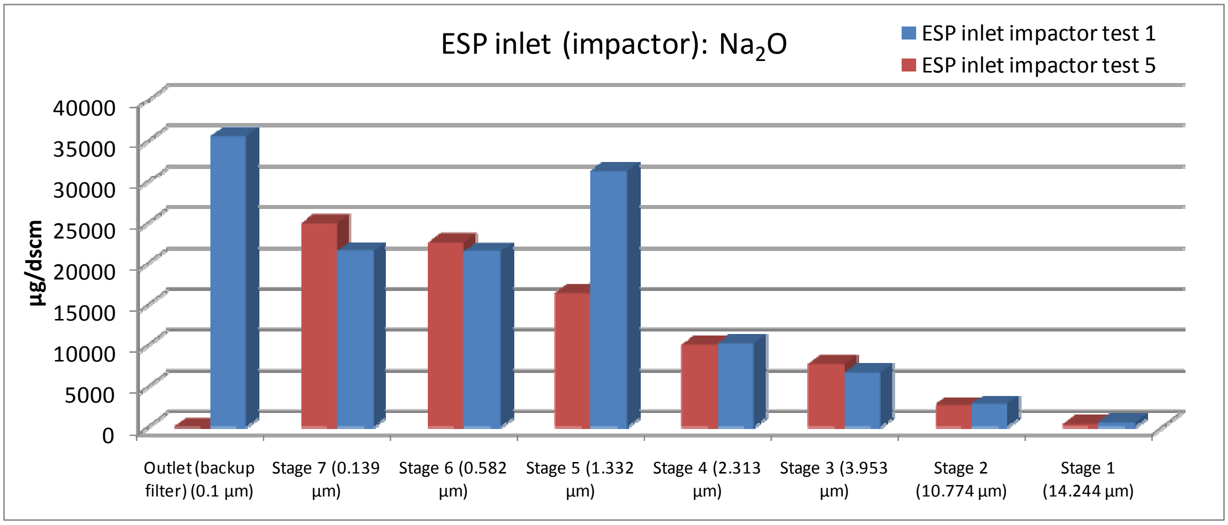


Figure A-1. Sodium concentration by sample stage (average diameter in microns).

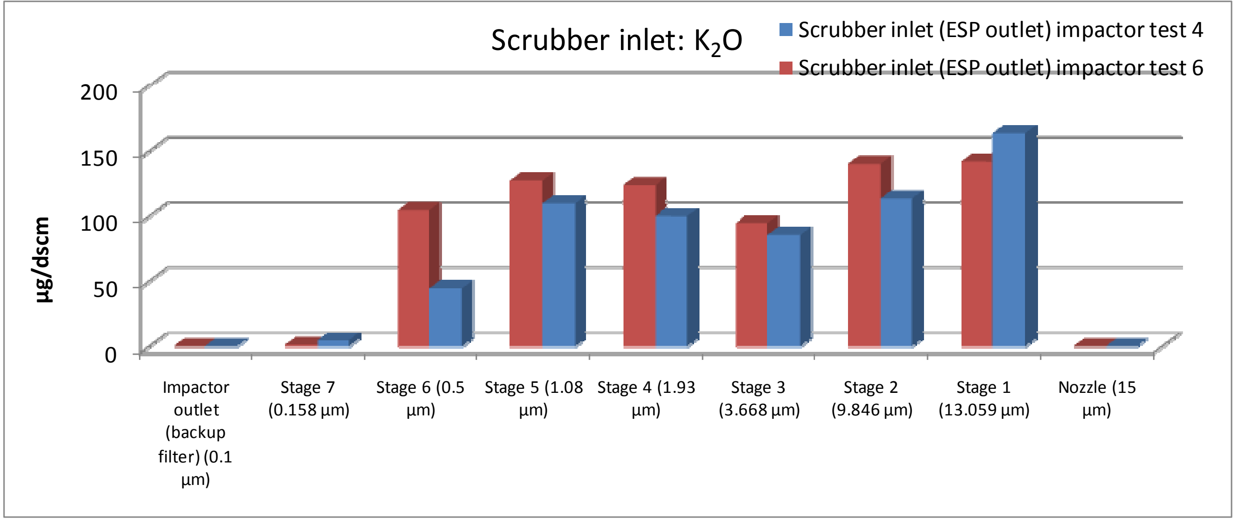


Figure A-2. Potassium concentration by sample stage (average diameter in microns).

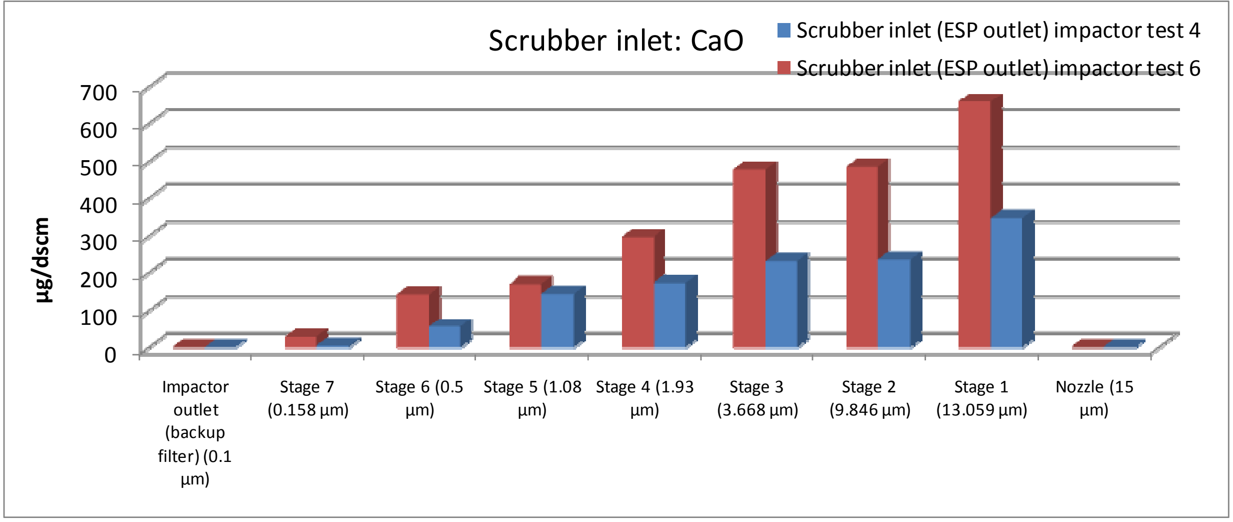


Figure A-3. Calcium concentration by sample stage (average diameter in microns).

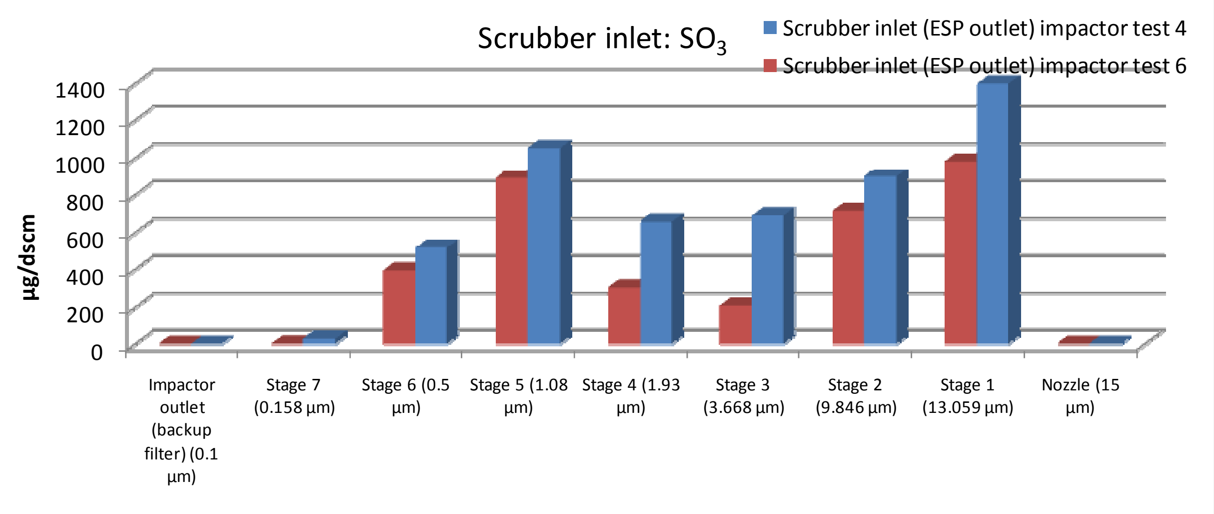


Figure A-4. Sulfur concentration by sample stage (average diameter in microns).

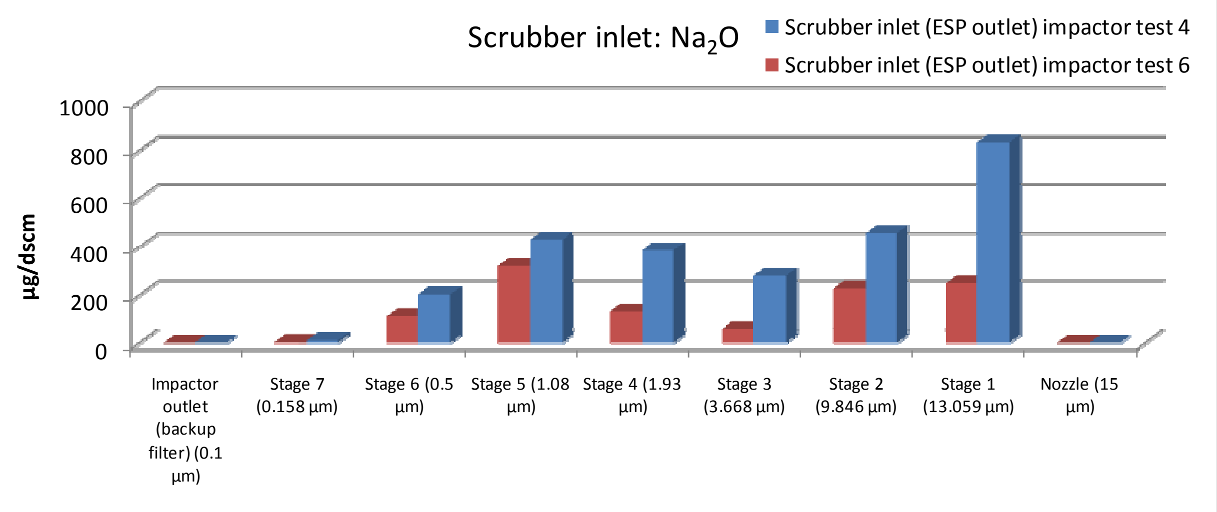


Figure A-5. Sodium concentration by sample stage (average diameter in microns).

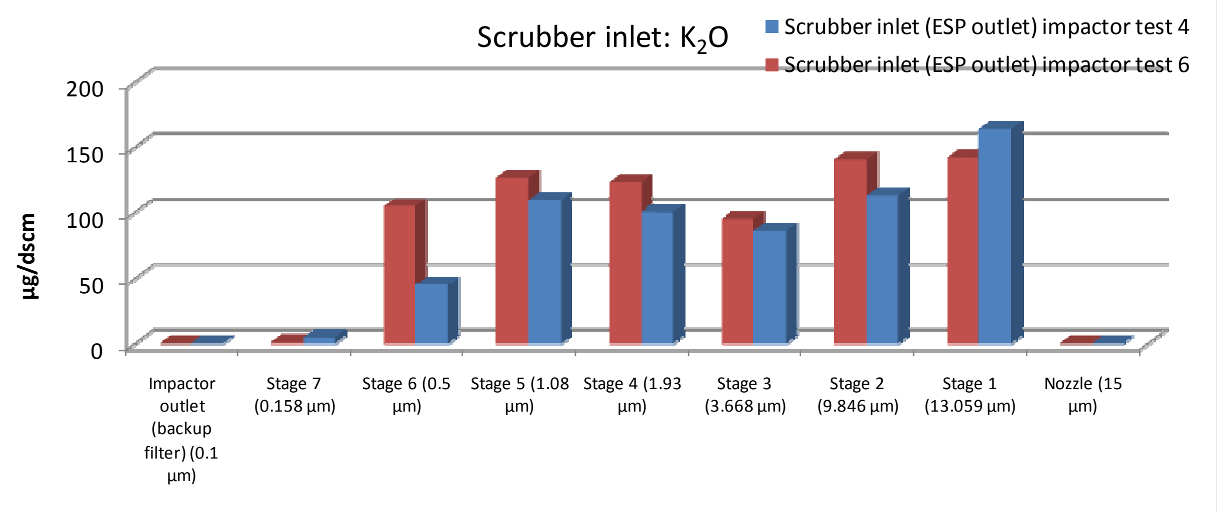


Figure A-6. Potassium concentration by sample stage (average diameter in microns).

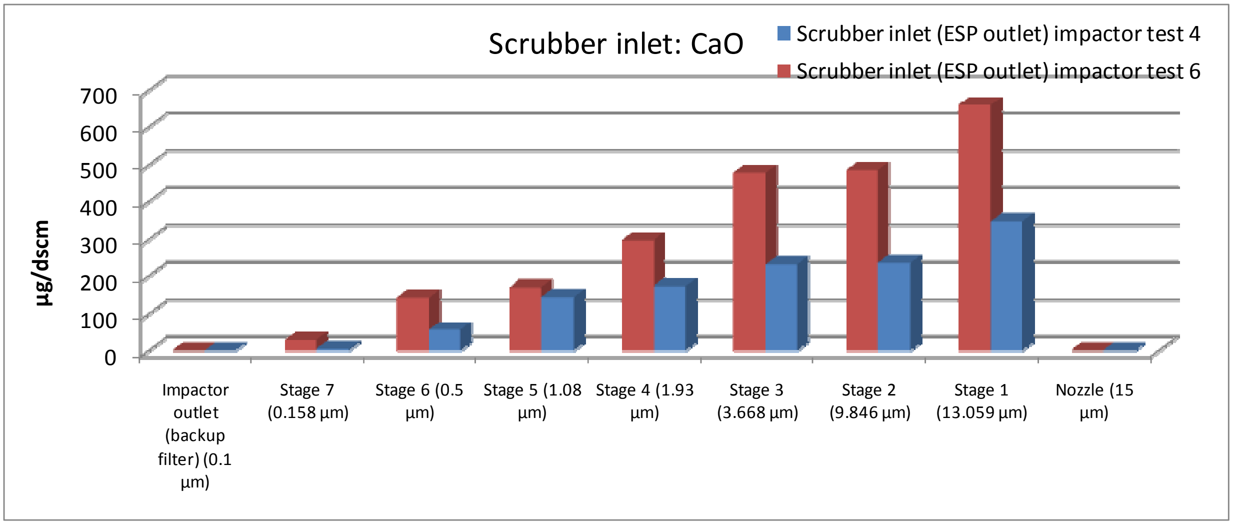


Figure A-7. Calcium concentration by sample stage (average diameter in microns).

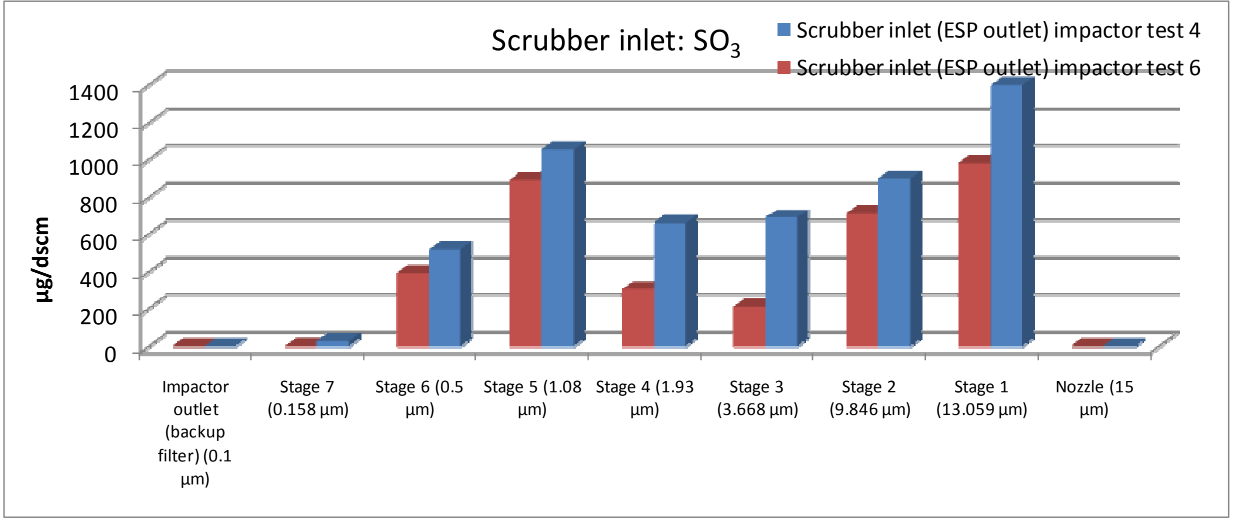


Figure A-8. Sulfur concentration by sample stage (average diameter in microns).

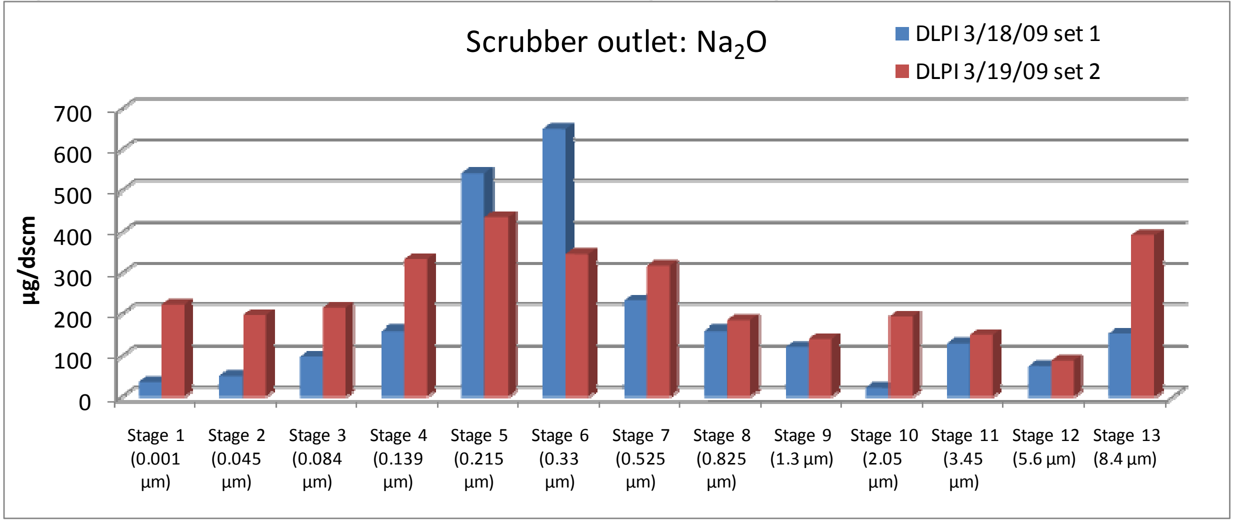


Figure A-9. Sodium concentration by sample stage (average diameter in microns).

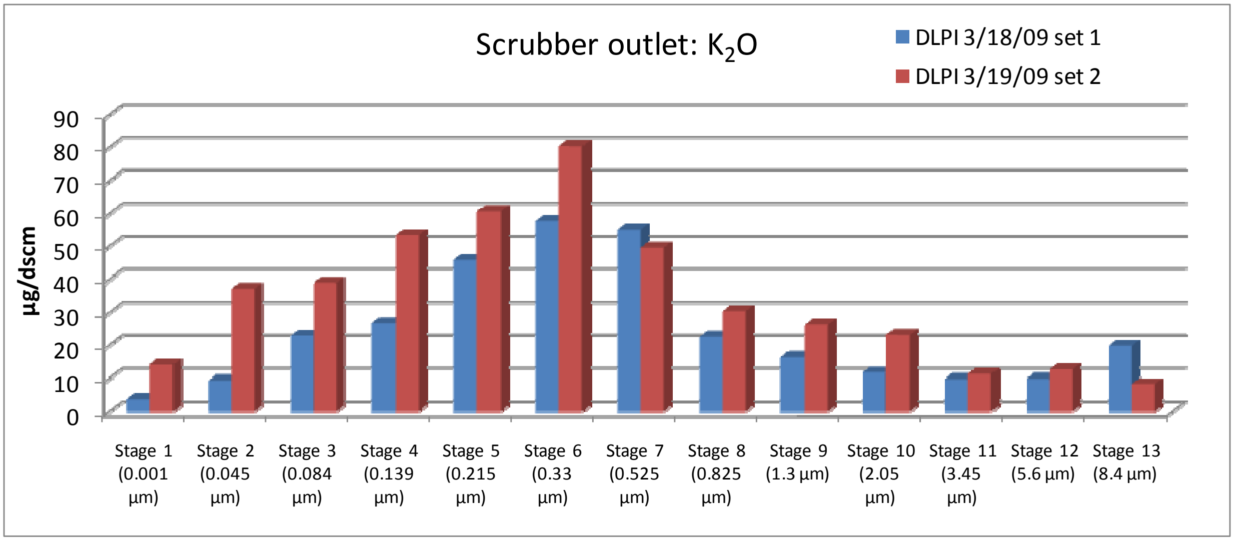


Figure A-10. Potassium concentration by sample stage (average diameter in microns).

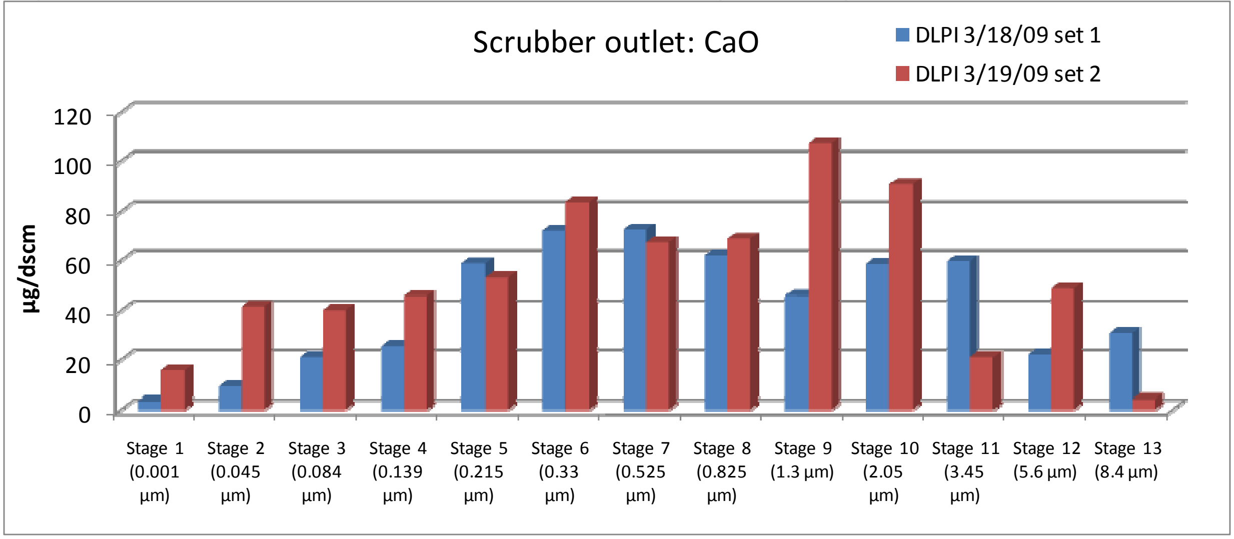


Figure A-11. Calcium concentration by sample stage (average diameter in microns).

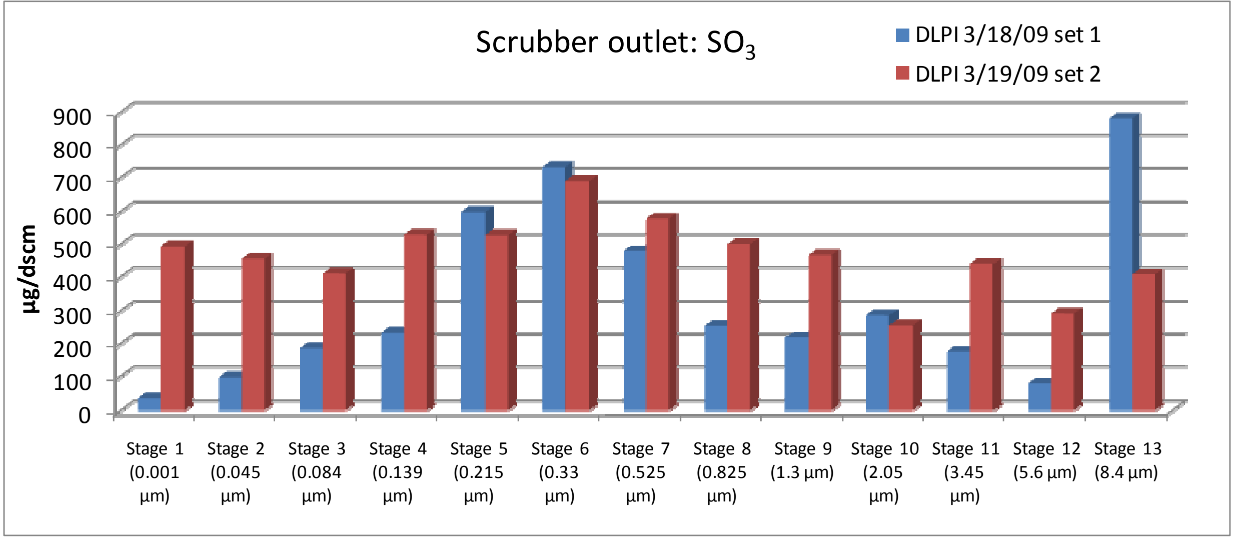


Figure A-12. Sulfur concentration by sample stage (average diameter in microns).

APPENDIX B - SMPS FIELD CONDITIONS AND CHALLENGES

Temperature

The temperature in the field during this test was approximately 24°F. This made it very difficult for the equipment to start and warm up to normal operation conditions, especially the CPC. With the help of a fish tent, carpets, and small blow heaters, the CPC was brought to normal operating temperature. Because of the cold conditions, there was a significant condensation issue in the lines that fed the SMPS system. Although this problem was reasonably resolved for all lines from the probe end to the EC by applying heat/thermal tapes, the lines connecting the EC and CPC also had a buildup of condensed fluid to the extent that they had to be drained at one point to help stabilize the flow via the CPC pump.

Wind

Another challenge faced in the field was the high winds of more than 20 mph. With the scrubber outlet location being about 105 feet above the ground, such windy conditions constantly shook the grid and the equipment; thereby introducing turbulence to the flow through the CPC pump.

Pore Flue Gas Pressure

A more serious problem was the lack of adequate positive pressure from the sampling port to supply enough flue gas through lines into the SMPS system. This resulted in very low counts observed in many data sets. Although the sampling port at the scrubber outlet is at positive pressure, it probably was not high enough to feed enough flue gas through the small nozzle of the sampling probe to the SMPS system.

Milton R. Young Unit 2

MRY Unit 2 is a Babcock & Wilcox (B&W) Carolina-type radiant boiler designed to burn high-moisture, high-slagging/fouling North Dakota lignite. Nominally rated at 3,050,000 lb/hr, this unit is a cyclone-fired, balanced-draft, pump-assisted circulation boiler. The unit began commercial operation in May 1977 and is base-loaded at 470 MW gross. The unit is equipped with a cold-side ESP for particulate control and a wet FGD unit for SO_2 control. The cold-side ESP has a specific collection area (SCA) of 375 ft^2/1000 acfm. The wet FGD for SO_2 control utilizes alkaline ash and lime. The MRY Station fires North Dakota lignite coal from the Kinneman Creek and Hagel Seams at the Center Mine.

Form of Sodium in Center Lignite

Sodium is associated with the organic matrix in Center lignite. That means the sodium is atomically dispersed in the organic matrix. The sodium is associated with a carboxylic acid groups (ion exchange sites). The carboxylic acid groups act as bonding sites for various elements such as Ba, Ca, Mg, and Sr along with minor amounts of K. Figure C-1 illustrates the bonding of sodium to the organic fraction of the coal and the association of other coal impurities.

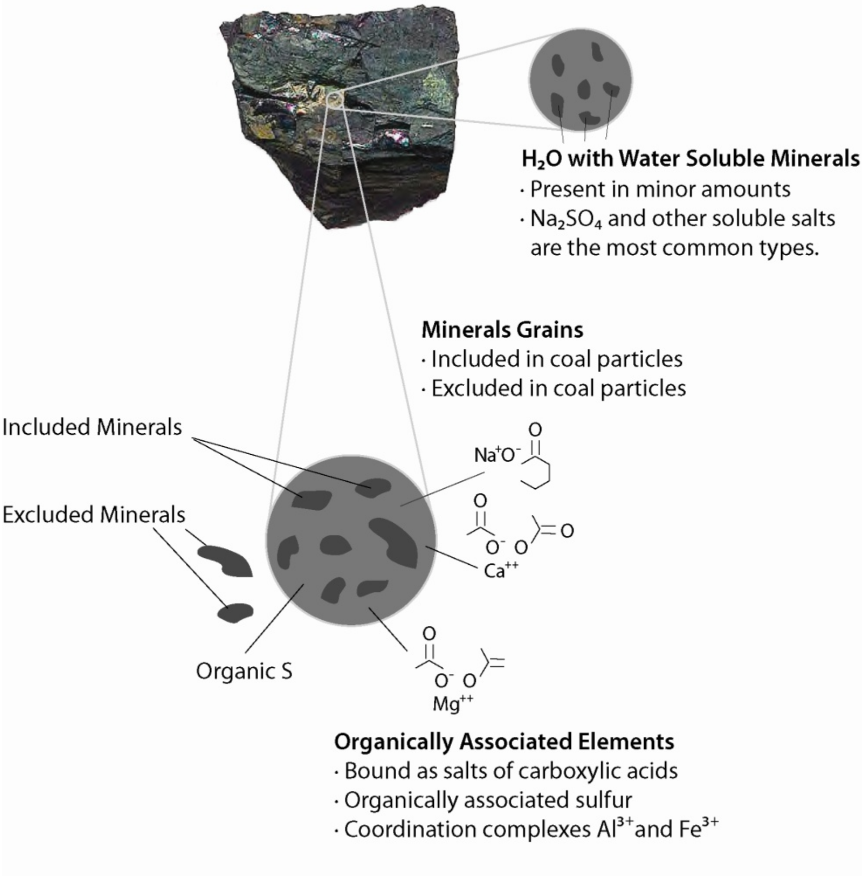


Figure C-1. Form of sodium in coal (Benson and Laumb, 2008).

Vaporization of sodium in PC and cyclone-fired systems

Sodium is a volatile element and will be transformed into a gas upon combustion. The vaporization of sodium during the combustion of lignite is a very well known fact that has been examined by numerous investigators; include work conducted by MIT, CalTech, Sandia National Laboratory, National Energy Technology Laboratory, University of Utah, and others. For example, research conducted by Senior and others (2000) reported that relative to other coals, North Dakota lignite produced more vaporized ash. The actual amount vaporized for ND lignite is double the level vaporized as compared to subbituminous and lignite coals from Montana as illustrated in Figure C-2. Work conducted at the MRY plant related to the vaporization of sodium from a cyclone fired systems is illustrated in Figure C-3. The results show over two thirds of the sodium is not retained in the slag and is vaporized.

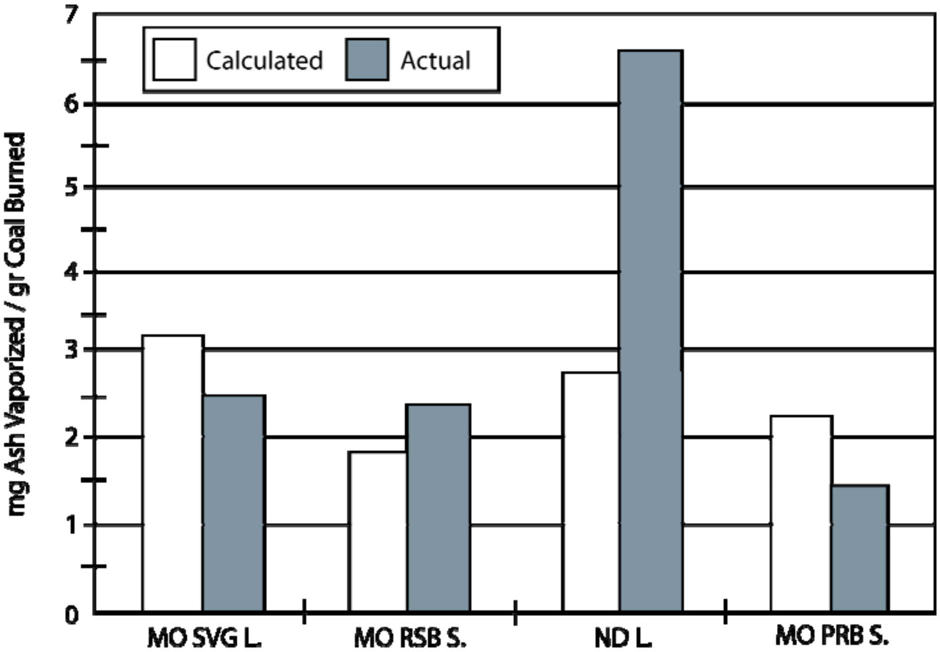


Figure C-2. Ash vaporized during combustion of lignite and subbituminous coals (Senior and others, 2000).

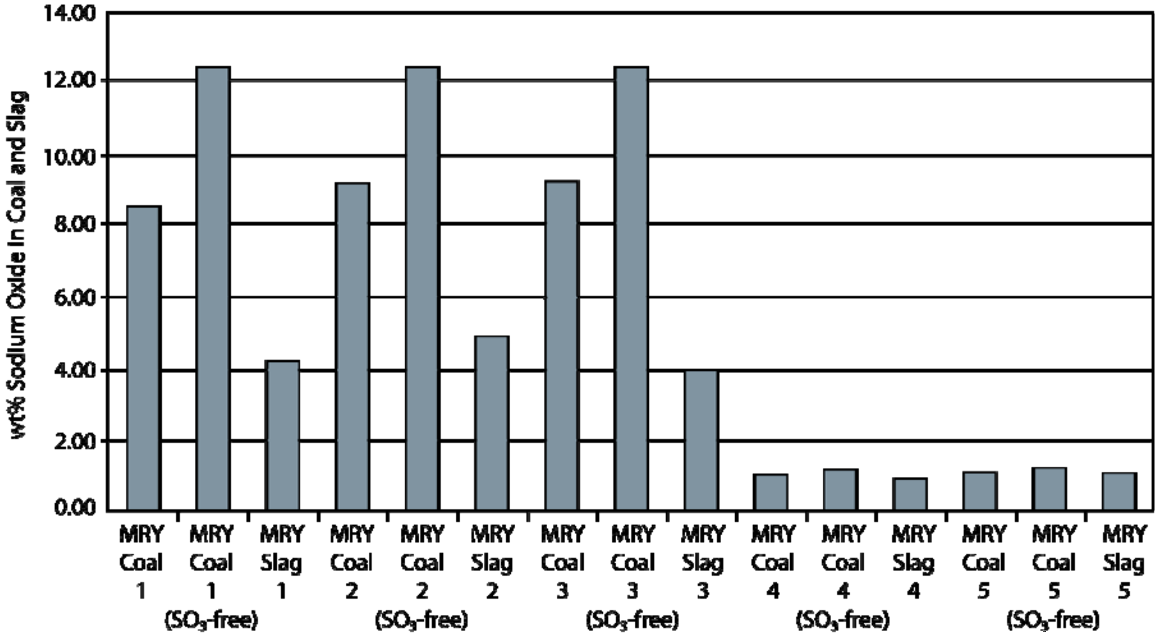


Figure C-3. Comparison of sodium levels in Center lignite coal and slag samples.

Condensation of vaporized species to form aerosols

EPA has evaluated the literature on particle formation during combustion and from other sources and incorporated it into an educational module that can be found on the following website (http://www.epa.gov/apti/bces/module3/formation/formate.htm). The classification of particle types shown by EPA is illustrated in Figure C-4. The EPA classification is consistent with the review conducted by Lighty and others (2000). Vaporized species can condense heterogeneously on surface of other entrained coarse ash particle and can condense homogeneously to form the fine and ultrafine particles. The distribution of particles depicted in Figure C-4 is shown on a frequency percent of particles by mass basis. The particle number versus size is also important and a comparison of the number of particles and particle size is summarized in Table C-1. The number of aerosol particles is significant. These particles have high surface areas and are very reactive.

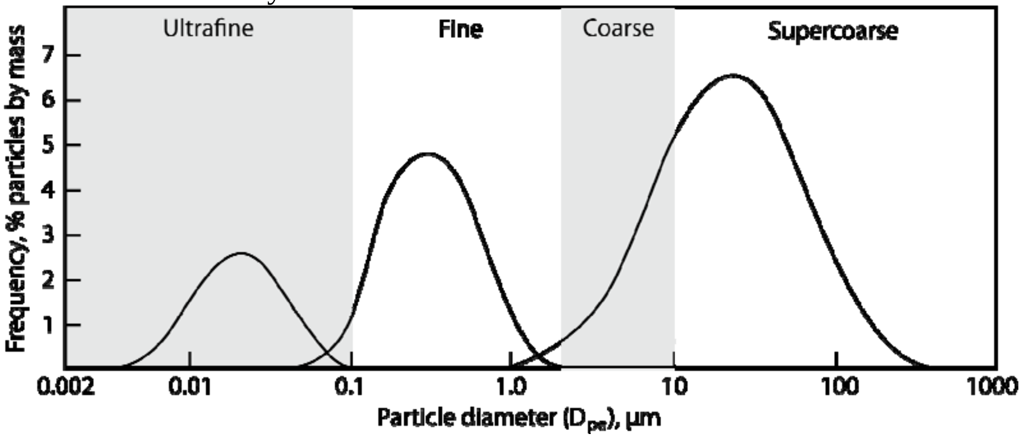


Figure C-4. Particle size categories used to classify particles (http://www.epa.gov/apti/bces/module3/category/category.htm)

Table C-1. Particle size, number of particles, and surface area[1] (http://www.epa.gov/apti/bces/module3/category/category.htm)

Total Mass	Diameter of Particles (µm)	Number of Particles (Approx. In millions)	Total Surface Area (cm²)	(m²)
1.0 gm	1,000	0.002	60	0.006
	100	2	600	0.06
	10	2,000	6 000	0.6
	1	2,000,000	60,000	6
	0.1	2,000,000,000	600,000	60

(1) Based on density of 1.0 gm/cm³

Figure C-5 provides a comparison of the mass distribution and particle number distribution. As the particle size decreases the number of particles in the size fraction increases. In addition, as illustrated in Table C-1, the surface area increases significantly with decreasing particle resulting in the opportunity for reactive gases such as sulfur oxides to react forming sticky phases that bond particles together.

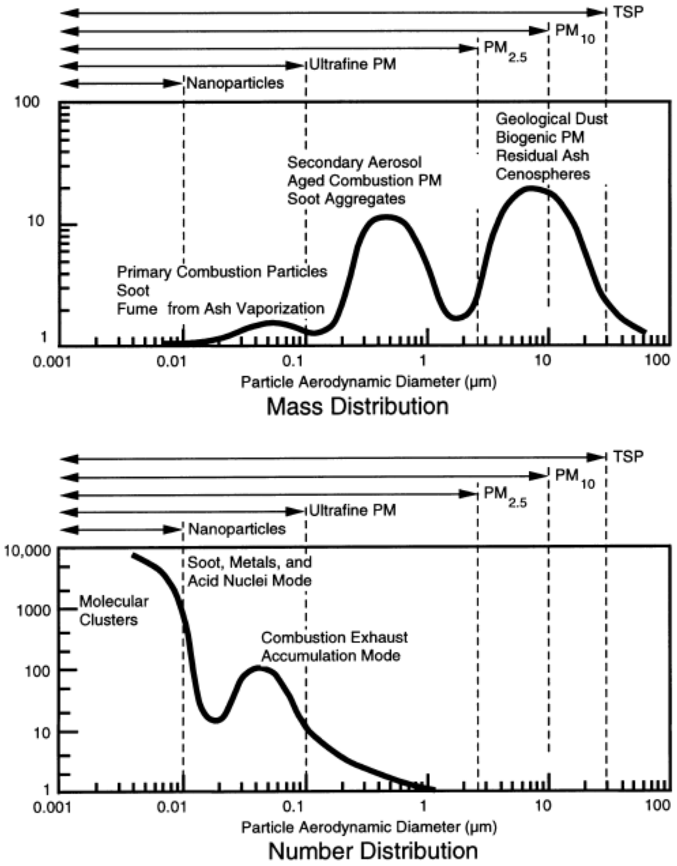
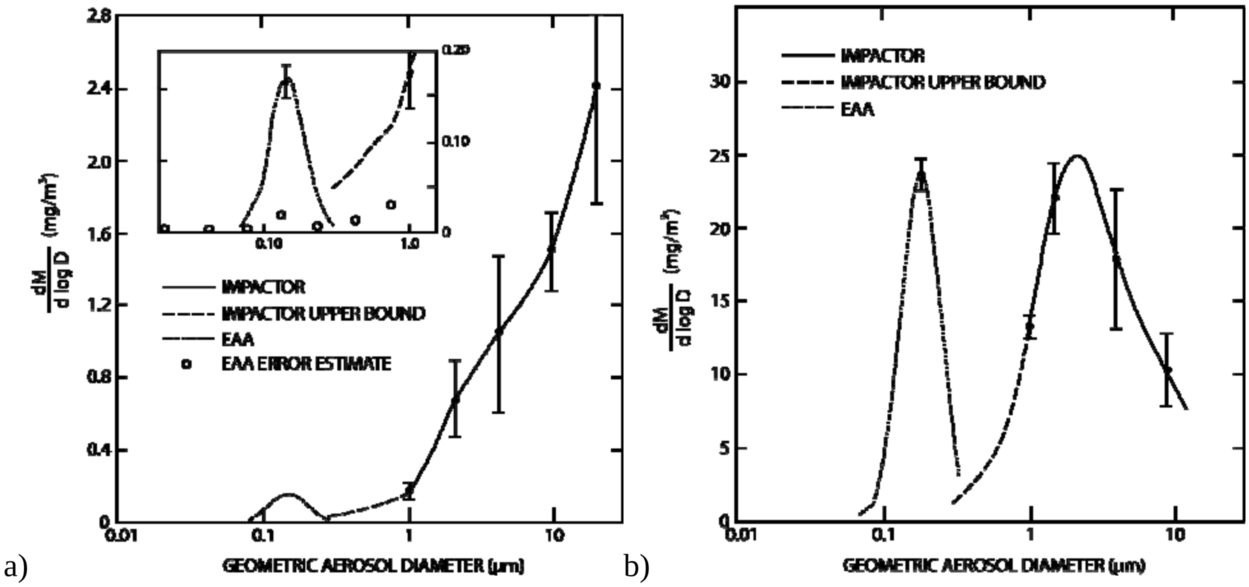


Figure C-5. Comparison of mass distribution and particle number distribution for combustion derived particles and aerosols (Lighty and others, 2000).

Particle size distributions for fly ash collected upstream and downstream of an ESP are illustrated in Figure C-6. This work was conducted by Markowski and others (2000) specifically aimed at characterizing the submicron aerosol mode of fly ash formation.



a) b)

Figure C-6. Typical differential mass distributions of particulate collected a) upstream and b) downstream of an ESP (Markowski and others, 2000).

Fly ash produced upon the combustion of high sodium lignites in a pulverized coal (PC) fired system shows significant enrichment of sodium in the smaller size fractions as shown in Figure C-7. This figure illustrates the increase in the sodium content in the finer size fractions of ash as a result of firing high sodium lignite. The sodium and sulfur content of the less that 3 micrometer size fraction of the sampling train approached 20% Na_2O, and 25% SO_3. The form of the sodium is likely sodium oxide and sulfate.

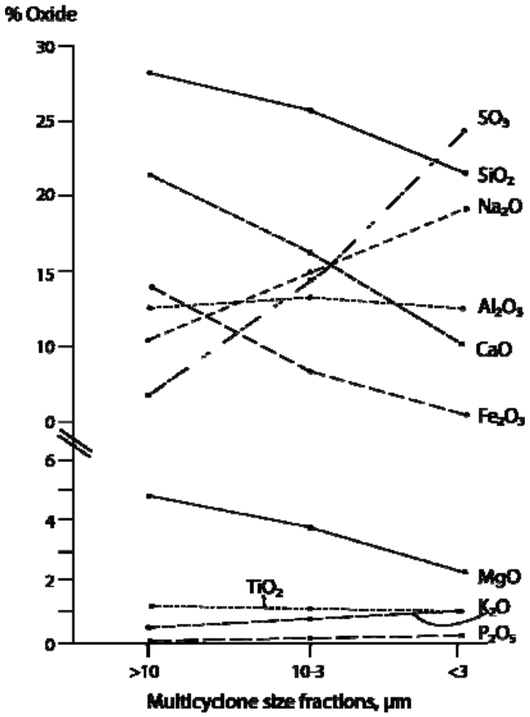


Figure C-7. Composition distribution of ash particles during combustion of North Dakota Lignite (Benson and others, 1984).

Electrostatic precipitator collection efficiency

The classical curve for ESP particle collection efficiency is shown in Figure C-8. This curve is typical of well behaved ash materials that do not present significant problems in collection. The collection efficiency is very good for particles greater than 5 to 10µm and the collection efficiency decreases with decreasing particles size with minimum collection efficiency between 0.2 to 2 µm in diameter. The collection efficiencies vary significantly because of particle size and composition.

Low collection efficiency for difficult to collect particles is between 0.1 to 1 µm in particle diameter. Figure C-9 provides an illustration of the range of collection efficiencies. Based on EPA education modules, no air pollution control device shows high collection efficiency in this range (0.1 to 1.0 µm) due to inherent limitations of the collection devices and particle characteristics (http://www.epa.gov/apti/bces/module3/collect/collect.htm). The following mechanisms of particle capture are impacted by the size of the particles:

- Inertial impaction and interception
- Brownian diffusion
- Gravitational settling
- Electrostatic attraction
- Thermophoresis
- Diffusiophoresis

The EPA (http://www.epa.gov/apti/bces/module3/collect/collect.htm) has indicated that based on a number of studies of actual "*sources stationary sources generating high* *concentrations of particles in the 0.1 to 0.5 micrometer range may be an especially challenging control problem. … The gap is most noticeable in wet scrubbers and electrostatic precipitators.*" A generalized plot showing the range of collection efficiencies is shown in Figure C-9. Overlaid on the diagram is the mass size distribution of particles collected downstream of the ESP wet FGD at the MRY plant (Markowski and others, 1983). This shows that ash produced in the MRY plant have a particle size that can pass through the scrubber and that these particles are rich in sodium as shown in Figure C-7.

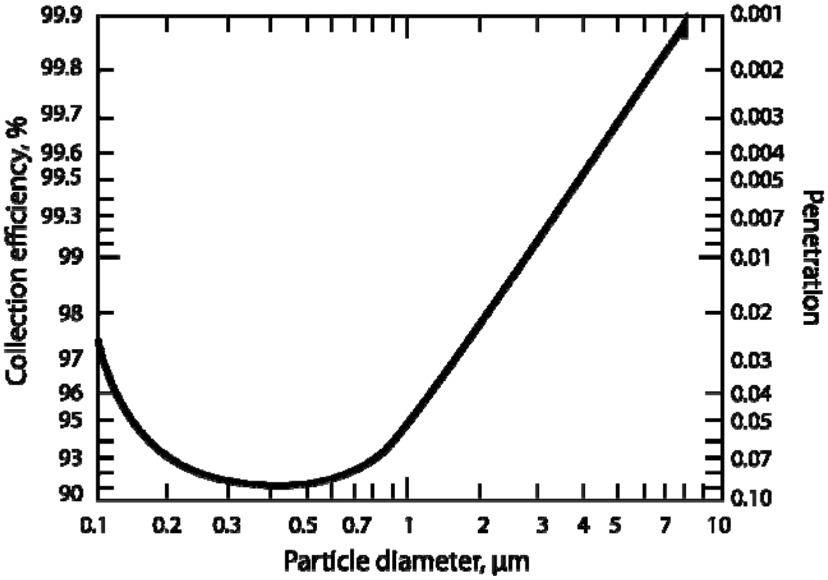


Figure C-8. Typical ESP Collection efficiency curve for removal of particulate from gas streams (http://www.epa.gov/apti/bces/module3/collect/collect.htm).

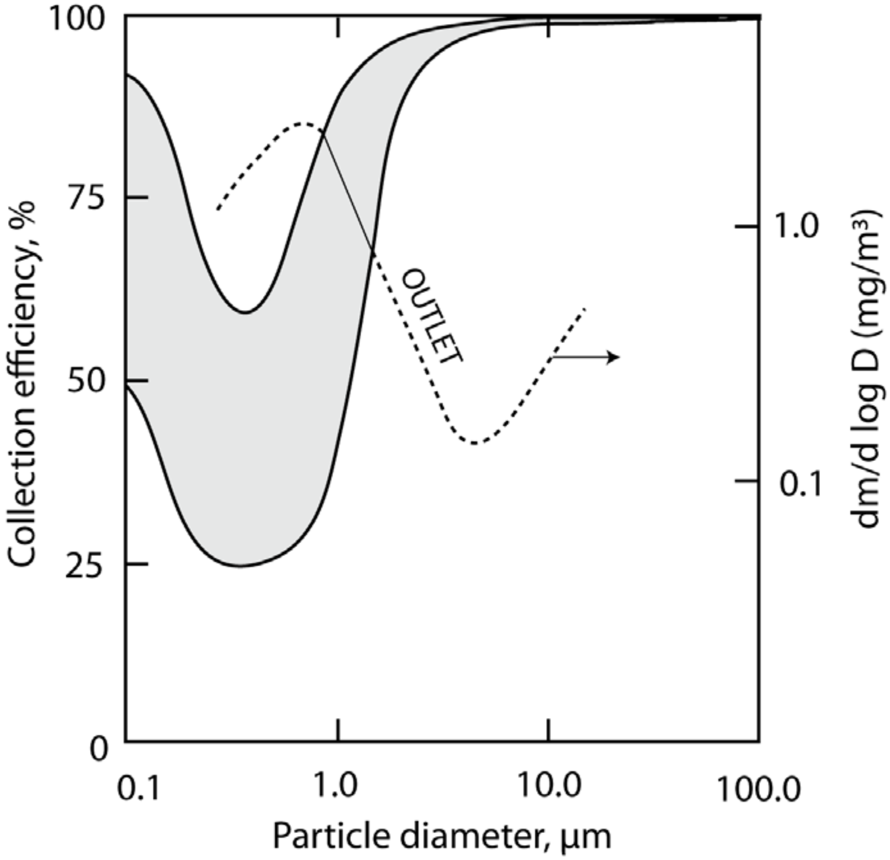


Figure C-9. Particulate control efficiency for difficult to control particulate combined with the mass distribution of particulate collected downstream of the scrubber at MRY (Markowski and others, 1983, http://www.epa.gov/apti/bces/module3/collect/collect.htm)

Field Experience and Testing

As indicated by EPA (Woodward, 1998), scrubbers do not effectively remove particulate less than 1µm in diameter. There is significant evidence that sodium-rich aerosols penetrate ESPs as well as scrubbers at full-scale power plants when firing high-alkali-containing fuels. An example is a biomass fired system using a tower type scrubber where the removal efficiency of the smaller size fraction of ash is low, as shown in Figure C-10 (Ohlström and others, 2006).

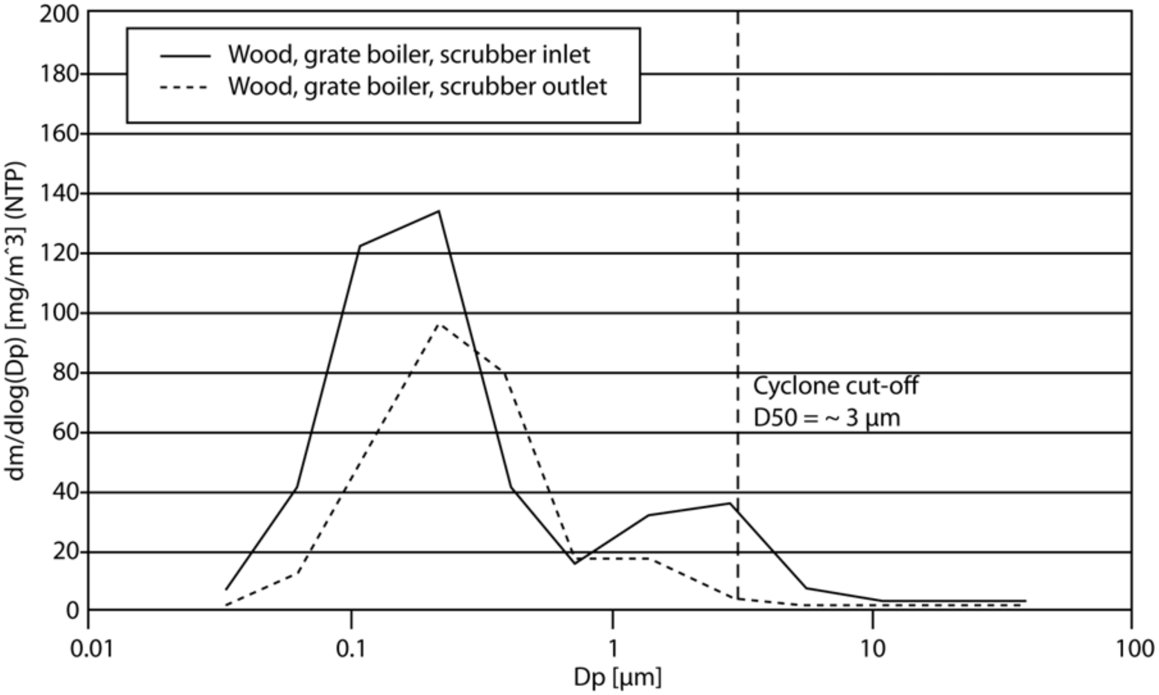
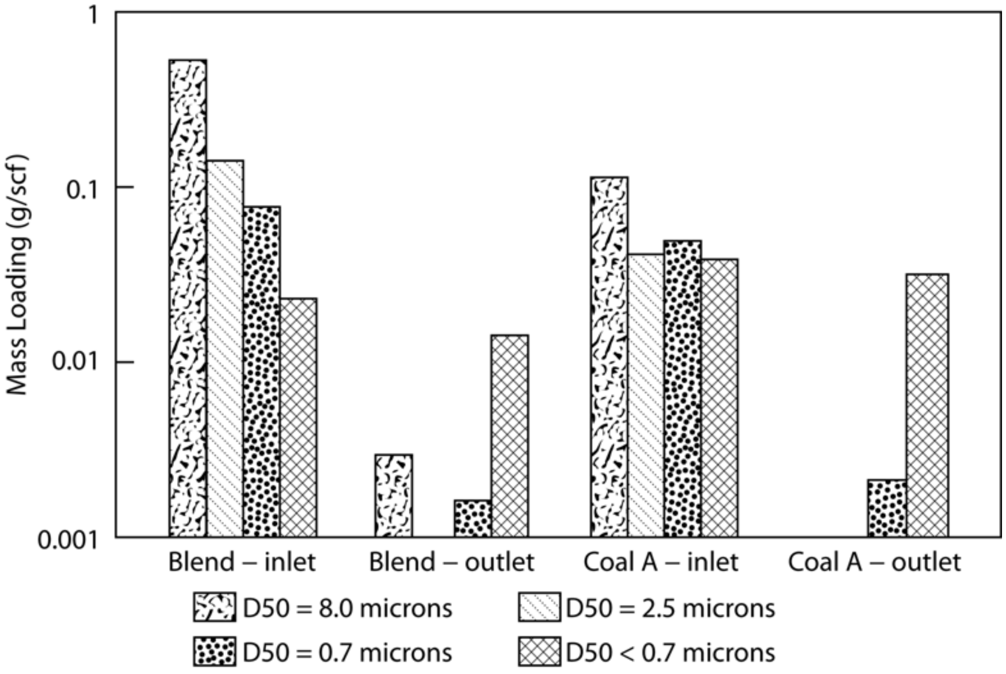


Figure C-10. Removal of fine aerosols using a scrubber on a wood fired combustor (Ohlström and others, 2006).

Minnesota Power's Boswell Energy Station found that when it fired high-sodium, lower-ash northern Powder River Basin subbituminous coal (7% Na_2O in the ash), it experienced increases in opacity. Hurley and Katrinak (1992) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with a venturi wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using multicyclone followed by an impactor and a Nucleopore filter. The sized fractions were weighed and analyzed to determine the abundance and composition of the submicron-sized fractions. The mass loadings in the various size bins are plotted in Figure C-11, showing that the scrubber is quite effective in removing the larger particles. However, the scrubber is not very effective in removing the aerosols less than 1 micrometer in diameter for both the blended coal and the high sodium coal (Coal A).

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of the coals. Vapor-phase sodium condenses in the boiler's convective pass to form fine sodium-rich aerosols or other Na species that later react with ash particles. Pure Na_2SO_4 particles are too small to be removed by such scrubbing. Figure C-12 shows the spikes of the ash material collected on Stage 10 of the impactor. This impactor accumulation represents particles of less than 0.7 to 2.5 micrometer size fraction of the submicron aerosol. The spikes are made up of submicron particulate matter, and the chemical analyses of the spikes and ash particles collected on the Nucleopore filters downstream of the impactor plates are shown in Table C-4. Both samples are dominated by sodium and sulfur that are likely in the form of sodium sulfate. These sulfate materials exhibit highly cohesive tendencies.



Overall mass size distributions for entrained ash samples.

Figure C-11. Mass loadings and size for particulate collected upstream and downstream of the wet venturi scrubber at Clay Boswell (Hurley and Katrinak, 1992).

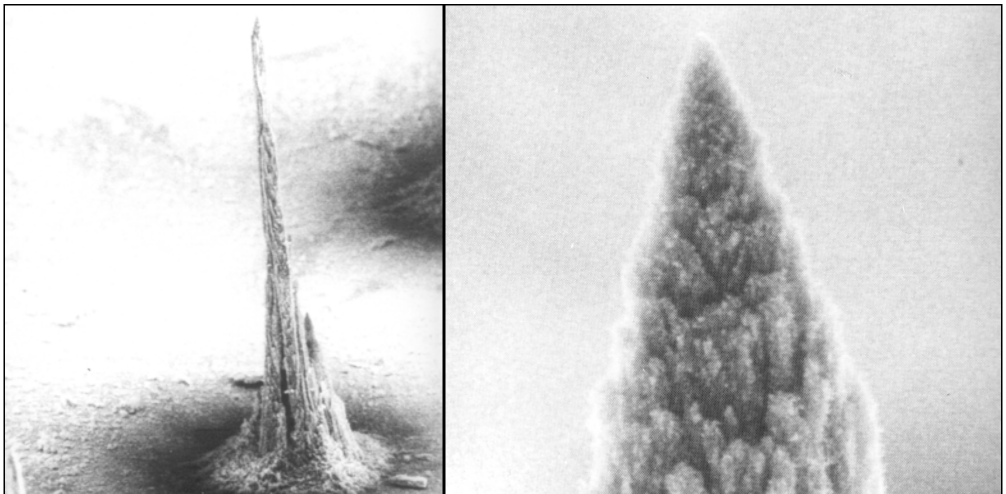


Figure C-12. Scanning electron microscope images of spike formed on impactor plate upon combustion of high-sodium subbituminous coal (right - close-up of spike) (Hurley and Katrinak, 1992).

Table C-4. Chemical Composition of the Spike Shown in Figure C-12 and the Filter (weight percent expressed as equivalent oxide).

	100% Coal A	
Oxide	**Spike**	**Filter**
Na_2O	**35.1**	**17.3**
MgO	1.4	7.8
Al_2O_3	2.0	9.8
SiO_2	9.1	10.6
P_2O_5	0.4	0.2
SO_3	**39.7**	**28.0**
K_2O	2.6	1.5
CaO	6.2	15.7
TiO_2	0.2	1.8
Cr_2O_3	1.4	0.1
Fe_2O_3	0.9	2.9
BaO	0.5	2.6

In addition to the aforementioned testing results, penetration of submicron particles through ESP and scrubbers has been reported by numerous researchers (Markowski and others, 1983, and Lighty and others, 2000).

Power Span Testing at MRY

Aerosols passing through the ESP at MRY Unit 1 resulted in significant accumulation on Powerspan's ECO barrier discharge reactor resulting in significant degradation in performance. The ECO DBD reactor is located just downstream of the plant's ESP or fabric filter (FF) and can be exposed to aerosols. The DBD reactor has quartz electrode rods inside where electric current is passed in order to generate the plasma used to oxidize NO. The temperature of the flue gas at the DBD reactor ranged between 300°F and 350°F. The temperature of the quartz electrodes is approximately 100°F higher than the gas temperature.

The Powerspan ECO reactor slip stream system was designed by Powerspan and the EERC. The slip stream system was installed by the EERC at Minnkota Power Company's Milton R. Young Station Unit #1 down stream of the ESP where the flue gas temperature was ranged from 300°F to 350°F. The system was commissioned on July 3, 2007, operated for 107 days. Operational performance of the system was monitored and data were archived for post processing. A pair of electrodes were extracted and replaced on a bi-weekly basis. Each pair of electrodes were shipped to Powerspan for testing in their laboratory reactor. Tested electrodes were then shipped to the EERC for scanning electron microscopy imaging and x-ray microanalysis. Measurement of NOx conversion by the slip stream system was not possible due to the nitric acid production of the DBD reactor.

The operational observations, performance results, and lab testing showed that the system was adversely affected by ash fouling. NOx conversion by ash covered electrodes was significantly reduced. Figure C-13 compares rods exposed to flue gas and aerosols downstream of the ESP at MRY Unit 1. The abundance of sodium in coal fired during the Powerspan testing is shown in Figure C-14. The results show sodium levels measured by the full stream elemental analyzer (FSEA) ranged from 3.5 to 6 % Na2O in ash. Figure C-15 shows the degradation in NO conversion as a result of being coated with aerosols. The NO conversion was severely impacted.

Figure C-13. Comparison of (left) clean quartz rod and (right) dirty quartz rod exposed to flue gas downstream of ESP at MRY Unit 1 for sixteen days.

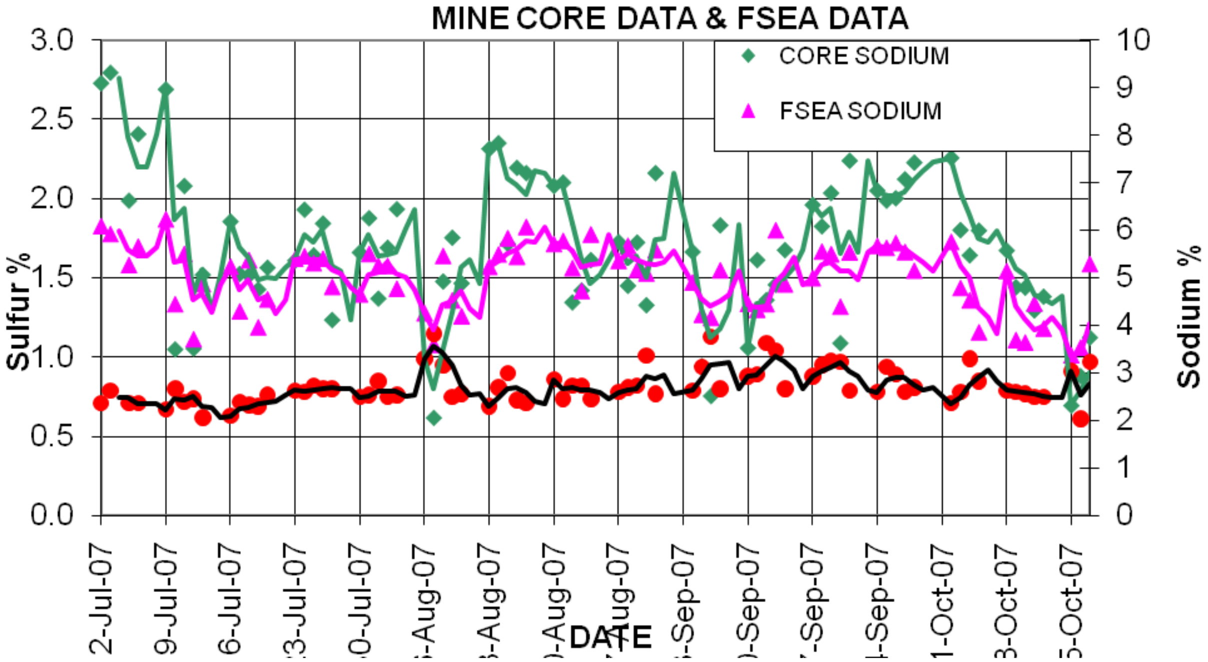


Figure C-14. Sodium and sulfur levels in lignite delivered during testing of the Powerspan barrier discharge reactor.

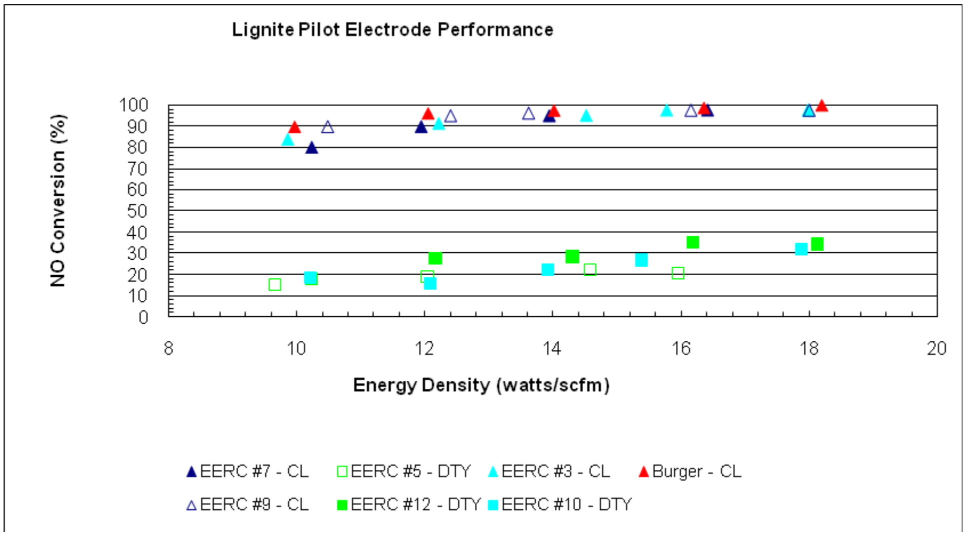
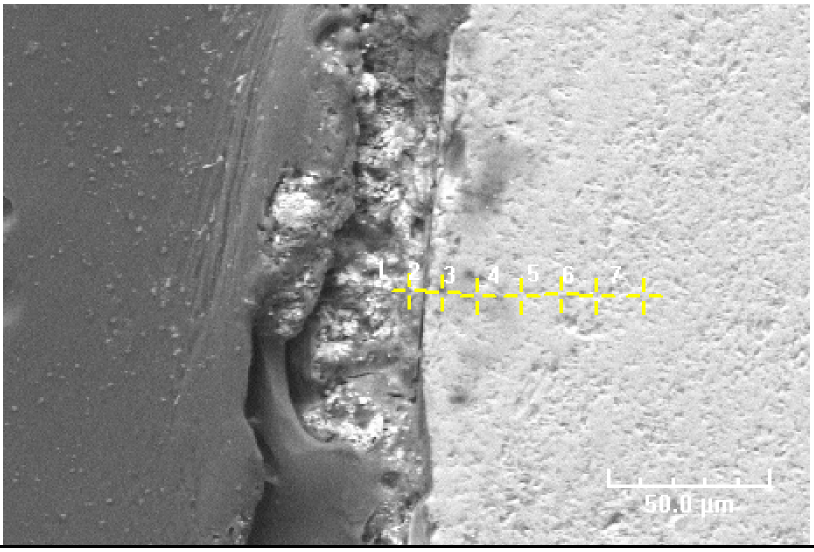


Figure C-15. NO conversion for clean (CL) and dirty (DTY) for quartz tube exposed the flue gas during the MRY testing.

Examination of the quartz rods (cross-sectioned to expose coating thickness) using scanning electron microscope elemental analysis showed significant elemental sodium, sulfur, and calcium in the ash coating the tubes after only 16 days of testing. The data is reported on Figure C-16. The thickness of the layer was approximately 25 µm. The rods were exposed to sootblowing. Images of the reactor and coatings on the electrodes are shown in Figure C-17.



Tag	Na	Mg	Al	Si	P	S	Cl	K	Ca	Ti	Fe	Ba
1	35.38%	0.98%	14.10%	4.68%	0.00%	35.75%	0.00%	1.42%	6.61%	0.02%	1.07%	0.00%
2	0.00%	0.00%	0.22%	98.52%	0.00%	0.00%	0.07%	0.89%	0.00%	0.30%	0.00%	0.00%
3	0.00%	0.00%	0.61%	98.11%	0.00%	0.00%	0.00%	1.05%	0.00%	0.00%	0.22%	0.00%
4	0.00%	0.00%	0.20%	98.33%	0.00%	0.00%	0.00%	1.19%	0.00%	0.00%	0.27%	0.00%
5	0.00%	0.00%	0.00%	98.70%	0.00%	0.00%	0.00%	1.24%	0.00%	0.00%	0.06%	0.00%
6	0.00%	0.00%	0.25%	97.26%	0.00%	0.00%	0.27%	1.70%	0.00%	0.00%	0.36%	0.16%
7	0.00%	0.00%	0.00%	97.93%	0.00%	0.00%	0.00%	1.55%	0.00%	0.00%	0.47%	0.05%

Figure C-16. SEM point analysis on electrode #11 (16 days of service).

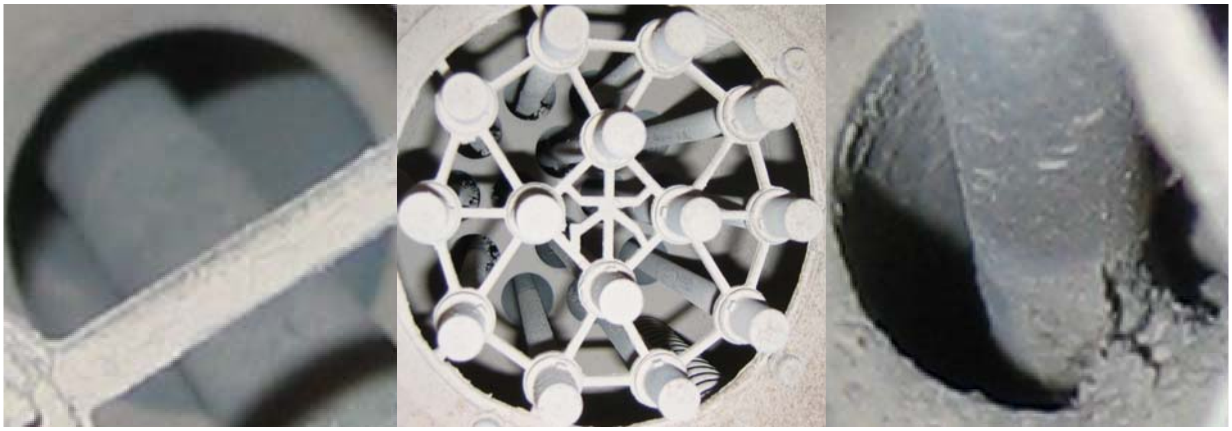


Figure C-17. Images of top of DBD reactor showing ash accumulations on electrodes and reactor surfaces.

Conclusions gained by this work were:

1. Sodium rich aerosols and small ash particles that had penetrated the ESP accumulate and become bonded on the surface of the silica electrodes in spite of soot blowing using a sonic horn as recommended by Powerspan.
2. Ash accumulations adversely affected the NOx conversion.
3. The adverse impact occurs within a two week time period.

MRY Sulfate Aerosol Sampling

The penetration of aerosols through ESP and wet scrubbers is well known and has been studied since the mid 1970s (McCain and others, 1975; Ensor and others, 1975). As a result of these challenges, the quantity of total aerosols and sulfate aerosols was measured at the MRY by Markowski and others, 1983. Markowski and others (1983) collected EPA Method 17 particulate samples and size-segregated the particles using an impactor (aerodynamically separates particles and allows for the characterization of each fraction). The results of the EPA method 17 sampling (mass concentration) conducted over a four-day period are illustrated in Figure C-18 for the inlet and outlet of the scrubber. At the inlet, aerosol mass concentrations ranged from a high of more than 10,000 µg/m^3 to a low of 4,000 µg/m^3. Significant levels were also found at the scrubber outlet, ranging from 8,800 to 2,500 µg/m^3. The removal efficiency varied from -25 to 66%.

Markowski and other (1983) offered no explanation of the differences in the levels of aerosols measured in the flue gas and removal efficiency. They did not consider that the ash content of the coal varied significantly during the testing. Results of testing at MRY have shown significant differences in the quantity vaporized for coals that have different ash contents (see Figure C-3). The variations in ash content shown in Figure C-18 reflect changing coal characteristics that resulted in differences in aerosol mass concentration.

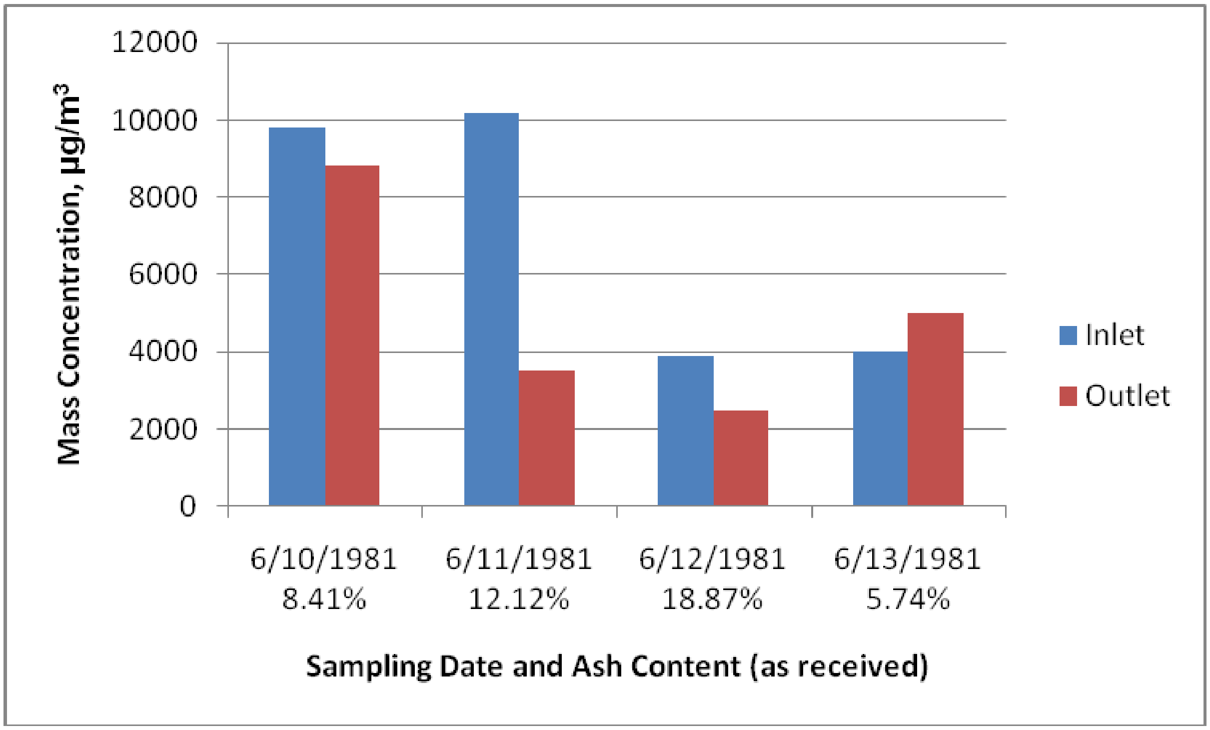


Figure C-18. Mass Concentration of Aerosol Collected at MRY Unit 2 at the Scrubber Inlet and Outlet (Markowski and others, 1983).

The results of the measurements of aerosol capture are illustrated in Figure C-19. The results show that aerosols less than one micrometer in diameter are not effectively captured in the wet FGD at the MRY facility. The graph also indicates the penetration of the particles through the FGD as a function of particle size. The penetration is the outlet size distribution divided by the inlet size distribution. (*Note: Penetration = 1- efficiency*). Markowski and others (1983) showed that the "metallic" sulfate aerosols (sodium sulfate) penetrated the FGD much more effectively than the larger particulate materials.

The mass of each of the impactor size fractions for the aerosols collected at the inlet and the outlet of the wet FGD upstream and downstream of the scrubber are illustrated in Figure C-20 and 21 with the results tabulated in Table C-5. The total mass distributions are summarized in Figure C-20 and the sulfate mass distribution is illustrated in Figure C-20.

Based on the impactor data the total mass of particulate that penetrates the scrubber is 5990 µg/m^3 (Markowski and others, 1983). These ash materials consist of a combination of sulfates and oxides of sodium, calcium, and sulfur. Much of the aerosol is present in the >14 µm size fraction. There are also significant mass in the less than 1 µm size fraction. All of these particles have the potential to penetrate the pores of the catalyst. In addition, there is a significant mass in the <0.26 µm fraction. This fraction represents the ultrafine component that has been implicated as the most significant contributor to catalyst poisoning (Kling and others, 2007).

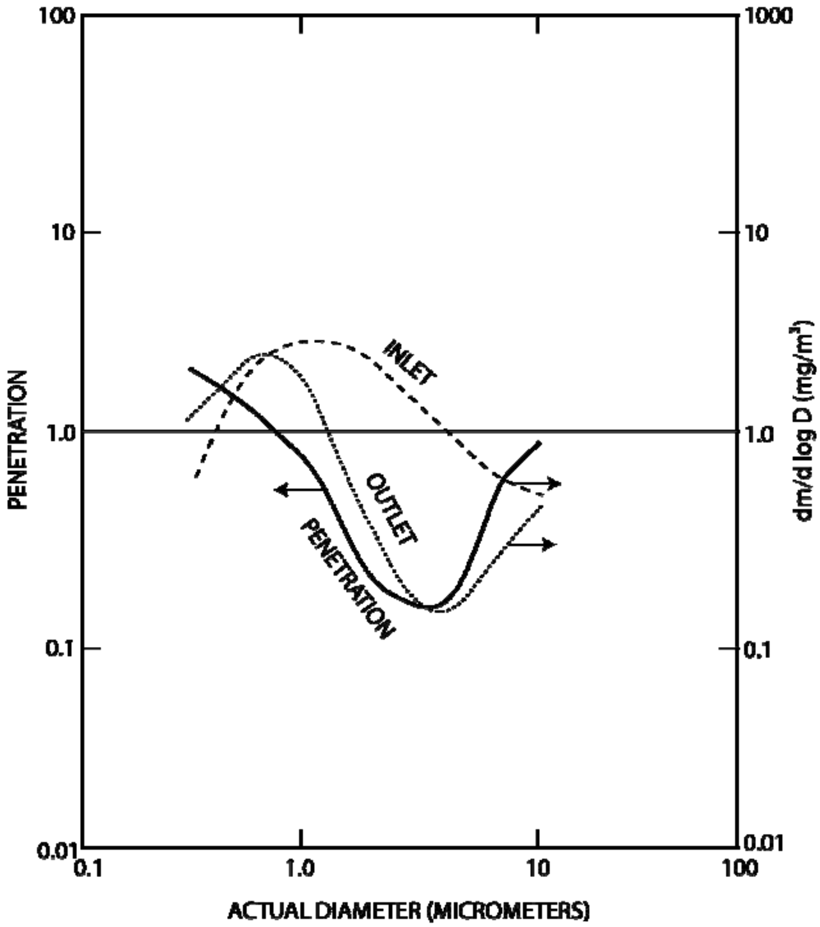


Figure C-19. Penetration through the wet scrubber (Markowski and others, 1983).

Table C-5. Size-segregated total and sulfate particulate collected upstream and downstream of the MRY FGD. (Markowski and others, 1983).

	Inlet	**Outlet**	**Inlet**	**Outlet**
Size, µm	Total, µg/m^3	Total, µg/m^3	Sulfate, µg/m^3	Sulfate, µg/m^3
<0.26	1910	769	436	602
0.26-0.52	401	640	164	274
0.52-1.1	883	1410	293	459
1.1-2.5	1020	265	291	69.2
2.5-6.7	337	154	173	94
6.7-14	300	367	100	103
>14	700	2390	439	46.2
Total	5550	5990	1896	1650
>1.1	2357	3176	1003	312.4
<1.1	3194	2819	893	1335
Percent				
>1.1	42.5 %	53.0 %	52.9 %	18.9 %
<1.1	57.5 %	47.1 %	47.1 %	80.9 %

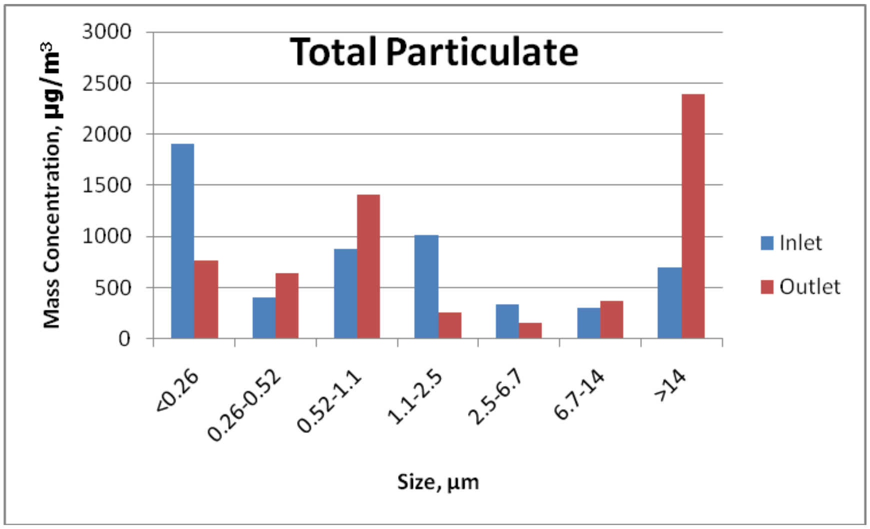


Figure C-20. Total particulate removal across scrubber at MRY.

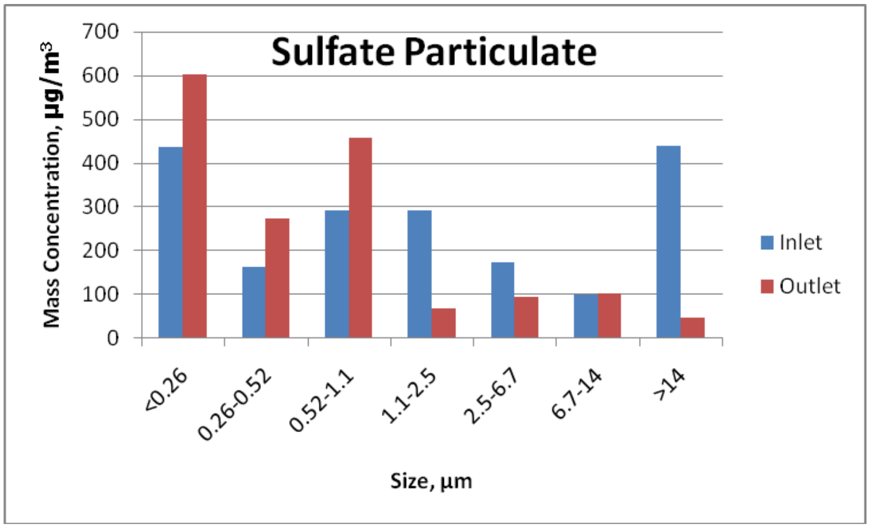


Figure C-21. Sulfate particulate removal across scrubber at MRY.

Estimation of Alkali Aerosol Loading and Catalyst Deactivation

The following data was used to estimate alkali aerosol loading and catalyst deactivation. The particle loading was based on the results of testing conducted by Markowski and others (1983) where they determined the mass loadings of aerosols at the inlet and outlet of the wet FGD at MRY Unit 2. The key data utilized is illustrated in Figure C-22 to estimate the loadings. The data provided shows a range of mass concentrations up to 8,800 µg/m^3 at the outlet of the scrubber. Based on results in mass size distribution of the aerosol 47 to 80% of the aerosols that pass through the scrubber is less than 1.1 µm. Much of this material is in the ultrafine fraction.

These materials have the potential to penetrate into the catalyst causing plugging and can react with active components in the catalyst. There are numerous publications supporting these mechanisms. Kling and others(2007) found that the rate of catalyst deactivation was related to the accumulation of sodium and potassium on the catalyst as shown in Figure C-23 and 24. The work by Kling and others (2007) is consistent with the work conducted by Khodayari (2001) illustrated in Figure C-25 where it was shown that the deactivation rate is more significant for PC fired systems as compared to fluidized beds. The work based on Kling and others when applied to PC- and cyclone-fired systems will likely underestimate the degree of deactivation because of the firing methods.

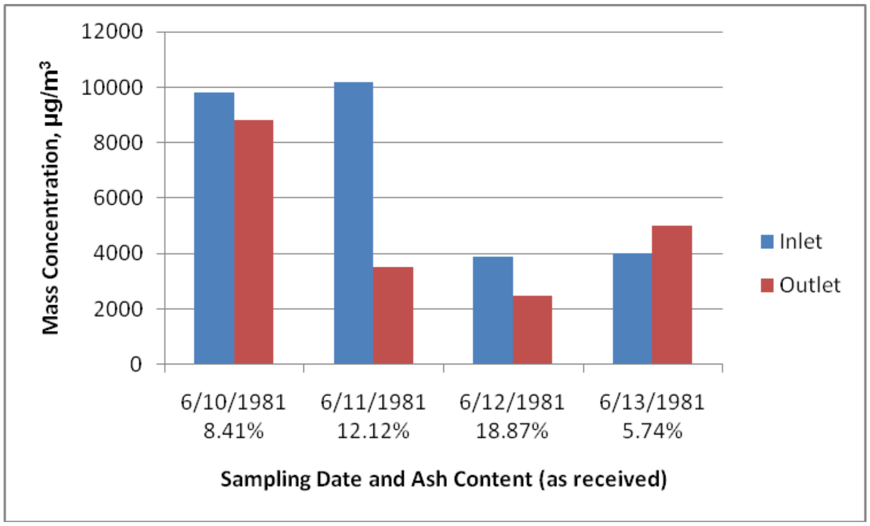


Figure C-22. Mass Concentration of particulate collected at MRY using EPA Method 17 (Markowski and others, 1983).

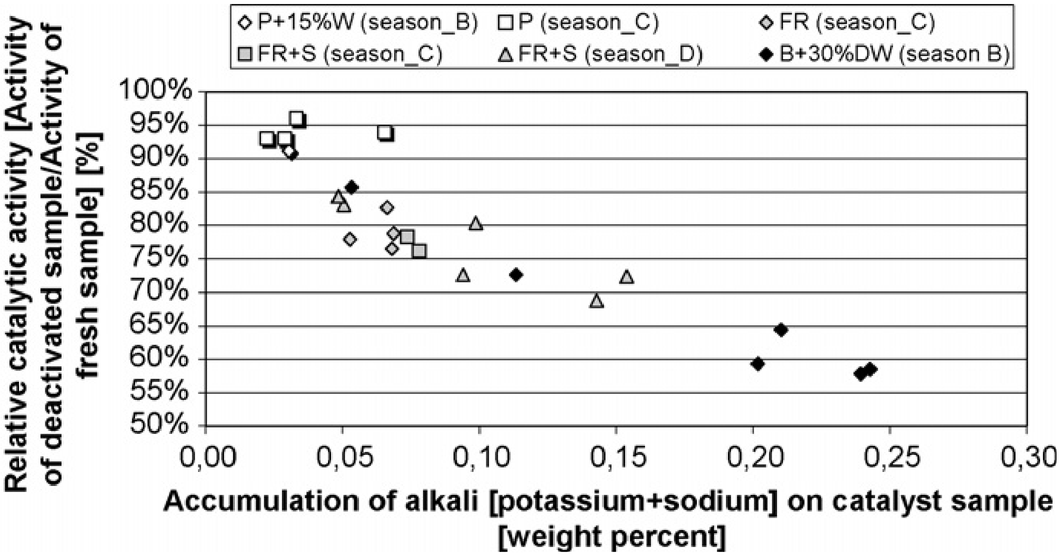


Figure C-23. Catalyst deactivation compared to accumulation of potassium and sodium on the catalyst surface (Kling and others, 2007).

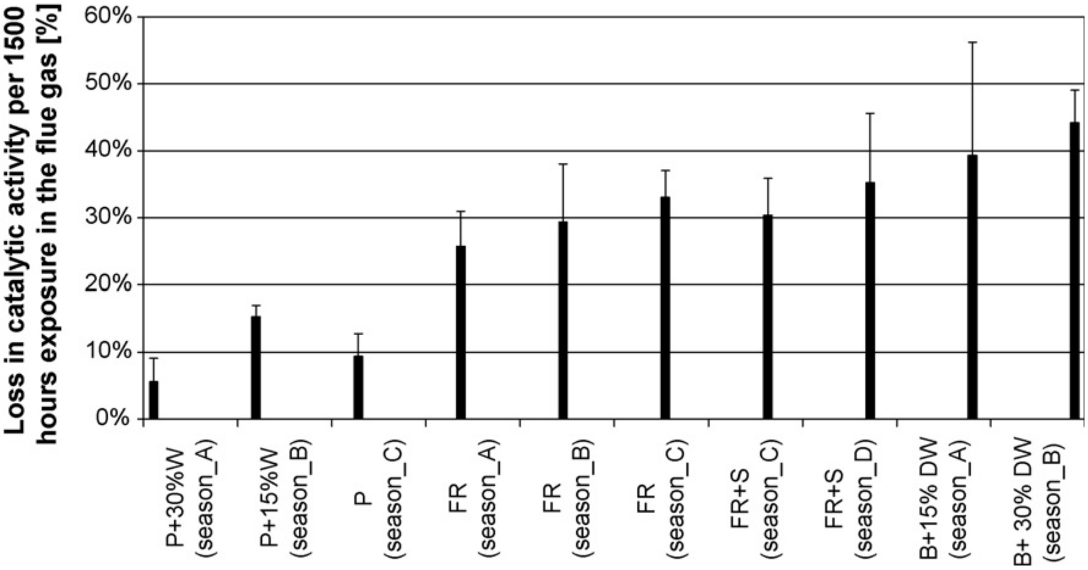


Figure C-24. Loss in catalyst activity when exposed to flue gases containing vaporized Na and K when combusting biomass in a fluidized bed combustion system (Kling and others, 2007).

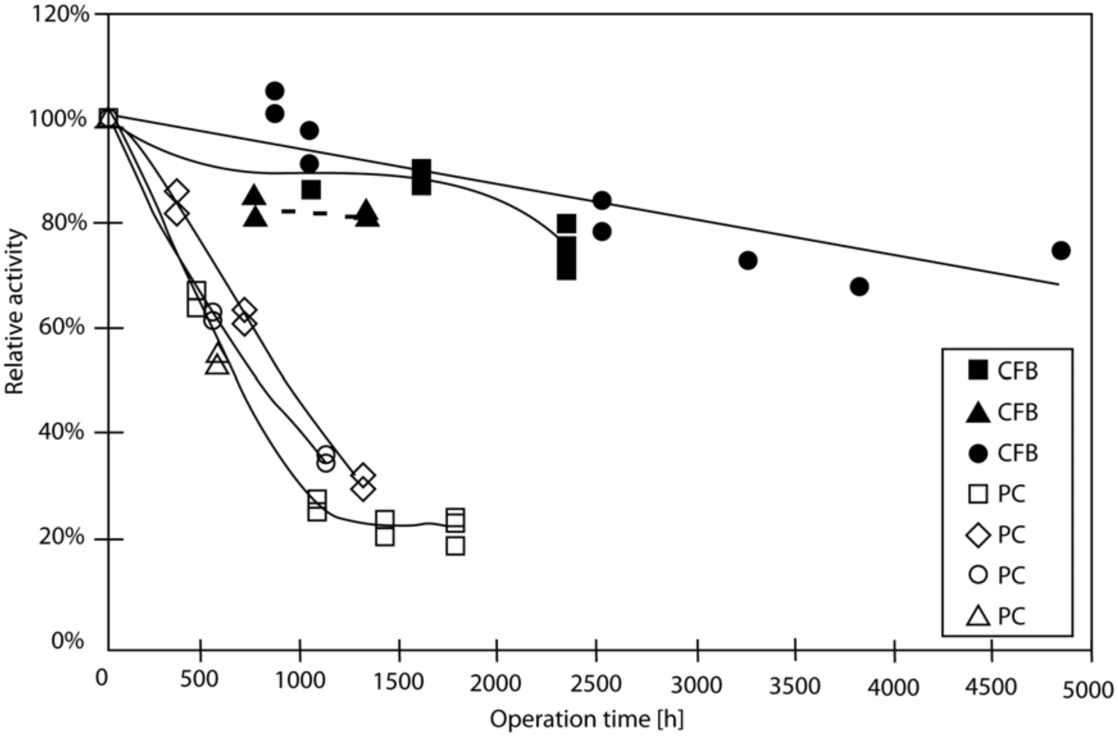


Figure C-25. Comparison of poisoning of catalysts in a CFB boiler firing forest residues, and in a PC firing pulverized wood (Khodayari, 2001).

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Table 4 – MRYS Unit Design and Operating Parameters

Design Unit Operating Characteristics(1)	**Unit 1 Design**	**Unit 2 Design**
Boiler Type	Cyclone	Cyclone
Boiler Manufacturer	B&W	B&W
Boiler Design Heat Input Capacity (nameplate), mmBtu/hr	2,510	4,696
Unit Nameplate Generator Output Capacity, MW_g (gross)	257	477
Unit Nominal Full Load (NFL) Output, MW_g (gross)	235	450
Boiler Heat Input for Unit NFL Output, mmBtu/hr	2,508	4,814
Boiler Excess O_2, %, (wet, NFL)	3.17	4.04
Boiler Excess Air, % (NFL)	21.3	28.5
Fly Ash Portion of Total Ash, % (NFL)	45	50
Typical Maximum Continuous Rating (MCR) output, MW_g	253	462
Maximum Unit Output (URGE) Rating, MW_g	278	512
Boiler Firing Conditions for Flue Gas Flow Calculations:		
Boiler Heat Input, mmBtu/hr	2,852	4,740
Coal Higher Heating Value, Btu/lb as-received	6,578	6,578
Coal Flow Rate for heat input, lb/hr	433,500	720,500
Fly Ash Portion of Total Ash, %	50	50
Flue Gas Conditions at the boiler flue gas outlet:		
Boiler Excess O_2, %, (wet)	2.87	4.77
Boiler Excess Air, %	19.0	35.4
Flue Gas Mass Flow Rate, lb/hr	3,811,000	7,117,000
Flue Gas Volumetric Flow Rate, acfm	2,502,000	4,371,000
Flue Gas Temperature, degrees F	910	818
Flue Gas Pressure, in. w.g.	-11.5	-13.5
Boiler Outlet Maximum SO_2, lb/mmBtu	3.0(2)	3.0(2)
Boiler Outlet Maximum SO_2, lb/hr	8,970	15,474
Average Boiler Heat Input for SO_2, mmBtu/hr	2,990	5,158
Expected Boiler Outlet Maximum 30-day average SO_3, lb/hr	135(3)	236(3)

(1) – Boiler unit operating parameters are provided for more than one load or output condition.

(2) – Boiler Outlet Maximum SO_2 lb/mmBtu is based on 1.0% S and 6,578 Btu/lb higher heating value content in the as-received lignite coal.

(3) – Boiler Outlet Maximum SO_3 lb/hr is based on the assumed conversion of 1.5% of the boiler outlet SO_2 to SO_3 upstream of any flue gas treatment. This conversion percentage has not been confirmed by actual boiler outlet flue gas test measurements. The SO_2 lb/mmBtu and lb/hr values have not been reduced by this assumed SO_3 conversion.

Table C2 summarizes the average, maximum and minimum values for the entire as-fired coal database. The ranges on the various components can be very large. For example, the ash content ranges from 5 to 25%. Sodium oxide content ranges from 0.6 to 13% of the ash.

Table C2. Average, maximum, and minimum of basic coal analysis for all the coals in the as-fired database - Center Lignite Coal

ID NUMBER	Moisture	Ash	Sulfur	Btu	Volatile Matter	Fixed Carbon	Aluminum Oxide	Barium Oxide	Calcium Oxide	Iron Oxide	Magnesium Oxide	Manganese Dioxide	Phosphorus Pentoxide	Potassium Oxide	Silicon Dioxide	Sodium Oxide	Strontium Oxide	SO3	Titanium Dioxide	Basic total	Acid Total	Base/Acid Ratio
							Al_2O_3	Ba	CaO	Fe_2O_3	MgO	Mn	P_2O_5	K_2O	SiO_2	Na_2O	Sr	SO_3	TiO_2			
Average	**37.1**	**9.64**	**1.0**	**6578.1**	**25.3**	**28.0**	**11.7**	**0.5**	**13.2**	**8.9**	**4.0**	**0.1**	**0.1**	**1.3**	**36.0**	**4.4**	**0.4**	**18.4**	**0.5**			**0.7**
Max	**39.4**	**25.5**	**2.6**	**7101.0**	**31.1**	**31.2**	**15.6**	**1.2**	**24.0**	**24.7**	**7.1**	**0.3**	**1.0**	**2.3**	**56.0**	**13.0**	**37.0**	**34.5**	**0.7**			**2.5**
Min	**33.6**	**5.0**	**0.5**	**5852.0**	**22.3**	**13.7**	**6.3**	**0.2**	**6.8**	**5.4**	**2.3**	**0.0**	**0.0**	**0.2**	**12.3**	**0.6**	**0.2**	**8.1**	**0.2**			**0.3**
90th Perc.	**38.10**	**12.51**	**1.29**	**6820**	**26.5**	**29.9**	**14.2**	**0.8**	**19.9**	**12.2**	**5.7**	**0.1**	**0.4**	**1.9**	**46.0**	**8.71**	**0.6**	**26.3**	**0.6**			**1.26**
10th Perc.	**35.95**	**7.06**	**0.72**	**6359**	**24.3**	**26.1**	**9.6**	**0.4**	**9.7**	**7.1**	**3.0**	**0.1**	**0.0**	**0.6**	**22.7**	**1.99**	**0.2**	**14.4**	**0.4**			**0.44**
45th Perc.	**37.17**	**9.33**	**0.90**	**6552**	**25.2**	**28.0**	**11.6**	**0.5**	**12.2**	**8.3**	**3.8**	**0.1**	**0.1**	**1.4**	**37.0**	**4.09**	**0.3**	**17.3**	**0.5**			**0.592**
55th Perc.	**37.37**	**9.75**	**0.94**	**6592**	**25.4**	**28.3**	**12.0**	**0.5**	**12.7**	**8.7**	**4.0**	**0.1**	**0.1**	**1.4**	**38.4**	**4.61**	**0.4**	**18.0**	**0.5**			**0.637**

1. Ash weight percent was determined on an “as-fired” lignite coal basis.
2. BTU (higher heating value) content expressed on an “as-fired” lignite coal basis.
3. Constituent weight percent of the ash, elemental weight percent expressed as equivalent oxide.
4. B/A is the base to acid weight ratio of the ash constituents (B/A=[Na_2O+MgO+CaO+ K_2O+FeO]/[SiO_2+Al_2O_3+TiO_2]).

MJa 1017-1

UTILITY BOILER PERFORMANCE SUMMARY

A FUEL AS FIRED

SAMPLES		
ANALYSES SPECIFIED		
KIND		-
ASTM CLASS		IV
ASTM GROUP		I
ASTM MINE		
SOURCE SEAM		
SOURCE DISTRICT		
SOURCE COUNTY		OLIVER
SOURCE STATE		N.D.
COAL SIZE		
GRINDABILITY	22	30
SURFACE MOISTURE, %	3.0-5.0	5.0
ASH SOFT. TEMP., F (REDUCING)		
PROX. ANAL. % MOISTURE, TOTAL	276-403	36.0
PROX. ANAL. % VOLATILE MATTER	270-320	29.1
PROX. ANAL. % FIXED CARBON	270-320	29.1
PROX. ANAL. % ASH	3.9-8.3	5.8
PROX. ANAL. % TOTAL		100.0

ULTIMATE ANALYSIS				
FUEL			LIGNITE	LIGNITE
% W				WT.
ASH			3.9-8.3	5.80
S				0.74
H_2			2.9-3.5	1.00
C			389-46.1	40.40
CH_4				
C_2H_6				
C_2H_4				
C_3H_8				
C_4H_{10}				
C_5H_{12}				
C_6H_{14}				
CO			001-001	0.01
CO_2				
SO_2				
H_2O			275-40.3	36.00
N_2			.4-.74	0.65
O_2				13.40
TOTAL				100.00
BTU/LB			6250-7830	6900
BTU/CU FT AT 60F 30 IN. HG				

BY APPD. DATE April [illegible]

THE BABCOCK & WILCOX COMPANY

P1-3941-1LX0-1S0

3

B PREDICTED PERFORMANCE

STEAM LEAVING SH, M LB/HR		990	1650	1714
STEAM LEAVING RH1, M LB/HR		876	1460	1534
STEAM LEAVING RH2, M LB/HR				
TYPE OF FUEL			LIGNITE	
LOAD DURATION			CONTINUOUS	
EXCESS AIR ENTERING AIRHEATER		31	28	28
NO. OF BURNERS IN OPERATION		7	7	7
FUEL INPUT, MKB/HR		1565	2422	2510
HEAT AVAIL. MKB/HR (FUEL & HEATED AIR)		1620	2559	2649
QUANTITY, M LB/HR: FUEL (MCFH-NAT. GAS)		227	352	364
QUANTITY, M LB/HR: FLUE GAS ENTERING AIR HEATER		2250	2817	2919
QUANTITY, M LB/HR: AIR LEAVING SEC. AH & PRI. AH		1520	2312	2396
QUANTITY, M LB/HR: AIR HEATER LEAKAGE				
PRESSURE, PSIG: STEAM AT SH OUTLET		1875	1875	1970
PRESSURE, PSIG: STEAM AT RH1 INLET		258	457	480
PRESSURE, PSIG: STEAM AT RH2 INLET				
PRESSURE DROP: REHEATER 1		15	25	26
PRESSURE DROP: REHEATER 2				
PRESSURE DROP: ECONOMIZER		11	30	33
PRESSURE DROP: DRUM TO SH OUTLET		45	125	135
TEMPERATURE, F: STEAM: LEAVING SUPERHEATER		1010	1010	1010
TEMPERATURE, F: STEAM: LEAVING REHEATER 1		970	1010	1010
TEMPERATURE, F: STEAM: ENTERING REHEATER 1		590	664	663
TEMPERATURE, F: STEAM: LEAVING REHEATER 2				
TEMPERATURE, F: STEAM: ENTERING REHEATER 2				
TEMPERATURE, F: FLUE GAS: LEAVING PRI. SH		810	890	900
TEMPERATURE, F: FLUE GAS: LEAVING AH (EXCL. LKG)		370	325	330
TEMPERATURE, F: FLUE GAS: LEAVING AH (INCL. LKG)				
TEMPERATURE, F: WATER ENTERING ECONOMIZER		408	461	466
TEMPERATURE, F: AIR: ENTERING AIR HEATER		100	100	100
TEMPERATURE, F: AIR: LEAVING AIR HEATER		735	768	777
RESISTANCE, IN. OF WATER: GAS: FURNACE & CONVECTION BANKS		2.4	3.7	4.0
RESISTANCE, IN. OF WATER: GAS: FLUES TO STACK		1.3	1.9	2.0
RESISTANCE, IN. OF WATER: GAS: AIR HEATER & ECON.		4.9	7.6	8.1
RESISTANCE, IN. OF WATER: GAS: DUST COLLECTOR		1.7	2.7	3.0
RESISTANCE, IN. OF WATER: GAS: TOTAL DRAFT LOSS		10.3	15.9	17.1
RESISTANCE, IN. OF WATER: AIR: FUEL BURNERS & WINDBOX		36.5	36.5	36.5
RESISTANCE, IN. OF WATER: AIR: DUCTS & FLOW METER		2.1	3.2	3.5
RESISTANCE, IN. OF WATER: AIR: AIR HEATER		1.5	2.4	2.6
RESISTANCE, IN. OF WATER: AIR: STEAM COIL AH		0.3	0.5	0.5
TOT. AIR RESISTANCE		40.4	42.6	43.1
HEAT LOSS, %: DRY GAS		6.70	5.46	5.58
HEAT LOSS, %: H_2 & H_2O IN FUEL		10.51	10.38	10.40
HEAT LOSS, %: MOISTURE IN AIR		0.17	0.14	0.14
HEAT LOSS, %: UNBURNED COMBUSTIBLE		0.10	0.10	0.10
HEAT LOSS, %: RADIATION		0.32	0.19	0.18
HEAT LOSS, %: UNACC. FOR & MFRS. MARGIN		1.10	1.10	1.10
HEAT LOSS, %: SLAG TANK		0.40	0.40	0.40
HEAT LOSS, %: TOTAL HEAT LOSS		19.30	17.77	17.90
EFFICIENCY OF UNIT, %		80.70	82.23	82.10
NO. IN USE PER BOILER				
TOTAL POWER, KWHR/TON MOTOR OUTPUT				
% THRU 200 U.S.S. SIEVE				

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 27.72 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING 11X0

C EQUIPMENT PER UNIT

TYPE RADIANT

SIZE

RBC 57/CY.

DESIGN PRESSURE 2325 PSIG

PRESSURE PART HEATING SURFACE, SQ FT	
FURNACE: WATER COOLED SCREEN (CIRCUMFERENTIAL)	
FURNACE: WATER COOLED (PROJECTED)	33760
FURNACE: SUPERHEATER (CIRCUMFERENTIAL)	9229
FURNACE: SUPERHEATER (PROJECTED)	1200
FURNACE: TOTAL FURNACE HEATING SURFACE	44189
CONVECTION: SATURATED (CIRCUMFERENTIAL)	5910
CONVECTION: SUPERHEATER (CIRCUMFERENTIAL)	91607
CONVECTION: REHEATER 1 (CIRCUMFERENTIAL)	36947
CONVECTION: REHEATER 2 (CIRCUMFERENTIAL)	
CONVECTION: ECONOMIZER	44900
CONVECTION: TOTAL CONVECTION HEATING SURFACE	179164
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.	223553
FLAT PROJECTED FURNACE HEATING SURFACE	
TO FACE OF PLATENS	37925
TO FACE OF CONVECTION SURFACE	
FURNACE VOLUME, CU FT	148800

AIR HEATER: TYPE TUBULAR NO. 1

AIR HEATER: TOTAL HEATING SURFACE, SQ FT 742,000

FUEL BURNER: TYPE CYCLONE

FUEL BURNER: NO. 7-10 FT. DIA.

PULVERIZER: TYPE SIZE NO.

CAPACITY OF PULV. IS M LB STEAM/HR BASED ON GRIND BTU COAL AT % THRU 200 U.S.S. SIEVE FOR M LB COAL/PULV.-HR AT % THRU 200 U.S.S. SIEVE. MIN. GRIND IS , MAXIMUM SURFACE MOISTURE IS % REQUIRING F AIR

STEAM TEMP. CONTROL: STEAM TEMPERATURE CONTROLLED BY GAS RECIRCULATION

UNIT CONSTRUCTION FEATURES:
BALANCED DRAFT
SEMI-OUTDOOR
MEMBRANE WALL

SOLIDS IN STEAM 1 PPM

REVISIONS NO.	DESCRIPTION	BY	DATE

1

MINNKOTA POWER COOPERATIVE
SANDERSON AND PORTER, INC.
ENGINEERS

235MWe UNIT 1 RB-457

A FUEL AS FIRED

SAMPLES			
ANALYSES	CUSTOMER SPECIFICATIONS		
KIND		DESIGN	PERF.
ASTM	CLASS	LIGNITE	LIGNITE
	GROUP		
SOURCE	MINE		
	SEAM		
	DISTRICT		
	COUNTY		OLIVER
	STATE		N. DAK.
COAL	SIZE		1¼ - 1½
	GRINDABILITY	20 MIN	25
	SURFACE MOISTURE, %		
	$H = \frac{1}{2}W$		
	ASH SOFT. TEMP., F (REDUCING)	2235-2500	2410
PROX. ANAL., %	MOISTURE, TOTAL	38	38.4
	VOLATILE MATTER		25.0
	FIXED CARBON	1	25.0
	ASH	13	11.6
	TOTAL		100.0
ULTIMATE ANALYSIS	FUEL		LIGNITE
	% BY		WT.
	ASH		11.60
	S		0.63
	H_2		2.60
	C		34.70
	CH_4		
	C_2H_4		
	C_2H_6		
	C_3H_8		
	C_4H_{10}		
	C_5H_{12}		
	C_6H_{14}		
	Cl		0.01
	CO_2		
	SO_2		
	H_2O		38.40
	N_2		0.56
	O_2		11.50
	TOTAL		100.00
	BTU/LB	6000	6250
	BTU/CU FT AT 60F 30 IN.HG		

* EXCL. STATIC HEAD AND FEED STOP AND CHECK VALVE.

** INPUT & ALL GENERAL PERFORMANCE INCLUDES ALLOWANCE FOR AVERAGE SOOT BLOWER STEAM CONSUMPTION RATE (40,000 LB/HR).

UTILITY BOILER PERFORMANCE SUMMARY

BY VFH APPD. PJS. DATE 3-27-73

THE BABCOCK & WILCOX COMPANY

PS-2783-1YO-1ST

B PREDICTED PERFORMANCE

STEAM LEAVING SH., M LB/HR		1830	2560	3050	3200
STEAM LEAVING RH¹, M LB/HR		1510	2110	2513	2769.6
BLOWDOWN, M LB/HR		18.5	25.9	30.8	32.4
TYPE OF FUEL		LIGNITE	LIGNITE	LIGNITE	LIGNITE
LOAD CONDITION		NORMAL	NORMAL	NORMAL	NORMAL MAX
EXCESS AIR LEAVING ECON., %		38	31	28	25
NO. OF BURNERS IN OPERATION		12	12	12	12
FUEL INPUT, MKB/HR **		2849	3883	4505	4676
HEAT AVAIL. MKB/HR (FUEL & HEATED AIR)		2974	4050	4761	4975
QUANTITY, M LB/HR	FUEL	455.8	621.2	720.7	751.4
	FLUE GAS ENTERING AIR HEATER	3410	4439	5050	5264
	AIR TO BURNING EQUIPMENT	2932	3802	4330	4491
	AIR HEATER LEAKAGE				
PRESSURE, PSIG	STEAM AT SH OUTLET	2495	2495	2495	2620
	STEAM AT RH¹ INLET	296	407	518	570
	STEAM AT RH² INLET				
PRESSURE DROP	REHEATER 1	17	23	28	30
	REHEATER 2				
	ECONOMIZER TO DRUM*	17	30	45	50
	DRUM TO SH OUTLET	60	106	155	180
TEMPERATURE, F — STEAM	LEAVING SUPERHEATER	1005	1005	1005	1005
	LEAVING REHEATER 1	980	1005	1005	1005
	ENTERING REHEATER 1	545	582	618	626
	LEAVING REHEATER 2				
	ENTERING REHEATER 2				
TEMPERATURE, F — FLUE GAS	LEAVING ECONOMIZER TO AH/TOGR	756/560	819/620	863/685	870/695
	LEAVING AH (EXCL. LKG)	284	310	328	330
	LEAVING AH (INCL. LKG)				
	WATER ENTERING ECONOMIZER	421	450	473.7	483.7
TEMPERATURE, F — AIR	ENTERING UNIT	108	100	100	100
	LEAVING AIR HEATER	661	710	745	750
RESISTANCE, IN. OF WATER — GAS	FURNACE & CONVECTION BANKS	3.7	5.3	8.0	8.8
	FLUES TO AH OUTLET	1.6	2.2	2.7	2.8
	AIR HEATER	3.0	5.0	6.5	6.9
	TOT. FURN. TO AH OUTLET	8.3	12.5	17.2	18.5
RESISTANCE, IN. OF WATER — AIR	FUEL BURNERS & WINDBOX	43.0	43.0	43.0	44.5
	DUCTS	1.5	2.5	3.2	3.5
	AIR HEATER	2.1	3.6	4.7	5.1
	TOT. FROM FD FAN TO FURN.	46.6	49.1	50.9	53.1
HEAT LOSS, %	DRY GAS	4.79	5.20	5.53	5.58
	H_2 & H_2O IN FUEL	11.08	11.21	11.28	11.30
	MOISTURE IN AIR	0.12	0.13	0.14	0.14
	UNBURNED COMBUSTIBLE	0.10	0.10	0.10	0.10
	RADIATION	0.28	0.21	0.18	0.17
	UNACC. FOR & MFRS. MARGIN & SLAG TANK LOSS	1.83	1.83	1.83	1.83
	TOTAL HEAT LOSS	18.20	18.68	19.06	19.12
EFFICIENCY OF UNIT, %		81.80	81.32	80.94	80.88
PULV., FAN & FEEDER	NO. IN USE PER BOILER				
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE				

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 27.72 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING PS-2783-1YO

C EQUIPMENT PER UNIT

TYPE RADIANT

SIZE RBC 48/CY

DESIGN PRESSURE 2950 PSIG

PRESSURE PART HEATING SURFACE, SQ FT	FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)	
		WATER COOLED (PROJECTED)	43,260
		SUPERHEATER (CIRCUMFERENTIAL)	
		SUPERHEATER (PROJECTED)	15,360
		TOTAL FURNACE HEATING SURFACE	58,620
	CONVECTION	SATURATED (CIRCUMFERENTIAL)	7,120
		SUPERHEATER (CIRCUMFERENTIAL)	127,300
		REHEATER 1 (CIRCUMFERENTIAL	56,060
		REHEATER 2 (CIRCUMFERENTIAL)	
		ECONOMIZER	161,425
		TOTAL CONVECTION HEATING SURFACE	351,905
	TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.		410,525
	FLAT PROJECTED FURNACE HEATING SURFACE		
	TO FACE OF PLATENS		45,520
	TO FACE OF CONVECTION SURFACE		60,390
FURNACE VOLUME, CU FT			403,500

AIR HEATER: TYPE TUBULAR NO. 1

TOTAL HEATING SURFACE, SQ FT 1,336,400

FUEL BURNER: TYPE CYCLONE

NO. 12

PULVERIZER: TYPE SIZE NO.

CAPACITY OF PULV. IS M LB STEAM/HR BASED ON GRIND

BTU COAL AT % THRU 200 U.S.S. SIEVE

FOR M LB COAL/PULV.-HR AT % THRU 200 U.S.S. SIEVE MIN. GRIND

IS MAXIMUM SURFACE MOISTURE IS % REQUIRING F AIR

SOLIDS IN STEAM - 0.1 PPM

STEAM TEMP. CONTROL: GAS RECIRCULATION

UNIT CONSTRUCTION FEATURES:

MEMBRANE WALL

BALANCED DRAFT

INDOOR

REVISIONS

NO.	DESCRIPTION	BY	DATE
0-1	C59	VFH	4/25/73

SANDERSON & PORTER, INC.

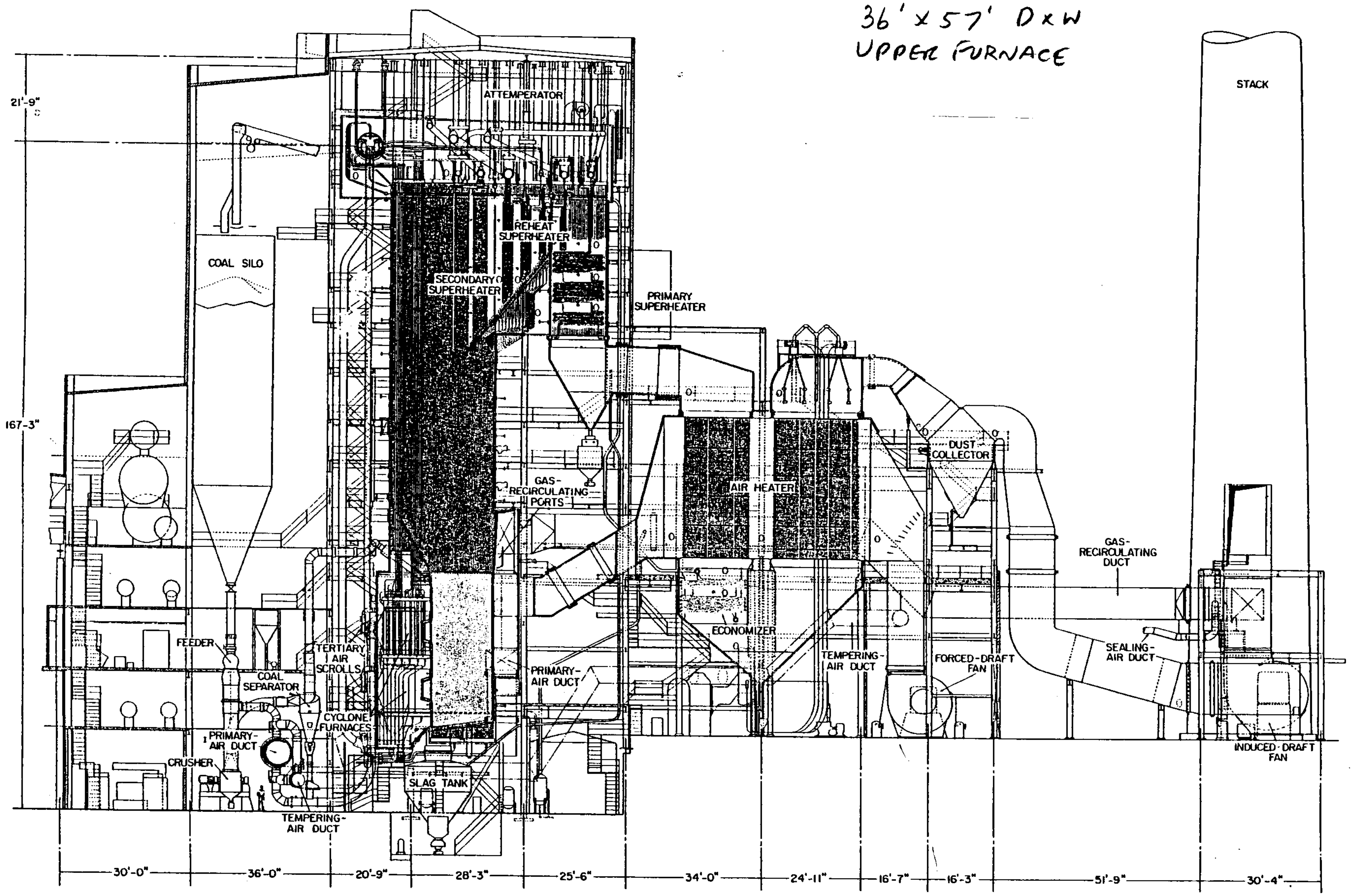
2 FOR: SQUARE BUTTE ELECTRIC COOPERATIVE, INC.

MILTON R. YOUNG STATION, NORTH DAKOTA

439 MWe RB-525

26' x 57' DxW
LOWER FURNACE

36' x 57' DxW
UPPER FURNACE

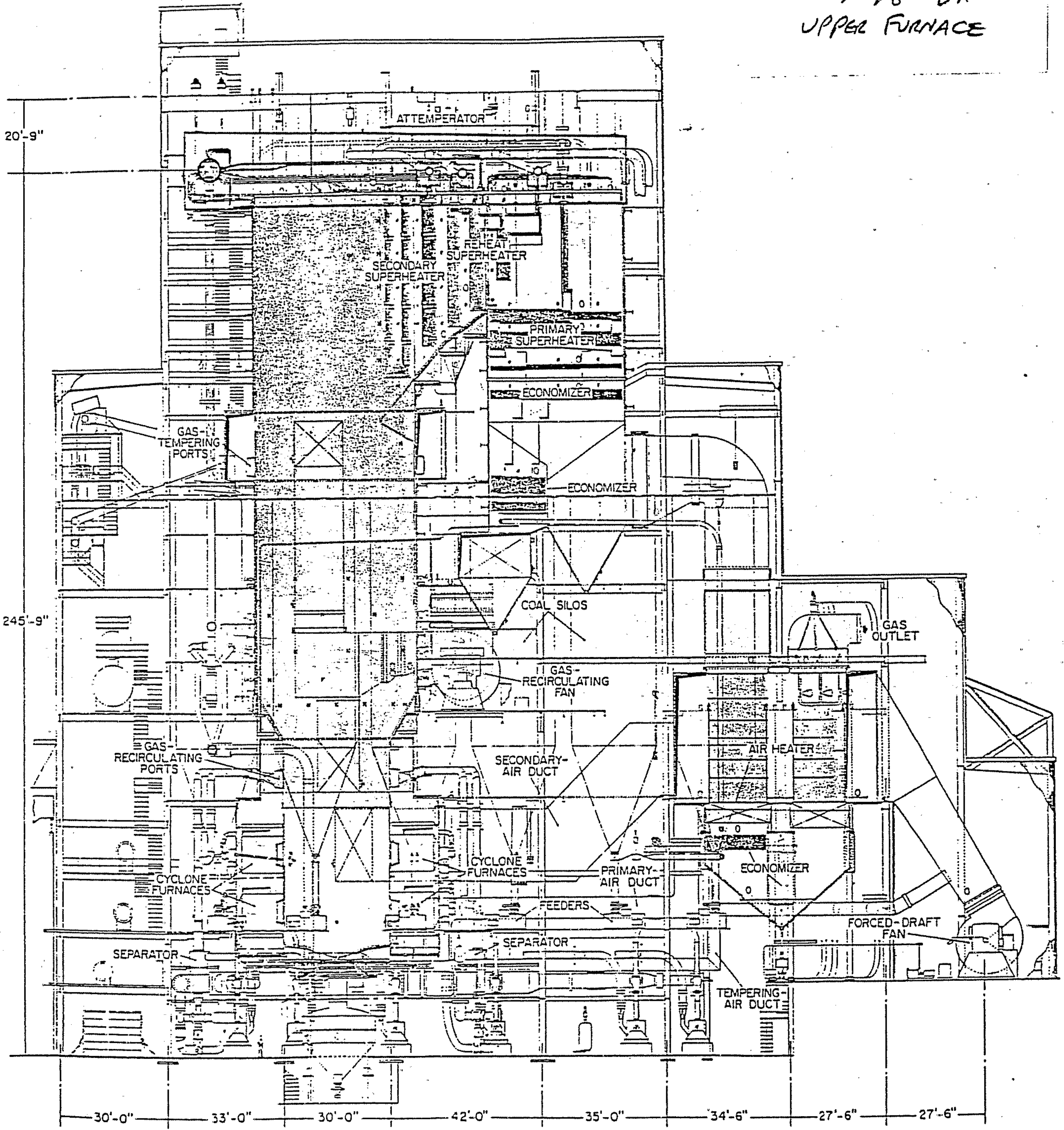


MINNKOTA POWER COOPERATIVE, INC.
CENTER POWER PLANT - UNIT NO. 1
CENTER, NORTH DAKOTA
B & W CONTRACT NO. RB-457

RB-457-500-2N

30' x 48' D x W
LOWER FURNACE

45' x 48' D x W
UPPER FURNACE



SQUARE BUTTE ELECTRIC COOPERATIVE
CENTER POWER PLANT – UNIT NO. 2
CENTER, NORTH DAKOTA
B & W CONTRACT NO. RB-525

Bryant, Ronald

From: Bryant, Ronald

Sent: Wednesday, August 26, 2009 4:30 PM

To: Noel Rosha

Cc: 'lkvernen@minnkota.com'; John Graves; Craig Bleth (cbleth@minnkota.com); Gerry Pfau (gpfau@minnkota.com); Andy Freidt; Weilert, Carl; Blakley, Robert; sbenson@undeerc.org; 51684

Subject: Minnkota SCR Catalyst Recommendations

Attachments: Scope of Services 26Aug09.doc; Report 1084 - Particulate - FINAL 8-20-09.pdf; MRY SCR Vendor Query (4-18-07) - Abbreviated.pdf

Noel

Minnkota Power is requesting recommendations on SCR catalyst design for low-dust and tail-end applications as discussed in our offices on August 11.

Attached are the following documents for your consideration:

1. Scope of Services 26Aug09
2. Report 1084 - Particulate - FINAL 8-20-09
3. MRY SCR Vendor Query (4-18-07) – Abbreviated

The first document summarizes items Minnkota Power is requesting in support of the required BACT.

The second document is flue gas testing data performed at the Milton R. Young Station. This information should be treated confidential.

The third document includes some basic boiler operating parameters and was extracted from the MRY SCR Vendor Query originally transmitted in April of 2007.

Please contact us if you need any additional information or would like to discuss the project.

Thank you for your assistance.
Ron Bryant
816-822-3023

Scope of Services
SCR Catalyst Recommendations

Minnkota Power Cooperative
Milton R Young Station
August 26, 2009

1. Minnkota Power Cooperative (MPC) operates two coal-fired electric generating units at the Milton R. Young Station. Both units are Babcock & Wilcox balanced-draft cyclone fired boilers burning 100% North Dakota lignite coal supplied from an adjacent mine. Unit 1 has a gross design output capacity of 257 MW and was initially placed into commercial service in 1970. Unit 2 has a gross original design output capacity of 477 MW and was initially put into service in 1977. The units are located approximately 40 miles northwest of Bismarck, ND.

2. MPC is performing a SCR cost estimate for both units as part of a NO_X BACT Study required by the North Dakota Department of Health. Because of the unique characteristics of North Dakota lignite, MPC is requesting assistant with SCR catalyst selection and sizing.

3. The scope of services MPC is requesting includes the following for both low dust and tail end SCR applications for both units:

   a. Size the reactors to provide the optimal gas velocity and NO_X reduction for the specific applications.

   b. Provide anticipated guarantees for NO_X reduction for the specific applications. Nominal anticipated NO_X concentration entering the reactors is 0.5 lb/million Btu. Nominal desired maximum NO_X concentration exiting the reactors is 0.05 lb/million Btu.

   c. Provide anticipated guarantees for ammonia usage and ammonia slip for the specific applications. The maximum ammonia slip should not exceed 5 ppm.

   d. Provide anticipated guarantees for catalyst deactivation rate and life (number of operating hours between catalyst replacement). It is desired to have a 3 year interval between catalyst layer change-out. If a 3 year interval is not achievable, provide the longest interval the catalyst vendor is able to guarantee.

   e. Provide budgetary pricing for the recommended catalyst.

   f. Review preliminary ductwork layout drawings to determine if any fatal flaws are apparent.

4. Additional design parameters and flue gas testing results are included as an attachment. It is the intent that Dr. Steve Benson and other team members will discuss the test data and related implications of the catalyst selection and design with the catalyst supplier.

5. Please provide requested items by September 18, 2009.

MICROBEAM
TECHNOLOGIES, INC.
www.microbeam.com

FINAL REPORT:

ASSESSMENT OF PARTICULATE CHARACTERISTICS UPSTREAM AND DOWNSTREAM OF ESP AND WET FGD

Prepared for:

Andrew Freidt
Permit and Compliance Engineer
Minnkota Power Cooperative, Inc.
Milton R. Young Power Station
Center, ND

Prepared by:

Margaret Laumb, Research Engineer and
Steve Benson, President
Microbeam Technologies, Inc.

John Kay and
Don McCollor
UND Energy and Environmental Research Center

Frank Bowman and
Dennis Sisk
UND Chemical Engineering

July 1, 2009

MTI Report 1084 – final

Confidential

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EXECUTIVE SUMMARY

Particulate sampling was conducted at Minnkota Power Cooperative's Milton R. Young plant to determine the particulate size and composition distribution of samples collected upstream of the ESP, upstream of the wet scrubber, and downstream of the wet scrubber. Emphasis was placed on determining the fate of sodium, potassium, and calcium since these elements can cause significant plugging and deposition problem.

During the testing, operating conditions of the plant were constant and there was no gas bypass. The coal fired during the testing remained relatively consistent. The as-received ash content ranged from 7.73 to 7.89%. Sodium oxide content of the ash ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing (a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels). Sampling upstream of the ESP and scrubber were conducted using a combination multicylones and impactors. The cyclones collected sized fractions of larger particles (greater than one to five microns) and the impactor collected the sub-micron particulate. Sampling downstream of the scrubber was conducted with a single cyclone followed by a 13-stage advanced impactor. In addition, the submicron particle number concentration was measured using a scanning mobility particle sizer (SMPS).

The results of the particulate mass information indicated a high loading at the ESP inlet of 4.96×10^6 µg/dscm, a scrubber inlet loading of 1.1×10^4 µg/dscm, and a scrubber outlet loading of 1.08×10^4 µg/dscm. These results show very little overall removal of the submicron particulate across the wet scrubber system. A significant fraction of the particulate was removed by the ESP, with a removal efficiency of 99.76%.

The size distribution of the particulate collected upstream of the ESP and upstream of the scrubber was multi-modal as summarized below:

- Upstream of the ESP there were at least three modes – a larger mode at 40 to 50 µm, a second mode at just under 10 µm, and third mode at about 1 µm. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite. The intermediate-sized particles are typically derived from small minerals and organically associated elements. The smaller mode (about one-micron and smaller) contains fine particles and condensed vapor phase species.
- Upstream of the scrubber there were two distinct modes – a larger mode between 8 to 10 µm and another mode centered at about 1 to 2 µm in diameter. The smaller mode is typically condensed vapor phase and small particles.
- Downstream of the scrubber, the primary mode centered at about 0.5 to 0.7 µm, and another possible mode occurred at 3 µm and larger.
- Particle number distributions were as follows:
    - Inlet to the ESP – between 1×10^7 to 10^8 particles per dry normal cubic centimeter (dncc);
    - Inlet to the scrubber is 10^5 particles/dncc;
    - Outlet of the scrubber 7×10^5 particles/dncc.

- Particle number distributions into the nanometer scale (1 µm = 1000 nm) was found to be as high as 10^5 particles/dncc.

Particle composition distributions of the particulate were determined for each of the major elements. The results were reported as µg/dscm of the element as illustrated in the Appendix and in the figures in the text.

- Upstream of the ESP the composition trends for sodium, potassium, calcium and sulfur showed greater concentrations of these elements in the particles that are smaller than 10 µm, with a significant increase in concentration in the flue gas at a particle size of less than 2 µm. There is another increase at 0.1 µm.
- Upstream of the scrubber the compositional trends for sodium, potassium, calcium and sulfur show higher levels at the 1 µm level. The ESP was effective in removing larger-sized particles, as well as some of the 0.1 µm particles. However, in the intermediate 1 µm particles, the ESP is not as effective in removing the particles.
- Downstream of the scrubber the composition size distribution determined for sodium, potassium, calcium and sulfur showed significant levels of sodium and sulfur in size fraction finer than 1 µm. The DLPI sampling system provides very accurate sizing data in the submicron size range. Other elements such as aluminum, silicon and iron show a significant depletion below 1 µm.

Comparison of the characteristics of the particles in terms of mass and composition indicate that, at the time of the testing, the total average mass of the particulate was about 10,800 µg/dscm. The particulate consisted mainly of sodium, potassium, and sulfur. The total quantity of sodium and potassium exiting was between 2000 to 3000 µg/dscm.

INTRODUCTION AND BACKGROUND

Microbeam Technologies, Inc. (MTI) teamed with Energy & Environmental Research Center (EERC) and the Chemical Engineering Department at the University of North Dakota (UND-ChE) to determine the abundance and composition of particulate materials produced at Unit #2 of Minnkota Power Cooperative's Milton R. Young Station (MRY), equipped with an electrostatic precipitator (ESP) and a wet flue gas desulfurization (FGD) system.

Very small particles or aerosols are produced upon combustion of all fuels. These particles have diameters less than ten microns, and in many cases less than one micron. They are formed during the combustion process - when the fuel is exposed to high temperatures and gaseous environments, impurities within the fuel are vaporized. When the gas is cooled, the vaporized species condense to form the small particles or aerosols.

Abundance and composition of the aerosols vary depending upon the fuel type and the combustion system. High-temperature combustion systems, such as cyclone-fired systems, produce higher levels of vaporized species than other combustion system types. Fuels (such as biomass or lignite) that contain high levels of alkali (sodium and potassium) and alkaline earth elements (calcium and magnesium) are especially likely to produce abundant aerosols in the cooler regions of combustion systems, such as air pollution control systems.

Collection of aerosol particles finer than five- to ten-microns in electrostatic precipitators and scrubbers is difficult because physical processes used by these technologies to capture particles are very limited in the one-tenth to five-micron size range. Detailed discussion of the processes can be found in the appendix of this report.

This report contains the results of analyses performed on coal and ash samples collected during field testing at MRY Unit 2. The work was performed to determine the properties (including size, mass, and composition) of particulates collected upstream and downstream electrostatic precipitator and wet FGD.

GOALS AND OBJECTIVES

Objectives of the project were as follows: 1) obtain representative, size-segregated samples of particulate material, including super- and sub-micron particulate, from three locations; 2) perform analyses on these samples to determine the size, mass, and composition distribution; and 3) provide an assessment of the probable impact of particulate inorganic species on the performance of NO_x reduction technologies.

SAMPLE COLLECTION AND CHARACTERIZATION

Sampling

Particulate material in the flue gas was collected and measured upstream and downstream of the MRY electrostatic precipitator, also denoted as the "air heater inlet" and at the wet flue gas desulfurization (FGD) or "scrubber inlet". Multi-cyclone samples were taken at the locations during the impactor testing. Sampling at the ESP inlet and scrubber inlet were conducted at single port locations and traversed for depth. The sampling at the ESP inlet was performed using two different ports; the total sampling time was divided equally between the selected sampling depths. The sampling depths, along with a summary of sampling activities, are summarized in **Table 1**. Sampling locations are shown on a simplified schematic in **Figure 1**.

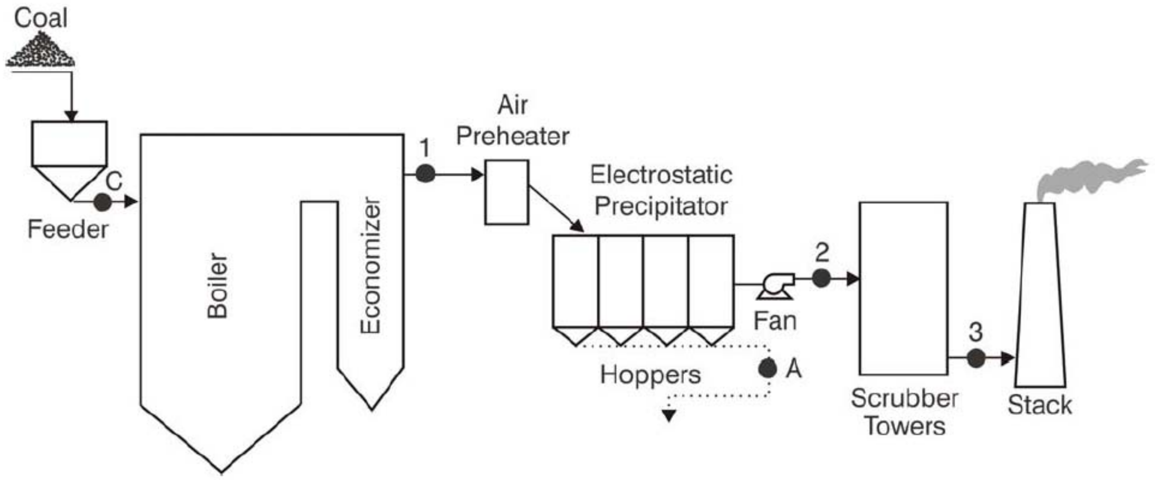


Figure 1. Location of sampling points at MRY Unit 2.

Table 1. Summary of sampling activities at MRY Unit 2.

Test	Location	Date	Start Time	End Time	Duration (minutes)	Sampling Depth (inches)	Notes
IMP/MC Test #1	ESP inlet	3/17/2009	15:40	16:23	43	56,112,161	Figure 1 – point 1
IMP/MC Test #5	ESP inlet	3/19/2009	13:37	13:49	12	56,112,168	Figure 1 – point 1
IMP/MC Test #2	ESP outlet/B scrubber inlet	3/16/2009	16:35	18:13	98	48,102,161	Figure 1 – point 2
IMP/MC Test #3	ESP outlet/B scrubber inlet	3/17/2009	13:47	15:47	120	48,102,161	Figure 1 – point 2
IMP/MC Test #4	ESP outlet/B scrubber inlet	3/18/2009	13:00	15:00	120	48,102,161	Figure 1 – point 2
IMP/MC Test #6	ESP outlet/B scrubber inlet	3/19/2009	12:20	14:20	120	48,102,161	Figure 1 – point 2
SMPS	B Scrubber outlet	3/18/2009			240	~84	Figure 1 – point D
SMPC	B Scrubber outlet	3/19/2009			240	~84	Figure 1 – point D
Dekati "SEM"	B Scrubber outlet	3/18/2009	16:30	17:30	60		*Not weighed* Figure 1 – point D
Dekati Run #1	B Scrubber outlet	3/18/2009	22:00	23:15	75		Figure 1 – point D
Dekati Run #2	B Scrubber outlet	3/19/2009	13:00	16:00	180		Figure 1 – point D

Sample	Location	Date	Time Collected	Notes
ESP ash sample	3B1 - row 1	3/19/2009	14:00	Figure 1 – point A
ESP ash sample	3B2 - row 2	3/19/2009	14:00	Figure 1 – point A
ESP ash sample	3B3 - row 3	3/19/2009	14:00	Figure 1 – point A
ESP ash sample	3B4 - row 4	3/19/2009	14:00	Figure 1 – point A
Coal sample	Feeder 1	3/16/2009	17:05	Figure 1 – point C
Coal sample	Feeder 6	3/16/2009	17:10	Figure 1 – point C
Coal sample	Feeder 7	3/16/2009	17:15	Figure 1 – point C
Coal sample	Feeder 12	3/16/2009	17:00	Figure 1 – point C
Coal sample	Feeder 1	3/17/2009	14:40	*Labeled 13:40 - Assumed to be 14:40* Figure 1 – point C

Sample	Location	Date	Time Collected	Notes
Coal sample	Feeder 6	3/17/2009	14:50	Figure 1 – point C
Coal sample	Feeder 7	3/17/2009	14:55	Figure 1 – point C
Coal sample	Feeder 12	3/17/2009	14:30	Figure 1 – point C
Coal sample	Feeder 1	3/17/2009	17:55	Figure 1 – point C
Coal sample	Feeder 6	3/17/2009	18:00	Figure 1 – point C
Coal sample	Feeder 7	3/17/2009	18:30	Figure 1 – point C
Coal sample	Feeder 12	3/17/2009	17:50	Figure 1 – point C
Coal sample	Feeder 1	3/18/2009	14:10	Figure 1 – point C
Coal sample	Feeder 6	3/18/2009	16:25	Figure 1 – point C
Coal sample	Feeder 7	3/18/2009	16:15	Figure 1 – point C
Coal sample	Feeder 12	3/18/2009	14:00	Figure 1 – point C
Coal sample	Feeder 1	3/18/2009	19:50	Figure 1 – point C
Coal sample	Feeder 6	3/18/2009	19:45	Figure 1 – point C
Coal sample	Feeder 7	3/18/2009	19:45	Figure 1 – point C
Coal sample	Feeder 12	3/18/2009	19:50	Figure 1 – point C
Coal sample	Feeder 1	3/19/2009	14:15	Figure 1 – point C
Coal sample	Feeder 6	3/19/2009	14:30	Figure 1 – point C
Coal sample	Feeder 7	3/19/2009	14:20	Figure 1 – point C
Coal sample	Feeder 12	3/19/2009	14:10	Figure 1 – point C

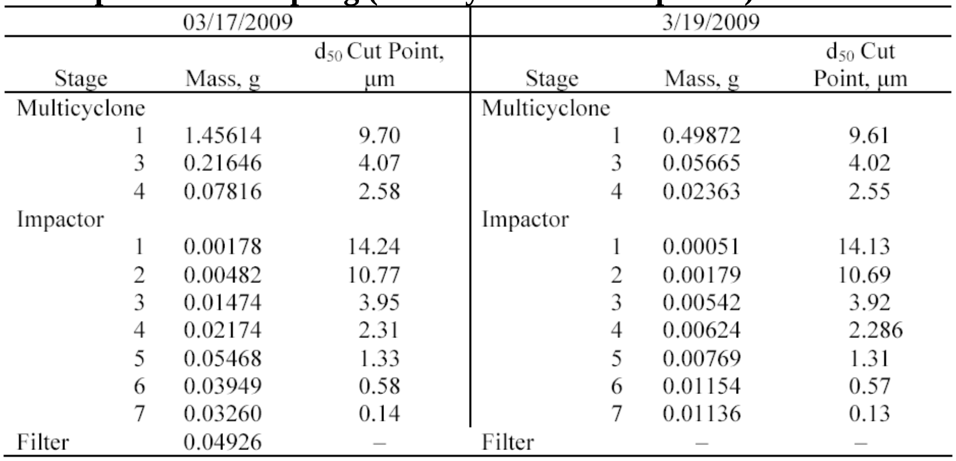
Multicyclone Sampling

Size-fractionated fly ash samples were collected with a Southern Research Institute multi-staged multi-cyclone placed in the duct work at the air heater inlet (ESP inlet). The multicyclone consists of five cyclones, with decreasing d50 cut points, placed in series. The d50 particle size for each test is determined by the temperature and gas flow rate through the cyclone. For the testing at the MRY station, three of the five cyclone stages were used, along with the impactor, to collect selected coarser and finer fractions simultaneously. Size cut data for the multicyclone sampling performed at the air heater inlet are shown in **Table 2**.

Impactor Sampling

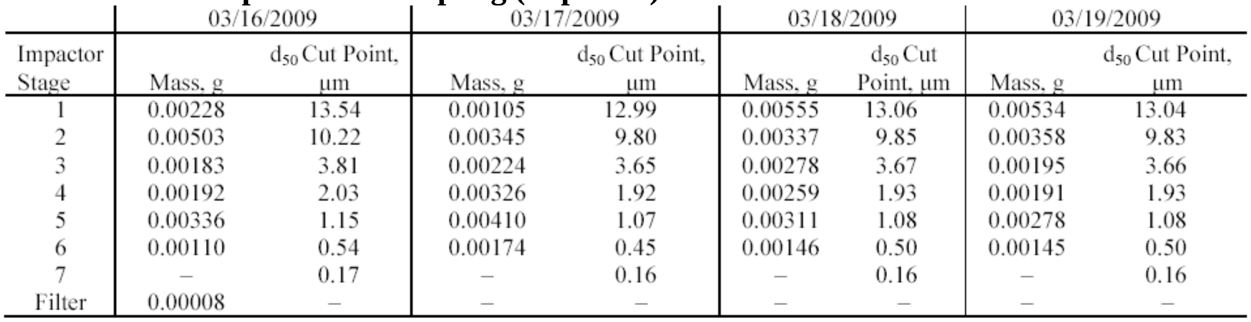
Size-fractionated fly ash samples were collected with a University of Washington seven-stage impactor placed in the gas stream behind the three multi-cyclone stages at the ESP inlet, and was used without multi-cyclone stages at the ESP outlet/scrubber inlet sampling location. The impactor is a round hole, multiple jet-type impactor with seven stages and a backup filter. Each stage has a decreasing d50 cut point. The d50 particle sizes for each test are determined by temperature and gas flow rate through the impactor. Cut points for the impactor at the air heater inlet are shown in **Table 2**. Cut points for the impactor at the scrubber inlet are shown in **Table 3**.

Table 2. D50 cut points for sampling (multicyclone and impactor) at the air heater inlet.



03/17/2009			3/19/2009		
Stage	Mass, g	d_{50} Cut Point, µm	Stage	Mass, g	d_{50} Cut Point, µm
Multicyclone			Multicyclone		
1	1.45614	9.70	1	0.49872	9.61
3	0.21646	4.07	3	0.05665	4.02
4	0.07816	2.58	4	0.02363	2.55
Impactor			Impactor		
1	0.00178	14.24	1	0.00051	14.13
2	0.00482	10.77	2	0.00179	10.69
3	0.01474	3.95	3	0.00542	3.92
4	0.02174	2.31	4	0.00624	2.286
5	0.05468	1.33	5	0.00769	1.31
6	0.03949	0.58	6	0.01154	0.57
7	0.03260	0.14	7	0.01136	0.13
Filter	0.04926	–	Filter	–	–

Table 3. D50 cut points for sampling (impactor) at the B scrubber inlet.



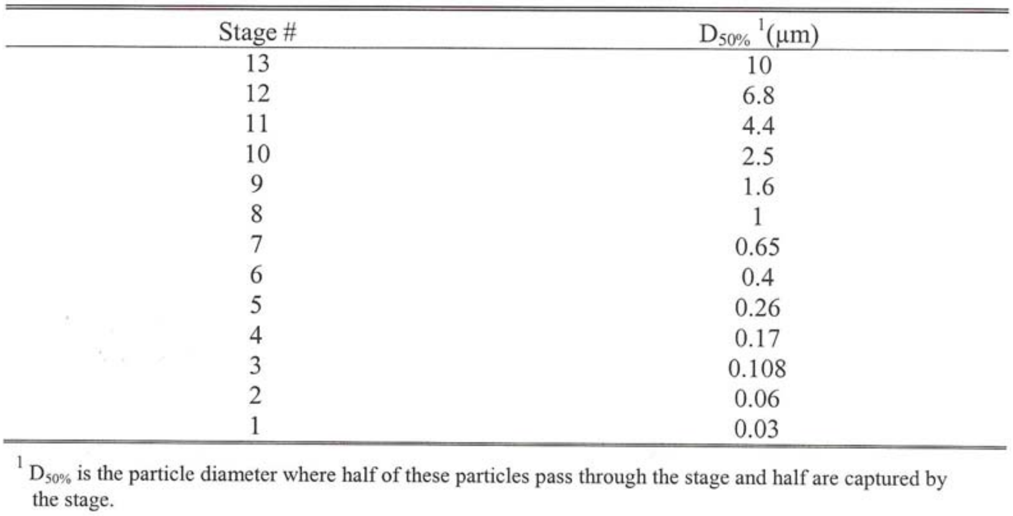
	03/16/2009		03/17/2009		03/18/2009		03/19/2009	
Impactor Stage	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm
1	0.00228	13.54	0.00105	12.99	0.00555	13.06	0.00534	13.04
2	0.00503	10.22	0.00345	9.80	0.00337	9.85	0.00358	9.83
3	0.00183	3.81	0.00224	3.65	0.00278	3.67	0.00195	3.66
4	0.00192	2.03	0.00326	1.92	0.00259	1.93	0.00191	1.93
5	0.00336	1.15	0.00410	1.07	0.00311	1.08	0.00278	1.08
6	0.00110	0.54	0.00174	0.45	0.00146	0.50	0.00145	0.50
7	–	0.17	–	0.16	–	0.16	–	0.16
Filter	0.00008	–	–	–	–	–	–	–

DLPI Sampling

The Dekati Low Pressure Impactor (DLPI) is a state-of-the-art 13-stage cascade impactor for measuring gravimetric particle size distribution of very small particles. It size-classified particles from 10 microns (µm) to 30 nm, and a filter stage accessory enables collection of particles smaller than 30 nm in diameter. **Figure 2** shows the impactor and stages. The d50 cut points for sampling with the DLPI are shown in **Table 4**.

Figure 2. Dekati Low-Pressure Impactor.

Table 4. D50 cut points for sampling (Dekati Low Pressure Impactor) at the B scrubber outlet.



Stage #	$D_{50\%}$ [1] (μm)
13	10
12	6.8
11	4.4
10	2.5
9	1.6
8	1
7	0.65
6	0.4
5	0.26
4	0.17
3	0.108
2	0.06
1	0.03

[1] $D_{50\%}$ is the particle diameter where half of these particles pass through the stage and half are captured by the stage.

SMPS Sampling

Sampling at the scrubber outlet was conducted utilizing the scanning mobility particle scanning (SMPS) system that consists of an electrostatic classifier (EC), a condensation particle counter (CPC), and data analysis center (DAC). A schematic of the system is shown in **Figure 3**. The EC classifies the particles, and the concentration is measured by the CPC. The DAC includes a personal computer with custom software, which controls individual instruments and performs data reduction. The components of the SMPS system, particularly the CPC, function normally at about 35°C (95°F). However, the EC does not appear to be too sensitive to temperature conditions.

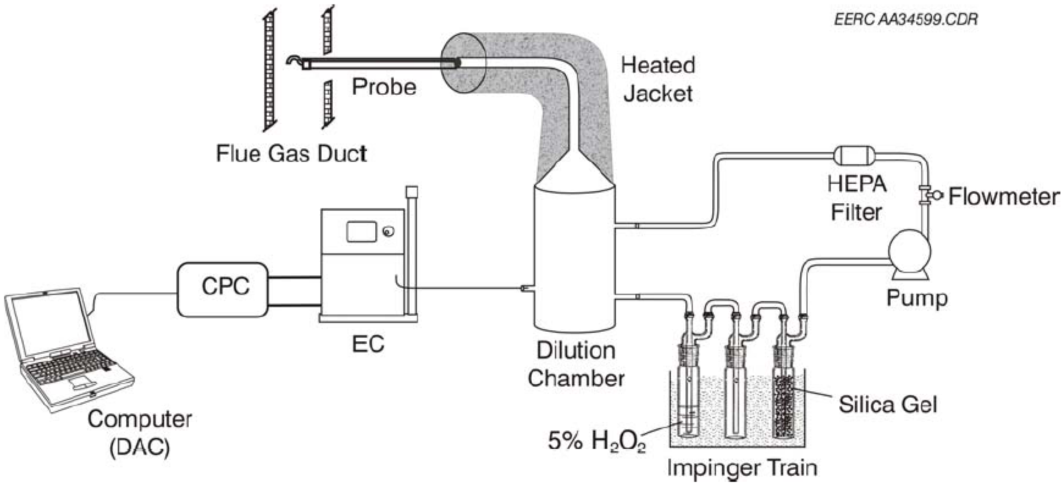


Figure 3. Schematic of the scanning mobility particle scanning (SMPS) system used at the B scrubber outlet.

The procedure for making particulate measurements with the SMPS system is conceptually simple, although manipulating the entire system is quite complex. Typically, flue gas enters the dilution chamber and is mixed with excess air fed through an external pump and at the flow rate of about 45–50 liters per minute (lpm). Dilution air from the pump passes through a HEPA filter to remove any particles that may be in the air. Part of the dilution air is sucked back from the dilution chamber and passed through an impinger train; the wet impinger contains about 250 milliliters (mL) of a 5% hydrogen peroxide (H_2O_2) solution, and the air is dried by passing it through a silica gel flask. The air from the flask is circulated through the pump back to the dilution chamber, and the recirculation process continues for the duration of the measurement. At the bottom of the dilution chamber, a ¼-inch line extracts a sample of the diluted flue gas and delivers it to the EC. The flow rates and pressure drop used in the EC are shown in **Table 5**.

Table 5. Electrostatic classifier (EC) flow meter set points.

Parameter	Monodisperse Air	Sheath Air	Excess Air
Flow Rate, lpm	0.3	3	3
Output, volts	2.305	2.735	2.627
Pressure Drop, cm H_2O	9	N/A*	N/A

* Not applicable.

Measurement does not begin until the CPC is running normally and flow is stable. At a typical working temperature of about 35°C (95°F), indicator lights are checked to ensure all parts are functioning properly (including the liquid level, laser, optics, pump flow, condenser, and saturator). The liquid used in running the CPC is n-butyl alcohol (n-butanol).

Analysis

Table 6 contains a full list of the samples collected and analyses performed. Samples collected were analyzed to determine chemical composition. Scanning electron microscopy with x-ray elemental analysis was performed on the ash samples. Information gained from this method included images and point and area (average) analyses. This type of analysis is called "morphology" because it combines image analysis for features of interest with chemical analysis.

The multicyclone samples were analyzed using bulk chemical anlaysis at EERC. The bulk analysis involved microwave digestion of the ash followed by inductively-coupled plasma-mass spectrometry (ICP-MS). Concentrations of the major elements sodium, potassium, phosphorus, calcium, magnesium and iron were determined.

The coal samples collected during the tests were composited for standard ASTM tests (proximate and ash composition or "mineral ash" analysis) and for computer-controlled scanning electron microscopy (CCSEM) analysis, which provides information on mineral types, abundance, and sizes within the coal.

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-083	3/17/2009	IMP/MC Test #1 - Cyclone nozzle	ESP inlet (A/H inlet)	None
09-084	3/17/2009	IMP/MC Test #1 - Cyclone #1	ESP inlet (A/H inlet)	Morphology
09-085	3/17/2009	IMP/MC Test #1 - Cyclone #3	ESP inlet (A/H inlet)	Morphology
09-086	3/17/2009	IMP/MC Test #1 - Cyclone #4	ESP inlet (A/H inlet)	Morphology
09-087	3/17/2009	IMP/MC Test #1 - Impactor Stage 1	ESP inlet (A/H inlet)	Morphology
09-088	3/17/2009	IMP/MC Test #1 - Impactor Stage 2	ESP inlet (A/H inlet)	Morphology
09-089	3/17/2009	IMP/MC Test #1 - Impactor Stage 3	ESP inlet (A/H inlet)	Morphology
09-090	3/17/2009	IMP/MC Test #1 - Impactor Stage 4	ESP inlet (A/H inlet)	Morphology
09-091	3/17/2009	IMP/MC Test #1 - Impactor Stage 5	ESP inlet (A/H inlet)	Morphology
09-092	3/17/2009	IMP/MC Test #1 - Impactor Stage 6	ESP inlet (A/H inlet)	Morphology
09-093	3/17/2009	IMP/MC Test #1 - Impactor Stage 7	ESP inlet (A/H inlet)	Morphology
09-094	3/17/2009	IMP/MC Test #1 - Impactor outlet (backup filter)	ESP inlet (A/H inlet)	Morphology
09-097	3/18/2009	Dekati Run #1 - Stage 1	Scrubber outlet	Morphology
09-098	3/18/2009	Dekati Run #1 - Stage 2	Scrubber outlet	Morphology
09-099	3/18/2009	Dekati Run #1 - Stage 3	Scrubber outlet	Morphology
09-100	3/18/2009	Dekati Run #1 - Stage 4	Scrubber outlet	Morphology
09-101	3/18/2009	Dekati Run #1 - Stage 5	Scrubber outlet	Morphology
09-102	3/18/2009	Dekati Run #1 - Stage 6	Scrubber outlet	Morphology
09-103	3/18/2009	Dekati Run #1 - Stage 7	Scrubber outlet	Morphology
09-104	3/18/2009	Dekati Run #1 - Stage 8	Scrubber outlet	Morphology
09-105	3/18/2009	Dekati Run #1 - Stage 9	Scrubber outlet	Morphology
09-106	3/18/2009	Dekati Run #1 - Stage 10	Scrubber outlet	Morphology
09-107	3/18/2009	Dekati Run #1 - Stage 11	Scrubber outlet	Morphology
09-108	3/18/2009	Dekati Run #1 - Stage 12	Scrubber outlet	Morphology
09-109	3/18/2009	Dekati Run #1 - Stage 13	Scrubber outlet	Morphology
09-110	3/18/2009	Dekati "SEM" - Stage 1	Scrubber outlet	None
09-111	3/18/2009	Dekati "SEM" - Stage 2	Scrubber outlet	None
09-112	3/18/2009	Dekati "SEM" - Stage 3	Scrubber outlet	None
09-113	3/18/2009	Dekati "SEM" - Stage 4	Scrubber outlet	None
09-114	3/18/2009	Dekati "SEM" - Stage 5	Scrubber outlet	None
09-115	3/18/2009	Dekati "SEM" - Stage 6	Scrubber outlet	None
09-116	3/18/2009	Dekati "SEM" - Stage 7	Scrubber outlet	None
09-117	3/18/2009	Dekati "SEM" - Stage 8	Scrubber outlet	None

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-118	3/18/2009	Dekati "SEM" - Stage 9	Scrubber outlet	None
09-119	3/18/2009	Dekati "SEM" - Stage 10	Scrubber outlet	None
09-120	3/18/2009	Dekati "SEM" - Stage 11	Scrubber outlet	None
09-121	3/18/2009	Dekati "SEM" - Stage 12	Scrubber outlet	None
09-122	3/18/2009	Dekati "SEM" - Stage 13	Scrubber outlet	None
09-123	3/19/2009	Dekati Run #2 - Stage 1	Scrubber outlet	Morphology
09-124	3/19/2009	Dekati Run #2 - Stage 2	Scrubber outlet	Morphology
09-125	3/19/2009	Dekati Run #2 - Stage 3	Scrubber outlet	Morphology
09-126	3/19/2009	Dekati Run #2 - Stage 4	Scrubber outlet	Morphology
09-127	3/19/2009	Dekati Run #2 - Stage 5	Scrubber outlet	Morphology
09-128	3/19/2009	Dekati Run #2 - Stage 6	Scrubber outlet	Morphology
09-129	3/19/2009	Dekati Run #2 - Stage 7	Scrubber outlet	Morphology
09-130	3/19/2009	Dekati Run #2 - Stage 8	Scrubber outlet	Morphology
09-131	3/19/2009	Dekati Run #2 - Stage 9	Scrubber outlet	Morphology
09-132	3/19/2009	Dekati Run #2 - Stage 10	Scrubber outlet	Morphology
09-133	3/19/2009	Dekati Run #2 - Stage 11	Scrubber outlet	Morphology
09-134	3/19/2009	Dekati Run #2 - Stage 12	Scrubber outlet	Morphology
09-135	3/19/2009	Dekati Run #2 - Stage 13	Scrubber outlet	Morphology
09-136	3/18/2009	IMP Test #4 - Inlet nozzle	ESP outlet/scrubber inlet	Morphology
09-137	3/18/2009	IMP Test #4 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-138	3/18/2009	IMP Test #4 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-139	3/18/2009	IMP Test #4 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-140	3/18/2009	IMP Test #4 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-141	3/18/2009	IMP Test #4 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-142	3/18/2009	IMP Test #4 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-143	3/18/2009	IMP Test #4 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-144	3/18/2009	IMP Test #4 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-145	3/19/2009	IMP/MC Test #5 - Impactor stage 1	ESP inlet (A/H inlet)	Morphology
09-146	3/19/2009	IMP/MC Test #5 - Impactor stage 2	ESP inlet (A/H inlet)	Morphology
09-147	3/19/2009	IMP/MC Test #5 - Impactor stage 3	ESP inlet (A/H inlet)	Morphology
09-148	3/19/2009	IMP/MC Test #5 - Impactor stage 4	ESP inlet (A/H inlet)	Morphology
09-149	3/19/2009	IMP/MC Test #5 - Impactor stage 5	ESP inlet (A/H inlet)	Morphology
09-150	3/19/2009	IMP/MC Test #5 - Impactor stage 6	ESP inlet (A/H inlet)	Morphology
09-151	3/19/2009	IMP/MC Test #5 - Impactor stage 7	ESP inlet (A/H inlet)	Morphology
09-152	3/19/2009	IMP Test #5 - Impactor outlet (backup filter)	ESP inlet (A/H inlet)	Morphology
09-153	3/19/2009	IMP Test #6 - Inlet nozzle	ESP outlet/scrubber inlet	Morphology
09-154	3/19/2009	IMP Test #6 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-155	3/19/2009	IMP Test #6 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-156	3/19/2009	IMP Test #6 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-157	3/19/2009	IMP Test #6 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-158	3/19/2009	IMP Test #6 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-159	3/19/2009	IMP Test #6 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-160	3/19/2009	IMP Test #6 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-161	3/19/2009	IMP Test #6 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-162	3/19/2009	IMP Test #5 - Film from stage 1	ESP outlet/scrubber inlet	Morphology
09-163	3/18/2009	IMP Test #4 - Film from stage 2 (bottom of jets)	ESP outlet/scrubber inlet	None

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-164	3/18/2009	IMP Test #4 - Film from stage 3 (bottom of jets)	ESP outlet/scrubber inlet	None
09-165	3/18/2009	IMP Test #4 - Film from stage 4 (bottom of jets)	ESP outlet/scrubber inlet	None
09-166	3/18/2009	IMP Test #4 - Film from stage 5 (bottom of jets)	ESP outlet/scrubber inlet	None
09-167	3/19/2009	IMP Test #6 - Film from stage 4 (back of jets)	ESP outlet/scrubber inlet	Morphology
09-168	3/19/2009	IMP/MC Test #5 - Cyclone stage 6	ESP inlet (A/H inlet)	Morphology
09-169	3/19/2009	IMP/MC Test #5 - Cyclone stage 7	ESP inlet (A/H inlet)	Morphology
09-170	3/19/2009	IMP/MC Test #5 - Cyclone #1	ESP inlet (A/H inlet)	Morphology
09-171	3/19/2009	IMP/MC Test #5 - Cyclone #3	ESP inlet (A/H inlet)	Morphology
09-172	3/19/2009	IMP/MC Test #5 - Cyclone #4	ESP inlet (A/H inlet)	Morphology
09-173	3/19/2009	IMP/MC Test #5 - Cyclone nozzle	ESP inlet (A/H inlet)	Morphology
09-174	3/19/2009	ESP Ash - Row 1 3B1	ESP	None
09-175	3/19/2009	ESP Ash - Row 2 3B2	ESP	None
09-176	3/19/2009	ESP Ash - Row 3 3B3	ESP	None
09-177	3/19/2009	ESP Ash - Row 4 3B4	ESP	None
09-178	3/16/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-179	3/17/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-180	3/18/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-181	3/19/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-184	3/16/2009	IMP Test #2 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-185	3/16/2009	IMP Test #2 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-186	3/16/2009	IMP Test #2 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-187	3/16/2009	IMP Test #2 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-188	3/16/2009	IMP Test #2 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-189	3/16/2009	IMP Test #2 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-190	3/16/2009	IMP Test #2 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-191	3/16/2009	IMP Test #2 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-192	3/16/2009	IMP Test #2 - Impactor nozzle	ESP outlet/scrubber inlet	None
09-193	3/17/2009	IMP Test #3 - Impactor stage 1	ESP outlet/scrubber inlet	None
09-194	3/17/2009	IMP Test #3 - Impactor stage 2	ESP outlet/scrubber inlet	None
09-195	3/17/2009	IMP Test #3 - Impactor stage 3	ESP outlet/scrubber inlet	None
09-196	3/17/2009	IMP Test #3 - Impactor stage 4	ESP outlet/scrubber inlet	None
09-197	3/17/2009	IMP Test #3 - Impactor stage 5	ESP outlet/scrubber inlet	None
09-198	3/17/2009	IMP Test #3 - Impactor stage 6	ESP outlet/scrubber inlet	None
09-199	3/17/2009	IMP Test #3 - Impactor stage 7	ESP outlet/scrubber inlet	None
09-200	3/17/2009	IMP Test #3 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	None
09-201	3/17/2009	IMP Test #3 - Impactor nozzle	ESP outlet/scrubber inlet	None

RESULTS AND DISCUSSION

Coal Analysis and Plant Operating Conditions during Testing

The coal samples for each day were composited to form one larger sample; the four resulting composite coal samples were subjected to proximate and ash composition analyses. The results of the analyses are shown in **Table 7**. The coal was relatively consistent over the time period sampled. The as-received ash content ranged from 7.73 to 7.89%. Sodium content ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing as a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels.

Table 7. Proximate and ash composition analyses for four composite coal samples taken from MRY coal feeders on March 16 through 19, 2009.

	MTI 09-178 3/16/09 Composite		**MTI 09-179 3/17/09 Composite**		**MTI 09-208 3/18/09 Composite**		**MTI 09-209 3/19/09 Composite**	
Proximate (wt% in coal)	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*
Total moisture	37.58		37.24		37.23		36.10	
Ash	7.89	12.64	7.85	12.51	7.84	12.49	7.73	12.10
Volatile matter	24.80	39.73	25.15	40.07	25.22	40.18	25.81	40.39
Fixed carbon	29.73	47.63	29.76	47.42	29.71	47.33	30.36	47.51
Heating value (BTU/lb)	6732	10785	6784	10810	6701	10676	6851	10721
Total sulfur	0.90	1.44	1.00	1.59	0.65	1.04	0.77	1.21
Ash Composition (wt% in ash)								
SiO2		26.92		26.08		34.46		31.06
Al2O3		8.78		8.81		11.61		10.63
TiO2		0.39		0.36		0.44		0.39
Fe2O3		11.17		12.96		7.75		8.49
CaO		15.23		14.99		14.01		15.26
MgO		4.55		4.38		4.37		4.70
K2O		1.24		1.55		1.68		1.46
Na2O		7.22		7.57		7.31		7.24
SO3		19.50		18.70		14.88		16.92
P2O5		0.45		0.40		0.33		0.47
SrO		0.45		0.43		0.41		0.44
BaO		0.72		0.55		0.61		0.63
MnO2		0.09		0.08		0.08		0.08
SiO2/Al2O3		***3.07***		***2.96***		***2.97***		***2.92***
Base/Acid		***1.09***		***1.18***		***0.76***		***0.88***

Figures 4 and **5** show the overall coal flow rate, along with the ash quantity and base-to-acid ratio determined with the Full-Stream Elemental Analyzer (FSEA) during the test period. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and feeding coal to the cyclones. These data show a decrease in the base-to-acid ratio during the testing period. This was observed in the analysis of the four daily composite samples.

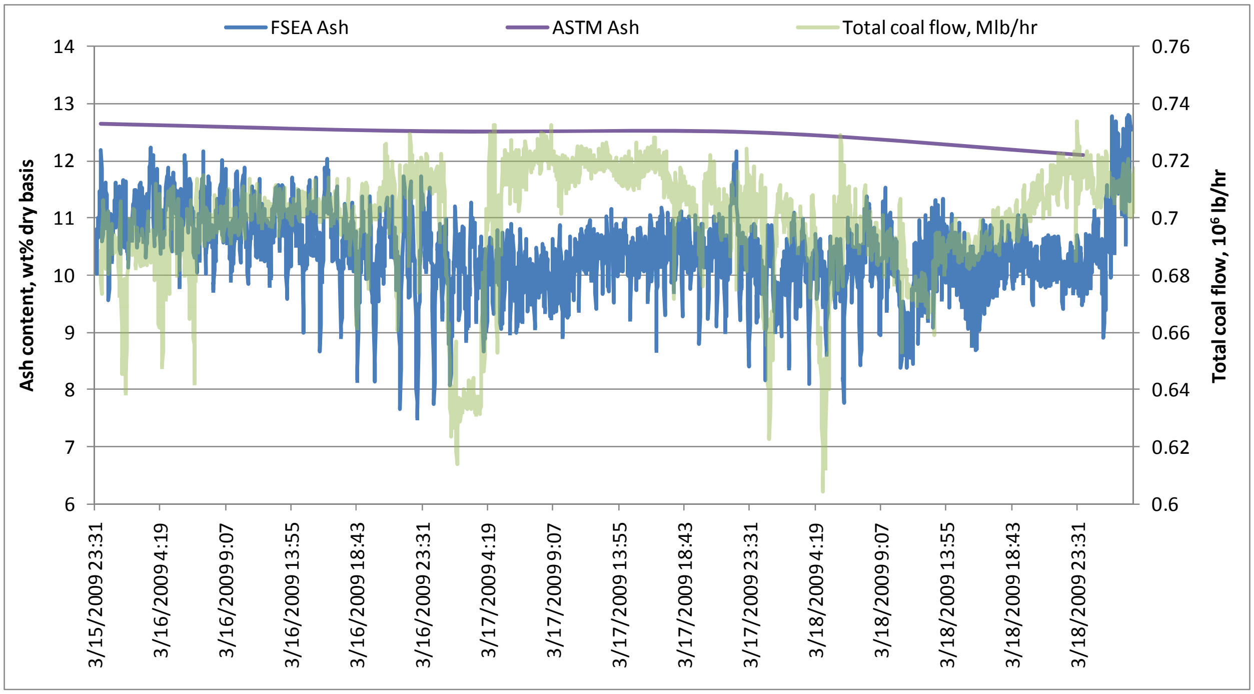


Figure 4. Coal belt flow and fuel ash quantity (determined with FSEA and by ASTM method on composite coal samples) during the testing. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and estimated fuel fed to the cyclones.

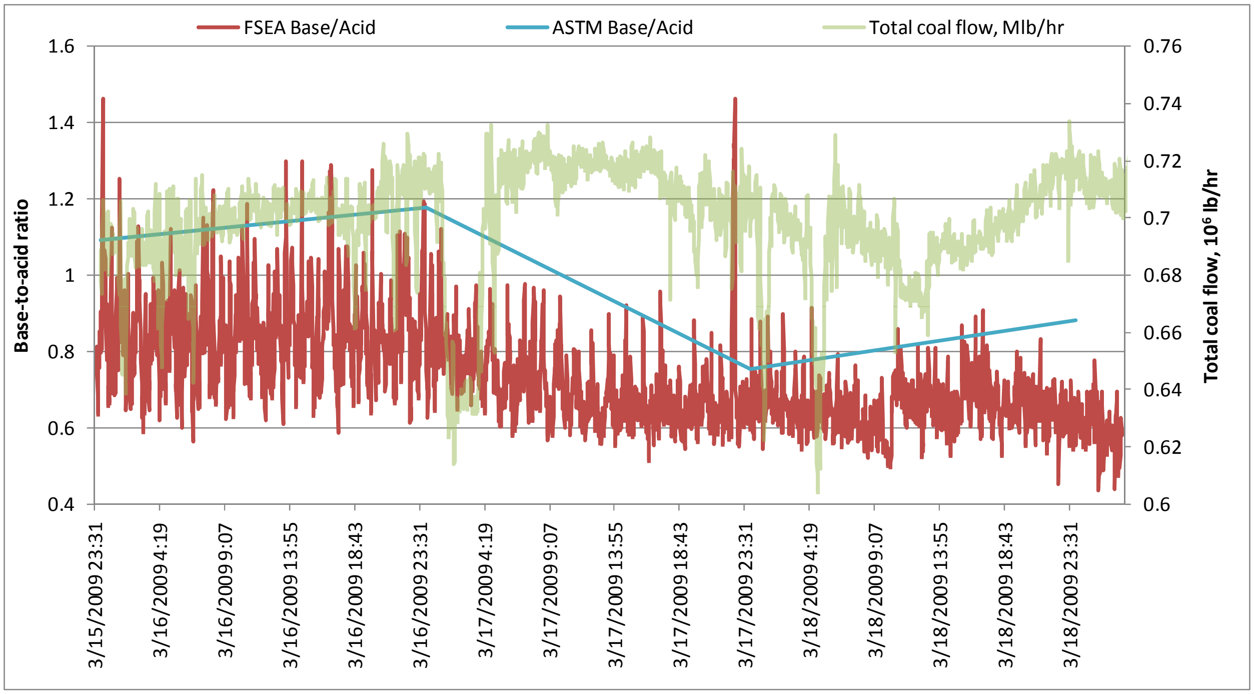


Figure 5. Coal belt flow and base-to-acid ratio (determined with FSEA and by ASTM ash composition analyses performed on composite coal samples) during the testing. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and estimated fuel fed to the cyclones.

Particulate Mass and Number Distribution

Mass Distribution as Function of Location

The total mass loadings obtained with the multicyclone and impactors are illustrated in **Figure 6**. The results show a high average loading of $4.96\text{x}10^6$ micrograms per dry standard cubic meter (µg/dscm) at the ESP inlet, and average scrubber inlet and outlet loadings of $1.1\text{x}10^4$ µg/dscm and $1.08\text{x}10^4$ µg/dscm, respectively. Significant removal of particulate occurred across the ESP, with removal efficiency of 99.76%. These results show that very little removal of particulate material has occurred across the wet scrubber system. This is consistent with past work conducted by Markowski and others (1983) (a literature review is contained in **Appendix B** of this report). The results are also summarized in **Table 8**.

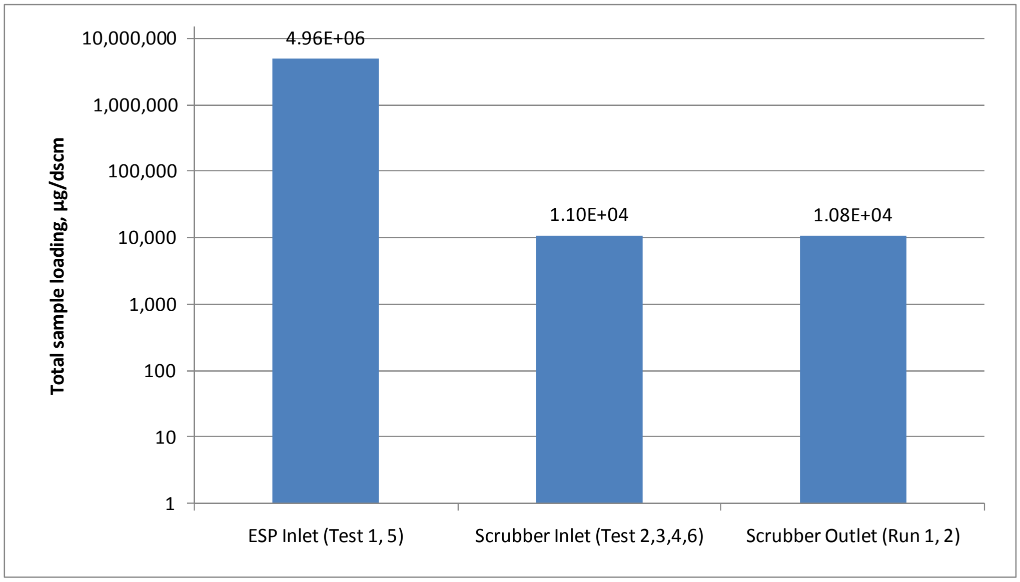


Figure 6. Total mass loadings at ESP inlet, wet scrubber inlet, and wet scrubber outlet.

Table 8. Total mass loadings for all testing conducted at ESP inlet, wet scrubber inlet, and wet scrubber outlet.

				Sampler loading		Total loading
Location	**Date**	**Test #**	**Sampler type**	**mg/dscm**	**µg/dscm**	**µg/dscm**
ESP inlet	3/17/2009	Test 1	Impactor	5.25E+02	5.25E+05	
ESP inlet	3/17/2009	Test 1	Cyclone	4.19E+03	4.19E+06	4.72E+06
Scrubber inlet	3/16/2009	Test 2	Impactor	1.25E+01	1.25E+04	1.25E+04
Scrubber inlet	3/17/2009	Test 3	Impactor	9.77E+00	9.77E+03	9.77E+03
Scrubber inlet	3/18/2009	Test 4	Impactor	1.15E+01	1.15E+04	1.15E+04
ESP inlet	3/19/2009	Test 5	Impactor	3.73E+02	3.73E+05	
ESP inlet	3/19/2009	Test 5	Cyclone	4.84E+03	4.84E+06	5.21E+06
Scrubber inlet	3/19/2009	Test 6	Impactor	1.03E+01	1.03E+04	1.03E+04
Scrubber outlet	3/18/2009	Run 1	Dekati Impactor		9109.506	9.11E+03
Scrubber outlet	3/19/2009	Run 2	Dekati Impactor		12560.87	1.26E+04

Particulate Mass Loading as a Function of Size

Sampling at the ESP inlet was conducted using both the multicyclone and the impactor. The cyclones are designed to capture larger-size particles and the impactor collects small particles. **Figure 7** shows the mass size distributions for the cyclone and impactor. The size distribution of the particulate at the ESP inlet is multimodal. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite minerals. The intermediate-sized particles are typically derived from small minerals and organically associated elements. Particles less than a micron in diameter and finer are condensed vapor phase species.

The sample collected on 3/17/09 show a multimodal size distribution, with a mode occurring at one to three microns, and another mode at 0.1 µm. The sample collected on 3/19/09 also has a multimodal distribution, with a shift in the finer mode from 0.1 µm to about 0.5 µm. This shift may be due to the change in fuel composition (the coal sample collected on 3/17/09 had a higher base-to-acid ratio as compared to the coal collected on 3/19/09).

The mass size distribution of the particulate collected upstream of the scrubber is illustrated in **Figure 8**. Sampling was conducted at this location on all four days of the period. The results show a bimodal distribution of particles with a mode between one to two microns and another mode between seven and eleven microns. A general trend of decreasing abundance of the modes during the testing is observed. The change in abundance is likely due to changes in coal ash composition. Coals sampled on 3/16 and 3/17 had higher base-to-acid ratios; coals on 3/18 and 3/19 had lower ratios.

The mass size distribution of the scrubber outlet particulate is illustrated in **Figure 9**. The size distribution shows a main mode at about 0.8 µm and possibly a minor larger mode of 2 µm. The particle size distribution is shifted to finer particles downstream of the scrubber and the smaller particle size mode appears to dominate the size distribution. The samples were collected on 3/18 and 3/19, when the coals fired had lower base-to-acid ratios.

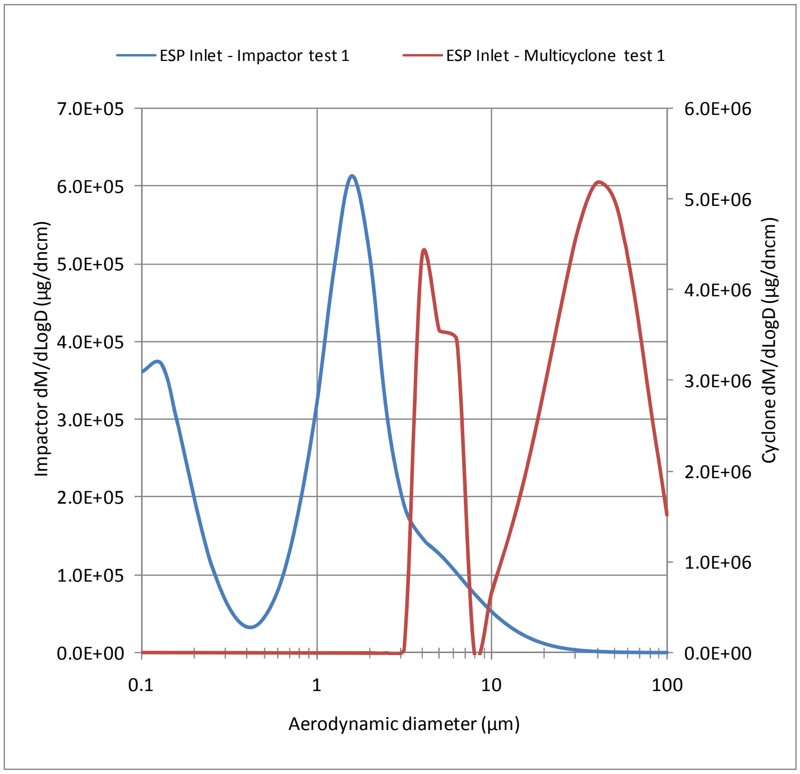


Figure 7a. Multicyclone and impactor data collected at ESP inlet on 3/17/09.

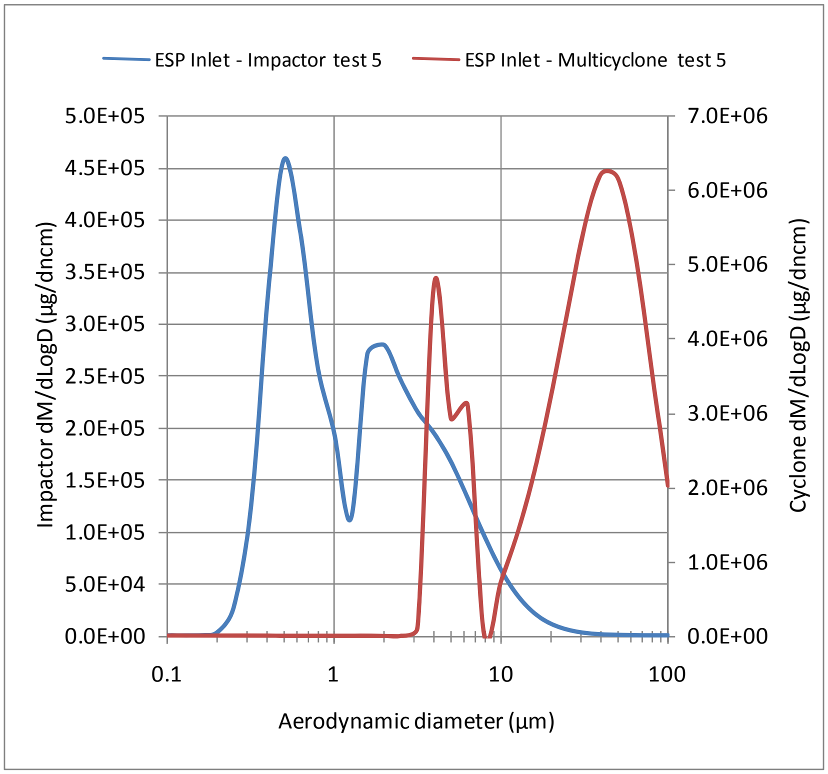


Figure 7b. Multicyclone and impactor data collected at ESP inlet on 3/19/09.

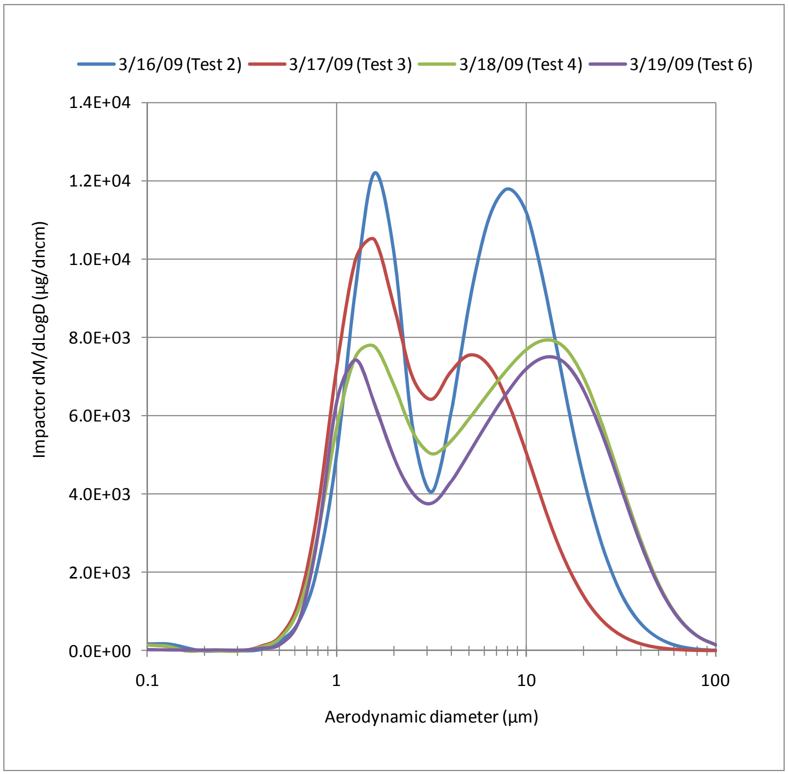


Figure 8. Mass versus size distribution of ash collected downstream of the ESP at the scrubber inlet.

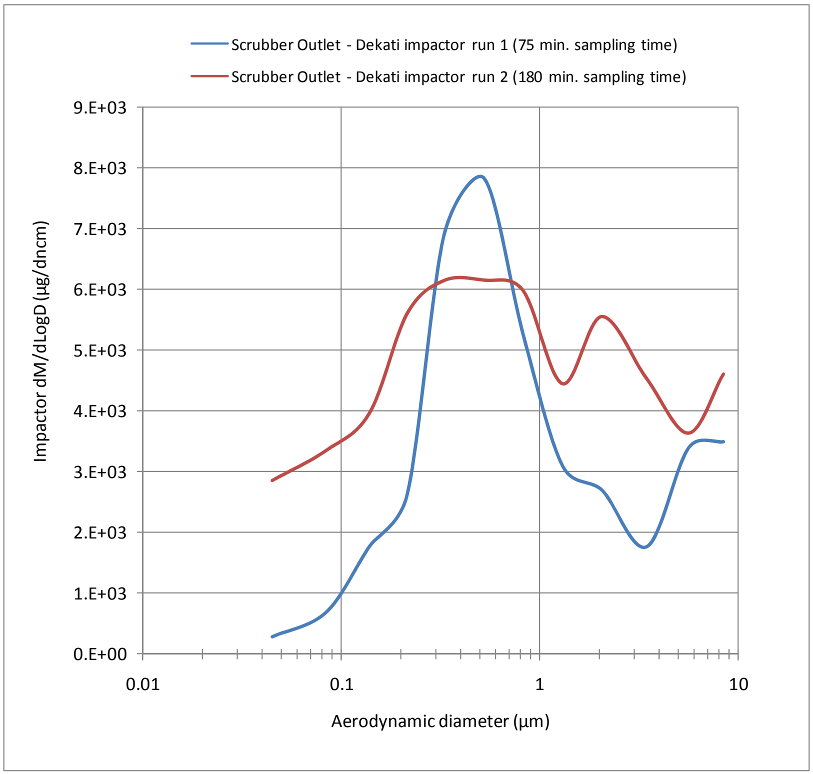


Figure 9. Mass distribution of particulate collected downstream of scrubber.

Particle Number Size Distribution

The number distributions for the particles are shown in **Figures 10** through **12** for the ESP inlet, scrubber inlet, and scrubber outlet. This information is shown as the number of particles per dry normal cubic centimeters (*not* cubic meters ash summarized above). This is the convention used by researchers.

The number of particle increases significantly with decreasing particles size. **Figure 10** shows the number of particles for the scrubber inlet. The ESP inlet sample had the highest number of particles in the smallest size fraction. The number of particles in the smallest size fraction at the scrubber inlet and outlet are similar – the slight increase in number at the scrubber outlet is likely to differences in sampling methods.

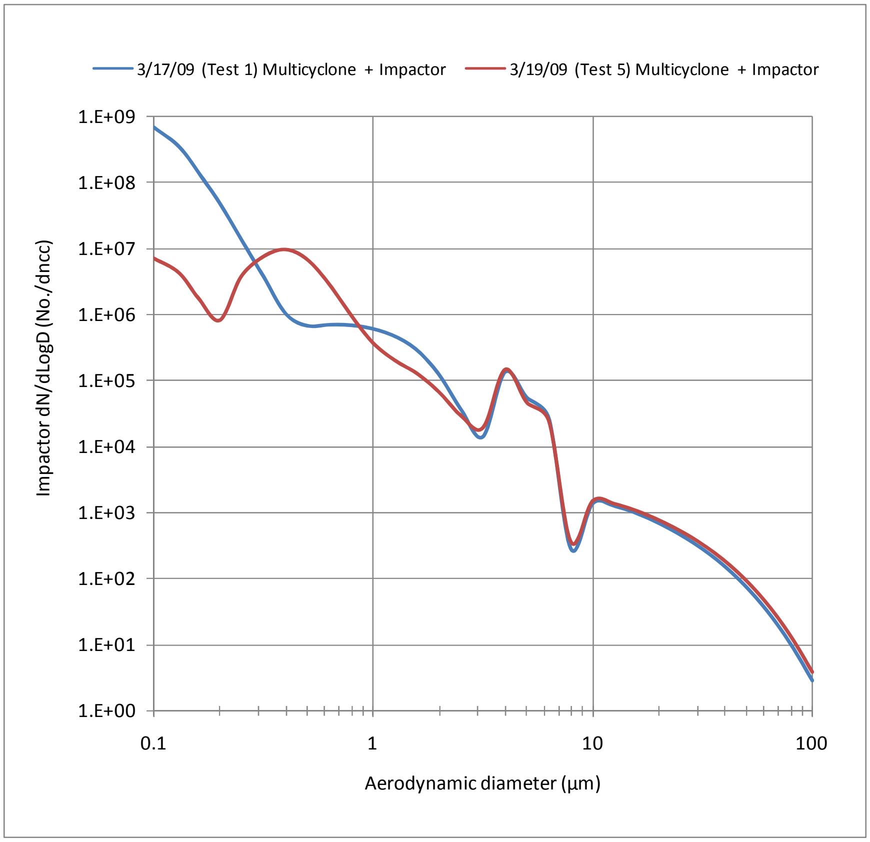


Figure 10. Number of particles as a function of size at the ESP Inlet.

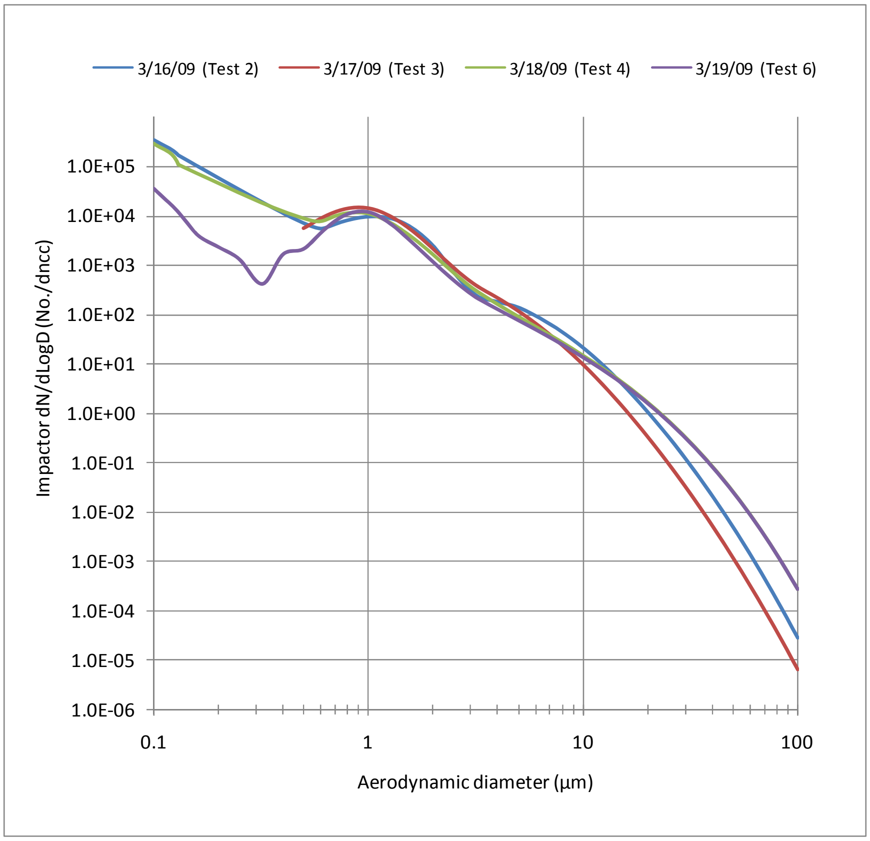


Figure 11. Number of particles as a function of size at the scrubber inlet.

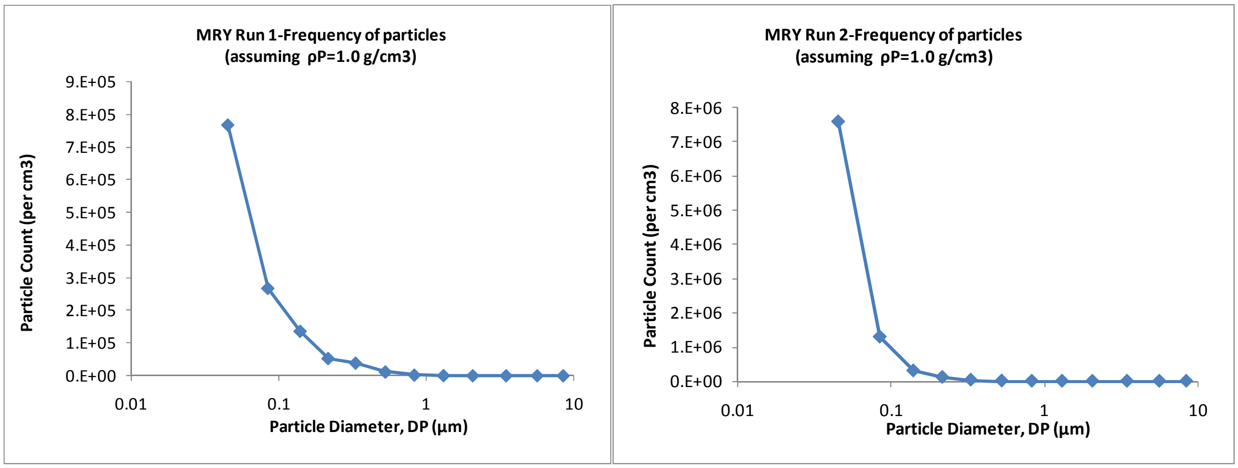


Figure 12. Number of particles as a function of size at the scrubber outlet.

Scanning Mobility Particle Scanning (SMPS)

Number-based concentration data obtained by the SMPS system at the scrubber outlet is shown in **Figures 13** and **14**. The data shown are for the on one good data set obtained during the sampling trip. A summary of the conditions at the sampling site that limited the ability of the SMPS to gain reliable data is listed in the Appendix.

The SMPS reports size data on a nanometer (nm) scale, not a micrometer (µm) scale. There are 1,000 nm in one micron. The data shown was obtained from a 10-sample test run, each 60 seconds apart, and includes two scans per sample: 60 seconds for the up scan and 30 seconds for the down scan. The scan window of the instrument covers a particle range of 16.5–605 nm (0.0165–0.605 µm).

Plots of the concentration versus particle diameter are given in **Figure 13** for number basis and in **Figure 14** for the mass basis. The number of particles observed using the SMPS is larger than that observed for the impactors but it is generally consistent the impactor data.

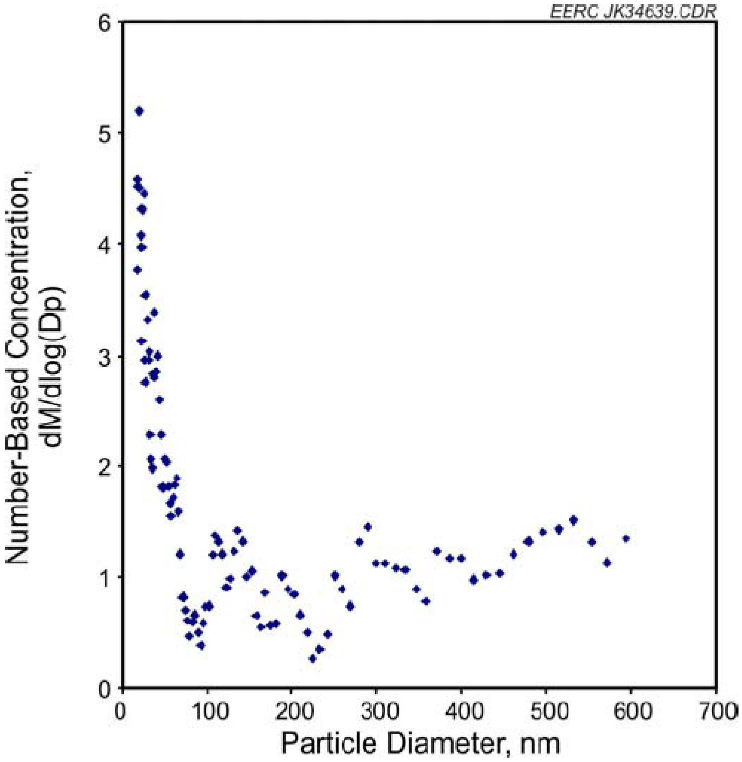


Figure 13. Plot of number-based particle concentration as a function of particle diameter (nanometers).

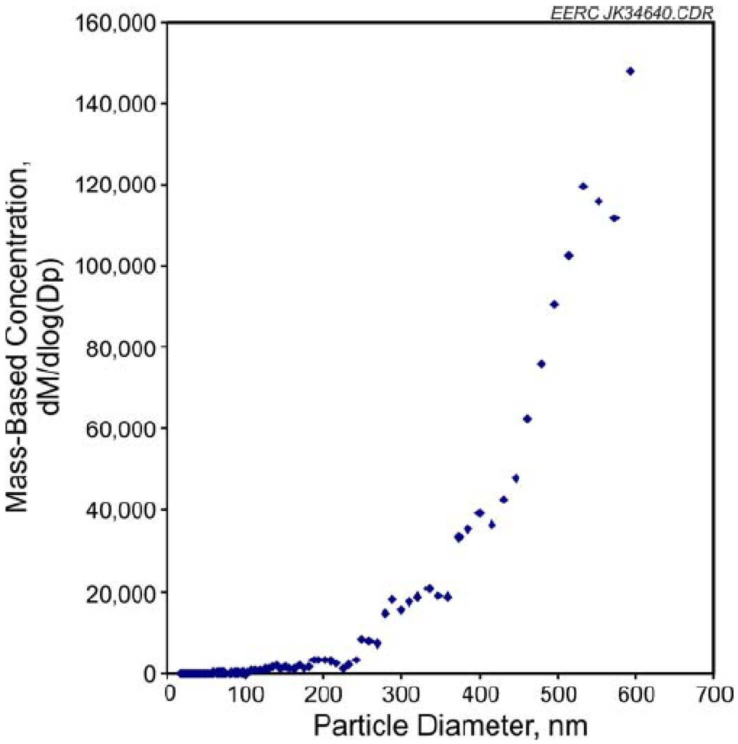


Figure 14. Plot of mass-based particle concentration as a function of particle diameter (nanometers).

Bulk Composition of Ash Materials

The composition of the size fractions of ash materials collected using the multicyclone are summarized for the element of interest specifically the Na, K, Ca, and S. These elements produce very small particles upon combustion. Data is available in the appendix that includes the major elements determined. The trends for the ESP inlet are shown in **Figure 15** for sodium, potassium, calcium and sulfur, and in **Figure 16** for silicon, aluminum, magnesium and iron. The results show concentrating of the elements in the particles that are less than 10 μm in diameter.

Figure 17 shows the trend for the ESP inlet cyclone samples (cyclones 1, 3 and 4) for sodium, potassium, calcium and sulfur and **Figure 18** shows the trends for silicon, aluminum, magnesium and iron for the ESP inlet cyclone samples.

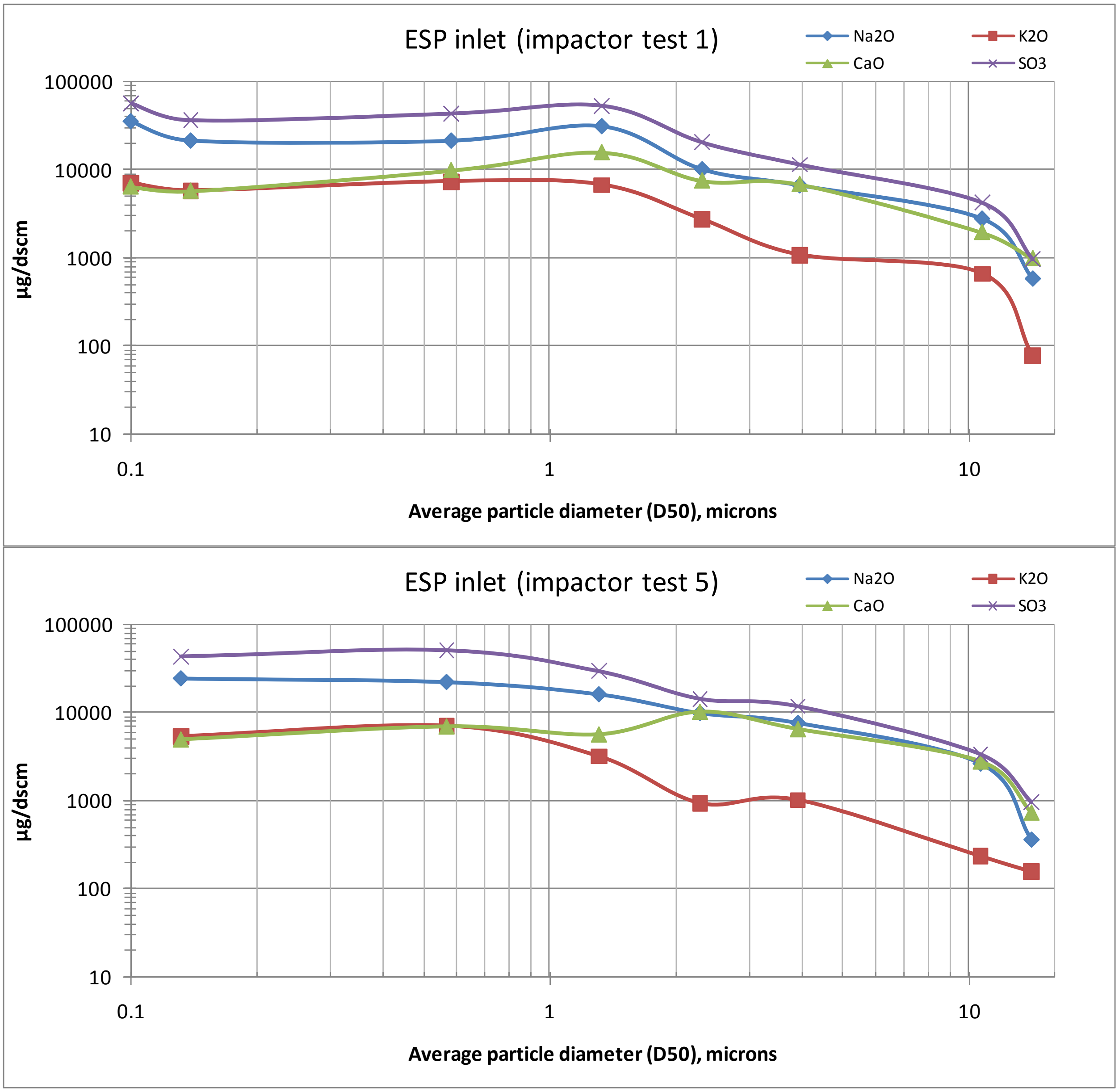


Figure 15. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter for ESP inlet (impactor) samples.

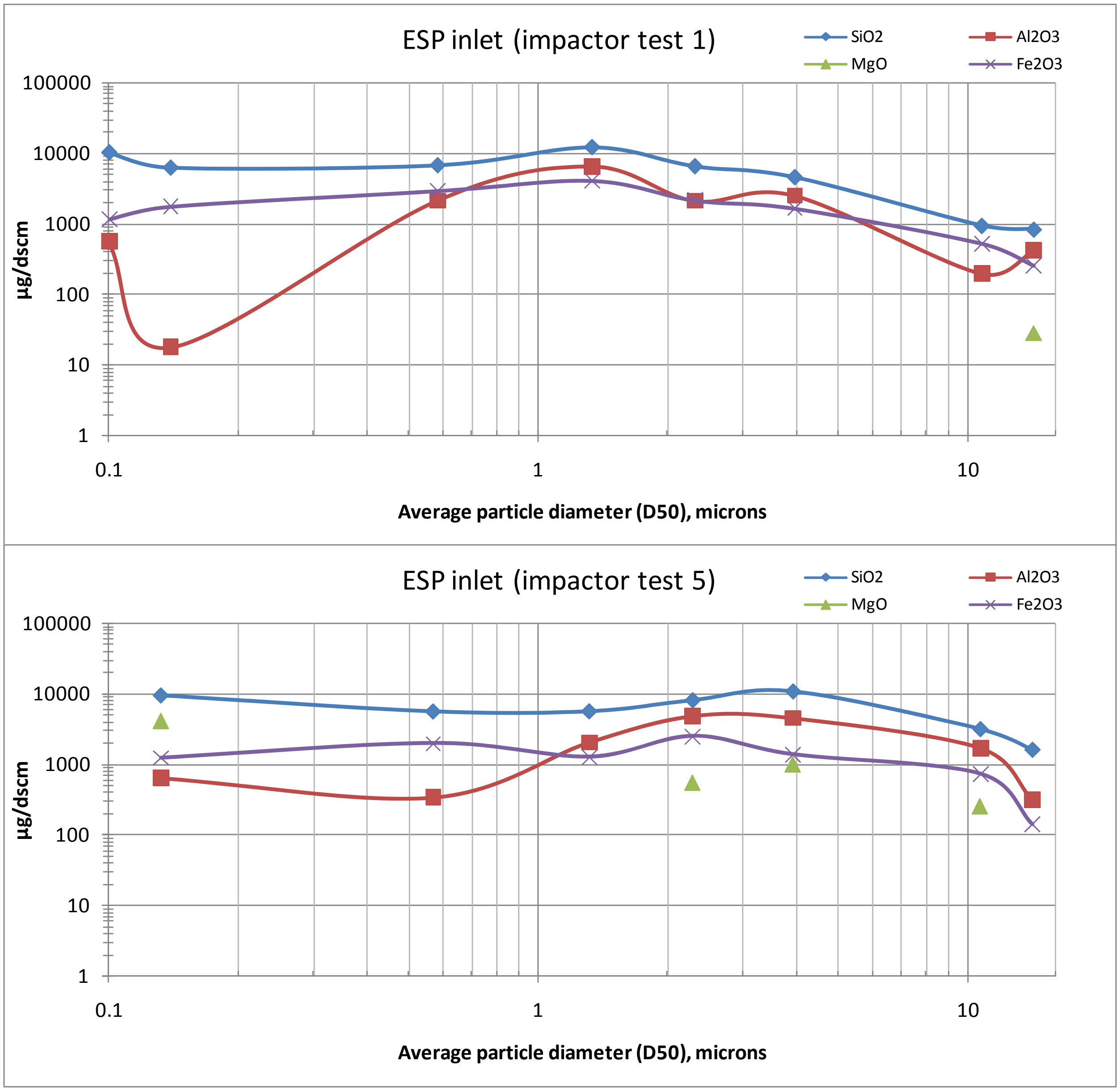


Figure 16. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter for ESP inlet (impactor) samples.

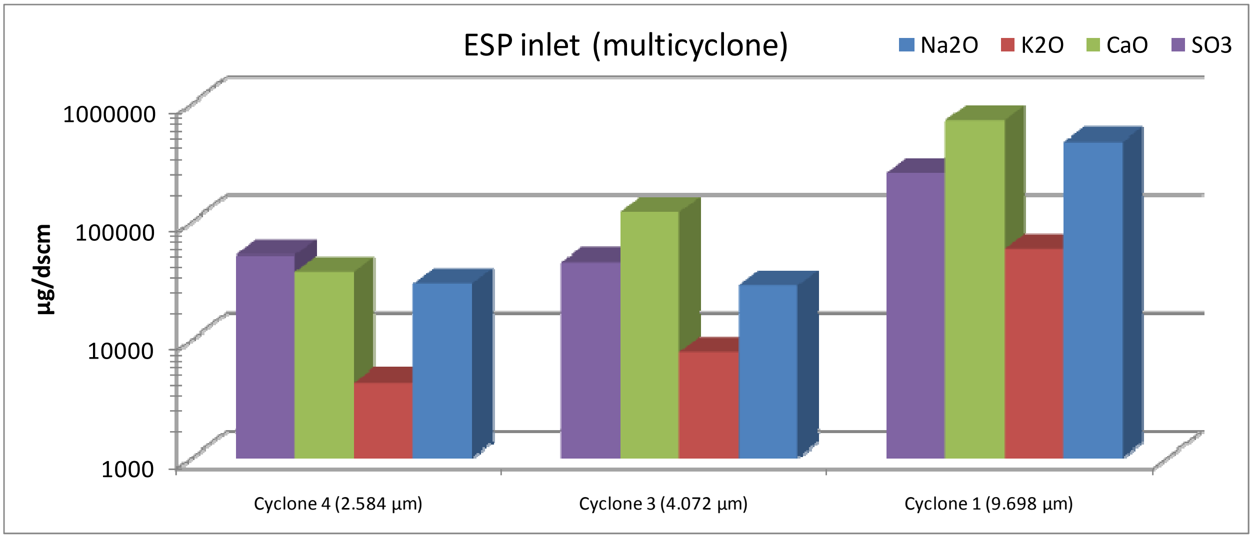


Figure 17. Sodium, potassium, calcium and sulfur concentrations for ESP inlet cyclone samples.

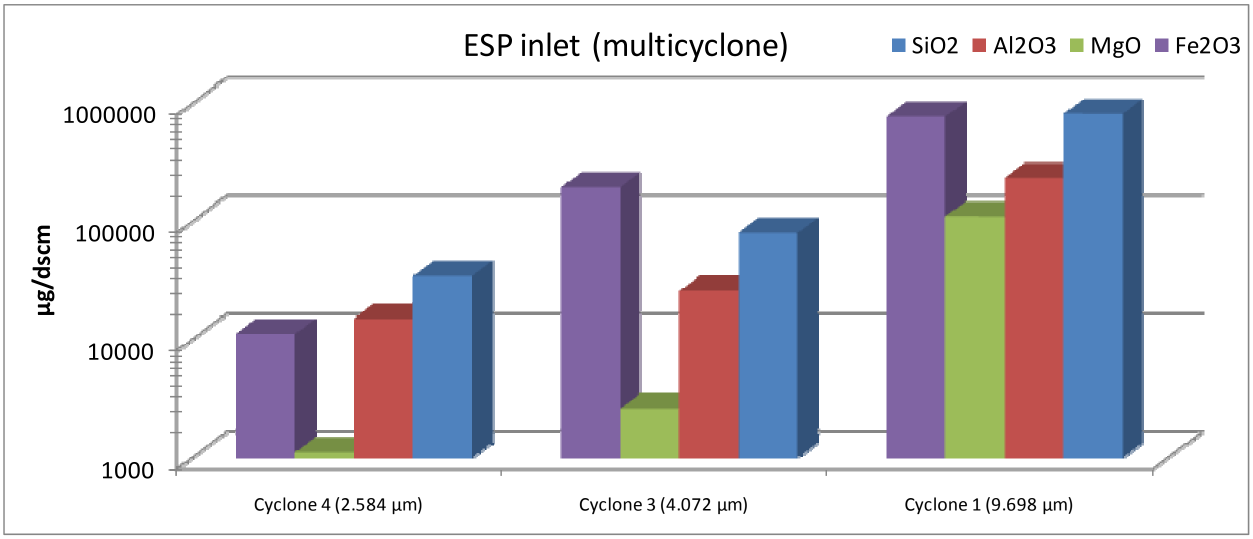


Figure 18. Silicon, aluminum, magnesium and iron concentrations for ESP inlet cyclone samples.

Analysis using digestion and inductively coupled plasma–mass spectrometry was performed to determine the concentrations of selected major elements (Ca, Fe, Mg, P, K, and Na) in the ash collected in the multicyclone stages. Table 9 lists the composition of selected elements based on the total sample collected in the multicyclone. Table 10 displays the fraction of each element, based on the total percent found in Table 9, by each cyclone stage. The largest concentrations of the selected elements were found in the first cyclone stage. The nozzle sample is material collected within the nozzle before the first multicyclone stage. This material is not size-fractionated.

The concentrations of the cyclone ash analyzed with ICP-MS cannot be compared well with the ash analyzed using SEM, as the ICP-MS samples were not analyzed for all major elements (including silicon, aluminum and sulfur).

Table 9. Percentage of each element in the total multicyclone sample (EERC).

Element	03/17/2009	03/19/2009
Calcium	13.36	12.15
Iron	6.85	6.54
Magnesium	3.27	3.14
Phosphorous	LBD*	LBD
Potassium	0.93	1.00
Sodium	6.63	6.26

*Level below detection (<400 ppm).

Table 10. Fractional percentage of each element by stage (EERC).

	03/17/2009				03/19/2009			
Element	Nozzle	Stage 1	Stage 3	Stage 4	Nozzle	Stage 1	Stage 3	Stage 4
Calcium	3.96	81.23	11.63	3.18	4.99	81.98	9.77	3.26
Iron	4.21	81.77	10.16	3.86	5.25	81.06	8.90	4.79
Magnesium	4.10	81.45	11.71	2.75	5.25	81.81	9.91	3.03
Phosphorous	LBD	LBD	LBD	LBD	LBD	LBD	LBD	LBD
Potassium	3.91	77.32	12.77	5.99	5.08	80.67	10.18	4.07
Sodium	4.21	77.80	12.82	5.17	5.67	80.59	9.88	3.85

The distribution of sodium, potassium, calcium and sulfur is illustrated in **Figure 19** and the distribution of silicon, aluminum, magnesium and iron is shown in **Figure 20**. The results show higher levels of sodium, potassium and sulfur at the one-micron level. The ESP was effective in removing larger-sized particles as well as some of the 0.1-µm particles. However, in the intermediate one-micron particle range the ESP is not as effective in removing the particles. This is a characteristic of all ESPs.

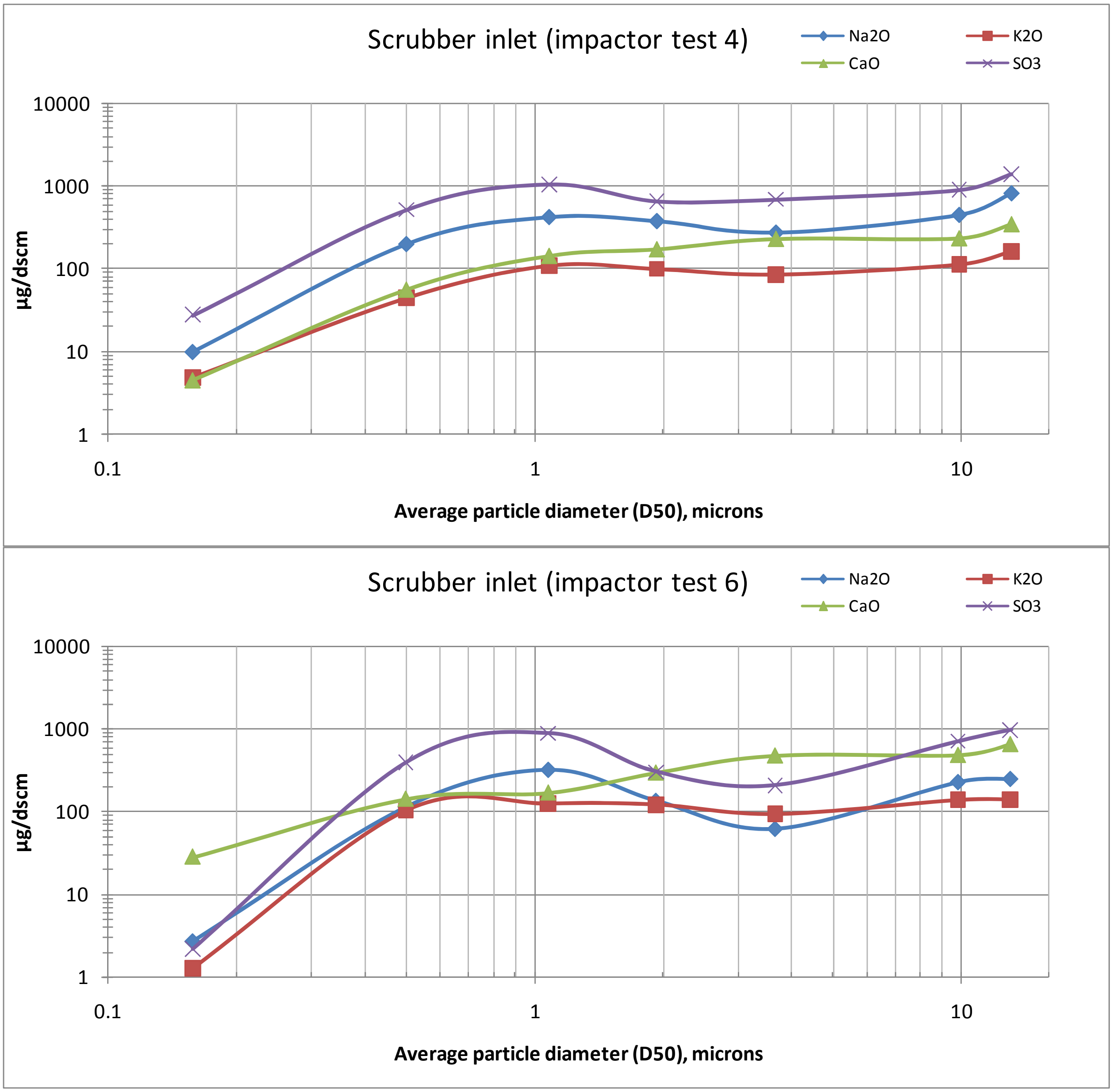


Figure 19. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter in scrubber inlet samples.

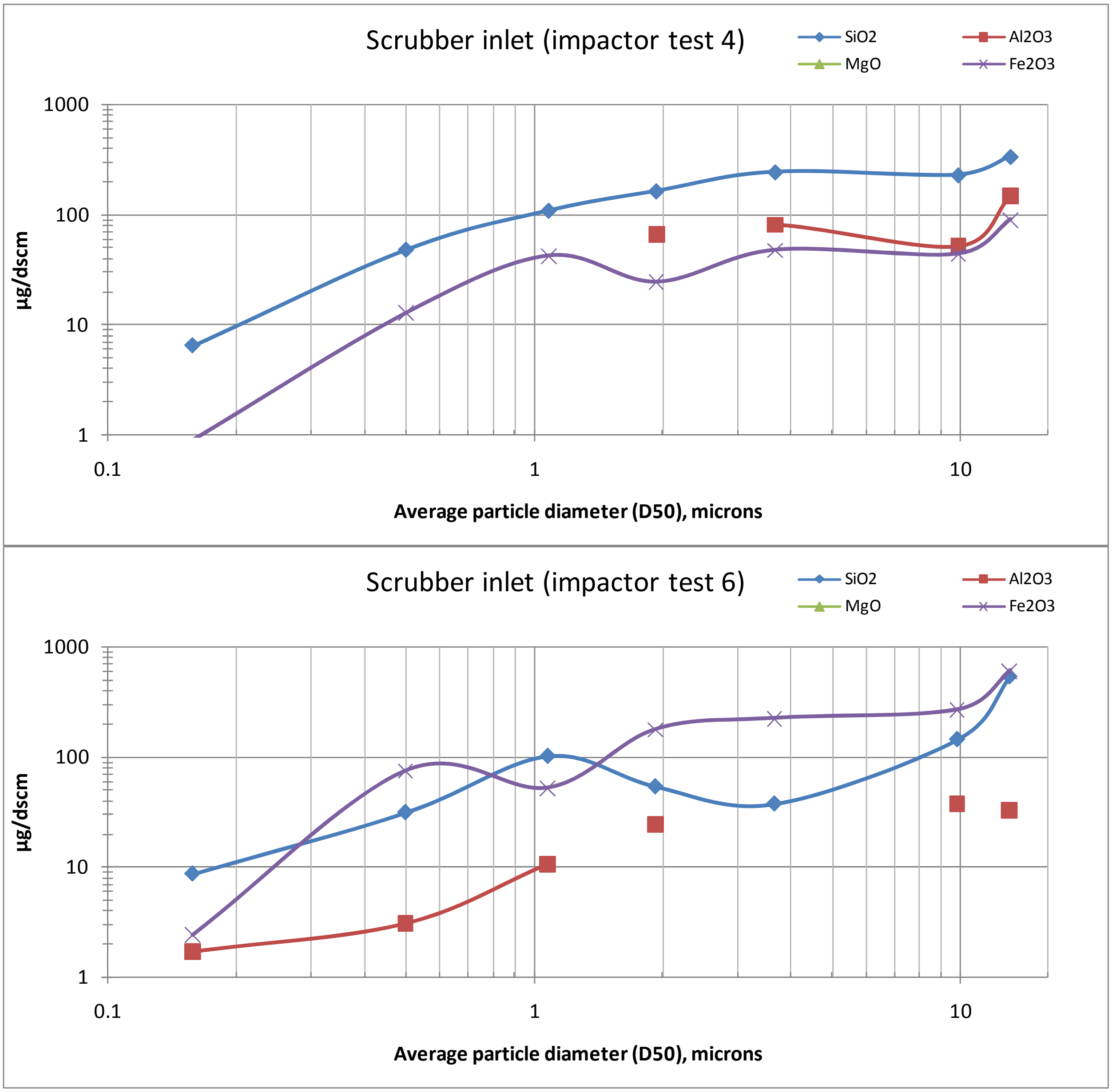


Figure 20. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter in scrubber inlet samples.

The composition size distribution determined for sodium, potassium, calcium and sulfur downstream of the scrubber is illustrated in Figure 21. The results show a significant level of sodium and sulfur in the less than 1 µm size fraction. The DLPI sampling system provides very accurate sizing data in the submicron size range. The results show a maximum for sodium and sulfur at about 0.3 µm.

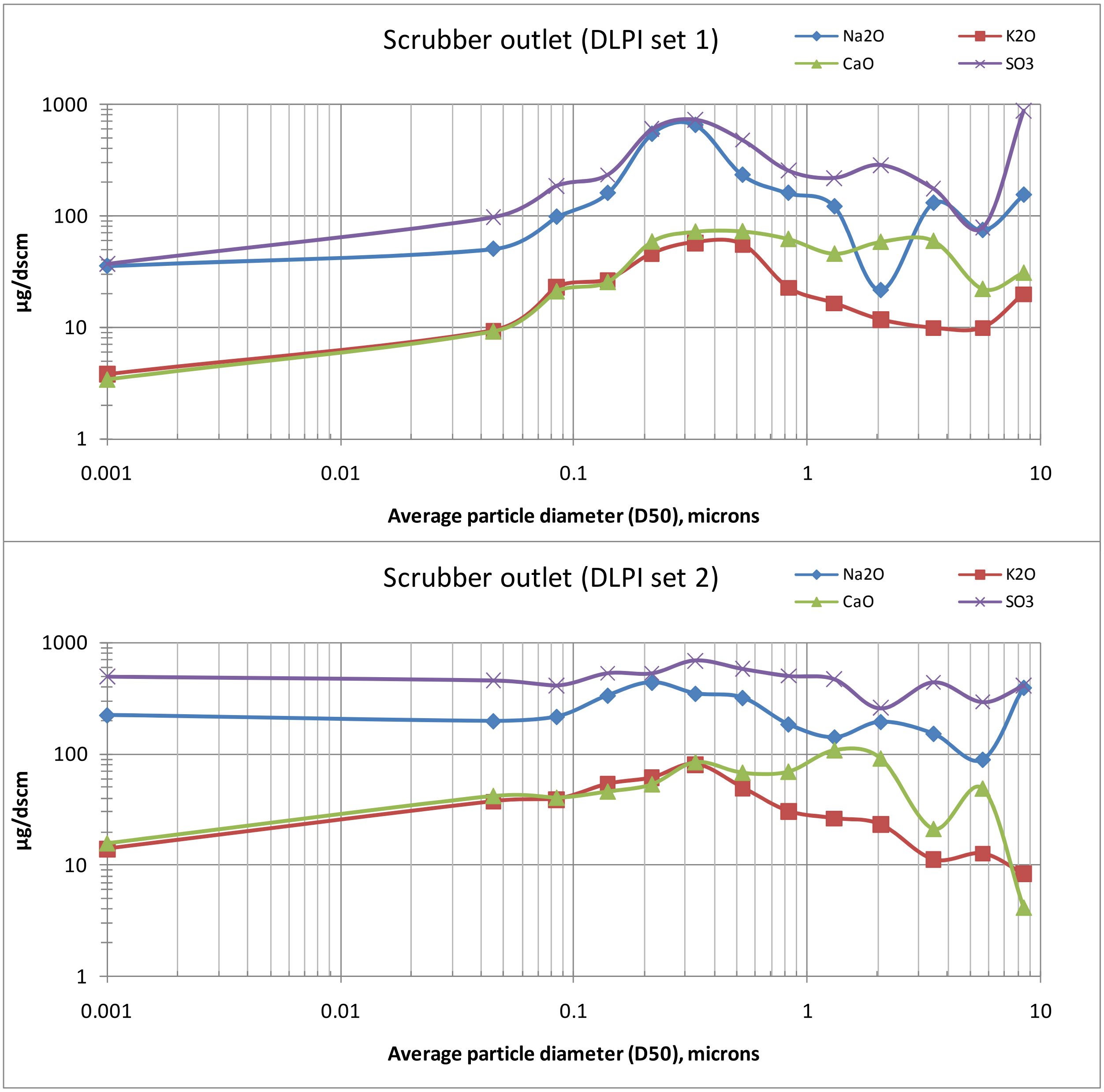


Figure 21. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter in scrubber outlet samples.

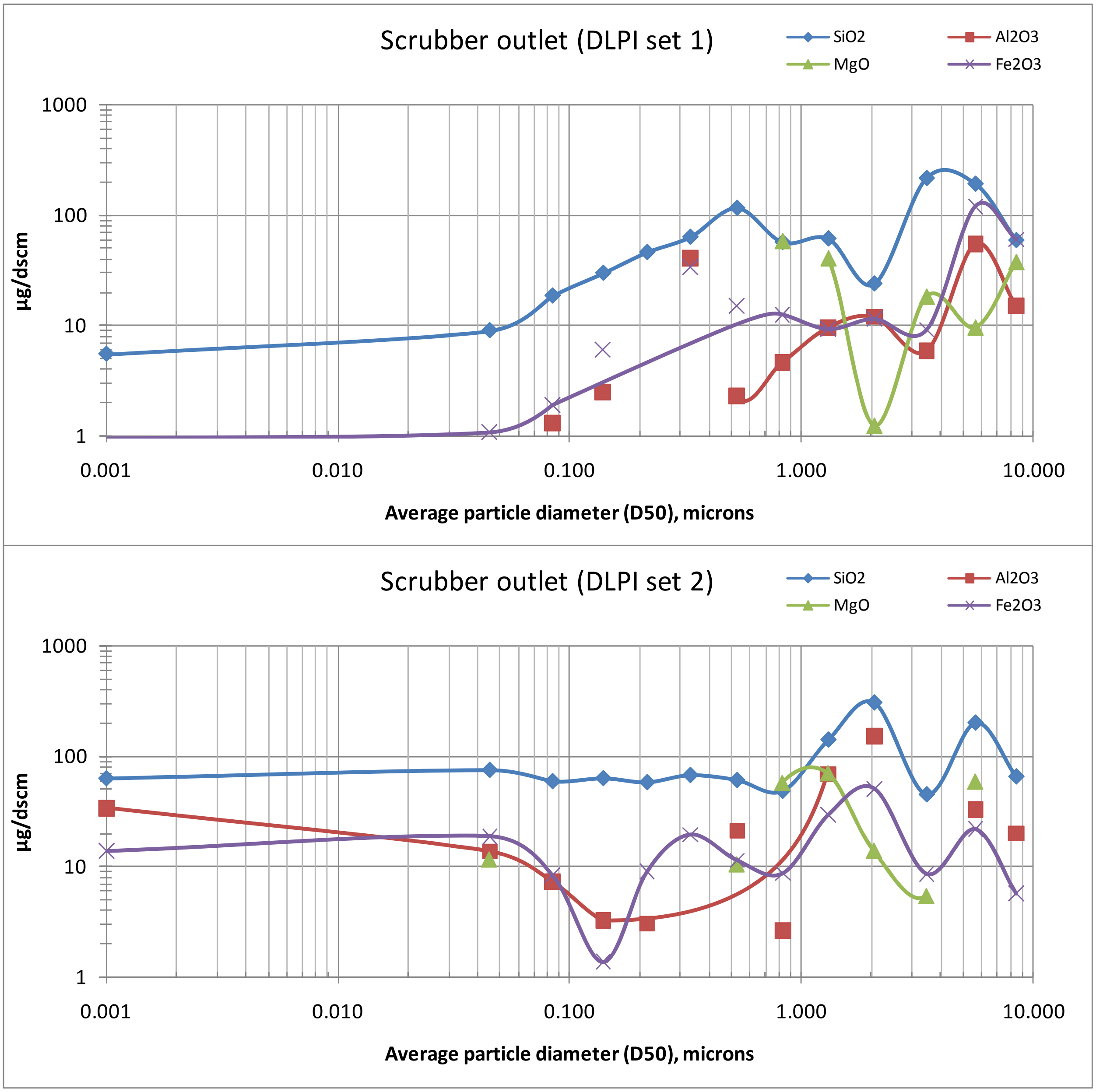


Figure 22. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter in scrubber outlet samples.

Comparison of the mass of the particles in terms of composition is shown in **Figure 23**. The results show that sodium and potassium are reduced across the ESP. However, no reduction of sodium and potassium was observed across the scrubber. This is consistent with other scrubbers operating globally.

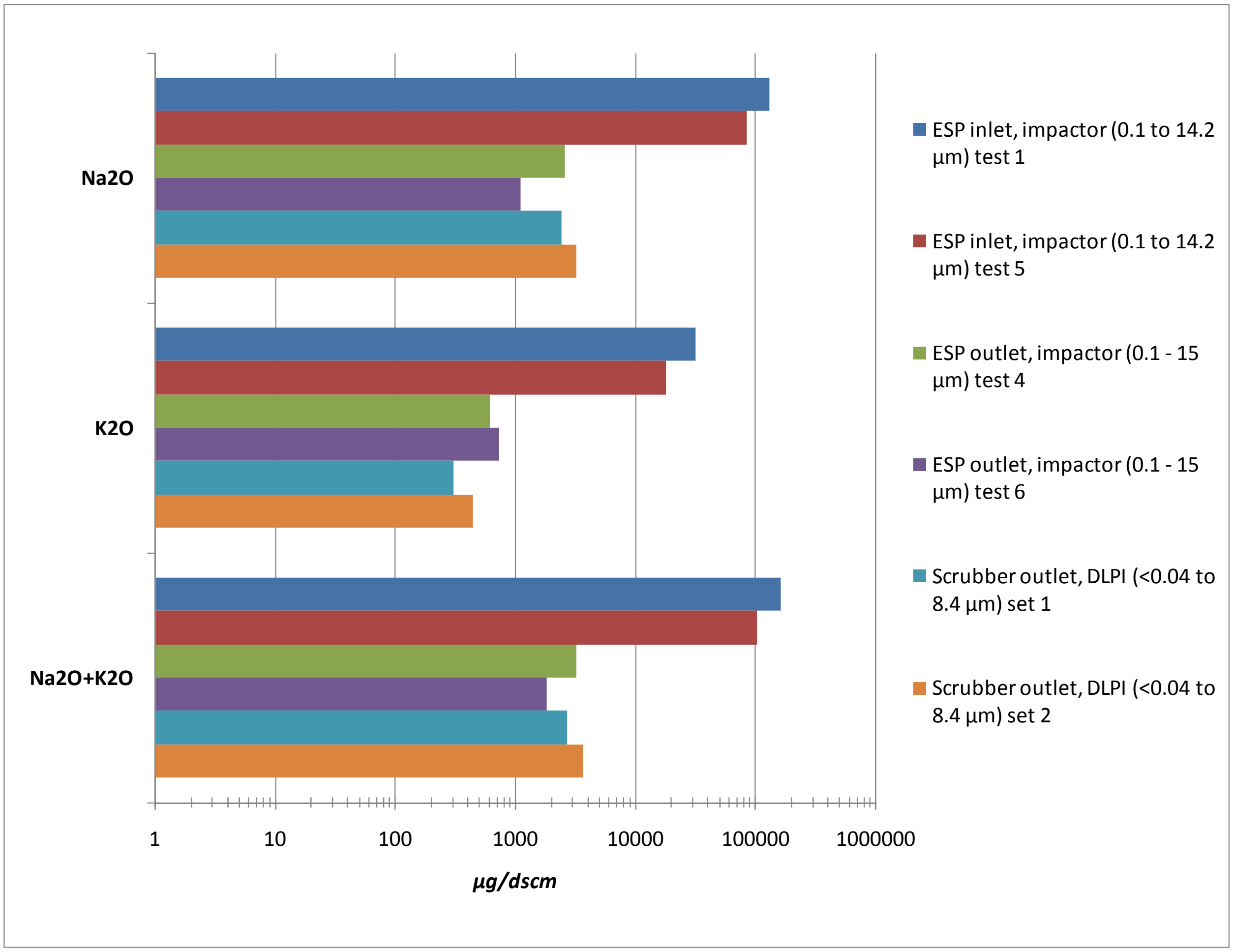


Figure 23. Mass of sodium and potassium oxide in the flue gas upstream and downstream of air pollution control devices at MRY.

SUMMARY AND CONCLUSIONS

Particulate sampling was conducted at Minnkota Power Cooperative's Milton R. Young plant to determine the particulate size and composition distribution of samples collected upstream of the ESP, upstream of the wet scrubber, and downstream of the wet scrubber. Emphasis was placed on determining the fate of sodium, potassium, and calcium since these elements can cause significant plugging and deposition problem.

During the testing, operating conditions of the plant were constant and there was no gas bypass. The coal fired during the testing remained relatively consistent. The as-received ash content ranged from 7.73 to 7.89%. Sodium oxide content of the ash ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing (a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels). Sampling upstream of the ESP and scrubber were conducted using a combination multicylones and impactors. The cyclones collected sized fractions of larger particles (greater than one to five microns) and the impactor collected the sub-micron particulate. Sampling downstream of the scrubber was conducted with a single cyclone followed by a 13-stage advanced impactor. In addition, the submicron particle number concentration was measured using a scanning mobility particle sizer (SMPS).

The results of the particulate mass information indicated a high loading at the ESP inlet of 4.96×10^6 µg/dscm, a scrubber inlet loading of 1.1×10^4 µg/dscm, and a scrubber outlet loading of 1.08×10^4 µg/dscm. These results show very little overall removal of the submicron particulate across the wet scrubber system. A significant fraction of the particulate was removed by the ESP, with a removal efficiency of 99.76%.

The size distribution of the particulate collected upstream of the ESP and upstream of the scrubber was multi-modal as summarized below:

- Upstream of the ESP there were at least three modes – a larger mode at 40 to 50 µm, a second mode at just under 10 µm, and third mode at about 1 µm. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite. The intermediate-sized particles are typically derived from small minerals and organically associated elements. The smaller mode (about one-micron and smaller) contains fine particles and condensed vapor phase species.
- Upstream of the scrubber there were two distinct modes – a larger mode between 8 to 10 µm and another mode centered at about 1 to 2 µm in diameter. The smaller mode is typically condensed vapor phase and small particles.
- Downstream of the scrubber, the primary mode centered at about 0.5 to 0.7 µm, and another possible mode occurred at 3 µm and larger.
- Particle number distributions were as follows:
    - Inlet to the ESP – between 1×10^7 to 10^8 particles per dry normal cubic centimeter (dncc);
    - Inlet to the scrubber is 10^5 particles/dncc;
    - Outlet of the scrubber 7×10^5 particles/dncc.
- Particle number distributions into the nanometer scale (1 µm = 1000 nm) was found to be as high as 10^5 particles/dncc.

Particle composition distributions of the particulate were determined for each of the major elements. The results were reported as µg/dscm of the element as illustrated in the Appendix and in the figures in the text.

- Upstream of the ESP the composition trends for sodium, potassium, calcium and sulfur showed greater concentrations of these elements in the particles that are smaller than 10 µm, with a significant increase in concentration in the flue gas at a particle size of less than 2 µm. There is another increase at 0.1 µm.
- Upstream of the scrubber the compositional trends for sodium, potassium, calcium and sulfur show higher levels at the 1 µm level. The ESP was effective in removing larger-sized particles, as well as some of the 0.1 µm particles. However, in the intermediate 1 µm particles, the ESP is not as effective in removing the particles.
- Downstream of the scrubber the composition size distribution determined for sodium, potassium, calcium and sulfur showed significant levels of sodium and sulfur in size fraction finer than 1 µm. The DLPI sampling system provides very accurate sizing data in the submicron size range. Other elements such as aluminum, silicon and iron show a significant depletion below 1 µm.

Comparison of the characteristics of the particles in terms of mass and composition indicate that, at the time of the testing, the total average mass of the particulate was about 10,800 µg/dscm. The particulate consisted mainly of sodium, potassium, and sulfur. The total quantity of sodium and potassium exiting was between 2000 to 3000 µg/dscm.

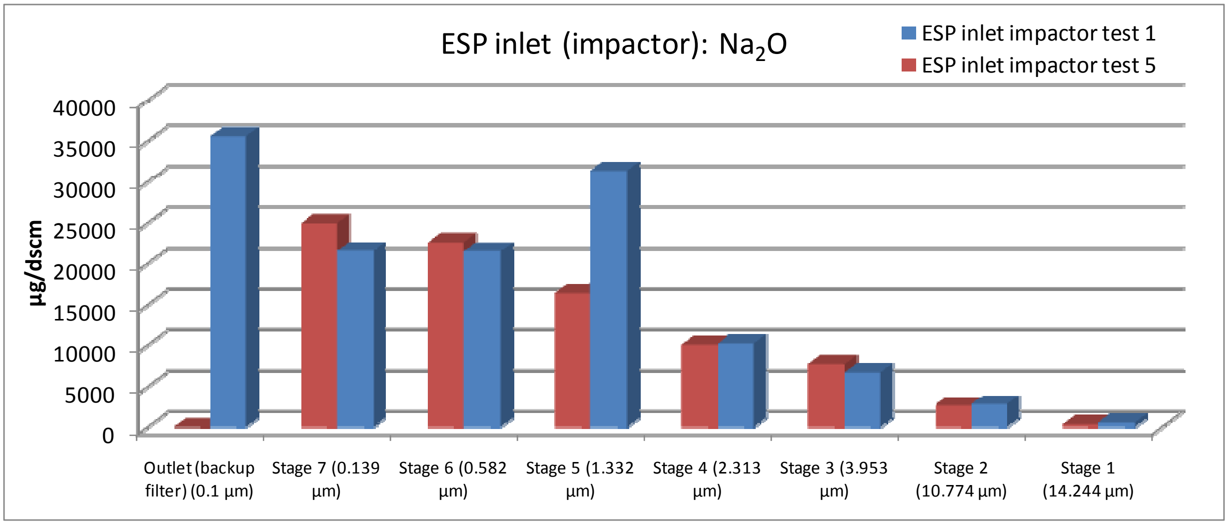


Figure A-1. Sodium concentration by sample stage (average diameter in microns).

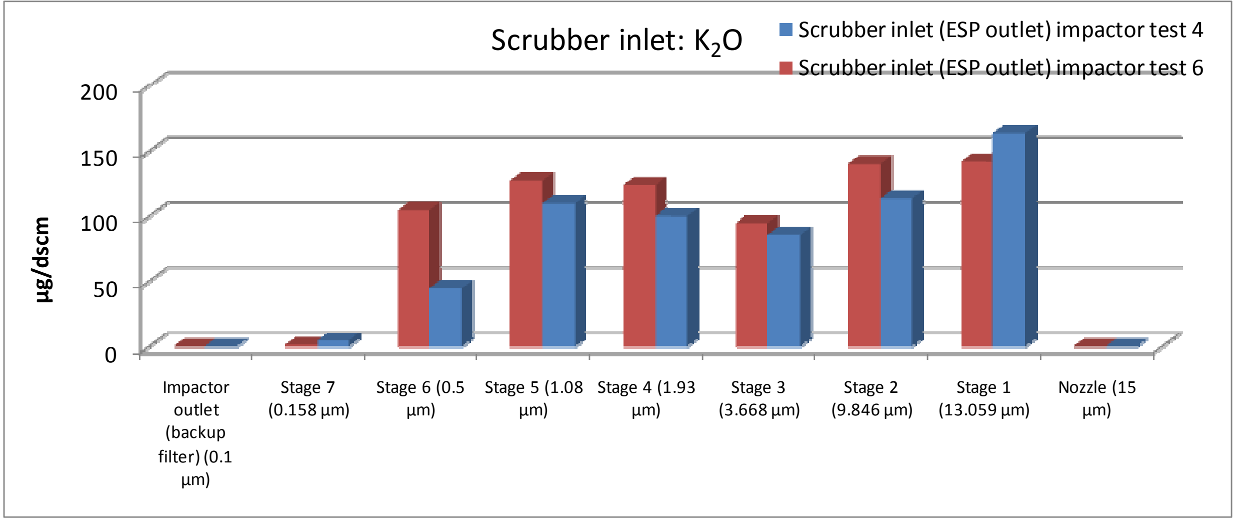


Figure A-2. Potassium concentration by sample stage (average diameter in microns).

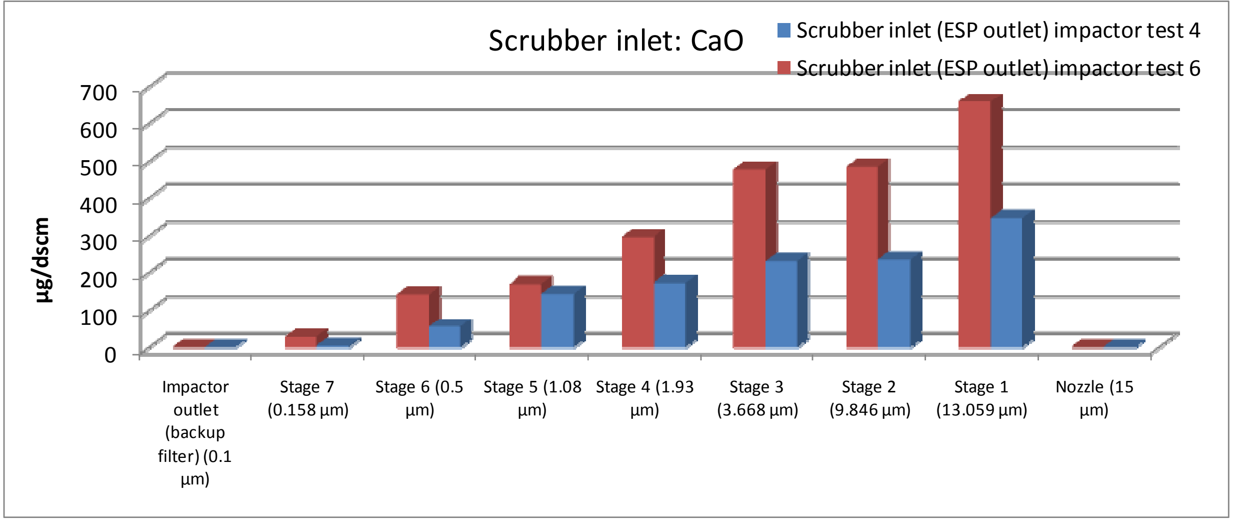


Figure A-3. Calcium concentration by sample stage (average diameter in microns).

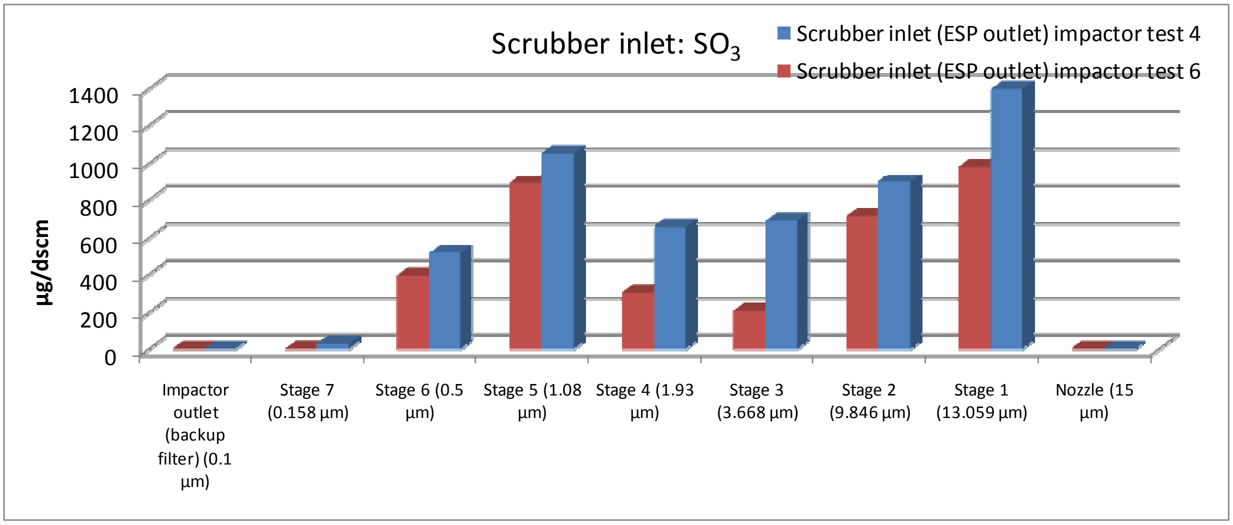


Figure A-4. Sulfur concentration by sample stage (average diameter in microns).

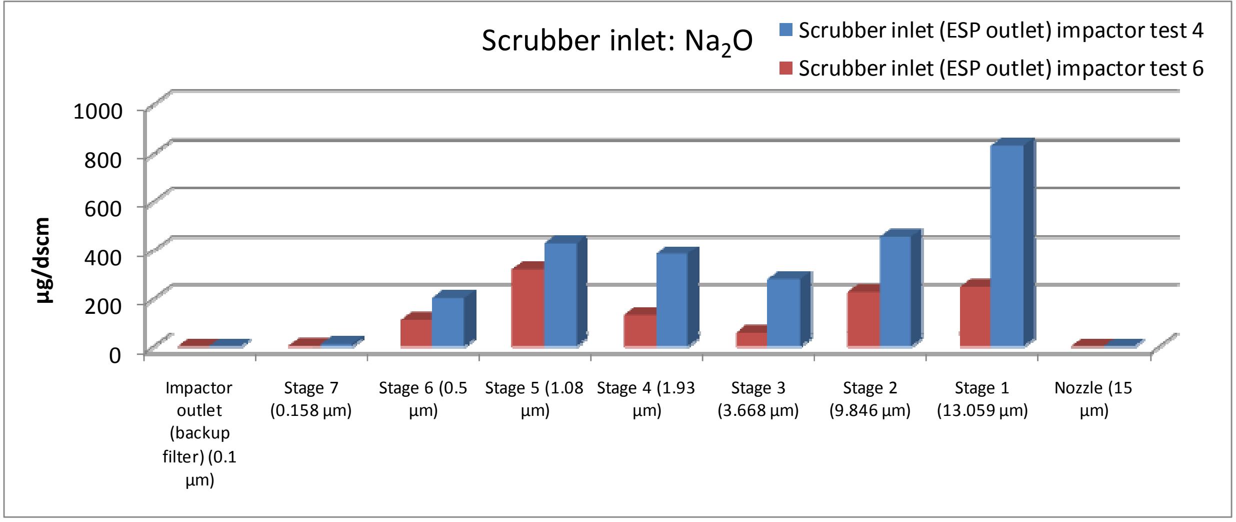


Figure A-5. Sodium concentration by sample stage (average diameter in microns).

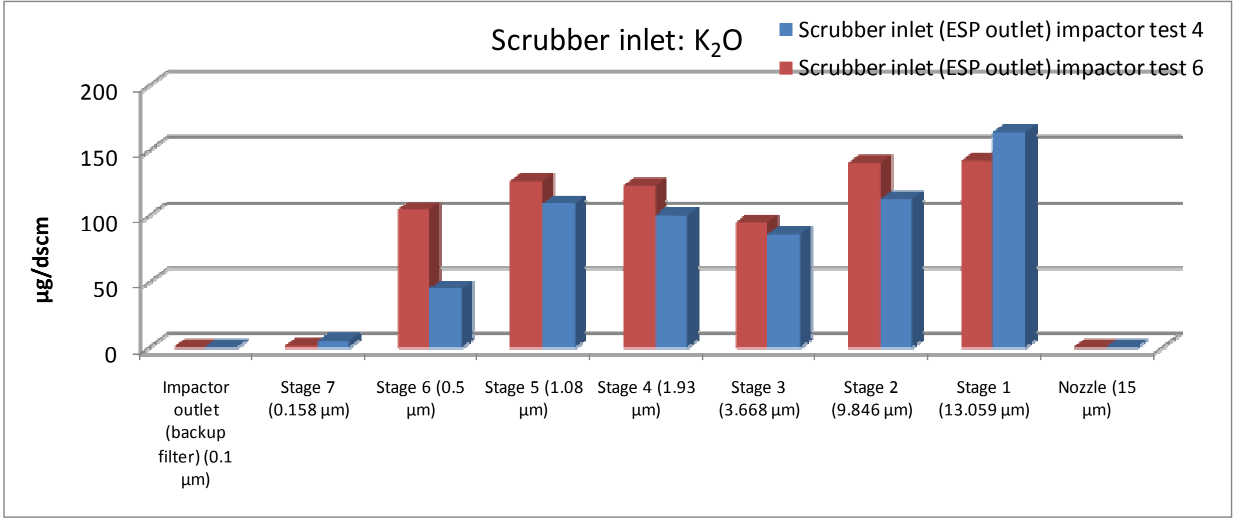


Figure A-6. Potassium concentration by sample stage (average diameter in microns).

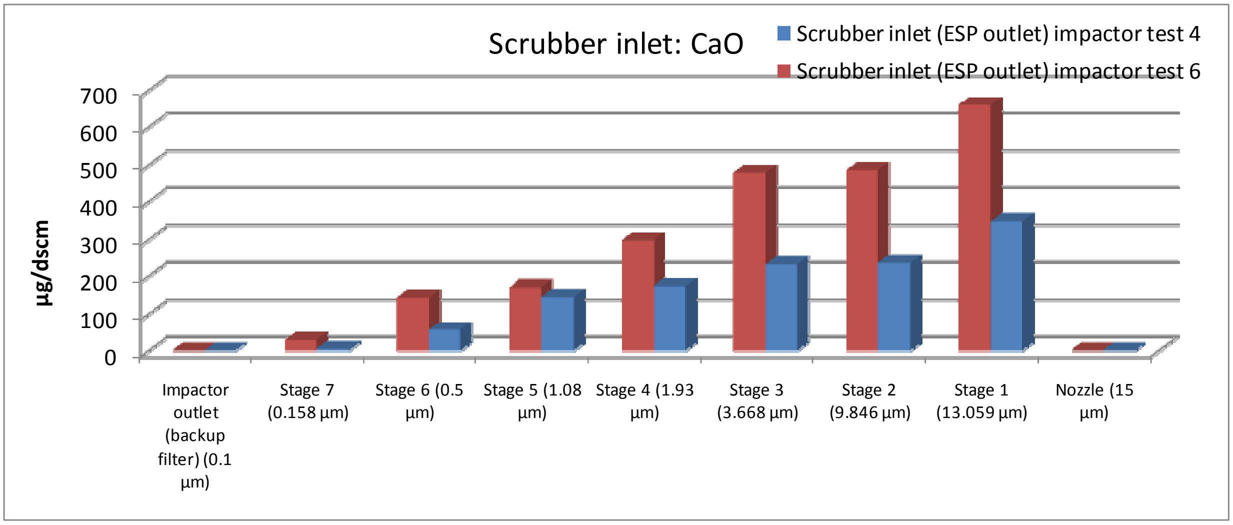


Figure A-7. Calcium concentration by sample stage (average diameter in microns).

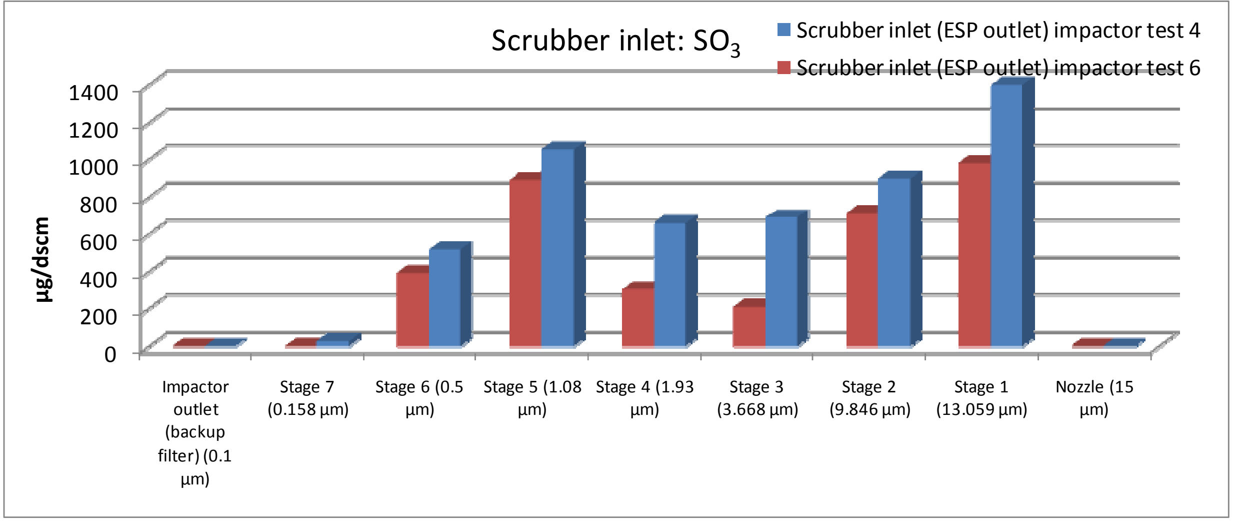


Figure A-8. Sulfur concentration by sample stage (average diameter in microns).

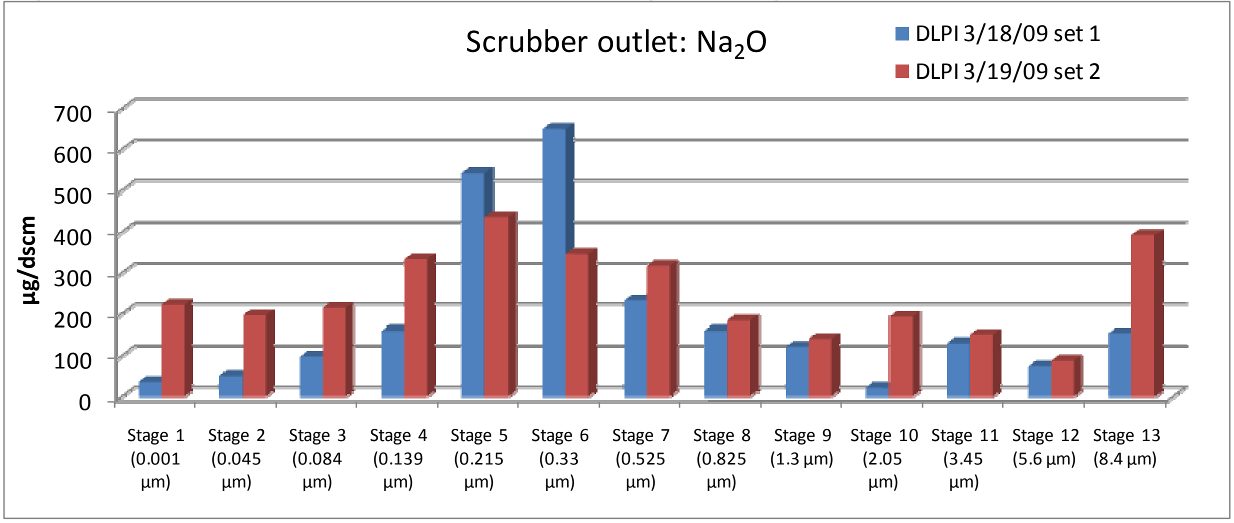


Figure A-9. Sodium concentration by sample stage (average diameter in microns).

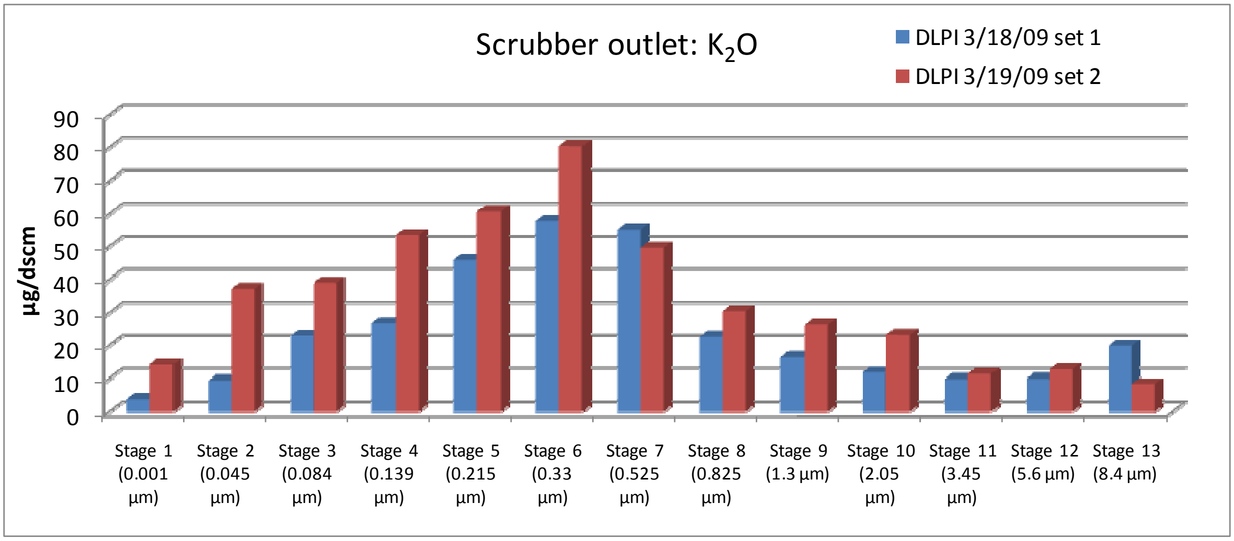


Figure A-10. Potassium concentration by sample stage (average diameter in microns).

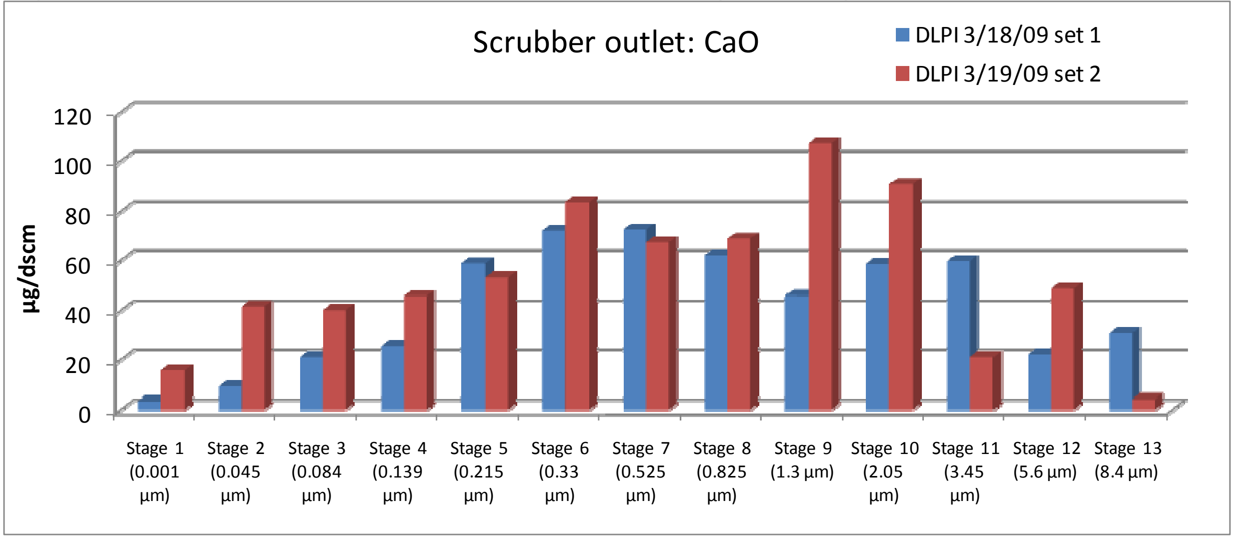


Figure A-11. Calcium concentration by sample stage (average diameter in microns).

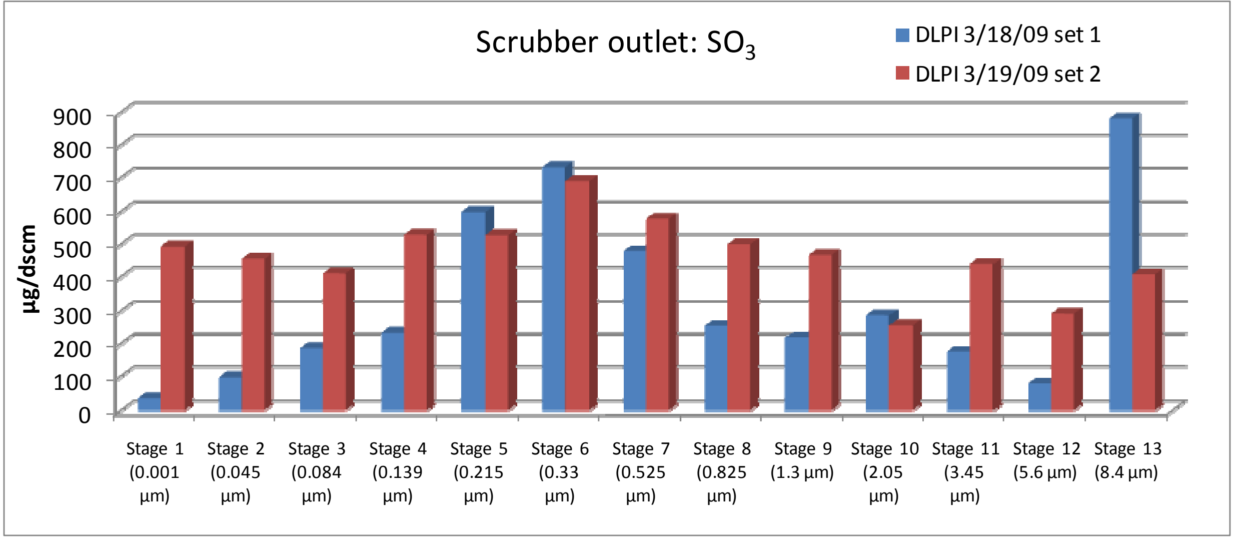


Figure A-12. Sulfur concentration by sample stage (average diameter in microns).

APPENDIX B - SMPS FIELD CONDITIONS AND CHALLENGES

Temperature

The temperature in the field during this test was approximately 24°F. This made it very difficult for the equipment to start and warm up to normal operation conditions, especially the CPC. With the help of a fish tent, carpets, and small blow heaters, the CPC was brought to normal operating temperature. Because of the cold conditions, there was a significant condensation issue in the lines that fed the SMPS system. Although this problem was reasonably resolved for all lines from the probe end to the EC by applying heat/thermal tapes, the lines connecting the EC and CPC also had a buildup of condensed fluid to the extent that they had to be drained at one point to help stabilize the flow via the CPC pump.

Wind

Another challenge faced in the field was the high winds of more than 20 mph. With the scrubber outlet location being about 105 feet above the ground, such windy conditions constantly shook the grid and the equipment; thereby introducing turbulence to the flow through the CPC pump.

Pore Flue Gas Pressure

A more serious problem was the lack of adequate positive pressure from the sampling port to supply enough flue gas through lines into the SMPS system. This resulted in very low counts observed in many data sets. Although the sampling port at the scrubber outlet is at positive pressure, it probably was not high enough to feed enough flue gas through the small nozzle of the sampling probe to the SMPS system.

Milton R. Young Unit 2

MRY Unit 2 is a Babcock & Wilcox (B&W) Carolina-type radiant boiler designed to burn high-moisture, high-slagging/fouling North Dakota lignite. Nominally rated at 3,050,000 lb/hr, this unit is a cyclone-fired, balanced-draft, pump-assisted circulation boiler. The unit began commercial operation in May 1977 and is base-loaded at 470 MW gross. The unit is equipped with a cold-side ESP for particulate control and a wet FGD unit for SO_2 control. The cold-side ESP has a specific collection area (SCA) of 375 ft^2/1000 acfm. The wet FGD for SO_2 control utilizes alkaline ash and lime. The MRY Station fires North Dakota lignite coal from the Kinneman Creek and Hagel Seams at the Center Mine.

Form of Sodium in Center Lignite

Sodium is associated with the organic matrix in Center lignite. That means the sodium is atomically dispersed in the organic matrix. The sodium is associated with a carboxylic acid groups (ion exchange sites). The carboxylic acid groups act as bonding sites for various elements such as Ba, Ca, Mg, and Sr along with minor amounts of K. Figure C-1 illustrates the bonding of sodium to the organic fraction of the coal and the association of other coal impurities.

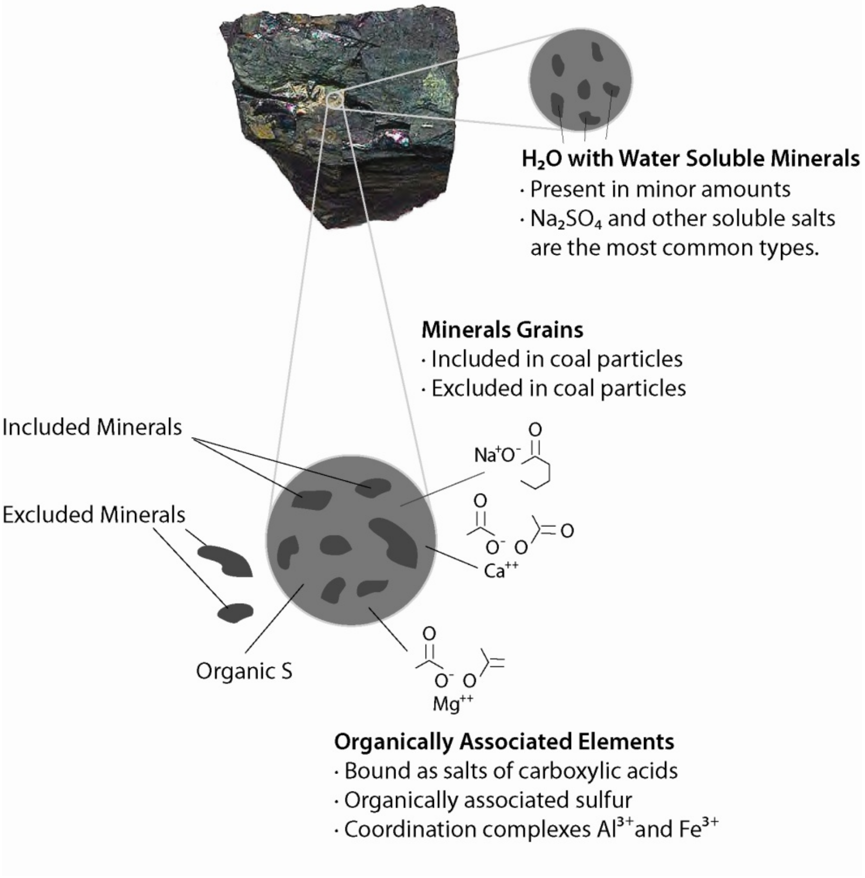


Figure C-1. Form of sodium in coal (Benson and Laumb, 2008).

Vaporization of sodium in PC and cyclone-fired systems

Sodium is a volatile element and will be transformed into a gas upon combustion. The vaporization of sodium during the combustion of lignite is a very well known fact that has been examined by numerous investigators; include work conducted by MIT, CalTech, Sandia National Laboratory, National Energy Technology Laboratory, University of Utah, and others. For example, research conducted by Senior and others (2000) reported that relative to other coals, North Dakota lignite produced more vaporized ash. The actual amount vaporized for ND lignite is double the level vaporized as compared to subbituminous and lignite coals from Montana as illustrated in Figure C-2. Work conducted at the MRY plant related to the vaporization of sodium from a cyclone fired systems is illustrated in Figure C-3. The results show over two thirds of the sodium is not retained in the slag and is vaporized.

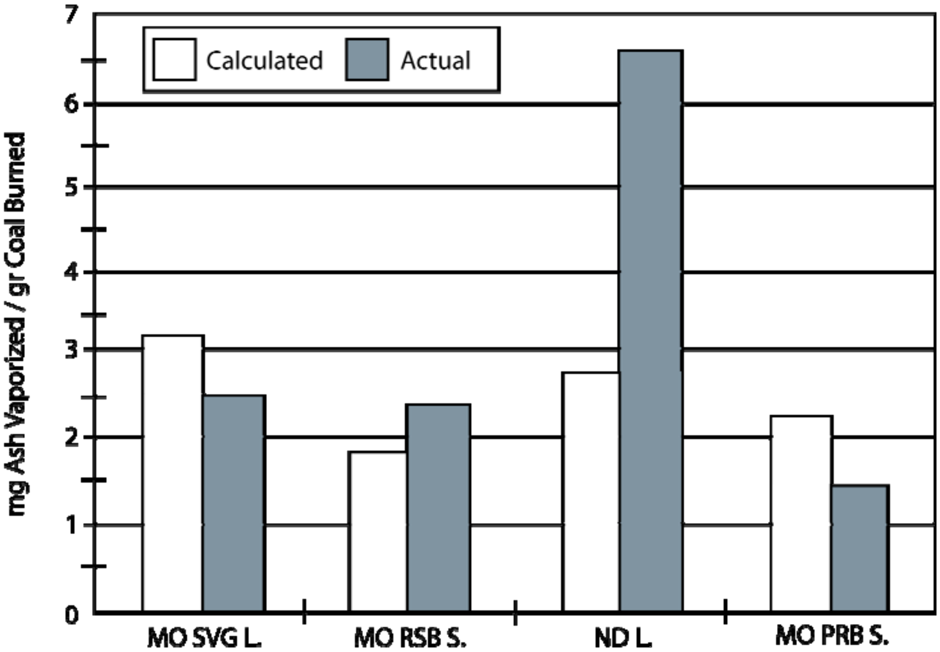


Figure C-2. Ash vaporized during combustion of lignite and subbituminous coals (Senior and others, 2000).

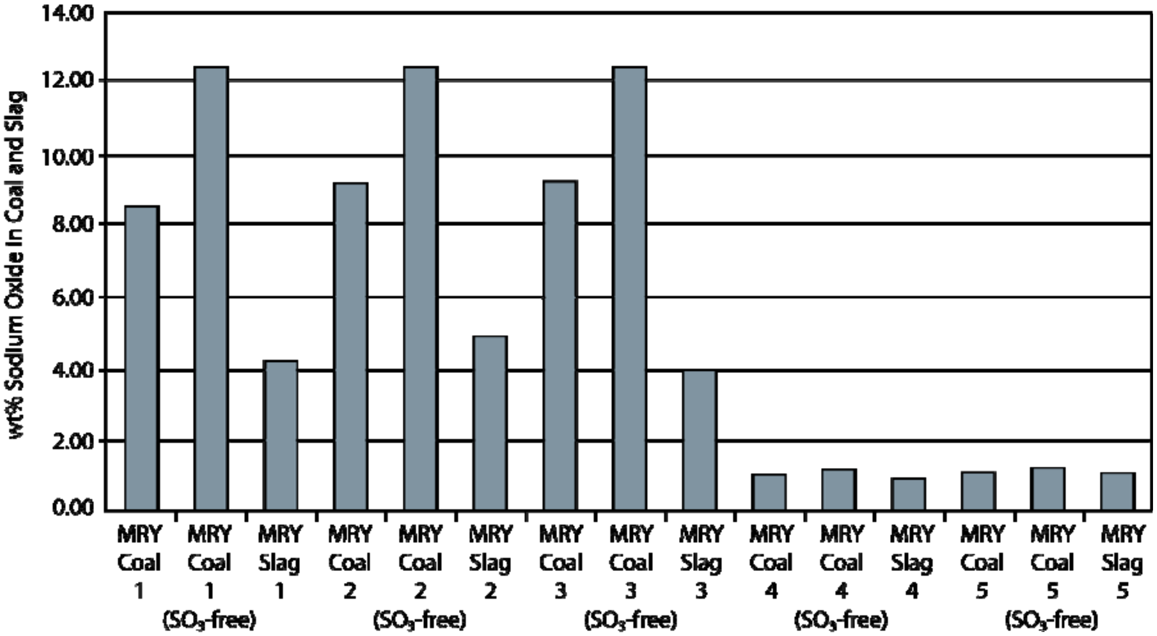


Figure C-3. Comparison of sodium levels in Center lignite coal and slag samples.

Condensation of vaporized species to form aerosols

EPA has evaluated the literature on particle formation during combustion and from other sources and incorporated it into an educational module that can be found on the following website (http://www.epa.gov/apti/bces/module3/formation/formate.htm). The classification of particle types shown by EPA is illustrated in Figure C-4. The EPA classification is consistent with the review conducted by Lighty and others (2000). Vaporized species can condense heterogeneously on surface of other entrained coarse ash particle and can condense homogeneously to form the fine and ultrafine particles. The distribution of particles depicted in Figure C-4 is shown on a frequency percent of particles by mass basis. The particle number versus size is also important and a comparison of the number of particles and particle size is summarized in Table C-1. The number of aerosol particles is significant. These particles have high surface areas and are very reactive.

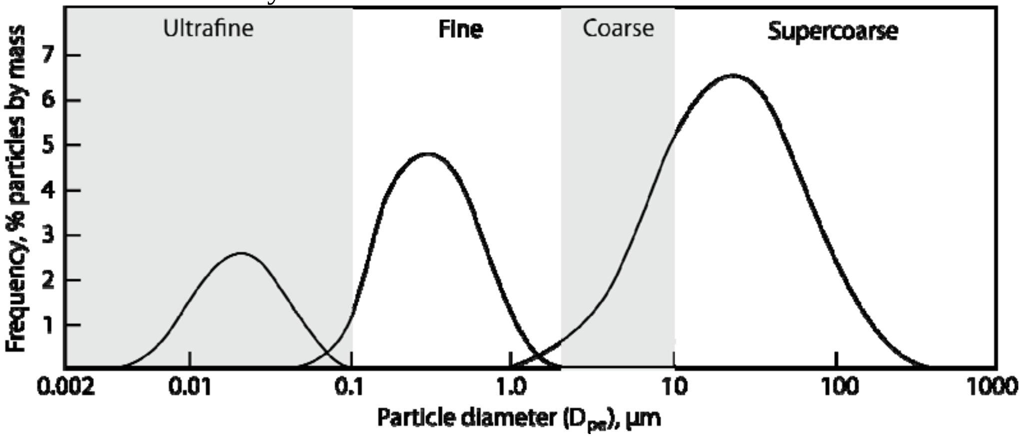
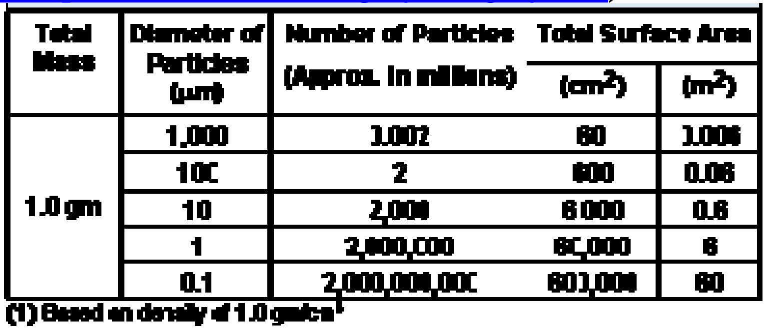


Figure C-4. Particle size categories used to classify particles (http://www.epa.gov/apti/bces/module3/category/category.htm)

Table C-1. Particle size, number of particles, and surface area[1] **(http://www.epa.gov/apti/bces/module3/category/category.htm)**



Total Mass	Diameter of Particles (µm)	Number of Particles (Approx. In millions)	Total Surface Area (cm²)	(m²)
1.0 gm	1,000	0.002	60	0.006
	100	2	600	0.06
	10	2,000	6 000	0.6
	1	2,000,000	60,000	6
	0.1	2,000,000,000	600,000	60

(1) Based on density of 1.0 gm/cm³

Figure C-5 provides a comparison of the mass distribution and particle number distribution. As the particle size decreases the number of particles in the size fraction increases. In addition, as illustrated in Table C-1, the surface area increases significantly with decreasing particle resulting in the opportunity for reactive gases such as sulfur oxides to react forming sticky phases that bond particles together.

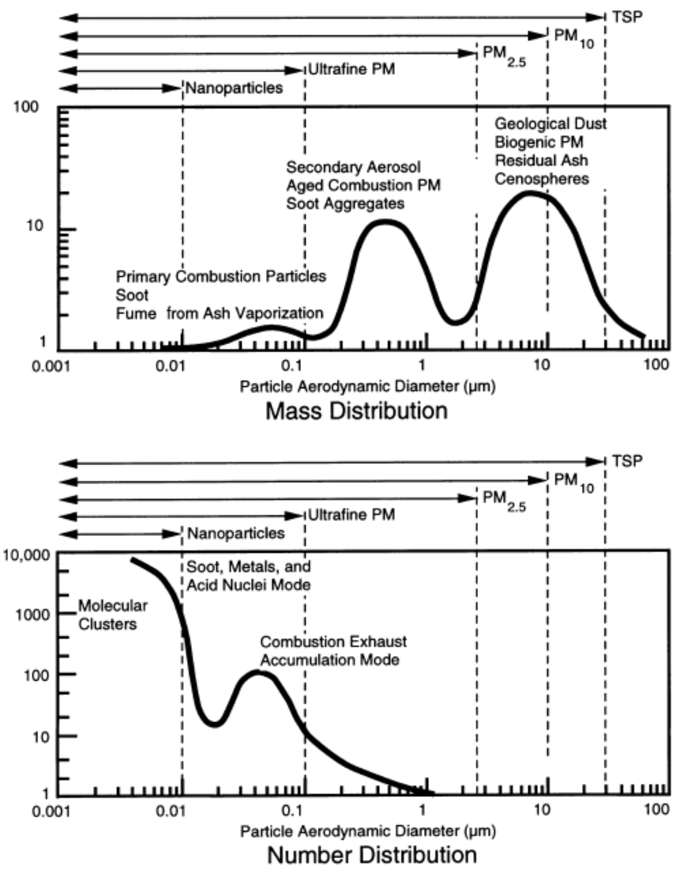


Figure C-5. Comparison of mass distribution and particle number distribution for combustion derived particles and aerosols (Lighty and others, 2000).

Particle size distributions for fly ash collected upstream and downstream of an ESP are illustrated in Figure C-6. This work was conducted by Markowski and others (2000) specifically aimed at characterizing the submicron aerosol mode of fly ash formation.

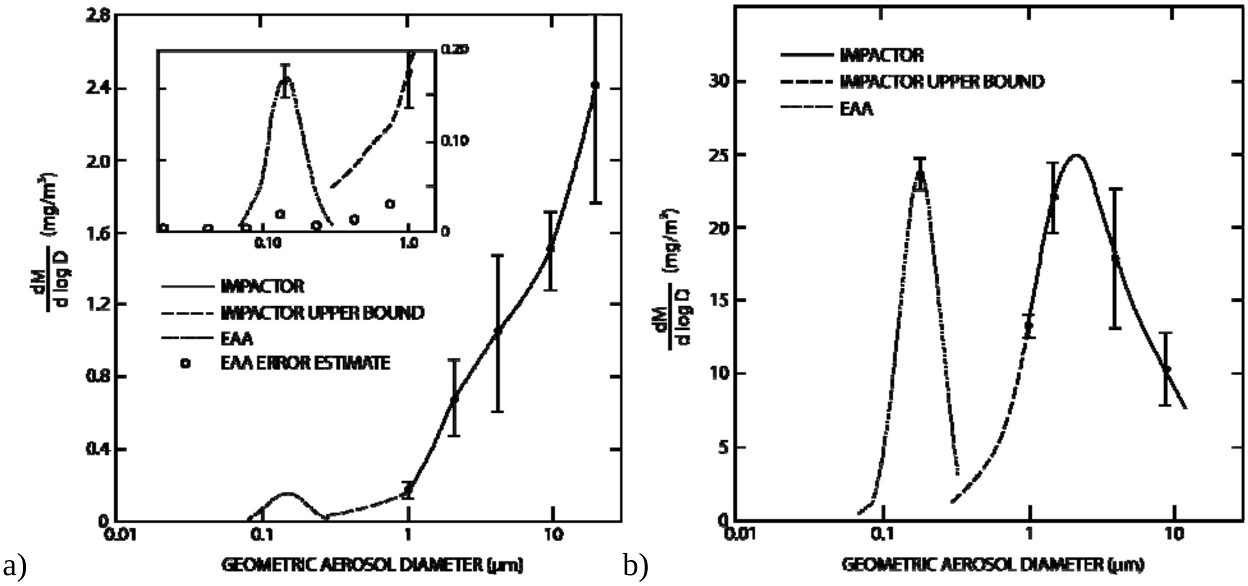


Figure C-6. Typical differential mass distributions of particulate collected a) upstream and b) downstream of an ESP (Markowski and others, 2000).

Fly ash produced upon the combustion of high sodium lignites in a pulverized coal (PC) fired system shows significant enrichment of sodium in the smaller size fractions as shown in Figure C-7. This figure illustrates the increase in the sodium content in the finer size fractions of ash as a result of firing high sodium lignite. The sodium and sulfur content of the less that 3 micrometer size fraction of the sampling train approached 20% Na_2O, and 25% SO_3. The form of the sodium is likely sodium oxide and sulfate.

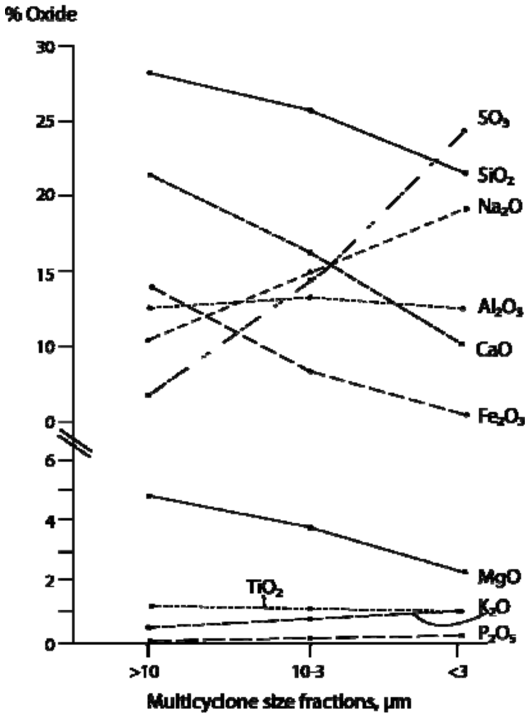


Figure C-7. Composition distribution of ash particles during combustion of North Dakota Lignite (Benson and others, 1984).

Electrostatic precipitator collection efficiency

The classical curve for ESP particle collection efficiency is shown in Figure C-8. This curve is typical of well behaved ash materials that do not present significant problems in collection. The collection efficiency is very good for particles greater than 5 to 10µm and the collection efficiency decreases with decreasing particles size with minimum collection efficiency between 0.2 to 2 µm in diameter. The collection efficiencies vary significantly because of particle size and composition.

Low collection efficiency for difficult to collect particles is between 0.1 to 1 µm in particle diameter. Figure C-9 provides an illustration of the range of collection efficiencies. Based on EPA education modules, no air pollution control device shows high collection efficiency in this range (0.1 to 1.0 µm) due to inherent limitations of the collection devices and particle characteristics (http://www.epa.gov/apti/bces/module3/collect/collect.htm). The following mechanisms of particle capture are impacted by the size of the particles:

- Inertial impaction and interception
- Brownian diffusion
- Gravitational settling
- Electrostatic attraction
- Thermophoresis
- Diffusiophoresis

The EPA (http://www.epa.gov/apti/bces/module3/collect/collect.htm) has indicated that based on a number of studies of actual "*sources stationary sources generating high* *concentrations of particles in the 0.1 to 0.5 micrometer range may be an especially challenging control problem. … The gap is most noticeable in wet scrubbers and electrostatic precipitators.*" A generalized plot showing the range of collection efficiencies is shown in Figure C-9. Overlaid on the diagram is the mass size distribution of particles collected downstream of the ESP wet FGD at the MRY plant (Markowski and others, 1983). This shows that ash produced in the MRY plant have a particle size that can pass through the scrubber and that these particles are rich in sodium as shown in Figure C-7.

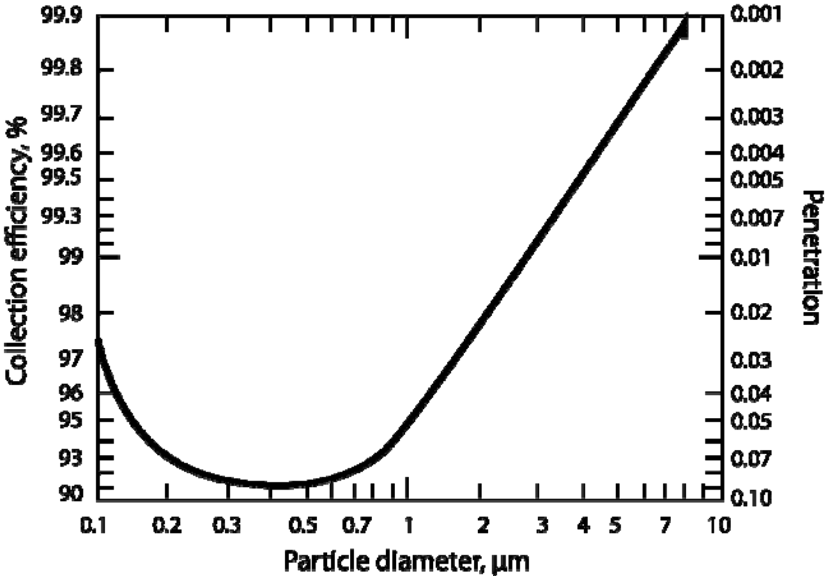


Figure C-8. Typical ESP Collection efficiency curve for removal of particulate from gas streams (http://www.epa.gov/apti/bces/module3/collect/collect.htm).

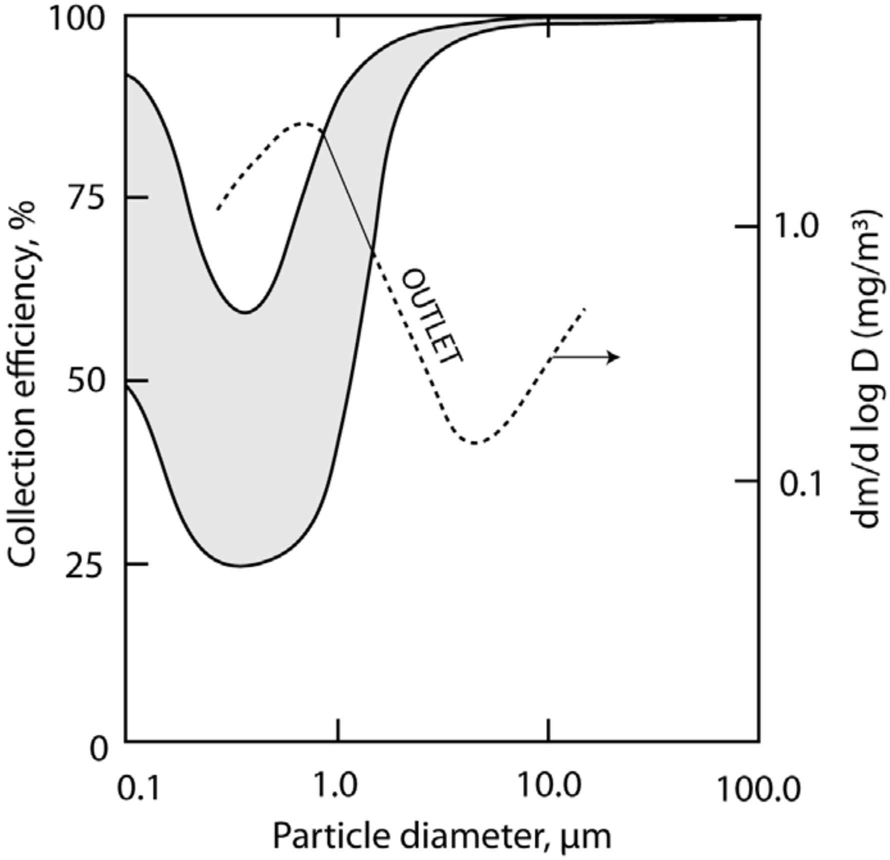


Figure C-9. Particulate control efficiency for difficult to control particulate combined with the mass distribution of particulate collected downstream of the scrubber at MRY (Markowski and others, 1983, http://www.epa.gov/apti/bces/module3/collect/collect.htm)

Field Experience and Testing

As indicated by EPA (Woodward, 1998), scrubbers do not effectively remove particulate less than 1µm in diameter. There is significant evidence that sodium-rich aerosols penetrate ESPs as well as scrubbers at full-scale power plants when firing high-alkali-containing fuels. An example is a biomass fired system using a tower type scrubber where the removal efficiency of the smaller size fraction of ash is low, as shown in Figure C-10 (Ohlström and others, 2006).

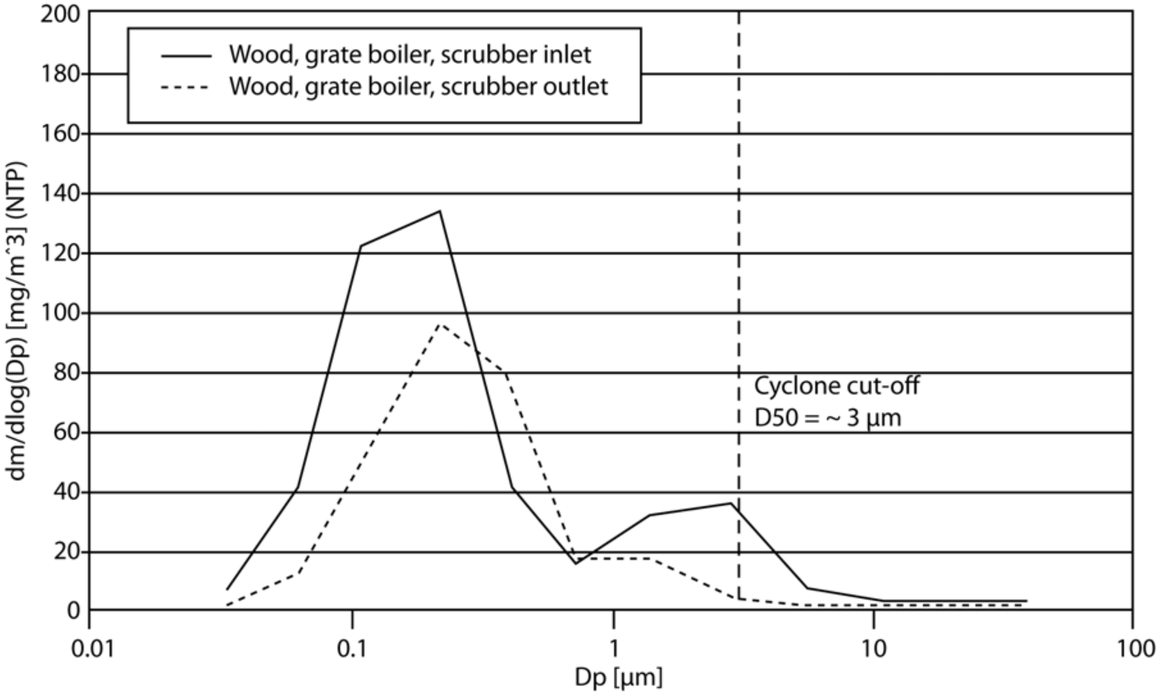


Figure C-10. Removal of fine aerosols using a scrubber on a wood fired combustor (Ohlström and others, 2006).

Minnesota Power's Boswell Energy Station found that when it fired high-sodium, lower-ash northern Powder River Basin subbituminous coal (7% Na_2O in the ash), it experienced increases in opacity. Hurley and Katrinak (1992) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with a venturi wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using multicyclone followed by an impactor and a Nucleopore filter. The sized fractions were weighed and analyzed to determine the abundance and composition of the submicron-sized fractions. The mass loadings in the various size bins are plotted in Figure C-11, showing that the scrubber is quite effective in removing the larger particles. However, the scrubber is not very effective in removing the aerosols less than 1 micrometer in diameter for both the blended coal and the high sodium coal (Coal A).

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of the coals. Vapor-phase sodium condenses in the boiler's convective pass to form fine sodium-rich aerosols or other Na species that later react with ash particles. Pure Na_2SO_4 particles are too small to be removed by such scrubbing. Figure C-12 shows the spikes of the ash material collected on Stage 10 of the impactor. This impactor accumulation represents particles of less than 0.7 to 2.5 micrometer size fraction of the submicron aerosol. The spikes are made up of submicron particulate matter, and the chemical analyses of the spikes and ash particles collected on the Nucleopore filters downstream of the impactor plates are shown in Table C-4. Both samples are dominated by sodium and sulfur that are likely in the form of sodium sulfate. These sulfate materials exhibit highly cohesive tendencies.

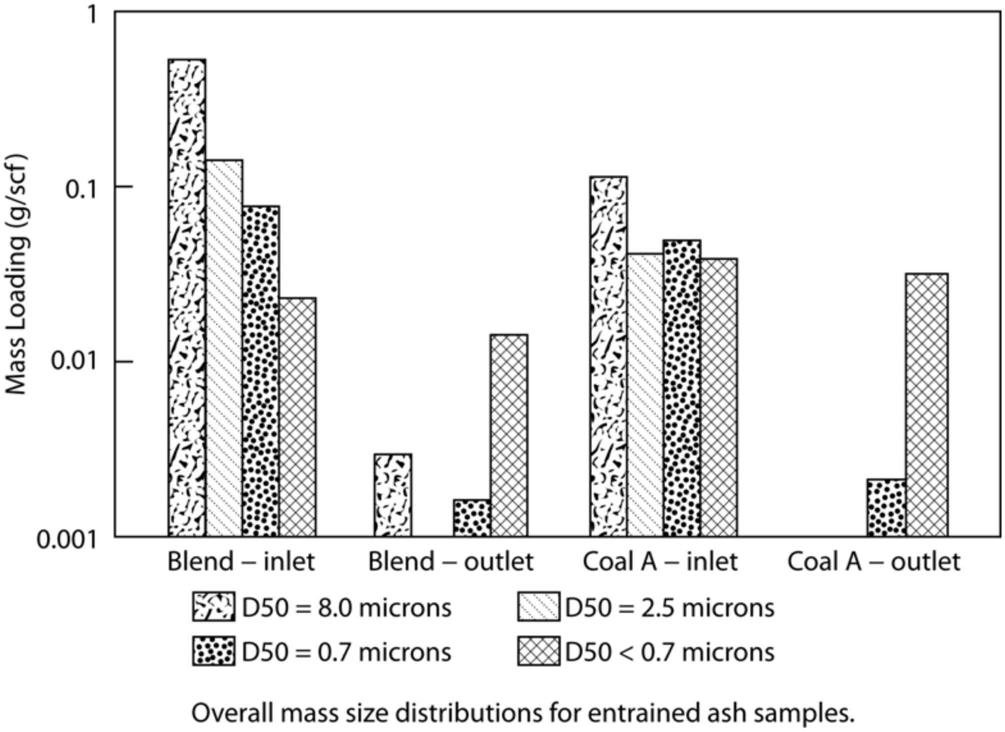


Figure C-11. Mass loadings and size for particulate collected upstream and downstream of the wet venturi scrubber at Clay Boswell (Hurley and Katrinak, 1992).

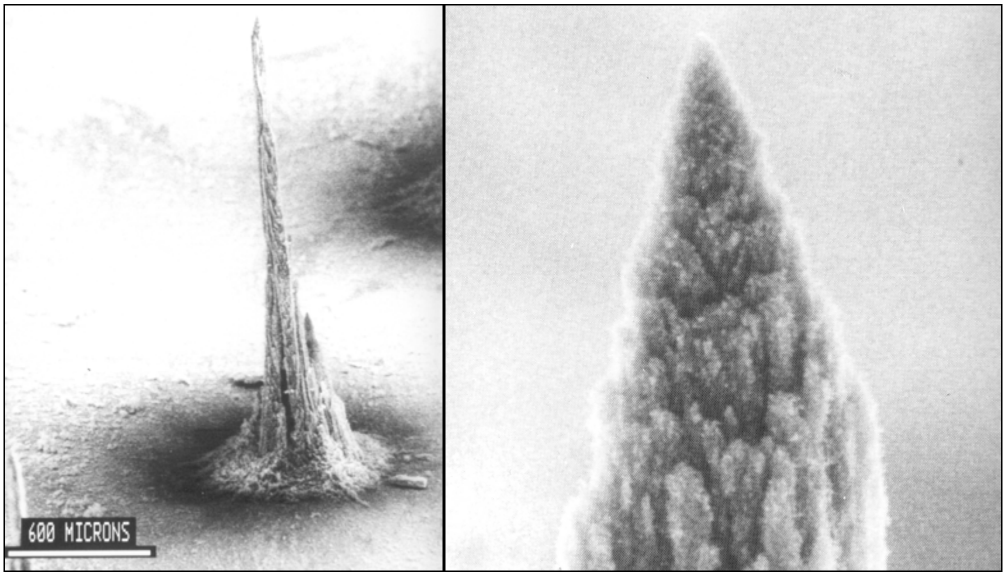


Figure C-12. Scanning electron microscope images of spike formed on impactor plate upon combustion of high-sodium subbituminous coal (right - close-up of spike) (Hurley and Katrinak, 1992).

Table C-4. Chemical Composition of the Spike Shown in Figure C-12 and the Filter (weight percent expressed as equivalent oxide).

	100% Coal A	
Oxide	**Spike**	**Filter**
Na_2O	**35.1**	**17.3**
MgO	1.4	7.8
Al_2O_3	2.0	9.8
SiO_2	9.1	10.6
P_2O_5	0.4	0.2
SO_3	**39.7**	**28.0**
K_2O	2.6	1.5
CaO	6.2	15.7
TiO_2	0.2	1.8
Cr_2O_3	1.4	0.1
Fe_2O_3	0.9	2.9
BaO	0.5	2.6

In addition to the aforementioned testing results, penetration of submicron particles through ESP and scrubbers has been reported by numerous researchers (Markowski and others, 1983, and Lighty and others, 2000).

Power Span Testing at MRY

Aerosols passing through the ESP at MRY Unit 1 resulted in significant accumulation on Powerspan's ECO barrier discharge reactor resulting in significant degradation in performance. The ECO DBD reactor is located just downstream of the plant's ESP or fabric filter (FF) and can be exposed to aerosols. The DBD reactor has quartz electrode rods inside where electric current is passed in order to generate the plasma used to oxidize NO. The temperature of the flue gas at the DBD reactor ranged between 300°F and 350°F. The temperature of the quartz electrodes is approximately 100°F higher than the gas temperature.

The Powerspan ECO reactor slip stream system was designed by Powerspan and the EERC. The slip stream system was installed by the EERC at Minnkota Power Company's Milton R. Young Station Unit #1 down stream of the ESP where the flue gas temperature was ranged from 300°F to 350°F. The system was commissioned on July 3, 2007, operated for 107 days. Operational performance of the system was monitored and data were archived for post processing. A pair of electrodes were extracted and replaced on a bi-weekly basis. Each pair of electrodes were shipped to Powerspan for testing in their laboratory reactor. Tested electrodes were then shipped to the EERC for scanning electron microscopy imaging and x-ray microanalysis. Measurement of NOx conversion by the slip stream system was not possible due to the nitric acid production of the DBD reactor.

The operational observations, performance results, and lab testing showed that the system was adversely affected by ash fouling. NOx conversion by ash covered electrodes was significantly reduced. Figure C-13 compares rods exposed to flue gas and aerosols downstream of the ESP at MRY Unit 1. The abundance of sodium in coal fired during the Powerspan testing is shown in Figure C-14. The results show sodium levels measured by the full stream elemental analyzer (FSEA) ranged from 3.5 to 6 % Na2O in ash. Figure C-15 shows the degradation in NO conversion as a result of being coated with aerosols. The NO conversion was severely impacted.

Figure C-13. Comparison of (left) clean quartz rod and (right) dirty quartz rod exposed to flue gas downstream of ESP at MRY Unit 1 for sixteen days.

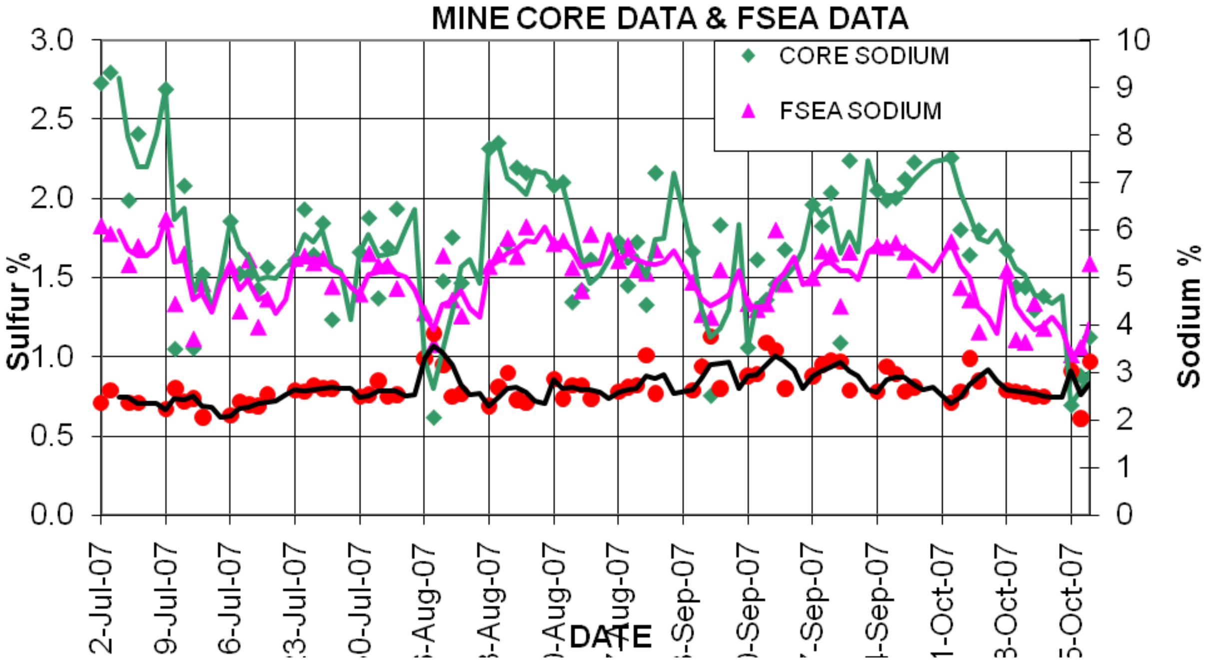


Figure C-14. Sodium and sulfur levels in lignite delivered during testing of the Powerspan barrier discharge reactor.

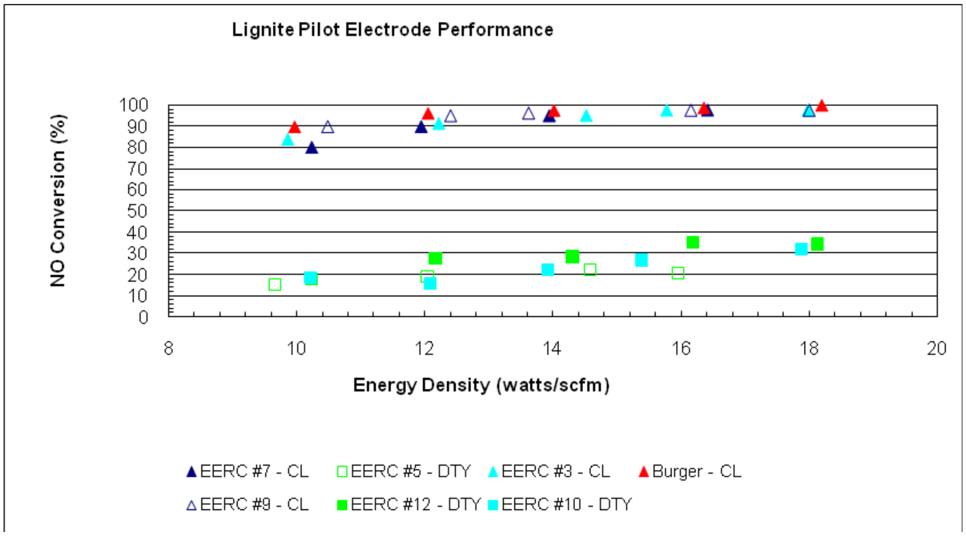
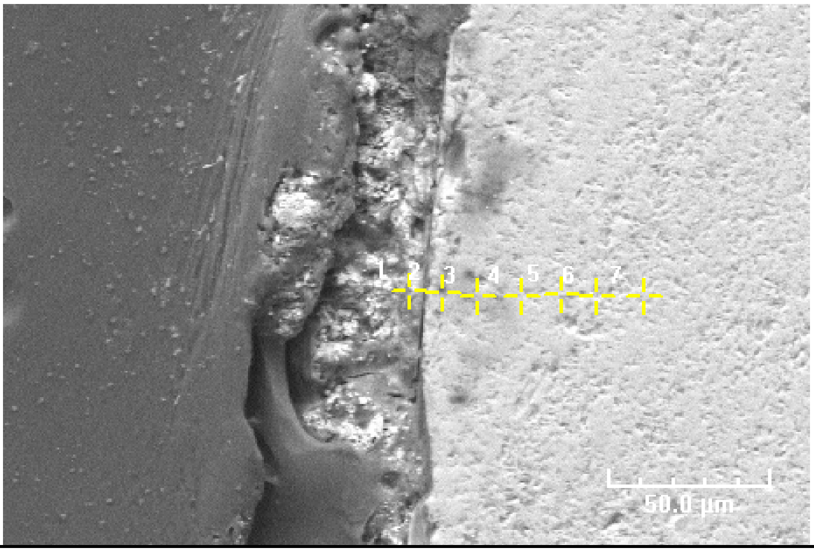


Figure C-15. NO conversion for clean (CL) and dirty (DTY) for quartz tube exposed the flue gas during the MRY testing.

Examination of the quartz rods (cross-sectioned to expose coating thickness) using scanning electron microscope elemental analysis showed significant elemental sodium, sulfur, and calcium in the ash coating the tubes after only 16 days of testing. The data is reported on Figure C-16. The thickness of the layer was approximately 25 µm. The rods were exposed to sootblowing. Images of the reactor and coatings on the electrodes are shown in Figure C-17.



Tag	Na	Mg	Al	Si	P	S	Cl	K	Ca	Ti	Fe	Ba
1	35.38%	0.98%	14.10%	4.68%	0.00%	35.75%	0.00%	1.42%	6.61%	0.02%	1.07%	0.00%
2	0.00%	0.00%	0.22%	98.52%	0.00%	0.00%	0.07%	0.89%	0.00%	0.30%	0.00%	0.00%
3	0.00%	0.00%	0.61%	98.11%	0.00%	0.00%	0.00%	1.05%	0.00%	0.00%	0.22%	0.00%
4	0.00%	0.00%	0.20%	98.33%	0.00%	0.00%	0.00%	1.19%	0.00%	0.00%	0.27%	0.00%
5	0.00%	0.00%	0.00%	98.70%	0.00%	0.00%	0.00%	1.24%	0.00%	0.00%	0.06%	0.00%
6	0.00%	0.00%	0.25%	97.26%	0.00%	0.00%	0.27%	1.70%	0.00%	0.00%	0.36%	0.16%
7	0.00%	0.00%	0.00%	97.93%	0.00%	0.00%	0.00%	1.55%	0.00%	0.00%	0.47%	0.05%

Figure C-16. SEM point analysis on electrode #11 (16 days of service).

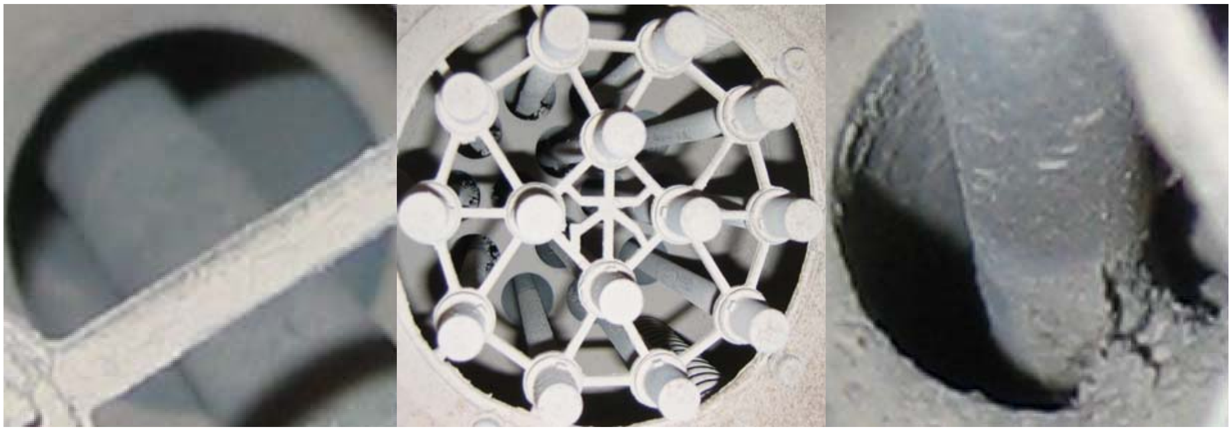


Figure C-17. Images of top of DBD reactor showing ash accumulations on electrodes and reactor surfaces.

Conclusions gained by this work were:

1. Sodium rich aerosols and small ash particles that had penetrated the ESP accumulate and become bonded on the surface of the silica electrodes in spite of soot blowing using a sonic horn as recommended by Powerspan.
2. Ash accumulations adversely affected the NOx conversion.
3. The adverse impact occurs within a two week time period.

MRY Sulfate Aerosol Sampling

The penetration of aerosols through ESP and wet scrubbers is well known and has been studied since the mid 1970s (McCain and others, 1975; Ensor and others, 1975). As a result of these challenges, the quantity of total aerosols and sulfate aerosols was measured at the MRY by Markowski and others, 1983. Markowski and others (1983) collected EPA Method 17 particulate samples and size-segregated the particles using an impactor (aerodynamically separates particles and allows for the characterization of each fraction). The results of the EPA method 17 sampling (mass concentration) conducted over a four-day period are illustrated in Figure C-18 for the inlet and outlet of the scrubber. At the inlet, aerosol mass concentrations ranged from a high of more than 10,000 µg/m^3 to a low of 4,000 µg/m^3. Significant levels were also found at the scrubber outlet, ranging from 8,800 to 2,500 µg/m^3. The removal efficiency varied from -25 to 66%.

Markowski and other (1983) offered no explanation of the differences in the levels of aerosols measured in the flue gas and removal efficiency. They did not consider that the ash content of the coal varied significantly during the testing. Results of testing at MRY have shown significant differences in the quantity vaporized for coals that have different ash contents (see Figure C-3). The variations in ash content shown in Figure C-18 reflect changing coal characteristics that resulted in differences in aerosol mass concentration.

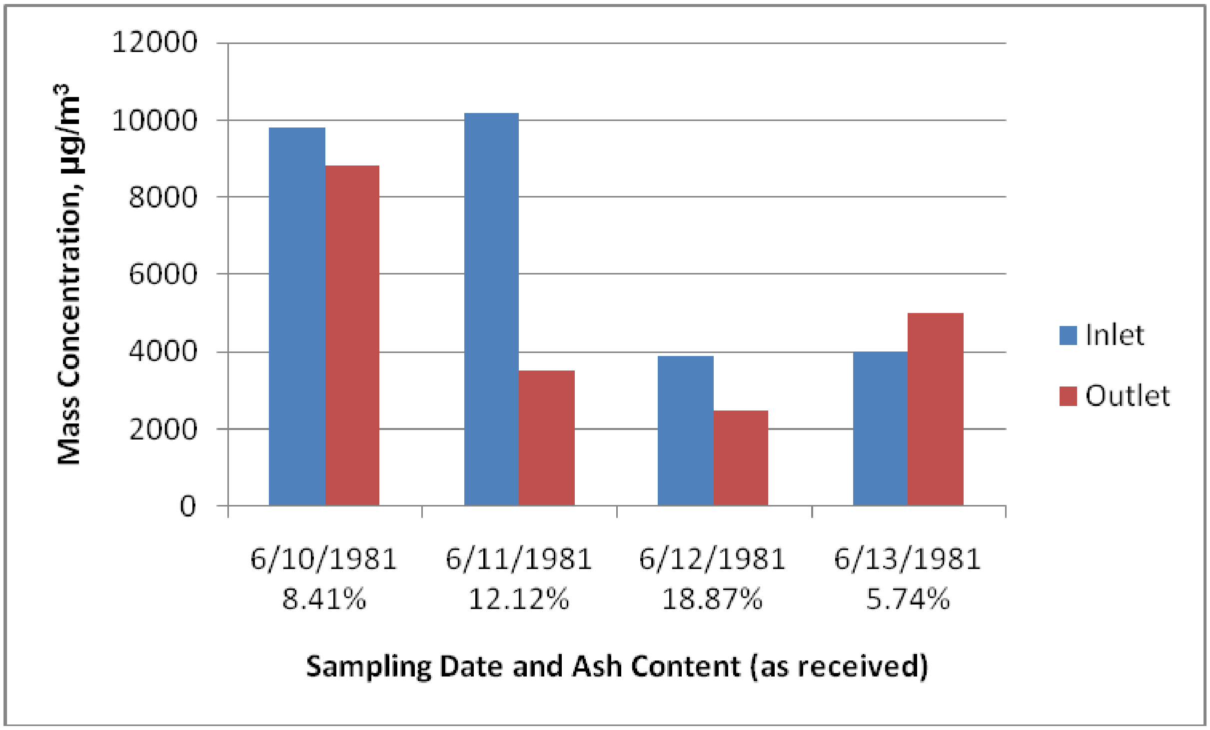


Figure C-18. Mass Concentration of Aerosol Collected at MRY Unit 2 at the Scrubber Inlet and Outlet (Markowski and others, 1983).

The results of the measurements of aerosol capture are illustrated in Figure C-19. The results show that aerosols less than one micrometer in diameter are not effectively captured in the wet FGD at the MRY facility. The graph also indicates the penetration of the particles through the FGD as a function of particle size. The penetration is the outlet size distribution divided by the inlet size distribution. (*Note: Penetration = 1- efficiency*). Markowski and others (1983) showed that the "metallic" sulfate aerosols (sodium sulfate) penetrated the FGD much more effectively than the larger particulate materials.

The mass of each of the impactor size fractions for the aerosols collected at the inlet and the outlet of the wet FGD upstream and downstream of the scrubber are illustrated in Figure C-20 and 21 with the results tabulated in Table C-5. The total mass distributions are summarized in Figure C-20 and the sulfate mass distribution is illustrated in Figure C-20.

Based on the impactor data the total mass of particulate that penetrates the scrubber is 5990 µg/m^3 (Markowski and others, 1983). These ash materials consist of a combination of sulfates and oxides of sodium, calcium, and sulfur. Much of the aerosol is present in the >14 µm size fraction. There are also significant mass in the less than 1 µm size fraction. All of these particles have the potential to penetrate the pores of the catalyst. In addition, there is a significant mass in the <0.26 µm fraction. This fraction represents the ultrafine component that has been implicated as the most significant contributor to catalyst poisoning (Kling and others, 2007).

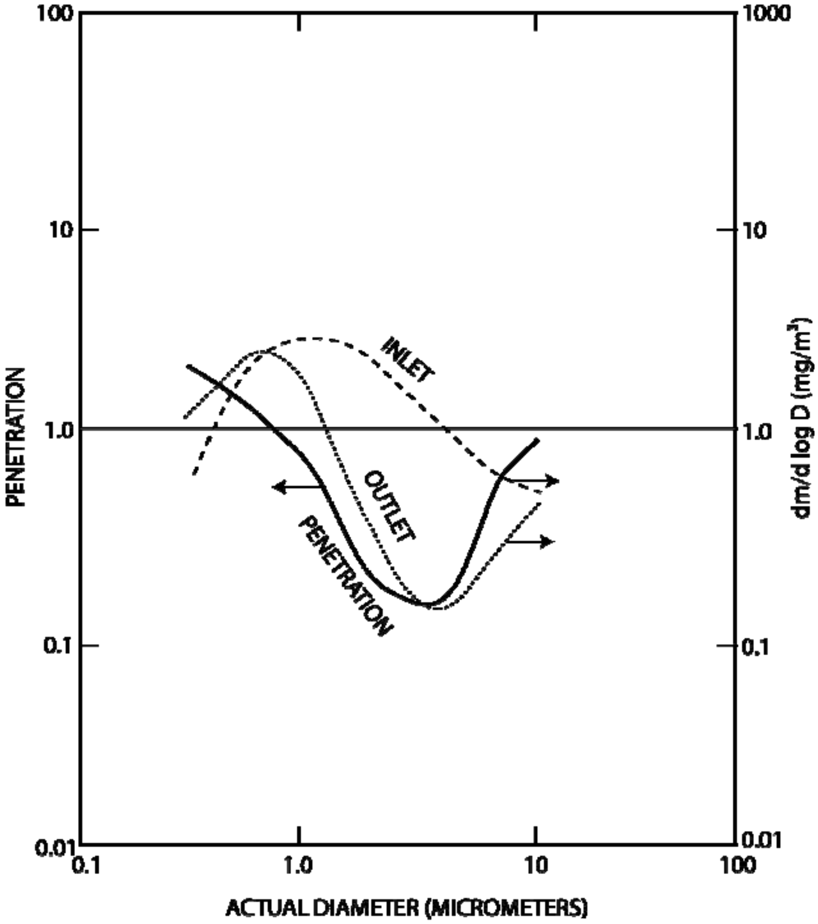


Figure C-19. Penetration through the wet scrubber (Markowski and others, 1983).

Table C-5. Size-segregated total and sulfate particulate collected upstream and downstream of the MRY FGD. (Markowski and others, 1983).

	Inlet	Outlet	Inlet	Outlet
Size, µm	Total, µg/m^3	Total, µg/m^3	Sulfate, µg/m^3	Sulfate, µg/m^3
<0.26	1910	769	436	602
0.26-0.52	401	640	164	274
0.52-1.1	883	1410	293	459
1.1-2.5	1020	265	291	69.2
2.5-6.7	337	154	173	94
6.7-14	300	367	100	103
>14	700	2390	439	46.2
Total	5550	5990	1896	1650
>1.1	2357	3176	1003	312.4
<1.1	3194	2819	893	1335
Percent				
>1.1	42.5 %	53.0 %	52.9 %	18.9 %
<1.1	57.5 %	47.1 %	47.1 %	80.9 %

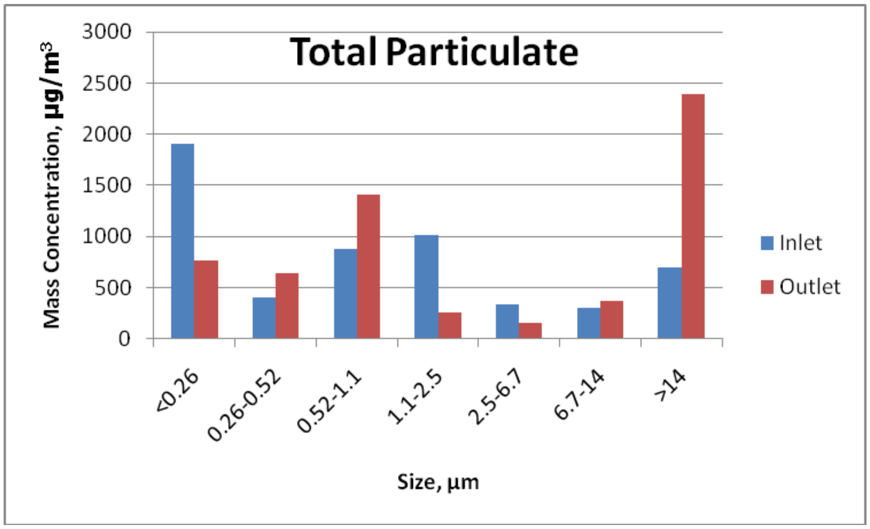


Figure C-20. Total particulate removal across scrubber at MRY.

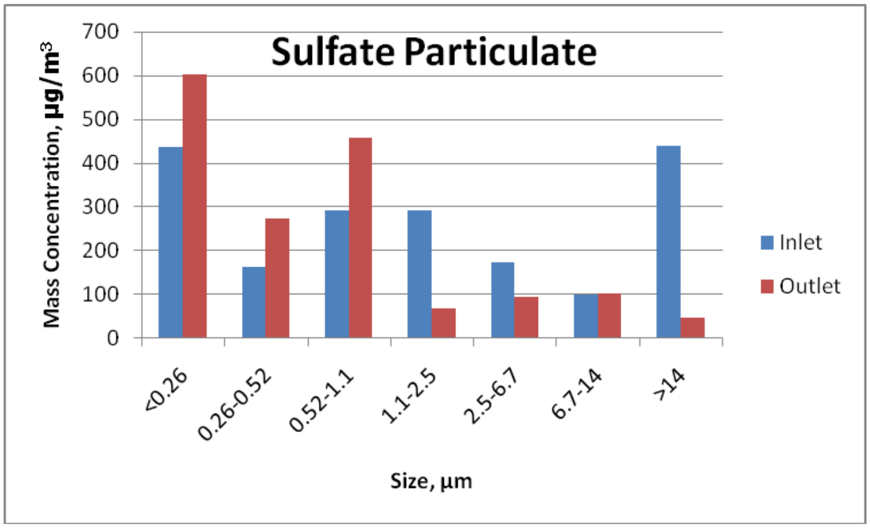


Figure C-21. Sulfate particulate removal across scrubber at MRY.

Estimation of Alkali Aerosol Loading and Catalyst Deactivation

The following data was used to estimate alkali aerosol loading and catalyst deactivation. The particle loading was based on the results of testing conducted by Markowski and others (1983) where they determined the mass loadings of aerosols at the inlet and outlet of the wet FGD at MRY Unit 2. The key data utilized is illustrated in Figure C-22 to estimate the loadings. The data provided shows a range of mass concentrations up to 8,800 µg/m^3 at the outlet of the scrubber. Based on results in mass size distribution of the aerosol 47 to 80% of the aerosols that pass through the scrubber is less than 1.1 µm. Much of this material is in the ultrafine fraction.

These materials have the potential to penetrate into the catalyst causing plugging and can react with active components in the catalyst. There are numerous publications supporting these mechanisms. Kling and others(2007) found that the rate of catalyst deactivation was related to the accumulation of sodium and potassium on the catalyst as shown in Figure C-23 and 24. The work by Kling and others (2007) is consistent with the work conducted by Khodayari (2001) illustrated in Figure C-25 where it was shown that the deactivation rate is more significant for PC fired systems as compared to fluidized beds. The work based on Kling and others when applied to PC- and cyclone-fired systems will likely underestimate the degree of deactivation because of the firing methods.

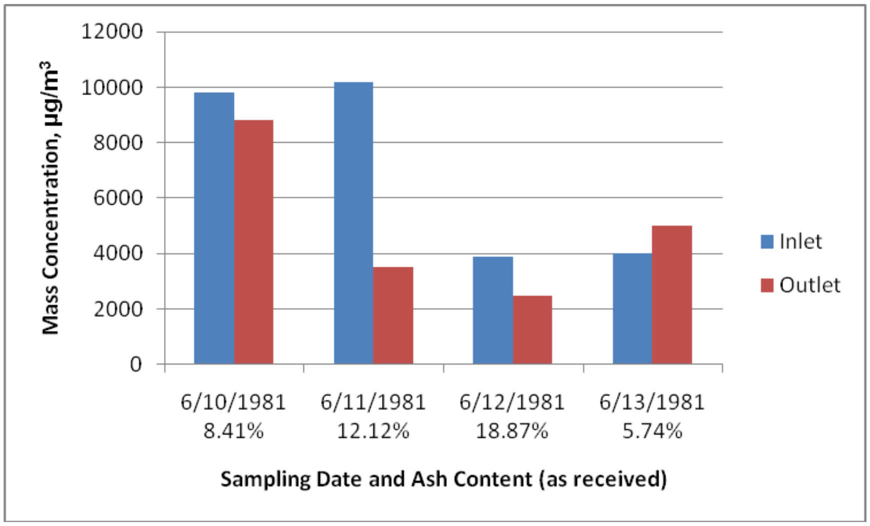


Figure C-22. Mass Concentration of particulate collected at MRY using EPA Method 17 (Markowski and others, 1983).

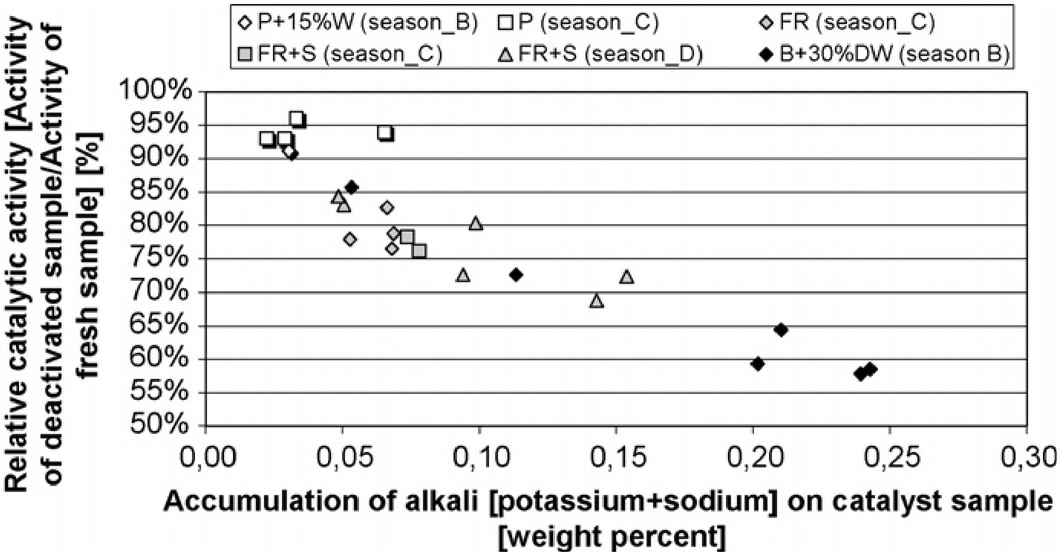


Figure C-23. Catalyst deactivation compared to accumulation of potassium and sodium on the catalyst surface (Kling and others, 2007).

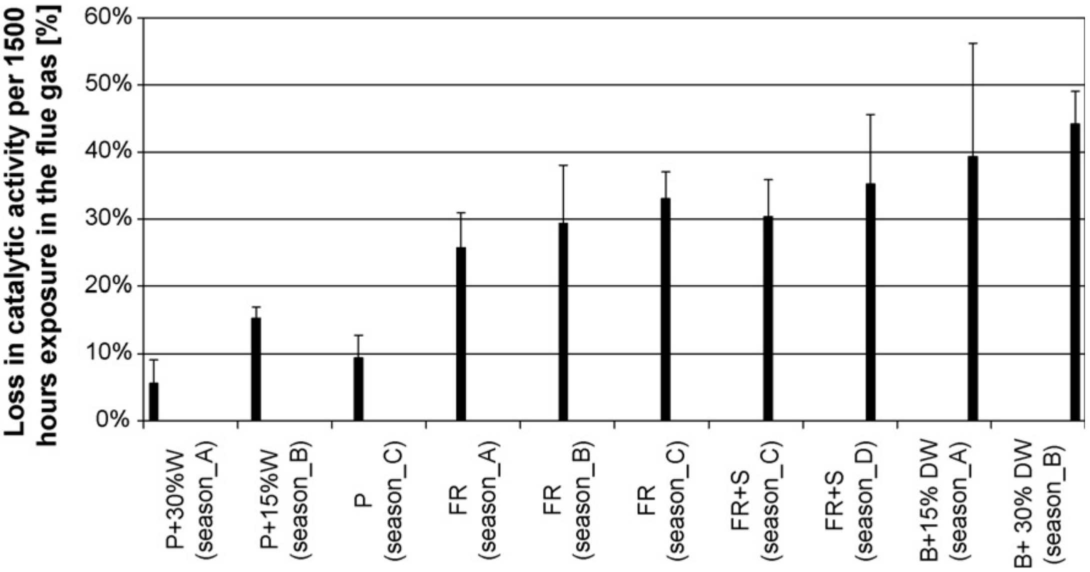


Figure C-24. Loss in catalyst activity when exposed to flue gases containing vaporized Na and K when combusting biomass in a fluidized bed combustion system (Kling and others, 2007).

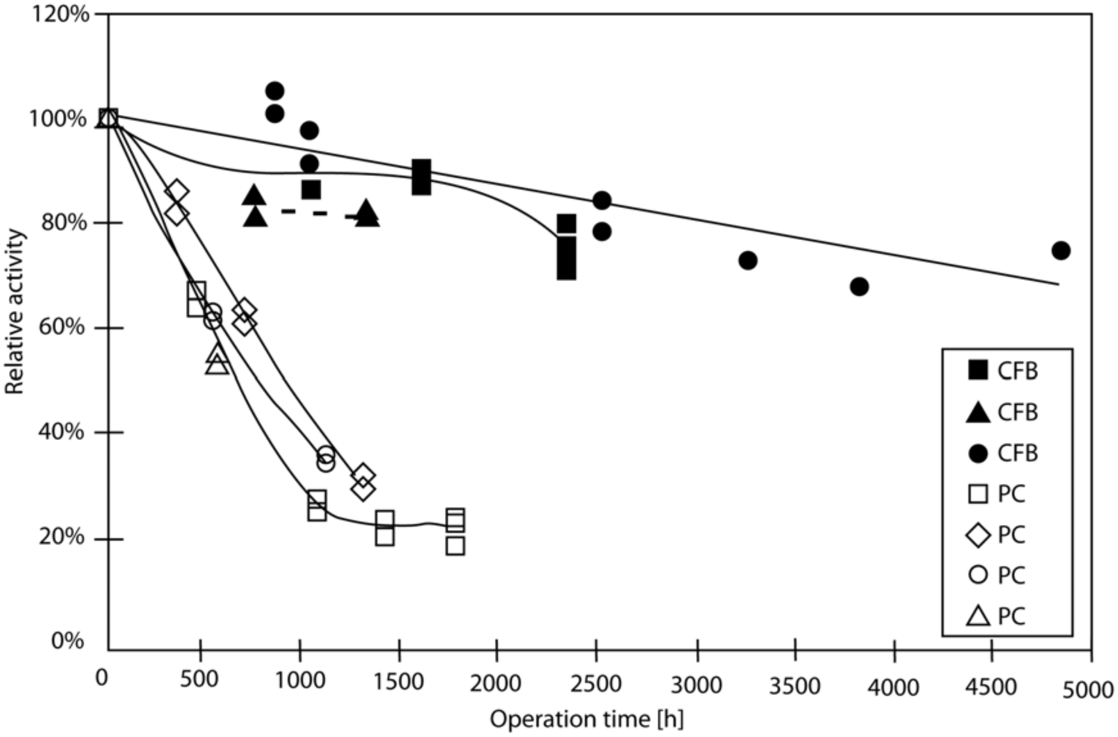


Figure C-25. Comparison of poisoning of catalysts in a CFB boiler firing forest residues, and in a PC firing pulverized wood (Khodayari, 2001).

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Table 4 – MRYS Unit Design and Operating Parameters

Design Unit Operating Characteristics(1)	Unit 1 Design	Unit 2 Design
Boiler Type	Cyclone	Cyclone
Boiler Manufacturer	B&W	B&W
Boiler Design Heat Input Capacity (nameplate), mmBtu/hr	2,510	4,696
Unit Nameplate Generator Output Capacity, MW_g (gross)	257	477
Unit Nominal Full Load (NFL) Output, MW_g (gross)	235	450
Boiler Heat Input for Unit NFL Output, mmBtu/hr	2,508	4,814
Boiler Excess O_2, %, (wet, NFL)	3.17	4.04
Boiler Excess Air, % (NFL)	21.3	28.5
Fly Ash Portion of Total Ash, % (NFL)	45	50
Typical Maximum Continuous Rating (MCR) output, MW_g	253	462
Maximum Unit Output (URGE) Rating, MW_g	278	512
Boiler Firing Conditions for Flue Gas Flow Calculations:		
Boiler Heat Input, mmBtu/hr	2,852	4,740
Coal Higher Heating Value, Btu/lb as-received	6,578	6,578
Coal Flow Rate for heat input, lb/hr	433,500	720,500
Fly Ash Portion of Total Ash, %	50	50
Flue Gas Conditions at the boiler flue gas outlet:		
Boiler Excess O_2, %, (wet)	2.87	4.77
Boiler Excess Air, %	19.0	35.4
Flue Gas Mass Flow Rate, lb/hr	3,811,000	7,117,000
Flue Gas Volumetric Flow Rate, acfm	2,502,000	4,371,000
Flue Gas Temperature, degrees F	910	818
Flue Gas Pressure, in. w.g.	-11.5	-13.5
Boiler Outlet Maximum SO_2, lb/mmBtu	3.0(2)	3.0(2)
Boiler Outlet Maximum SO_2, lb/hr	8,970	15,474
Average Boiler Heat Input for SO_2, mmBtu/hr	2,990	5,158
Expected Boiler Outlet Maximum 30-day average SO_3, lb/hr	135(3)	236(3)

(1) – Boiler unit operating parameters are provided for more than one load or output condition.

(2) – Boiler Outlet Maximum SO_2 lb/mmBtu is based on 1.0% S and 6,578 Btu/lb higher heating value content in the as-received lignite coal.

(3) – Boiler Outlet Maximum SO_3 lb/hr is based on the assumed conversion of 1.5% of the boiler outlet SO_2 to SO_3 upstream of any flue gas treatment. This conversion percentage has not been confirmed by actual boiler outlet flue gas test measurements. The SO_2 lb/mmBtu and lb/hr values have not been reduced by this assumed SO_3 conversion.

Table C2 summarizes the average, maximum and minimum values for the entire as-fired coal database. The ranges on the various components can be very large. For example, the ash content ranges from 5 to 25%. Sodium oxide content ranges from 0.6 to 13% of the ash.

Table C2. Average, maximum, and minimum of basic coal analysis for all the coals in the as-fired database - Center Lignite Coal

ID NUMBER	Moisture	Ash	Sulfur	Btu	Volatile Matter	Fixed Carbon	Aluminum Oxide	Barium Oxide	Calcium Oxide	Iron Oxide	Magnesium Oxide	Manganese Dioxide	Phosphorus Pentoxide	Potassium Oxide	Silicon Dioxide	Sodium Oxide	Strontium Oxide	SO3	Titanium Dioxide	Basic total	Acid Total	Base/Acid Ratio
							Al_2O_3	Ba	CaO	Fe_2O_3	MgO	Mn	P_2O_5	K_2O	SiO_2	Na_2O	Sr	SO_3	TiO_2			
Average	**37.1**	**9.64**	**1.0**	**6578.1**	**25.3**	**28.0**	**11.7**	**0.5**	**13.2**	**8.9**	**4.0**	**0.1**	**0.1**	**1.3**	**36.0**	**4.4**	**0.4**	**18.4**	**0.5**			**0.7**
Max	**39.4**	**25.5**	**2.6**	**7101.0**	**31.1**	**31.2**	**15.6**	**1.2**	**24.0**	**24.7**	**7.1**	**0.3**	**1.0**	**2.3**	**56.0**	**13.0**	**37.0**	**34.5**	**0.7**			**2.5**
Min	**33.6**	**5.0**	**0.5**	**5852.0**	**22.3**	**13.7**	**6.3**	**0.2**	**6.8**	**5.4**	**2.3**	**0.0**	**0.0**	**0.2**	**12.3**	**0.6**	**0.2**	**8.1**	**0.2**			**0.3**
90th Perc.	**38.10**	**12.51**	**1.29**	**6820**	**26.5**	**29.9**	**14.2**	**0.8**	**19.9**	**12.2**	**5.7**	**0.1**	**0.4**	**1.9**	**46.0**	**8.71**	**0.6**	**26.3**	**0.6**			**1.26**
10th Perc.	**35.95**	**7.06**	**0.72**	**6359**	**24.3**	**26.1**	**9.6**	**0.4**	**9.7**	**7.1**	**3.0**	**0.1**	**0.0**	**0.6**	**22.7**	**1.99**	**0.2**	**14.4**	**0.4**			**0.44**
45th Perc.	**37.17**	**9.33**	**0.90**	**6552**	**25.2**	**28.0**	**11.6**	**0.5**	**12.2**	**8.3**	**3.8**	**0.1**	**0.1**	**1.4**	**37.0**	**4.09**	**0.3**	**17.3**	**0.5**			**0.592**
55th Perc.	**37.37**	**9.75**	**0.94**	**6592**	**25.4**	**28.3**	**12.0**	**0.5**	**12.7**	**8.7**	**4.0**	**0.1**	**0.1**	**1.4**	**38.4**	**4.61**	**0.4**	**18.0**	**0.5**			**0.637**

1. Ash weight percent was determined on an “as-fired” lignite coal basis.
2. BTU (higher heating value) content expressed on an “as-fired” lignite coal basis.
3. Constituent weight percent of the ash, elemental weight percent expressed as equivalent oxide.
4. B/A is the base to acid weight ratio of the ash constituents (B/A=[Na_2O+MgO+CaO+ K_2O+FeO]/[SiO_2+Al_2O_3+TiO_2]).

MJJ 3017-1

UTILITY BOILER PERFORMANCE SUMMARY

A FUEL AS FIRED

SAMPLES			
ANALYSES	SPECIFIED		
KIND			-
ASTM	CLASS		IV
ASTM	GROUP		I
ASTM	MINE		
SOURCE	SEAM &		
SOURCE	DISTRICT		
SOURCE	COUNTY		OLIVER
SOURCE	STATE		N.D.
COAL	SIZE		
COAL	GRINDABILITY	22	30
COAL	SURFACE MOISTURE, %	3.0-5.0	5.0
COAL	ASH SOFT. TEMP., F (REDUCING)		
PROX. ANAL. %	MOISTURE, TOTAL	276-403	36.0
PROX. ANAL. %	VOLATILE MATTER	270-320	29.1
PROX. ANAL. %	FIXED CARBON	270-320	29.1
PROX. ANAL. %	ASH	3.9-8.3	5.8
PROX. ANAL. %	TOTAL		100.0
ULTIMATE ANALYSIS	FUEL	LIGNITE	LIGNITE
ULTIMATE ANALYSIS	% W		WT.
ULTIMATE ANALYSIS	ASH	3.9-8.3	5.80
ULTIMATE ANALYSIS	S		0.74
ULTIMATE ANALYSIS	H_2	2.9-3.5	1.00
ULTIMATE ANALYSIS	C	389-46.1	40.40
ULTIMATE ANALYSIS	CH_4		
ULTIMATE ANALYSIS	C_2H_6		
ULTIMATE ANALYSIS	C_2H_4		
ULTIMATE ANALYSIS	C_3H_8		
ULTIMATE ANALYSIS	C_4H_{10}		
ULTIMATE ANALYSIS	C_5H_{12}		
ULTIMATE ANALYSIS	C_6H_{14}		
ULTIMATE ANALYSIS	CO	001-001	0.01
ULTIMATE ANALYSIS	CO_2		
ULTIMATE ANALYSIS	SO_2		
ULTIMATE ANALYSIS	H_2O	275-40.3	36.00
ULTIMATE ANALYSIS	N_2	.4-.74	0.65
ULTIMATE ANALYSIS	O_2		13.40
ULTIMATE ANALYSIS	TOTAL		100.00
ULTIMATE ANALYSIS	BTU/LB	6250-7830	6900
ULTIMATE ANALYSIS	BTU/CU FT AT 60F 30 IN. HG		

B PREDICTED PERFORMANCE

STEAM LEAVING SH, M LB/HR		990	1650	1714
STEAM LEAVING RH1, M LB/HR		876	1460	1534
STEAM LEAVING RH2, M LB/HR				
TYPE OF FUEL		LIGNITE		
LOAD DURATION		CONTINUOUS		
EXCESS AIR ENTERING AIRHEATER		31	28	28
NO. OF BURNERS IN OPERATION		7	7	7
FUEL INPUT, MKB/HR		1565	2422 /	2510
HEAT AVAIL. MKB/HR (FUEL & HEATED AIR)		1620	2559	2649
QUANTITY, M LB/HR	FUEL (MCFH-NAT. GAS)	227	352	364
QUANTITY, M LB/HR	FLUE GAS ENTERING AIR HEATER	2250	2817	2919
QUANTITY, M LB/HR	AIR LEAVING SEC. AH & PRI. AH	1520	2312	2396
QUANTITY, M LB/HR	AIR HEATER LEAKAGE			
PRESSURE, PSIG	STEAM AT SH OUTLET	1875	1875	1970
PRESSURE, PSIG	STEAM AT RH1 INLET	258	457	480
PRESSURE, PSIG	STEAM AT RH2 INLET			
PRESSURE, PSIG — PRESSURE DROP	REHEATER 1	15	25	26
PRESSURE, PSIG — PRESSURE DROP	REHEATER 2			
PRESSURE, PSIG — PRESSURE DROP	ECONOMIZER	11	30	33
PRESSURE, PSIG — PRESSURE DROP	DRUM TO SH OUTLET	45	125	135
TEMPERATURE, F — STEAM	LEAVING SUPERHEATER	1010	1010	1010
TEMPERATURE, F — STEAM	LEAVING REHEATER 1	970	1010	1010
TEMPERATURE, F — STEAM	ENTERING REHEATER 1	590	664	663
TEMPERATURE, F — STEAM	LEAVING REHEATER 2			
TEMPERATURE, F — STEAM	ENTERING REHEATER 2			
TEMPERATURE, F — FLUE GAS	LEAVING PRI. SH	810	890	900
TEMPERATURE, F — FLUE GAS	LEAVING AH (EXCL. LKG)	370	325	330
TEMPERATURE, F — FLUE GAS	LEAVING AH (INCL. LKG)			
TEMPERATURE, F	WATER ENTERING ECONOMIZER	408	461	466
TEMPERATURE, F — AIR	ENTERING AIR HEATER	100	100	100
TEMPERATURE, F — AIR	LEAVING AIR HEATER	735	768	777
RESISTANCE, IN. OF WATER — GAS	FURNACE & CONVECTION BANKS	2.4	3.7	4.0
RESISTANCE, IN. OF WATER — GAS	FLUES TO STACK	1.3	1.9	2.0
RESISTANCE, IN. OF WATER — GAS	AIR HEATER & ECON.	4.9	7.6	8.1
RESISTANCE, IN. OF WATER — GAS	DUST COLLECTOR	1.7	2.7	3.0
RESISTANCE, IN. OF WATER — GAS	TOTAL DRAFT LOSS	10.3	15.9	17.1
RESISTANCE, IN. OF WATER — AIR	FUEL BURNERS & WINDBOX	36.5	36.5	36.5
RESISTANCE, IN. OF WATER — AIR	DUCTS & FLOW METER	2.1	3.2	3.5
RESISTANCE, IN. OF WATER — AIR	AIR HEATER	1.5	2.4	2.6
RESISTANCE, IN. OF WATER — AIR	STEAM COIL AH	0.3	0.5	0.5
RESISTANCE, IN. OF WATER — AIR				
RESISTANCE, IN. OF WATER	TOT. AIR RESISTANCE	40.4	42.6	43.1
HEAT LOSS, %	DRY GAS	6.70	5.46	5.58
HEAT LOSS, %	H_2 & H_2O IN FUEL	10.51	10.38	10.40
HEAT LOSS, %	MOISTURE IN AIR	0.17	0.14	0.14
HEAT LOSS, %	UNBURNED COMBUSTIBLE	0.10	0.10	0.10
HEAT LOSS, %	RADIATION	0.32	0.19	0.18
HEAT LOSS, %	UNACC. FOR & MFRS. MARGIN	1.10	1.10	1.10
HEAT LOSS, %	SLAG TANK	0.40	0.40	0.40
HEAT LOSS, %	TOTAL HEAT LOSS	19.30	17.77	17.90
EFFICIENCY OF UNIT, %		80.70	82.23	82.10
PULV. PER BOILER	NO. IN USE PER BOILER			
PULV. PER BOILER	TOTAL POWER, KWHR/TON MOTOR OUTPUT			
PULV. PER BOILER	% THRU 200 U.S.S. SIEVE			

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 27.72 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING 11X0

C EQUIPMENT PER UNIT

2	TYPE RADIANT		
3	SIZE		
4		RBC 57/CY.	
5		DESIGN PRESSURE 2325 PSIG	
6			
7	PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)	
8	PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED (PROJECTED)	33760
9	PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	SUPERHEATER (CIRCUMFERENTIAL)	9229
10	PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	SUPERHEATER (PROJECTED)	1200
11	PRESSURE PART HEATING SURFACE, SQ FT — FURNACE		
12	PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	TOTAL FURNACE HEATING SURFACE	44189
13	PRESSURE PART HEATING SURFACE, SQ FT — CONVECTION	SATURATED (CIRCUMFERENTIAL)	5910
14	PRESSURE PART HEATING SURFACE, SQ FT — CONVECTION	SUPERHEATER (CIRCUMFERENTIAL)	91607
15	PRESSURE PART HEATING SURFACE, SQ FT — CONVECTION	REHEATER 1 (CIRCUMFERENTIAL)	36947
16	PRESSURE PART HEATING SURFACE, SQ FT — CONVECTION	REHEATER 2 (CIRCUMFERENTIAL)	
17	PRESSURE PART HEATING SURFACE, SQ FT — CONVECTION	ECONOMIZER	44900
18	PRESSURE PART HEATING SURFACE, SQ FT — CONVECTION	TOTAL CONVECTION HEATING SURFACE	179164
19	PRESSURE PART HEATING SURFACE, SQ FT	TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.	223553
20	PRESSURE PART HEATING SURFACE, SQ FT	FLAT PROJECTED FURNACE HEATING SURFACE	
21	PRESSURE PART HEATING SURFACE, SQ FT	TO FACE OF PLATENS	37925
22	PRESSURE PART HEATING SURFACE, SQ FT	TO FACE OF CONVECTION SURFACE	
23	FURNACE VOLUME, CU FT		148800
24	AIR HEATER	TYPE TUBULAR NO. 1	
25	AIR HEATER	TOTAL HEATING SURFACE, SQ FT 742,000	
26			
27	FUEL BURNER	TYPE CYCLONE	
28	FUEL BURNER	NO. 7-10 FT. DIA.	
29	PULVERIZER	TYPE SIZE NO.	
30	PULVERIZER	CAPACITY OF PULV. IS M LB STEAM/HR BASED ON GRIND	
31	PULVERIZER	BTU COAL AT % THRU 200 U.S.S. SIEVE	
32	PULVERIZER	FOR M LB COAL/PULV.-HR AT % THRU 200 U.S.S. SIEVE. MIN. GRIND	
33	PULVERIZER	IS , MAXIMUM SURFACE MOISTURE IS % REQUIRING F AIR	
34	PULVERIZER		
35			
36			
37			
38			
39	STEAM TEMP. CONTROL	STEAM TEMPERATURE CONTROLLED BY GAS	
40	STEAM TEMP. CONTROL	RECIRCULATION	
41	STEAM TEMP. CONTROL		
42	STEAM TEMP. CONTROL		
43	UNIT CONSTRUCTION FEATURES	BALANCED DRAFT	
44	UNIT CONSTRUCTION FEATURES	SEMI-OUTDOOR	
45	UNIT CONSTRUCTION FEATURES	MEMBRANE WALL	
46	UNIT CONSTRUCTION FEATURES		
47		SOLIDS IN STEAM 1 PPM	

REVISIONS NO.	DESCRIPTION	BY	DATE

BY [illegible] APPD. DATE April 1969

THE BABCOCK & WILCOX COMPANY

P1-3941-11X0-150

-3

1

MINNKOTA POWER COOPERATIVE
SANDERSON AND PORTER, INC.
ENGINEERS

235MWe UNIT 1 RB-457

A FUEL AS FIRED

SAMPLES

ANALYSES CUSTOMER SPECIFICATIONS

		DESIGN	PERF.
KIND			
ASTM	CLASS	LIGNITE	LIGNITE
	GROUP		
SOURCE	MINE		
	SEAM		
	DISTRICT		
	COUNTY		OLIVER
	STATE		N. DAK.
COAL	SIZE		1¼ - 1½
	GRINDABILITY	20 MIN	25
	SURFACE MOISTURE, %		
	S=½M		
	ASH SOFT.TEMP.,F (REDUCING)	2235-2500	2410
PROX. ANAL. %	MOISTURE, TOTAL	38	38.4
	VOLATILE MATTER		25.0
	FIXED CARBON	1	25.0
	ASH	13	11.6
	TOTAL		100.0
ULTIMATE ANALYSIS	FUEL		LIGNITE
	% BY		WT.
	ASH		11.60
	S		0.63
	H_2		2.60
	C		34.70
	CH_4		
	C_2H_4		
	C_2H_6		
	C_3H_8		
	C_4H_{10}		
	C_5H_{12}		
	C_6H_{14}		
	Cl		0.01
	CO_2		
	SO_2		
	H_2O		38.40
	N_2		0.56
	O_2		11.50
	TOTAL		100.00
	BTU/LB	6000	6250
	BTU/CU FT AT 60F 30 IN.HG		

* EXCL. STATIC HEAD AND FEED STOP AND CHECK VALVE.

** INPUT & ALL GENERAL PERFORMANCE INCLUDES ALLOWANCE FOR AVERAGE SOOT BLOWER STEAM CONSUMPTION RATE (40,000 LB/HR).

UTILITY BOILER PERFORMANCE SUMMARY

BY VFH APPD. PTP. DATE 3-27-73

THE BABCOCK & WILCOX COMPANY

P5-2783-1Y0-1ST

B PREDICTED PERFORMANCE

	STEAM LEAVING SH, M LB/HR	1830	2560	3050	3200
	STEAM LEAVING RH¹, M LB/HR	1510	2110	2513	2709.6
	BLOWDOWN, M LB/HR	18.5	25.9	30.8	32.4
	TYPE OF FUEL	LIGNITE	LIGNITE	LIGNITE	LIGNITE
	LOAD CONDITION	NORMAL	NORMAL	NORMAL	NORMAL MAX
	EXCESS AIR LEAVING ECON., %	38	31	28	25
	NO. OF BURNERS IN OPERATION	12	12	12	12
	FUEL INPUT, MKB/HR **	2849	3883	4565	4676
	HEAT AVAIL.MKB/HR (FUEL & HEATED AIR)	2974	4050	4761	4975
QUANTITY, M LB/HR	FUEL	455.8	621.2	720.7	751.4
	FLUE GAS ENTERING AIR HEATER	3410	4439	5050	5264
	AIR TO BURNING EQUIPMENT	2932	3802	4330	4491
	AIR HEATER LEAKAGE				
PRESSURE, PSIG	STEAM AT SH OUTLET	2495	2495	2495	2620
	STEAM AT RH¹ INLET	296	407	518	570
	STEAM AT RH² INLET				
PRESSURE DROP	REHEATER 1	17	23	28	30
	REHEATER 2				
	ECONOMIZER TO DRUM*	17	30	45	50
	DRUM TO SH OUTLET	60	106	155	180
TEMPERATURE, F — STEAM	LEAVING SUPERHEATER	1005	1005	1005	1005
	LEAVING REHEATER 1	980	1005	1005	1005
	ENTERING REHEATER 1	545	582	618	626
	LEAVING REHEATER 2				
	ENTERING REHEATER 2				
FLUE GAS	LEAVING ECONOMIZER TO AH/TO GR	756/560	819/620	863/685	870/695
	LEAVING AH (EXCL.LKG)	284	310	328	330
	LEAVING AH (INCL. LKG)				
	WATER ENTERING ECONOMIZER	421	450	473.7	483.7
AIR	ENTERING UNIT	108	100	100	100
	LEAVING AIR HEATER	661	710	745	750
RESISTANCE, IN. OF WATER — GAS	FURNACE & CONVECTION BANKS	3.7	5.1	8.0	8.8
	FLUES TO AH OUTLET	1.6	2.2	2.7	2.8
	AIR HEATER	3.0	5.0	6.5	6.9
	TOT.FURN.TO AH OUTLET	8.3	12.5	17.2	18.5
AIR	FUEL BURNERS & WINDBOX	43.0	43.0	43.0	44.5
	DUCTS	1.5	2.5	3.2	3.5
	AIR HEATER	2.1	3.6	4.7	5.1
	TOT. FROM FD FAN TO FURN.	40.6	49.1	50.9	53.1
HEAT LOSS, %	DRY GAS	4.79	5.20	5.53	5.58
	H_2 & H_2O IN FUEL	11.08	11.21	11.28	11.30
	MOISTURE IN AIR	0.12	0.13	0.14	0.14
	UNBURNED COMBUSTIBLE	0.10	0.10	0.10	0.10
	RADIATION	0.28	0.21	0.18	0.17
	UNACC. FOR & MFRS. MARGIN & SLAG TANK LOSS	1.83	1.83	1.83	1.83
	TOTAL HEAT LOSS	18.20	18.68	19.06	19.12
	EFFICIENCY OF UNIT, %	81.80	81.32	80.94	80.88
PULV., FAN & FEEDER	NO. IN USE PER BOILER				
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE				

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 27.72 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING P5-2783-1Y0

C EQUIPMENT PER UNIT

TYPE RADIANT

SIZE RBC 48/CY

DESIGN PRESSURE 2950 PSIG

PRESSURE PART HEATING SURFACE, SQ FT	FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)	
		WATER COOLED (PROJECTED)	43,260
		SUPERHEATER (CIRCUMFERENTIAL)	
		SUPERHEATER (PROJECTED)	15,360
		TOTAL FURNACE HEATING SURFACE	58,620
	CONVECTION	SATURATED (CIRCUMFERENTIAL)	7,120
		SUPERHEATER (CIRCUMFERENTIAL)	127,300
		REHEATER 1 (CIRCUMFERENTIAL	56,060
		REHEATER 2 (CIRCUMFERENTIAL)	
		ECONOMIZER	161,425
		TOTAL CONVECTION HEATING SURFACE	351,905
		TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.	410,525
		FLAT PROJECTED FURNACE HEATING SURFACE	
		TO FACE OF PLATENS	45,520
		TO FACE OF CONVECTION SURFACE	60,390
		FURNACE VOLUME, CU FT	403,500

AIR HEATER: TYPE TUBULAR NO. 1

TOTAL HEATING SURFACE, SQ FT 1,336,400

FUEL BURNER: TYPE CYCLONE

NO. 12

PULVERIZER:
TYPE SIZE NO.
CAPACITY OF PULV. IS M LB STEAM/HR BASED ON GRIND
BTU COAL AT % THRU 200 U.S.S. SIEVE
FOR M LB COAL/PULV.-HR AT % THRU 200 U.S.S. SIEVE MIN. GRIND
IS MAXIMUM SURFACE MOISTURE IS % REQUIRING F AIR

SOLIDS IN STEAM - 0.1 PPM

STEAM TEMP. CONTROL: GAS RECIRCULATION

UNIT CONSTRUCTION FEATURES:
MEMBRANE WALL
BALANCED DRAFT
INDOOR

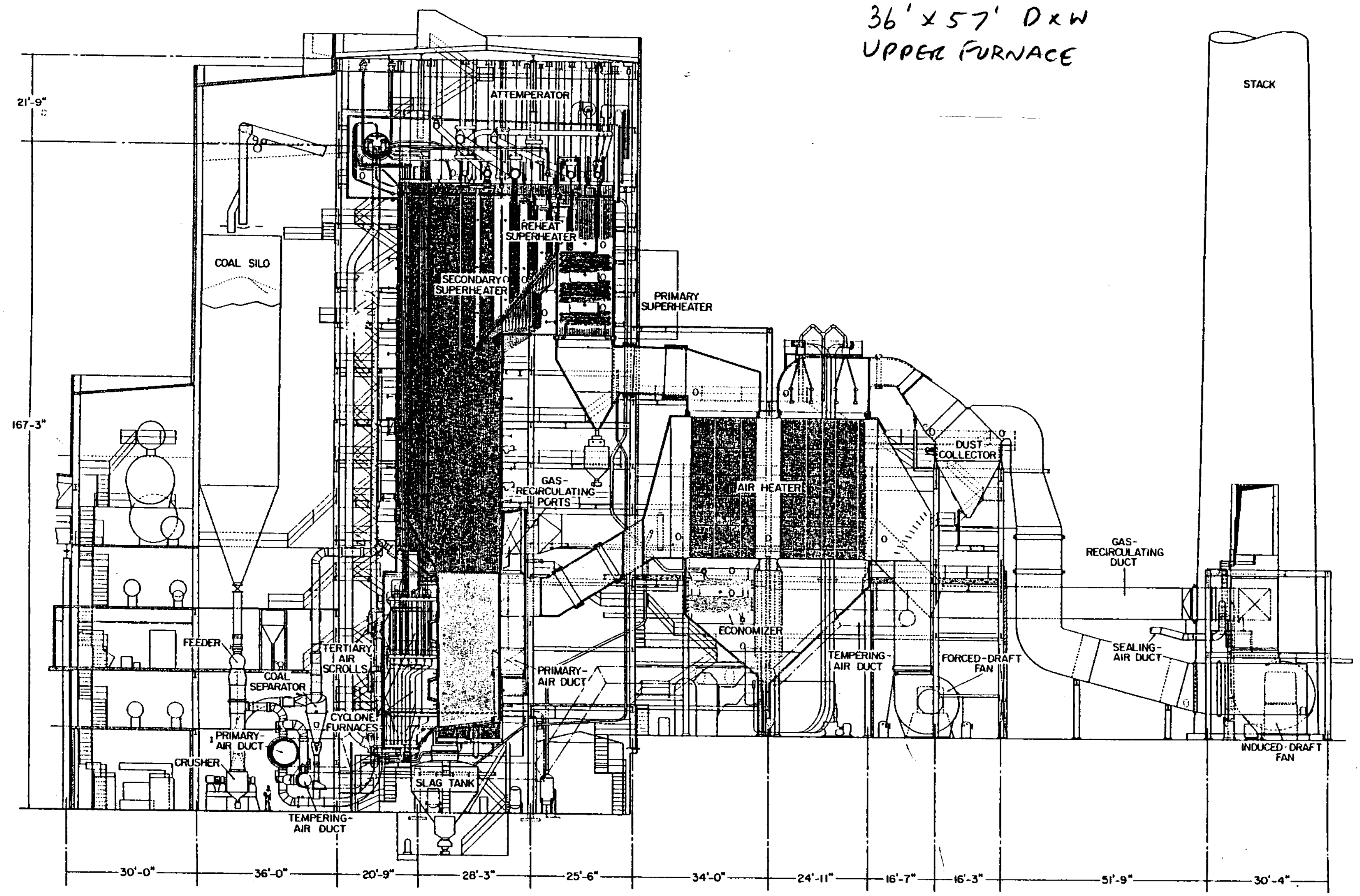
REVISIONS NO.	DESCRIPTION	BY	DATE
0-1	C59	VFH	4/25/73

SANDERSON & PORTER, INC.
2 FOR: SQUARE BUTTE ELECTRIC COOPERATIVE, INC.
MILTON R. YOUNG STATION, NORTH DAKOTA

439 MWe RB-525

26' x 57' DxW
Lower Furnace

36' x 57' DxW
Upper Furnace

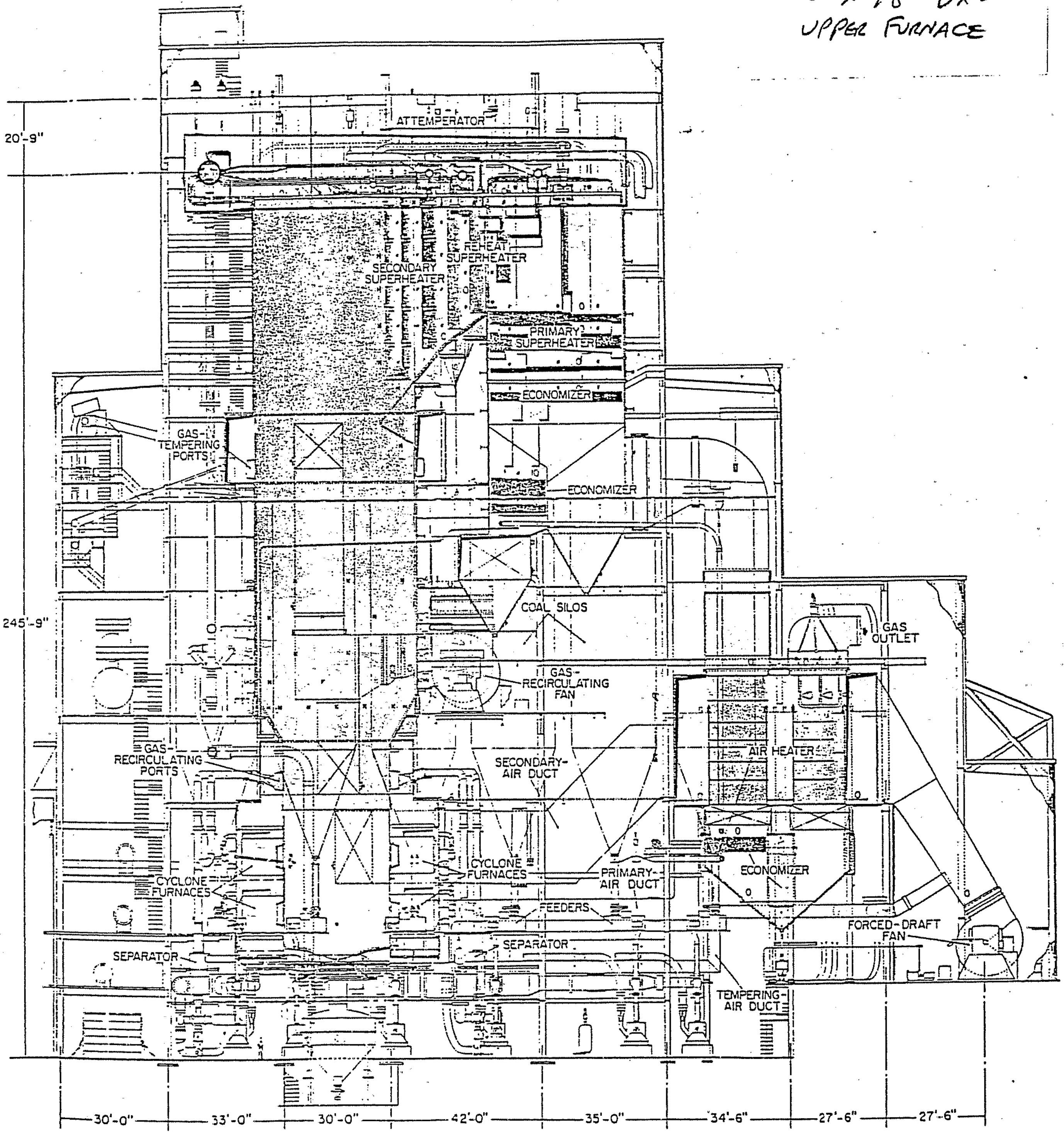


MINNKOTA POWER COOPERATIVE, INC.
CENTER POWER PLANT - UNIT NO. 1
CENTER, NORTH DAKOTA
B & W CONTRACT NO. RB-457

RB-457-500-2N

30' x 48' D x W
LOWER FURNACE

45' x 48' D x W
UPPER FURNACE



SQUARE BUTTE ELECTRIC COOPERATIVE
CENTER POWER PLANT – UNIT NO. 2
CENTER, NORTH DAKOTA
B & W CONTRACT NO. RB-525

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]

Sent: Tuesday, September 01, 2009 6:57 AM

To: Blakley, Robert

Cc: Volker Rummenhohl

Subject: Preliminary PFDs for MRY

Attachments: Sep09_MRY2TailEnd_Rev0_PFD.pdf; Sep09_MRY1LowDust_Rev0_PFD.pdf; Sep09_MRY1TailEnd_Rev0_PFD.pdf; Sep09_MRY2LowDust_Rev0_PFD.pdf

Bob,
Attached are the preliminary PFDs for Minnkota. Volker and I have yet to discuss these in detail, but we should be able to finalize them by the end of the week.

We can review these later at your office.

Thanks, Bob

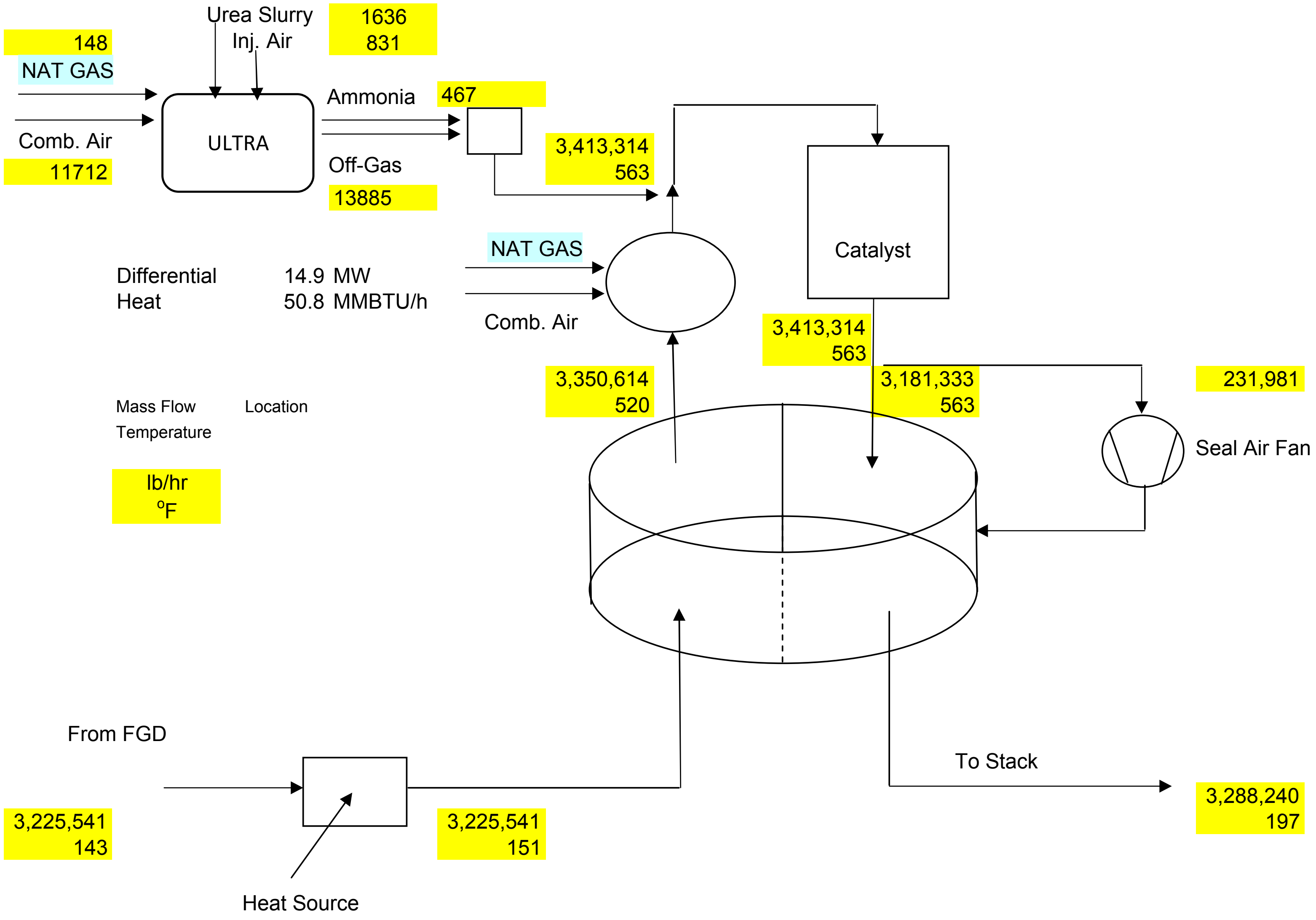
Robert E. Johnson

Fuel Tech, Inc

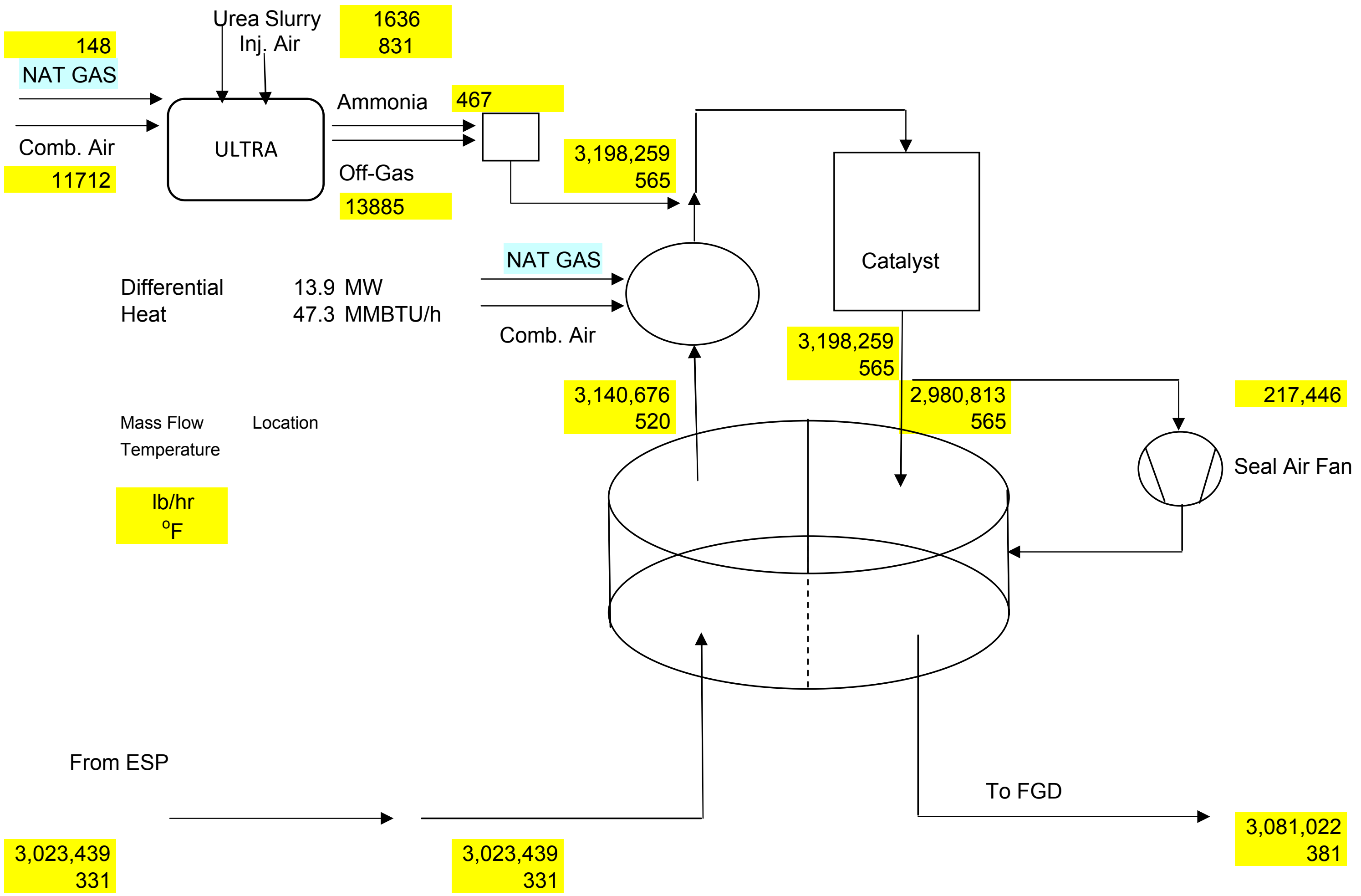
(913) 897 0727

<<Sep09_MRY2TailEnd_Rev0_PFD.pdf>> <<Sep09_MRY1LowDust_Rev0_PFD.pdf>>
<<Sep09_MRY1TailEnd_Rev0_PFD.pdf>> <<Sep09_MRY2LowDust_Rev0_PFD.pdf>>

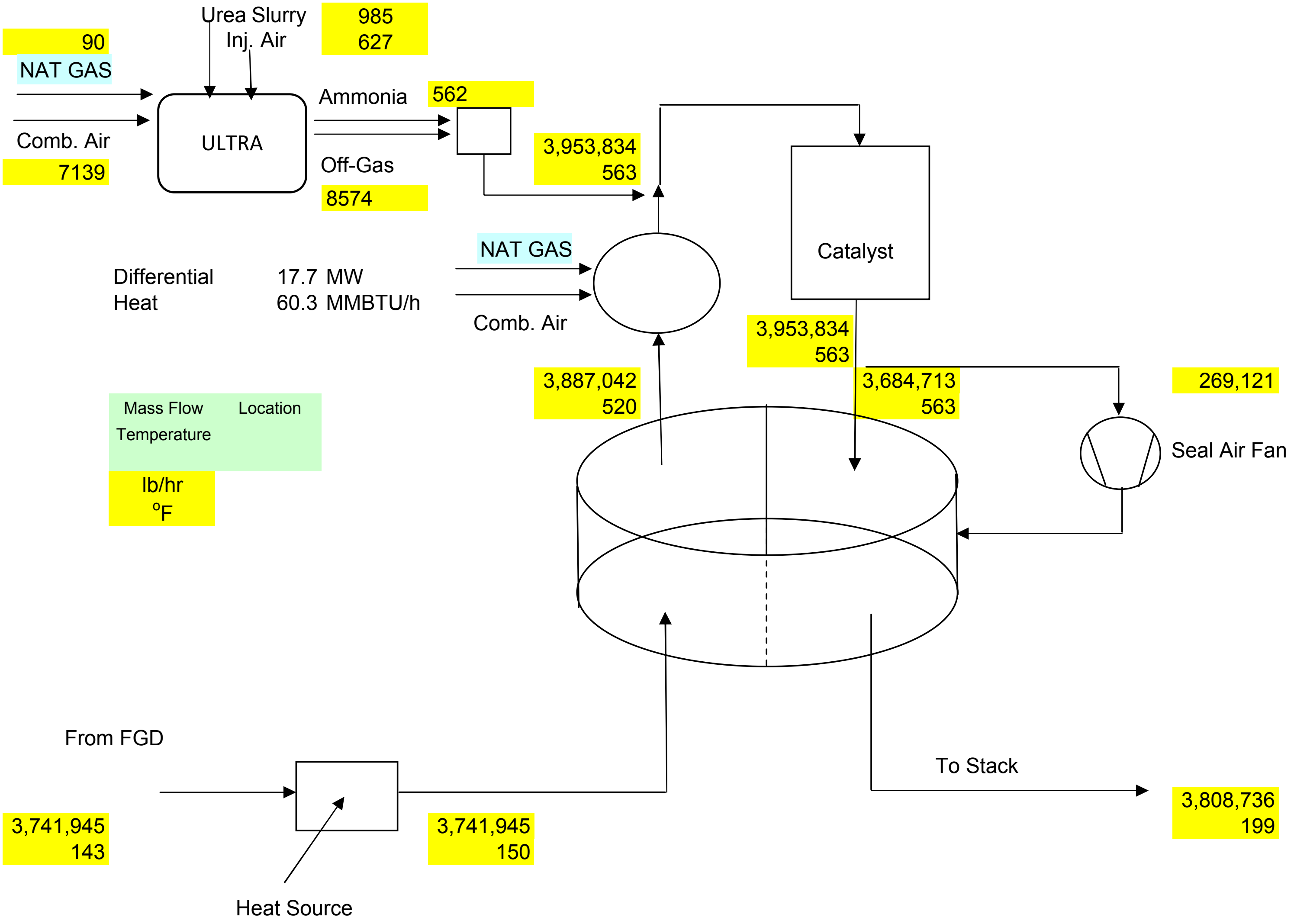
MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



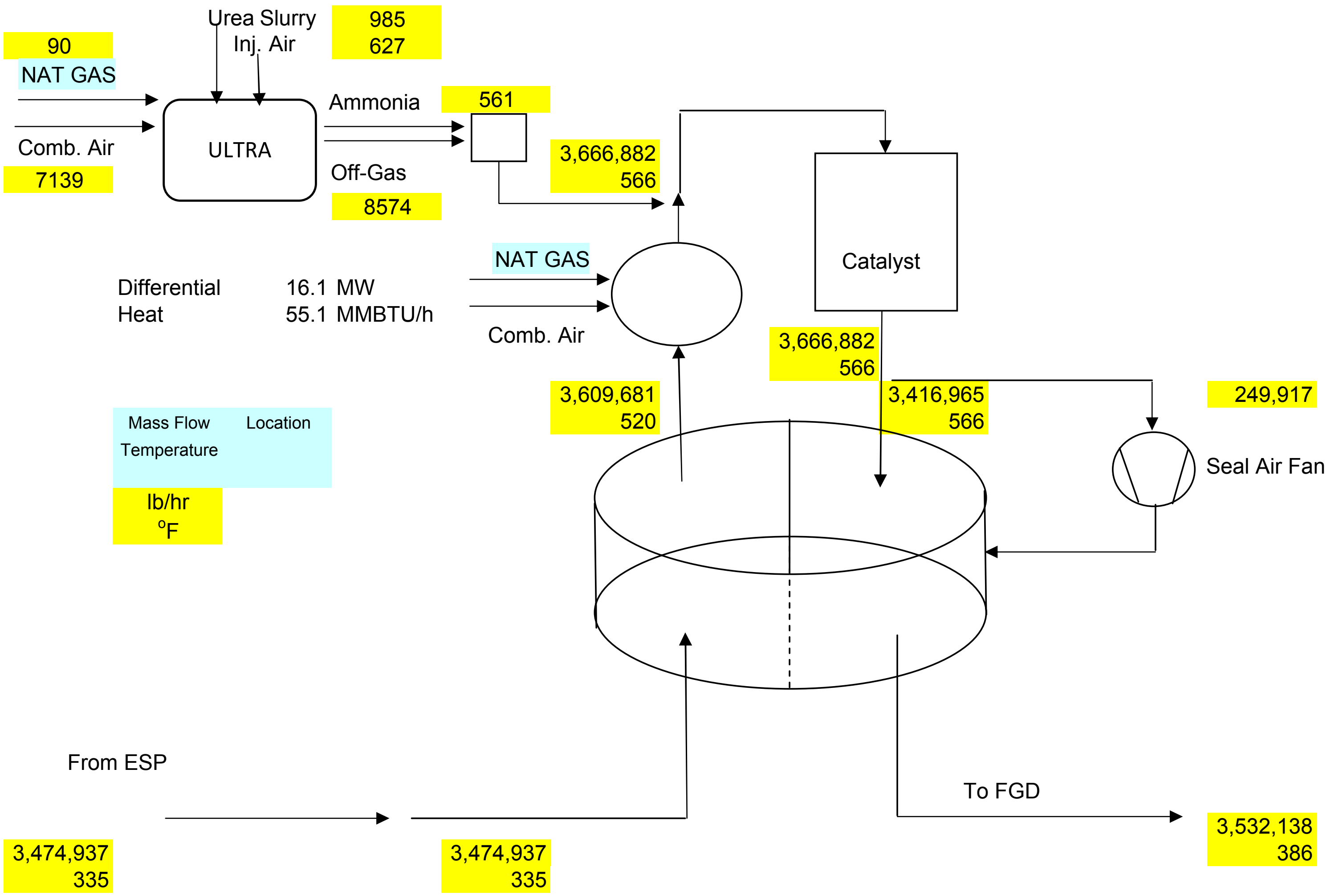
MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Thursday, September 03, 2009 3:00 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: RE: LD and TE SCR Review and Recommendations for MRYS
Attachments: Risiko_SINOx_E.pdf; GGH Brochure.pdf

Bob,
Thanks for compiling the discussion minutes. Volker and I have discussed these once and plan to do so again tomorrow. I will summarize our comments and send them along.

But, all of the attachments in your message are the same, though titled differently.

Attached is a brochure of the Hitachi FGD GGH that they have installed in Japan. it may be suitable and you may find the information useful.

Also, in anticipation of a response from the catalyst suppliers, I studied the Na concentrations from the tests at MRY. If I calculated correctly, 5,000 to 10,000 micrograms/Nm^3 are approximately 3 to 6 ppmv or 3.2 to 6.4 mg/Nm^3. according to Argillons Risk Analysis, this is right at the edge of their range. Let's see what Ceram and Topsoe have to say.

Best Regards, Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, September 01, 2009 5:04 PM
To: Robert Johnson; Volker Rummenhohl
Cc: 51684; Bryant, Ronald; Weilert, Carl; Voss, Steve
Subject: RE: LD and TE SCR Review and Recommendations for MRYS

Bob and Volker -

Here are the latest BMcD conceptual layout drawings of the ductwork and SCR/GGH "towers" that assume the Babcock Power approach for low-dust and tail end SCCR configurations. We are looking at one reactor for Unit 1 low dust or tail-end, and two reactors in parallel for Unit 2 low-dust or tail-end. We are looking for you to provide a review looking for "fatal flaws" or issues that could have significant impacts on function, performance, and capital cost.

Comments from our discussion with Bob in our office 9/1/09:
Our main concern is the potential leakage of untreated flue gas from the FGD GGH on the inlet side of the scrubber to the outlet side of the scrubber must be very close to zero, as any significant amount will make it difficult or impossible to maintain 95% SO2 removal across the wet scrubber. BPEI appears to be using a rotary regenerative type gas-gas heat exchanger for these SCR applications for both the FGD and SCR GGHs. They have not provided any details on these GGHs other than what we have already provided to you for review.

This approach does not reflect Steve Voss' idea raised this morning that the warm (dirty) side of the FGD GGH inlet be connected before the ID fan, so that any leakage would tend to be from the treated gas to the dirty gas side because of the higher pressure after the scrubber than before the ID fan.

We asked if there are other GGH options that have been proven successful in heat recovery-SCR operation that avoid the leakage issue. You said you could provide us with more information on such equipment.

We need to know where any special materials of construction may be required for corrosion resistance that are not obvious, such as after the tail-end SCR reactor to the chimney inlet, and the booster fan for this same location. This gas stream entering the fiberglass-reinforced plastic Unit 2 chimney liner must be less than 200 degreesF continuously, although it will tolerate 400 degrees F upset for 15 minutes. We plan on adding an emergency quench header to protect the fiberglass liner and any ductwork from failure of the TE SCR GGHs. Because the flue gas downstream of a TE-SCR may have some SO3 that has been oxidized from SO2 remaining in the gas after the scrubber removes 95-97%, we welcome your comments on duct and fan materials.

We asked about startup of a LD- or TE-SCR after an extended boiler outage where everthing is cold. Does the flue gas need to be warmed up inside the reactors before exposing the catalyst to coal flue gas, especially for tail end where the GGHs don't have much heat to recycle?

How long could it take to cool down the reactor and remove and replace the catalyst was also of interest.

It would be helpful if you could provide some idea regarding possible budgetary cost and schedule estimates for a slip stream pilot SCR test program - low dust and tail-end configurations, from start to getting the results analyzed after operating for a significant amount of time with a suitably sized reactor and system that simulates low-dust and tail-end SCR conditions.

We'll be interested in further discussions once we have received the updated preliminary mass balances and other information. Let us know if you have any questions.

Thanks,

Bob Blakley

From: Blakley, Robert
Sent: Monday, August 31, 2009 4:41 PM
To: 'Robert Johnson'
Cc: 51684; Bryant, Ronald; Weilert, Carl; 'Volker Rummenhohl'; Voss, Steve
Subject: RE: LD and TE SCR Review and Recommendations for MRYS

Bob -

Thanks for calling me back and letting me know you are available for low-dust and tail-end SCR discussions for the Minnkota SCR Cost study project here in our office on Tuesday, 9/1 at 10 am.

Ron Bryant is arranging for food (pizza) so you can stay and join us for that if you wish.

I see this starting with the process review (updated preliminary mass balances and process flow diagrams), and then moving to the conceptual design review of the various SCR layouts, discussion of duct materials, booster fan locations, materials, and design pressure rise considerations, and then review of auxiliary systems.

I looked for the photos of Mercer Station that you mentioned, but it wasn't where I thought its was saved on the server and Steve Voss wasn't here to ask.

Bob Blakley

From: Blakley, Robert
Sent: Tuesday, August 25, 2009 5:17 PM
To: 'Robert Johnson'; Volker Rummenhohl
Cc: 51684; Bryant, Ronald; Weilert, Carl
Subject: LD and TE SCR Review and Recommendations for MRYS

Bob & Volker -

It's been awhile since we've emailed or talked. We hope you've been enjoying the summer weather. It's been relatively benign here in Kansas City.

We have been asked to proceed with performing a cost study and BACT cost effectiveness update for Minnkota's Unit 1 and Unit 2 involving low-dust and tail-end SCR technology. We are committed to having a draft cost study report to Minnkota for review by September 30, so we hope that you will be able to assist in this effort in the short term.

1. Update previous March 2009 LD and TE SCR preliminary mass balance calaculations with process flow diagrams - assuming a nominal NOx baseline of 0.50 lb/mmBtu with overfire air then 90% NOx reduction (30 day rolling average). We need you to convert numbers in the PFDs to English units (lbs/hr, deg F, in. w.c.), assuming a single SCR reactor for Unit 1 and two reactors in parallel for Unit 2.

2. Review of BMcD conceptual designs of reactors, GGH's, ductwork, and isolation damper locations (based on BPEI approaches) for "fatal flaws". Our preliminary layouts are attached, based upon a low-dust or tail-end SCR reactor "tower" that was developed by a system supplier recently involved with two low-dust projects in the U.S..

3. Recommendations for booster fans' locations for low-dust and tail-end SCR applications. We assume that avoiding a "wet" fan between the wet FGD outlet and SCR GGH is desirable, as well as having the SCR reactor under negative pressure.

4. Review of BMcD's selections for materials of construction for ductwork, and recommendations for GGHs and SCR reactor isolation dampers for TE SCR systems, assuming both Units have saturated flue gas following the wet lime FGD absorbers.

5. Recommendations for SCR catalyst online cleaning (air "knife" sootblowing rakes) and GGH online cleaning, assuming that high-pressure compressed air is preferred over steam. Is water needed to flush condensed acids from the FGD-GGH plates? Is this a continuous consumption? What do we need to consider and include in our cost estimate?

6. Recommendations for standby (outage) catalyst heating system - what do we need to consider and include in cost estimate.

7. TE SCR pilot slipstream - approach, cost and schedule estimates.

We have a total of four estimates and conceptual designs that we are developing:
>low-dust SCR for Unit 1,
> low dust SCR for Unit 2;
> tail-end SCR for Unit 1,
> tail-end SCR for Unit 2.
There are a few common systems that we also expect could be shared between the Units - urea solution receiving and storage; urea solution feed/circulation [to Fuel Tech "ULTRA" urea-to-ammonia conversion system(s)]; individual or common "ULTRA" system(s) to decompose the urea to ammonia gas; individual high-pressure compressed air compressor and air receiver tank(s) for on-line cleaning of the catalyst; individual standby (outage) catalyst heating system(s) - can this use the "Ultra" system without urea injection to provide heated air when the boiler is shutdown for fireside cleaning outages 3 or 4 times per year?

We have engaged two SCR system suppliers and two SCR catalyst manufacturers to help with our conceptual design efforts and installed cost estimates, but there are several areas (noted above) that we think that your experience could help improve the quality of our conceptual design development work.

Please confirm your interest and availability to assist on this effort. We are running short on time and your help would be very beneficial.

Bob Blakley
Associate Project Engineer
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-2842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

HITACHI Non-Leakage Type Gas-Gas Heater

Hitachi Power Systems America
Basking Ridge, NJ

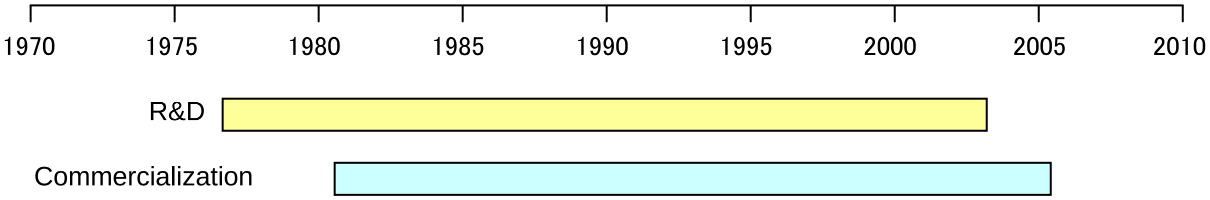
HITACHI
Inspire the Next

Technology Development

Babcock-Hitachi K.K.has started R&D activities for developing heat pipe technology in 1976. Since the first plant was delivered in 1978, Babcock-Hitachi K.K. has been working on the higher efficiency and rationalization of Gas-Gas Heater. Babcock-Hitachi K.K. has already delivered more than 10 non-leak type Gas-Gas Heater not only large-scale domestic power plant but also overseas, supported by boiler manufacturing technologies.

Non-leak type Gas-Gas heater is dispensable for stringent environmental emission.

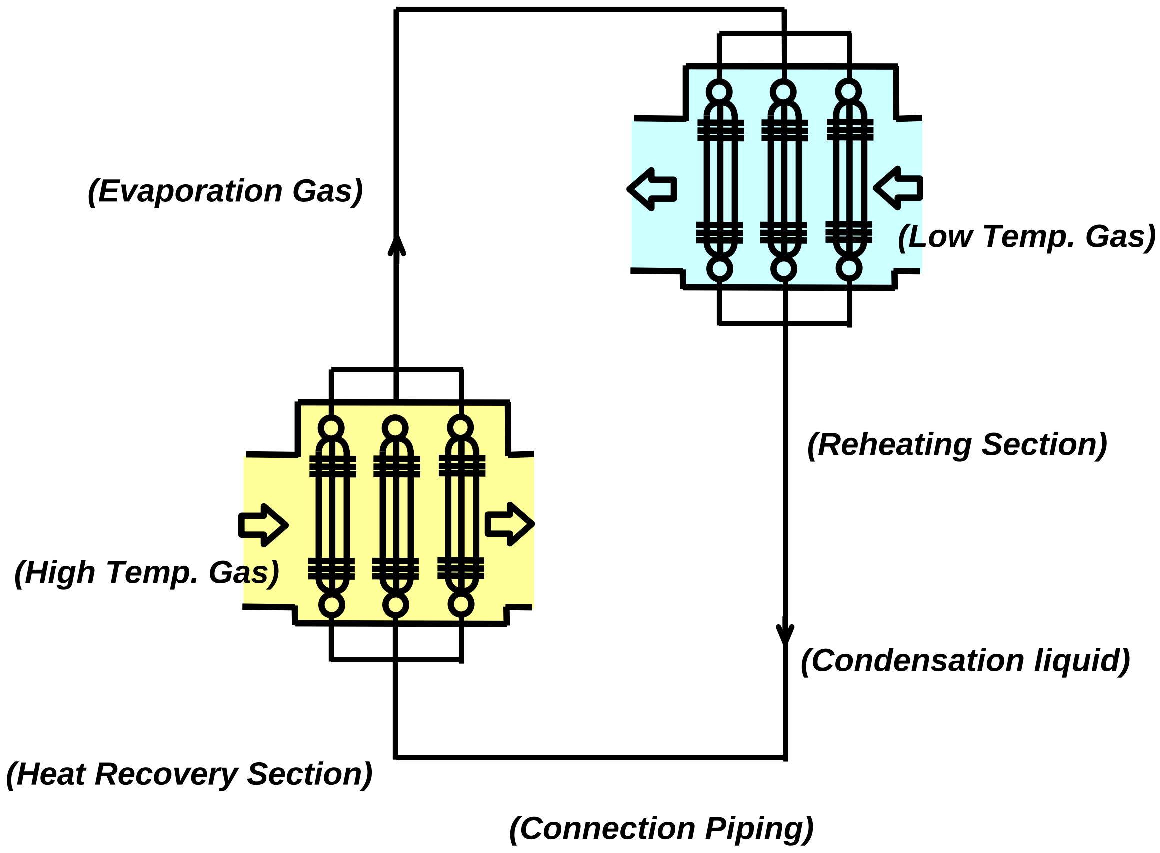
R&D and Commercialization Record



Application Concepts

(Heat Pipe Type)

A heat transfer medium,that is water, is hermetically sealed inside a vacuumed pipe container(Heat Pipe), which consists of a heat recovery (evaporation) section and a reheating (condensation) section. The transportation of the heat medium requires no power because of the use of gravity action,etc. Therefore this method requires no additional auxiliaries such as pumps, drives for rotation of heat exchanger unit which other heat exchangers do require.

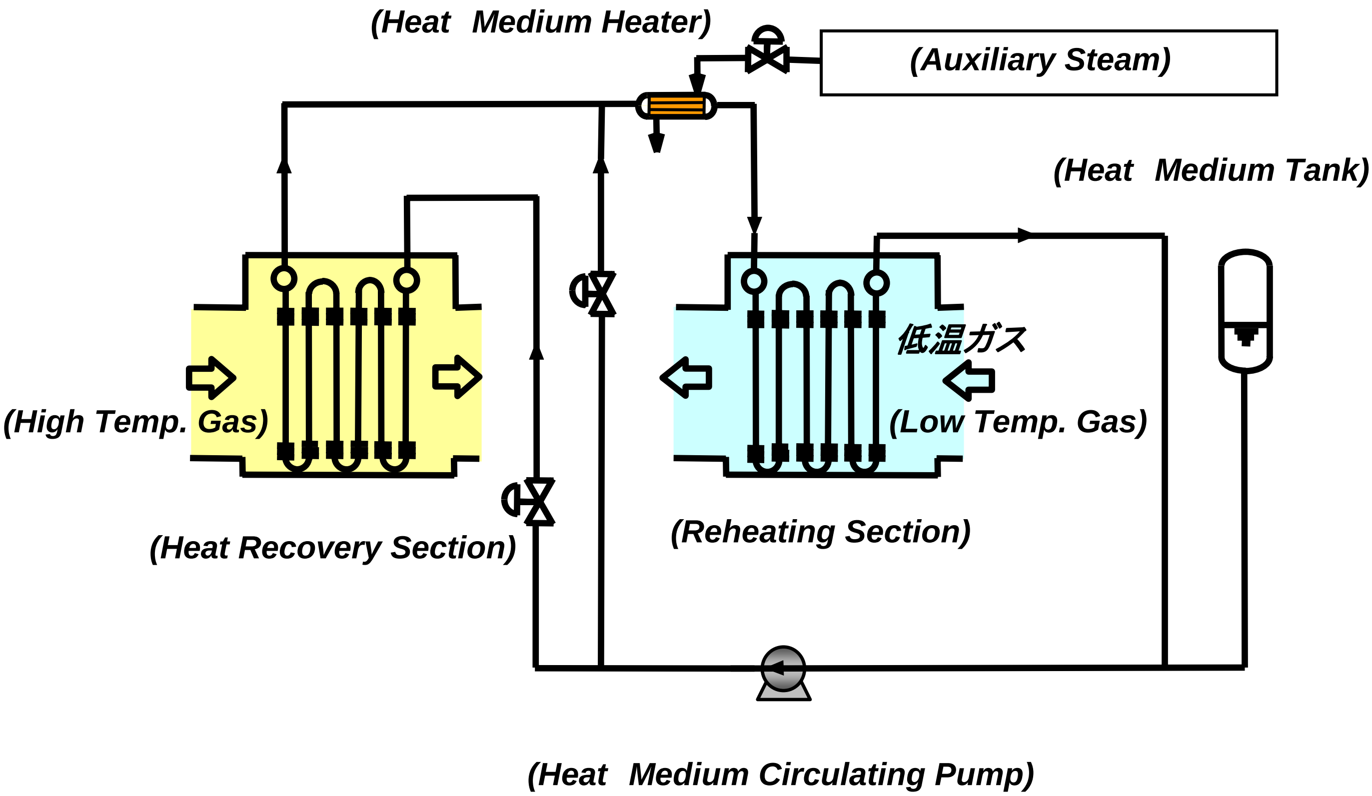


<u>Flow Diagram of Heat Pipe Type</u>

Application Concepts - continued

(Heat Medium Forced Circulated Type)

This type utilizes a pump forced hot water circulation system.Heat exchange between heat recovery section and reheating section can be achieved by circulating heat medium.
High temperature gas is cooled by heat recovery section, then low temperature gas is heated up to certain temperature by reheating section.
Although a heat pipe type needs to locate reheating section in a high position, this type does not have the restrictions on arrangement.



Flow Diagram of Heat Medium Forced Circulated Type

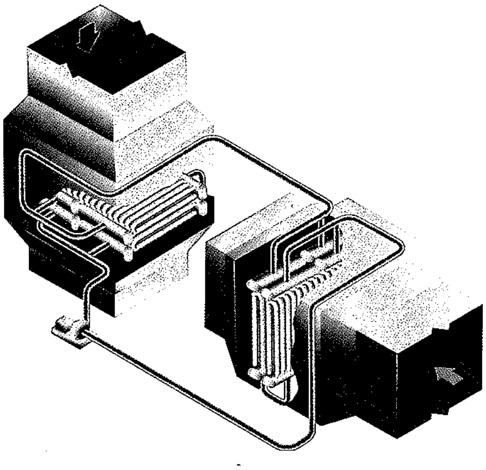
Features

EASY ARRANGEMENT

The heat recovery section and Reheating section are separated and are connected through re-circulation pipes.
This separate type helps to make duct arrangement easy.

NON LEAKAGE

There is no leakage of fluid. Therefore, this type can be used for Combustible fluid, Pressurized fluid, Poisonous fluid, etc. and can perform a high heat transfer efficiency.



Typical Configuration

Features - continued

EASY DESIGN FOR ANTI-CORROSION

Suitable material for the heat recovery section and reheating section can be selected separately.

EASY DESIGN FOR ANTI-CORROSION

By adopting the finned tube as heating tube, much heating surface area is obtained and compact arrangement is possible.
By adopting the optimal fin specification according to the flue gas composition, It makes long term stable operation possible.

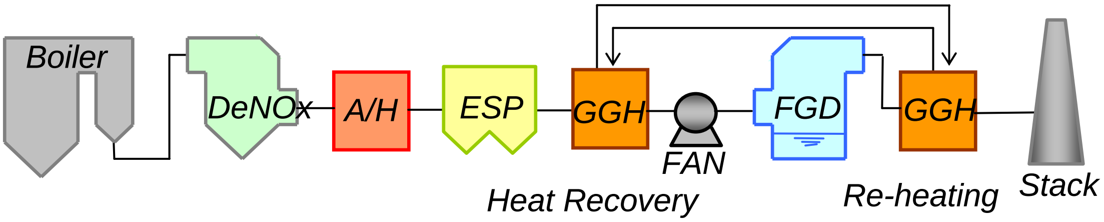
Heating Tube

The State of the Heating Tubes
(After 2 yeas of operation)

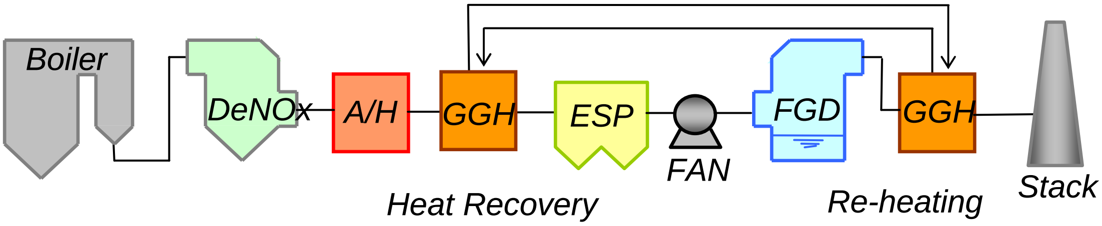
Applications

(1) (For FGD System)

TYPE —1



TYPE —2



In the FGD plant, it is necessary to make an exhaust gas re-heat as follows.

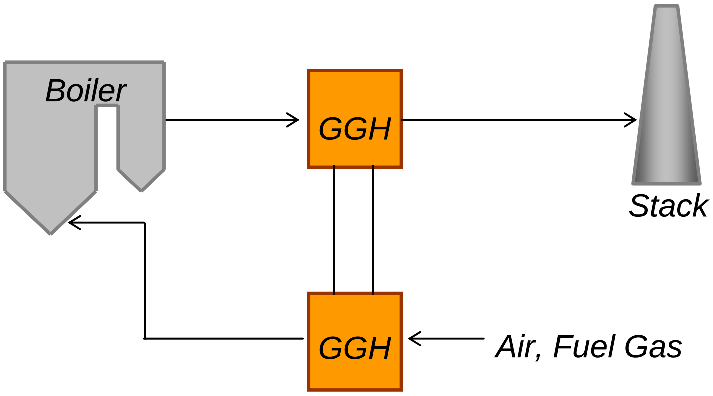
(1) Improvement of the Diffusion
(2) Prevention of the corrosion of Duct ,Stack
(3) Prevention of the visible gas

Babcock-Hitachi K.K. is one of the leader as the non-leak type Gas-Gas Heater which recovers heat from flue gas and reheat treated gas at the FGD without any leakage of untreated flue gas. According to more stringent emission, no leakage of untreated flue gas at the Gas-Gas Heater is dispensable for FGD instead of re-generative type Gas-Gas Heater.
To the 1990s, Type -1 was in use.
Recently, Type -2 which can improve the dust removal performance of ESP is becoming in use because of strengthening of regulations of dust emission

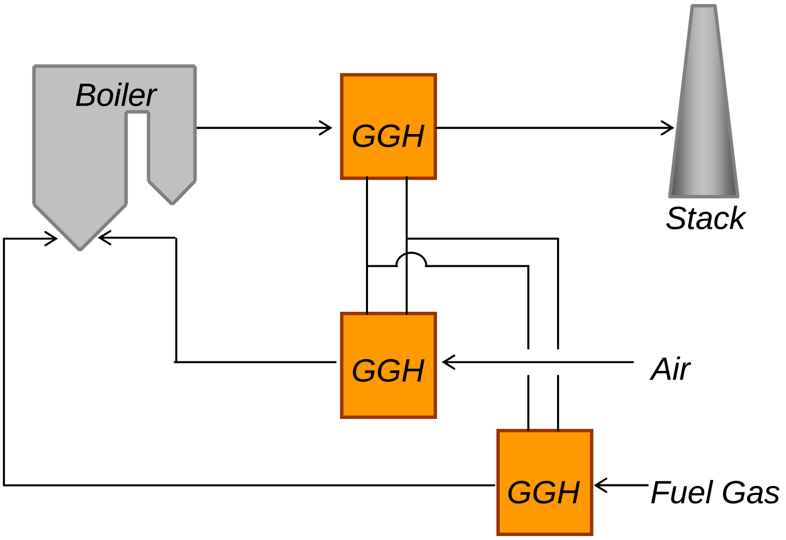
Applications - continued

(2) (For Fuel Gas/Air Preheat System)

TYPE −1



TYPE −2



Not only heat recovery of the boiler exhaust gas for power plant but reuse of various exhaust gases is possible.

Experience

HEAT PIPE TYPE

Item	Evaporation	Condensation
Fluid	Exhaust Gas	Air
Capacity	460,000m^3N/h	260,000m^3N/h
Inlet Temp.	230℃	15℃
Outlet Temp.	147℃	180℃
Heat Exchange	13.5 × 10^6 Kcal/h	
Customer	JFE Steel Corporation	
Service	Air Preheater for Blast Furnace Hot Stove	
Operation	Feb.1982	

HEAT PIPE TYPE

Item	Evaporation	Condensation
Fluid	Boiler Outlet Gas	FGD Outlet Gas
Capacity	3,075,000m^3N/h	3,282,060m^3N/h
Inlet Temp.	142℃	49℃
Outlet Temp.	96℃	93℃
Heat Exchange	47 × 10^6 Kcal/h (Boiler Capacity 1,000MW)	
Customer	Soma Kyodo Power Co,,Ltd.	
Service	For FGD System	
Operation	Jun.1994	

Experience - continued

Heat Medium Forced Circulated Type

Item	Heat Recovery	Reheating
Fluid	Boiler Outlet Gas	FGD Outlet Gas
Capacity	3,084,000m^{3}N/h	3,230,000m^{3}N/h
Inlet Temp.	133℃	47℃
Outlet Temp.	88℃	90℃
Heat Exchange	46×10^6 Kcal/h (Boiler Capacity 1,050MW)	
Customer	Electric Power Development Co,,Ltd.	
Service	For FGD System	
Operation	Dec.2000	

Heat Medium Forced Circulated Type

（Transport Situation of GGH Module）

Item	Heat Recovery	Reheating
Fluid	Boiler Outlet Gas	FGD Outlet Gas
Capacity	2,787,000m^{3}N/h	2,942,600m^{3}N/h
Inlet Temp.	126℃	51℃
Outlet Temp.	87℃	88℃
Heat Exchange	36×10^6 Kcal/h (Boiler Capacity 1,000MW)	
Customer	Chubu Electric Power Co,,Ltd.	
Service	For FGD System	
Operation	Nov.2001	

Data Required For Design

Please supply HITACHI with the following data when making inquiries;

Item	Unit	Specification	
		High Temp	Low Temp
Source of Fluid	—		
Fluid	—		
Capacity	m^3N/h		
Composition			
N_2	Vol%		
O_2	Vol%		
CO_2	Vol%		
H_2O	Vol%		
SO_2	ppm		
SO_3	ppm		
その他	—		
Dust	mg/m^3N		
Inlet Temp.	℃		
Outlet Temp.	℃		
Inlet Press.	mmH_2O		
Outlet Press.	mmH_2O		
Remarks	1. Fuel ? 2. Rough sketch of installation site giving altitude ?		

ARGILLON

List of Toxic Agents for SINOx® Systems and Catalysts

To keep our guarantee the following values (maximal concentrations of catalyst poisons in the exhaust gas) must be strictly respected:

Alkali metals	mg/m^3 wet.	max.	5
Alkaline-earth metals	mg/m^3 wet.	max.	1
Hydrochloric acid, chlorides	mg/m^3 wet.	max.	100
Hydrofluoric acid, fluorides	mg/m^3 wet	max.	1
P_2O_5, organic phosphorus Compound, As, As-compounds, Si-organics, Si-halides	mg/m^3 wet	max.	0,005
Pb + Zn	mg/m^3 wet	max.	0,1
Hg + Cd	mg/m^3 wet	max.	0,1

Rev.	Date	Provided by/Department.	Released by/ Department
5	May 1th, 2003	Dr. Michael Joisten / C P	Dr. Guenther Pajonk / C D

Blakley, Robert

From:	Robert Johnson [RJohnson@ftek.com]
Sent:	Friday, September 11, 2009 3:45 PM
To:	Blakley, Robert
Cc:	Volker Rummenhohl
Subject:	Updated PFDs for MRYS
Attachments:	11Sep09_MRY2TailEnd_Rev1_natgas.pdf; 11Sep09_MRY1LowDust_Rev1_natgas_580F.pdf; 11Sep09_MRY1TailEnd_Rev1_natgas.pdf; 11Sep09_MRY2LowDust_Rev1_natgas_580F.pdf

Bob,
Attached are updated PFDs and mass balance for the four options. We have added a table with flue gas constituents for the process.

After discussing the application some more, Volker and I recommend that the operating flue gas temperature for the LD cases should be raised to 580F. This is just to provide some margin pertaining to the minimum operating temperature of the SCR.

Also, as I mentioned in our discussion, these PFDs are still preliminary, pending selection of the GGH supplier and their opportunity to provide the balance around the GGH.

Volker and I are drafting comments re: other open items. We expect to issue this to you on Monday.

Best Regards, Bob

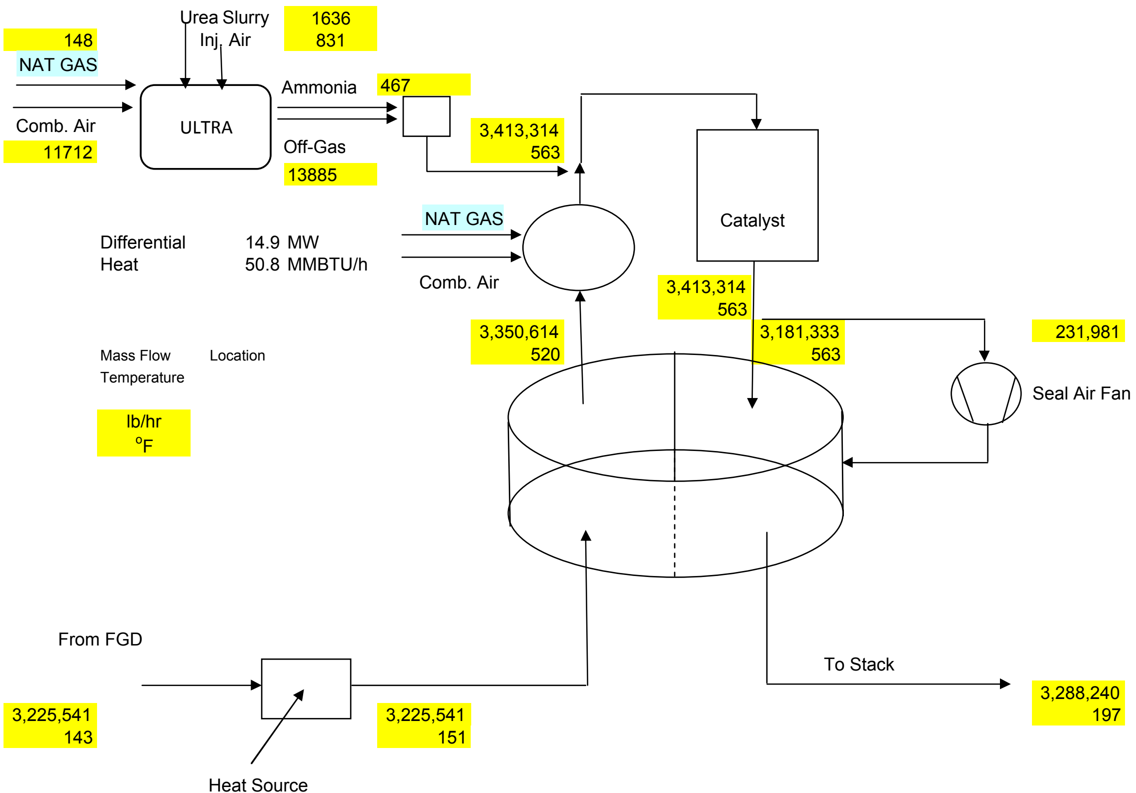
Robert E. Johnson

Fuel Tech, Inc

(913) 897 0727

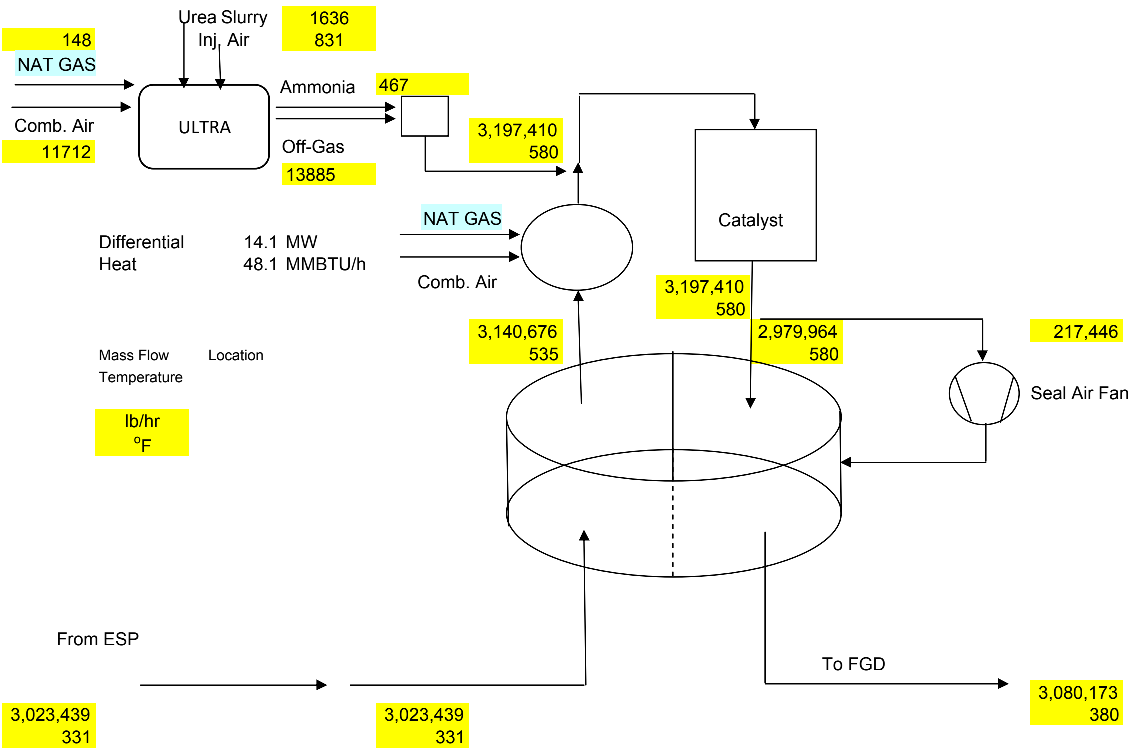
<<11Sep09_MRY2TailEnd_Rev1_natgas.pdf>> <<11Sep09_MRY1LowDust_Rev1_natgas_580F.pdf>>
<<11Sep09_MRY1TailEnd_Rev1_natgas.pdf>> <<11Sep09_MRY2LowDust_Rev1_natgas_580F.pdf>>

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



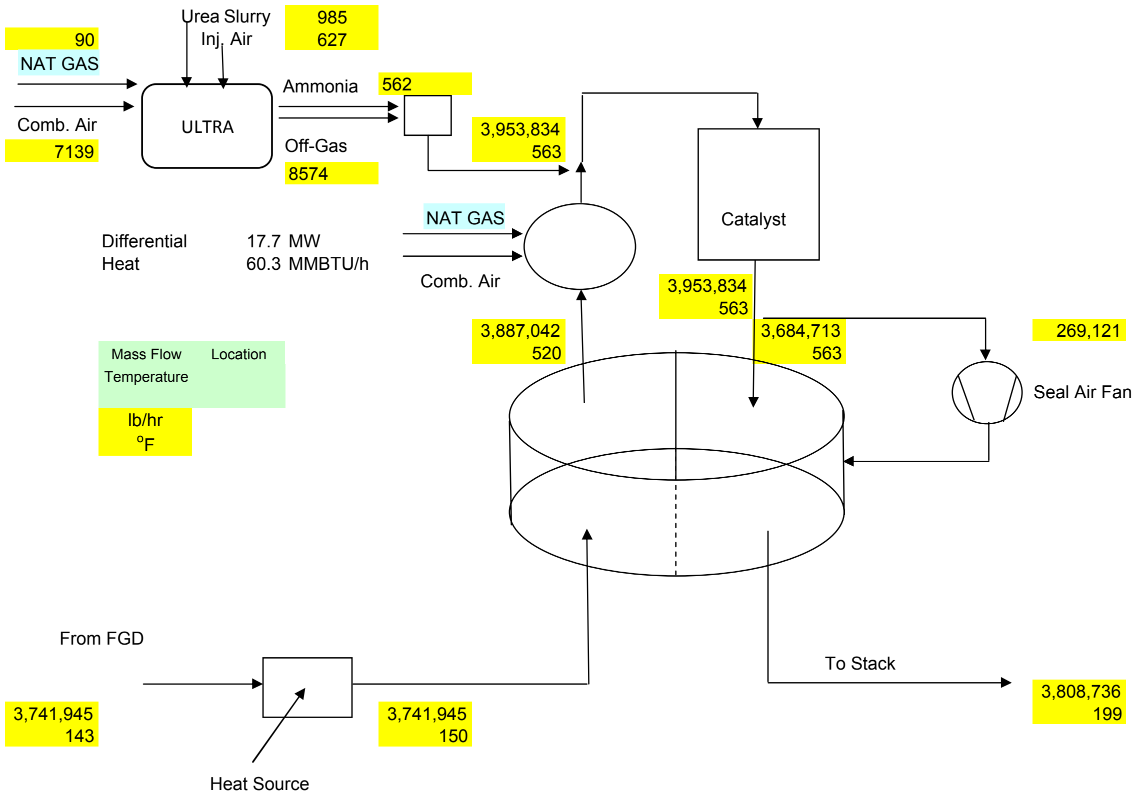
		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,153	2,180,798	2,190,180	2,191,336	2,042,555	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,883	569,281	570,295	570,295	531,575	543,915
Oxygen	lb/h	184,328	184,328	191,503	192,324	194,569	194,130	180,949	185,704
Moisture	lb/h	437,137	437,137	454,118	458,657	459,759	460,502	429,236	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	510	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



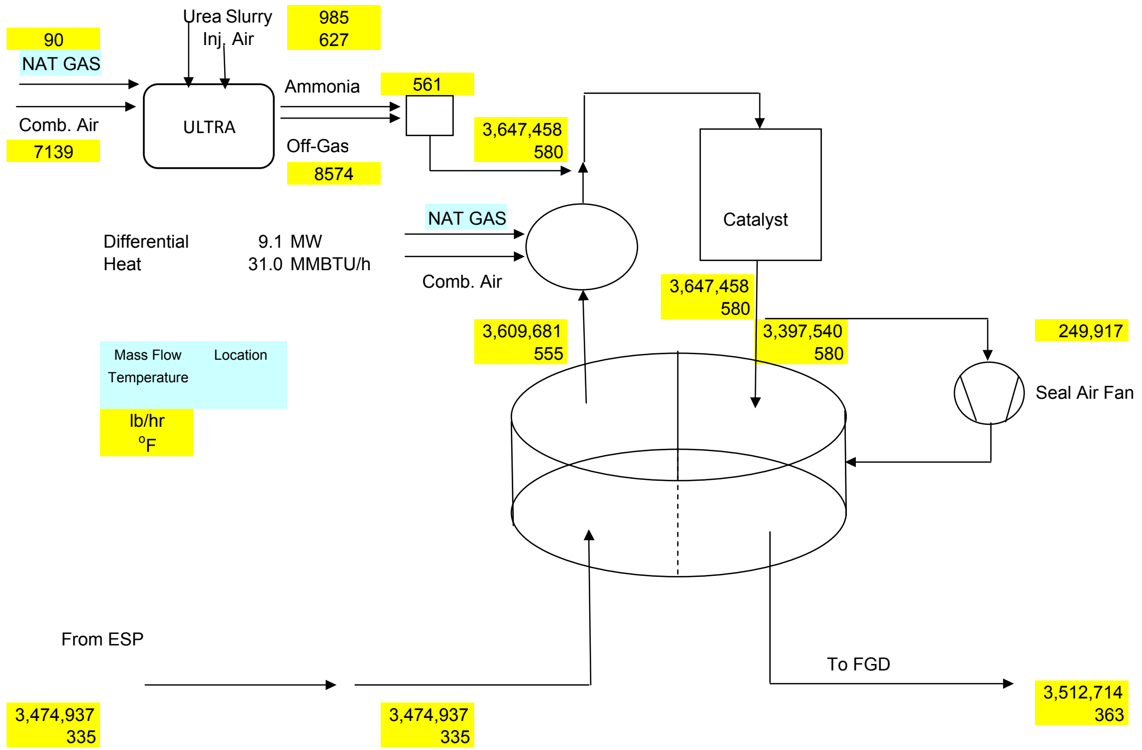
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,656	2,143,657	2,153,039	2,154,192	2,007,837	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,143	561,875	562,889	562,889	524,646	537,433
Oxygen	lb/h	177,258	177,258	184,157	184,877	187,122	186,683	174,000	178,633
Moisture	lb/h	270,167	270,167	280,707	284,686	285,788	286,530	267,063	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,463,985	2,508,879	2,514,687	2,516,076	2,344,997	2,379,123
Carbon di oxide	lb/h	622,053	622,053	646,129	652,566	653,180	653,180	608,768	622,667
Oxygen	lb/h	213,652	213,652	221,928	222,907	224,302	223,774	208,558	214,002
Moisture	lb/h	536,485	536,485	557,343	562,756	563,425	564,318	525,948	538,919
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	5	5	103	103	96	98
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,758	2,449,060	2,454,868	2,456,248	2,288,130	2,343,304
Carbon di oxide	lb/hr	614,626	614,626	638,408	641,606	642,220	642,220	598,263	615,240
Oxygen	lb/hr	205,551	205,551	213,511	213,998	215,393	214,868	200,161	205,901
Moisture	lb/hr	309,692	309,692	321,780	324,469	325,138	326,026	303,711	312,126
Sulfur di oxide	lb/hr	11,381	11,381	11,815	11,815	11,815	11,701	10,901	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,669	1,669	159	148	167
Argon	lb/hr	0	0	5	5	103	103	96	98
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Tuesday, September 15, 2009 7:36 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 15Sep09_MRYS Comments

Bob,
Volker and I have prepared the attached comments pertaining to MRYS SCRs.
We'd be glad to discuss at your convenience.
Best Regards, Bob

Robert E. Johnson

Fuel Tech, Inc

(913) 897 0727

<<15Sep09_BMcD for MRYS_Comments.pdf>>

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems Comments

Conceptual Arrangement Drawings

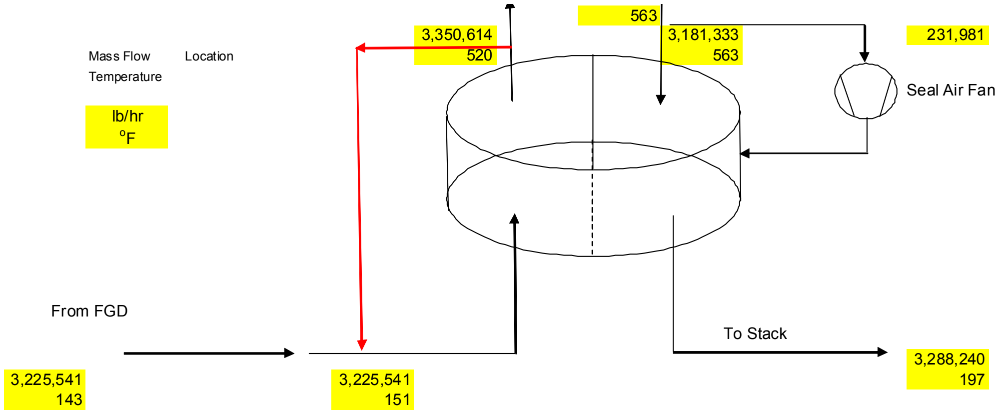
Fuel Tech has reviewed the initial arrangement drawings. Here are our comments:

- Based on what was provided, we don't see anything that could be considered a "fatal flaw."
- In general, there are two design considerations that deserve closer evaluation once we have the opportunity to review 3-D models:
  - Location of bypass dampers and ducts;
  - Duct transitions within the inlet ductwork and into the reactor hood. It is important to maintain uniform ammonia and flue gas distributions into the catalyst, and severe angles and transitions have significant effects.

Flue Gas Heating & FGD GGH Options

For Tail End systems, it is important for the flue gas temperature entering the SCR GGH to be above the water dewpoint. This will prevent condensation and potential corrosion within the GGH. There are a few methods for raising the FGD outlet temperature:

- FGD GGH: Regenerative type heat exchangers have been used in Europe for this application. When FGD systems were deployed in German powerplants, heat exchangers were needed to raise flue gas temperatures to >72°C for plume buoyancy. These same exchangers were integrated into Tail End SCR systems. Some corrosion issues have been documented. Some solutions that have been used include alloy elements, plastic elements, and enameled elements.
- FGD Heat Pipes: Another type of heat exchanger is the heat pipe technology, such as that marketed by Hitachi. Hitachi has installed this type of exchanger in Japanese plants.
- Flue Gas Heating with Duct Burners: Direct gas firing in the duct would eliminate the need for a heat exchanger. In contrast to the use of duct burners for maintaining flue gas temperature to the inlet of the SCR catalyst, continuous gas firing would be needed for controlling the flue gas temperature at the inlet to the SCR GGH.
- Heat Exchange Loop at the SCR GGH: Another method includes the use of a slipstream from the SCR GGH outlet back to the inlet to raise the inlet flue gas temperature. This alternative is shown below in red:



The latter two methods would affect the overall mass balance of the Tail End system, primarily due to the increased natural gas consumption by the duct burners.

A cost-benefit comparison of these alternatives should be prepared specifically for the MRYS installation.

Start Up Procedures

Start up procedures need to be specifically prepared for MRYS based on the final operating permit. In some cases, partial or full bypass of the SCR may be permitted for a certain period to allow the catalyst to be warmed to operating temperature before ammonia injection is permitted to commence. If bypass is not allowed, then other procedural methods will be developed for the MRYS installation.

One alternative is described here. After purging the entire flue gas duct work of the unit, FD and ID fans will ramp up to the highest capacity. The SCR GGH must be in operation. The SCR burners will be turned on to preheat the catalyst to operating temperature. Once this is established, boiler startup can be initiated and the bypass dampers to the SCR can be closed to permit flue gas to flow into the reactor. The reagent for the SCR can be injected immediately after the first fire in the boiler.

Other procedural methods may be developed in conjunction with overall system design, the final selection of a Tail End or Low Dust system, and the final permit for the plant if this kind of preheat is not acceptable.

Catalyst Exchange Information

In practice, catalyst loading, removal and exchange procedures vary widely among the operating SCR plants in the United States. It is our experience that Architect-Engineers, System suppliers, catalyst suppliers and Utilities have assimilated “best practices” and have developed site specific procedures. Unfortunately, we are unaware of specific and published comparisons or time & motion studies that document actual experience.

Fuel Tech knows specific procedures for some of our clients and we are aware of their experiences. In our opinion, it is not appropriate to use these particular experiences to validate other experiences or catalyst handling designs within the industry.

To achieve a specific requirement, such as a complete catalyst layer exchange within a certain period, the complete SCR system must be designed to accommodate this. For instance, catalyst module handling, storage, and movement must be consistent with the reactor platforms, access door number and location, catalyst transport systems from storage to platform, handling within the reactor and the number of personnel and shifts to perform the exchange.

Our "rule of thumb" estimate for catalyst installation is thirty (30) minutes per module. This is based on conventional access, use of hoists for module handling and transport, and a typical crew of 4 to 6 people. With a different system design and more personnel, the time period can certainly be reduced.

Catalyst Slipstream Test

Concerning the budgetary estimate and schedule for a comprehensive slipstream test, we suggest the following:

- The test should include a reactor large enough to house multiple catalyst types and layers;
- The test should run preferably nine (9) months to a year, in order to observe effects on the catalyst;
- An independent lab should be used to evaluate all of the catalysts at various intervals to develop trends;
- The operation of the test reactor needs to be monitored throughout the duration of the test for proper correlation of catalyst effects with flow and temperature.

Without specific details or requirements, we estimate the cost to design, build and install the test reactor to range from $400,000 to $600,000. Testing, operating and monitoring the program is estimated to cost $250,000 to $400,000 depending on the duration and final program.

Blakley, Robert

From: Blakley, Robert
Sent: Tuesday, September 15, 2009 9:18 AM
To: Robert Johnson
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
Subject: FW: Fuel Tech Flow Diagram Discrepancy
Attachments: Fuel Tech Comparison.xls; Sep09_MRY1LowDust_Rev0_PFD.pdf; Sep09_MRY1TailEnd_Rev0_PFD.pdf; Sep09_MRY2LowDust_Rev0_PFD.pdf; Sep09_MRY2TailEnd_Rev0_PFD.pdf

Bob -

Please confirm the urea consumption rates and natural gas consumption for flue gas reheating recently provided for Unit 1 low-dust and tail-end SCRs.
These are for a single SCR reactor for Unit 1 in each of the two configurations.

Also advise on the status of the updated preliminary mass balance calculations for all 4 cases.

Let us know if questions arise.

Thanks for the comments on your review of our preliminary SCR arrangements. We will review and advise if we want additional comments that you may be able to provide.

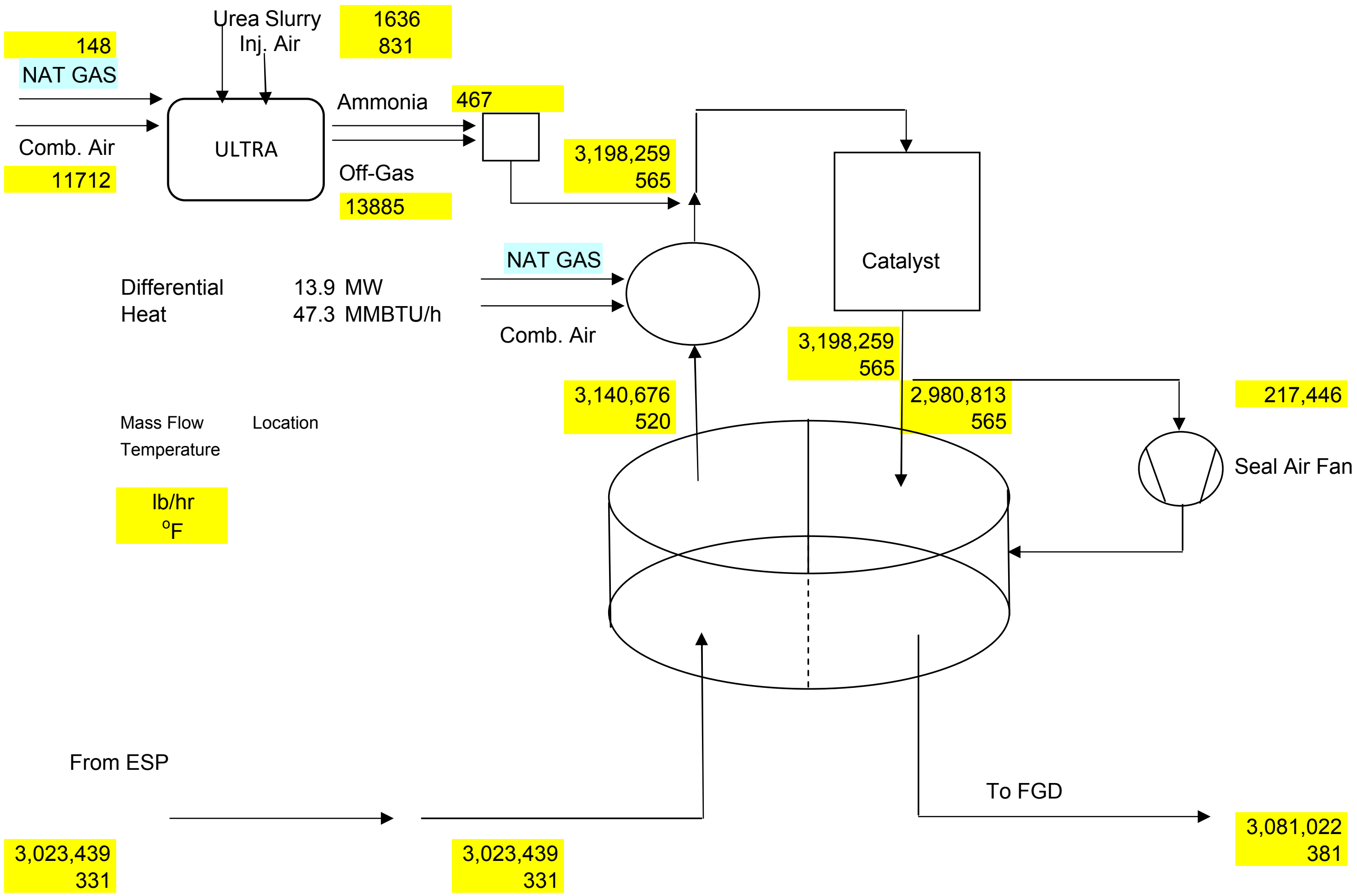
Bob Blakley

From: Loehr, Zachary
Sent: Friday, September 11, 2009 9:49 AM
To: Blakley, Robert
Cc: Blackwood, Dave; Bryant, Ronald
Subject: Fuel Tech Flow Diagram Discrepancy

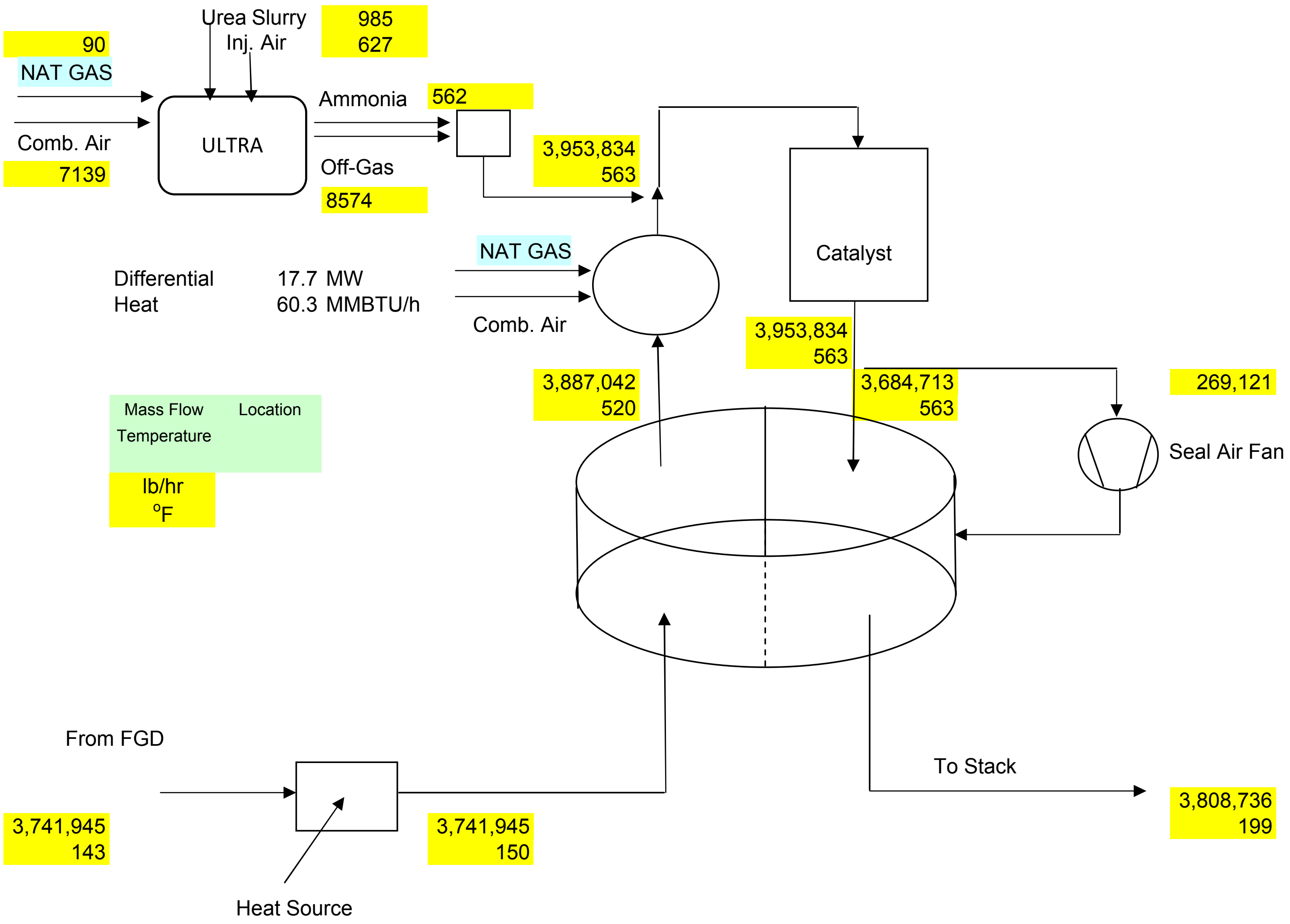
Robert,
I was reviewing the Fuel Tech flow diagrams to pull the urea and natural gas usages for the economic evaluation. I found that some of the numbers aren't adding up. If you compare the Sept 09 flow diagrams vs the March 09 diagrams, the urea and natural gas usages look off for the Unit 1 Tail End and Low Dust options. The ammonia values match fairly closely though. It looks like they may have forgotten that the March 09 numbers were based on two reactors while the Sept 09 numbers where only based on one reactor. The urea and natural gas numbers are half of what they should be. Attached is a spreadsheet that compares the two sets of data. Please verify this with Fuel Tech.
Thanks,

Zac Loehr
Development Engineer, Energy Group
Burns & McDonnell
9400 Ward Parkway
Kansas City, MO 64114
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com

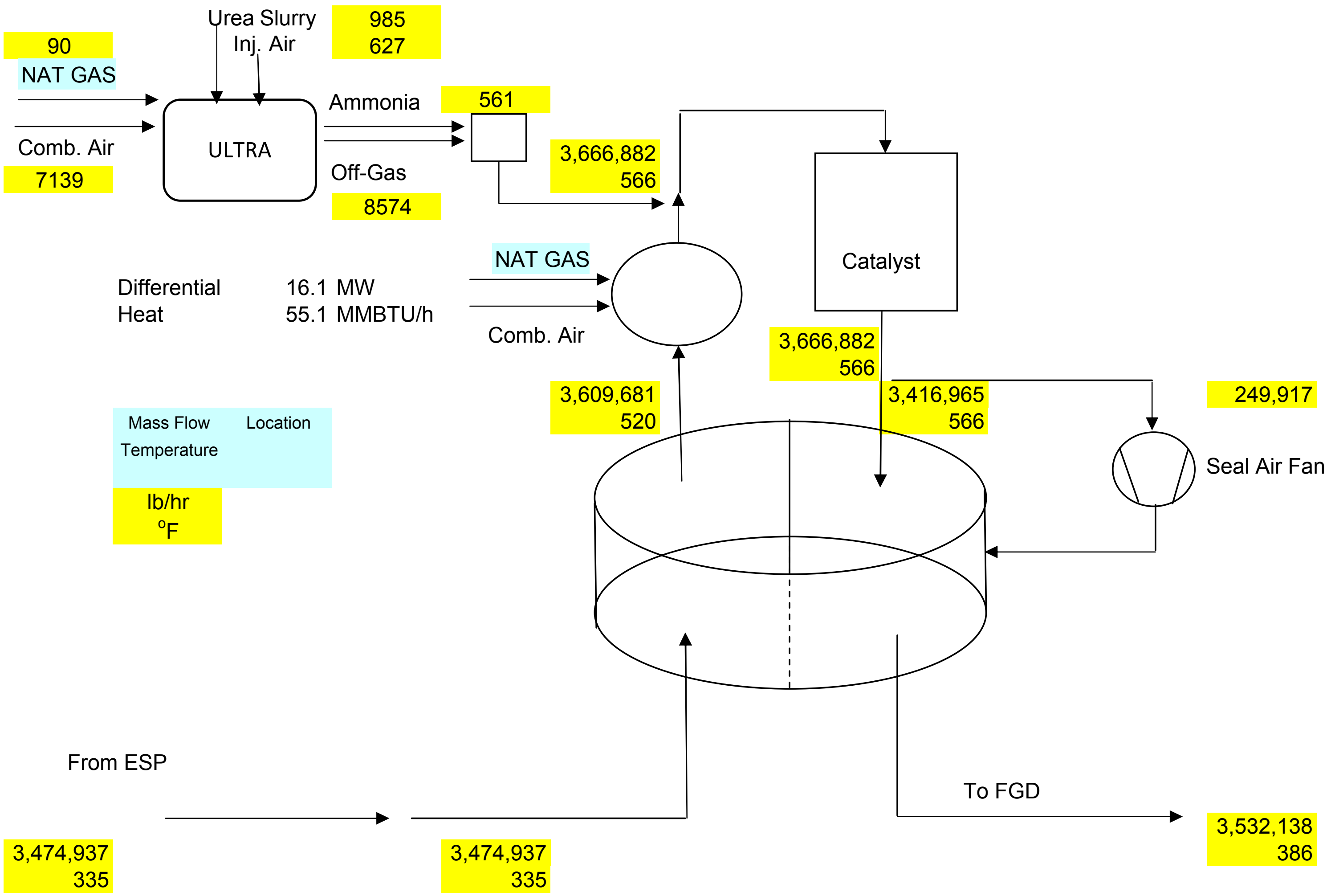
MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



March, 2009

Low Dust

	Urea	Ammonia	NG		Am/Ur	Gas Flow lb/hr
Unit 1	1972	530	180	lb/hr	0.268763	3,680,676
Unit 2	3276	884	296	lb/hr	0.269841	6,402,446
Total	5248	1414	476	lb/hr		

Tail End

	Urea	Ammonia	NG		Am/Ur	Gas Flow lb/hr
Unit 1	1972	532	180	lb/hr	0.269777	3,964,412
Unit 2	3276	884	296	lb/hr	0.269841	6,832,108
Total	5248	1416	476	lb/hr		

September, 2009

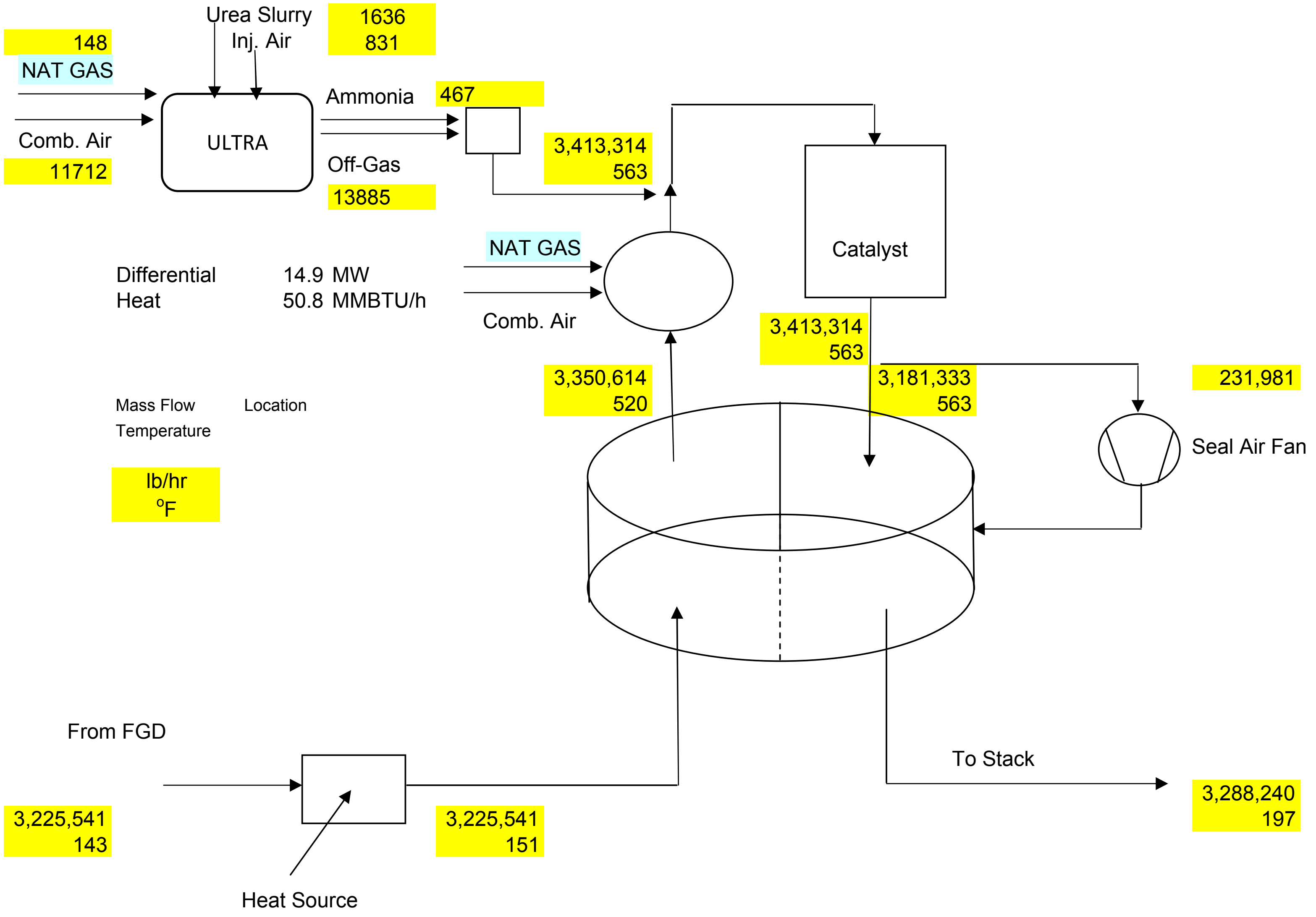
Low Dust

	Urea	Ammonia	NG		Am/Ur	Gas Flow lb/hr
Unit 1	985	561	90	lb/hr	0.569543	3,666,882
Unit 2	3272	934	296	lb/hr	0.285452	6,396,518
Total	4257	1495	386	lb/hr		

Tail End

	Urea	Ammonia	NG		Am/Ur	Gas Flow lb/hr
Unit 1	985	562	90	lb/hr	0.570558	3,953,834
Unit 2	3272	934	296	lb/hr	0.285452	6,826,628
Total	4257	1496	386	lb/hr		

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Tuesday, September 15, 2009 9:53 AM
To: Blakley, Robert
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
Subject: RE: Fuel Tech Flow Diagram Discrepancy

Bob,
Thanks for picking up the discrepancy.
yes, we overlooked the linkage between sheets in the file.
We'll revise and re-issue for U1 TE and LD.
Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, September 15, 2009 9:18 AM
To: Robert Johnson
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
Subject: FW: Fuel Tech Flow Diagram Discrepancy

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Let us know if questions arise.

Thanks for the comments on your review of our preliminary SCR arrangements. We will review and advise if we want additional comments that you may be able to provide.

Bob Blakley

From: Loehr, Zachary
Sent: Friday, September 11, 2009 9:49 AM
To: Blakley, Robert
Cc: Blackwood, Dave; Bryant, Ronald
Subject: Fuel Tech Flow Diagram Discrepancy

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www.burnsmcd.com

Proud to be one of FORTUNE's 100 Best Companies To Work For

Blakley, Robert

From: Blakley, Robert
Sent: Thursday, September 17, 2009 11:16 AM
To: Robert Johnson
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
Subject: RE: Fuel Tech Flow Diagram and Mass Balanace Updates

Bob -

When updating the preliminary process flow diagrams and mass balance calculations, can you provide more information on:

1. flue gas reheat natural gas fuel consumption in million Btu/hr and SCFH in addition to mass flow (lb/hr)?

2. percent excess air and mass flow (lb/hr) of ambient combustion air assumed for the reheat burner natural gas firing?

3. FTI's ULTRA urea-to-ammonia system urea versus ambient dilution air mass flows (lb/hr)?

4. FTI's ULTRA urea-to-ammonia system natural gas fuel consumption in million Btu/hr and SCFH, and how much of the ambient dilution air is used in the combustion of the natural gas?

We are interested in also knowing the amount of NOx expected to be produced by the flue gas reheat natural gas firing and if the ULTRA conversion system's NOx is a significant quantity that the SCR reactor catalyst has to remove by reaction with ammonia.

It would also be beneficial to know if the amount of natural gas consumed (million Btu/hr) and NOx produced (lb/mmBtu) by the flue gas reheat natural gas firing ahead of the SCR reactors for what amount of time during system startup is higher than the steady-state rates which are shown in the preliminary PFDs/ mass balances. Our interest is whether this firing has substantially greater rates to shorten the amount of time for ramp-up of the gas temperature into the reactor and subsequent ability to start the boiler coal-firing period. This will help us include this in our economic and BACT analysis studies.

We realize that the design basis of the Fuel Tech ULTRA systems recently provided (by Julie Higgins) with budgetary pricing is slightly different than that for the SCRs' design basis, i.e. slightly higher inlet NOx lb/mmBtu, lower NOx removal percentage. This is acceptable, as we can assume the numbers you provide for the SCRs and know that the ULTRA proposal design basis numbers are slightly higher so we have a conservative approach, i.e. built-in capacity margin above maximum expected demand.

Thanks,

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Tuesday, September 15, 2009 9:53 AM
To: Blakley, Robert
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
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Robert,
I was reviewing the Fuel Tech flow diagrams to pull the urea and natural gas usages for the economic evaluation. I found that some of the numbers aren't adding up. If you compare the Sept 09 flow diagrams vs the March 09 diagrams, the urea and natural gas usages look off for the Unit 1 Tail End and Low Dust options. The ammonia values match fairly closely though. It looks like they may have forgotten that the March 09 numbers were based on two reactors while the Sept 09 numbers where only based on one reactor. The urea and natural gas numbers are half of what they should be. Attached is a spreadsheet that compares the two sets of data. Please verify this with Fuel Tech.
Thanks,

Zac Loehr
Development Engineer, Energy Group
Burns & McDonnell
9400 Ward Parkway
Kansas City, MO 64114
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Tuesday, September 22, 2009 11:57 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 22Sep_MRYS Additional Data & Revised PFDs
Attachments: 22Sep09_MRY1TailEnd_Rev2_natgas.pdf; 22Sep09_BMcD for MRYS_Additional Process Data.pdf; 22Sep09_MRY1LowDust_Rev2_natgas_580F.pdf

Bob,
Attached are the revised PFDs for Unit 1 to reflect the single reactor.
Also attached is the summary of data you requested last Thursday.

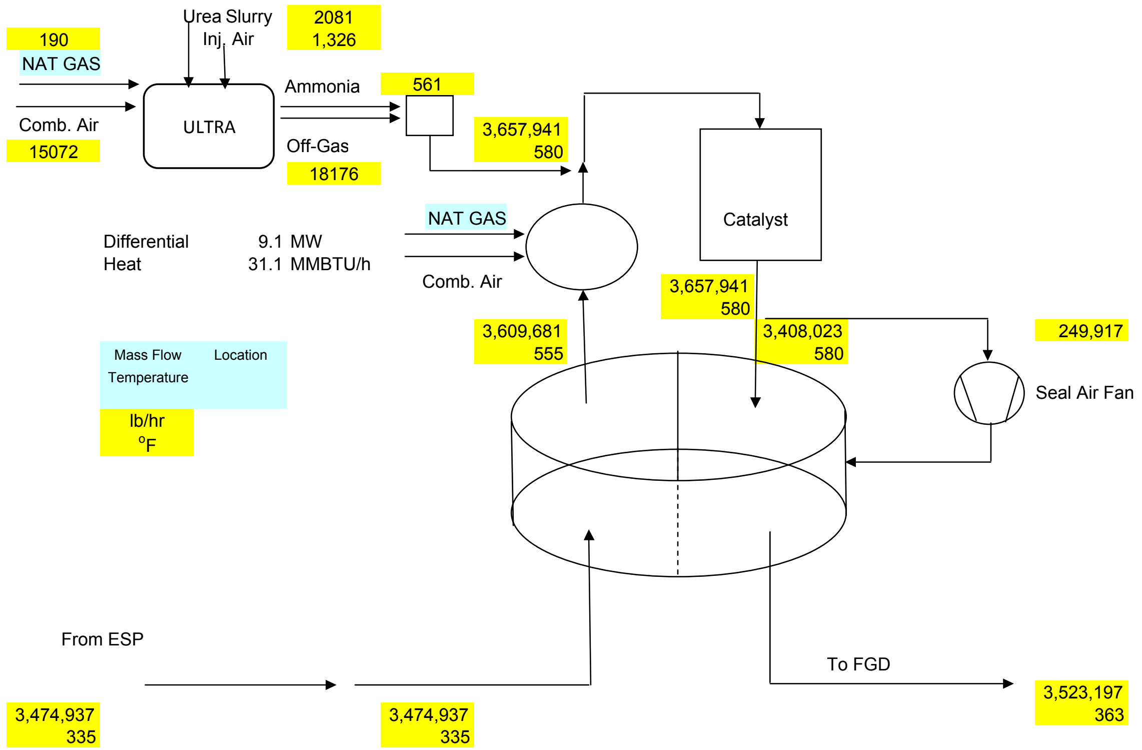
At this time, we have not estimated the natural gas consumption during startup. This is in part a function of the GGH design and the specific startup procedure. Volker and I will discuss and see if we can provide some context.

Please let us know if we can clarify anything.
Best Regards,
Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

<<22Sep09_MRY1TailEnd_Rev2_natgas.pdf>> <<22Sep09_BMcD for MRYS_Additional Process Data.pdf>> <<22Sep09_MRY1LowDust_Rev2_natgas_580F.pdf>>

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



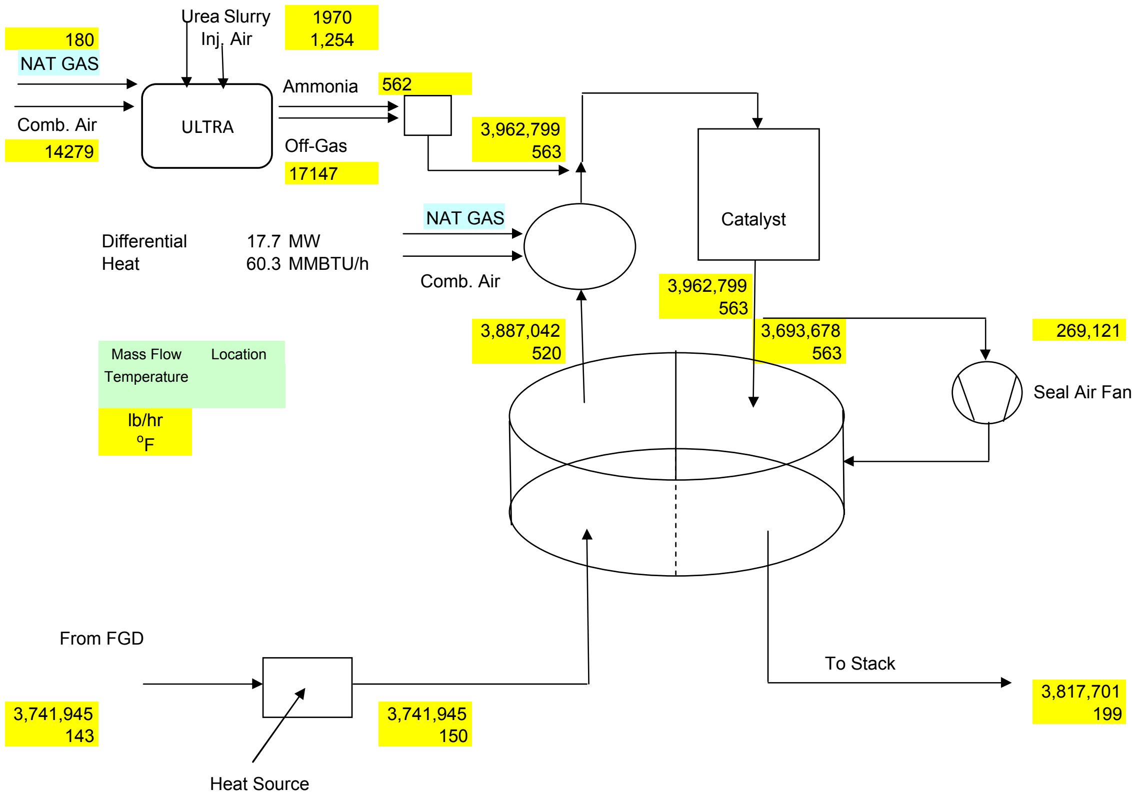
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,760	2,449,748	2,462,061	2,463,441	2,295,314	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,358	641,655	642,957	642,957	599,076	615,928
Oxygen	lb/hr	205,551	205,551	213,561	214,062	217,019	216,494	201,718	207,463
Moisture	lb/hr	309,692	309,692	321,775	324,547	325,965	326,852	304,545	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,814	11,814	11,814	11,700	10,901	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data

		Unit 1 Low Dust	**Unit 1 Tail End**	**Unit 2 Low Dust**	**Unit 2 Tail End**
Reheat Natural Gas	MMBtu/hr	30	33	43.1	49.2
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.04	3.33	3.33
ULTRA System Natural Gas	scfm	70	66	54	54
NOx Reheat Natural Gas	Lb/hr	5	9	6	7
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,464,003	2,509,202	2,520,818	2,522,207	2,351,099	2,384,931
Carbon di oxide	lb/h	622,053	622,053	646,089	652,570	653,798	653,798	609,444	623,281
Oxygen	lb/h	213,652	213,652	221,973	222,959	225,749	225,220	209,941	215,397
Moisture	lb/h	536,485	536,485	557,315	562,765	564,103	564,996	526,667	539,588
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	206	206	192	196
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70

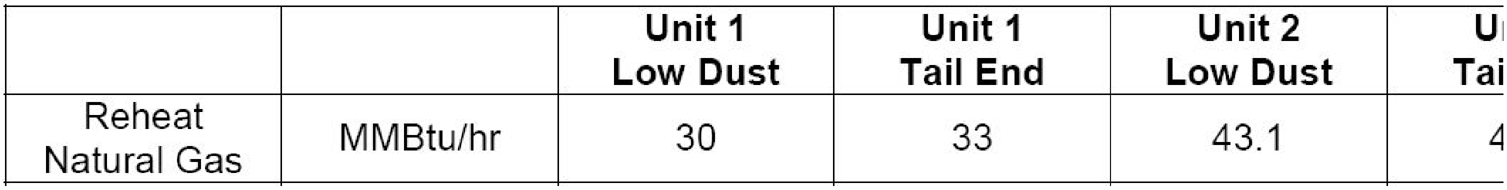
Blakley, Robert

From:	Blakley, Robert
Sent:	Wednesday, September 23, 2009 4:51 PM
To:	Robert Johnson
Cc:	51684; Volker Rummenhohl; Weilert, Carl; Bryant, Ronald; Loehr, Zachary
Subject:	FW: 22Sep_MRYS Additional Data & Revised PFDs
Attachments:	22Sep09_MRY1TailEnd_Rev2_natgas.pdf; 22Sep09_BMcD for MRYS_Additional Process Data.pdf; 22Sep09_MRY1LowDust_Rev2_natgas_580F.pdf; 11Sep09_MRY2LowDust_Rev1_natgas_580F.pdf; 11Sep09_MRY2TailEnd_Rev1_natgas.pdf; 11Sep09_MRY1TailEnd_Rev1_natgas.pdf; 11Sep09_MRY1LowDust_Rev1_natgas_580F.pdf

Bob -

We have discovered several inconsistencies that we need you to confirm and/or clarify, as noted in the email below. I have not independently verified the natural gas heat inputs for the flue gas reheating that Zac has provided in the tables for Unit 2 from September 11th PFDs. My numbers below are different for Unit 2 "differential heat" gas consumption inputs.

We also note that the updated flue gas reheat mMMBtu/hr numbers provided in the summary table included in your 9/22/09 email do not match the values shown on the individual process flow diagrams and preliminary mass balance calculations:



		Unit 1 Low Dust	Unit 1 Tail End	Unit 2 Low Dust	U Tai
Reheat Natural Gas	MMBtu/hr	30	33	43.1	4

9/22 PFD	MM Btu/hr	31.1	60.3		
9/11 PFD	MM Btu/hr			48.1	50.8

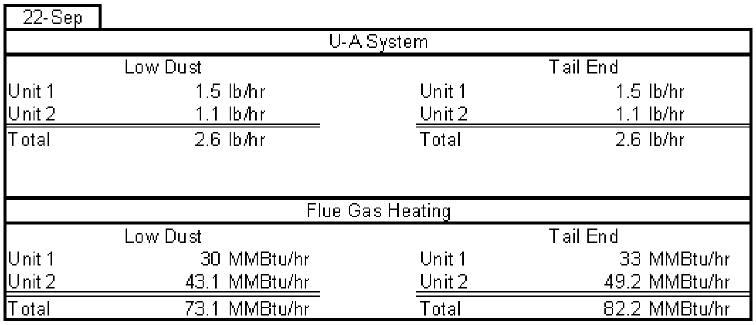
Please review and let us know promptly with your findings and any corrections needed. We are trying to wrap this up for submittal to Minnkota next week.

Bob Blakley

From: Loehr, Zachary
Sent: Wednesday, September 23, 2009 3:28 PM
To: Blakley, Robert; Blackwood, Dave
Cc: 51684; Bryant, Ronald; Phillips, John; Durant, Bryan; Root, Arlen; Weilert, Carl
Subject: RE: 22Sep_MRYS Additional Data & Revised PFDs

Bob,
There are some additional discrepancies in the documents attached. The NG and Urea rates are now different between the Unit 1 Low Dust and Tail End options. The NG and Urea flow rates for the U1 Tail End case is 180 and 1970 lb/hr respectively. The NG and Urea flow rates for the U1 Low Dust case is 190 and 2081 lb/hr respectively. The rates for both U1 options should be the same. The U1 Tail End case is the same as previous PFD's so I would assume that the Low Dust case is incorrect.

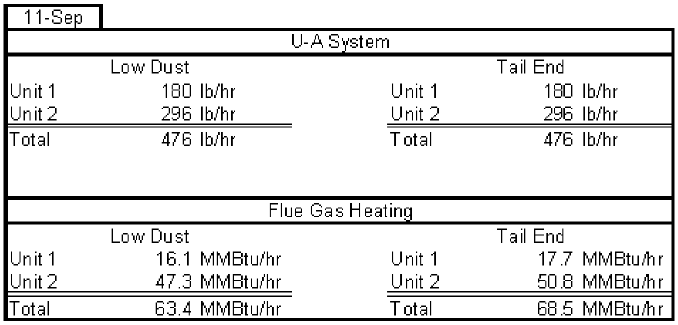
Also, NG usage rates presented in the Additional Mass Balance Data table are different than what was shown in the previous PFD's. See the comparison below. The lb/hr rates look very odd and the lb/MMbtu rates are different that the previous PFD's.



22-Sep

U-A System			
Low Dust		Tail End	
Unit 1	1.5 lb/hr	Unit 1	1.5 lb/hr
Unit 2	1.1 lb/hr	Unit 2	1.1 lb/hr
Total	2.6 lb/hr	Total	2.6 lb/hr

Flue Gas Heating			
Low Dust		Tail End	
Unit 1	30 MMBtu/hr	Unit 1	33 MMBtu/hr
Unit 2	43.1 MMBtu/hr	Unit 2	49.2 MMBtu/hr
Total	73.1 MMBtu/hr	Total	82.2 MMBtu/hr



11-Sep

U-A System			
Low Dust		Tail End	
Unit 1	180 lb/hr	Unit 1	180 lb/hr
Unit 2	296 lb/hr	Unit 2	296 lb/hr
Total	476 lb/hr	Total	476 lb/hr

Flue Gas Heating			
Low Dust		Tail End	
Unit 1	16.1 MMBtu/hr	Unit 1	17.7 MMBtu/hr
Unit 2	47.3 MMBtu/hr	Unit 2	50.8 MMBtu/hr
Total	63.4 MMBtu/hr	Total	68.5 MMBtu/hr

Please have Fuel Tech verify which values are correct.
Zac

From: Blakley, Robert
Sent: Wednesday, September 23, 2009 8:07 AM
To: Blackwood, Dave
Cc: 51684; Bryant, Ronald; Phillips, John; Loehr, Zachary; Durant, Bryan; Root, Arlen; Weilert, Carl
Subject: FW: 22Sep_MRYS Additional Data & Revised PFDs

All -

Here are the updated preliminary process flow diagrams with abbreviated mass balance calculations of Unit 1.
Unit 2's updates were previously provided on Sept. 11.

Please advise if additional information is desired.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Tuesday, September 22, 2009 11:57 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 22Sep_MRYS Additional Data & Revised PFDs

Bob,
Attached are the revised PFDs for Unit 1 to reflect the single reactor.
Also attached is the summary of data you requested last Thursday.

At this time, we have not estimated the natural gas consumption during startup. This is in part a function of the GGH design and the specific startup procedure. Volker and I will discuss and see if we can provide some context.

Please let us know if we can clarify anything.
Best Regards,
Bob

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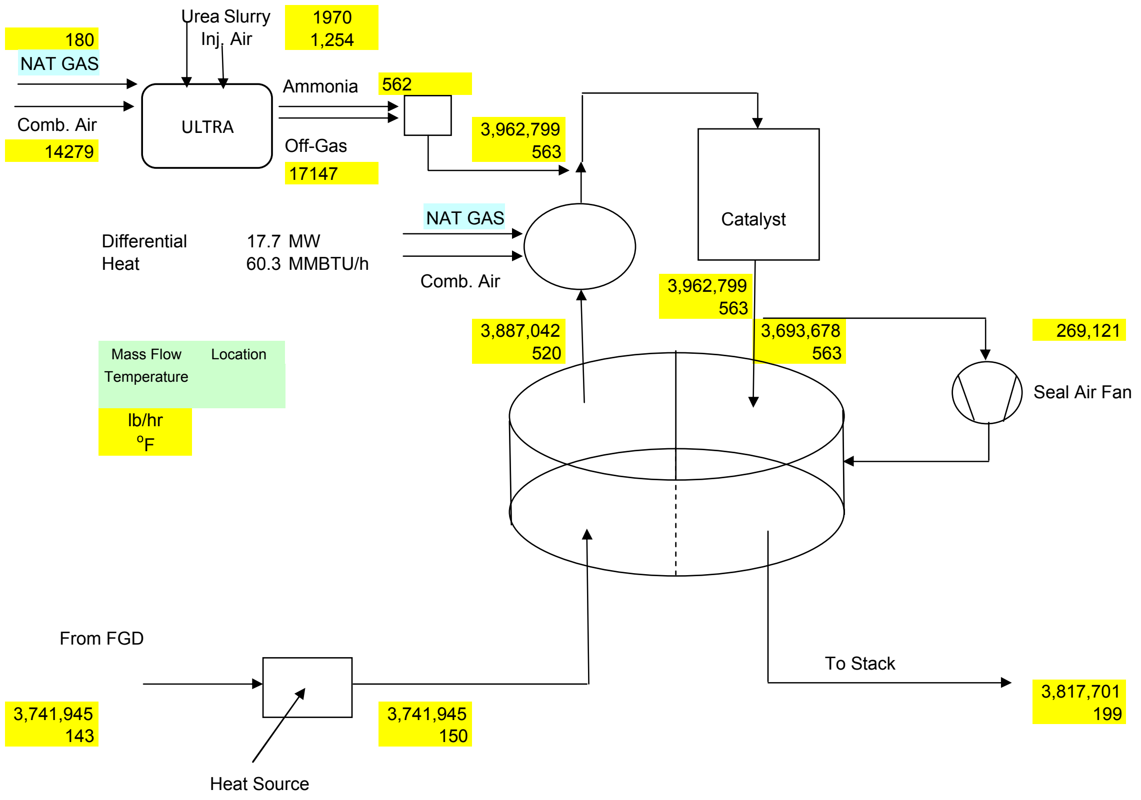
MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
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Moisture	lb/h	536,485	536,485	557,315	562,765	564,103	564,996	526,667	539,588
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Argon	lb/h	0	0	10	10	206	206	192	196
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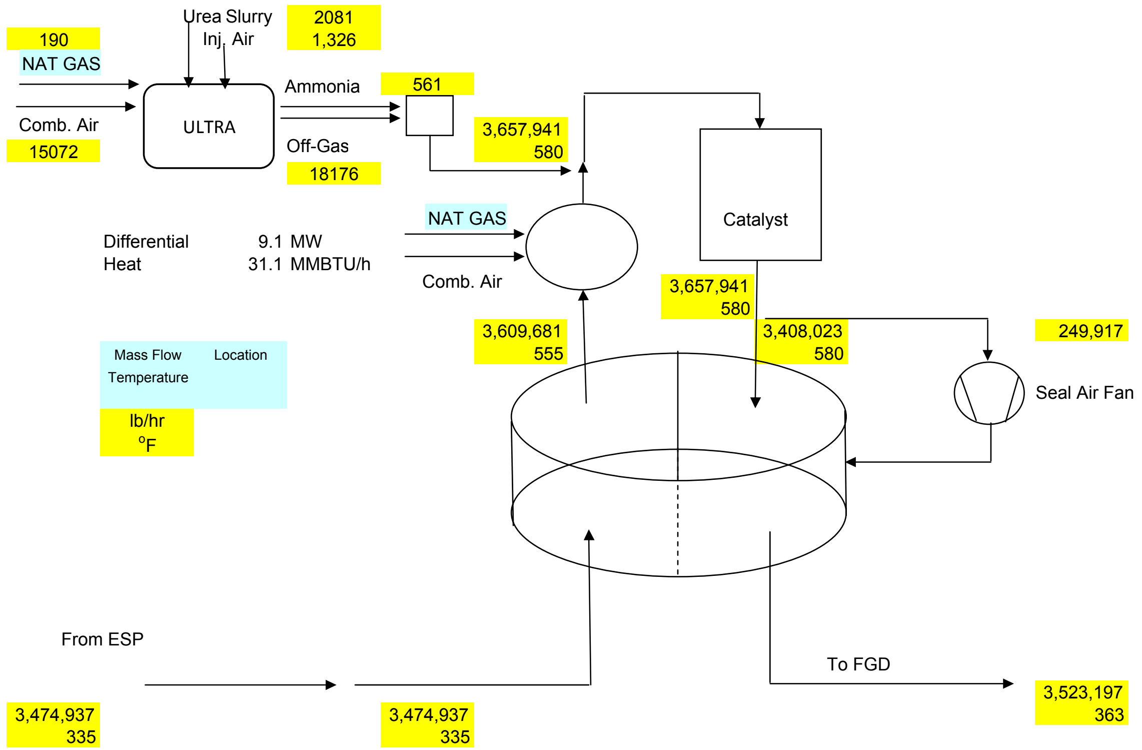
Particulate	lb/h	70	70	73	73	73	73	0	70

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



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Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data

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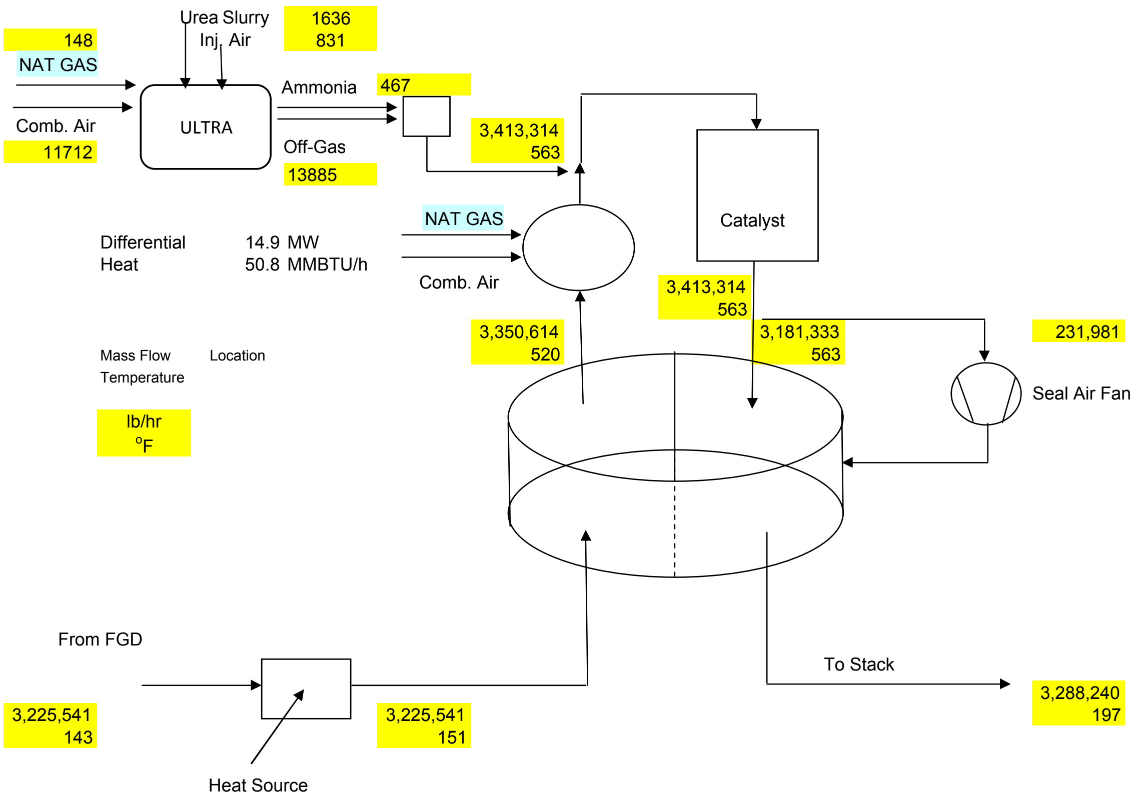
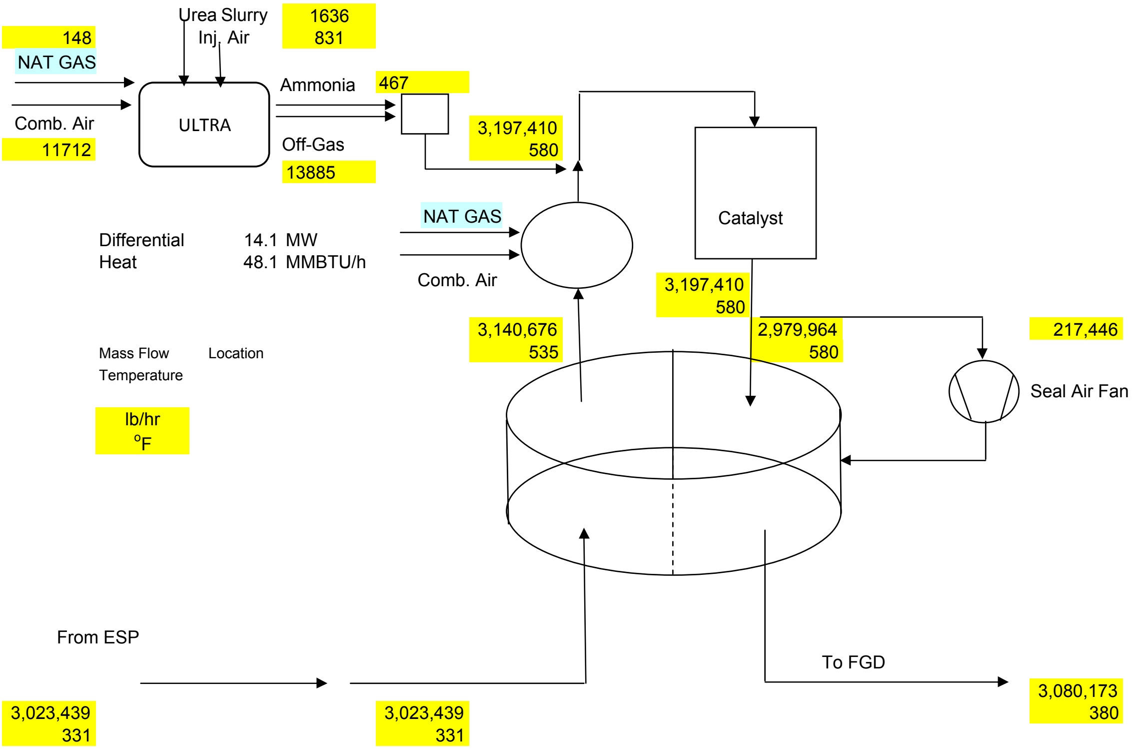
ULTRA System Natural Gas	MMBtu/hr	4.27	4.04	3.33	3.33
ULTRA System Natural Gas	scfm	70	66	54	54
NOx Reheat Natural Gas	Lb/hr	5	9	6	7
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



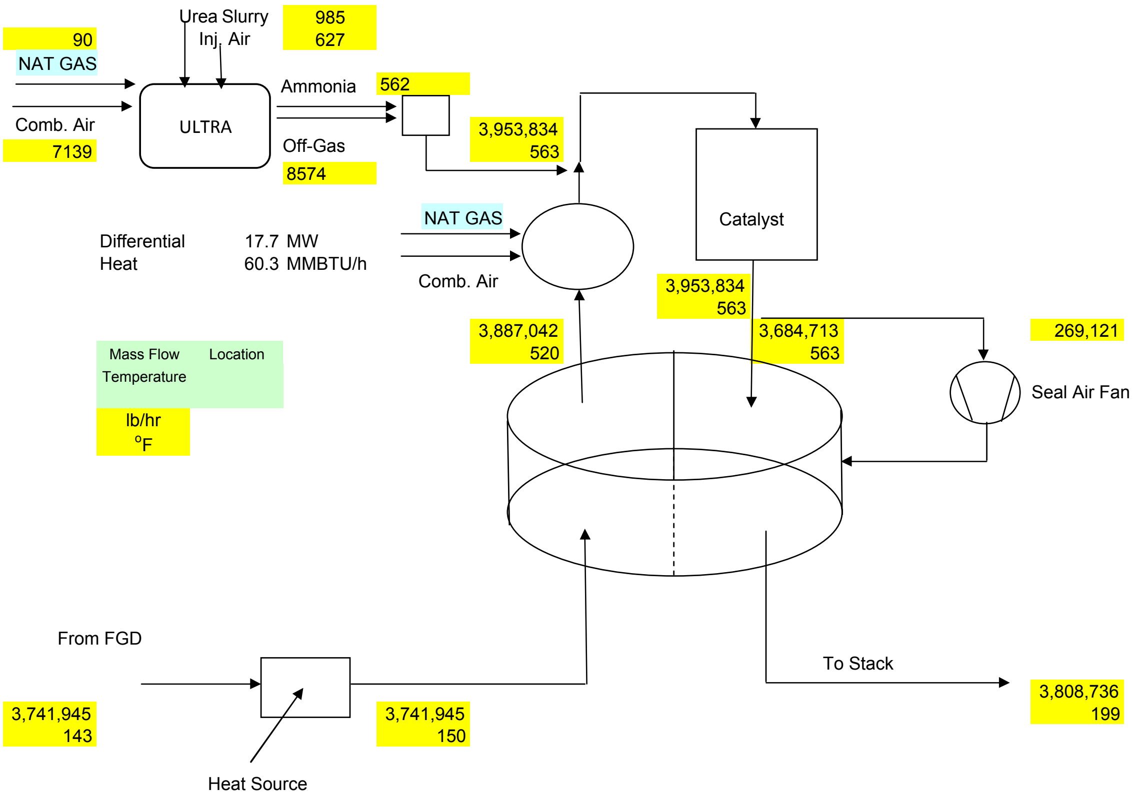
		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,153	2,180,798	2,190,180	2,191,336	2,042,555	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,883	569,281	570,295	570,295	531,575	543,915
Oxygen	lb/h	184,328	184,328	191,503	192,324	194,569	194,130	180,949	185,704
Moisture	lb/h	437,137	437,137	454,118	458,657	459,759	460,502	429,236	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	510	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,656	2,143,657	2,153,039	2,154,192	2,007,837	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,143	561,875	562,889	562,889	524,646	537,433
Oxygen	lb/h	177,258	177,258	184,157	184,877	187,122	186,683	174,000	178,633
Moisture	lb/h	270,167	270,167	280,707	284,686	285,788	286,530	267,063	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,463,985	2,508,879	2,514,687	2,516,076	2,344,997	2,379,123
Carbon di oxide	lb/h	622,053	622,053	646,129	652,566	653,180	653,180	608,768	622,667
Oxygen	lb/h	213,652	213,652	221,928	222,907	224,302	223,774	208,558	214,002
Moisture	lb/h	536,485	536,485	557,343	562,756	563,425	564,318	525,948	538,919
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	5	5	103	103	96	98
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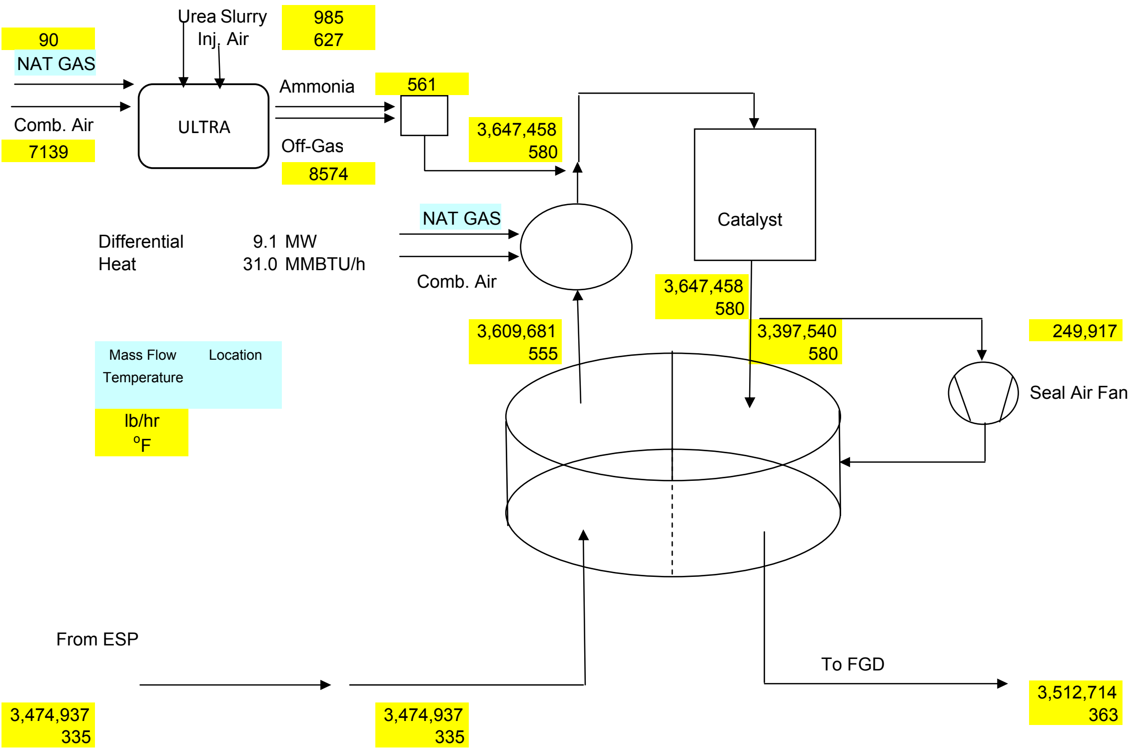
MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



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Nitrogen	lb/hr	2,336,123	2,336,123	2,426,758	2,449,060	2,454,868	2,456,248	2,288,130	2,343,304
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Oxygen	lb/hr	205,551	205,551	213,511	213,998	215,393	214,868	200,161	205,901
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Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,669	1,669	159	148	167
Argon	lb/hr	0	0	5	5	103	103	96	98
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Friday, September 25, 2009 6:59 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: MRYS Mass Balance Revision
Attachments: 24Sep09_BMcD for MRYS_Additional Process Data_R1.pdf; 22Sep09_MRY1TailEnd_Rev3_natgas.pdf

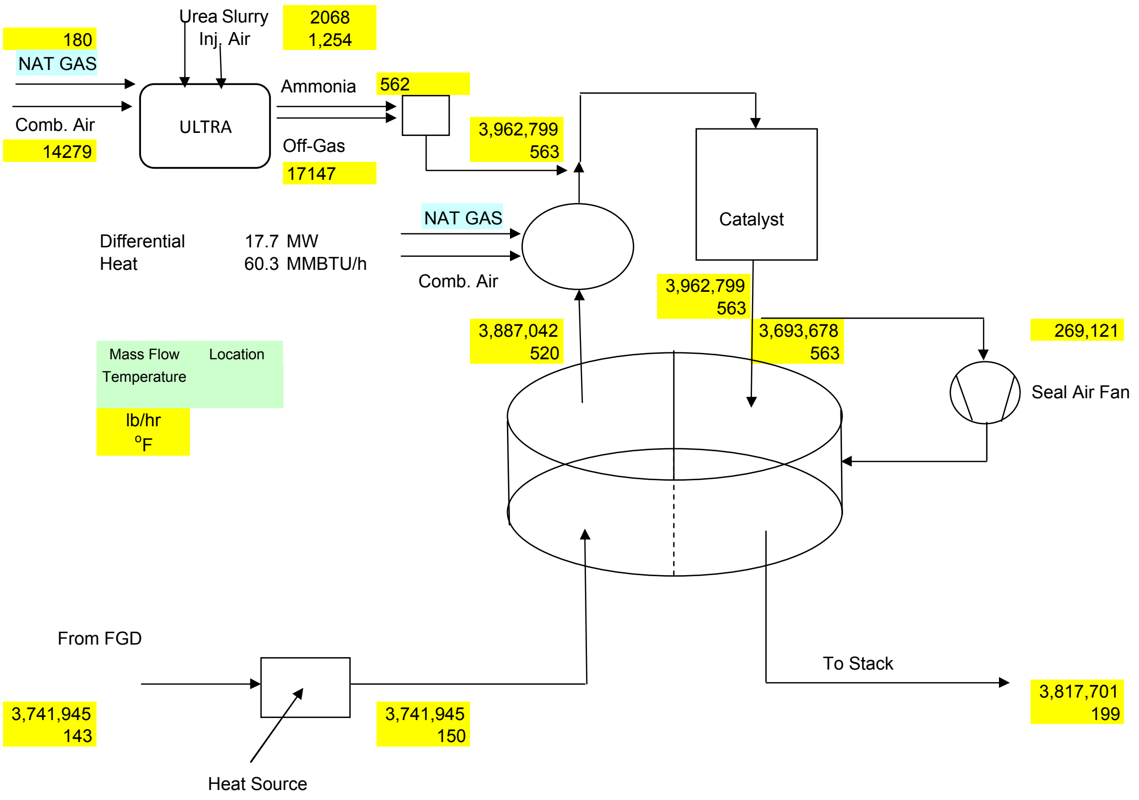
Bob,
Attached are the corrected data for the reheat requirements and the updated PFD for U1TE that reflects the corrected urea slurry rate.

Please let us know if we can clarify anything.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

<<24Sep09_BMcD for MRYS_Additional Process Data_R1.pdf>> <<22Sep09_MRY1TailEnd_Rev3_natgas.pdf>>

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



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Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
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Ammonia	lb/h	0	0	0	0	563	6	6	6
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Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data (Rev 1)

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Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.04	3.33	3.33
ULTRA System Natural Gas	scfm	70	66	54	54
NOx Reheat Natural Gas	Lb/hr	5	9	6	7
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

From: Stu Libby [mailto:slibby@minnkota.com]
Sent: Fri 9/25/2009 1:31 PM
To: Dyer, Paul
Subject: Fw: [aregc] SCR Maintenance

Here is a B&W response.

Stuart M. Libby
Plant Manager-Operations
Minnkota Power Cooperative
Milton R. Young Station
Tel (701) 794-7215
Cell (701) 391-3653
Fax (701) 794-7258
slibby@minnkota.com
----- Forwarded by Stu Libby/PowerProduction/Minnkota on 09/25/2009 01:29
PM -----

From: "Andrisevic, Dean M" <dmandrisevic@babcock.com>

To: "Piechocki, Matthew A" <MAPiechocki@diamondpower.com>, <slibby@minnkota.com>

Cc: "Pavlik, David L" <dlpavlik@babcock.com>, "Koslosky, John V" <jvkoslosky@babcock.com>

Date: 09/25/2009 01:20 PM

Subject: RE: [aregc] SCR Maintenance

Stu

I will try to give you some answers to your questions although as you are aware, in this business there are so many variables that affect the outcome, it is difficult come up with some absolutes.

1) cool-down of the SCR; Depending upon the outside air temperature and specific operating procedures which should open all dampers, doors and continuous operation of the fans, we typically see 36 to 48 hrs before entering the SCR.

(2) removal of the catalyst including time to scaffold, and vacuum ash prior to catalyst removal; This is dependent upon the your design, humidity, your operation of the sonic horns and pitch of your chosen catalyst. We have seen anything from a shift to several days to perform the vacuuming. Scaffolding is minimal and is installed in less than a shift.

(3) replacement of the catalyst including time to remove scaffolding, planking and re-seal the reactor; Typical removal on and replacement on units in the 500-650MW size has been accomplished in approximately 1 week per layer of catalyst, separate SCR boxes can accommodate simultaneous work but we typically don't have people working on top of each other. This is dependent upon the type of catalyst, number of blocks, design which should include permanent monorails for every layer and sufficient hoisting equipment.

(4) total time elapsed from shutdown of ammonia feed to restart of
Ammonia - I'm sorry but at this time, I do not have any information to share on this item.

Hopefully this helps.

Sincerely

Dean M. Andrisevic
General Manager Central Operations
Babcock & Wilcox Construction Co. Inc.

-----Original Message-----
From: Piechocki, Matthew A
Sent: Tuesday, September 22, 2009 12:51 PM
To: slibby@minnkota.com
Cc: Andrisevic, Dean M; Pavlik, David L; Koslosky, John V
Subject: FW: [aregc] SCR Maintenance

Stu,

I don't know if you have requested support from anyone within the Babcock & Wilcox Construction organization, but they should be very qualified to answer your questions regarding SCR demo and installation.

I have copied several individuals within the B&W Co. that should be able to provide you the information you need.

Good luck.

Matt Piechocki
New Project Business Development
Diamond Power International, Inc.
Phone (740) 687-4065
Cell (614) 648-0191
Fax (740) 687-4304
e-mail mapiechocki@diamondpower.com

-----Original Message-----
From: Stu Libby [mailto:slibby@minnkota.com]
Sent: Tuesday, September 22, 2009 11:32 AM
To: The Association of Rural Electric Generating Cooperatives
Cc: pdyer@burnsmcd.com

Subject: [aregc] SCR Maintenance

Hi, Everyone,

On September 2, 2009, I sent out a request for information regarding SCR maintenance. I did receive some responses and I greatly appreciate it. However, it appears that I lacked specificity in my question. Therefore, I am once again appealing to you for additional information. I will be grateful for any help you can give me by responding to the questions below. Thanks all.

We are investigating the requirements for a possible SCR retrofit at Milton R. Young Station. We need to assess the time required to change out a layer of catalyst in an SCR for cases in which there is not a planned maintenance outage available. We need to know how long we can expect the unit to be down. We are looking for actual experience as to the time required for the following steps in this process:
(1) cool-down of the SCR;
(2) removal of the catalyst including time to scaffold, and vacuum ash prior to catalyst removal;
(3) replacement of the catalyst including time to remove scaffolding, planking and re-seal the reactor;
(4) total time elapsed from shutdown of ammonia feed to restart of ammonia feed. For comparison purposes, please indicate the number of catalyst modules involved in your case.

Please indicate the number of shifts and shift length or total elapsed time hours for each step (1-4) above. Please also indicate the time required to stage for the change-out assuming the change-out occurs as a non-planned activity.

Stuart M. Libby
Plant Manager-Operations
Minnkota Power Cooperative
Milton R. Young Station
Tel (701) 794-7215
Cell (701) 391-3653
Fax (701) 794-7258
slibby@minnkota.com

Blakley, Robert

From:	Blakley, Robert
Sent:	Friday, September 25, 2009 3:31 PM
To:	Robert Johnson
Cc:	Volker Rummenhohl; 51684
Subject:	RE: MRYS Mass Balance Revision
Attachments:	11Sep09_MRY2LowDust_Rev1_natgas_580F.pdf; 11Sep09_MRY2TailEnd_Rev1_natgas.pdf; 22Sep09_MRY1LowDust_Rev2_natgas_580F.pdf; 22Sep09_MRY1TailEnd_Rev3_natgas.pdf; 24Sep09_BMcD for MRYS_Additional Process Data_R1.pdf

Bob -

As we discussed, please check the total gas mass flow numbers in the PFDs versus the sum of the values copied from the spreadsheet as they do not match for any of the four cases:
> 9/11 U2 TE & LD SCRs
> 9/22 U1 LD SCR and 9/24 U1 TE SCR.

Also, in these PFDs, the urea mass flow and ULTRA system natural gas heat input for the Unit 1 low dust SCR are not the same as the Unit 1 tail end SCR, which we believe should match.
The revised summary table also shows two different values for the ULTRA system natural gas flows for Unit 1. Unit 2's ULTRA numbers are matching.

We appreciate your help in getting this corrected and back to us on Monday, 9/28.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Friday, September 25, 2009 6:59 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: MRYS Mass Balance Revision

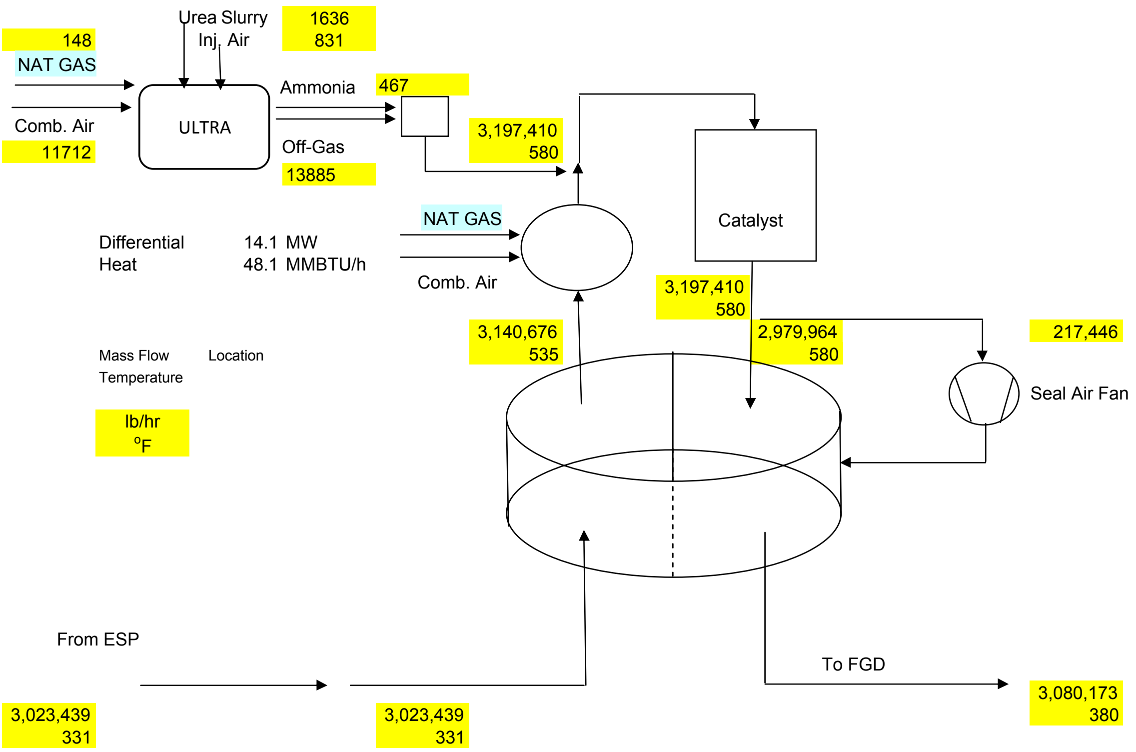
Bob,
Attached are the corrected data for the reheat requirements and the updated PFD for U1TE that reflects the corrected urea slurry rate.

Please let us know if we can clarify anything.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

<<24Sep09_BMcD for MRYS_Additional Process Data_R1.pdf>> <<22Sep09_MRY1TailEnd_Rev3_natgas.pdf>>

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,656	2,143,657	2,153,039	2,154,192	2,007,837	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,143	561,875	562,889	562,889	524,646	537,433
Oxygen	lb/h	177,258	177,258	184,157	184,877	187,122	186,683	174,000	178,633
Moisture	lb/h	270,167	270,167	280,707	284,686	285,788	286,530	267,063	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77

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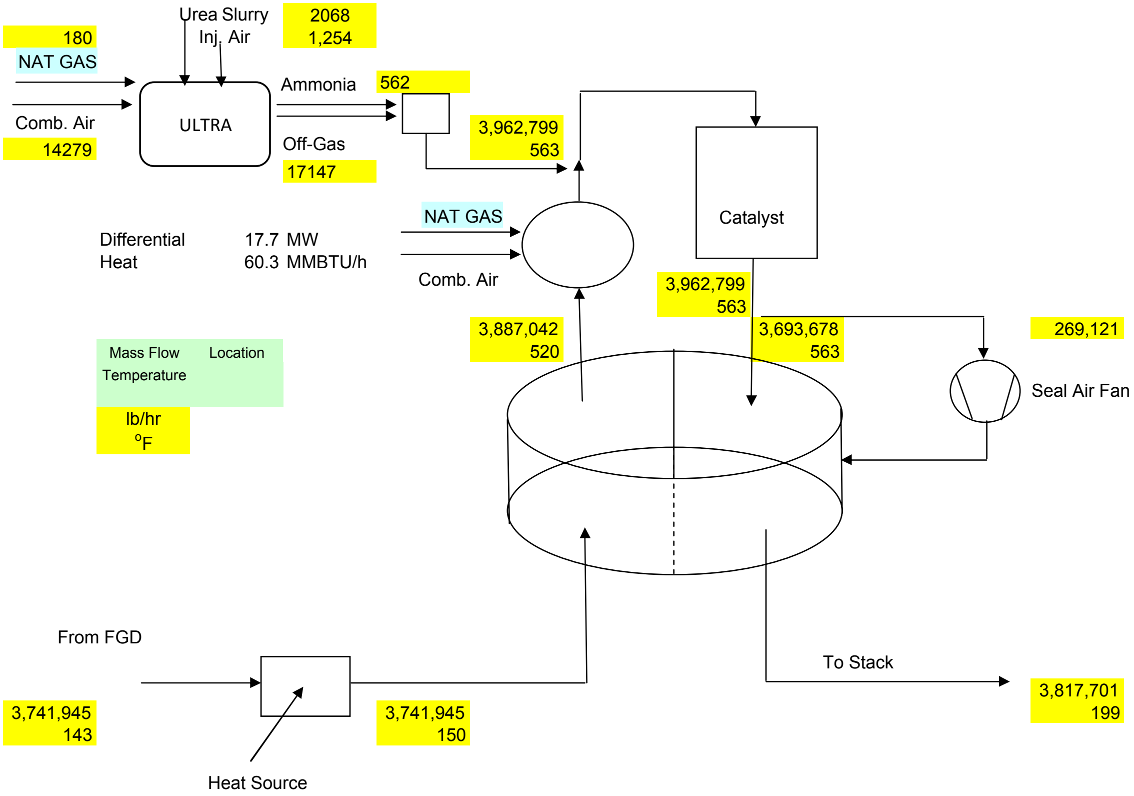
Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data (Rev 1)

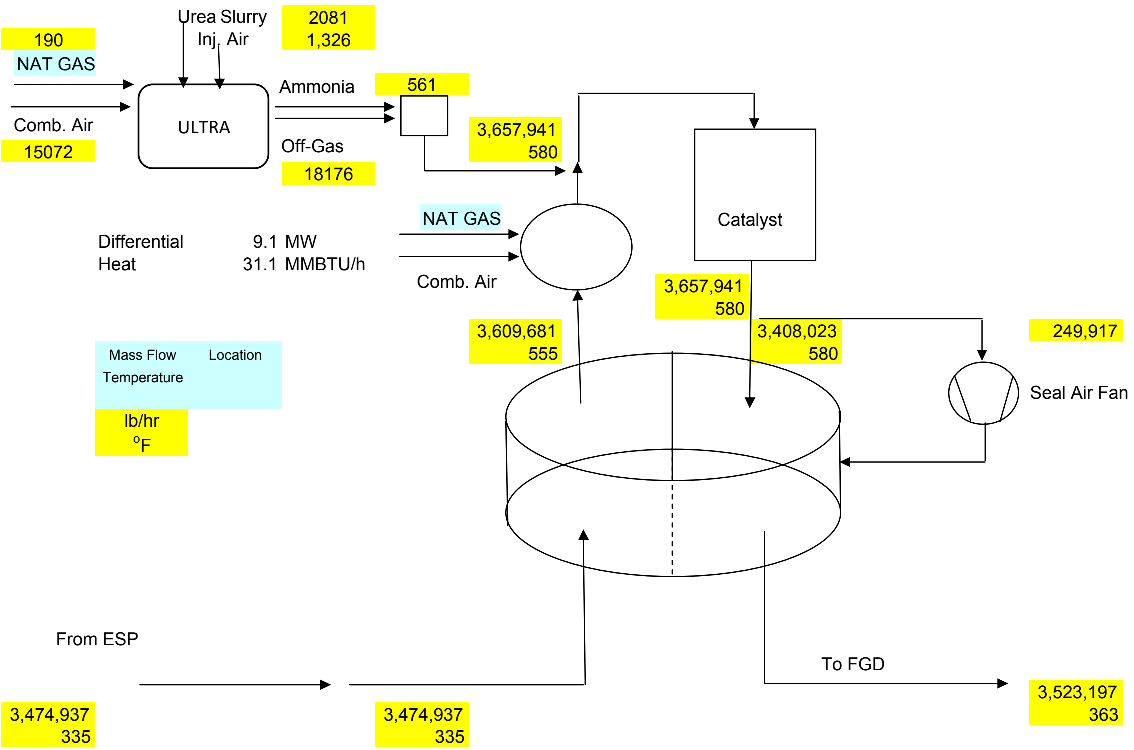
		Unit 1 Low Dust	**Unit 1 Tail End**	**Unit 2 Low Dust (per reactor)**	**Unit 2 Tail End (per reactor)**
Reheat Natural Gas	MMBtu/hr	31.1	60.3	48.1	50.8
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.04	3.33	3.33
ULTRA System Natural Gas	scfm	70	66	54	54
NOx Reheat Natural Gas	Lb/hr	5	9	6	7
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



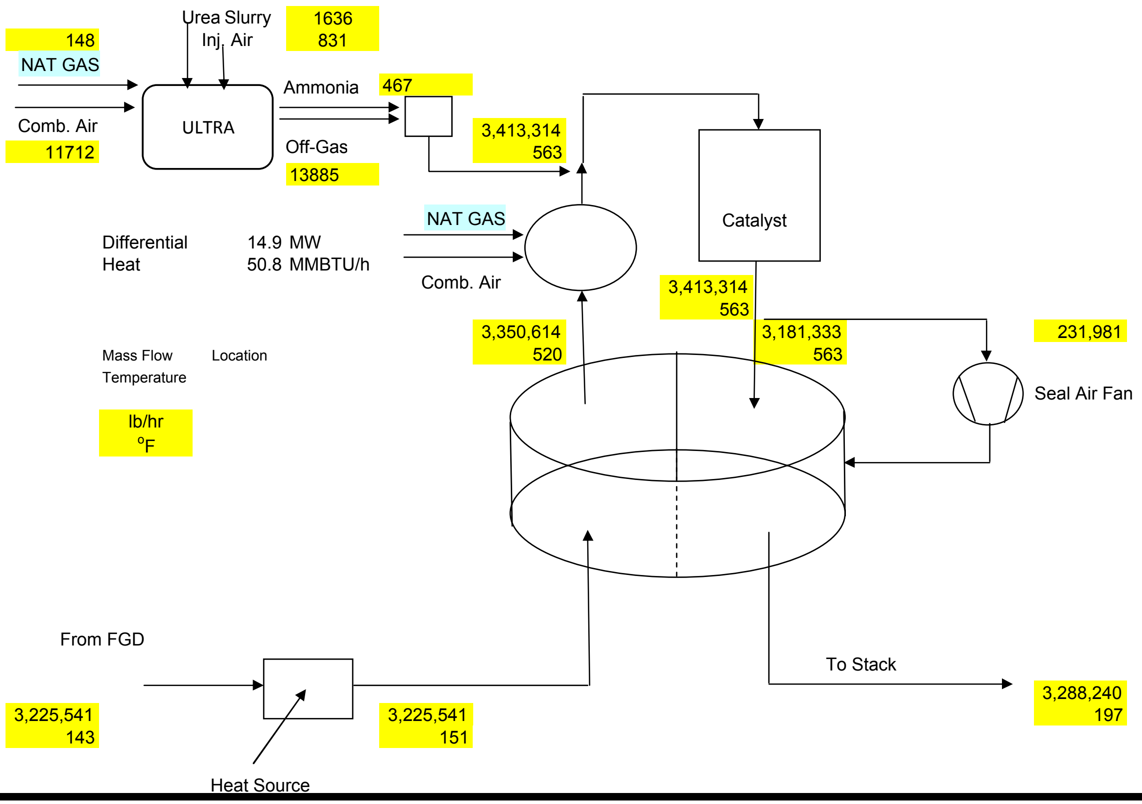
		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,464,003	2,509,202	2,520,818	2,522,207	2,351,099	2,384,931
Carbon di oxide	lb/h	622,053	622,053	646,089	652,570	653,798	653,798	609,444	623,281
Oxygen	lb/h	213,652	213,652	221,973	222,959	225,749	225,220	209,941	215,397
Moisture	lb/h	536,485	536,485	557,315	562,765	564,103	564,996	526,667	539,588
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	206	206	192	196
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,760	2,449,748	2,462,061	2,463,441	2,295,314	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,358	641,655	642,957	642,957	599,076	615,928
Oxygen	lb/hr	205,551	205,551	213,561	214,062	217,019	216,494	201,718	207,463
Moisture	lb/hr	309,692	309,692	321,775	324,547	325,965	326,852	304,545	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,814	11,814	11,814	11,700	10,901	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,153	2,180,798	2,190,180	2,191,336	2,042,555	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,883	569,281	570,295	570,295	531,575	543,915
Oxygen	lb/h	184,328	184,328	191,503	192,324	194,569	194,130	180,949	185,704
Moisture	lb/h	437,137	437,137	454,118	458,657	459,759	460,502	429,236	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	510	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77

Blakley, Robert

From:	Robert Johnson [RJohnson@ftek.com]
Sent:	Monday, September 28, 2009 10:05 AM
To:	Blakley, Robert
Cc:	Volker Rummenhohl
Subject:	28Sep_PFD Revisions
Attachments:	28Sep09_MRY2TailEnd_Rev2_natgas.pdf; 27Sep09_BMcD for MRYS_Additional Process Data_R2.doc; 28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf; 28Sep09_MRY1TailEnd_Rev4_natgas.pdf; 28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf

Bob,

Attached are the revised PFDs.

I added a summary line to the mass balance table, and all of the flows match those on the flow diagram.

The balance around the ULTRA system for the U1 systems has been corrected.

Please let us know if we can clarify anything.

Best Regards, Bob

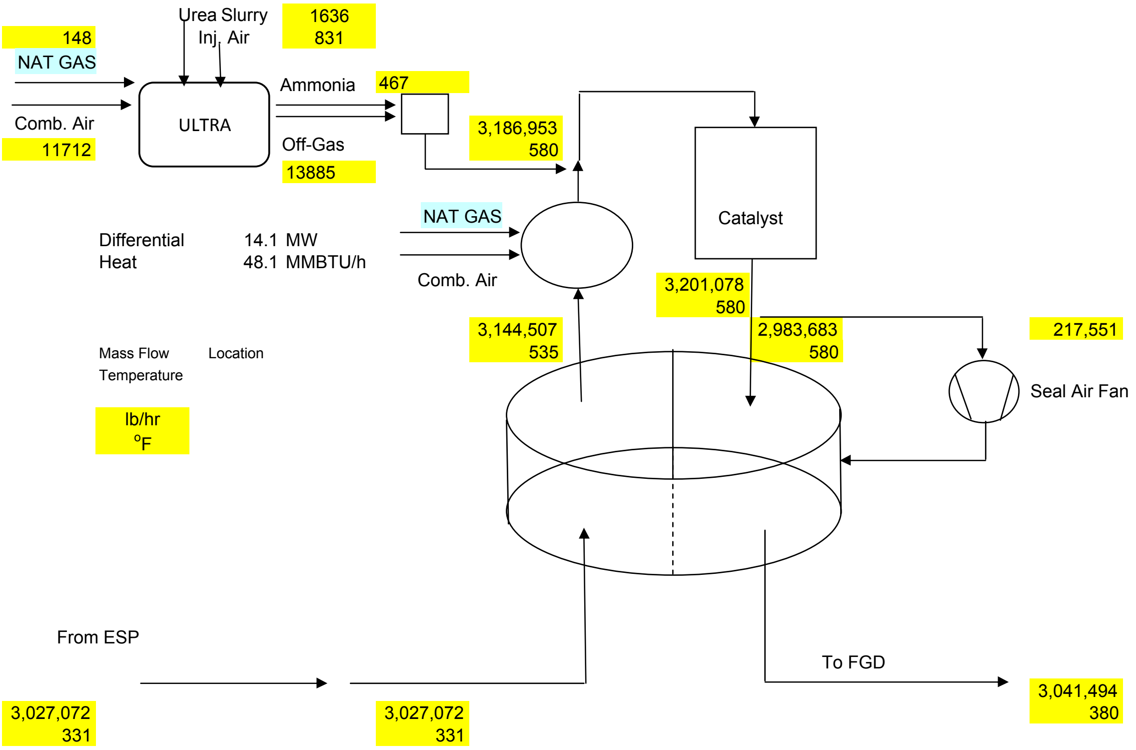
Robert E. Johnson

Fuel Tech, Inc

(913) 897 0727

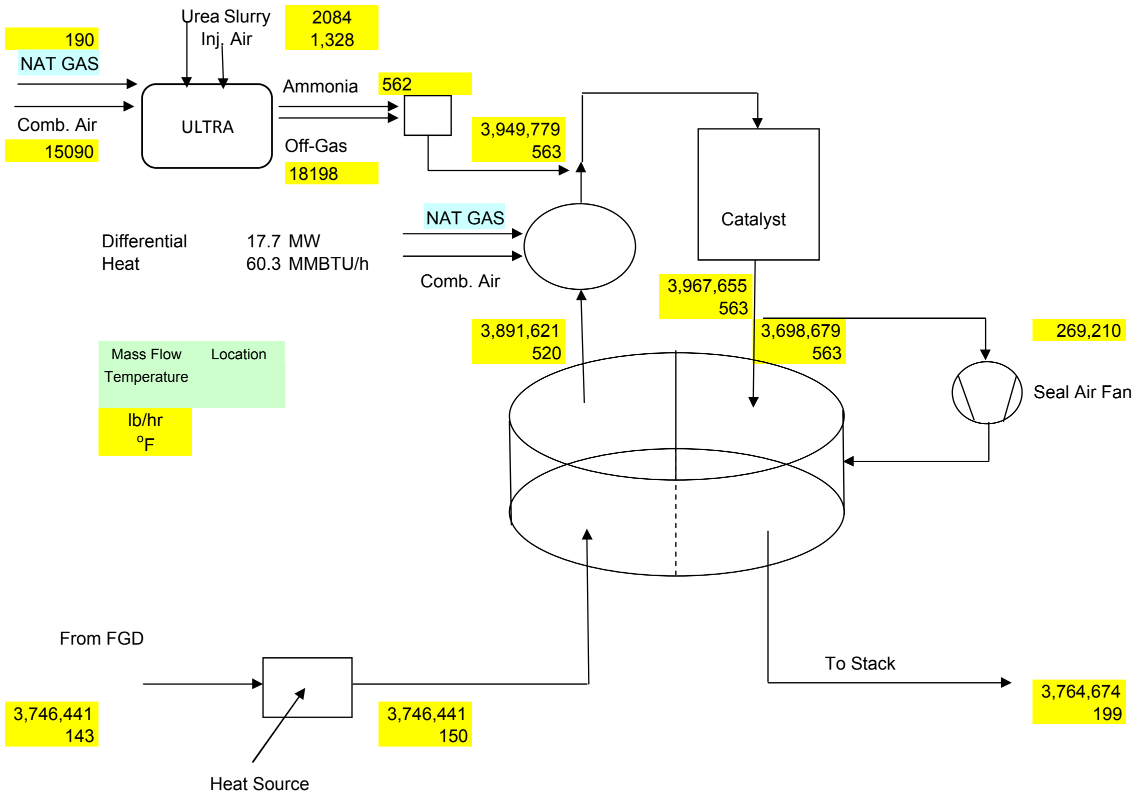
<<28Sep09_MRY2TailEnd_Rev2_natgas.pdf>> <<27Sep09_BMcD for MRYS_Additional Process Data_R2.doc>> <<28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf>> <<28Sep09_MRY1TailEnd_Rev4_natgas.pdf>> <<28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf>>

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



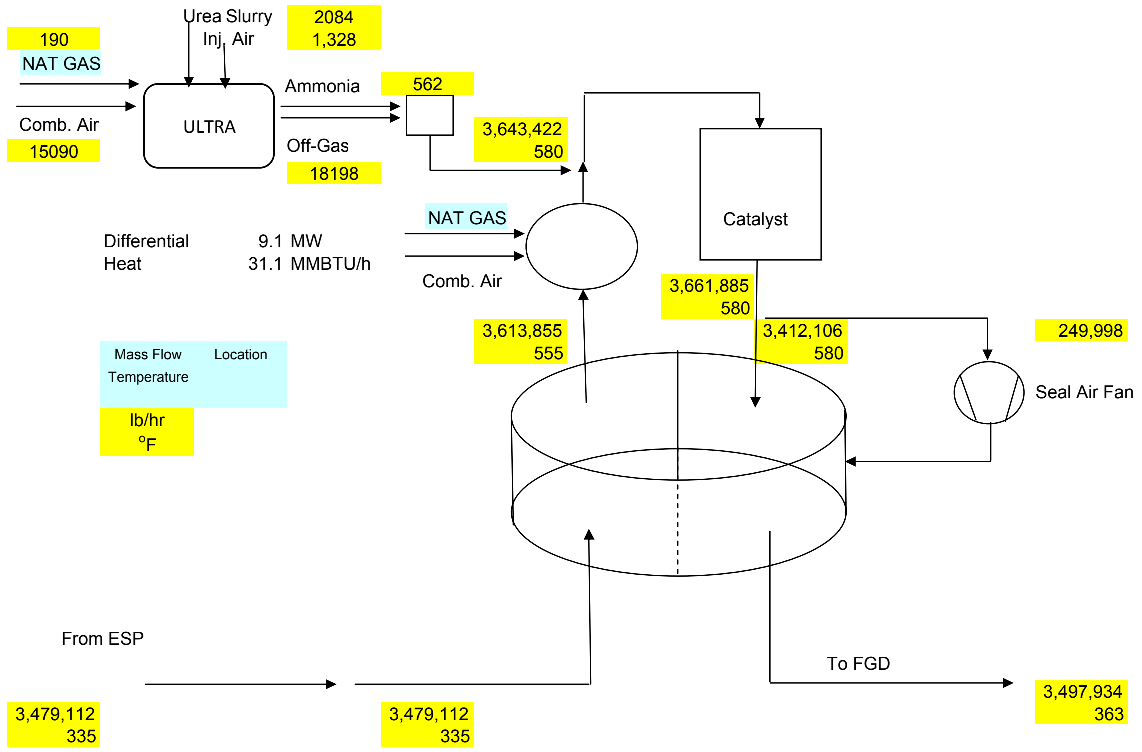
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,694	2,143,695	2,153,077	2,154,231	2,007,981	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,153	561,885	562,899	562,899	524,684	537,433
Oxygen	lb/h	177,258	177,258	184,161	184,881	187,126	186,686	174,012	178,633
Moisture	lb/h	270,167	270,167	280,712	284,691	285,793	286,535	267,082	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,027,072	3,027,072	3,144,507	3,186,953	3,201,323	3,201,078	2,983,683	3,041,494

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,463,945	2,509,161	2,521,083	2,522,472	2,351,512	2,385,237
Carbon di oxide	lb/h	622,053	622,053	646,071	652,555	653,815	653,815	609,503	623,313
Oxygen	lb/h	213,652	213,652	221,970	222,956	225,821	225,293	210,023	215,472
Moisture	lb/h	536,485	536,485	557,301	562,753	564,141	565,034	526,739	539,638
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	211	211	197	201
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70
Total	lb/hr	3,746,441	3,746,441	3,891,621	3,949,779	3,967,977	3,967,655	3,698,679	3,764,674

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



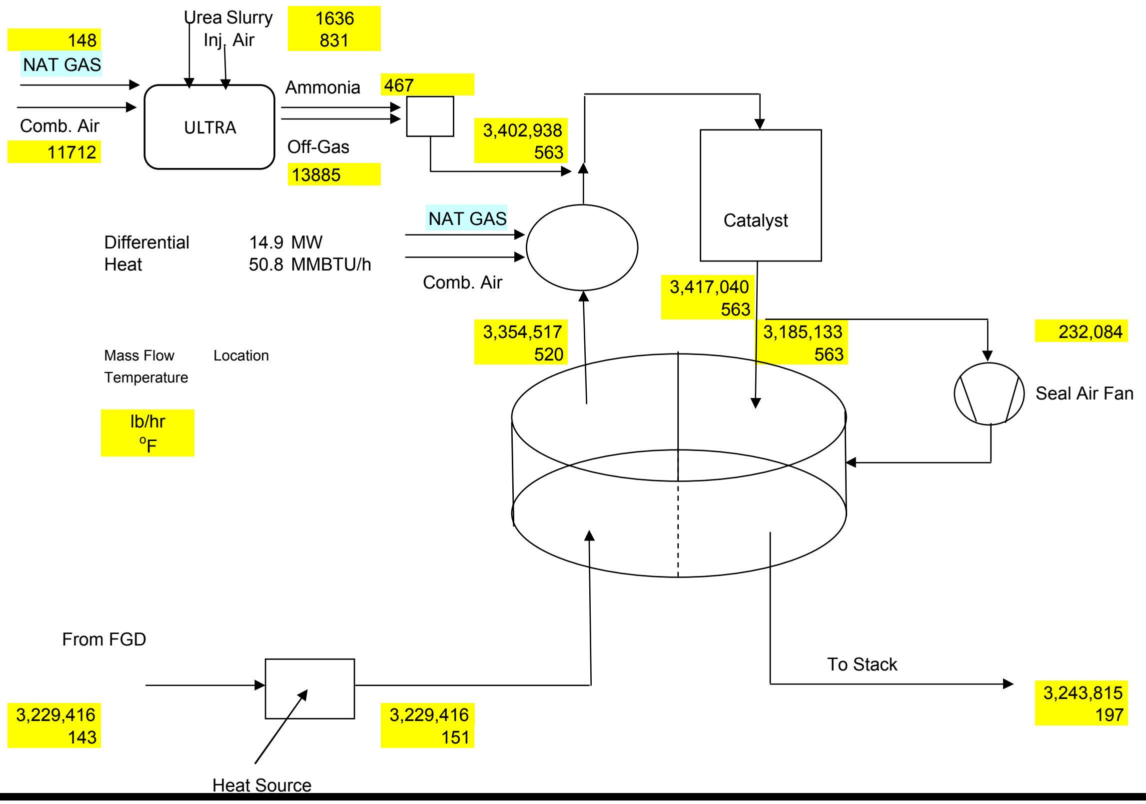
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,651	2,449,638	2,461,951	2,463,331	2,295,352	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,330	641,626	642,928	642,928	599,086	615,928
Oxygen	lb/hr	205,551	205,551	213,551	214,052	217,009	216,484	201,722	207,463
Moisture	lb/hr	309,692	309,692	321,760	324,532	325,950	326,837	304,550	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,813	11,813	11,813	11,699	10,902	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70
Total	lb/hr	3,479,112	3,479,112	3,613,855	3,643,422	3,662,182	3,661,885	3,412,106	3,497,934

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems Additional Mass Balance Data (Rev 2)

		Unit 1 Low Dust	Unit 1 Tail End	Unit 2 Low Dust (per reactor)	Unit 2 Tail End (per reactor)
Reheat Natural Gas	MMBtu/hr	31.1	60.3	48.1	50.8
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.27	3.33	3.33
ULTRA System Natural Gas	scfm	70	70	54	54
NOx Reheat Natural Gas	Lb/hr	10	20	14	16
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,074	2,180,720	2,190,102	2,191,257	2,042,589	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,862	569,261	570,275	570,275	531,584	543,915
Oxygen	lb/h	184,328	184,328	191,496	192,317	194,562	194,123	180,952	185,704
Moisture	lb/h	437,137	437,137	454,101	458,641	459,743	460,485	429,243	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	509	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,229,416	3,229,416	3,354,517	3,402,938	3,417,308	3,417,040	3,185,133	3,243,815

Blakley, Robert

From: Steve Benson [sbenson@microbeam.com]
Sent: Monday, October 05, 2009 1:27 PM
To: Wayne Jones
Cc: Bryant, Ronald; Luther Kvernen
Subject: Sulfation of fine particles

Attachments: Sulfation of fly ash.pdf

Sulfation of fly ash.pdf (49 K...

Wayne,

Attached is some information on the increase in sulfation rates of small fly ash particles (less than 5 microns) with and without catalyst.

Let me know if you have questions.

Steve

Steven A. Benson, Ph.D.
President
Microbeam Technologies Inc.
4200 James Ray Drive, Ste. 191
Grand Forks, ND 58203
Ph. 701-777-6530
Cell 701-213-7070
Fax 701-777-6532
www.microbeam.com

Extracted from past report “Ash Impacts on SCR Performance, S. Benson, 2005.”

Tests of fly ash sulfation were conducted using a thermogravimetric analyzer (TGA). TGA testing was conducted using a <5-µm-size fraction of ash produced from Powder River Basin (PRB) coals and lignites and exposing them to vapor-phase sulfur dioxide with and without catalyst at several temperatures. The aim of the testing was to determine the potential of the formation of sulfates to cause particle-to-particle bonding that leads to the formation of deposits in the temperature range where SCR catalysts are used. The TGA testing is focused on determining the reactivity of the <5-µm ash produced from selected PRB and blends to sulfur dioxide and gas-phase phosphorus species as a function of temperature. Testing was conducted to determine the weight gain with flue gas containing ammonia. The impact temperature on the weight gain due to the formation of sulfates for a PRB blend is shown in Figure 8. The rates of sulfation were found to increase with increased temperature. The results show an increase in the weight gains when ammonia and phosphorus were added. Ground catalyst was mixed with PRB and placed in the TGA. Increases in weight gain were observed when catalyst was added as compared to baseline cases for 100% PRB, as shown in Figures 8 and 9, respectively. The presence of catalyst enhances the formation of sulfates.

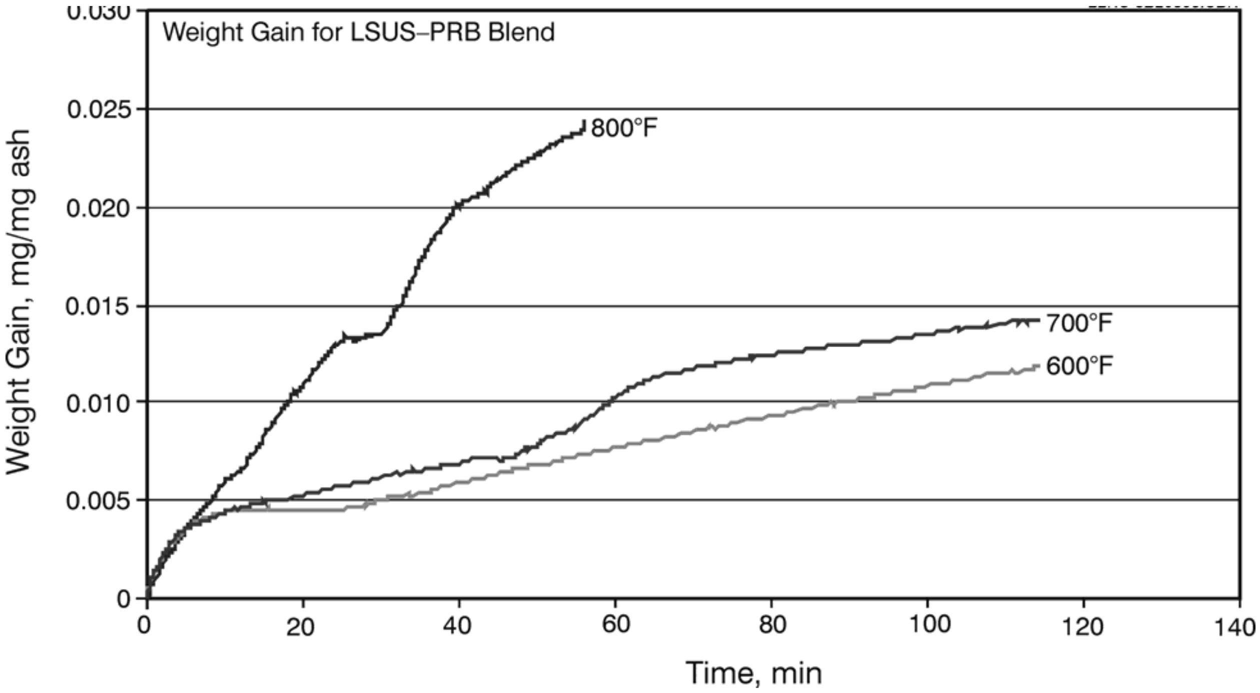


Figure 8. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia at three temperatures.

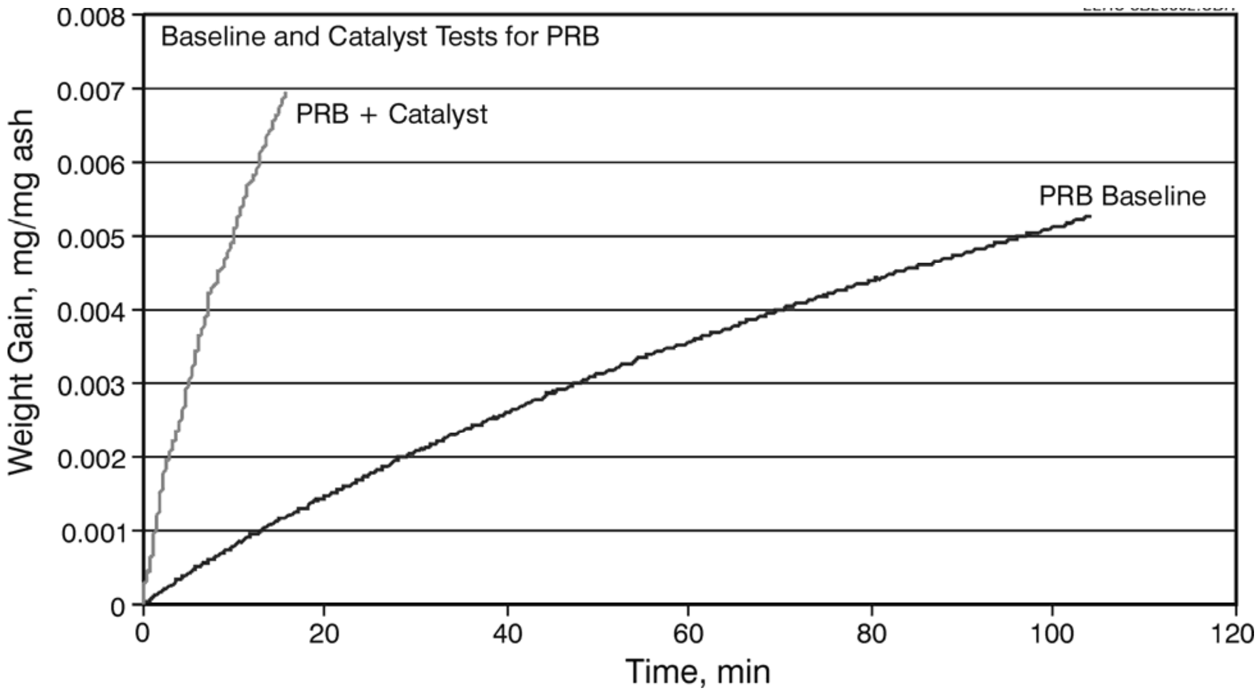


Figure 9. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia with and without SCR catalyst present.

Blakley, Robert

From: Wayne Jones [WSJ@topsoe.com]

Sent: Friday, October 09, 2009 9:33 AM

To: Bryant, Ronald

Cc: TNW@topsoe.com

Subject: Minnkota

Ron,

I got a response back today from Denmark with answers to some of the questions posed during our conference call earlier this week.

Amager, has not started up so we have no data concerning SCR operation. They seem to be having problems with the boiler and FGD systems and that has prevented any significant run time.

Also, an issue came up yesterday requiring me to travel today. I had planned to finish the proposal today but I don't think that will be possible. I will work on it this weekend and have it you as early on Monday as possible.

Thanks,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

Blakley, Robert

From: Blakley, Robert
Sent: Tuesday, December 22, 2009 9:21 AM
To: Robert Johnson
Cc: 49861; Volker Rummenhohl; Blackwood, Dave; Bryant, Ronald; Weilert, Carl
Subject: FW: 28Sep_PFD Revisions
Attachments: 28Sep09_MRY2TailEnd_Rev2_natgas.pdf; 27Sep09_BMcD for MRYS_Additional Process Data_R2.doc; 28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf; 28Sep09_MRY1TailEnd_Rev4_natgas.pdf; 28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf

Bob -

Carl Weilert and I reviewed information involving hypothetical applications of tail end and low dust SCR technologies at Minnkota's Milton R. Young Station with the North Dakota Department of Health's Air Quality Division on Monday, December 21, 2009.

Estimated Natural Gas Consumption for Reheating Flue Gas:

> Unit 1 Low Dust SCR System	31 MMBtu/hr
> Unit 1 Tail End SCR System	60.3 MMBtu/hr
> Unit 2 Low Dust SCR System	96.2 MMBtu/hr
> Unit 2 Tail End SCR System	101.6 MMBtu/hr

Estimated Natural Gas Consumption for Urea to Ammonia Conversion:

> Unit 1 SCR System	4.3 MMBtu/hr
> Unit 2 SCR System	6.7 MMBtu/hr

The NDDH technical lead person wanted to know if Unit 2's low dust gas for reheat was correct, as it appears to be much closer to the natural gas consumption for tail end than when comparing Unit 1's LD to TESCR natural gas numbers. We told him we also noticed this difference in proportion but didn't know what numbers may be in need of revision.

We ask that you review the preliminary process design numbers for reheat fuel (and Ultra system fuel) in all four SCR cases by January 7th, so we can respond back to the NDDH on this issue, as it affects the cost effectiveness analysis for these alternatives in the updated BACT studies.

Hope you are getting a change to enjoy time with your families this holiday season.

Merry Christmas.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Monday, September 28, 2009 10:05 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 28Sep_PFD Revisions

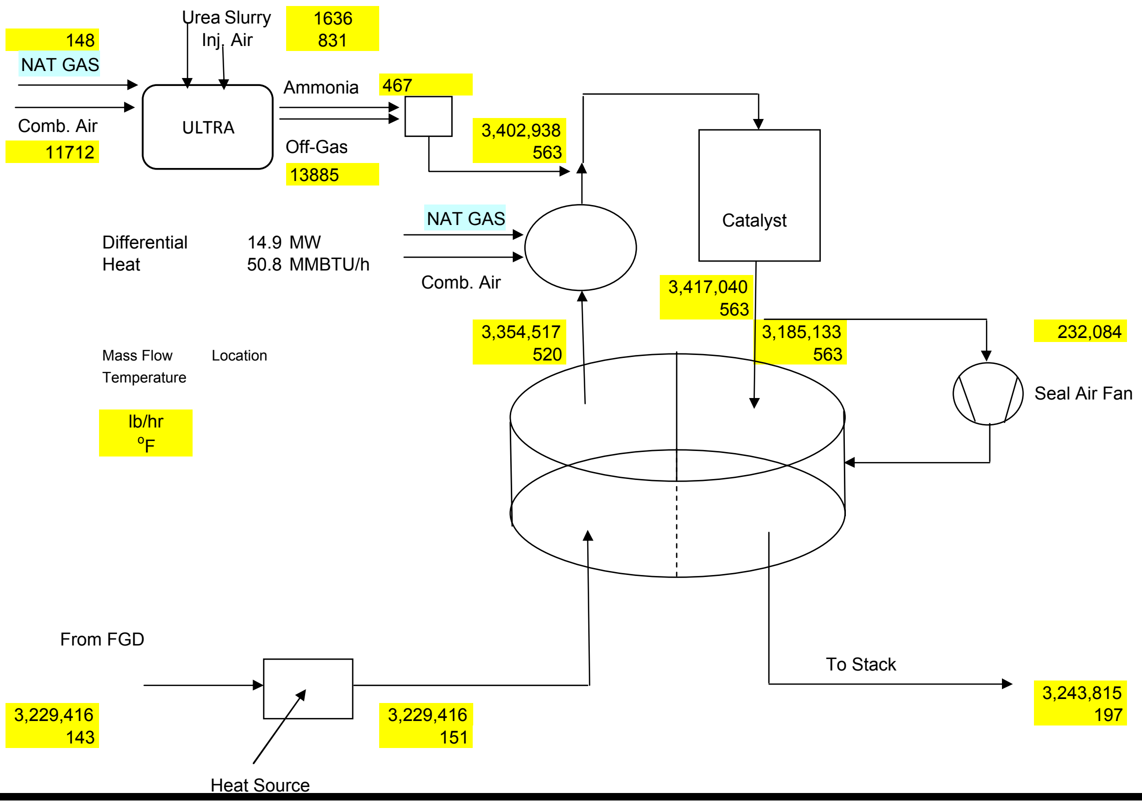
Bob,
Attached are the revised PFDs.
I added a summary line to the mass balance table, and all of the flows match those on the flow diagram.
The balance around the ULTRA system for the U1 systems has been corrected.

Please let us know if we can clarify anything.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

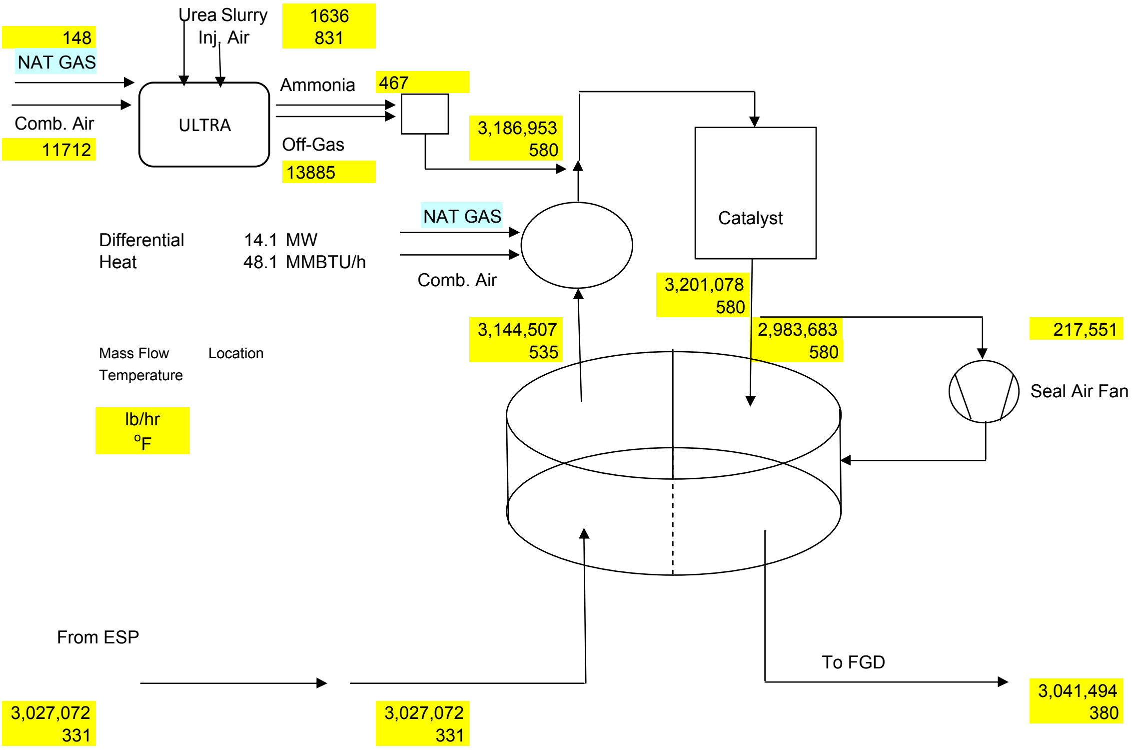
<<28Sep09_MRY2TailEnd_Rev2_natgas.pdf>> <<27Sep09_BMcD for MRYS_Additional Process Data_R2.doc>>
<<28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf>> <<28Sep09_MRY1TailEnd_Rev4_natgas.pdf>>
<<28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf>>

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



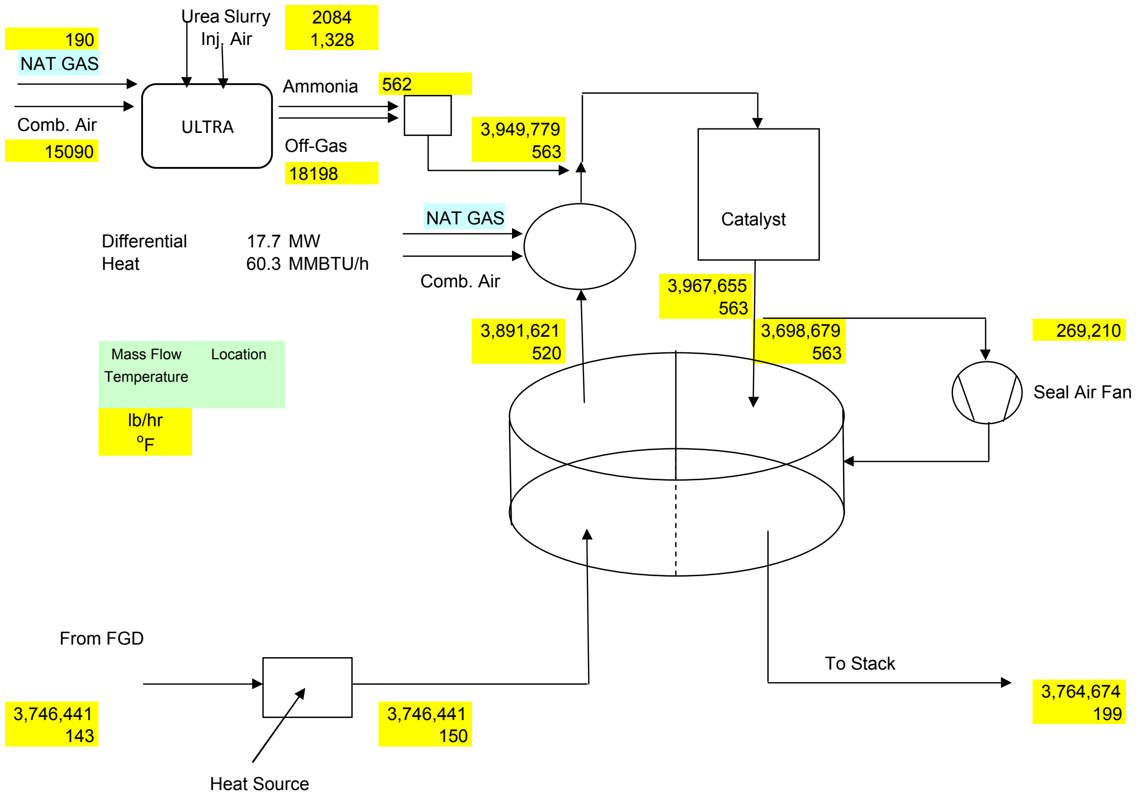
		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,074	2,180,720	2,190,102	2,191,257	2,042,589	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,862	569,261	570,275	570,275	531,584	543,915
Oxygen	lb/h	184,328	184,328	191,496	192,317	194,562	194,123	180,952	185,704
Moisture	lb/h	437,137	437,137	454,101	458,641	459,743	460,485	429,243	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	509	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,229,416	3,229,416	3,354,517	3,402,938	3,417,308	3,417,040	3,185,133	3,243,815

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



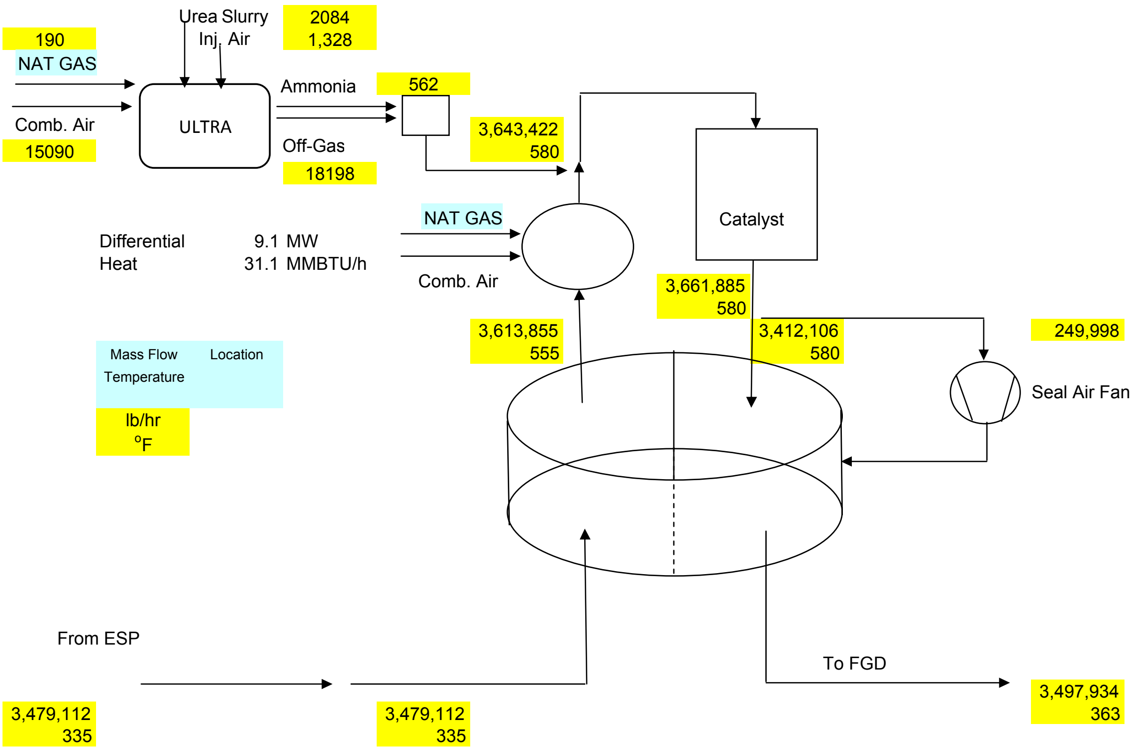
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,694	2,143,695	2,153,077	2,154,231	2,007,981	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,153	561,885	562,899	562,899	524,684	537,433
Oxygen	lb/h	177,258	177,258	184,161	184,881	187,126	186,686	174,012	178,633
Moisture	lb/h	270,167	270,167	280,712	284,691	285,793	286,535	267,082	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,027,072	3,027,072	3,144,507	3,186,953	3,201,323	3,201,078	2,983,683	3,041,494

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,463,945	2,509,161	2,521,083	2,522,472	2,351,512	2,385,237
Carbon di oxide	lb/h	622,053	622,053	646,071	652,555	653,815	653,815	609,503	623,313
Oxygen	lb/h	213,652	213,652	221,970	222,956	225,821	225,293	210,023	215,472
Moisture	lb/h	536,485	536,485	557,301	562,753	564,141	565,034	526,739	539,638
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	211	211	197	201
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70
Total	lb/hr	3,746,441	3,746,441	3,891,621	3,949,779	3,967,977	3,967,655	3,698,679	3,764,674

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,651	2,449,638	2,461,951	2,463,331	2,295,352	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,330	641,626	642,928	642,928	599,086	615,928
Oxygen	lb/hr	205,551	205,551	213,551	214,052	217,009	216,484	201,722	207,463
Moisture	lb/hr	309,692	309,692	321,760	324,532	325,950	326,837	304,550	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,813	11,813	11,813	11,699	10,902	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70
Total	lb/hr	3,479,112	3,479,112	3,613,855	3,643,422	3,662,182	3,661,885	3,412,106	3,497,934

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data (Rev 2)

		Unit 1 Low Dust	**Unit 1 Tail End**	**Unit 2 Low Dust (per reactor)**	**Unit 2 Tail End (per reactor)**
Reheat Natural Gas	MMBtu/hr	31.1	60.3	48.1	50.8
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.27	3.33	3.33
ULTRA System Natural Gas	scfm	70	70	54	54
NOx Reheat Natural Gas	Lb/hr	10	20	14	16
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

Blakley, Robert

From: Blakley, Robert
Sent: Wednesday, January 06, 2010 2:45 PM
To: 'Wayne Jones'
Cc: Weilert, Carl
Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Attachments: HT Jan 06_2010 (signed).pdf

Wayne:

Confirming my voice mail message of January 6, 2010. Please call me when you have a chance.

We are asking for review of our attached letter with written confirmation regarding stating Haldor Topsoe's catalyst life guarantee being contingent upon successful completion of pilot-scale slipstream testing that confirm catalyst deactivation and fouling rates of the studied hypothetical applications of tail end and low-dust SCRs for Units 1 and 2 at Milton R. Young Station for Minnkota Power Cooperative.

Robert D. Blakley, P.E.

Associate Project Engineer
(Currently registered and licensed in North Dakota)
Burns & McDonnell
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

Burns & McDonnell
SINCE 1898

January 6, 2010

Mr. Wayne Jones
Haldor Topsoe, Inc.
17629 El Camino Real
Suite 300
Houston, Texas 77058

Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD Project 31777

Dear Mr. Jones:

Burns & McDonnell has prepared supplemental reports for the NOx BACT analyses for Milton R. Young Station (MRYS) Units 1 and 2, and these reports have been submitted by Minnkota Power Cooperative to the North Dakota Department of Health. In the text of these reports, we stated that:

> During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Please review this statement and respond in writing to confirm that we have correctly stated your company's position on catalyst life guarantees for the application of SCR systems to MRYS Units 1 & 2 without successful completion of pilot testing.

Sincerely,

Robert D. Blakley

Robert D Blakley, P.E.
Project Engineer

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816-333-9400
Fax: 816-333-3690
http://www.burnsmcd.com

Blakley, Robert

From: Blakley, Robert

Sent: Wednesday, January 06, 2010 2:48 PM

To: 'Noel.Rosha@ceram-usa.com'

Cc: Weilert, Carl

Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2

Noel:

Confirming our phone conversation of January 6, 2010.

We are asking for review of our attached letter with written confirmation regarding stating CERAM-USA's catalyst life guarantee being contingent upon successful completion of pilot-scale slipstream testing that confirm catalyst deactivation and fouling rates of the studied hypothetical applications of tail end and low-dust SCRs for Units 1 and 2 at Milton R. Young Station for Minnkota Power Cooperative.

Robert D. Blakley, P.E.

Associate Project Engineer
(Currently registered and licensed in North Dakota)
Burns & McDonnell
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

Burns & McDonnell
SINCE 1898

January 6, 2010

Mr. Noel Rosha
CERAM Environmental, Inc.
7304 W. 130th St.
Suite 140
Overland Park, Kansas 66213

Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD Project 31777

Dear Mr. Rosha:

Burns & McDonnell has prepared supplemental reports for the NOx BACT analyses for Milton R. Young Station (MRYS) Units 1 and 2, and these reports have been submitted by Minnkota Power Cooperative to the North Dakota Department of Health. In the text of these reports, we stated that:

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Kansas City, Missouri 64114-3319
Tel: 816-333-9400
Fax: 816-333-3690
http://www.burnsmcd.com

Blakley, Robert

From: Blakley, Robert
Sent: Monday, January 11, 2010 1:03 PM
To: Volker Rummenhohl
Cc: 51684; Bryant, Ronald; Weilert, Carl; Blackwood, Dave
Subject: FW: 28Sep_PFD Revisions
Attachments: 28Sep09_MRY2TailEnd_Rev2_natgas.pdf; 27Sep09_BMcD for MRYS_Additional Process Data_R2.doc; 28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf; 28Sep09_MRY1TailEnd_Rev4_natgas.pdf; 28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf

Volker -

I am resending this email from 12/22, seeking your assistance in confirming the natural gas consumption rates for all four cases studied (see below and attached).

We are now on a tight timeline for response back to Minnkota for providing the correct numbers and any revised BACT Analysis ($ per ton) so they can respond the the State of North Dakota's Health Department - Air Quality Division.

Please advise you can confirm the process design as regards natural gas rates by 1/15/10.

Thanks,

Robert D. Blakley, P.E.

Associate Project Engineer
(Currently registered and licensed in North Dakota)
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
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Hope you are getting a change to enjoy time with your families this holiday season.

Merry Christmas.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Monday, September 28, 2009 10:05 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 28Sep_PFD Revisions

Bob,
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Robert E. Johnson
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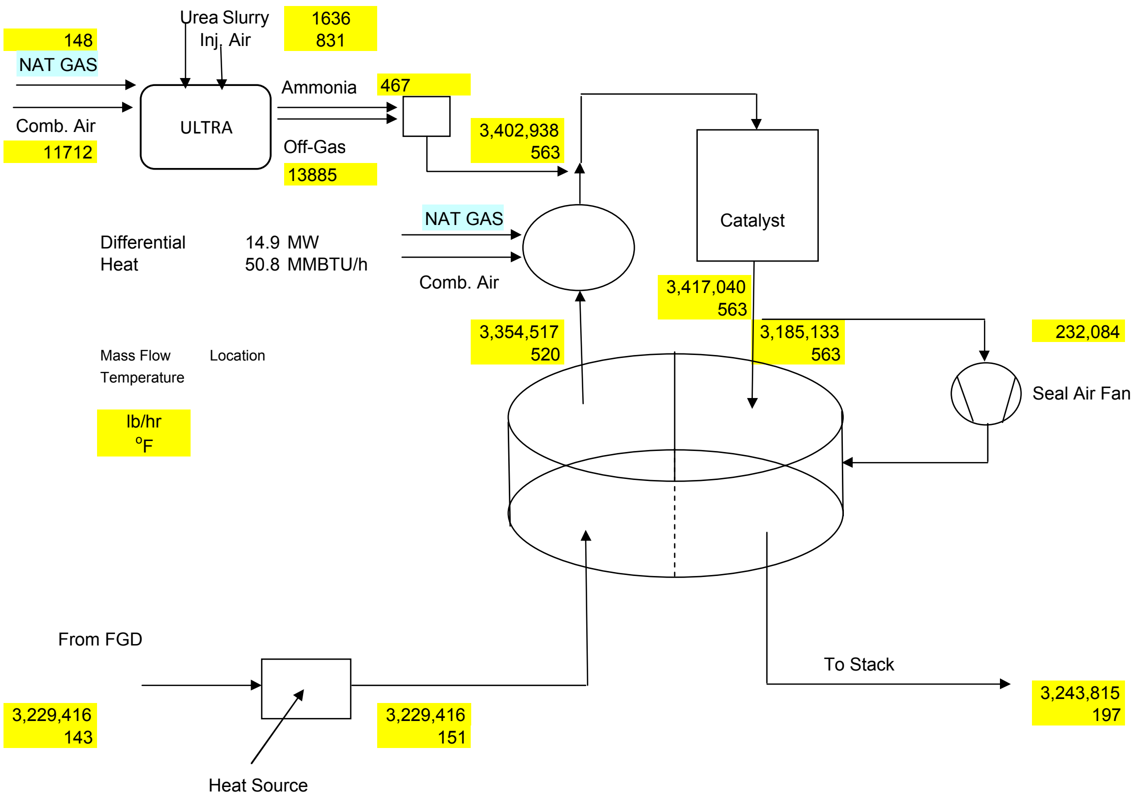

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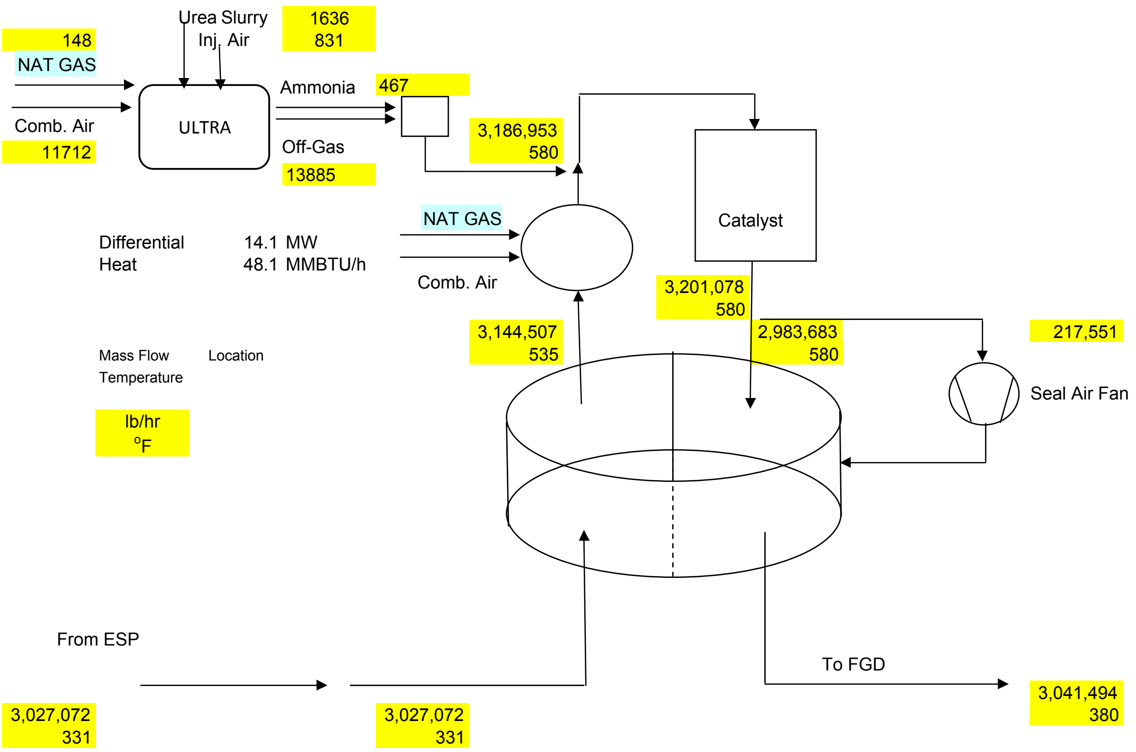

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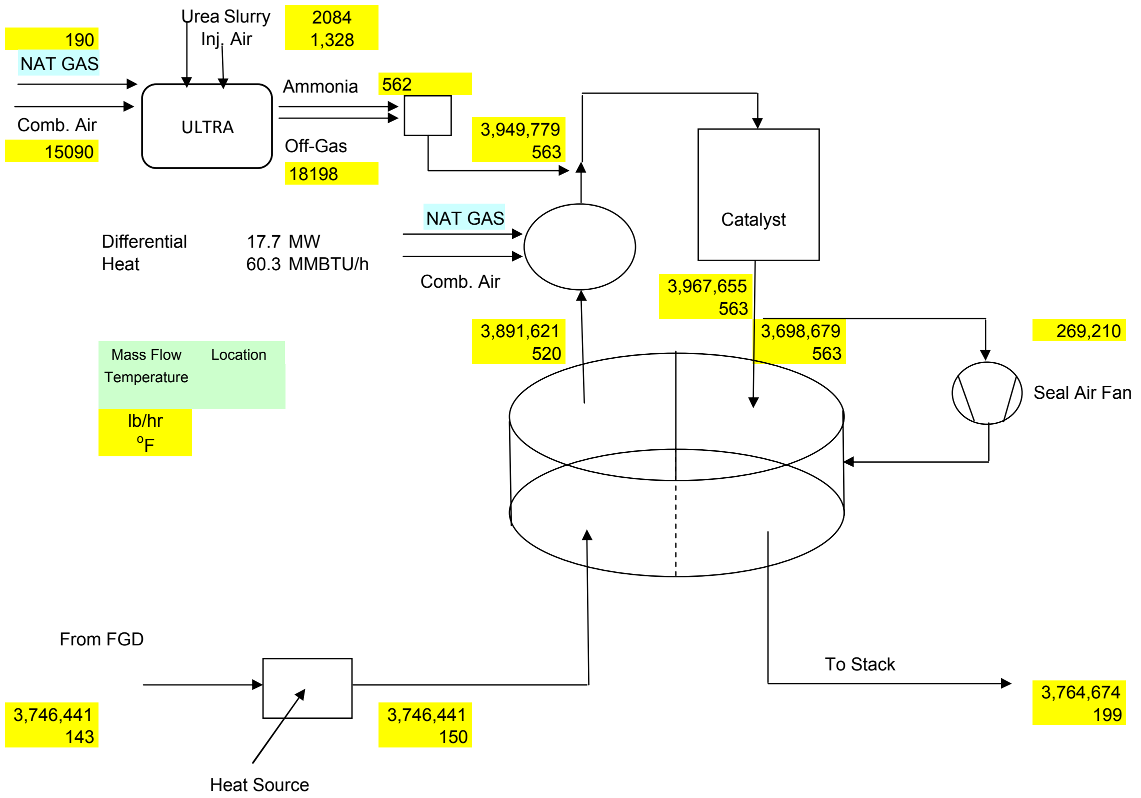
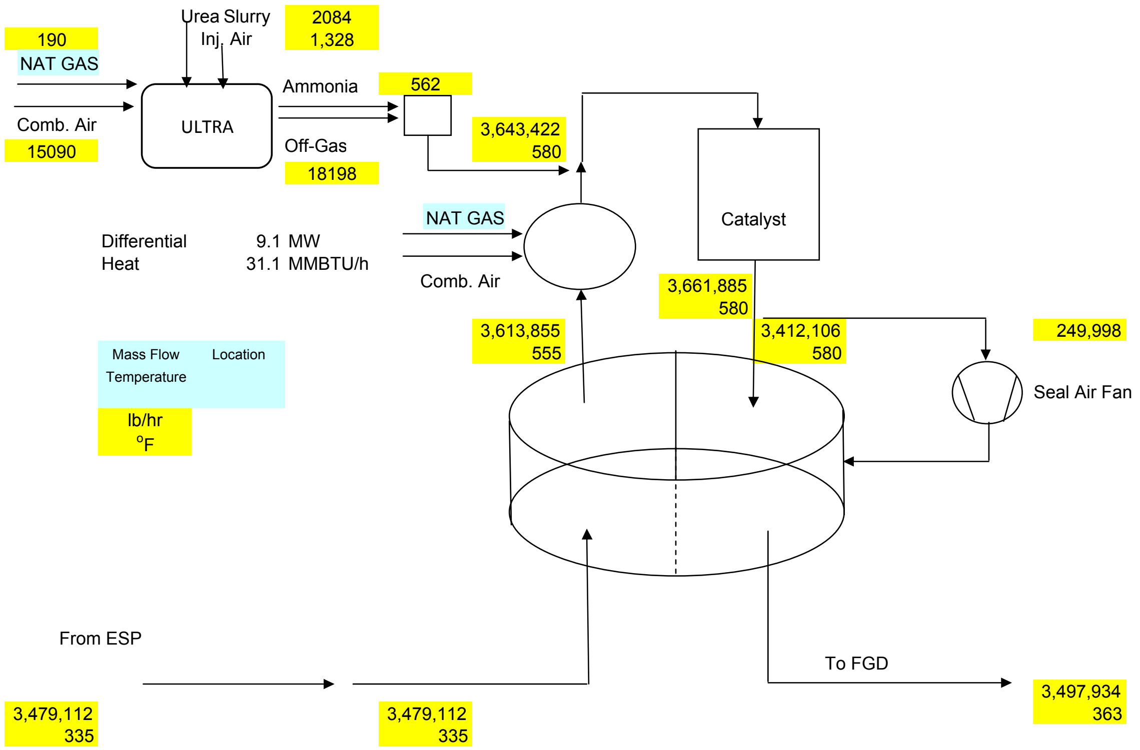
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,027,072	3,027,072	3,144,507	3,186,953	3,201,323	3,201,078	2,983,683	3,041,494

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,463,945	2,509,161	2,521,083	2,522,472	2,351,512	2,385,237
Carbon di oxide	lb/h	622,053	622,053	646,071	652,555	653,815	653,815	609,503	623,313
Oxygen	lb/h	213,652	213,652	221,970	222,956	225,821	225,293	210,023	215,472
Moisture	lb/h	536,485	536,485	557,301	562,753	564,141	565,034	526,739	539,638
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	211	211	197	201
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70
Total	lb/hr	3,746,441	3,746,441	3,891,621	3,949,779	3,967,977	3,967,655	3,698,679	3,764,674

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,651	2,449,638	2,461,951	2,463,331	2,295,352	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,330	641,626	642,928	642,928	599,086	615,928
Oxygen	lb/hr	205,551	205,551	213,551	214,052	217,009	216,484	201,722	207,463
Moisture	lb/hr	309,692	309,692	321,760	324,532	325,950	326,837	304,550	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,813	11,813	11,813	11,699	10,902	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70
Total	lb/hr	3,479,112	3,479,112	3,613,855	3,643,422	3,662,182	3,661,885	3,412,106	3,497,934

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data (Rev 2)

		Unit 1 Low Dust	**Unit 1 Tail End**	**Unit 2 Low Dust (per reactor)**	**Unit 2 Tail End (per reactor)**
Reheat Natural Gas	MMBtu/hr	31.1	60.3	48.1	50.8
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.27	3.33	3.33
ULTRA System Natural Gas	scfm	70	70	54	54
NOx Reheat Natural Gas	Lb/hr	10	20	14	16
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

Blakley, Robert

From: Noel Rosha [Noel.Rosha@ceram-usa.com]
Sent: Wednesday, January 13, 2010 3:02 PM
To: Blakley, Robert
Cc: Weilert, Carl
Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Attachments: CERAM Jan 06_2010 (signed).pdf

Robert,

CERAM confirms that the attached letter accurately reflects our position regarding catalyst life guarantees for the Milton R. Young Station tail end and low-dust SCR applications.

Best regards,

Noel Rosha, P.E.
Senior Applications Engineer

CERAM Environmental, Inc.
Phone: 913-239-9896
Mobile: 913-638-9672

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Wednesday, January 06, 2010 2:48 PM
To: Noel Rosha
Cc: Weilert, Carl
Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2

Noel:
Confirming our phone conversation of January 6, 2010.
We are asking for review of our attached letter with written confirmation regarding stating CERAM-USA's catalyst life guarantee being contingent upon successful completion of pilot-scale slipstream testing that confirm catalyst deactivation and fouling rates of the studied hypothetical applications of tail end and low-dust SCRs for Units 1 and 2 at Milton R. Young Station for Minnkota Power Cooperative.
Robert D. Blakley, P.E.
Associate Project Engineer
(Currently registered and licensed in North Dakota)
Burns & McDonnell
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

Burns & McDonnell
SINCE 1898

January 6, 2010

Mr. Noel Rosha
CERAM Environmental, Inc.
7304 W. 130th St.
Suite 140
Overland Park, Kansas 66213

Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD Project 31777

Dear Mr. Rosha:

Burns & McDonnell has prepared supplemental reports for the NOx BACT analyses for Milton R. Young Station (MRYS) Units 1 and 2, and these reports have been submitted by Minnkota Power Cooperative to the North Dakota Department of Health. In the text of these reports, we stated that:

> During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Please review this statement and respond in writing to confirm that we have correctly stated your company's position on catalyst life guarantees for the application of SCR systems to MRYS Units 1 & 2 without successful completion of pilot testing.

Sincerely,

Robert D. Blakley

Robert D Blakley, P.E.
Project Engineer

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816-333-9400
Fax: 816-333-3690
http://www.burnsmcd.com

Blakley, Robert

From: Wayne Jones [WSJ@topsoe.com]

Sent: Wednesday, January 13, 2010 5:29 PM

To: Blakley, Robert

Cc: Weilert, Carl; TNW@topsoe.com; CAW@topsoe.com

Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2

Attachments: HT Jan 06_2010 (signed).pdf; Microsoft Word - WSJ Letter 1-07-2010 on HTI Letterhead.pdf

Robert,

Please find attached below your requested letter defining HTI's position with respect to providing a catalyst guaranteed life on either Unit 1 or Unit 2 at Minnkota's Milton R. Young station. If you have any questions please let me know.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

"Blakley, Robert" <rblakley@burnsmcd.com>

01/06/2010 02:45 PM

To Wayne Jones <WSJ@topsoe.com>

cc "Weilert, Carl" <cweiler@burnsmcd.com>

Subject RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2

Wayne:

Confirming my voice mail message of January 6, 2010. Please call me when you have a chance.

We are asking for review of our attached letter with written confirmation regarding stating Haldor Topsoe's catalyst life guarantee being contingent upon successful completion of pilot-scale slipstream testing that confirm catalyst deactivation and fouling rates of the studied hypothetical applications of tail end and low-dust SCRs for Units 1 and 2 at Milton R. Young Station for Minnkota Power Cooperative.

Robert D. Blakley, P.E.

Associate Project Engineer
(Currently registered and licensed in North Dakota)
Burns & McDonnell
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

HALDOR TOPSØE

Haldor Topsoe, Inc.
17629 El Camino Real
Suite 300
Houston, Texas 77058
www.topsoe.com

Tel: (281) 228-5000
Fax: (281) 228-5019

January 13, 2010

Mr. Robert D. Blakley, P.E.
Burns & McDonnell
9400 Ward Parkway
Kansas City, Missouri 64114

Minnkota Power Cooperative, Milton R. Young Units 1&2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD project 31777

Mr. Blakley,

This letter is to confirm that it is my understanding, based on the information currently at hand, that Haldor Topsoe, Inc would consider providing a SCR catalyst life guarantee for either Milton R. Young Unit 1 or Unit 2 for either a tail end (TESCR) or low dust (LDSCR) configuration only following the successful completion of a pilot-scale slipstream test of our SCR catalyst on one of the two MRY units. The issuance of a SCR catalyst life guarantee, if any, would be for only the configuration tested during the pilot-scale testing.

If you have any question please feel free to contact me at 281-228-5136

Sincerely,

Wayne S. Jones
Sales Manager, Power Generation
SCR/DeNOx Catalyst & Technology

Burns &
McDonnell
SINCE 1898

January 6, 2010

Mr. Wayne Jones
Haldor Topsoe, Inc.
17629 El Camino Real
Suite 300
Houston, Texas 77058

Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD Project 31777

Dear Mr. Jones:

Burns & McDonnell has prepared supplemental reports for the NOx BACT analyses for Milton R. Young Station (MRYS) Units 1 and 2, and these reports have been submitted by Minnkota Power Cooperative to the North Dakota Department of Health. In the text of these reports, we stated that:

> During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Please review this statement and respond in writing to confirm that we have correctly stated your company's position on catalyst life guarantees for the application of SCR systems to MRYS Units 1 & 2 without successful completion of pilot testing.

Sincerely,

Robert D. Blakley

Robert D Blakley, P.E.
Project Engineer

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816-333-9400
Fax: 816-333-3690
http://www.burnsmcd.com

Blakley, Robert

From: Volker Rummenhohl [VRummenhohl@ftek.com]
Sent: Friday, January 15, 2010 9:14 AM
To: Blakley, Robert
Cc: 51684; Bryant, Ronald; Weilert, Carl; Blackwood, Dave; Robert Johnson; Julie Higgins
Subject: RE: 28Sep_PFD Revisions

Dear Bob,

Both Bob Johnson and I reviewed the calculations and I would like to confirm that we did not find any error. The only adjustment will come once to get the final GGH design, since this is an iterative process. The changes will be minor and the same for all options, the ratio between the options will not change.

Best regards,

Volker

Volker Rummenhohl
Vice President Catalyst Technologies
Fuel Tech, Inc.
2300 Englert Dr Ste C
Durham, NC 27713
Phone 919-484-1500
Cell 919-602-1063

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Monday, January 11, 2010 2:03 PM
To: Volker Rummenhohl
Cc: 51684; Bryant, Ronald; Weilert, Carl; Blackwood, Dave
Subject: FW: 28Sep_PFD Revisions

Volker -

I am resending this email from 12/22, seeking your assistance in confirming the natural gas consumption rates for all four cases studied (see below and attached).

We are now on a tight timeline for response back to Minnkota for providing the correct numbers and any revised BACT Analysis ($ per ton) so they can respond the the State of North Dakota's Health Department - Air Quality Division.

Please advise you can confirm the process design as regards natural gas rates by 1/15/10.

Thanks,

Robert D. Blakley, P.E.

Associate Project Engineer
(Currently registered and licensed in North Dakota)
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

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ey, Robert
Sent: Tuesday, December 22, 2009 9:21 AM
To: 'Robert Johnson'
Cc: 49861; Volker Rummenhohl; Blackwood, Dave; Bryant, Ronald; Weilert, Carl
Subject: FW: 28Sep_PFD Revisions

Bob -

Carl Weilert and I reviewed information involving hypothetical applications of tail end and low dust SCR technologies at Minnkota's Milton R. Young Station with the North Dakota Department of Health's Air Quality Division on Monday, December 21, 2009.

Estimated Natural Gas Consumption for Reheating Flue Gas:

> Unit 1 Low Dust SCR System	31 MMBtu/hr
> Unit 1 Tail End SCR System	60.3 MMBtu/hr
> Unit 2 Low Dust SCR System	96.2 MMBtu/hr
> Unit 2 Tail End SCR System	101.6 MMBtu/hr

Estimated Natural Gas Consumption for Urea to Ammonia Conversion:

> Unit 1 SCR System	4.3 MMBtu/hr
> Unit 2 SCR System	6.7 MMBtu/hr

The NDDH technical lead person wanted to know if Unit 2's low dust gas for reheat was correct, as it appears to be much closer to the natural gas consumption for tail end than when comparing Unit 1's LD to TESCR natural gas numbers. We told him we also noticed this difference in proportion but didn't know what numbers may be in need of revision.

We ask that you review the preliminary process design numbers for reheat fuel (and Ultra system fuel) in all four SCR cases by January 7th, so we can respond back to the NDDH on this issue, as it affects the cost effectiveness analysis for these alternatives in the updated BACT studies.

Hope you are getting a change to enjoy time with your families this holiday season.

Merry Christmas.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Monday, September 28, 2009 10:05 AM
To: Blakley, Robert

Cc: Volker Rummenhohl
Subject: 28Sep_PFD Revisions

Bob,
Attached are the revised PFDs.
I added a summary line to the mass balance table, and all of the flows match those on the flow diagram.
The balance around the ULTRA system for the U1 systems has been corrected.
Please let us know if we can clarify anything.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

<<28Sep09_MRY2TailEnd_Rev2_natgas.pdf>> <<27Sep09_BMcD for MRYS_Additional Process Data_R2.doc>> <<28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf>> <<28Sep09_MRY1TailEnd_Rev4_natgas.pdf>> <<28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf>>

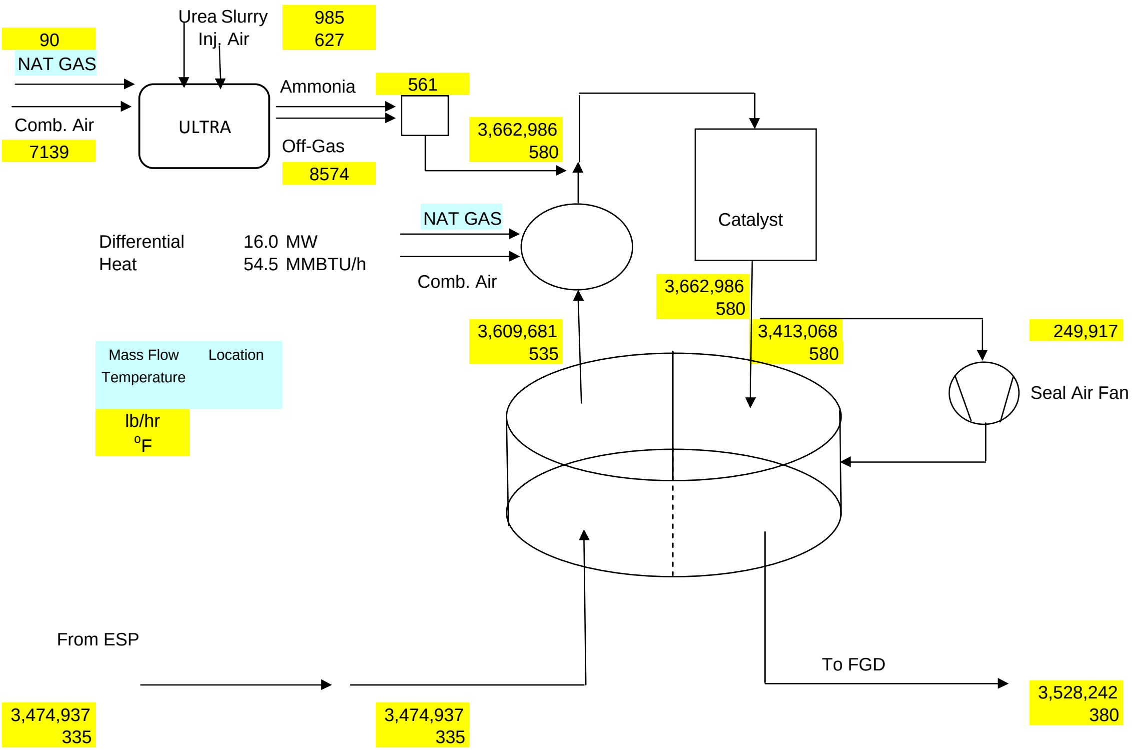
Blakley, Robert

From: Volker Rummenhohl [VRummenhohl@ftek.com]
Sent: Friday, January 22, 2010 1:46 PM
To: Blakley, Robert; Weilert, Carl
Subject: MYRS
Attachments: Jan22 2010_MRY1LowDust_Rev1_natgas_580F.pdf

Please, find attached the corrected Unit 1 Low Dust PFD.

Volker

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,758	2,461,151	2,466,959	2,468,343	2,300,110	2,343,304
Carbon di oxide	lb/hr	614,626	614,626	638,408	643,340	643,954	643,954	600,065	615,240
Oxygen	lb/hr	205,551	205,551	213,511	214,262	215,657	215,130	200,467	205,901
Moisture	lb/hr	309,692	309,692	321,780	325,927	326,596	327,487	305,166	312,126
Sulfur di oxide	lb/hr	11,381	11,381	11,815	11,815	11,815	11,701	10,904	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,675	1,675	159	148	167
Argon	lb/hr	0	0	5	5	103	103	96	98
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70

11/20/09

AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT
FOR
BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Pursuant to the Air Pollution Control Rules of the State of North Dakota (North Dakota Administrative Code Article 33-15, Chapter 33-15-14 and Chapter 33-15-25), the North Dakota Department of Health hereby grants a Permit to Construct for the following BART source:

I. **General Information**:

A. **Permit to Construct Number**: TBD

B. **Source**:

1. **Name**: Leland Olds Station

2. **Location**: Stanton, North Dakota, Mercer County

3. **Source Type**: Fossil-fuel fired steam electric plant with a nominal generating capacity of 656 megawatts.

4. **Equipment at the Facility Subject to BART**:

Unit 1 - Coal-fired boiler (nominal 2622 x 10^6 Btu/hour heat input)

Unit 2 - Coal-fired boiler (nominal 5130 x 10^6 Btu/hour heat input)

C. **Owner/Operator**:

1. **Name**: Basin Electric Power Coop.

2. **Address**:
1717 E Interstate Avenue
Bismarck, ND 58501-0564

II. **Permit Conditions**:

The Permit to Construct only establishes the BART emission limits if, and when, EPA approves those limits as part of the Regional Haze SIP. This permit allows the construction and initial operation of new or modified air pollution control equipment and process modifications at the source to comply with the BART limits. If new emission units are created, a new Permit to Construct may be required in accordance with NDAC 33-15-14-02. The source shall be operated in accordance with the terms of this Permit to Construct and the Title V Permit to Operate until a revised Title V Permit to Operate is issued. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Health and to the conditions specified below:

A. **Special Conditions**:

1. **Emission Limits**: The term "30-day rolling average," as used in this permit, shall be determined by calculating an arithmetic average of all hourly rates for the current boiler operating day and the previous 29 boiler operating days. A new 30-day rolling average shall be calculated for each boiler operating day. Each 30-day rolling average rate shall include start-up, shutdown, emergency and malfunction periods unless those periods are exempt by this permit. The 30-day rolling average emission rate is calculated as follows:

- Calculate the hourly average emission rate for any hour in which any fuel is combusted in the boiler.

- Calculate the daily average emission rate from the hourly average emission rates for that boiler operating day.

- Calculate the 30-day rolling average emission rate from the daily average emission rate for the current boiler operating day and the daily average emission rate for the previous 29 boiler operating days.

The term "boiler operating day," as used in this permit, means any twenty-four-hour period between midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

a. Basin Electric shall not discharge or cause the discharge of sulfur dioxide (SO_2) into the atmosphere from Unit 1 and Unit 2 in excess of either:

(1) 0.15 pounds per million British thermal units ($lb/10^6$ Btu) of heat input on a 30-day rolling average basis;

or as an alternative

(2) 5.0% of the SO_2 reaching the inlet of the scrubber (95.0% reduction) on a 30-day rolling average basis.

For determining compliance with the above emission limits, Basin Electric may average emissions from Unit 1 and Unit 2 provided the average does not exceed 0.15 $lb/10^6$ Btu; or 5.0 percent (95.0% reduction) of the SO_2 reaching the inlet of the scrubbing system(s), as appropriate.

b. Basin Electric shall not discharge or cause the discharge of nitrogen oxides (NO_x) into the atmosphere from Unit 1 in excess of 0.19 pounds per million British thermal units ($lb/10^6$ Btu) of heat input, on a 30-day rolling average basis.

Basin Electric shall not discharge or cause the discharge of nitrogen oxides (NO_x) into the atmosphere from Unit 2 in excess of 0.35 pounds per million British thermal units ($lb/10^6$ Btu) of heat input, on a 30-day rolling average basis.

For determining compliance with the above emission limits, Basin Electric may average emissions from Unit 1 and Unit 2 provided the actual average emission rate does not exceed the average allowable emission rate calculated in accordance with Condition II.A(4)(b)(8).

c. Basin Electric shall not discharge or cause the discharge of filterable (non-condensible) particulate matter (PM) into the atmosphere in excess of the following:

Unit 1 - 0.07 lb/10^6 Btu
Unit 2 - 0.07 lb/10^6 Btu

Compliance with the limits is determined in accordance with the procedures in Condition II.A.4.b.5.

d. The emission limits apply at all times including startup, shutdown, emergency and malfunction.

2. **Compliance Date**: Compliance with the emission limits and other requirements of this permit is required as expeditiously as practicable but in no event later than five years after the U.S. Environmental Protection Agency approves this permit as a part of the Regional Haze SIP. Compliance shall be demonstrated within 180 days of initial startup of the equipment required to meet the BART limits, but no later than 5 years after the U.S. Environmental Protection Agency approves this permit as a part of the BART SIP.

3. **Continuous Emission Monitoring (CEM)**: The emissions from Unit 1 (main stack) and Unit 2 (main stack) shall each be measured by continuous emission monitors (CEM) for SO_2, NO_x, CO_2, and flow. The monitoring requirements under Condition II.A.4 shall be the compliance determination method for SO_2 and NO_x.

4. **Monitoring Requirements and Conditions**:

a. Requirements:

Basin Electric is only required to monitor compliance with one SO_2 limit (i.e., either the lb/10^6 Btu limit or the 95% reduction limit). If Basin Electric monitors for both limits, and compliance is indicated for one limit but not the other, no excess emissions or monitoring deviations shall be reported with respect to the other limit.

Testing and monitoring protocols used to demonstrate compliance with the emission limits of Condition II.A.1 above shall be as follows:

Pollutant/ Parameter	**Monitoring Requirement (Method)**	**Condition Number**
Particulate	Compliance Assurance Monitoring (CAM)/	4.b.(6)/4.b.(5)

Pollutant/ Parameter	**Monitoring Requirement (Method)**	**Condition Number**
	Emissions Test	
SO_2 (inlet)	CEM; or Coal Sampling Data & Emission Factor[a]	4.b.(1), 4.b.(2), 4.b.(3), 4.b.(7), & 4.b.(8)
SO_2 (outlet)	CEM	
NO_x	CEM	4.b.(1), 4.b.(2), 4.b.(3), & 4.b.(8)
CO_2	CEM	4.b.(1), 4.b.(2), & 4.b.(3)
Flow	Flow Monitor	4.b.(1), 4.b.(2), & 4.b.(3)

[a] Emission factor refers to the value (e.g. percentage of inlet sulfur leaving the boiler), that is determined by stack testing, which is used to calculate the scrubber SO_2 inlet rate.

b. Emission Monitoring Conditions:

(1) The monitoring shall be in accordance with the following applicable requirements of Chapter 33-15-06 of the North Dakota Air Pollution Control Rules and the Acid Rain Program. Emissions are calculated using 40 CFR Part 75.

(a) Section 33-15-06-04 of the North Dakota Air Pollution Control Rules, Monitoring Requirements.

(b) 40 CFR 72 and 40 CFR 75.

(2) The Department may require additional performance audits of the CEM systems.

(3) When a failure of a continuous emission monitoring system occurs, an alternative method, acceptable to the Department, for measuring or estimating emissions must be undertaken as soon as possible. The procedures outlined in 40 CFR 75, Subpart D for substitution are considered an acceptable method for the emission rate limit. The procedures of Method 19, Paragraph 12.7, are considered an acceptable method for the percent reduction requirement. Timely repair of the emission monitoring system must be made.

(4) Basin Electric shall maintain and operate air pollution control monitoring equipment in a manner consistent the manufacturer’s recommended Operations and Maintenance (O&M) procedures, or a site-specific O&M procedure (developed from the manufacturer’s recommended O&M procedures). Basin Electric shall have the O&M procedures available on-site and provide the Department with a copy when requested.

(5) Within 180 days of initial startup of the equipment required to meet the BART limits, but not later than 5 years after approval of the Regional Haze SIP by the U.S. Environmental Protection Agency, Basin Electric shall conduct an emissions test to measure particulate emissions, using EPA Test Method 5B or Method 17 in 40 CFR Part 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Other EPA approved test methods may be used provided they are approved, in advance, by the Department.

(6) Monitoring for particulate matter shall be conducted in accordance with the Compliance Assurance Monitoring (CAM) Plan developed in accordance with NDAC 33-15-14-06.10. The CAM plan revision to address the BART PM limit shall be submitted with the Title V permit revision application for the BART limits.

(7) In lieu of using a continuous emission monitor to determine the SO_2 reaching the scrubber inlet(s) in accordance with Condition II.A.1.a., Basin Electric may use coal sampling and an emission factor established by stack testing. The requirements in 40 CFR 60, Appendix A, Method 19 shall be used to determine coal sampling and analysis requirements.

For purposes of determining compliance with the SO_2 percent reduction requirement, the reduction efficiency shall be determined as follows:

$$\%\ \text{Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where: The Inlet SO_2 Rate is in units of $lb/10^6$ Btu, lb/hr, or ppmvd @ 3% O_2 and the Outlet SO_2 Rate is in the same units as the Inlet SO_2 Rate.

(8) When averaging the emissions of Unit 1 and Unit 2, compliance shall be determined in accordance with the following:

$$\text{Average AER} = \frac{[(AER_1)(HI_1)+(AER_2)(HI_2)]}{(HI_1 + HI_2)}$$

$$\text{Average ER} = \frac{[(ER_1)(HI_1)+(ER_2)(HI_2)]}{(HI_1 + HI_2)}$$

AER = Allowable Emission Rate (lb/MMBtu or % Reduction)
Average ER = Average Actual Emission Rate
ER_1 = Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 1

ER_2 = Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 2
HI_1 = Actual Heat Input (MMBtu) of Unit 1
HI_2 = Actual Heat Input (MMBtu) of Unit 2

Notes:
- ER and HI are 30-day rolling averages.
- 30-day rolling average for the 30 successive boiler operating days as defined in Condition II.A.1.
- % Reduction can be on either a lb/10^6 Btu, ppmvd @ 3% O_2, or pounds of SO_2 basis.

5. **Recordkeeping Requirements**:

a. Basin Electric shall maintain compliance monitoring records for Unit 1 and Unit 2 as outlined in Table 1 Monitoring Records, that includes the following information:

(1) The date, place (as defined in the permit) and time of sampling or measurement.

(2) The date(s) testing was performed.

(3) The company, entity, or person that performed the testing.

(4) The testing techniques or methods used.

(5) The results of such testing.

(6) The unit load that existed at the time of sampling or measurement.

(7) The records of quality assurance for emissions measuring systems including but not limited to quality control activities, audits and calibration drifts as required by the applicable test method.

(8) A copy of all field data sheets from the emissions testing.

(9) A record shall be kept of all major maintenance activities conducted on the emission units or air pollution control equipment.

(10) Records shall be kept as to the type of fuel usage.

Table 1 Monitoring Records

Pollutant/Parameter	Compliance Monitoring Record
Particulate	CAM Data & Emissions Test Data

Pollutant/Parameter	Compliance Monitoring Record
SO_2 outlet (lb/10^6 Btu)	CEM Data
SO_2 inlet (% Reduction)	CEM Data; or Coal Sampling Data & Emission Factor for Inlet SO_2 Rate
SO_2 outlet (% reduction)	CEM Data
NO_x	CEM Data
CO_2	CEM Data
Flow	Flow Monitor Data

b. In addition to requirements outlined in Condition II.5.a., recordkeeping for Unit 1 and Unit 2 shall be in accordance with the following applicable requirements of Chapter 33-15-06 and Chapter 33-15-14 of the North Dakota Air Pollution Control Rules and the Acid Rain Program:

(1) Section 33-15-06-05 of the North Dakota Air Pollution Control Rules, Reporting and Recordkeeping Requirements.

(2) 40 CFR 72 and 40 CFR 75.

(3) 40 CFR Part 64, Section 64.9 - Reporting and Recordkeeping Requirements, Paragraph (b) General Recordkeeping Requirements.

c. Basin Electric shall retain records of all required compliance monitoring data and support information for a period of at least five years from the date of the compliance monitoring sampling, measurement, report, or application. Support information includes all maintenance records of the emission units and all original strip-chart recordings/computer printouts and calibrations of the continuous compliance monitoring instrumentation, and copies of all reports required by the permit.

6. **Reporting**:

a. For Unit 1 and Unit 2, reporting shall be in accordance with the following applicable requirements of Chapter 33-15-06 and Chapter 33-15-14 of the North Dakota Air Pollution Control Rules and the Acid Rain Program.

(1) Section 33-15-06-05 of the North Dakota Air Pollution Control Rules, Reporting and Recordkeeping Requirements.

(2) 40 CFR 72 and 40 CFR 75.

(3) 40 CFR Part 64, Section 64.9 - Reporting and Recordkeeping Requirements, Paragraph (a) General Reporting Requirements.

(4) Quarterly excess emissions reports for Unit 1 and Unit 2 shall be submitted no later than the 30th day following the end of each calendar quarter. Excess emissions are defined as emissions which exceed the emission limits for Unit 1 and Unit 2 as outlined in Condition II.A.1. Data regarding only one of the two SO_2 limits must be included in the excess emissions report. Excess emissions shall be reported for the following:

Parameter	Reporting Period
SO_2 lb/10^6 Btu or percent reduction	(30-day rolling average)
NO_x lb/10^6 Btu	(30-day rolling average)

b. Basin Electric shall submit a semi-annual report for all monitoring records required under Condition II.A.5 on forms supplied or approved by the Department. All instances of deviations from the permit must be identified in the report. A monitoring report shall be submitted within 45 days after June 30 and December 31 of each year.

c. Basin Electric shall submit an annual compliance certification report within 45 days after December 31 of each year on forms supplied or approved by the Department.

d. For emission units where the method of compliance monitoring is demonstrated by either an EPA Test Method or portable analyzer, the test report shall be submitted to the Department within 60 days after completion of the test.

e. Basin Electric shall submit an annual emission inventory report on forms supplied or approved by the Department. This report shall be submitted by March 15 of each calendar year. Insignificant units/activities listed in this permit do not need to be included in the annual emission inventory report.

f. Basin Electric shall submit to the Department written semi-annual reports detailing progress toward completion of the requirements of this permit. The semi-annual reports shall be due no later than 45 days after June 30 and December 31 of each year. The first report shall be due following the end of the first complete semi-annual period after the permit is issued.

g. Basin Electric shall notify the Department of the actual startup date of the equipment required to meet the BART limits.

B. **General Conditions**:

1. This permit shall in no way permit or authorize the maintenance of a public nuisance or danger to public health or safety.

2. Basin Electric shall comply with all State and Federal environmental laws and rules. In addition, Basin Electric shall comply with all local building, fire, zoning, and other applicable ordinances, codes, rules and regulations.

3. All reasonable precautions shall be taken by Basin Electric to prevent and/or minimize fugitive emissions during the construction period.

4. Basin Electric shall at all times, including periods of startup, shutdown, and malfunction, maintain and operate Unit 1 and Unit 2 and all other emission units including associated air pollution equipment and fugitive dust suppression operations in a manner consistent with good air pollution control practices for minimizing emissions.

5. Any duly authorized officer, employee or agent of the North Dakota Department of Health may enter and inspect any property, premise or place at which the source listed in Item I.B. of this permit is or will be located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules and the conditions of this permit.

6. Any violation of a condition issued as part of this approval to construct is regarded as a violation of construction authority and is subject to enforcement action.

7. The conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23-25. Each and every condition of this permit is a material part thereof, and is not severable.

FOR THE NORTH DAKOTA
DEPARTMENT OF HEALTH

Date:________________________

By:_____________________________
Terry L. O’Clair, P.E.
Director
Division of Air Quality

11/4/09

AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT
FOR
BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Pursuant to the Air Pollution Control Rules of the State of North Dakota (North Dakota Administrative Code Article 33-15, Chapter 33-15-14 and Chapter 33-15-25), the North Dakota Department of Health hereby grants a Permit to Construct for the following BART source:

I. General Information:

A. **Permit to Construct Number**: TBD

B. **Source**:

1. **Name**: Coal Creek Station

2. **Location**: Sections 8, 9, 16, 17, T145N, R82W, McLean County, North Dakota

3. **Source Type**: Fossil-fuel fired steam electric plant with a nominal generating capacity of 1,100 megawatts.

4. **Equipment at the Facility Subject to BART**:

Unit 1 -Lignite-fired boiler (nominal 6015 x 10^6 Btu/hour heat input)

Unit 2 -Lignite-fired boiler (nominal 6022 x 10^6 Btu/hour heat input)

C. **Owner/Operator**:

1. **Name**: Great River Energy

2. **Address**:
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718

II. Permit Conditions:

The Permit to Construct only establishes the BART emission limits if, and when, EPA approves those limits as a part of the Regional Haze SIP. This permit allows the construction and initial operation of new or modified air pollution control equipment and process modifications at the source to comply with the BART limits. If new emission units are created, then a new Permit to Construct may be required in accordance with NDAC 33-15-14-02. The source shall be operated in accordance with the terms of this Permit to Construct and the Title V Permit to Operate until a revised Title V Permit to Operate is issued. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Health and to the conditions specified below:

A. **Special Conditions**:

1. **Emission Limits**: The term “30-day rolling average”, as used in this permit, shall be determined by calculating an arithmetic average of all hourly rates for the current boiler operating day and the previous 29 boiler operating days. A new 30-day rolling average shall be calculated for each boiler operating day. Each 30-day rolling average rate shall include start-up, shutdown, emergency and malfunction periods unless those periods are exempt by this permit. The 30-day rolling average emission rate is calculated as follows:

   - Calculate the hourly average emission rate for any hour in which any fuel is combusted in the boiler.

   - Calculate the daily average emission rate from the hourly average emission rates for that boiler operating day.

   - Calculate the 30-day rolling average emission rate from the daily average emission rate for the current boiler operating day and the daily average emission rate for the previous 29 boiler operating days.

   The term “boiler operating day”, as used in this permit, means any twenty-four-hour period between midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

   a. Great River Energy shall not discharge or cause the discharge of sulfur dioxide (SO_2) into the atmosphere from Unit 1 and Unit 2 in excess of either:

      (1) 0.15 pounds per million British thermal units ($lb/10^6$ Btu) of heat input on a 30-day rolling average basis;

      or as an alternative

      (2) 5.0 percent of the SO_2 reaching the scrubber inlet on a 30-day rolling average basis (95.0% reduction).

      Great River Energy may average emissions from Unit 1 and Unit 2 provided the average does not exceed either 0.15 $lb/10^6$ Btu; or 5.0 percent of the SO_2 reaching the inlet of both scrubbers.

   b. Great River Energy shall not discharge or cause the discharge of nitrogen oxides (NO_x) into the atmosphere from Unit 1 and Unit 2 in excess of 0.17 pounds per million British thermal units ($lb/10^6$ Btu) of heat input per unit, on a 30-day rolling average basis.

      Great River Energy may average emissions from Unit 1 and Unit 2 provided the actual average emission rate does not exceed 0.17 pounds per million British Thermal Units ($lb/10^6$ Btu) of heat input on a 30-day rolling average basis.

c. Great River Energy shall not discharge or cause the discharge of filterable (non-condensible) particulate matter (PM) into the atmosphere in excess of the following:

Unit 1 - 0.07 lb/10^6 Btu
Unit 2 - 0.07 lb/10^6 Btu

Compliance with the limit is determined in accordance with the procedures in II.A.4.b.5.

d. The emission limits apply at all times including startup, shutdown, emergency and malfunction.

2. **Compliance Date**: Compliance with the emission limits and other requirements of this permit is required as expeditiously as practicable but in no event later than five years after the U.S. Environmental Protection Agency approves this permit as a part of the Regional Haze SIP. Compliance shall be demonstrated within 180 days of initial startup of the equipment required to meet the BART limits, but no later than five years after the U.S. EPA approves this permit as a part of the Regional Haze SIP.

3. **Continuous Emission Monitoring (CEM)**: The emissions from Unit 1 (main stack) and Unit 2 (main stack) shall each be measured by continuous emission monitors (CEM) for SO_2, NO_x, CO_2, and flow. The monitoring requirements under Condition II.A.4 shall be the compliance determination method for SO_2 and NO_x.

4. **Monitoring Requirements and Conditions**:

a. Requirements:

Great River Energy is only required to monitor compliance with one SO_2 limit (i.e., either the lb/10^6 Btu limit or the 94% reduction limit). If Great River Energy monitors for both limits, and compliance is indicated for one limit but not the other, no excess emissions or monitoring deviations shall be reported with respect to the other limit.

Testing and monitoring protocols used to demonstrate compliance with the emission limits of Condition II.A.1 above shall be as follows:

Pollutant/ Parameter	**Monitoring Requirement (Method)**	**Condition Number**
Particulate	Compliance Assurance Monitoring (CAM)/ Emissions Test	4.b.(6)/4.b.(5)
SO_2 (inlet)	CEM; or Coal Sampling Data & Emission Factor[a]	4.b.(1), 4.b.(2), 4.b.(3), 4.b.(7), & 4.b.(8)

Pollutant/ Parameter	**Monitoring Requirement (Method)**	**Condition Number**
SO_2 (outlet)	CEM	
NO_x	CEM	4.b.(1), 4.b.(2), 4.b.(3), & 4.b.(8)
CO_2	CEM	4.b.(1), 4.b.(2), & 4.b.(3)
Flow	Flow Monitor	4.b.(1), 4.b.(2), & 4.b.(3)

[a] Emission factor refers to the value (e.g. percentage of inlet sulfur leaving the boiler), that is determined by stack testing, which is used to calculate the scrubber SO_2 inlet rate.

b. Emission Monitoring Conditions:

(1) The monitoring shall be in accordance with the following applicable requirements of Chapter 33-15-06 of the North Dakota Air Pollution Control Rules and the Acid Rain Program. Emissions are calculated using 40 CFR 75.

(a) Section 33-15-06-04 of the North Dakota Air Pollution Control Rules, Monitoring Requirements.

(b) 40 CFR 72 and 40 CFR 75.

(2) The Department may require additional performance audits of the CEM systems.

(3) When a failure of a continuous emission monitoring system occurs, an alternative method, acceptable to the Department, for measuring or estimating emissions must be undertaken as soon as possible. The procedures outlined in 40 CFR 75, Subpart D for substitution are considered an acceptable method for the emission rate limit. The procedures of Method 19, Paragraph 12.7, are considered an acceptable method for the percent reduction requirement. Timely repair of the emission monitoring system must be made.

(4) Great River Energy shall maintain and operate air pollution control monitoring equipment in a manner consistent with the manufacturer's recommended Operations and Maintenance (O&M) procedures, or a site-specific O&M procedure (developed from the manufacturer's recommended O&M procedures). Great River Energy shall have the O&M procedures available on-site and provide the Department with a copy when requested.

(5) Within 180 days of initial startup of the equipment required to meet the BART limits, but not later than 5 years after approval of the Regional Haze SIP by the

U.S. Environmental Protection Agency, Great River Energy shall conduct an emissions test to measure particulate emissions, using EPA Test Method 5B or Method 17 in 40 CFR 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Other EPA approved test methods may be used provided they are approved, in advance, by the Department.

(6) Monitoring for particulate matter shall be conducted in accordance with the Compliance Assurance Monitoring (CAM) Plan developed in accordance with NDAC 33-15-14-06.10. The CAM plan revision to address the BART PM limit shall be submitted with the Title V revision application for the BART limits.

(7) In lieu of using a continuous emission monitor to determine the SO_2 reaching the wet scrubber inlets in accordance with Condition II.A.1.a., Great River Energy may use coal sampling and an emission factor established by stack testing. The requirements in 40 CFR 60, Appendix A, Method 19 shall be used to determine coal sampling and analysis requirements.

For purposes of determining compliance with the SO_2 percent reduction requirement, the reduction efficiency shall be determined as follows:

$$\text{\% Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where: The Inlet SO_2 Rate is in units of lb/10^6 Btu, lb/hr, or ppmvd @ 3% O_2 and the Outlet SO_2 Rate is in the same units as the Inlet SO_2 Rate.

(8) When averaging the emissions of Unit 1 and Unit 2, compliance shall be determined in accordance with the following:

$$\text{Average ER} = \frac{[(ER_1)(HI_1) + (ER_2)(HI_2)]}{(HI_1 + HI_2)}$$

Where:

Average ER = Average Emission Rate
ER_1 = Actual Emission Rate (lb/10^6 Btu or % Reduction) of Unit 1
ER_2 = Actual Emission Rate (lb/10^6 Btu or % Reduction) of Unit 2
HI_1 = Actual Heat Input (10^6 Btu) of Unit 1
HI_2 = Actual Heat Input (10^6 Btu) of Unit 2

Notes:
- ER and HI are 30-day rolling averages.
- 30-day rolling average for the 30 successive boiler operating days as defined in Condition II.A.1.

- % Reduction can be on either a lb/10^6 Btu, ppmvd @ 3% O_2, or pounds of SO_2 basis.

5. **Recordkeeping Requirements**:

a. Great River Energy shall maintain compliance monitoring records for Unit 1 and Unit 2 as outlined in Table 1 Monitoring Records, that includes the following information:

(1) The date, place (as defined in the permit) and time of sampling or measurement.

(2) The date(s) testing was performed.

(3) The company, entity, or person that performed the testing.

(4) The testing techniques or methods used.

(5) The results of such testing.

(6) The unit load that existed at the time of sampling or measurement.

(7) The records of quality assurance for emissions measuring systems including but not limited to quality control activities, audits and calibration drifts as required by the applicable test method.

(8) A copy of all field data sheets from the emissions testing.

(9) A record shall be kept of all major maintenance activities conducted on the emission units or air pollution control equipment.

(10) Records shall be kept as to the type of fuel usage.

Table 1 Monitoring Records

Pollutant/Parameter	**Compliance Monitoring Record**
Particulate	CAM Data & Emissions Test Data
SO_2 outlet (lb/10^6 Btu)	CEM Data
SO_2 inlet (% Reduction)	CEM Data; or Coal Sampling Data & Emission Factor for Inlet SO_2 Rate
SO_2 outlet (% Reduction)	CEM Data
NO_x	CEM Data
CO_2	CEM Data

Pollutant/Parameter	**Compliance Monitoring Record**
Flow	Flow Monitor Data

b. In addition to requirements outlined in Condition II.5.a., recordkeeping for Unit 1 and Unit 2 shall be in accordance with the following applicable requirements of Chapter 33-15-06 and Chapter 33-15-14 of the North Dakota Air Pollution Control Rules and the Acid Rain Program.

(1) Section 33-15-06-05 of the North Dakota Air Pollution Control Rules, Reporting and Recordkeeping Requirements.

(2) 40 CFR 72 and 40 CFR 75.

(3) 40 CFR 64, Section 64.9 - Reporting and Recordkeeping Requirements, Paragraph (b) General Recordkeeping Requirements.

c. Great River Energy shall retain records of all required compliance monitoring data and support information for a period of at least five years from the date of the compliance monitoring sampling, measurement, report, or application. Support information includes all maintenance records of the emission units and all original strip-chart recordings/computer printouts and calibrations of the continuous compliance monitoring instrumentation, and copies of all reports required by the permit.

6. **Reporting**:

a. For Unit 1 and Unit 2, reporting shall be in accordance with the following applicable requirements of Chapter 33-15-06 and Chapter 33-15-14 of the North Dakota Air Pollution Control Rules and the Acid Rain Program.

(1) Section 33-15-06-05 of the North Dakota Air Pollution Control Rules, Reporting and Recordkeeping Requirements.

(2) 40 CFR 72 and 40 CFR 75.

(3) 40 CFR Part 64, Section 64.9 - Reporting and Recordkeeping Requirements, Paragraph (a) General Reporting Requirements.

(4) Quarterly excess emissions reports for Unit 1 and Unit 2 shall be submitted no later than the 30th day following the end of each calendar quarter. Excess emissions are defined as emissions which exceed the emission limits for Unit 1 and Unit 2 as outlined in Condition II.A.1. Data regarding only one of the two SO_2 limits needs to be included in the excess emissions report. Excess emissions shall be reported for the following:

Parameter	Reporting Period
SO_2 lb/10^6 Btu or % reduction	(30-day rolling average)
NO_x lb/10^6 Btu	(30-day rolling average)

b. Great River Energy shall submit a semi-annual report for all monitoring records required under Condition II.A.5 on forms supplied or approved by the Department. All instances of deviations from the permit must be identified in the report. A monitoring report shall be submitted within 45 days after June 30 and December 31 of each year.

c. Great River Energy shall submit an annual compliance certification report within 45 days after December 31 of each year on forms supplied or approved by the Department.

d. For emission units where the method of compliance monitoring is demonstrated by either an EPA Test Method or portable analyzer, the test report shall be submitted to the Department within 60 days after completion of the test.

e. Great River Energy shall submit an annual emission inventory report on forms supplied or approved by the Department. This report shall be submitted by March 15 of each calendar year. Insignificant units/activities listed in this permit do not need to be included in the annual emission inventory report.

f. Great River Energy shall submit to the Department written semi-annual reports detailing progress toward completion of the requirements of this permit. The semi-annual reports shall be submitted no later than 45 days after June 30 and December 31 of each year. The first report shall be due following the end of the first complete semi-annual period after the permit is issued.

g. Great River Energy shall notify the Department of the actual startup date of the equipment required to meet the BART limits.

B. **General Conditions**:

1. This permit shall in no way permit or authorize the maintenance of a public nuisance or danger to public health or safety.

2. Great River Energy shall comply with all State and Federal environmental laws and rules. In addition, Great River Energy shall comply with all local building, fire, zoning, and other applicable ordinances, codes, rules and regulations.

3. All reasonable precautions shall be taken by Great River Energy to prevent and/or minimize fugitive emissions during the construction period.

4. Great River Energy shall at all times, including periods of startup, shutdown, and malfunction, maintain and operate Unit 1 and Unit 2 and all other emission units including associated air

pollution equipment and fugitive dust suppression operations in a manner consistent with good air pollution control practices for minimizing emissions.

5. Any duly authorized officer, employee or agent of the North Dakota Department of Health may enter and inspect any property, premise or place at which the source listed in Item I.B. of this permit is or will be located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules and the conditions of this permit.

6. Any violation of a condition issued as part of this approval to construct is regarded as a violation of construction authority and is subject to enforcement action.

7. The conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23-25. Each and every condition of this permit is a material part thereof, and is not severable.

FOR THE NORTH DAKOTA
DEPARTMENT OF HEALTH

Date:____________________

By:______________________________
Terry L. O’Clair, P.E., Director
Division of Air Quality

11/18/09

AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT
FOR
BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Pursuant to the Air Pollution Control Rules of the State of North Dakota (North Dakota Administrative Code Article 33-15, Chapter 33-15-14 and Chapter 33-15-25), the North Dakota Department of Health hereby grants a Permit to Construct for the following BART source:

I. **General Information**:

A. **Permit to Construct Number**: TBD

B. **Source**:

1. **Name**: Stanton Generating Station

2. **Location**: Section 21, T144N, R84W, Mercer County, North Dakota

3. **Source Type**: Fossil-fuel fired steam electric plant with a nominal generating capacity of 188 megawatts.

4. **Equipment at the Facility Subject to BART**:

Unit 1 - Coal-fired boiler (nominal 1,800 x 10^6 Btu/hour heat input)

C. **Owner/Operator**:

1. **Name**: Great River Energy

2. **Address**: 12300 Elm Creek Blvd
Maple Grove, MN 55369-4718

II. **Permit Conditions**:

The Permit to Construct only establishes the BART emission limits if, and when, EPA approves those limits as part of the Regional Haze SIP. This permit allows the construction and initial operation of new or modified air pollution control equipment and process modifications at the source to comply with the BART limits. If new emission units are created, then a new Permit to Construct may be required in accordance with NDAC 33-15-14-02. The source shall be operated in accordance with the terms of this Permit to Construct and the Title V Permit to Operate until a revised Title V Permit to Operate is issued. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Health and to the conditions specified below:

A. **Special Conditions**:

1. **Emission Limits**: The term “30-day rolling average”, as used in this permit, shall be determined by calculating an arithmetic average of all hourly rates for the current boiler operating day and the previous 29 boiler operating days. A new 30-day rolling average shall be calculated for each boiler operating day. Each 30-day rolling average rate shall include start-up, shutdown, emergency and malfunction periods unless those periods are exempt by this permit. The 30-day rolling average emission rate is calculated as follows:

   - Calculate the hourly average emission rate for any hour in which any fuel is combusted in the boiler.

   - Calculate the daily average emission rate from the hourly average emission rates for that boiler operating day.

   - Calculate the 30-day rolling average emission rate from the daily average emission rate for the current boiler operating day and the daily average emission rate for the previous 29 boiler operating days.

   The term “boiler operating day”, as used in this permit, means any twenty-four-hour period between midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

   a. When burning only lignite coal, Great River Energy shall not discharge or cause the discharge of sulfur dioxide (SO_2) into the atmosphere from Unit No. 1 in excess of either:

      1) 0.24 pounds per million British thermal units (lb/10^6 Btu) of heat input on a 30-day rolling average basis;

         or

      2) 10.0% of the SO_2 reaching the spray dryer inlet on a 30-day rolling average basis (90.0% reduction).

   b. When burning subbituminous coal, Great River Energy shall not discharge or cause the discharge of sulfur dioxide (SO_2) into the atmosphere from Unit No. 1 in excess of either:

      1) 0.16 pounds per million British thermal units (lb/10^6 Btu) of heat input on a 30-day rolling average basis;

         or

      2) 10.0% of the SO_2 reaching the spray dryer inlet on a 30-day rolling average basis (90.0% reduction).

c. When both lignite coal and subbituminous coal are burned in Unit 1 in a 30-day averaging period, Great River Energy shall not discharge or cause the discharge of sulfur dioxide (SO_2) into the atmosphere from Unit 1 in excess of either:

1) The SO_2 emission limit determined using the following formula:

$$E_{SO2} = (E_L H_L + E_S H_S) / (H_L + H_S)$$

Where:

E_{SO2} = SO_2 emission limit in pounds per million British thermal units ($lb/10^6$ Btu) of heat input on a 30-day rolling average basis

E_L = 0.24 $lb/10^6$ Btu of heat input

E_S = 0.16 $lb/10^6$ Btu of heat input

H_L = total heat input (in million Btu) from the combustion of lignite coal for the current operating day and the previous 29 boiler operating days

H_S = total heat input (in million Btu) from the combustion of subbituminous coal for the current operating day and the previous 29 boiler operating days

or

2) 10.0% of the SO_2 reaching the spray dryer inlet on a 30-day rolling average basis (90.0% reduction).

d. When burning only lignite coal, Great River Energy shall not discharge or cause the discharge of nitrogen oxides (NO_x) into the atmosphere from Unit No. 1 in excess of 0.29 pounds per million British thermal units ($lb/10^6$ Btu) of heat input, on a 30-day rolling average basis.

e. When burning subbituminous coal, Great River Energy shall not discharge or cause the discharge of nitrogen oxides (NO_x) into the atmosphere from Unit No. 1 in excess of 0.23 pounds per million British thermal units ($lb/10^6$ Btu) of heat input, on a 30-day rolling average basis.

f. When both lignite coal and subbituminous coal are burned in Unit 1 in a 30-day averaging period, Great River Energy shall not discharge or cause the discharge of nitrogen oxides (NO_x) into the atmosphere from Unit No. 1 in excess of the NO_x emission limit determined using the following formula:

$E_{NOX} = (E_L H_L + E_S H_S) / (H_L + H_S)$

Where:

E_{NOX} =	NO_x emission limit in pounds per million British thermal units (lb/10^6 Btu) of heat input on a 30-day rolling average basis
E_L =	0.29 lb/10^6 Btu of heat input
E_S =	0.23 lb/10^6 Btu of heat input
H_L =	total heat input (in million Btu) from the combustion of lignite coal for the current operating day and the previous 29 boiler operating days
H_S =	total heat input (in million Btu) from the combustion of subbituminous coal for the current operating day and the previous 29 boiler operating days

g. Great River Energy shall not discharge or cause the discharge of filterable (non-condensible) particulate matter (PM) into the atmosphere from Unit No. 1 in excess of 0.07 pounds per million British thermal units (lb/10^6 Btu) of heat input. Compliance with the limit is determined in accordance with the procedures in Condition II.A.4.b.(5).

h. The emission limits shall apply at all times including startup, shutdown, emergency and malfunction.

2. **Compliance Date**: Compliance with the emission limits and other requirements of this permit is required as expeditiously as practicable but in no event later than five years after the U.S. Environmental Protection Agency approves this permit as a part of the Regional Haze SIP. Compliance shall be demonstrated within 180 days of initial startup of the equipment required to meet the BART limits, but no later than five years after the U.S. EPA approves this permit as a part of the BART SIP.

3. **Continuous Emission Monitoring (CEM)**: The emissions from Unit 1 shall be measured by continuous emission monitors (CEM) for SO_2, NO_x, CO_2, and flow. The monitoring requirements under Condition II.A.4 shall be the compliance determination method for SO_2 and NO_x.

4. **Monitoring Requirements and Conditions**:

a. Requirements:

Great River Energy is only required to monitor compliance with one SO_2 limit (i.e., either the lb/10^6 Btu limit or the 90% reduction limit). If Great River Energy monitors for both limits, and compliance is indicated for one limit but not the other, no excess emissions or monitoring deviations shall be reported with respect to the other limit.

Testing and monitoring protocols used to demonstrate compliance with the emission limits of Condition II.A.1 above shall be as follows:

Pollutant/ Parameter	**Monitoring Requirement (Method)**	**Condition Number**
Particulate	Compliance Assurance Monitoring (CAM)/ Emissions Test	4.b.(6)/4.b.(5)
SO_2 (inlet)	CEM; or Coal Sampling Data & Emission Factor[a]	4.b.(1), 4.b.(2), 4.b.(3), & 4.b.(7)
SO_2 (outlet)	CEM	4.b.(1), 4.b.(2), 4.b.(3) & 4.b.(7)
NO_x	CEM	4.b.(1), 4.b.(2) & 4.b.(3)
CO_2	CEM	4.b.(1), 4.b.(2), & 4.b.(3)
Flow	Flow Monitor	4.b.(1), 4.b.(2), & 4.b.(3)

[a] Emission factor refers to the value (e.g. percentage of inlet sulfur leaving the boiler), that is determined by stack testing, which is used to calculate the scrubber SO_2 inlet rate.

b. Emission Monitoring Conditions

(1) The monitoring shall be in accordance with the following applicable requirements of Chapter 33-15-06 of the North Dakota Air Pollution Control Rules and the Acid Rain Program. Emissions are calculated using 40 CFR Part 75.

(a) Section 33-15-06-04 of the North Dakota Air Pollution Control Rules, Monitoring Requirements.

(b) 40 CFR 72 and 40 CFR 75.

(2) The Department may require additional performance audits of the CEM systems.

(3) When a failure of a continuous emission monitoring system occurs, an alternative method, acceptable to the Department, for measuring or estimating emissions must be undertaken as soon as possible. The procedures outlined in 40 CFR 75, Subpart D for substitution are considered an acceptable method for the emission rate limit. The procedures of Method 19, Paragraph 12.7, are

considered an acceptable method for the percent reduction requirement. Timely repair of the emission monitoring system must be made.

(4) Great River Energy shall maintain and operate air pollution control monitoring equipment in a manner consistent with the manufacturer's recommended Operations and Maintenance (O&M) procedures, or a site-specific O&M procedure (developed from the manufacturer's recommended O&M procedures). Great River Energy shall have the O&M procedures available on-site and provide the Department with a copy when requested.

(5) Within 180 days of initial startup of the equipment required to meet the BART limits, but not later than 5 years after approval of the Regional Haze SIP by the U.S. Environmental Protection Agency, Great River Energy shall conduct an emissions test to measure particulate emissions, using EPA Test Method 5B or Method 17 in 40 CFR Part 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Other EPA-approved test methods may be used provided they are approved, in advance, by the Department.

(6) Monitoring for particulate matter shall be conducted in accordance with the Compliance Assurance Monitoring (CAM) Plan developed in accordance with NDAC 33-15-14-06.10. The CAM plan revision to address the BART PM limit shall be submitted with the Title V revision application for the BART limits.

(7) In lieu of using a continuous emission monitor to determine the SO_2 reaching the spray dryer / fabric filter inlet in accordance with Condition II.A.1.a., II.A.1.b. or II.A.1.c., Great River Energy may use coal sampling and an emission factor established by stack testing. The requirements in 40 CFR 60, Appendix A, Method 19 shall be used to determine coal sampling and analysis requirements.

For purposes of determining compliance with the SO_2 percent reduction requirement, the reduction efficiency shall be determined as follows:

$$\%\text{Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where: The Inlet SO_2 Rate is in units of lb/10^6 Btu, lb/hr, or ppmvd @ 3% O_2 and the Outlet SO_2 Rate is in the same units as the Inlet SO_2 Rate.

Notes:

- 30-day rolling average is determined for the 30 successive boiler operating days defined in the permit.
- % reduction can be on either a lb/10^6 Btu, ppmvd @ 3% O_2, or pounds

of SO_2 basis.

5. **Recordkeeping Requirements**:

a. Great River Energy shall maintain compliance monitoring records for Unit 1 as outlined in Table 1 Monitoring Records, that includes the following information:

(1) The date, place (as defined in the permit) and time of sampling or measurement.

(2) The date(s) testing was performed.

(3) The company, entity, or person that performed the testing.

(4) The testing techniques or methods used.

(5) The results of such testing.

(6) The unit load that existed at the time of sampling or measurement.

(7) The records of quality assurance for emissions measuring systems including but not limited to quality control activities, audits and calibration drifts as required by the applicable test method.

(8) A copy of all field data sheets from the emissions testing.

(9) A record shall be kept of all major maintenance activities conducted on the emission units or air pollution control equipment.

(10) Records shall be kept as to the type of fuel usage.

Table 1 Monitoring Records

Pollutant/Parameter	**Compliance Monitoring Record**
Particulate	CAM Data & Emissions Test Data
SO_2 outlet (lb/10^6 Btu)	CEM Data
SO_2 inlet (% Reduction)	CEM Data; or Coal Sampling Data & Emission Factor for Inlet SO_2 Rate
SO_2 outlet (% Reduction)	CEM Data
NO_x	CEM Data
CO_2	CEM Data
Flow	Flow Monitor Data

b. In addition to requirements outlined in Condition II.5.a., recordkeeping for Unit 1 shall be in accordance with the following applicable requirements of Chapter 33-15-06 and Chapter 33-15-14 of the North Dakota Air Pollution Control Rules and the Acid Rain Program:

(1) Section 33-15-06-05 of the North Dakota Air Pollution Control Rules, Reporting and Recordkeeping Requirements.

(2) 40 CFR 72 and 40 CFR 75.

(3) 40 CFR Part 64, Section 64.9 - Reporting and Recordkeeping Requirements, Paragraph (b) General Recordkeeping Requirements.

c. Great River Energy shall retain records of all required compliance monitoring data and support information for a period of at least five years from the date of the compliance monitoring sampling, measurement, report, or application. Support information includes all maintenance records of the emission units and all original strip-chart recordings/computer printouts and calibrations of the continuous compliance monitoring instrumentation, and copies of all reports required by the permit.

6. **Reporting**:

a. For Unit 1, reporting shall be in accordance with the following applicable requirements of Chapter 33-15-06 and Chapter 33-15-14 of the North Dakota Air Pollution Control Rules and the Acid Rain Program.

(1) Section 33-15-06-05 of the North Dakota Air Pollution Control Rules, Reporting and Recordkeeping Requirements.

(2) 40 CFR 72 and 40 CFR 75.

(3) 40 CFR Part 64, Section 64.9 - Reporting and Recordkeeping Requirements, Paragraph (a) General Reporting Requirements.

(4) Quarterly excess emissions reports for Unit 1 shall be submitted no later than the 30th day following the end of each calendar quarter. Excess emissions are defined as emissions which exceed the emission limits for Unit 1 as outlined in Condition II.A.1. Data regarding only one of the two SO_2 limits needs to be included in the excess emissions report. Excess emissions shall be reported for the following:

Parameter	Reporting Period
SO_2 lb/10^6 Btu or % reduction	(30-day rolling average)
NO_x lb/10^6 Btu	(30-day rolling average)

b. Great River Energy shall submit a semi-annual report for all monitoring records required under Condition II.A.5 on forms supplied or approved by the Department. All instances of deviations from the permit must be identified in the report. A monitoring report shall be submitted within 45 days after June 30 and December 31 of each year.

c. Great River Energy shall submit an annual compliance certification report within 45 days after December 31 of each year on forms supplied or approved by the Department.

d. For emission units where the method of compliance monitoring is demonstrated by either an EPA Test Method or a portable analyzer test, the test report shall be submitted to the Department within 60 days after completion of the test.

e. Great River Energy shall submit an annual emission inventory report on forms supplied or approved by the Department. This report shall be submitted by March 15 of each calendar year. Insignificant units/activities listed in this permit do not need to be included in the annual emission inventory report.

f. Great River Energy shall submit to the Department written semi-annual reports detailing progress toward completion of the requirements of this permit. The semi-annual reports shall be submitted no later than 45 days after June 30 and December 31 of each year. The first report shall be due following the end of the first complete semi-annual period after the permit is issued.

g. Great River Energy shall notify the Department of the actual startup date of the equipment required to meet the BART limits.

B. **General Conditions**:

1. This permit shall in no way permit or authorize the maintenance of a public nuisance or danger to public health or safety.

2. Great River Energy shall comply with all State and Federal environmental laws and rules. In addition, Great River Energy shall comply with all local building, fire, zoning, and other applicable ordinances, codes, rules and regulations.

3. All reasonable precautions shall be taken by Great River Energy to prevent and/or minimize fugitive emissions during the construction period.

4. Great River Energy shall at all times, including periods of startup, shutdown, and malfunction, maintain and operate Unit 1 and all other emission units including associated air pollution equipment and fugitive dust suppression operations in a manner consistent with good air pollution control practices for minimizing emissions.

5. Any duly authorized officer, employee or agent of the North Dakota Department of Health may enter and inspect any property, premise or place at which the source listed in Item I.B. of this permit is or will be located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules and the conditions of this permit.

6. Any violation of a condition issued as part of this approval to construct is regarded as a violation of construction authority and is subject to enforcement action.

7. The conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23-25. Each and every condition of this permit is a material part thereof, and is not severable.

FOR THE NORTH DAKOTA
DEPARTMENT OF HEALTH

Date:__________________________

By:________________________________
Terry L. O’Clair, P.E.
Director
Division of Air Quality

11/20/09

AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT
FOR
BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Pursuant to the Air Pollution Control Rules of the State of North Dakota (North Dakota Administrative Code Article 33-15, Chapter 33-15-14 and Chapter 33-15-25), the North Dakota Department of Health hereby grants a Permit to Construct for the following BART source:

I. **General Information**:

A. **Permit to Construct Number**: TBD

B. **Source**:

1. **Name**: Milton R. Young Station

2. **Location**: Center, North Dakota, Oliver County

3. **Source Type**: Fossil-fuel fired steam electric plant with a nameplate generating capacity of 734 megawatts.

4. **Equipment at the Facility Subject to BART**:

Unit 1 -	Lignite-fired boiler (nominal 3200 x 10^6 Btu/hour heat input)
Unit 2 -	Lignite-fired boiler (nominal 6300 x 10^6 Btu/hour heat input)

C. **Operator**:

1. **Name**: Minnkota Power Coop.

2. **Address**:
1822 Mill Road
Grand Forks, ND 58208-3200

II. **Permit Conditions**:

The Permit to Construct only establishes the BART emission limits if, and when, EPA approves those limits as part of the Regional Haze SIP. This permit allows the construction and initial operation of new or modified air pollution control equipment and process modifications at the source to comply with the BART limits. If new emission units are created, a new Permit to Construct may be required in accordance with NDAC 33-15-14-02. The source shall be operated in accordance with the terms of this Permit to Construct and the Title V Permit to Operate until a revised Title V Permit to Operate is issued. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Health and to the conditions specified below:

A. **Special Conditions**:

1. **Emission Limits**: The term "30-day rolling average," as used in this permit, shall be determined by calculating an arithmetic average of all hourly rates for the current boiler operating day and the previous 29 boiler operating days. A new 30-day rolling average shall be calculated for each boiler operating day. Each 30-day rolling average rate shall include start-up, shutdown, emergency and malfunction periods unless those periods are exempt by this permit. The 30-day rolling average emission rate is calculated as follows:

   - Calculate the hourly average emission rate for any hour in which any fuel is combusted in the boiler.

   - Calculate the daily average emission rate from the hourly average emission rates for that boiler operating day.

   - Calculate the 30-day rolling average emission rate from the daily average emission rate for the current boiler operating day and the daily average emission rate for the previous 29 boiler operating days.

   The term "boiler operating day," as used in this permit, means any twenty-four-hour period between midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

   a. Minnkota shall not discharge, or cause the discharge, of sulfur dioxide (SO_2) into the atmosphere from Unit 1 in excess of 5.0% of the SO_2 reaching the inlet of the scrubber on a 30-day rolling average basis (95% reduction).

   b. Minnkota shall not discharge, or cause the discharge, of sulfur dioxide (SO_2) into the atmosphere from Unit 2 in excess of either:

      1) 0.15 lb/10^6 Btu and 10% of the SO_2 reaching the inlet of the scrubber (90.0% reduction) on a 30-day rolling average basis;

         or as an alternative

      2) 5.0% of the SO_2 reaching the inlet of the scrubber (95.0% reduction) on a 30-day rolling average basis.

      If Minnkota chooses to comply with the 95% reduction requirement at Unit 2, Minnkota may average the % reduction from Unit 1 and Unit 2 provided:

      1) The average reduction is at least 95.0% as determined in accordance with Condition II.A.4.b(8).

2) The reduction by Unit 1 is at least 95.0%, and

3) The reduction by Unit 2 is at least 90.0%.

c. Minnkota shall not discharge or cause the discharge of nitrogen oxides (NO_x) into the atmosphere from Unit 1 in excess of 0.36 pounds per million British thermal units ($lb/10^6$ Btu) of heat input and from Unit 2 in excess of 0.35 pounds per million British thermal units ($lb/10^6$ Btu), on a 30-day rolling average basis. These limits do not apply during startup. During startup, NO_x emissions from Unit 1 shall not exceed 2070.2 lb/hr on a 24-hour rolling average basis and 3995.6 lb/hr from Unit 2 on a 24-hour rolling average basis. For purposes of this permit, startup is defined as follows:

Startup is the period of time from initial fuel combustion to the point in time when the measured heat input to the boiler on a 6-hour rolling average basis is greater than or equal to 2500 x 10^6 Btu/hr for Unit 1 and 4800 x 10^6 Btu/hr for Unit 2. For purposes of determining compliance, startup cannot exceed 61 hours for Unit 1 and 115 hours for Unit 2.

d. Minnkota shall not discharge or cause the discharge of filterable particulate matter (PM) into the atmosphere in excess of the following:

Unit 1 - 0.03 $lb/10^6$ Btu
Unit 2 - 0.03 $lb/10^6$ Btu

Compliance with the limit is determined in accordance with Condition II.A.4.b.5.

e. The sulfur dioxide and particulate matter emission limits apply at all times including startup, shutdown, emergency and malfunction.

2. **Compliance Date**: Compliance with the emission limits and other requirements of this permit is required as expeditiously as practicable but in no event later than five years after the U.S. Environmental Protection Agency approves this permit as a part of the Regional Haze SIP. Compliance shall be demonstrated within 180 days of initial startup of the equipment required to meet the BART limits, but no later than five years after the U.S. Environmental Protection Agency approves this permit as a part of the BART SIP.

3. **Continuous Emission Monitoring (CEM)**: The emissions from Unit 1 (main stack) and Unit 2 (main stack) shall each be measured by continuous emission monitors (CEM) for SO_2, NO_x, CO_2, and flow. The CEM systems shall be the compliance determination method for SO_2 and NO_x.

4. **Monitoring Requirements and Conditions**:

a. Requirements:

Testing and monitoring protocols used to demonstrate compliance with the emission limits of Condition II.A.1 above shall be as follows:

Pollutant/ Parameter	**Monitoring Requirement (Method)**	**Condition Number**
Particulate	Compliance Assurance Monitoring (CAM)/ Emissions Test	4.b.(6)/4.b.(5)
SO_2 (inlet and outlet)	CEM	4.b.(1), 4.b.(2), 4.b.(3), 4.b.(7) & 4.b.(8)
NO_x	CEM	4.b.(1), 4.b.(2), 4.b.(3), & 4.b.(8)
CO_2	CEM	4.b.(1), 4.b.(2), & 4.b.(3)
Flow	Flow Monitor	4.b.(1), 4.b.(2), & 4.b.(3)

b. Emission Monitoring Conditions:

(1) The monitoring shall be in accordance with the following applicable requirements of Chapter 33-15-06 ~~1~~ of the North Dakota Air Pollution Control Rules and the Acid Rain Program. Emissions are calculated using 40 CFR Part 75.

(a) Section 33-15-06-04 of the North Dakota Air Pollution Control Rules, Monitoring Requirements.

(b) 40 CFR 72 and 40 CFR 75.

(2) The Department may require additional performance audits of the CEM systems.

(3) When a failure of a continuous emission monitoring system occurs, an alternative method, acceptable to the Department, for measuring or estimating emissions must be undertaken as soon as possible. The procedures outlined in 40 CFR 75, Subpart D for substitution are considered an acceptable method for the emission rate limit. The procedures of Method 19, Paragraph 12.7, are considered an acceptable method for the percent reduction requirement. Timely repair of the emission monitoring system must be made.

(4) Minnkota shall maintain and operate air pollution control monitoring equipment in a manner consistent the manufacturer's recommended Operations and Maintenance (O&M) procedures, or a site-specific O&M

procedure (developed from the manufacturer's recommended O&M procedures). Minnkota shall have the O&M procedures available on-site and provide the Department with a copy when requested.

(5) Within 180 days of initial startup of the equipment required to meet the BART limits, but not later than 5 years after approval of the Regional Haze SIP by the U.S. Environmental Protection Agency, Minnkota shall conduct an emissions test to measure particulate emissions, using EPA Test Method 5B or Method 17 in 40 CFR Part 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Other EPA approved test methods may be used provided they are approved, in advance, by the Department.

(6) Monitoring for particulate matter shall be conducted in accordance with the Compliance Assurance Monitoring (CAM) Plan developed in accordance with NDAC 33-15-14-06.10. The CAM plan revision to address the BART PM limit shall be submitted with the Title V permit revision application for the BART limits.

(7) For purposes of determining compliance with the SO_2 percent reduction requirement, the reduction efficiency shall be determined as follows:

$$\% \text{ Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where: The Inlet SO_2 Rate and Outlet SO_2 Rate are in units of lb/10^6 Btu (30-day rolling average).

(8) When averaging the SO_2 emissions of Unit 1 and Unit 2, compliance shall be determined in accordance with the following:

$$\text{Average } \% \text{ Reduction} = \frac{[(ER_1)(HI_1) + (ER_2)(HI_2)]}{(HI_1 + HI_2)}$$

ER_1 = Actual % Reduction of Unit 1
ER_2 = Actual % Reduction of Unit 2
HI_1 = Actual Heat Input (MMBtu) of Unit 1
HI_2 = Actual Heat Input (MMBtu) of Unit 2

Notes:

- ER and HI are 30-day rolling averages.
- 30-day rolling average for the 30 successive boiler operating days as defined in Condition II.A.1.
- % Reduction is on a lb/10^6 Btu of SO_2 basis.

5. **Recordkeeping Requirements**:

a. Minnkota shall maintain compliance monitoring records for Unit 1 and Unit 2 as outlined in Table 1 Monitoring Records, that includes the following information:

(1) The date, place (as defined in the permit) and time of sampling or measurement.

(2) The date(s) testing was performed.

(3) The company, entity, or person that performed the testing.

(4) The testing techniques or methods used.

(5) The results of such testing.

(6) The unit load that existed at the time of sampling or measurement.

(7) The records of quality assurance for emissions measuring systems including but not limited to quality control activities, audits and calibration drifts as required by the applicable test method.

(8) A copy of all field data sheets from the emissions testing.

(9) A record shall be kept of all major maintenance activities conducted on the emission units or air pollution control equipment.

(10) Records shall be kept as to the type of fuel usage.

Table 1 Monitoring Records

Pollutant/Parameter	Compliance Monitoring Record
Particulate	CAM Data & Emissions Test Data
SO_2 (lb/10^6 Btu) inlet and outlet	CEM Data
SO_2 (% Reduction) inlet and outlet	CEM Data
NO_x	CEM Data
CO_2	CEM Data
Flow	Flow Monitor Data

b. In addition to requirements outlined in Condition II.5.a., recordkeeping for Unit 1 and Unit 2 shall be in accordance with the following applicable requirements of

Chapter 33-15-06 and Chapter 33-15-14 of the North Dakota Air Pollution Control Rules and the Acid Rain Program:

(1) Section 33-15-06-05 of the North Dakota Air Pollution Control Rules, Reporting and Recordkeeping Requirements.

(2) 40 CFR 72 and 40 CFR 75.

(3) 40 CFR Part 64, Section 64.9 - Reporting and Recordkeeping Requirements, Paragraph (b) General Recordkeeping Requirements.

c. Minnkota shall retain records of all required compliance monitoring data and support information for a period of at least five years from the date of the compliance monitoring sampling, measurement, report, or application. Support information includes all maintenance records of the emission units and all original strip-chart recordings/computer printouts and calibrations of the continuous compliance monitoring instrumentation, and copies of all reports required by the permit.

6. **Reporting**:

a. For Unit 1 and Unit 2, reporting shall be in accordance with the following applicable requirements of Chapter 33-15-06 and Chapter 33-15-14 of the North Dakota Air Pollution Control Rules and the Acid Rain Program.

(1) Section 33-15-06-05 of the North Dakota Air Pollution Control Rules, Reporting and Recordkeeping Requirements.

(2) 40 CFR 72 and 40 CFR 75.

(3) 40 CFR Part 64, Section 64.9 - Reporting and Recordkeeping Requirements, Paragraph (a) General Reporting Requirements.

(4) Quarterly excess emissions reports for Unit 1 and Unit 2 shall be submitted no later than the 30th day following the end of each calendar quarter. Excess emissions are defined as emissions which exceed the emission limits for Unit 1 and Unit 2 as outlined in Condition II.A.1. For Unit 2, data regarding only one of the two alternative SO_2 limits must be included in the excess emissions report. Excess emissions shall be reported for the following:

Parameter	Reporting Period
SO_2 lb/10^6 Btu	(30-day rolling average)
	SO_2 percent emitted (reduction) (30-day rolling average)
NO_x lb/10^6 Btu	(30-day rolling average)

NO_x lb/hr (startup)	(24-hour rolling average)

b. Minnkota shall submit a semi-annual report for all monitoring records required under Condition II.A.5 on forms supplied or approved by the Department. All instances of deviations from the permit must be identified in the report. A monitoring report shall be submitted within 45 days after June 30 and December 31 of each year.

c. Minnkota shall submit an annual compliance certification report within 45 days after December 31 of each year on forms supplied or approved by the Department.

d. For emission units where the method of compliance monitoring is demonstrated by either an EPA Test Method or a portable analyzer test, the test report shall be submitted to the Department within 60 days after completion of the test.

e. Minnkota shall submit an annual emission inventory report on forms supplied or approved by the Department. This report shall be submitted by March 15 of each calendar year. Insignificant units/activities listed in this permit do not need to be included in the annual emission inventory report.

f. Minnkota shall submit to the Department written semi-annual reports detailing progress toward completion of the requirements of this permit. The semi-annual reports shall be submitted no later than 45 days after June 30 and December 31 of each year. The first report shall be due following the end of the first complete semi-annual period after the permit is issued.

g. Minnkota shall notify the Department of the actual startup date of the equipment required to meet the BART limits.

B. **General Conditions**:

1. This permit shall in no way permit or authorize the maintenance of a public nuisance or danger to public health or safety.

2. Minnkota shall comply with all State and Federal environmental laws and rules. In addition, Minnkota shall comply with all local building, fire, zoning, and other applicable ordinances, codes, rules and regulations.

3. All reasonable precautions shall be taken by Minnkota to prevent and/or minimize fugitive emissions during the construction period.

4. Minnkota shall at all times, including periods of startup, shutdown, and malfunction, maintain and operate Unit 1 and Unit 2 and all other emission units including associated air pollution equipment and fugitive dust suppression operations in a manner consistent with good air pollution control practices for minimizing emissions.

5. Any duly authorized officer, employee or agent of the North Dakota Department of Health may enter and inspect any property, premise or place at which the source listed in Item I.B. of this permit is or will be located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules and the conditions of this permit.

6. Any violation of a condition issued as part of this approval to construct is regarded as a violation of construction authority and is subject to enforcement action.

7. The conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23-25. Each and every condition of this permit is a material part thereof, and is not severable.

FOR THE NORTH DAKOTA
DEPARTMENT OF HEALTH

Date:__________________

By: ________________________________
Terry L. O'Clair, P.E.
Director
Division of Air Quality

Modeling Protocol for Regional Haze Reasonable Progress Goals in North Dakota

(Final)

October 3, 2008

North Dakota Department of Health
Division of Air Quality
918 E. Divide Avenue
Bismarck, ND 58501

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1 Introduction

The EPA Regional Haze Rule[1] (Rule) specifies that modeling must be conducted to demonstrate reasonable progress toward the goal of achieving natural visibility in each PSD Class I area. The Rule also specifies that natural visibility conditions should be achieved by 2064. The uniform rate of progress defines the visibility improvement that would be needed each year, starting with the base period of 2000-2004, to achieve natural visibility conditions in 2064 in each Class I area. This progression is illustrated in Figure 1-1. To track visibility improvement, the Rule specifies several milestone dates for meeting intermediate reasonable progress goals, that the State must establish, the first of which is the 2018 goal, for each Class I area. The uniform rate of progress for 2018 is determined by interpolating from the uniform rate of progress path, as illustrated in Figure 1-1. This protocol will assume that the 2018 goal for each Class I area is the glide path (uniform rate of progress), but the reasonable progress goal established by the State for 2018 for each Class I area may or may not be equal to the uniform rate of progress for 2018.

To demonstrate reasonable progress with respect to the 2018 visibility goals, the Rule specifies that visibility on the 20% worst days must improve enough to meet the goal, while visibility on the 20% best days must not deteriorate, between the base period (2000-2004) and 2018. Air quality modeling will be used to project future visibility, accounting for proposed BART controls and other visibility-affecting emissions increases/decreases. Modeling will be used in a relative sense. Baseline and projected future emission inventories will be modeled to develop a future/baseline prediction ratio (relative response factor). The ratio will then be applied to baseline monitoring data for visibility-affecting species to project future visibility.

The Western Regional Air Partnership (WRAP) regional planning organization has established a Regional Modeling Center (RMC) to assist member States, including North Dakota, with modeling to determine status with respect to the 2018 goals. The RMC is applying a chemically sophisticated grid model (CMAQ), on a regional basis, to project future visibility in Class I areas in the WRAP region[2]. The RMC has developed comprehensive base period and future period visibility-affecting emission inventories to use with CMAQ, and has performed numerous studies using base period model and monitoring data to evaluate CMAQ performance[3].

Though the North Dakota Department of Health (NDDoH) intends to incorporate much of the WRAP RMC work in its own analysis of visibility goals in North Dakota Class I areas, the NDDoH recognized it would have to develop its own modeling capability for visibility projection

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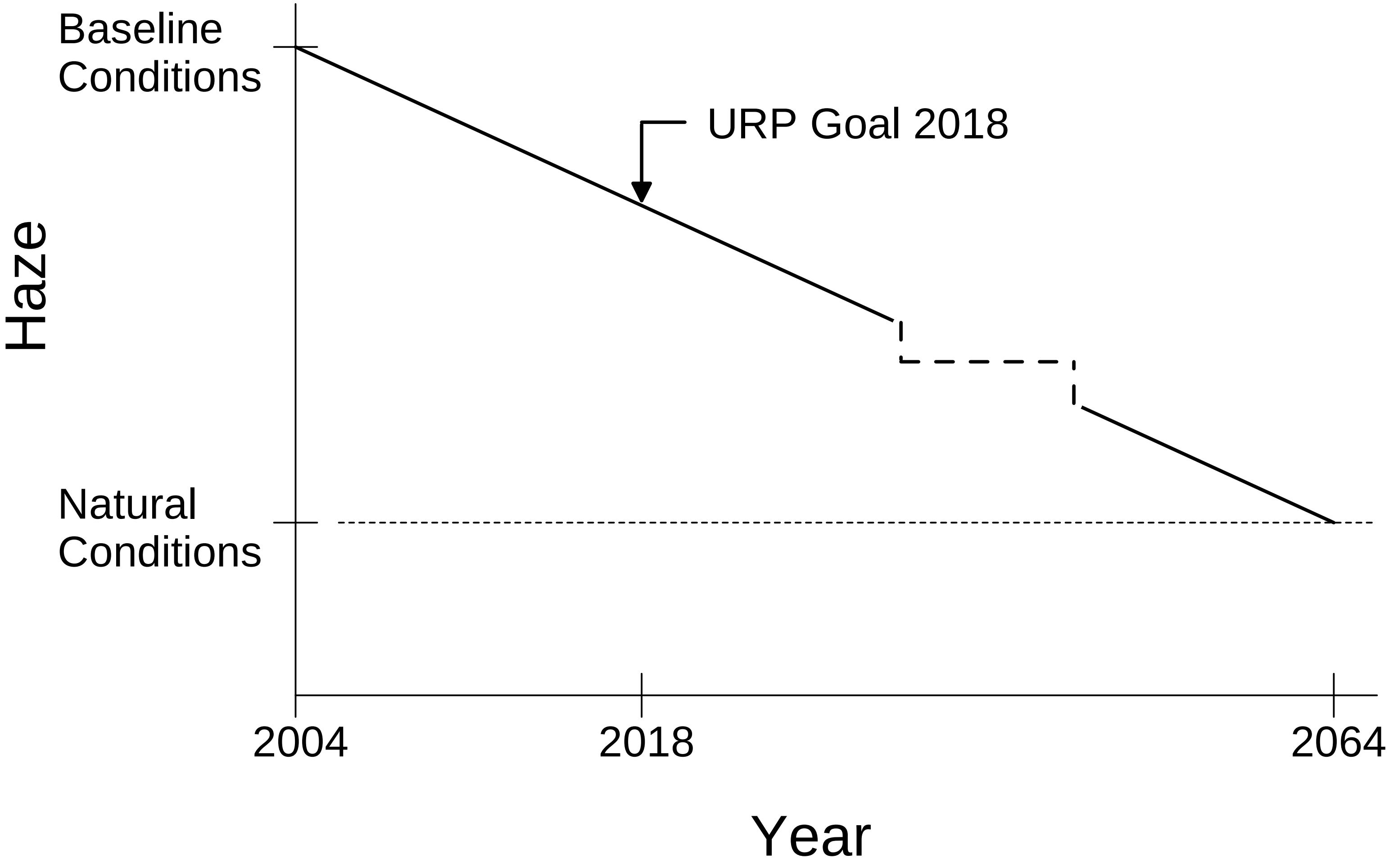
[1] 40 CFR 51.308

[2] Tonnesen et. al., Morris, Adelman, 2006. 2006 Report for the Western Regional Air Partnership (WRAP) Regional Modeling Center (RMC). Western Regional Air Partnership, Denver, CO 80202.

[3] See WRAP RMC web site at http://pah.cert.ucr.edu/aqm/308/

Figure 1-1
Regional Haze Uniform Rate of Progress



in order to address weight of evidence issues not included in WRAP modeling, such as discounting the impact of international sources. Further, the NDDoH had concerns regarding the resolution of the WRAP CMAQ simulations, particularly for large point sources.

The RMC is applying CMAQ on a National basis using a grid resolution of 36 km, with no plume-in-grid treatment. This means that emissions from point sources are immediately mixed uniformly throughout a 36 km (square) grid cell volume, which may overstate the dilution of the plume, and the speed of chemical reactions for species contained in the plume, especially for sources located relatively near Class I areas. Consequently, the contribution of visibility-affecting species from these sources may be misrepresented for both base period and future period modeling. This limitation in treatment of point sources is recognized in CMAQ documentation[4].

To provide a local modeling capability, the NDDoH proposes a hybrid modeling approach for determining status with respect to the visibility goals. This approach involves nesting the local NDDoH CALPUFF domain within the WRAP National CMAQ domain, and applying the Lagrangian CALPUFF model in a retrospective sense to more realistically define plume geometry for local point sources. To implement the nesting, hourly output concentrations from WRAP CMAQ will be used to set hourly boundary conditions for CALPUFF. The use of CMAQ output to set CALPUFF boundary conditions has been suggested by Escoffier-Czaja and Scire[5]. Location of the NDDoH CALPUFF domain within the National CMAQ domain is illustrated in Figure 1-2.

CALPUFF nesting will be used for simulation of SO_2-SO_4-NO_X-HNO_3-NO_3 chemistry and transport, and thus sulfate and nitrate predictions, only. Results for all other visibility-affecting species, including organic carbon mass, elemental carbon, fine particulate, and coarse particulate, will be obtained directly from the CMAQ output for the grid cell containing the subject Class I area IMPROVE monitor. CMAQ output will be combined with CALPUFF results for sulfate and nitrate in order to perform necessary light extinction calculations. In this way, the NDDoH will take advantage of the sophistication of the RMC approach for other particulate components, which reflect a very small percentage of emissions from the local point sources of concern.

The NDDoH protocol for modeling visibility progress goals will generally adhere to EPA *Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality*

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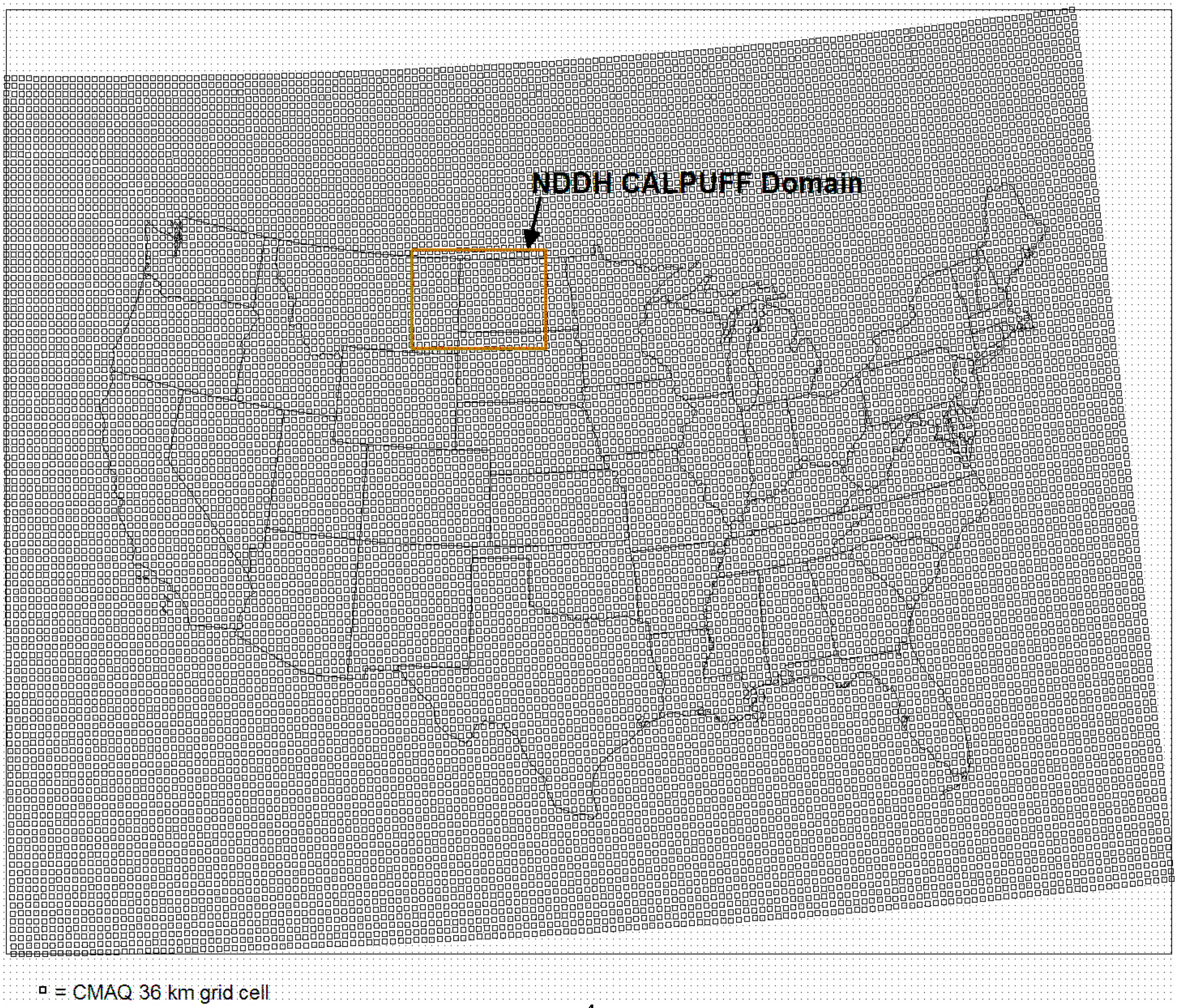
[4] EPA, 1999. Science Algorithms of the EPA Models-3 Community Multiscale Air Quality (CMAQ) Modeling System. Office of Research and Development, Washington DC 20460.

[5] Escoffier-Czaja and Scire, 2005. Comments on the Computation of Nitrate Using the Ammonia Limiting Method in CALPUFF. Appendix A, Draft Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART), VISTAS.

Figure 1-2
WRAP CMAQ Domain and NDDoH CALPUFF Domain



Goals for Ozone, $PM_{2.5}$, and Regional Haze[6]. An evaluation of performance for the CMAQ-CALPUFF hybrid modeling system will be conducted first. Then baseline (2000-2004) and future (2018) emission scenarios will be modeled, using the hybrid modeling system, in order to develop relative response factors (RRF's). Finally, RRF's will be applied to baseline IMPROVE monitoring data to project future visibility in North Dakota Class I areas. These Class I areas include Theodore Roosevelt National Park (TRNP) and Lostwood National Wilderness Area (NWA). Locations of North Dakota Class I areas, IMPROVE monitor sites, and major visibility-affecting sources are depicted in Figure 1-3.

2 Regional Haze Metrics

Metrics used to assess regional haze include light extinction and deciview. Calculation of light extinction from visibility affecting aerosols for the NDDoH regional haze analysis will be based on the "new" IMPROVE algorithm[7]. This new equation was seen to reduce bias associated with use of the "old" IMPROVE algorithm, and was adopted as an alternative by the IMPROVE Steering Committee in December 2005. The new algorithm splits ammonium sulfate, ammonium nitrate, and organic mass concentrations into two fractions: small and large. The new algorithm for light extinction is:

$$\begin{aligned} b_{ext} = \; & 2.2 \text{ x } f_s(RH) \text{ x [small sulfate]} + 4.8 \text{ x } f_L(RH) \text{ x [large sulfate]} \\ & + 2.4 \text{ x } f_s(RH) \text{ x [small nitrate]} + 5.1 \text{ x } f_L(RH) \text{ x [large nitrate]} \\ & + 2.8 \text{ x [small organic mass]} + 6.1 \text{ x [large organic mass]} \\ & + 10.0 \text{ x [elemental carbon]} \\ & + 1.0 \text{ x [fine soil]} \\ & + 1.7 \text{ x } f_{ss}(RH) \text{ x [sea salt]} \\ & + 0.6 \text{ x [coarse mass]} \\ & + \text{Rayleigh scattering (site-specific)} \\ & + 0.33 \text{ x } [NO_2 \text{ (ppb)}] \end{aligned}$$

where

b_{ext} = light extinction in units of inverse megameters (Mm^{-1}),
$f_s(RH)$ = function of relative humidity for small size fraction,

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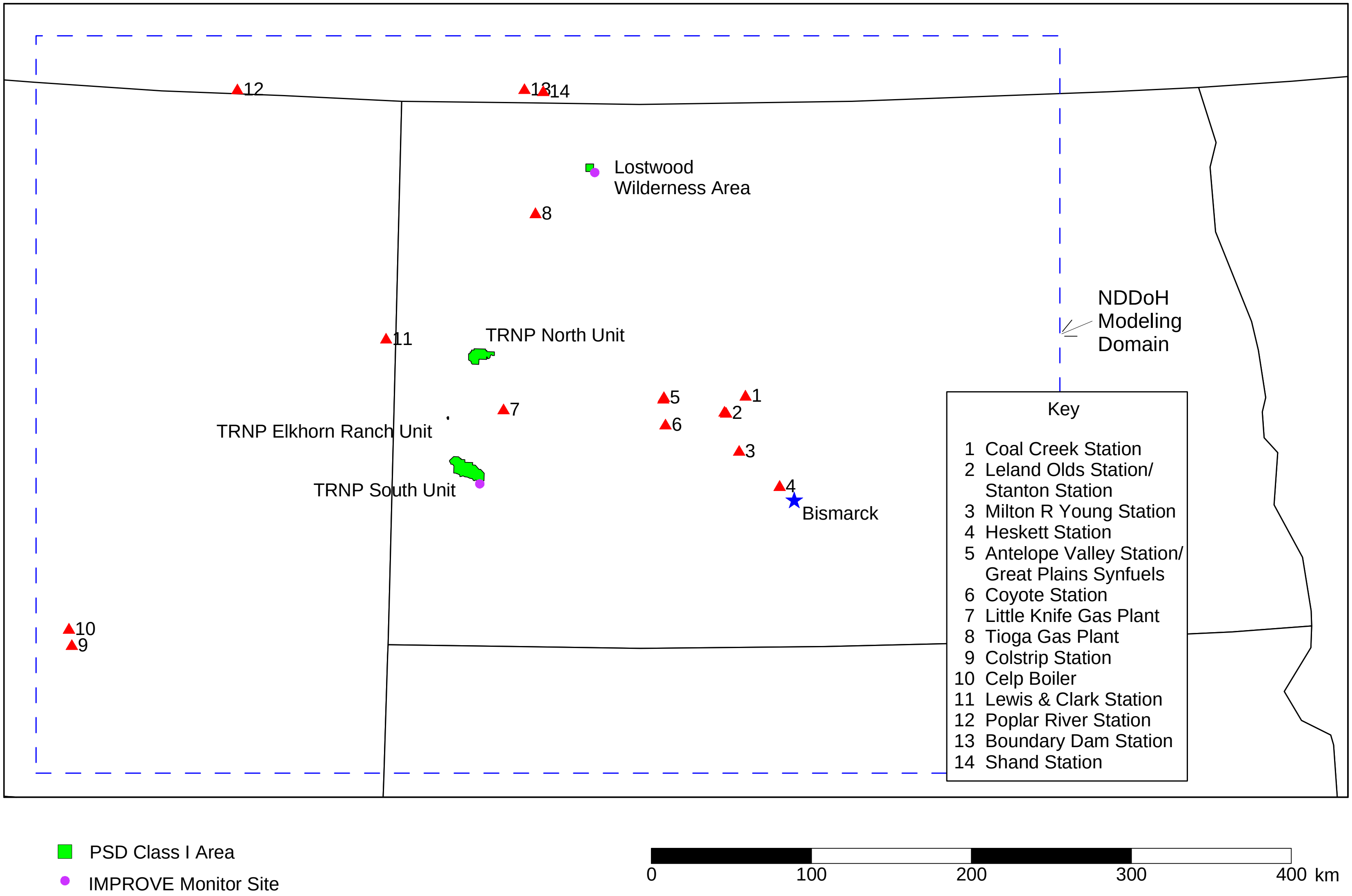
[6] EPA, 2007. Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze. Publication No. EPA 454/B-07-002, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

[7] IMPROVE, 2005. New IMPROVE algorithm for estimating light extinction approved for use. The IMPROVE Newsletter, Volume 14, Number 4. Air Resource Specialists, Inc., Fort Collins, CO 80525.

Figure 1-3
Major Sources and PSD Class I Areas



$f_L(RH)$ = function of relative humidity for large size fraction,
$f_{ss}(RH)$ = function of relative humidity for sea salt,
all species concentrations are provided in ug/m^3,
sulfate/nitrate implies ammonium sulfate / ammonium nitrate.

Apportionment of total sulfate concentrations into small and large size fractions is defined:

$$[\text{large sulfate}] = \frac{\underline{[\text{total sulfate}]}}{20\ ug/m^3} \times [\text{total sulfate}], \quad \text{for } [\text{total sulfate}] < 20\ ug/m^3$$

$$[\text{large sulfate}] = [\text{total sulfate}], \quad \text{for } [\text{total sulfate}] \geq 20\ ug/m^3$$

$$[\text{small sulfate}] = [\text{total sulfate}] - [\text{large sulfate}]$$

The same equations are used to apportion nitrate and organic mass size fractions.

WRAP and the NDDoH have determined that the NO_2 term has very little impact on total extinction, and the IMPROVE network does not include NO_2 monitoring. A review of observational NO_2 data from an NDDoH monitoring site in Theodore Roosevelt National Park revealed that readings were less than the minimum detectable level of 2.0 ppb more than 80% of the time in 2002. WRAP has not accounted for the NO_2 term in it's analyses for future visibility. Accordingly, the NDDoH proposes to omit the NO_2 term when implementing the new extinction algorithm.

Regarding the sea salt term in the extinction equation, very little impact from sea salt is expected in North Dakota. However, IMPROVE monitoring data in North Dakota Class I areas does occasionally include small values for sea salt. Because of the negligible impact of sea salt in the IMPROVE equation for North Dakota Class I areas, the impact would remain negligible even if some variation in sea salt occurs in the future. Therefore, sea salt will be omitted from the modeling process and an RRF of 1.0 will be assumed.

Light extinction is converted to deciview using the following relationship:

$$dv = 10 \times \ln(b_{ext} / 10)$$

where

dv = deciview
b_{ext} = light extinction in units of inverse megameters (Mm^{-1})

Visibility goals are generally expressed as deciviews. A change of one deciview represents a generally perceptible change in visibility to most people.

3 Overview of Methodology

3.1 General

Methodology for NDDoH projection of future visibility is based on EPA *Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze* [8]. The guidance proposes a relative modeling approach to project future (2018) visibility, in order to determine compliance status with respect to visibility goals at Class I areas. Implementation of the relative modeling approach relies on relative response factors (RRF's) which represent the modeled impact of the future (visibility affecting) source inventory divided by the modeled impact of the baseline source inventory at Class I areas. These RRF's are applied to baseline IMPROVE monitoring data to project future visibility.

Projection of future visibility is needed for the 20% worst and 20% best visibility days at each Class I area. The 20% worst days and 20% best days are determined from Class I area IMPROVE monitoring data for each year for the 5-year baseline period 2000-2004. Because IMPROVE sampling occurs once every three days, the maximum number of monitored days per year would be 122, and the maximum number of 20% worst (best) days per year would be 24.

According to the EPA guidance, RRF's are developed by comparing the future average predicted concentration for 20% worst days (best days) to the baseline average predicted concentration for 20% worst days (best days), for each species. The 20% worst (best) modeled days are selected for consistency with the worst (best) monitored days (i.e., represent the same temporal periods), assuming modeling is based on 2000-2004 meteorological data. For each visibility affecting species (SO_4, NO_3, OMC, EC, Soil, CM), a single RRF is developed for each Class I area. The RRF is calculated by dividing the predicted future concentration averaged over all worst (best) days by the predicted baseline concentration averaged over all worst (best) days. Then, future concentrations for each species are projected by multiplying the RRF by the observed species concentration on each of the baseline worst (best) days.

The RRF approach can be expressed mathematically:

$$X^{i,j}_{of} = X^{i,j}_{ob}\,(RRF^{i}) = X^{i,j}_{ob}\,(\overline{X}^{i}_{pf}/\overline{X}^{i}_{pb})$$

where

$X^{i,j}_{of}$ represents projected **o**bserved **f**uture concentration for species i on day j (each of 20% worst days for each baseline year),

$X^{i,j}_{ob}$ represents **o**bserved **b**aseline (IMPROVE data) concentration for species i on day j (each of 20% worst days for each baseline year),

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[8] See Supra note 6

$\overline{X}^i_{pf}$ represents average **p**redicted **f**uture concentration for species i (average of 20% worst days),

$\overline{X}^i_{pb}$ represents average **p**redicted **b**aseline concentration for species i (average of 20% worst days),

RRF^i represents the relative response factor for species i.

The projected future worst-day (best-day) concentrations are converted to light extinction using the IMPROVE equation, then daily light extinction is converted to deciview for each day. Finally, projected daily deciview is averaged over all worst-case (best-case) days for each year, then averaged over all years to produce the single future value needed to address visibility goals for each Class I area.

The NDDoH will implement the approach described above. The WRAP RMC has previously developed emission inventories (baseline and future), conducted modeling, and projected future visibility for the WRAP region Class I IMPROVE sites using the CMAQ grid model[9]. But to address weight of evidences issues, and possibly concerns about the resolution of the WRAP CMAQ simulations, the NDDoH needed an in-house modeling capability. The RMC is applying CMAQ on a National basis using a grid resolution of 36 km, with no plume-in-grid treatment. As such, dilution of point source plumes, and the speed of chemical reactions for species contained in the plume, may be overstated, particularly for large sources located relatively near Class I areas.

The NDDoH proposes to apply a hybrid modeling procedure by nesting the local NDDoH CALPUFF domain within the WRAP National CMAQ domain, and applying the Lagrangian CALPUFF model in a retrospective sense to more realistically define plume geometry for local point sources. To implement the nesting, hourly output concentrations from WRAP CMAQ will be used to set hourly boundary conditions for CALPUFF. The NDDoH will prepare baseline and future emission inventories for the CALPUFF domain, and will include the effect of proposed BART controls in the future inventory. CMAQ output used to set CALPUFF boundary conditions will reflect corresponding WRAP cases for baseline and future emission inventories. After this modeling system has been applied, the baseline and future case output from CALPUFF will be used to develop RRF’s.

The hybrid modeling approach will be used for simulation of SO_2-SO_4-NO_X-HNO_3-NO_3 chemistry and transport, and thus sulfate and nitrate predictions, only. The larger sources located relatively near North Dakota Class I areas, where CMAQ dilution is a concern, are primarily emitters of SO_2 and NO_X. Further, IMPROVE measurements at North Dakota Class I areas indicate that sulfate and nitrate are primary contributors to light extinction on most worst-case days. Individual species contribution to light extinction for worst-case days at Theodore

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[9] See Supra note 2

Roosevelt National Park is illustrated in Figure 3-1. Therefore, weight of evidence assessments will be most applicable to sulfate and nitrate species.

For all other visibility-affecting species, including OMC, EC, Soil, and CM, predictions needed for developing RRF's will be taken directly from CMAQ output. WRAP CMAQ output from the grid cell containing the subject Class I area IMPROVE site for baseline and future cases will be utilized. In this way, the NDDoH will take advantage of the extensive work WRAP has undertaken to develop accurate model emissions inventories for OMC-EC-Soil-CM species and precursors. CMAQ output for these species will be combined with hybrid modeling results for sulfate and nitrate in order to project future concentrations necessary for light extinction calculations for worst (best) days.

Along with setting boundary conditions, WRAP CMAQ data will be used for developing area source emissions inventories within the CALPUFF domain. The NDDoH will develop it's own point source inventory for SO_2 and NO_X, but will rely on WRAP CMAQ data for all other source categories (and for point source SO_4 and NO_3) to apportion emissions within the CALPUFF domain. WRAP is using the SMOKE emissions model[10] to develop the emissions inventory for CMAQ. The NDDoH will request and further process SMOKE output to define area source emissions for the CALPUFF domain. The CALPUFF area source emissions inventory will include the species SO_2, SO_4, NO_X, and NO_3. In addition, primary SO_4 and NO_3 emissions data will be extracted from the SMOKE inventory for point sources, and apportioned to the CALPUFF domain as area sources. WRAP CMAQ source categories to be included in the CALPUFF emissions inventory are outlined in Table 3-1. Note that WRAP SMOKE output did not contain all four species for some source categories.

Table 3-1
CMAQ-CALPUFF Area Source Categories

Source Category	Species Included
All Fires	SO_2, NO_X, SO_4, NO_3
Biogenics	NO_X
Fugitive Dust	SO_4, NO_3
On-Road Mobile	SO_2, NO_X, SO_4
Off-Road Mobile	SO_2, NO_X, SO_4, NO_3
Road Dust	SO_4, NO_3
Oil & Gas	SO_2, NO_X
Conventional Area	SO_2, NO_X, SO_4, NO_3
Point	SO_4, NO_3

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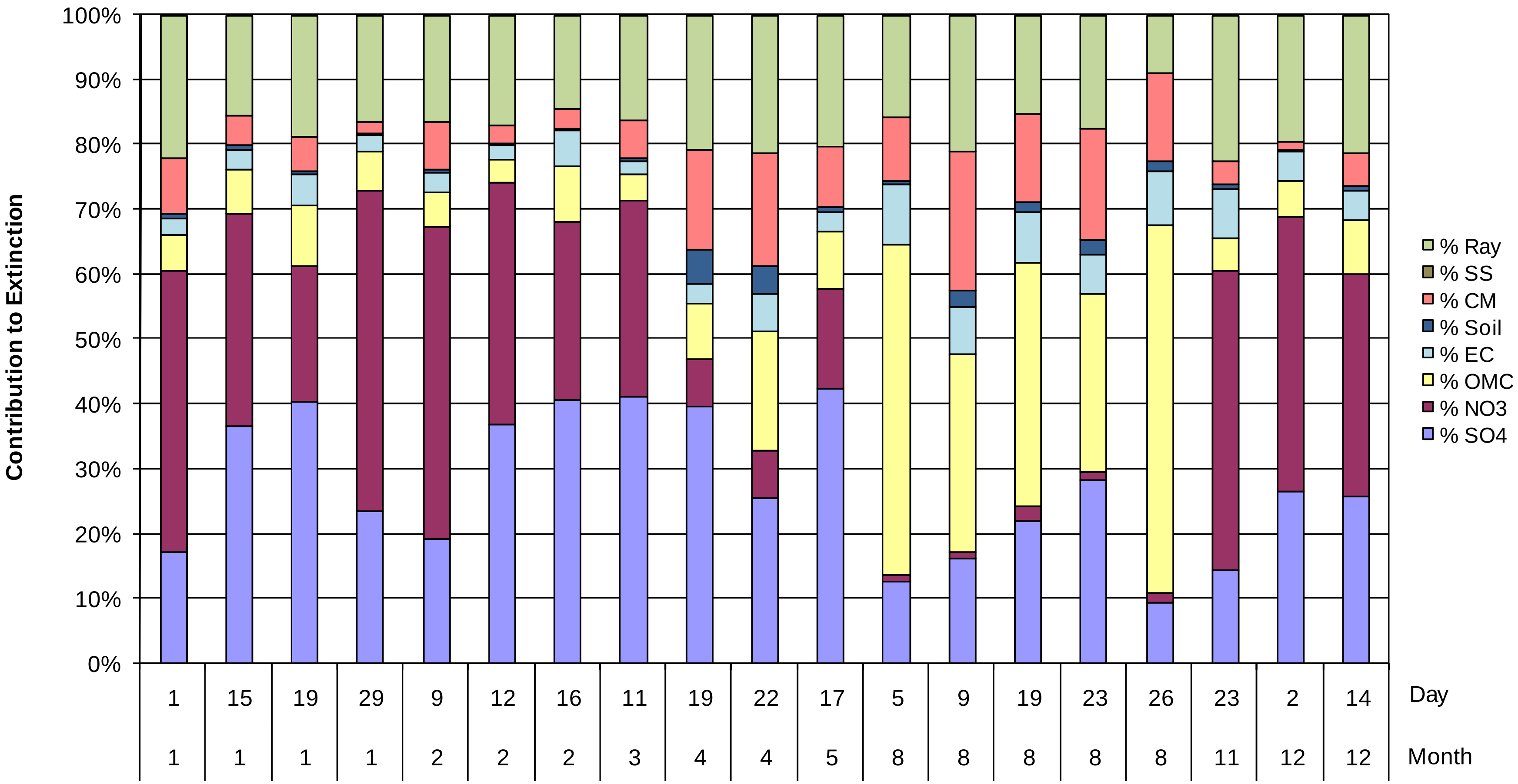
[10] University of North Carolina, 2007. SMOKE User's Manual. The Institute for the Environment, University of North Carolina.

Figure 3-1
IMPROVE 20% Worst Days – TRNP 2000



The proposed interfacing of CMAQ and CALPUFF modeling systems for the hybrid approach is illustrated in the flow diagram in Figure 3-2. Necessary software for processing SMOKE emissions and CMAQ concentration data will be developed by the NDDoH. The software will be made available for public review.

Prior to baseline and future case CALPUFF modeling, the NDDoH will undertake a model performance evaluation. This evaluation will focus on the performance of the hybrid CMAQ-CALPUFF modeling system for sulfate and nitrate. As indicated previously, the CMAQ performance evaluations conducted by WRAP for OMC, EC, Soil, and CM species also apply.

The NDDoH will obtain CMAQ emissions input data (SMOKE output) and hourly concentration output files from the WRAP RMC. CMAQ data used to set CALPUFF boundary conditions and develop the CALPUFF area source inventory will be based on WRAP cases BASE02b, PLAN02d, and PRP18a, for performance evaluation, baseline case, and future case modeling, respectively. These WRAP scenarios are described as follows.

- Case BASE02b reflects CMAQ modeling using year 2002 emissions with year 2002 meteorology. WRAP is using this case for performance evaluations.

- Case PLAN02d reflects CMAQ modeling using composite 2000-2004 emissions with 2002 meteorology. WRAP is using this case for the base period to generate relative response factors.

- Case PRP18a (Preliminary Reasonable Progress 18a) reflects CMAQ modeling using projected year 2018 emissions with 2002 meteorology. Case PRP18a represents base period emissions projected to 2018, accounting for preliminary estimates of the effect of BART controls, and assuming other growth and control factors. WRAP is using this case for the future period, on an interim basis, to generate relative response factors.

WRAP will eventually be refining it's PRP18a case in order to more accurately represent the effect of BART and other controls. The NDDoH will request data from the updated CMAQ case(s) when available, and revise the future case modeling.

WRAP RMC has conducted CMAQ modeling for the above cases using 2002 meteorological data, only. Therefore, the hybrid modeling conducted by the NDDoH will be limited to this single year of meteorological data. The RRF's developed from 2002 modeling will be applied to all five years of baseline monitoring data (2000-2004) to project future visibility. To the extent applicable, CALMET-CALPUFF input settings for regional haze modeling will be consistent with those specified in the North Dakota BART modeling protocol[11].

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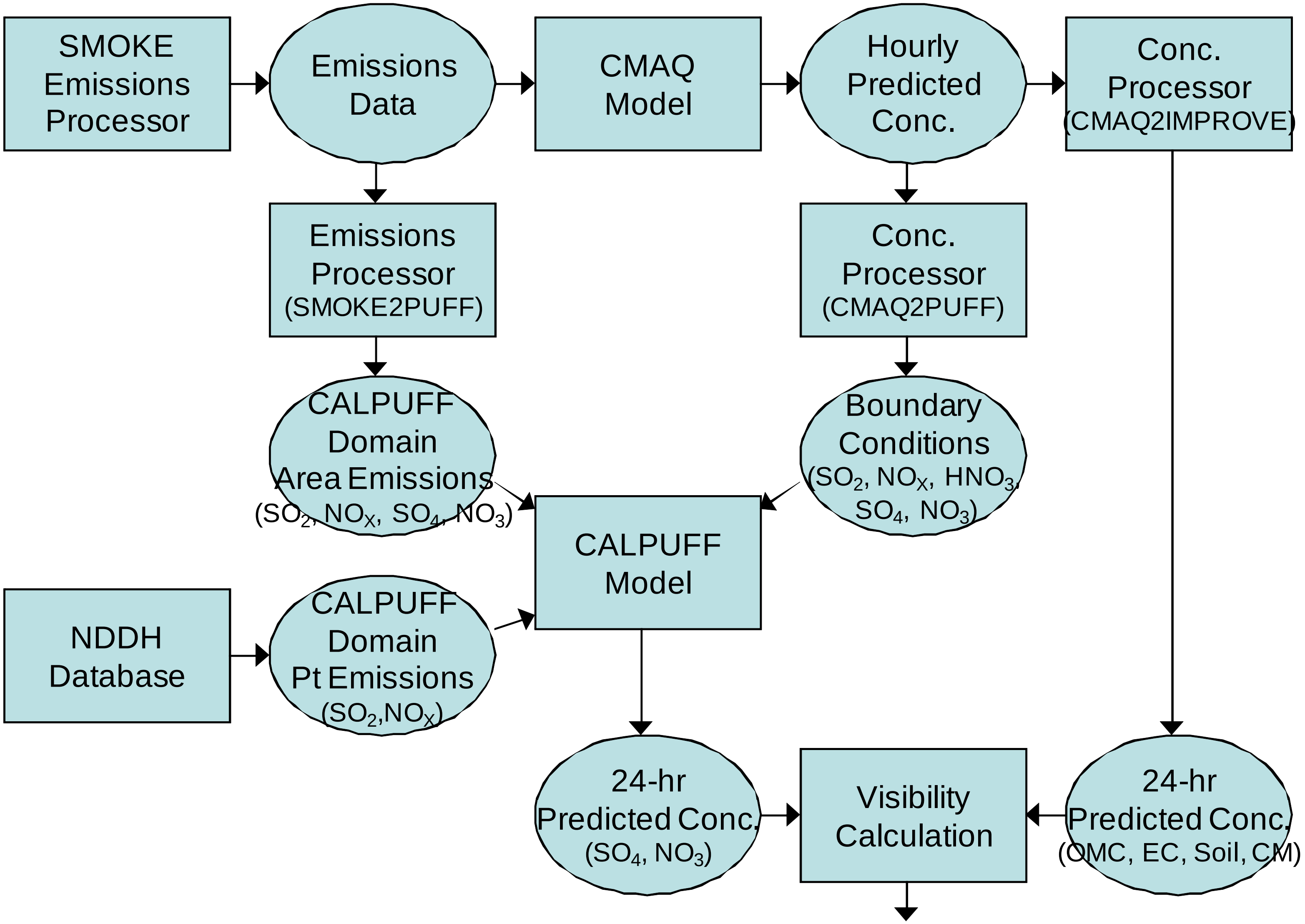
[11] NDDoH, 2005. Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota. North Dakota Department of Health, Bismarck, ND 58501.

Figure 9-4
Interfacing of CMAQ and CALPUFF Modeling Systems



The versions of CALPUFF and associated programs which the NDDoH will utilize for regional haze modeling are summarized in Table 3-2.

Table 3-2
CALPUFF System Versions Applicable For Regional Haze Modeling

Program	**Version**	**Level**
CALMET	5.8	70623
CALPUFF	5.8	70623
POSTUTIL	1.56	70627
CALPOST	5.6394	70622

Specifics of the NDDoH plan for projecting future visibility are outlined in Section 4.

3.2 Normalizing Hybrid Model RRF to WRAP CMAQ RRF

Based on initial performance testing conducted by NDDoH, the hybrid CMAQ-CALPUFF modeling system performs well in replicating observed concentrations of SO_4 and NO_3 (see Appendix A). However, performance regarding sensitivity to changes in emissions appears less robust, with CMAQ-CALPUFF overstating future case nitrate formation compared to predictions obtained by WRAP using CMAQ alone. For this reason, the NDDoH is proposing to modify the methodology for projection of future visibility by normalizing or standardizing the hybrid CMAQ-CALPUFF RRF to the CMAQ RRF obtained by WRAP, for species SO_4 and NO_3. This normalized approach can be expressed:

$$\text{RRF}^{i,k} = \text{WRAP CMAQ RRF}^{i} \; \frac{\text{Hybrid Model production RRF}^{i,k}}{\text{Hybrid Model CMAQ emulation RRF}^{i,k}} \qquad (3\text{-}1)$$

where

RRF^{i} represents the EPA default relative response factor for species i (specific days for PLAN02d and PRP18a,

$\text{RRF}^{i,k}$ represents the relative response factor for species i and NDDoH scenario k,

> Hybrid Model production RRF represents the result from the weight of evidence modeling step (see Sections 4.4, 4.5),
>
> Hybrid Model CMAQ emulation RRF represents the result from the CMAQ emulation modeling step (see Section 4.6)

Note that the production RRF varies for each weight of evidence scenario, while the CMAQ emulation RRF remains constant for all weight of evidence scenarios. This is because all weight of evidence scenarios are normalized to the single (EPA default) modeling scenario conducted by WRAP

By standardizing or normalizing RRF's to the default CMAQ values obtained by WRAP, this approach acknowledges the sophistication of CMAQ chemistry compared to CALPUFF chemistry, especially the CMAQ sensitivity to changes in emissions. But the approach also retains the benefits of CALPUFF in providing better definition of point sources, plumes, and receptors. As discussed earlier, CMAQ-CALPUFF integration allows the NDDoH to explore future visibility impact from various local weight of evidence options which were not included in WRAP modeling. All weight of evidence scenario CMAQ-CALPUFF RRF's will be normalized to the WRAP CMAQ default RRF.

As indicated in Equation 3-1, the normalization scheme requires an RRF based on hybrid CMAQ-CALPUFF emulation of the WRAP CMAQ default configuration. CALPUFF inputs must be set so that the CMAQ-CALPUFF run replicates WRAP CMAQ as closely as possible. Though it is acknowledged that CALPUFF cannot reproduce the CMAQ chemistry, the configuration of emissions and receptors in CALPUFF can be adjusted to more closely emulate the WRAP CMAQ configuration. Software will be developed to allocate all point source emissions to a CALPUFF 36-km area source grid. The CALPUFF "effective height" (plume height) and "initial sigma z" area source input parameters will be used to assign point source emissions to discrete vertical "layers" which are consistent with WRAP CMAQ layers. Effective height will be based on stack height plus plume rise as calculated in the software.

Receptor resolution in WRAP CMAQ is limited to the average concentration in the 36-km surface grid cell volume containing the Class I area IMPROVE site. To emulate in CALPUFF, the predicted concentration will reflect the average over a uniform receptor grid placed within the CALPUFF area-source 36-km grid cell containing the IMPROVE site. Receptors will be spaced at 3 km for a total of 12 x 12 or 144 receptors for each Class I area. Elevation for each receptor will reflect the value used for the CALPUFF area-source grid cell.

Note that no changes to CALMET inputs (and thus the meteorological data set) are required for the emulation scenario. The ammonia background concentrations (emulation scenario) used with POSTUTIL will be derived from CMAQ output, which includes the ammonia species. Hourly ammonia concentrations will be taken from the CMAQ grid cells containing the North Dakota IMPROVE monitoring sites.

WRAP CMAQ RRF's (specific day option) are provided in Table 3-3.

Table 3-3
WRAP CMAQ RRF
(Specific Day Option)

	TRSU Worst D	**TRSU Best D**	**Lost Worst D**	**Lost Best D**
SO_4	0.92	1.02	0.91	1.02
NO_3	0.92	0.93	0.96	0.89
OMC	1.01	1.01	1.05	1.01
EC	0.72	0.78	0.73	0.74
Soil	1.13	1.08	1.11	0.96
CM	1	1	1	1

An example may clarify the normalization process. If, for 20% worst days at TRSU, one obtains an SO_4 RRF of 0.95 from the hybrid model production modeling step (call it weight of evidence scenario 1), and an SO_4 RRF of 0.99 from the hybrid model CMAQ emulation modeling step, the resultant final RRF for SO_4 becomes 0.92(0.95/0.99) or 0.88. In other words, instead of relying on the WRAP RRF of 0.92 to project future SO_4 concentratons, the RRF value has been "corrected" to 0.88 based on assumptions in the weight of evidence scenario 1, and the difference in treatment of emissions/receptors in CMAQ vs. hybrid modeling systems.

4 Detailed Visibility Projection Plan

1. Obtain/prepare CMAQ-related data from WRAP/RMC.

    a. Obtain CMAQ 36-km hourly concentration output files for BASE02b, PLAN02d, and PRP18a modeling cases (also for updated PRP18a cases when available). These data will be used to set SO_2-SO_4-NO_X-HNO_3-NO_3 boundary conditions for CALPUFF, and provide direct estimates of OMC, EC, Soil, and CM for calculation of visibility.

    b. Obtain CMAQ (SMOKE) 36-km gridded area source emissions data (annual) used for cases BASE02b, PLAN02d, and PRP18a modeling cases (also for updated PRP18a cases when available). These data will be used to apportion area source emissions for CALPUFF modeling.

    c. Develop/implement software to convert CMAQ hourly output for SO_2-SO_4-NO_x-

HNO_3-NO_3 to hourly boundary condition input for CALPUFF. Conversion procedure will focus on CMAQ output for grid cells in vicinity of perimeter of NDDoH CALPUFF domain.

   d. Develop/implement software to extract CMAQ hourly output concentrations for OMC, EC, Soil, and CM for grid cells containing TRNP and Lostwood IMPROVE monitors. These concentrations will be used directly in calculation of daily light extinction for these Class I areas (recall that CALPUFF simulation will provide SO_4 and NO_3 species only).

   e. Establish 36 km CALPUFF grid structure for area source emissions. This 36 km area source grid will be aligned with the basic NDDoH CALMET 3 km meteorological/computational grid.

   f. Develop/implement software/procedure to apportion CMAQ 36-km gridded (area source) annual emissions data to CALPUFF 36-km grid cells for species NO_2-NO-NO_3-SO_2-SO_4. The software must account for the use of different Lambert projections in CMAQ and CALPUFF coordinate systems. Also, the CMAQ NO and NO_2 species must be combined to form the NO_X species used by CALPUFF.

2. Review five-year base period (2000-2004) IMPROVE monitoring data to determine 20 % worst/best days at TRNP South Unit and Lostwood NWA Class I areas.

   a. Obtain raw IMPROVE data containing daily deciview for each Class I area from "TSS" web site (http://vista.cira.colostate.edu/tss/) for 2000-2004. For each Class I area and each year, rank days from highest to lowest deciview.

   b. Based on ranked daily deciview, determine 20% worst and 20% best visibility days for each year for each Class I area. Before determining 20% worst and 20% best days, eliminate any days with missing data for extinction calculation.

   c. Optional (weight of evidence) - Examine species composition and met. data for worst days in order to estimate primary source of emissions. Develop/implement objective criteria to discard each 20% worst day (for each year) where primary contribution to total deciview comes from sources over which the NDDoH has no regulatory control (e.g., natural emission source). Determine whether appropriate to substitute for discarded days from remaining ranked pool. Use adjusted inventory of 20% worst days to calculate average deciview, below. Note that this optional screening is not intended to apply to Canadian emissions, as a more direct method for discounting impact of those emissions is proposed (see Section 5).

3. Conduct a performance evaluation of the CMAQ-CALPUFF hybrid modeling system for SO_4 and NO_3 using 2002 meteorology, 2002 emissions, and 2002 IMPROVE observations.

   a. Use WRAP CMAQ hourly output for SO_2-SO_4-NO_X-HNO_3-NO_3 to set hourly boundary conditions for CALPUFF. CMAQ hourly output will be drawn from WRAP Case BASE02b, which is consistent with the scenario WRAP is using to test CMAQ performance.

b. Develop local emissions inventory for SO_2 and NO_X point sources located within the NDDoH CALPUFF domain. Inventory will be based on emissions for Year 2002. Point source data, with exception of oil and gas related sources, will be taken from the NDDoH modeling database, State of Montana, and Canada. Source data for oil and gas related emissions will be taken from the NDDoH / Oil and Gas Division's joint database. Actual emission rates, annual tons per operating hour, will be used for major sources. If time permits, application of seasonal emissions profiles will also be considered. Where CEM's data is available, the NDDoH may consider use of hourly emission rates.

c. Develop local emissions inventory for SO_2-SO_4-NO_X-NO_3 area sources located within the NDDoH CALPUFF domain. Area source data will be based on the WRAP area source inventory for 2002. CMAQ (SMOKE) 36-km gridded data for case BASE02b, apportioned to CALPUFF 36-km grid structure, will constitute the area source inventory. State quarterly emissions data from the "TSS" web site (http://vista.cira.colostate.edu/tss/) for case BASE02b will be used to apply quarterly (seasonal) profiles to the annual WRAP data. Source categories to be included in the area source inventory were outlined in Table 3-1.

d. Apply CALPUFF modeling system (CALMET-CALPUFF-POSTUTIL-CALPOST) for SO_2-SO_4-NO_X-NO_3 source inventories and boundary conditions as outlined above. Execution of the CALPUFF modeling system will be based on the NDDoH BART visibility modeling protocol[12] and the following additional input conditions:

    i. Apply modeling system for Year 2002 emissions/meteorology, only.
    ii. Specify receptors for TRNP South Unit and Lostwood NWA IMPROVE monitor locations, only (two receptors).
    iii. CALPUFF emission factors will be used to facilitate sources for which temporal emission profiles have been applied.
    iv. Apply the ammonia limiting method using POSTUTIL.

e. Prepare statistical summary of hybrid system performance for sulfate and nitrate. Statistics will be based on EPA *Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze*[13] (Section 18). Assessment of performance will focus on accuracy for 20% worst day average, and on the sensitivity of the modeling system to respond to changes in emissions.

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[12] See Supra note 11

[13] See Supra note 6

f. Changes to CALMET-CALPUFF inputs, such as the configuration of emission inventories, which may improve performance and are scientifically defensible will be considered. Effectiveness of these changes will be addressed in a follow-up performance evaluation (i.e., repeat Steps d and e, above).

Note that NDDoH has conducted a preliminary performance evaluation, consistent with the procedure outlined above, which is described in Appendix A of this document.

4. Conduct RRF base period (2000-2004) production modeling for SO_4 and NO_3 using hybrid CMAQ-CALPUFF modeling system with 2002 meteorology.

   a. Use WRAP CMAQ hourly output for SO_2-SO_4-NO_X-HNO_3-NO_3 to set boundary conditions for CALPUFF. CMAQ hourly output for setting CALPUFF base period boundary conditions will be drawn from WRAP Case PLAN02d, which represents a composite emission scenario for the period 2000-2004.

   b. Develop local emissions inventory for SO_2 and NO_X point sources located within the NDDoH CALPUFF domain. Using the 2002 inventory developed for the performance evaluation (2b, above), edit emission rates to reflect average of annual emissions for 2000-2004 (use of unedited 2002 values for oil and gas related sources and other smaller sources may be adequate). WRAP has suggested monthly scaling of emissions[14]. If time permits, consider application of temporal emission profile to larger sources, where applicable (e.g., EGU's, agricultural facilities).

   c. Develop local emissions inventory for SO_2-SO_4-NO_X-NO_3 area sources located within the NDDoH CALPUFF domain. Area source data will be based on the WRAP area source inventory for the base period, 2000-2004. CMAQ (SMOKE) 36-km gridded data for case PLAN02d, apportioned to CALPUFF 36-km grid structure, will constitute the area source inventory. State quarterly emissions data from "TSS" web site (case PLAN02d) may be used to apply quarterly (seasonal) profiles to the annual WRAP data. Source categories to be included in the area source inventory were outlined in Table 3-1.

   d. Apply CALPUFF modeling system (CALMET-CALPUFF-POSTUTIL) for SO_2-SO_4-NO_X-NO_3 source inventories and boundary conditions as outlined above. Execution of the CALPUFF modeling system will be based on the NDDoH BART visibility modeling protocol and the following additional input conditions:

      i. Changes to CALMET-CALPUFF input settings (if any) established in performance evaluation.
      ii. Apply modeling system for year 2002 meteorology, only.

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[14] See Supra note 2

   iii. Specify receptors for TRNP South Unit and Lostwood NWA IMPROVE monitor locations. For consistency with EPA guidance[15], additional receptors will be included to accommodate receptor averaging (accounts for possible inaccuracy of plume placement by the model) at both sites. A 3 x 3 grid of receptors, at 5 km spacing, will be centered on the IMPROVE monitor location.
   iv. CALPUFF emission factors will be used to facilitate sources for which temporal emission profiles have been applied.
   v. Apply the ammonia limiting method using POSTUTIL with hourly background values. Note that, if modeled scenario involves discounting the impact of Canadian sources (see Section 5), the 3-step ammonia limiting method must be applied to properly account for scavenging of ammonia by Canadian source emissions.

5. Conduct RRF future period (2018) production modeling for SO_4 and NO_3 using CMAQ-CALPUFF hybrid modeling system with 2002 meteorology.

   a. Use WRAP CMAQ hourly output for SO_2-SO_4-NO_X-HNO_3-NO_3 to set boundary conditions for CALPUFF. CMAQ hourly output for setting CALPUFF future period boundary conditions will be drawn from WRAP case PRP18a, which represents the preliminary projected emission scenario for 2018.

   b. Develop local emissions inventory for SO_2 and NO_X point sources located within the NDDoH CALPUFF domain. Using the 2002 inventory developed for RRF base period modeling (4b, above), annual emission rates / stack parameters will be edited to reflect expected changes by 2018 (use of unedited 2002 values for oil and gas related sources and other smaller sources may be appropriate). Point sources which have received or are likely to receive North Dakota (Montana, Canada?) air quality permits subsequent to 2004 will be added to the inventory. Sources which have shut down or are likely to shut down subsequent to 2004 and prior to 2018 will be deleted. For BART-applicable point sources, the NDDoH preferred BART control scenario will be used to develop 2018 annual emission rates and stack parameters (i.e., until BART control strategies are final). Temporal emission scaling will be applied as in the baseline point source inventory.

   c. Develop local emissions inventory for SO_2-SO_4-NO_X-NO_3 area sources located within the NDDoH CALPUFF domain. Area source data will be based on the WRAP area source inventory for the future period 2018. CMAQ (SMOKE) 36-km gridded data for case PRP18a, apportioned to CALPUFF 36-km grid structure, will constitute the area source inventory. State quarterly emissions data from “TSS” web site (case PRP18a) may be used to apply quarterly (seasonal) resolution to the annual WRAP data. Source categories to be included in the area source inventory were outlined in Table 3-1.

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[15] See Supra note 6

d. Apply CALPUFF modeling system (CALMET/CALPUFF/POSTUTIL) for SO_2-SO_4-NO_X-NO_3 source inventories and boundary conditions as outlined above. Execution of the CALPUFF modeling system will be based on the NDDoH BART visibility modeling protocol and the following additional input conditions:

   i. Changes to CALMET/CALPUFF input settings (if any) established in performance evaluation.
   ii. Apply modeling system for year 2002 meteorology, only.
   iii. Specify receptors for TRNP South Unit and Lostwood NWA IMPROVE monitor locations. For consistency with EPA guidance[16], additional receptors will be included to accommodate receptor averaging (accounts for possible inaccuracy of plume placement by the model) at both sites. A 3 x 3 grid of receptors, at 5 km spacing, will be centered on the IMPROVE monitor location.
   iv. CALPUFF emission factors will be used to facilitate sources for which temporal emission profiles have been applied.
   v. Apply the ammonia limiting method using POSTUTIL with hourly background values. Note that, if modeled scenario involves discounting the impact of Canadian sources (see Section 5), the 3-step ammonia limiting method must be applied to properly account for scavenging of ammonia by Canadian source emissions.

e. Revise future case modeling (repeat 5a, 5c, and 5d) using WRAP CMAQ output representing updates to case PRP18a, when available.

f. Optional (weight of evidence) - To discount the effect of Canadian sources on compliance with visibility goals, delete all Canadian sources from the CALPUFF future emissions inventory before applying model (see discussion *The Impact of International Sources on North Dakota Class I Areas* in Section 5).

6. Conduct CMAQ emulation modeling needed to implement the normalization step described in Section 3.2, using CMAQ-CALPUFF hybrid modeling system with 2002 meteorology. (Note that CMAQ emulation modeling is conducted only once, with the same result used for any weight of evidence option).

   a. Modify the base and future period emissions inventories developed in above Steps 4 and 5 as follows:

      i. Reallocate point source emissions to area sources consistent with CALPUFF 36-km area source grid structure.
      ii. Use CALPUFF area-source “release height” and “initial sigma z” input parameters to configure all area sources (including those just created from point sources) in discrete “layers” consistent with WRAP CMAQ layers.

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[16] See Supra note 6

        iii. No modification necessary for boundary conditions (boundary condition resolution already 36 km).

    b. Apply CALPUFF modeling system (CALMET-CALPUFF-POSTUTIL) for emission inventories and boundary conditions as outlined above, for both base and future period scenarios. Execution of the CALPUFF modeling system will be based on the NDDoH BART visibility modeling protocol and the following additional input conditions:

        i. Changes to CALMET/CALPUFF input settings (if any) established in performance evaluation.
        ii. Apply modeling system for year 2002 meteorology, only.
        iii. Use uniform receptor grid spaced to fill the CALPUFF 36-km (area source) grid cell containing the TRNP South Unit and grid cell containing the Lostwood NWA IMPROVE monitor locations. Receptors will be spaced at 3 km for a total of 12x12 or 144 receptors for each Class I area.
        iv. CALPUFF emission factors will be used to facilitate sources for which temporal emission profiles have been applied.
        v. Apply the ammonia limiting method using POSTUTIL with WRAP CMAQ hourly background values.

7. Develop SO_4 and NO_3 relative response factors (RRF) using CMAQ emulation scenario modeling results. (Note that CMAQ emulation RRF's are developed only once, and the same values are used for any weight of evidence option.)

    a. Extract CALPUFF daily (24-hour) predicted concentrations for the days consistent with the 20% worst days identified in IMPROVE monitoring data for 2002. Calculate the average of the daily SO_4 and NO_3 predictions for these days, for both baseline and future period scenarios. Repeat procedure for each Class I area.

    b. Calculate 20% worst day RRF's for each species (SO_4, and NO_3) as the ratio of the future average worst-day prediction to the baseline average worst-day prediction. Repeat for each Class I area.

    c. Repeat a, b, above, for 20% best days.

8. Develop final relative response factors using baseline and future scenario production modeling results.

    a. Extract CALPUFF daily (24-hour) predicted concentrations for the days consistent with the 20% worst days identified in IMPROVE monitoring data for 2002. Calculate the average of the daily SO_4 and NO_3 predictions for these days, for each scenario. Repeat procedure for each Class I area.

    b. Calculate 20% worst day RRF's for SO_4 and NO_3 species as the ratio of the future average worst-day prediction to the baseline average worst-day prediction. Repeat for each Class I area.

c. Use these RRF's, the CMAQ emulation RRF's from item7b, and the WRAP CMAQ RRF's from Table 3-3 to calculate the final RRF's for SO_4 and NO_3, using Equation 3-1. Repeat for each Class I area

d. Repeat a, b, and c, above, for 20% best days.

e. For OMC, EC, Soil, and CM species, take final RRF's from WRAP CMAQ modeling, as provided in Table 3-3.

f. For sea salt (SS), assume RRF of 1.0 for worst-days/best-days for both Class I areas.

9. Apply final RRF's to baseline monitoring data (2000-2004) to project future visibility for each Class I area .

   a. Apply species-specific RRF's to 20% worst baseline monitored days in year 2000 to project future concentrations for each species for each day (the same species-specific RRF's are used for each day). Repeat for years 2001 through 2004.

   b. Using the projected future concentrations for 20% worst days in year 2000, calculate light extinction (using new IMPROVE equation) and convert to deciview for each day. Repeat for years 2001 through 2004.

   c. Calculate average worst-day future deciview from projected daily future deciview (7b), for each year (2000-2004). Then, calculate future five-year average worst-day deciview.

   d. Repeat a, b, and c, above, for 20% best baseline monitored days.

   e. Optional (weight of evidence) - Using the species-specific projections from items 8c and 8e, calculate five-year average future light extinction for each species for 20% worst days (to accommodate glide path goals for individual species).

10. Determine status with respect to 2018 visibility goals.

   a. Compare five-year average projected future deciview for worst days (item 9c) with five-year average monitored baseline deciview for worst days (WRAP TSS), for each Class I area, to determine status with respect to visibility goals.

   b. Compare five-year average projected future deciview for best days (item 9d) with five-year average monitored baseline deciview for best days (WRAP TSS), for each Class I area, to determine whether visibility has deteriorated.

c. Optional (weight of evidence) - Compare five-year average projected future light extinction for each species for worst days (item 9e) with five-year average monitored baseline extinction for each species for worst days (WRAP TSS) to determine status with respect to visibility goals for individual species.

5 The Impact of International Sources on North Dakota Class I Areas

5.1 Proposed Approach

In the process of analyzing progress with respect to visibility goals, it will be necessary for NDDoH to address the impact of Canadian sources north of the International border. One method, as part of a weight of evidence demonstration, would be to discount the effect of Canadian sources (over which the State has no regulatory control). This could be accomplished by eliminating the contribution of Canadian sources to baseline monitoring data used for visibility projections, eliminating Canadian sources from the modeled inventories used to develop RRF's, and developing an adjusted glide path for future visibility goals.

Recall that EPA guidance[17] provides that RRF's are developed by comparing the future average predicted concentration for 20% worst days (best days) to the baseline average predicted concentration for 20% worst days (best days), for each species. The species-specific RRF's are then applied to species-specific baseline monitored concentrations for each 20% worst day (best day), for each baseline year, to project corresponding future values. Finally, these future daily concentrations are converted to light extinction, then deciview, and averaged over all worst (best) days to project future deciview. This approach is incorporated in the NDDoH visibility projection plan (Section 4).

To discount the effect of Canadian sources, the RRF's are adjusted in the modeling process, and a modified glide path is developed.. As discussed in Section 3, the projection of future concentration can be expressed:

$$X^{i,j}_{of} = X^{i,j}_{ob}\,(RRF^{i}) = X^{i,j}_{ob}\,(\overline{X}^{i}_{pf}/\overline{X}^{i}_{pb}) \qquad (5\text{-}1)$$

where

$X^{i,j}_{of}$ represents projected **o**bserved **f**uture concentration for species i on day j (each of 20% worst days for each baseline year),

$X^{i,j}_{ob}$ represents **o**bserved **b**aseline (IMPROVE data) concentration for species i on day j (each of 20% worst days for each baseline year),

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[17] See Supra note 6

$\bar{X}^{i}_{pf}$ represents average **p**redicted **f**uture concentration for species i (average of 20% worst days),

$\bar{X}^{i}_{pb}$ represents average **p**redicted **b**aseline concentration for species i (average of 20% worst days),

RRF^{i} represents the relative response factor for species i.

To discount the effect of Canadian emissions, the impact of Canadian sources is removed from Equation 5-1 variables, which provides

$$X^{i,j}_{of(us)} = X^{i,j}_{ob(us)} \left(\bar{X}^{i}_{pf(us)} / \bar{X}^{i}_{pb(us)}\right) \qquad (5\text{-}2)$$

where

(us) represents the Equation 5-1 variable with the impact of Canadian sources removed (impact of US sources and natural background, only)

Thus, baseline US observations which exclude the impact of Canadian sources, and future and baseline modeling results which exclude the impact of Canadian sources, would be required to project future US concentrations. While baseline and future modeled inventories can be easily adjusted to remove Canadian sources, adjustment of baseline observations to exclude Canadian source impact could be technically difficult.

It is reasonable instead to consider a modeling solution for the estimation of adjusted baseline concentrations. A factor representing the ratio of modeled impact of “all baseline sources less Canadian sources” to “all baseline sources” could be applied to adjust the observed baseline, as follows:

$$X^{i,j}_{ob(us)} = X^{i,j}_{ob} \left(\bar{X}^{i}_{pb(us)} / \bar{X}^{i}_{pb}\right) \qquad (5\text{-}3)$$

Substituting Equation (5-3) into Equation (5-2) provides

$$X^{i,j}_{of(us)} = X^{i,j}_{ob} \left(\bar{X}^{i}_{pb(us)} / \bar{X}^{i}_{pb}\right) \left(\bar{X}^{i}_{pf(us)} / \bar{X}^{i}_{pb(us)}\right) \qquad (5\text{-}4)$$

Finally, Equation (5-4) reduces to

$$X^{i,j}_{of(us)} = X^{i,j}_{ob} \left(\bar{X}^{i}_{pf(us)} / \bar{X}^{i}_{pb}\right) \qquad (5\text{-}5)$$

So Equation 5-5 provides a modeling solution for projecting future concentrations without the impact of Canadian sources. The adjusted RRF’s ($\bar{X}^{i}_{pf(us)} / \bar{X}^{i}_{pb}$) would be inserted in the visibility projection plan item 8b to project future concentrations for each species for each day. Effectively, this approach is implemented by including Canadian sources in the baseline modeled inventory, and excluding Canadian sources from the future modeled inventory (i.e., the weight of evidence option included as modeling plan item 5f).

To complete the source apportionment process, the impact of Canadian emissions must also be removed from the glide path used to assess visibility improvement progress. The revised glide path would be based on Equation 5-3, which provides a baseline starting point without the effect of Canadian emissions. The adjusted species-specific glide path is illustrated in Figure 5-1, for a case where Canadian emissions comprise one-half of total observed concentrations for sulfate.

One caveat associated with the use of the adjusted glide path is that the impact of US-only emissions will not be consistent with 2018 IMPROVE monitoring data (which will reflect the total impact of all sources). If the 2018 IMPROVE data are to be used to monitor visibility progress with respect to the adjusted 2018 goal, the impact of 2018 Canadian emissions will first have to be subtracted from the monitored observations.

The NDDoH proposes to apply the adjusted RRF's and glide path for 20% worst days only, as the impact of Canadian sources is not likely to be problematic in meeting visibility goals for best days. Because hybrid modeling will be applied only for S and N chemistry, the RRF adjustment would apply only to sulfate and nitrate species.

Note that other methods have been suggested for discounting the effect of international sources on visibility improvement progress. CENRAP has proposed several options for discounting the impact of international sources[18]. Montana has suggested an adjusted glide path where the impact of international sources is added onto the 2064 natural background, rather than subtracted from the baseline. Effectively, the Montana approach produces the same result as the procedure suggested here.

5.2 Illustration

A species-specific illustration may clarify the proposed approach. Consider a hypothetical US Class I area where Canadian emissions contribute one-half of the average observed sulfate concentration for 20% worst days. For this illustration, it is assumed there are only two worst-case monitored days. It is also assumed that impact of US sources (plus natural sources) will be 25% lower in 2018 compared to the baseline, and that the inventory/impact of Canadian sources remains unchanged between the baseline and 2018. Finally, to implement the new IMPROVE equation, values for $f_s(RH)$, $f_l(RH)$, and conversion from sulfate to ammonium sulfate are assigned as 2.7, 2.1, and 1.375, respectively. (For simplification, this illustration does not include WRAP CMAQ normalization.)

First, consider what happens if no adjustment is made, and the impact of Canadian sources

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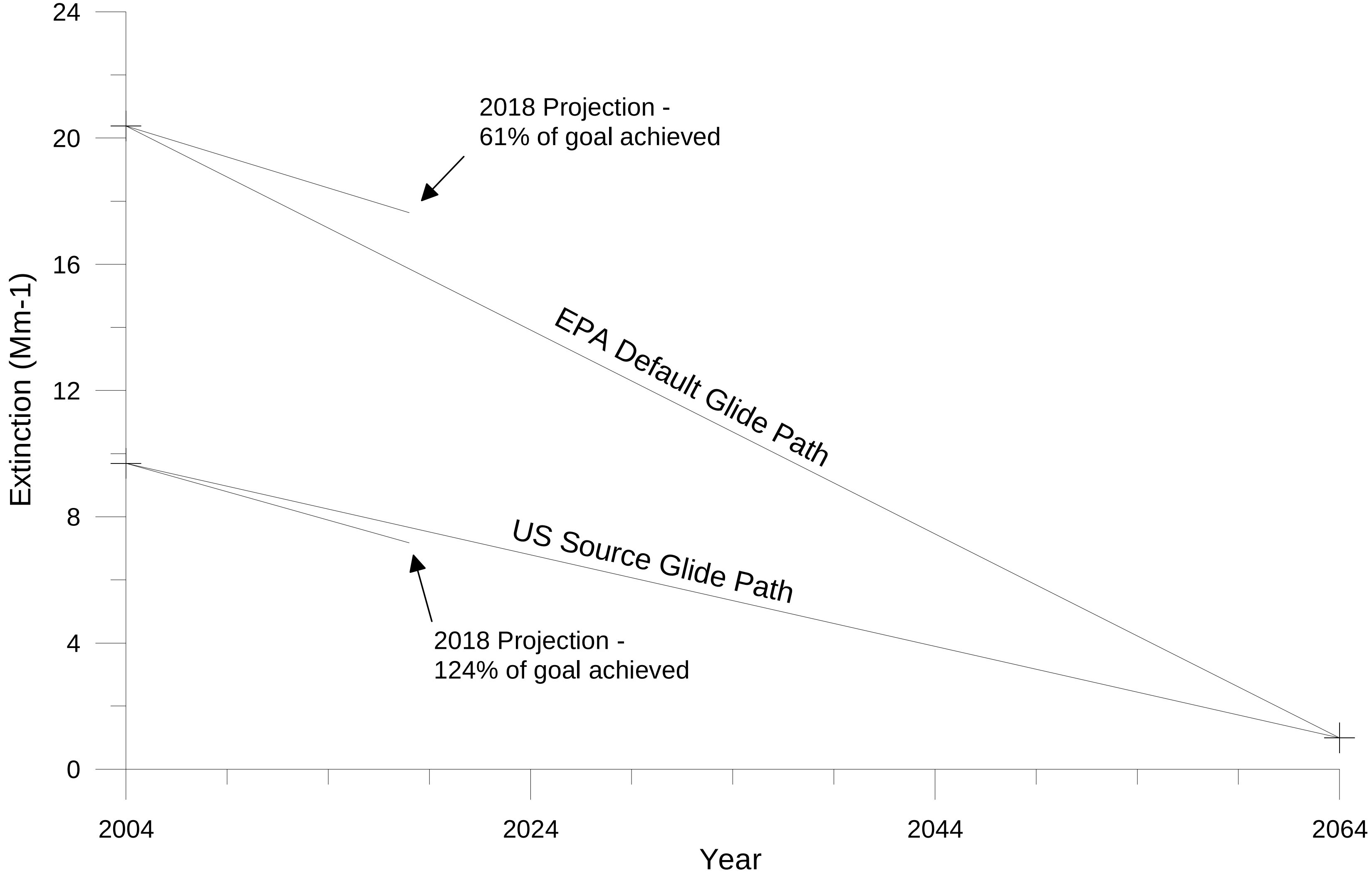
[18] CENRAP, 2007. CENRAP Policy Oversight Group (POG) - Summary of PM Source Apportionment Modeling and 2018 Projection Approaches. Power Point presentation, Joint Workgroup Meeting, Kansas City, Missouri, March 7, 2007.

Figure 5-1
Illustration of Visibility Improvement Using EPA Default Glide Path and US Source Adjusted Glide Path for Sulfate



remains in the IMPROVE baseline observations, and the modeled baseline and future emission inventories (future projection based on Equation 5-1):

1) Examination of IMPROVE monitor data for this Class I area reveals that May 30 and July 10 are the two worst 20% visibility days in 2002. The observed concentration of sulfate on May 30 is 2.5 ug/m3, and the observed concentration of sulfate on July 10 is 2 ug/m3.

2) Generate EPA default glide path for this Class I area (Figure 5-1). Species-specific starting point for this glide path is determined by converting observed baseline sulfate concentrations for 20% worst days (in this case 2.5 ug/m3 and 2.0 ug/m3) to light extinction (new IMPROVE equation), then averaging over all worst case days. This provides a value of 20.38 Mm^{-1}. The 2064 endpoint for this path is the natural background, which for sulfate is assumed at 1.0 Mm^{-1}.

3) Baseline and future emission inventories are developed which include all US and Canadian sources. The CALPUFF/CMAQ modeling system is executed for the baseline inventory and the future inventory.

4) Modeling results for May 30 show a baseline predicted sulfate concentration of 2.8 ug/m3, and a future predicted sulfate concentration of 2.45 ug/m3. Results for July 10 indicate a baseline predicted sulfate concentration of 2.4 ug/m3, and a future predicted sulfate concentration of 2.1 ug/m3. Note that these results are consistent with the assumptions, above.

5) To develop the RRF for worst-day sulfate, the average future prediction is divided by the average baseline prediction as follows:

$$RRF = ((2.45+2.1)/2) / ((2.8+2.4)/2) = 0.875$$

6) The RRF is applied to sulfate observations for worst-case baseline days to project future worst-case sulfate concentrations:

May 30 $2.5 (0.875) = 2.19$ ug/m^3
July 10 $2.0 (0.875) = 1.75$ ug/m^3

7) Using the new IMPROVE equation, projected sulfate concentrations are converted to light extinction, then averaged over all worst-case days. This provides an average projected extinction of 17.63 Mm^{-1}.

8) Finally, the average projected future light extinction is compared with the glide path goal. This is illustrated in Figure 5-1.

Now, the exercise is repeated using the suggested approach for discounting impact of Canadian sources (future projection based on Equation 5-5).

1) Examination of IMPROVE monitor data for a hypothetical Class I area reveals that May 30

and July 10 are the two worst 20% visibility days in 2002. The observed concentration of sulfate on May 30 is 2.5 ug/m3, and the observed concentration of sulfate on July 10 is 2.0 ug/m3.

2) Develop adjusted glide path using Equation 5-3 (Figure 5-1). Species-specific baseline starting point for this glide path is developed by applying Equation 3 to 20% worst day sulfate concentrations, then converting concentration to light extinction, and averaging over all worst case days. For this illustration, the baseline value is 9.69 Mm^{-1}. Again, the path terminates in 2064 at natural background, which is assumed at 1.0 Mm^{-1} for sulfate.

3) A baseline emission inventory is developed which includes all US and Canadian sources. A future emission inventory is developed which includes all US sources, but no Canadian sources. The CALPUFF/CMAQ modeling system is executed for the baseline inventory and the future inventory.

4) Modeling results for May 30 show a baseline predicted sulfate concentration of 2.8 ug/m3, and a future predicted sulfate concentration of 1.05 ug/m3. Results for July 10 indicate a baseline predicted sulfate concentration of 2.4 ug/m3, and a future predicted sulfate concentration of 0.9 ug/m3. Note that these results are consistent with illustration assumptions.

5) To develop the RRF for worst-day sulfate, the average future prediction is divided by the average baseline prediction as follows:

$$RRF = ((1.05+0.9)/2) / ((2.8+2.4)/2) = 0.375$$

6) The RRF is applied to sulfate observations for worst-case baseline days to project future worst-case sulfate concentrations:

May 30 $2.5 (0.375) = 0.94$ ug/m^3
July 10 $2.0 (0.375) = 0.75 ug/m^3$

7) Using the new IMPROVE equation, projected sulfate concentrations are converted to light extinction, then averaged over all worst-case days. This provides an average projected extinction of 7.18 Mm^{-1}.

8) Finally, the average projected future light extinction is compared with the adjusted glide path goal. This is illustrated in Figure 5-1.

As indicated in Figure 5-1, with the EPA default method including all sources, 61% of the 2018 visibility goal is achieved. With the alternate approach excluding Canadian source impact, 124% of the 2018 goal is achieved.

Note that values used in this illustration for observed and modeled sulfate concentrations are completely hypothetical. The assumed 2064 natural background for sulfate, 1.0 Mm^{-1}, is consistent with values posted on the TSS web site for North Dakota Class I areas. However, other natural background values have been suggested[19].

6 Weight of Evidence Options

The NDDoH will complete the default visibility projection plan as detailed in Section 4. But the Regional Haze Rule[20] specifies that the SIP may be based, in part, on evidence apart from results of the default projection methodology. For example, the analysis could logically be modified to discount the impact of visibility-affecting emission sources over which the NDDoH has no regulatory control.

Options which could be considered in the analysis of visibility goals include:

- Discounting the impact of Canadian source visibility-affecting emission sources (discussed in Section 5 and included in the Visibility Projection Plan as optional item 5f).

- Discard certain worst-case monitored days, before projecting future visibility, if it can be determined that primary species affecting light extinction on these days cannot be controlled by NDDoH. This approach is included as a “weight of evidence” option in the Visibility Projection Plan (item 2c).

- Use of species-specific visibility progress goals. This approach has been suggested by WRAP[21], and is incorporated in the Visibility Projection Plan as “weight of evidence” options (items 2f, 9e, and 10c).

- Basing 20% worst visibility days for determining RRF’s on baseline model results rather than IMPROVE monitor data. This may be justified because neither CMAQ nor CALPUFF perform well on a “paired-in-time” basis. The resultant RRF’s would still be applied to worst case IMPROVE days to project future visibility.

The above list is preliminary and not necessarily complete. The process or results of the visibility projection analysis may suggest other weight of evidence options the NDDoH will want to pursue.

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[19] EPA, 2003. Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program. Publication No. EPA-454/B-03-005, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

[20] See Supra note 1

[21] WRAP, 2007. Attribution of Haze Workgroup’s Technical Recommendations on Monitoring Metrics for Regional Haze Planning (2/23/07 Draft).

7 CALHAZE Software

The NDDoH is developing software (CALHAZE) to automate the analysis of IMPROVE baseline monitoring data, the development of RRF's, and the projection of future visibility. To establish baseline monitored conditions, the software will access IMPROVE data downloaded from the "VIEWS" web site. To develop RRF's, the software will operate on the CALPUFF (POSTUTIL) hourly output files from baseline and future modeled scenarios. The new IMPROVE equation, along with weight of evidence options noted above, will be incorporated in the software.

This software will be made available for public review. In order to validate it's accuracy, CALHAZE output values for baseline conditions and default RRF's have been successfully cross checked with data on the WRAP "TSS" web site.

Appendix A
Hybrid CMAQ-CALPUFF Performance Evaluation

The North Dakota Department of Health (NDDoH) has conducted a limited operational evaluation to assess performance of the hybrid CMAQ-CALPUFF modeling system. The focus of the evaluation was to assess performance in reproducing observed concentrations of sulfate and nitrate at IMPROVE monitoring sites in North Dakota. These sites include the Theodore Roosevelt National Park South Unit (TRSU) and the Lostwood Wilderness Area. Alternative input options which might improve performance were also explored. To the extent applicable, the performance evaluation followed EPA guidance for Regional Haze modeling analyses[22].

Evaluation of performance was based on the plan outlined in Section 4.3 of the modeling protocol. WRAP CMAQ hourly concentration output (SO_2-SO_4-NO_X-HNO_3-NO_3) for Case BASE02B was used to set hourly boundary conditions for CALPUFF. The emissions inventory (SO_2-NO_X) for the point source category was developed using data from the NDDoH emissions database for 2002, and sources were configured as conventional point sources in CALPUFF. This inventory included point sources located in adjacent parts of South Dakota, Montana, and Canada, which are included in the NDDoH CALPUFF domain (see Figure 1-2). This inventory also included SO_2 emissions associated with oil and gas production facilities (treaters and flares) in North Dakota, which did not appear to be accounted for in the WRAP inventory for BASE02B. Emission rates for the point source inventory reflect actual emissions for Year 2002.

All other source categories (see Protocol Table 3-1) were treated as area sources in CALPUFF, and the emissions inventory (SO_2-SO_4-NO_X-NO_3) for these categories was based on WRAP CMAQ input (SMOKE output) for all sources other than point sources. Software was prepared and implemented to apportion the gridded SMOKE output emissions for BASE02B into a 36-km area source grid structure developed for the NDDoH CALPUFF domain, on a consistent spatial basis. Emission rates for this area source inventory reflect annual averages for the SMOKE data.

The CALPUFF modeling system (CALMET-CALPUFF-POSTUTIL-CALPOST) was applied for SO_2-SO_4-NO_X-NO_3 source inventories and boundary conditions as described above. For all other input conditions, execution of the CALPUFF modeling system was initially based on the

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[22] EPA, 2007. Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze. Publication No. EPA 454/B-07-002, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

NDDoH BART visibility modeling protocol[23] using Year 2002 meteorology. Single receptors were placed at the TRNP and Lostwood IMPROVE sites. The ammonia limiting method was applied using POSTUTIL. Concurrent, monthly average ammonia data were taken from the NDDoH Beulah monitoring site.

After initial application of CALPUFF for the performance evaluation, it was concluded that certain scientifically-defensible adjustments to CALPUFF input conditions may improve performance for the hybrid modeling system, and should be investigated. Thus, the performance evaluation evolved into a suite of tests which are described below.

1) Test 1 - CALPUFF system executed with default input conditions, as outlined above. Air mass depth for boundary conditions was set to 2000 meters.

2) Test 2 - CALPUFF as in Test 1, but using CEMS 2002 hourly emissions data (SO_2, NO_X) for point sources, where available.

3) Test 3 - CALPUFF as in Test 1, but using WRAP MM5 12 km 2002 mesoscale data in CALMET, rather than the default NDDoH RUC 2002 mesoscale data.

4) Test 4 - CALPUFF as in Test 1, but increasing air mass depth for boundary conditions from 2000 to 3000 meters.

5) Test 5 - CALPUFF as in Test 1, but with addition of SO_4 and NO_3 emissions from point sources. (Previous tests excluded this component, because SO_4 and NO_3 emissions are not included in the NDDoH point source inventory. For Test 5, an SO_4-NO_3 emissions inventory was derived from SMOKE gridded output for the point source category, and configured as area sources for CALPUFF.)

6) Test 6 - CALPUFF as in Tests 4 and 5 (air mass depth = 3000 meters, SO_4 and NO_3 emissions from point sources included), but area sources configured as 4 groups to account for varying release heights, and Beulah hourly profile used for background NH_3 in POSTUTIL. (Area sources were configured as a single CALPUFF group in previous tests.)

7) Test 7 - CALPUFF as in Test 6, but Beulah hourly NH_3 profile doubled for Lostwood.

Results of the performance evaluation are summarized in Tables A-1 and A-2. Table A-1 compares predicted NO_3 and SO_4 concentrations to observed concentrations for both IMPROVE sites, while Table A-2 provides predicted-to-observed ratios. Note that both tables include a column labeled “CMAQ only”, which provides the original WRAP CMAQ results for Case BASE02B.

As shown in Tables A-1 and A-2, the three metrics selected to measure performance for this

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[23] See Supra Note 11

evaluation are 90th percentile day concentration (24-hour average), average of 20% worst days concentration, and annual average concentration. The first two metrics were selected for consistency with the time scale that applies to regional haze modeling, i.e., average of the 20% worst or 20% best days. The third metric, annual average concentration, is a measure of the model's ability to accurately conserve total annual mass. The comparison between predicted and observed concentrations for the first two metrics is unpaired in time.

Results in Tables A-1 and A-2 indicate that the hybrid modeling system performed well, in general. Even for the default Test 1, predictions were well within a factor of two of observations. In most cases, the hybrid system predictions were closer to observations than predictions from CMAQ, alone. Table A-2 illustrates that the hybrid system slightly over-predicted observations for TRSU NO_3, and slightly under-predicted, otherwise.

A comparison of results for Tests 1 through 5 reveals very little difference in predictions. The implication is that the input changes reflected in Tests 2 through 5 did not add significant value to the predictions. The increased temporal resolution obtained by using the CEMS hourly emissions for applicable point sources (Test 2) provided no consistent improvement. Test 3 results suggest that the NDDoH RUC mesoscale data is consistent with the WRAP MM5 mesoscale data. Test 4 results indicate that CALPUFF is not very sensitive to boundary air mass depth. Even the addition of point source NO_3 and SO_4 emissions in Test 5 achieved no meaningful improvement in predictions, suggesting that sources configured as area sources in CALPUFF may have only a small contribution to the total prediction.

While the operational evaluation to compare predictions with observations was being conducted, the NDDoH also undertook a preliminary diagnostic evaluation[24] to assess the response of the hybrid modeling system to changes in NO_3 and SO_4 predictions. In response to significant reductions in both SO_2 and NO_X emissions, the NDDoH found that the hybrid system responded reasonably well with lower SO_4 predictions, but seemed to overstate NO_3 predictions for the reduced emission scenario. In fact, NO_3 concentrations actually increased under some assumptions, possibly an overreaction to the newly freed ammonia in the reduced SO_2 emissions scenario (SO_2 preferentially scavanges ammonia in the CALPUFF chemistry). This behavior was not seen in the WRAP CMAQ results for baseline versus future predictions.

To address the problematic NO_3 response, the NDDoH discussed the issue with Joe Scire (TRC)[25], a recognized CALPUFF expert in the regulatory modeling community. Mr. Scire indicated that TRC testing has shown that the NO_3 response may improve if hourly background ammonia is used rather than monthly average values. Also, Mr. Scire provided some insight on configuring area sources in CALPUFF to be more consistent with the area source treatment in CMAQ. This involves proper settings for the CALPUFF "release height" and "initial sigma z" input parameters for area sources. The NDDoH retested after incorporating Mr. Scire's

---

[24] See Supra note 22

[25] TRC, 2008. Telephone consultation with Joe Scire, May 29, 2008. Joe Scire, TRC Corporation, Lowell, MA 01854

suggestions, i.e., using hourly ammonia background and reconfigured area sources. Although the NO_3 response improved, predicted reductions were still not consistent with CMAQ.

As a result of the initial diagnostic performance testing, the NDDoH concluded that the use of hourly ammonia background concentrations is preferable to the use of monthly averages, and that CALPUFF inputs for area sources should be reconfigured. Additional operational evaluation tests (Tests 6 and 7) were thus conducted to determine how these changes would affect the comparison with observations. Test 6 was conducted by first assuming a boundary air mass depth of 3000 meters (Test 4) and accounting for NO_3 and SO_4 emissions from point sources (Test 5). Then area sources were configured as suggested by Scire, including the use of 4 area source groups to account for varying release heights for different source categories (as opposed to one group in Tests 1-5). Finally, Test 6 included use of the Beulah hourly ammonia profile in POSTUTIL.

Results of Test 6, as shown in Tables A-1 and A-2, indicate significantly improved performance with respect to TRSU NO_3, but worse performance for Lostwood NO_3. Results for SO_4 were not significantly affected. This tendency for conflicting results for TRSU and Lostwood NO_3 was also exhibited in Tests 1 through 5, and led the NDDoH to conclude that the Beulah data may not be representative of ammonia background for both TRSU and Lostwood. Moreover, the actual ammonia background affecting Lostwood may be significantly higher than the background affecting TRSU.

In Test 7, the NDDoH found that observational agreement for Lostwood NO_3 can be vastly improved if the ammonia hourly backgound values are approximately doubled (for Lostwood only). All other conditions for Test 7, including the ammonia background for TRSU, remain the same as in Test 6. NO_3 predictions for Test 7 in Tables A-1 and A-2 now show good agreement with observations at both TRSU and Lostwood.

Table A-1
Hybrid CMAQ-CALPUFF Performance Evaluation
Observed and Predicted Concentrations Year 2002 (ug/m^3)

	Observed	Hybrid CMAQ-CALPUFF Predicted*							CMAQ only
		Test 1	Test 2	Test 3	Test 4	Test 5	Test 6	Test 7	
TRSU NO3									
90th Percentile Day	**1.21**	1.50	1.46	1.55	1.43	1.47	1.21	1.21	1.62
Avg 20% Worst Days	**1.42**	1.59	1.59	1.65	1.56	1.59	1.41	1.41	1.84
Annual Average	**0.50**	0.71	0.71	0.73	0.70	0.71	0.53	0.53	0.57
TRSU SO4									
90th Percentile Day	**1.88**	1.72	1.72	1.66	1.77	1.72	1.79	1.79	1.60
Avg 20% Worst Days	**2.43**	1.96	1.97	1.83	1.96	1.98	1.99	1.99	1.76
Annual Average	**1.03**	0.90	0.90	0.86	0.90	0.91	0.91	0.91	0.84
Lostwood NO3									
90th Percentile Day	**1.95**	1.48	1.50	1.56	1.47	1.44	1.13	1.76	2.04
Avg 20% Worst Days	**2.33**	1.55	1.55	1.61	1.52	1.50	1.30	2.03	2.34
Annual Average	**0.79**	0.70	0.70	0.73	0.69	0.67	0.47	0.80	0.79
Lostwood SO4									
90th Percentile Day	**2.22**	2.06	2.03	1.90	2.07	2.19	2.21	2.21	2.43
Avg 20% Worst Days	**2.49**	2.21	2.21	2.09	2.22	2.35	2.36	2.36	2.74
Annual Average	**1.18**	1.07	1.07	1.03	1.08	1.15	1.17	1.17	1.32

* Test 1 - Calpuff run with default BART screening protocol + full emissions inventory + boundary conditions
Test 2 - Calpuff as in Test 1 but using CEMS hrly emissions (SO2, NOX) where available
Test 3 - Calpuff as in Test 1 but using WRAP MM5 12km mesoscale data (in CALMET)
Test 4 - Calpuff as in Test 1 but assuming boundary air mass depth as 3000 m rather than 2000 m
Test 5 - Calpuff as in Test 1 but with addition of NO3 and SO4 emissions from point sources
Test 6 - Calpuff as in Test 1 but assuming boundary air mass depth as 3000 m (Test 4) and with addition of NO3 and SO4 emissions from point sources (Test 5). Area sources configured as 4 groups and Beulah hourly profile used for backgound NH3.
Test 7 - Calpuff as in Test 6 but Beulah hourly NH3 profile doubled for Lostwood

Table A-2
Hybrid CMAQ-CALPUFF Performance Evaluation
Predicted to Observed Ratios 2002

	Hybrid CMAQ-CALPUFF*							CMAQ only
	Test 1	Test 2	Test 3	Test 4	Test 5	Test 6	Test 7	
TRSU NO3								
90th Percentile Day	1.24	1.21	1.28	1.18	1.21	1.00	1.00	1.34
Avg 20% Worst Days	1.12	1.12	1.16	1.10	1.12	0.99	0.99	1.30
Annual Average	1.42	1.42	1.46	1.40	1.42	1.06	1.06	1.14
TRSU SO4								
90th Percentile Day	0.91	0.91	0.88	0.94	0.91	0.95	0.95	0.85
Avg 20% Worst Days	0.81	0.81	0.75	0.81	0.81	0.82	0.82	0.72
Annual Average	0.87	0.87	0.83	0.87	0.88	0.88	0.88	0.82
Lostwood NO3								
90th Percentile Day	0.76	0.77	0.80	0.75	0.74	0.58	0.90	1.05
Avg 20% Worst Days	0.67	0.67	0.69	0.65	0.64	0.56	0.87	1.00
Annual Average	0.89	0.89	0.92	0.87	0.85	0.59	1.01	1.00
Lostwood SO4								
90th Percentile Day	0.93	0.91	0.86	0.93	0.99	1.00	1.00	1.09
Avg 20% Worst Days	0.89	0.89	0.84	0.89	0.94	0.95	0.95	1.10
Annual Average	0.91	0.91	0.87	0.92	0.97	0.99	0.99	1.12

* Test 1 - Calpuff run with default BART screening protocol + full emissions inventory + boundary conditions
Test 2 - Calpuff as in Test 1 but using CEMS hrly emissions (SO2, NOX) where available
Test 3 - Calpuff as in Test 1 but using WRAP MM5 12km mesoscale data (in CALMET)
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Test 7 - Calpuff as in Test 6 but Beulah hourly NH3 profile doubled for Lostwood

Notice of Intent
To Amend the
State Implementation Plan
For Air Pollution Control
Relating to the Reduction of Regional Haze

North Dakota
Department of Health

will hold a public hearing to address proposed changes to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which address Regional Haze in the Federal Class I areas.

Environmental Training Center
2639 East Main Avenue
Bismarck, ND
January 7, 2010
9:00 a.m. CST

A copy of the proposed SIP revision may be viewed at the Department's website at www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E Divide Avenue, Second Floor, Bismarck, ND 58501-1947 or calling (701)328-5188. Written comments may be submitted to the above address from December 8, 2009 through January 8, 2010. The SIP revision addresses requirements on sources to reduce regional haze (visibility impairment) in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The SIP revision includes a Permit to Construct for each of five electric utility steam generating plants which establishes limits for sulfur dioxide and nitrogen oxides that are intended to improve visibility impairment in TRNP and LWA.

The National Park Service and the U.S. Fish and Wildlife Service, Federal Land Managers for TRNP and LWA respectively, as well as the U.S. Forest Service have provided comments on the draft Regional Haze SIP revision. The comments and the Department's response to those comments are found in Appendix J.1 of the SIP revision. These documents may be accessed at the website listed above or by contacting the Department.

If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above address at least seven days prior to the hearing.

Dated this 25th day of November 2009
Terry L. O'Clair, P.E.
Director, Division of Air Quality

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Grand Forks Public Library
2110 Library Circle
Grand Forks, ND 58201-6324

Ladies/Gentlemen:

Enclosed is a CD which contains a revision to the North Dakota State Implementation Plan for the control of air pollution. The State Implementation Plan revision addresses requirements for improvement of regional haze in Theodore Roosevelt National Park and Lostwood National Wildlife Refuge Wilderness Area.

We ask that you maintain the CD at the library for public viewing during the public comment period which is scheduled from December 8, 2009 to January 8, 2010. If additional copies of the CD are necessary, please contact me.

If you have any questions, please feel free to contact me at (701)328-5188.

Sincerely,

Tom Bachman

Tom Bachman
Senior Engineer
Division of Air Quality

TB:csc
Enc:

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
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December 3, 2009

FILE

Fargo Public Library
4630-15th Ave. North
Fargo, ND 58102-5801

Ladies/Gentlemen:

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Sincerely,

Tom Bachman

Tom Bachman
Senior Engineer
Division of Air Quality

TB:csc
Enc:

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Minot Public Library
516 Second Ave. SW
Minot, ND 58701-3740

Ladies/Gentlemen:

Enclosed is a CD which contains a revision to the North Dakota State Implementation Plan for the control of air pollution. The State Implementation Plan revision addresses requirements for improvement of regional haze in Theodore Roosevelt National Park and Lostwood National Wildlife Refuge Wilderness Area.

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If you have any questions, please feel free to contact me at (701)328-5188.

Sincerely,

Tom Bachman

Tom Bachman
Senior Engineer
Division of Air Quality

TB:csc
Enc:

NORTH DAKOTA
DEPARTMENT *of* HEALTH

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Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
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December 3, 2009

FILE

Williston Community Library
1302 Davidson Drive
Williston, ND 58801-3861

Ladies/Gentlemen:

Enclosed is a CD which contains a revision to the North Dakota State Implementation Plan for the control of air pollution. The State Implementation Plan revision addresses requirements for improvement of regional haze in Theodore Roosevelt National Park and Lostwood National Wildlife Refuge Wilderness Area.

We ask that you maintain the CD at the library for public viewing during the public comment period which is scheduled from December 8, 2009 to January 8, 2010. If additional copies of the CD are necessary, please contact me.

If you have any questions, please feel free to contact me at (701)328-5188.

Sincerely,

Tom Bachman

Tom Bachman
Senior Engineer
Division of Air Quality

TB:csc
Enc:

NORTH DAKOTA
DEPARTMENT *of* HEALTH

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www.ndhealth.gov

December 3, 2009

FILE

Dickinson Public Library
139 Third Street W
Dickinson, ND 58601-5147

Ladies/Gentlemen:

Enclosed is a CD which contains a revision to the North Dakota State Implementation Plan for the control of air pollution. The State Implementation Plan revision addresses requirements for improvement of regional haze in Theodore Roosevelt National Park and Lostwood National Wildlife Refuge Wilderness Area.

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If you have any questions, please feel free to contact me at (701)328-5188.

Sincerely,

Tom Bachman

Tom Bachman
Senior Engineer
Division of Air Quality

TB:csc
Enc:

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

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December 3, 2009

FILE

Ms. Callie Videtich (AP-AR)
Director – Air Programs
U.S. EPA, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Regional Haze SIP Revision

Dear Ms. Videtich:

Enclosed is a CD that contains North Dakota's draft State Implementation Plan (SIP) revision to address regional haze in the federal Class I areas. Also, enclosed is a public notice announcing a public hearing and comment period on the proposed SIP revision. We are providing these documents to you so that your staff can review them and provide any comments during the public comment period. The public comment period is scheduled from December 8, 2009 to January 8, 2010. A public hearing regarding the proposed SIP revision is scheduled for January 7, 2010 at the Department's Environmental Training Center at 2639 E. Main Ave., Bismarck, North Dakota at 9:00 a.m. CST.

We would like to note that only one facility in North Dakota is subject to the BART guidelines. This is the Coal Creek Station and it is not subject to the guidelines for sulfur dioxide emissions. When your staff provides comments, we ask that they provide a reference to applicable rule or law for any required changes to the SIP.

If you have any questions, please feel free to contact me or Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc
Enc:
xc: Amy Platt – EPA, Region 8
Maggie Olson – Attorney general's Office
Dave Glatt, Chief – Environmental Health Section

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www.ndhealth.gov

December 3, 2009

FILE

Lignite Energy Council
1016 E Owens Avenue
Bismarck, ND 58501

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the North Dakota Department of Health at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

Notice of Intent
To Amend the
State Implementation Plan
For Air Pollution Control
Relating to the Reduction of Regional Haze

North Dakota
Department of Health

will hold a public hearing to address proposed changes to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which address Regional Haze in the Federal Class I areas.

Environmental Training Center
2639 East Main Avenue
Bismarck, ND
January 7, 2010
9:00 a.m. CST

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If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above address at least seven days prior to the hearing.

Dated this 25th day of November 2009
Terry L. O'Clair, P.E.
Director, Division of Air Quality

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Mr. Mark Hummel
Deputy Forest Supervisor
U.S. Forest Service
8901 Grand Ave. Place
Duluth, MN 55808-1122

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Hummel:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the North Dakota Department of Health at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

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Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Ms. Sheila Crawford - Oliver
Water Resource Unit
Sisseton – Wahpeton Dakota Nation
Old Agency, Box 509
Agency Village, SD 57762-0509

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Crawford-Oliver:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

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Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

December 3, 2009

Ms. Chris Shaver
National Park Service – Air
P.O. Box 25287
Denver, CO 80225

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Shaver:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

NORTH DAKOTA
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Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Ms. Sandra Silva
U.S. Fish & Wildlife Service
P.O. Box 25287
Denver, CO 80225

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Silva:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Tribal Chairman
Turtle Mountain Tribe
Belcourt, ND 58316

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the North Dakota Department of Health at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
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www.ndhealth.gov

December 3, 2009

FILE

Tribal Chairman
Three Affiliated Tribes
Fort Berthold Indian Reservation
P.O. Box 460
New Town, ND 58736

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
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ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Tribal Chairman
Spirit Lake Tribe
P.O. Box 359
Fort Totten, ND 58335

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

Environmental Health Section Chief's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality
701.328.5150	701.328.5188	701.328.5211	701.328.5166	701.328.5210

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Tribal Chairman
Standing Rock Sioux Tribe
Fort Yates, ND 58538

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Director
Division of Air Quality

TLO/TB:csc

Environmental Health Section Chief's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality
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Bismarck, ND 58501-1947
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www.ndhealth.gov

December 3, 2009

FILE

Natural Resources Program
Env. Regulation Division
SD Dept. of Environmental and Natural Resources
523 E. Capital Ave.
Joe Foss Bldg.
Pierre, SD 57501

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Director
Division of Air Quality

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December 3, 2009

FILE

Division of Air Quality
Minnesota Pollution Control Agency
520 Lafayette Road
St. Paul, MN 55155

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

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Director
Division of Air Quality

TLO/TB:csc

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ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
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December 3, 2009

FILE

Dept. of Environmental Quality
Air Quality Division
MT State Dept. of Health & Env. Services
Metcalf Bldg.
P.O. Box 200901
Helena, MT 59620-0901

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Director
Division of Air Quality

TLO/TB:csc

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Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
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www.ndhealth.gov

FILE

December 3, 2009

Mr. M.E. Bonnickson WCK4508
Shell Western E&P, Inc.
P.O. Box 576
Houston, TX 77001-0576

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Bonnickson:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Director
Division of Air Quality

TLO/TB:csc

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Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Ms. Mary Jo Roth
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Roth:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Environmental Staff
WBI Holdings, Inc.
Box 131
Glendive, MT 59330

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Ms. Tina Anderson
DEQ - Air Quality Division
State of Wyoming
1866 S Sheridan Avenue
Sheridan, WY 82801-6136

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Anderson:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

December 3, 2009

Mr. Mike Machler
Baker GeoResearch, Inc.
1148 First Avenue N, #S-216
Billings, MT 59101-2671

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Machler:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
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www.ndhealth.gov

December 3, 2009

FILE

Environmental Manager
American Crystal Sugar Company
101 Third Street N
Moorhead, MN 56560

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

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Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Mr. Mark Trechock
Dakota Resource Council
113 W First Street
P.O. Box 1095
Dickinson, ND 58604

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Trechock:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Director
Division of Air Quality

TLO/TB:csc

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Gold Seal Center, 918 E. Divide Ave.
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www.ndhealth.gov

December 3, 2009

FILE

Mr. Kevin Fetherston
Bureau of National Affairs
1231 25th Street NW
Washington, DC 20037

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Fetherston:

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Division of Air Quality

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Gold Seal Center, 918 E. Divide Ave.
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December 3, 2009

FILE

Mr. David Clark
Petro-Hunt LLC
3900 Thanksgiving Tower
1601 Elm Street
Dallas, TX 75201

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Clark:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Director
Division of Air Quality

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NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
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www.ndhealth.gov

December 3, 2009

FILE

Mr. Rodney Krogh
Plant Manager
Petro-Hunt L.L.C.
813 - 123rd Avenue SW
Killdeer, ND 58640

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Krogh:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

December 3, 2009

Ms. Amy Platt (8P2-A)
U.S. EPA - Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Platt:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Division of Air Quality

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www.ndhealth.gov

December 3, 2009

FILE

Mr. Kevin Johnson
Env. Contaminants Specialist
U.S. Fish & Wildlife Service
3425 Miriam Avenue
Bismarck, ND 58501-7926

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Johnson:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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www.ndhealth.gov

December 3, 2009

FILE

Regulations Manager
State Net
2101 K Street
Sacramento, CA 95816

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

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701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Safety Officer
Radiation Safety Office
NDSU
P.O. Box 5569
Fargo, ND 58105

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

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Gold Seal Center, 918 E. Divide Ave.
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www.ndhealth.gov

FILE

December 3, 2009

Mr. Lawrence Bender
Pearce & Durick
314 E Thayer Avenue
P.O. Box 400
Bismarck, ND 58502

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Bender:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Division of Air Quality

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FILE

December 3, 2009

Mr. Terry Graumann
Otter Tail Power Company
P.O. Box 496
Fergus Falls MN 56538-0496

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Graumann:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Division of Air Quality

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www.ndhealth.gov

FILE

December 3, 2009

Ms. Ruth Jensen
Northern Border Pipeline Company
13710 FNB Parkway
Omaha, NE 68154-5200

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Jensen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Director
Division of Air Quality

TLO/TB:csc

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December 3, 2009

FILE

Mr. Steven D. Strege
ND Grain Dealers Association
Black Building, Suite 606
118 Broadway
Fargo, ND 58102

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Strege:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Division of Air Quality

TLO/TB:csc

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FILE

December 3, 2009

Ms. Abbie Krebsbach
Montana-Dakota Utilities Co.
400 N Fourth Street
Bismarck, ND 58501

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Krebsbach:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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TLO/TB:csc

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
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Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Mr. John T. Graves
Minnkota Power Cooperative
P.O. Box 13200
Grand Forks, ND 58208-3200

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Graves:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Mr. Jewel Roningen
Livestock Marketing Consultant
213 - 21st Avenue N
Fargo, ND 58102-2016

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Roningen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Gold Seal Center, 918 E. Divide Ave.
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701.328.5200 (fax)
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December 3, 2009

FILE

Stevan G. Dewald, PE
Lightowler Johnson Associates
700 Main Avenue
P.O. Box 2464
Fargo, ND 58103

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Dewald:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Ms. Paula Koble Gores
Dakota Westmoreland Corporation
P.O. Box 39
Beulah, ND 58523-0039

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Koble Gores:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Bismarck, ND 58501-1947
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December 3, 2009

FILE

Hogenson Construction, Inc.
P.O. Box 777
West Fargo, ND 58078-0777

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

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FILE

December 3, 2009

Mr. Rainey J. Crawford
Ford Motor Company
1201 NW Briarcliff Pkwy #315
Kansas City, MO 64116-1774

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Crawford:

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www.ndhealth.gov

December 3, 2009

FILE

Mr. D. Randall Crooke
Falkirk Mining Company
2801 First Street SE
Underwood, ND 58576-1087

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Crooke:

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Division of Air Quality

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Bismarck, ND 58501-1947
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FILE

December 3, 2009

Mr. Robert Nolan
Exxon Company USA
P.O. Box 2180, Room 4215
Houston, TX 77252-2180

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Nolan:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the North Dakota Department of Health at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Mr. Bruce Macdonald
ENSR Consulting
1601 Prospect Parkway
Ft. Collins, CO 80525-9769

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Macdonald:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Ms. Donna Bauer Owen
EHS Manager
Burlington Resources
P.O. Box 51810
Midland, TX 79710-1810

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Bauer Owen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Ms. Amy Phillips
BNA PLUS
1231 25th St. NW, Room 310-N
Washington, DC 20037

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Phillips:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the North Dakota Department of Health at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Ms. Deborah Levchak
Basin Electric Power Coop.
1717 E Interstate Avenue
Bismarck, ND 58501

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Levchak:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Mr. Robert L. Eriksen
Basin Electric Power Coop.
1717 E Interstate Avenue
Bismarck, ND 58504

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Eriksen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the North Dakota Department of Health at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Mr. Donny Worthington
Hunt Petroleum Corp.
P.O. Box 1350
Houston, TX 77251-1350

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Worthington:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Ms. Janel Schmitz
American Lung Association
of North Dakota
P.O. Box 5004
Bismarck, ND 58502

Re: Regional Haze State Implementation Plan Revision

Dear Ms. Schmitz:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

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DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Amerada Hess Corporation
113 Fourth Street E
Williston, ND 58801-5438

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

Mr. Michael Ford
Amerada Hess Corporation
P.O. Box 2040
Houston, TX 77252-2040

Re: Regional Haze State Implementation Plan Revision

Dear Mr. Ford:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 3, 2009

FILE

5 CES/CEV
Attn: Air Program Manager
320 Peacekeeper Place
Minot AFB, ND 58705-5006

Re: Regional Haze State Implementation Plan Revision

Dear Ladies/Gentlemen:

The North Dakota Department of Health has developed a State Implementation Plan (SIP) revision to address the regional haze requirements of 40 CFR 51.308. The proposed SIP revision may be viewed at the office of the North Dakota Department of Health, 918 E. Divide Ave., 2nd Floor, Bismarck, North Dakota or at the Department's website at: www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to consider testimony regarding the proposed SIP revision. The hearing is scheduled for January 7, 2010. The Department welcomes any comments you or your staff may have regarding the SIP revision. All comments received by January 8, 2010 will be included as part of the hearing record. Written comments must be sent to the address listed above.

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Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

Environmental Health Section Chief's Office 701.328.5150	Division of Air Quality 701.328.5188	Division of Municipal Facilities 701.328.5211	Division of Waste Management 701.328.5166	Division of Water Quality 701.328.5210

Printed on recycled paper.

NORTH DAKOTA
DEPARTMENT *of* HEALTH

NEWS RELEASE

For Immediate Release:
Jan. 4, 2010

For More Information, Contact:
Tom Bachman, Environmental Engineer
North Dakota Department of Health
Division of Air Quality
Phone: 701.328.5188
E-mail: tbachman@nd.gov

State Health Department Schedules Public Hearing

BISMARCK, ND – The North Dakota Department of Health has scheduled a public hearing to address proposed changes to the North Dakota State Implementation Plan for the control of air pollution. The public hearing will be held Jan. 7, 2010, at 9 a.m. at the department's Environmental Training Center, 2639 E. Main, Bismarck, N.D.

The hearing will address the Department of Health's plan for reducing regional haze (visibility impairment) in Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge Wilderness Area.

The public also may submit written comments regarding the changes by Jan. 8, 2010. The public is invited to direct their comments to Terry O'Clair, Division of Air Quality, North Dakota Department of Health, 918 E. Divide Ave., Bismarck, N.D. 58501-1947.

For more information, contact Tom Bachman, North Dakota Department of Health, at 701.328.5188.

-- 30 --

Please note: To access archived news releases and other information, visit the North Dakota Department of Health Press Room at www.nddohpressroom.gov.

Affidavit of Publication

Colleen Park, being duly sworn, states as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of: **ND Health Department – Reduction of Regional Haze; 1** time(s) as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Colleen Park

State of ND

County of BURLEIGH

Subscribed and sworn to before me this 21ST day of Dec., 2009.

Linda J Judd

LINDA J. JUDD
Notary Public
State of North Dakota
My Commission Expires July 9, 2014

nt, accrued payments then due and ienses advanced, are not paid within ty (30) days from the date of mailing or vice of this Notice, the Mortgagee will ɘm the whole sum secured by the rtgage to be due and payable in full hout further notice. Furthermore, proɔdings will be commenced to foreclose :h mortgage, and in the event of eriff's sale as provided by the laws of State of North Dakota, the time for renption shall be as provided by law, but ; less than sixty (60) days after the eriff's Sale.

Dated November 18, 2009.

MACKOFF KELLOGG LAW FIRM
Attorneys for the Plaintiff
Office and Post Office Address:
38 Second Avenue East
Dickinson, North Dakota 58601
Tel: (701) 227-1841
Fax: (701) 225-6878
By: Bethany Abrams, Attorney #06344

If you have previously received a disarge in a Chapter 7 bankruptcy, this is t an attempt to collect a debt against u personally, but only an attempt to demine your intention concerning retain- this property.

ec 7, 14, 21, 2009) 1011529

NOTICE OF SALE
Civil No. 09-08-C-04891

Notice is hereby given that by virtue of judgment of foreclosure by the District ourt of the East Central Judicial District and for the County of Cass and State of orth Dakota, and entered and docketed the Office of the Clerk of said Court on ctober 19, 2009, in an action wherein ank of New York as Trustee for the Cerlcate Holders of CWALT 2004-J09 was aintiff and Joshua A. Deutsch; Sarah K. eutsch; Mortgage Electronic Registraɔn Systems, Inc., on behalf of Lender ecision One Mortgage Company, LLC.; orth Dakota State Tax Commissioner; CI Credit Services Inc.; North Dakota tate University; and any person in posɘssion were Defendants, in favor of aintiff and against the Defendants for e sum of $104,039.19, which judgment nd decree, among other things, direct e sale by me of the real property hereinter described, to satisfy the amount of aid judgment, with interest thereon and e costs and expenses of such sale, or o much thereof as the proceeds of said ale will satisfy; and by virtue of a writ isued to me out of the office of the Clerk of aid Court, I, Paul D. Laney, Sheriff of ass County, North Dakota, will sell the roperty described in the Judgment to the ighest bidder for cash at public auction t the front door of the Courthouse in the ity of Fargo in the County of Cass and tate of North Dakota, on December 30, 009, at the hour of 10:00 A.M. (CT), to atisfy the amount due, with interest hereon, and the costs and expenses of uch sale, or so much thereof as the proeeds of such sale will satisfy. The property to be sold is situated in the County of ass and State of North Dakota, and decribed as follows:

Lots Sixteen and Seventeen, in Block 'Aa" of Erskine's Addition to the City of argo, Situate in the County of Cass and he State of North Dakota, a/k/a 1004 9th Street South, Fargo, ND 58103.

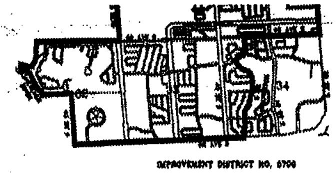
IN TESTIMONY WHEREOF, I have ereunto set my hand and seal this 25th day of November, 2009.

Paul D. Laney
Sheriff of Cass County, North Dakota
By: Dean Fercho, Deputy
STATE OF NORTH DAKOTA
ss
County of Cass

On this 25th day of November, 2009, before me, a Notary Public in and for said County and State, personally appeared Dean Fercho, known to me to be the person who is described in, and whose name s subscribed to this instrument.

Cindy Zetocha
Notary Public
Cass County, North Dakota
My Commission expires: 6-27-14
MACKOFF KELLOGG LAW FIRM
P.O. Box 1097
Dickinson, ND 58602-1097
Attorneys for Plaintiff

(Dec 7, 14, 21, 2009) 1013216



(December 7 and 14, 2009) 1011531

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

FirstLink
211 Designation
Application Case No. PU-09-713

NOTICE OF OPPORTUNITY FOR HEARING
November 25, 2009

The Federal Communications Commission (FCC) has designated the 211 dialing code to provide direct access to organizations providing community information and referral services that are currently not available through the 911 emergency code or the 311 police non-emergency code.

On September 24, 2003, the Commission designated the Mental Health Association in North Dakota (MHAND), as the user of the 211 dialing code in North Dakota.

On March 7, 2007, the Commission authorized MHAND to subcontract 211 operations within North Dakota. MHAND has been subcontracting with FirstLink for the provision of 211 operations in Cass County.

In its October 30, 2009 letter, MHAND notified the Commission that, due to lack of economic support, it must relinquish its designation as the 211 dialing code user.

On November 2, 2009, the Commission received a letter stating that effective October 30, 2009, FirstLink will temporarily provide 211 operations for North Dakota until a decision is made about 211's future.

On November 23, 2009, FirstLink filed a letter requesting designation as the 211 dialing code user for North Dakota.

The issues to be considered are:

1. Is any other entity interested in designation as the user of the 211 dial code in North Dakota?
2. Is the FirstLink's intended use of the 211 dial code in North Dakota consistent with the FCC intended use of that code?

Those interested are invited to comment in writing. Persons desiring a hearing must file a written request identifying their interest in the proceeding and the reasons for requesting a hearing. Comments and requests for hearing must be received by January 8, 2010. If deemed appropriate, the Commission can determine the matter without a hearing.

For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400; or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials please notify the Commission.

PUBLIC SERVICE COMMISSION
Tony Clark, Commissioner
Kevin Cramer, Chairman
Brian P. Kalk, Commissioner

(December 7, 2009) 1011667

NOTICE

YOU ARE HEREBY NOTIFIED that Elissa M. Waasdorp, as mother and natural guardian of Kailee Marie Johnson, minor, will petition the District Court for the County of Cass, State of North Dakota, to change her name to:

Kailee Marie Waasdorp

The petition will be heard by the Court on or after thirty (30) days from the date this notice is published.

Dated this 30th day of November, 2009.

Birrenkott Law Office, LLC
Michael A. Birrenkott (ND #05744)
1555 43rd St S, Suite 100
Fargo, ND 58103
701-365-0444
Attorney for Petitioner

(December 7, 2009) 1013306

North Dakota, will sell the property described in the Judgment to the highest bidder for cash at public auction at the front door of the Courthouse in the City of Fargo in the County of Cass and State of North Dakota, on January 6, 2010, at the hour of 10:00 A.M. (CT), to satisfy the amount due, with interest thereon, and the costs and expenses of such sale, or so much thereof as the proceeds of such sale will satisfy. The property to be sold is situated in the County of Cass and State of North Dakota, and described as follows:

Lot Eight (8), in Block One (1), of Cottonwood Second Addition to the City of Casselton, situate in the County of Cass and the State of North Dakota, a/k/a 408 Cottonwood Drive, Casselton, ND 58012.

IN TESTIMONY WHEREOF, I have hereunto set my hand and seal this 20th day of November, 2009.

Paul D. Laney
Sheriff of Cass County, North Dakota
By: Rick Majerus, Deputy
STATE OF NORTH DAKOTA
ss
County of Cass

On this 20th day of November, 2009, before me, a Notary Public in and for said County and State, personally appeared Rick Majerus, known to me to be the person who is described in, and whose name is subscribed to this instrument.

Cindy Zetocha
Notary Public
Cass County, North Dakota
My Commission expires: 6-27-14
MACKOFF KELLOGG LAW FIRM
P.O. Box 1097
Dickinson, ND 58602-1097
Attorneys for Plaintiff

(Dec 7, 14, 21, 2009) 1011699

Notice of Intent To Amend the State Implementation Plan For Air Pollution Control Relating to the Reduction of Regional Haze

North Dakota Department of Health will hold a public hearing to address proposed changes to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which address Regional Haze in the Federal Class I areas.

Environmental Training Center
2639 East Main Avenue
Bismarck, ND
January 7, 2010
9:00 a.m. CST

A copy of the proposed SIP revision may be viewed at the Department's website at www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed SIP revision may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E Divide Avenue, Second Floor, Bismarck, ND 58501-1947 or calling (701)328-5188. Written comments may be submitted to the above address from December 8, 2009 through January 8, 2010. The SIP revision addresses requirements on sources to reduce regional haze (visibility impairment) in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The SIP revision includes a Permit to Construct for each of five electric utility steam generating plants which establishes limits for sulfur dioxide and nitrogen oxides that are intended to improve visibility impairment in TRNP and LWA.

National Park Service and the U.S. Fish and Wildlife Service, Federal Land Managers for TRNP and LWA respectively, as well as the U.S. Forest Service have provided comments on the draft Regional Haze SIP revision. The comments and the Department's response to those comments are found in Appendix J.1 of the SIP revision. These documents may be accessed at the website listed above or by contacting the Department.

If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above address at least seven days prior to the hearing.

Dated this 25th day of November 2009
Terry L. O'Clair, P.E.
Director, Division of Air Quality

(December 7, 2009) 1011756

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Attn: TOM BACHMAN
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BISMARCK, ND 58505-0200
Voice: 701.328.5188 Fax: 701.328.5200

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56.00	SPR2	0.72	40.32	0.00		Reduction of .... Haze		12/05/09
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REGISTRATION

Regional Haze SIP Revision

1/07/10

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NAME	ADDRESS	REPRESENTING	CHECK HERE TO TESTIFY
Martin Schock	(H) 1121 N. 29th St/Bis.	ND Health Dept	
Tom Bachman	918 E. Divide	NDDH	
Lew Dendy	"	NDDH	
Craig Thorstenson	"	NDDH	
Jim Semerad	"	"	
Jerry O'Clair	"	"	
	"	NDDoH	
Abbie Krebsbach	400 N 4th St Bis ND	MDU	
	2875 3rd St. SW Underwood	CKE	
Wayde Schafer	311 E. Thayer #113	Sierra Club	
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L. David Glatt	918 E. DIVIDE AVE., BIS.	NDDH	
Adam Driscoll	234 W Century Ave	Barr Engineering	
Cris Miller	1717 E Interstate Ave	Basin Electric	
Rob White	918 E. Divide	NDDH	
Steve [illegible]	"	NDDH	
Jim Kambeitz	106 Seminole Ave.	Independent	

Regional Haze SIP Hearing
January 7, 2010
9:00 a.m.

Good Morning. Welcome to the Environmental Training Center. First of all, thank you for challenging North Dakota's frigid air temperatures this morning to attend the hearing. My name is Terry O'Clair and I will be acting as hearing officer for this public hearing. It is approximately 9:05 a.m., January 7, 2010 in the North Dakota State Health Department's Environmental Training Center. This public hearing has been called for the purpose of allowing all interested individuals an opportunity to submit information concerning the Department's draft State Implementation Plan revision addressing Regional Haze. Information gathered at the hearing will be transmitted to the Department's Division of Air Quality for deliberation and final decision. The Department will not be responding to comments at this hearing. Comments received at the hearing will be considered with any written comments that are received and the Department will present its consideration of all comments in writing. You may request a copy of the written response and one will be provided to you.

This hearing is being taped and we ask everyone offering testimony to use the podium so that the tape will be of good quality for transcribing purposes. Please identify yourself for the record before you speak. Everyone present will be given an opportunity to speak. If you have a prepared statement, a written copy of the statement is appreciated.

A registration sheet has been placed next to the door. I ask that everyone present please sign the sheet before they leave.

Before we begin accepting testimony, I would like to add a point of clarification pertaining to the MDU Heskett Station Unit 2 addressed in Section 7.3.4 of the draft SIP. Prior to commencing the public comment period, the Department had received comments from EPA and the Federal Land Managers suggesting that the MDU Heskett Station Unit 2 was not exempt from the Best Available Retrofit Technology review. The Department agreed to reassess our determination. MDU agreed to remodel the Heskett Station Unit 2 in accordance with the EPA preferred model settings and the methodology suggested by the Federal Land Managers that combines all three units of the Theodore Roosevelt National Park for modeling purposes. The Department has reviewed the original modeling as well as the revised modeling submitted by MDU and concluded that Heskett Station Unit 2 is exempt from the BART process. The information has been submitted to the U.S. Environmental Protection Agency and the Federal Land Managers. The revised modeling is on the Department's web site at: www.ndhealth.gov/aq/regionalhaze. This document is formally incorporated into the hearing record.

Although the modeling demonstrated that the MDU Heskett Station was exempt from BART requirements, the Department conducted additional modeling to determine the impact on visibility if BART-like emissions control equipment were to be installed. This BART-like control equipment would reduce sulfur dioxide emissions by 95% and nitrogen oxides emissions by 40%. The results of that modeling indicate only a 0.009 deciview improvement at Theodore

Roosevelt National Park and only a 0.003 deciview improvement at Lostwood Wilderness Area during the most impaired days. The Department considers this amount of visibility improvement to be inconsequential.

At this point I open the hearing for testimony. *At this point there was no one interested in providing oral testimony and the hearing was left open for 10-15 minutes to allow incoming people to arrive due to the weather conditions.*

Closing

Thank you all for coming. All information gathered at the hearing will be provided to the Department of Health which is the decision-making body. The record will be held open for written comment until January 8, 2010. At this point I close the hearing on the State Health Department's proposed State Implementation Plan revision for Regional Haze. *The hearing was closed at 9:20 a.m.*

After closing the hearing Jim Kambeitz arrived and stated he was late due to car problems and expressed his interest in providing oral testimony. The hearing was reopened at 9:30 a.m. to allow Mr. Kambietz to give his testimony.

My name is James Kambeitz and I am an educator and teacher for 10 years and resident of North Dakota. I would like to represent the young in the State and I would like to push for stronger air quality controls given that our eight power plants have been mostly grandfathered in and they already emit higher emissions than most of the power plants in the United States. According to the Clean Air Act, we require that we have Class I air in national parks and this protects us from manmade pollution. There is haze coming from the coal plants; it has been photographed, I have photographed it and a lot of people have seen it. It has also been tested. We know that we are burning about 30 million tons of coal each year and this does affect us. So, I would like the Health Department to try to make stricter goals and to move us further along in the future toward cleaner air and protecting us. That small river valley basin for the Knife River and coming down the Missouri River is a very heavily, densely, industrialized river valley and people in North Dakota don't realize it. So, we get by with polluting a lot more than we really should under the Clean Air Act. I hope that we will review, revise and strengthen our air quality plan here in North Dakota for the young, for all of our health and for the economy. The jobs in North Dakota are 3 to 1 green jobs which are outdoing normal job growth in North Dakota. It is also where the jobs are happening, that is a Pew study that I am citing there. There are a lot of studies based on what the trends are going to be and what will help us in the State. Also, tourism must be considered here since it is such a large part of our economy. So many millions of dollars and our state tourism department is putting so much money in trying to promote more hunting and more people to visit our national parks. So, we really need to protect these natural resources for us, for our economy and for our children. I also think that people who are polluting, the power plants, need to be the ones held responsible for the pollution they are emitting instead of just the public and us paying for our health problems as a result. Thank you all for listening so politely and I am not against energy and not against the coal industry. I would just like it to diversify so that it can survive and market itself better in the future.

Mr. O'Clair stated that that is one of the things that regional haze is attempting to do is reduce emissions from some of the older facilities that may be causing visibility issues. Mr. O'Clair thanked Mr. Kambietz and stated that if he would like to provide comments in writing that they would be accepted until close of business Friday, January 8. Mr. O'Clair once again closed the hearing.

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

Certification of Public Hearing

Re: Implementation Plan for the Control of Air Pollution
for the State of North Dakota

Certification:

The undersigned certifies that the public hearing held by the North Dakota Department of Health on January 7, 2010, for the purpose of receiving and considering testimony and evidence bearing on the proposed revisions to the Implementation Plan for the Control of Air Pollution for the State of North Dakota was held in accordance with the notice required by Section 51.102 Public Hearings of the Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Code of Federal Regulations, Title 40, Chapter I, Subchapter C, Part 51.

Date: January 7, 2010 Tom Bachman

Affidavit:

State of North Dakota

County of Burleigh

On the 7th day of January 2010 before me personally appeared Tom Bachman, who having been duly sworn, stated that to the best of his knowledge and belief the statements in the foregoing certification are true.

Subscribed and sworn to before me

Sherri A. Jahraus
Type, Print or Stamp Name

Sheri A. Jahraus

Notary Public Burleigh County

North Dakota
My Commission expires

SHERRI A. JAHRAUS
Notary Public
State of North Dakota
My Commission Expires Oct. 18, 2014

Environmental Protection Agency

Comment 1: Purpose/Legal Authority, last paragraph, p. 3: We note that the Coyote Station Permit to Construct is contained in Appendix A not Appendix D. Please clarify.

Response: The reference will be clarified to indicate the Coyote Permit to Construct is in Appendix A.

Comment 2: Tables 6.3 and 6.4, pp. 41-42: The NO_x emissions inventory for 2018 has been changed from previous versions reviewed. Please explain this change. It appears the point source number was revised downward to include projected emissions reductions from the Coyote Station. If so, we note that the Coyote Permit to Construct doesn't require compliance with the revised NO_x limit until July 1, 2019. Therefore, it is not appropriate to include the reduction in the 2018 inventory.

Response: The installation of the separated overfire air will be completed by July 1, 2018 or earlier. Based on our experience with the M.R. Young Station, the effects in reducing emissions should be immediate. By the end of 2018, we believe the NO_x will be reduced to the level of the Permit to Construct. Since we are indicating the reductions that will be achieved by this SIP revision, we believe it is appropriate to include the reductions from Coyote.

Comment 3: Exclusion of Montana Dakota Utilities Heskett Unit No. 2, p. 66-68:

(A) Table 7.2 – This table will need to be revised to include updated 98th percentile visibility impact results based on approved modeling.

(B) We are in the process of reviewing MDU's December 17, 2009 revised modeling report. EPA will provide additional comments on this issue if the revised modeling fails to address our concerns. See comment #21 below for more detail.

Response:

(A) Agreed

(B) No response necessary. It is the Department's understanding that EPA agrees that Heskett Unit 2 is exempt from BART.

Comment 4: Section 7.4.2, Department BART Determinations, p. 69-77: The modeling to determine if each BART-eligible source has a significant impact on visibility was performed by NDDH using the CALPUFF model following EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts specified in the Guidelines for BART Determinations Under the Regional Haze Rule, 40 CFR Part 51, Appendix Y. However, NDDH conducted an alternative cumulative visibility modeling approach in the NO_x BART determinations for M.R. Young and Leland Olds because it believes single source modeling results "tend to be five to seven times larger" than results when the same source is combined with all other sources in a cumulative analysis (although for other pollutants that affect visibility - PM and SO_2 - it appears that the State used the single source method contained in the BART Guidelines). The basis for NDDH's belief is that the perceived change in visibility from controls on a single source is reduced when background contributions from other sources are included in the modeling.

EPA does not agree that the single source modeling under the BART Guidelines overstates the degree of visibility improvement from emission reductions at the source. The Clean Air Act establishes a National goal of eliminating man-made visibility impairment from all mandatory Class I Federal areas. Use of a clean background (*i.e.*, not considering other nearby sources) is consistent with the ultimate goal of the program to reach natural background conditions. Moreover, the consistent use of a clean background in BART evaluations in North Dakota and surrounding states will foster emission reductions that will speed achievement of natural background conditions, and will ensure equity among states in achieving this goal. The NDDH has already modeled the 98th percentile values using the BART Guidelines' methodology for evaluating visibility improvements from the various control options. These values need to be used when weighing the visibility benefit factor in the NO_x BART analyses.

In addition, North Dakota has noted elsewhere that "according to the Regional Haze Rule, the focus of visibility improvement demonstrations is the 20% worst visibility days, not the cleanest days." This statement is contradicted by several provisions in the Regional Haze Rule that call for assessment of both the most and least impaired days. See, *e.g.*, 40 CFR 51.308(d)(2), (f)(1), and (g)(3).

Response: The Clean Air Act in Section 169A(g)(2) states: "in determining best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, **and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology**;" [emphasis added]. We believe the cumulative modeling provides a much more accurate estimate **of the degree of improvement in visibility which may reasonably be anticipated to result from the use of SCR**.

The difference between cumulative and BART single-source modeling results starts with the logarithmic relationship between deciview and light extinction, which is based on the proven concept that an observer will detect visibility changes more easily in clean air than in dirty air. Deciview is related to light extinction using the equation

$$dv = 10 \text{ x } \ln(b_{ext} / 10)$$

where

dv = deciview

b_{ext} = light extinction in units of inverse mega-meters (Mm^{-1})

In BART single-source modeling, the incremental impact of the subject source is based on a background of natural visibility conditions only. In cumulative modeling, as conducted by WRAP, the incremental impact of the subject source is based on a background of natural visibility conditions plus the impact of a complete inventory of all other source emissions which affect visibility. Therefore, calculated delta-deciview for the subject source for the cumulative case will be lower than for the single-source case.

A simple hypothetical example can illustrate the difference in single-source and cumulative visibility modeling. Assume that a subject source is contributing 5 Mm^{-1} to total light extinction and that the natural visibility background is 20 Mm^{-1}. Under single-source modeling, delta-deciview for the subject source would be calculated:

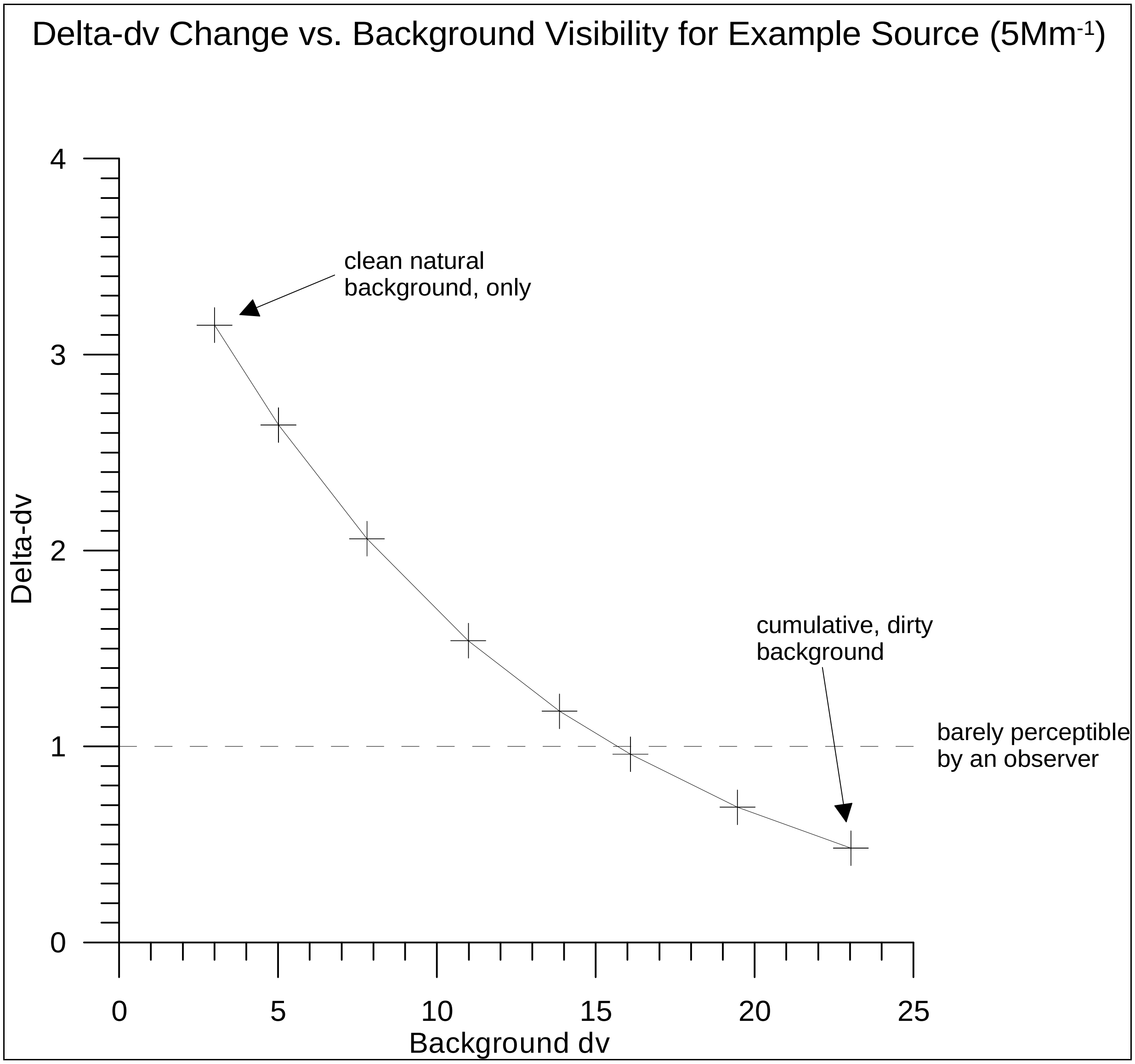
$$\text{delta-dv} = [10 \text{ x } \ln(25 / 10)] – [10 \text{ x } \ln(20 / 10)] = 9.16 – 6.93 = 2.23$$

WRAP and the NDDH have found that adding a complete emissions inventory in the cumulative modeling will typically result in a background more than double the natural visibility conditions. So to complete the example for the cumulative modeling case, we assume a background of 50 Mm^{-1} and the same subject source. Delta-deciview for the subject source would be calculated:

$$\text{delta-dv} = [10 \text{ x } \ln(55 / 10)] – [10 \text{ x } \ln(50 / 10)] = 17.05 – 16.09 = 0.96$$

Therefore, inclusion of the complete visibility-affecting emissions inventory in the cumulative modeling produces a smaller, but more realistic, observer-detected difference of 0.96 deciview from the subject source. In fact, for this example, the cumulative modeling result falls below the generally recognized observer-detectable threshold of about 1.0 deciview. Thus, the example illustrates that the impact of the subject source plume against a clean background would be much more noticeable to an observer than the impact of the same plume against the more realistic dirtier background. And, obviously, any change in visibility-affecting emissions from the subject source would have a smaller impact on the observer under the cumulative modeling scenario.

In the figure below, delta-deciview has been plotted for several background deciview levels, based on the subject source, above. The included background levels range from a clean natural background to a dirty background representing the cumulative effect of many visibility-affecting sources. The plot includes the two points calculated above. The plot illustrates the general dependency of the observed visibility change (delta-deciview) on the background level, and the fact that an observer’s perception of visibility change can vary greatly depending on the background deciview level. In fact, for this example, there is a factor of 6.6 difference in delta-deciview for the cleanest background compared with the dirtiest background (3.15 / 0.48 = 6.56).



To further illustrate the difference in single-source and cumulative visibility analyses, the NDDH conducted additional modeling using actual sources. For this illustration, the NDDH grouped the BART-applicable Coal Creek, Leland Olds, and Milton R Young Generating Stations (in North Dakota) as an effective single source. Single-source and cumulative modeling analyses were conducted to determine the incremental visibility improvement at Theodore Roosevelt National Park from the 3-source group, based on BART controls. Calpuff system versions 5.8, the new IMPROVE equation, annual average natural background, and consistent annual emission rates (for the three noted sources) were applied for both analyses. The 90th percentile visibility day from the single-source modeling results was used to emulate the 20% worst day average from the cumulative modeling results. (Given that the typical distribution of 20% worst day visibilities tends to be skewed toward the high end, the 90th percentile day may somewhat understate the 20% worst day average). Note that the post-BART emissions inventory for the cumulative analysis included changes only to the three sources referenced above.

Results of the NDDH modeling analyses are summarized in the table below. The modeling analyses discussed above are compared in the first two columns of results.

	20% Worst Day Avg. Cumulative Modeling	90th Percentile Day Single-Source Modeling	90th Percentile Day Single-Source Modeling Using 2005 ND BART Protocol
Baseline (dv)	16.954	6.552	5.583
Post-BART (dv)	16.493	5.641	3.288
Improvement (delta-dv)	0.461	0.911	2.295

As shown in the table, visibility improvement from the addition of BART controls to the three generating stations based on single-source modeling is about twice that found from cumulative modeling. These results are consistent with the hypothetical example discussed above.

Also shown in the table are results of a third modeling scenario, i.e., single-source modeling based on the North Dakota BART modeling protocol. Consistent with EPA recommendations at the time (2005), the North Dakota BART protocol specified the use of Calpuff Version 5.7, the old IMPROVE equation, and a natural background reflecting cleanest days. In addition, the protocol specified use of maximum 24-hour emission rates, per the BART Rule. As indicated in the table, use of this protocol resulted in a much greater "apparent" improvement in visibility, about a five-fold increase in the result from the cumulative modeling. This illustration, therefore, is another basis for the NDDH statement in the SIP that BART single-source modeling over predicts by a factor of 5 to 7.

All BART modeling conducted by the NDDH and industry was based on the North Dakota BART protocol. Given differences in the North Dakota BART protocol (compared to later protocols), combined with the logarithmic nature of the relationship between deciview and light extinction, it becomes clear that BART single-source modeling could have greatly overstated the more realistic results obtained from recent cumulative modeling for North Dakota.

Note that use of the ND BART single source modeling produces a visibility improvement at Theodore Roosevelt National Park (2.295 dv) which achieves compliance with the uniform rate of progress goal (2.3 dv as discussed in Section 5 of the North Dakota SIP). If one was to accept the premise that these single-source modeling results are realistic, it would logically follow that North Dakota has met the uniform rate of progress based on BART controls for the three modeled sources, and that the need to address additional (non-BART) visibility-affecting emissions reductions in North Dakota is therefore less compelling.

The 20% worst-day average metric from cumulative modeling and the 90th percentile day metric from single-source modeling have been compared in this illustration as they constitute a comparable moment of the annual distribution of daily visibility predictions. Obviously, the 98th percentile day metric from single-source modeling would provide an even greater exaggeration of actual visibility change than the 90th percentile, in the context of the 20% worst-day average metric required to measure progress with respect to visibility goals under the regional haze rule.

The Leland Olds Station and M.R. Young Station are not subject to the BART Guideline (see response to Comment 43.B regarding the M.R. Young Station). In the BART Guideline (40 CFR 51, Appendix Y, Section I.H) it states “For sources other than 750 MW power plants, however, states retain the discretion to adopt approaches that differ from the guidelines.” The Department is exercising this discretion for these sources since the cost of SCR is very high on a dollar per ton basis and on incremental cost basis. Therefore, the cumulative visibility modeling results were weighted significantly in our decision not to require SCR.

Comment 5: SO_2 BART section, p. 71: The SO_2 BART determination for Stanton Station Unit 1 may result in too high a limit when burning Powder River Basin (PRB) coal. Please see our Comment #49 below for more detail.

Response: See response to Comment 49.

Comment 6: NO_x BART section, p. 73: We do not agree that SNCR satisfies the BART requirements for Leland Olds Unit 2 and M.R. Young Units 1 & 2. See our comments below on the related BART determinations.

Response: See response to Comments 22-25, 27, 31-33.

Comment 7: Section 8.5.1, Hybrid Modeling System, pp. 95-96: The NDDH utilized a hybrid modeling approach for determining the status of its Class I areas with respect to the rate of progress visibility goals. This approach involved nesting a local NDDH CALPUFF modeling domain within the WRAP National CMAQ domain, and applying the CALPUFF model in a retrospective sense to more realistically define plume geometry for local point sources. The hybrid modeling results were used in a weight of evidence analysis to evaluate the effect of emission sources located outside of North Dakota. Please note that the last version of this modeling protocol to be reviewed by EPA was a draft dated April 2007 (*i.e.*, we never received the final October 2008 version for review). As modeling science has improved, there have been a number of technical changes in the CALPUFF modeling system and EPA/FLM recommended default settings since NDDH proposed the CMAQ/CALPUFF hybrid modeling approach in 2007. In the Reasonable Progress modeling, the hybrid CALPUFF/CAMx modeling results were adjusted based on IMPROVE monitoring data, and it is not clear whether the use of these obsolete settings affected the weight of evidence factors or the Reasonable Progress demonstration. The settings NDDH used in the CALPUFF model within the hybrid modeling system would not be considered technically sound if contained in a regulatory modeling protocol for a future project. However, in this instance it does not appear to have made a difference since North Dakota is not able to meet the uniform rate of progress with either the WRAP analysis or NDDH's hybrid modeling system.

Response: EPA was sent the final October 2008 version of the modeling protocol. The protocol was sent by email from Steve Weber to Kevin Golden on October 6, 2008 (see attached copy of this email).

As discussed in Section 8.5.6, the NDDH ultimately applied its hybrid modeling system to adjust or add value to WRAP CMAQ visibility modeling results, rather than as a stand-alone tool for absolute visibility projections. The adjustment is based on a correction where hybrid CMAQ-CALPUFF model output is involved in both the numerator and denominator of the correction factor (fraction). Therefore, the effects of the NDDH alternative CALMET/CALPUFF technical settings (reflected in both numerator and denominator model output) would have largely "cancelled out" when the correction factor was applied. In fact, had the CALMET/CALPUFF technical settings been reset to be completely consistent with EPA recommendations, it is not likely the correction factor would have meaningfully changed.

Comment 8: Section 8.6.1, Hybrid CMAQ-CALPUFF Performance Evaluation, p. 132, 1st paragraph, 1st sentence: Model performance was tested for the 90th percentile days. In addition, NDDH needs to compare performance on the 98th percentile day consistent with the BART metric.

Response: Section 8.6.1 has been revised to include hybrid model performance for the 98th percentile day.

Comment 9: Section 8.6.2.3, Apportionment by Source Group, pp. 146-153: We note that focus was on North Dakota EGUs and boundary condition groups due to their relatively "small" and "large" contributions, respectively. Since NDDH needs to be looking at what is within its control, North Dakota EGUs become the largest contributors. We also note that North Dakota's NO_3 percent contribution in 2018 actually increases at LWA (Table 8.16, p. 152), so it appears that there may be additional NO_x sources within North Dakota's control that can be addressed. This increase may be related to increased oil and gas development in the area.

Response: As we noted in the SIP, we believe WRAP has overestimated the increase in NO_x emissions from oil and gas production activity in North Dakota. Although the percent contribution for the North Dakota sources increases in 2018, the actual contribution ($\mu g/m^3$) and the total contribution of all sources decreases by 2018. The only area which increases the actual contribution to nitrates ($\mu g/m^3$) in LWA is Canada (see WRAP TSS).

Comment 10: Section 8.6.2.5, Conclusions, pp. 156-157: NDDH concludes that while the addition of proposed BART controls will substantially decrease the visibility impact of North Dakota EGUs, these EGUs comprise only a small component of total 20% worst day impacts at TRNP and LWA. The text needs to also note that during periods when EGU emissions are transported into the Class I areas, the proposed BART reductions will significantly improve visibility. This can be demonstrated by referencing the peak day and 98th percentile CALPUFF results for each EGU.

<u>Response</u>: Even though modeling demonstrated that North Dakota EGUs comprise only a small component of general 20% worst-day average impact at TRNP and LWA, the NDDH acknowledges that BART reductions from these EGUs likely resulted in substantial visibility improvement on certain worst days with favorable meteorology. Language has been added to the conclusions in Section 8.6.2.5 to facilitate this acknowledgement.

<u>Comment 11</u>: Section 9.5.1, Step 1, pp. 177-181: We have several comments related to this section. First, please note that the Q/D approach does not work for sources like Oil & Gas where the emissions are spread out over large areas, but cumulatively the emissions and impacts from these sources can be significant. In addition, the narrative needs to acknowledge the potential impact of primary PM if emissions are large. Next, please note that the reference to the BART Guidelines under the Q/D discussion is not necessarily applicable for Reasonable Progress purposes. Lastly, it appears that Heskett Station Unit 2 was omitted from the sources reviewed in Table 9.4. Please clarify.

<u>Response</u>: The Q/D analysis can work for certain oil and gas facilities such as compressor stations or natural gas processing plants. We agree it would not work well for oil production or development facilities. This has been added to Section 9.5.5.

With regard to oil and gas production and development emissions of particulate matter, both the Department and WRAP agree that emissions will be very small. The only emissions that are not covered in other source categories would be fugitive emissions from road and well pad construction. These emissions are short duration (a few days or less) and are subject to the fugitive dust control requirements in NDAC 33-15-17. As can be seen from Table 6.1 and 6.3, road dust emissions, which includes emissions associated with oil and oil development and production, are not expected to increase from 2002 rates. We do not anticipate any significant increase in visibility degradation due to PM emissions from oil and gas production activities.

Regarding the Q/D discussion for exemption from BART, we believe this is highly relevant. When the visibility impact of a source is so small it can be exempted from BART, additional controls under reasonable progress are likely not to be cost effective on a dollar per deciview basis.

Heskett Unit 2 will be added to Table 9.4.

<u>Comment 12</u>: Section 9.5.1, Table 9.8, p. 184:

(A) As noted in our August 12, 2009 preliminary comments on the WRAP's May 18, 2009 Draft *Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota,* the reliance on a 1982 NSPS analysis for Claus Sulfur Recovery Units raises questions regarding why newer data could not be utilized. Advancements in energy efficient technology and heat transfer media may affect tail gas treatment unit operational needs. Current data should be available and may indicate lower energy and steam usage. Please verify that these concerns with the WRAP report were not carried over into the North Dakota SIP.

(B) There appear to be numerous NO_x controls available at costs similar to, or less than, those selected under BART, raising the question of why Antelope Valley and Coyote Station warranted a decision by NDDH that NO_x controls carry excessive costs. Since NDDH has already determined BART controls - similar to the control options analyzed for the Reasonable Progress units - to be cost effective and to provide visibility improvement, it is unclear how similar controls on the EGUs at Antelope Valley and Coyote Station would not be justified.

(C) Some average cost effectiveness figures are lower for control options that provide greater reductions, *e.g.*, Low NO_x Burners (LNB)+SNCR at Antelope Valley Units 1 & 2 and Low-Emission Combustion (LEC) Retrofit at Tioga Gas Plant's five 1920 hp reciprocating engines. The clear advantage of these options warrants further consideration by NDDH.

(D) The estimated cost effectiveness of control options for Tioga Gas Plant's rebuilt engines (2350 hp) appears to be inaccurate since reductions are underestimated for add-on controls. Despite emission reductions achieved during rebuild, the percent control efficiency should not differ that much from engines that are not currently operating at peak performance. It appears that NDDH relied on the WRAP's May 18, 2009 Draft *Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota*, which assumed that "air-to-fuel ratio adjustments, ignition timing retarding, and LEC retrofit would not achieve further emission reductions since the estimated emission reductions for these measures are less than the reductions which appear to have already been achieved." However, the above reductions should have been assumed on top of reductions which appear to have been achieved through rebuild. In addition, the WRAP report indicates that SCR reduces emissions from reciprocating engines by 90%; therefore, NDDH needs to explain its use of 80% for the 1920 hp engines and 50% for the 2350 hp engines. Using an inappropriately low control efficiency will result in a biased high cost effectiveness of a control option.

Response:

(A) EPA has provided no evidence to support their claim that advancements have been made in energy efficiency and heat transfer media. The NDDH believes the cost estimate represents a reasonable representation of the cost of a tail gas clean up unit. Any savings in energy, including steam, will have a minor impact on the annualized costs. We believe the estimate is within the ±30% range of accuracy of the EPA Air Pollution Control Cost Manual recommended by EPA.

(B) In the BART determinations, visibility impacts were given very little weight for SO_2 and NO_x because of the inaccuracy of the BART single source modeling unless the control option had a high cost effectiveness or incremental cost. If cost effectiveness or incremental cost was high, we considered the cumulative type modeling. Had visibility impacts been weighed more heavily, some of the referenced selected BART technologies would not have been chosen. In evaluating reasonable progress, we evaluated the cost on a dollar per ton basis and the amount of visibility improvement (as you have correctly pointed out that the Department can consider). For Antelope Valley Station, all controls will improve visibility in the most impaired days by 0.01 deciviews or less. For the Coyote Station, the improvement is 0.04 deciviews or less and for the Tioga Gas Plant it is 0.05 deciviews or less. The maximum improvement for these facilities combined is 0.11 deciviews at LWA and 0.03 deciviews at TRNP during the most impaired days. To achieve this minute amount of improvement would require an annual cost of 68 million dollars. The Department has concluded that the trivial amount of visibility improvement does not warrant such costs. As pointed out in the SIP, other control options will improve visibility on the most impaired days even less.

(C) The Department did evaluate LNB+SNCR at the Antelope Valley Station and LEC Retrofit at the Tioga Gas Plant (see Tables 9.8 and 9.9). The cost on a dollar per deciview basis and the trivial amount of visibility improvement does not warrant requiring these controls.

(D) In establishing a baseline for calculating the cost effectiveness of a control option, we used the emissions for the 2350 Hp engines after they were refurbished since it represents current normal operations for these engines and anticipated future emissions. You cannot ignore money that has been spent to reduce emissions before the reasonable progress analysis began or was ever envisioned. To do so would provide an artificially low cost for additional reductions and is contrary to the methodology for making BART and BACT determinations.

The WRAP Report dated May 18, 2009 lists an efficiency of 80-90% in Table 4-1 for the 1920 Hp engines. Table 4-2 lists an efficiency of 80%. The NDDH has determined that 80% is more reasonable for emission limits that must include startup, shutdown and malfunctions. For the 2350 Hp engines, the WRAP Report lists a range of 33-67% (see Table 4-2). The NDDH determined the middle of the range was appropriate for these engines that are emitting 70% less NO_x than the engines that were not refurbished.

Comment 13: Section 9.5.1, Step 3, p. 183-185: Visibility improvement is not one of the four Reasonable Progress statutory factors (cost of compliance, time necessary for compliance, energy/non-air quality environmental impacts of compliance, and remaining useful life of any potentially affected sources), but the State has the flexibility to consider it in decision-making. The State selected a number of emission units for potential Reasonable Progress controls; however, as shown in Table 9.9, NDDH may have eliminated these from consideration due to a perceived small visibility improvement attributed to each control measure. The cost effectiveness ($/ton) for reducing emissions at a number of the sources considered for Reasonable Progress controls is similar to the cost effectiveness that NDDH considered appropriate for control at the BART sources. Thus, it is reasonable to consider controlling these sources as well. The relatively low visibility benefit for controlling an individual unit should not be a major factor to consider when selecting Reasonable Progress measures; given the ultimate purpose of the Regional Haze program, cumulative effects across sources need to be considered. In addition, since NDDH has chosen to rely heavily on visibility improvement for its decisions on Reasonable Progress controls, we consider it important to include the 98th percentile day results in addition to the 20% worst days results. In our view, since the 98th percentile day results are used in determining BART, and NDDH has chosen to rely on visibility improvement in determining Reasonable Progress controls, it makes sense to include the 98th percentile day results under Reasonable Progress to supplement the 20% worst days results.

Response: The purpose of the Regional Haze program is to improve visibility. The Department considers this purpose in its decision making process. EPA, in this comment, acknowledges that a state has the right to consider the amount of visibility improvement. Because of the purpose of the rule, visibility improvement has weighed heavily in our determinations on reasonable progress. (See our discussion in the response to Comment 12B on how visibility was weighed for the BART determinations.)

In 40 CFR 51.308(d) it states "The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 CFR 51.301 states "most impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the highest amount of visibility impairment." Least impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the lowest amount of visibility impairment. Because of the reasonable progress requirements and the regulatory definitions, we believe 98th percentile values for visibility improvement are inappropriate.

The maximum amount of improvement that would be achieved by the top controls listed in Table 9.9 is:

Source	TRNP*	LWA*
AVS (each unit)	0.028%	0.051%
Coyote Station	0.112%	0.205%
Tioga Gas Plant	0%	0.255%

* Calculated from the baseline visibility conditions.

If the top technologies from Table 9.9 are assessed cumulatively, the improvement would be 0.169% at TRNP and 0.561% at LWA. The Department considered this amount of improvement to be inconsequential. The other technologies evaluated would provide even less improvement. The capital cost to provide this much improvement is estimated at 243 million dollars with an annualized cost of over 68 million dollars. The cost effectiveness is over 618 million dollars per deciview at LWA and 2.3 billion dollars per deciview at TRNP. EPA's Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 1, 2007) states "Therefore, in assessing additional emissions reduction strategies for source categories or individual, large scale sources, a simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation... ." It appears EPA is ignoring its own guidance by dwelling on the dollar-per-ton cost effectiveness and ignoring the dollar-per-deciview cost effectiveness. We stand by our decision not to require additional controls.

Comment 14: Section 9.5.1, Time Necessary for Compliance, p. 185: As noted in our August 12, 2009 preliminary comments on the WRAP's May 18, 2009 Draft *Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota*, this timeline for compliance seems to be overestimated and/or doesn't account for steps that can be completed in parallel. In addition, the time necessary for compliance should not include time to develop regulations. If new regulations are necessary, such regulations need to be submitted with the forthcoming SIP. The WRAP report indicated that two years may be needed to develop the rules to implement Reasonable Progress strategies. This statement implies that the State lacks authority to develop and submit a SIP to address Reasonable Progress and Long-Term Strategy requirements, including relevant Reasonable Progress measures. Please verify that these concerns with the WRAP report were not carried over into the North Dakota SIP.

Response: The Department has stated that up to 6½ years would be needed to implement any additional controls. In the case of the Coyote Station it may be longer depending on when that portion of the SIP is approved. The Department believes it can issue Permits to Construct for the Coyote Station and Heskett Station that contain requirements to reduce emissions. However, we believe the full-time frame listed in the EC/R report is reasonable.

Comment 15: Section 9.5.1, Reasonable Progress Goals – Required Controls for Point Sources, p. 186-187: Again for comparison, since NDDH has chosen to rely on visibility improvement in determining Reasonable Progress controls, it is appropriate to also provide and consider the 98th percentile day results in aggregate. In addition, given that the cost effectiveness ($/ton) for reducing emissions at a number of the sources considered for Reasonable Progress controls is similar to, or less than, the cost effectiveness that NDDH considered appropriate for control at the BART sources, it is unclear why some additional Reasonable Progress controls are not warranted in the current planning period.

Response: See responses to Comments 12B and 13.

Comment 16: Section 9.5.4, Coyote Station, p. 189: It appears that NDDH believes at least this minimal level of control is reasonable now. As such, why isn't it included as a required Reasonable Progress control in the SIP? Further, why is the related Permit to Construct contained in Appendix A, BART Modeling Protocols and Analyses? Finally, this "agreement" must not preclude NDDH's re-evaluation of this source in future planning periods.

Response: The Department determined under the Reasonable Progress Analysis that no additional controls were required at the Coyote Station. Although no additional controls are required by rule or law, we have reached an agreement with the owners of the plant to reduce NO_x emissions even though no visibility improvement will be realized. To avoid any precedent for other sources under the Reasonable Progress analysis, the Coyote discussion is not included under the Point Sources Section (Section 9.5.1). The discussion regarding the Coyote Station has been relocated to Section 10.6.1, Emissions Reductions Due to Ongoing Air Pollution Control Programs.

Comment 17: Section 9.6, Visibility Modeling and Weight of Evidence, p. 191-193: The statement that implementing additional controls at Antelope Valley Station, Coyote Station, and Tioga Gas Plant "will not significantly affect current visibility conditions or the amount of time necessary to achieve natural conditions" – is misleading. Visibility improvement in aggregate should result in more progress. These sources are within NDDH's control (as opposed to the Canadian sources) and are cost effective to control. We understand that NDDH is not able to meet the uniform rate of progress in this planning period, but this does not justify the lack of Reasonable Progress controls on these sources.

Response: We strongly disagree with your assertion that the statement that additional controls at the Antelope Valley, Coyote Station and Tioga Gas Plant "will not significantly affect current conditions or the amount of time necessary to achieve natural conditions" – is misleading. As pointed out in the response to Comment 13, application of the most efficient cost effective ($/ton) controls will only produce a 0.169% improvement in visibility during the most impaired days at TRNP and 0.561% at LWA. The amount of time to achieve natural conditions would decrease from 156 years to 151 years at TRNP and from 232 years to 201 years at LWA. We stand by our statement.

As for requiring controls, see the Response to Comments 12B and 13 and our Reasonable Progress analysis with the SIP.

Comment 18: Table 9.14, Reasonable Progress Goals, p. 195: The addition of the goals based on WRAP's modeling approach is useful; however, clarification should be provided as to which goals are being established by NDDH.

Response: The SIP has been revised to indicate the Reasonable Progress goals are based on the Department's modeling.

Comment 19: Section 10.6.5, Smoke Management Techniques for Agriculture and Forest Management, pp. 204-205: A statement needs to be added that NDDH will re-evaluate potential emissions reductions on sources within North Dakota's control in future planning periods.

Response: Agreed

Comment 20: Section 11.6, Rules for Non-BART Point and Area Sources, p. 213: Although NDDH has determined that it is not reasonable to control these sources during the current planning period, this section implies that NDDH lacks authority to develop and submit a SIP to address Reasonable Progress and Long-term Strategy requirements, including relevant Reasonable Progress measures. It is not appropriate to use this lack of authority as justification for elimination of Reasonable Progress controls in the current planning period nor is a commitment of this nature acceptable to address requirements.

Response: The Department has not used the lack of clarity regarding implementation of controls on non-BART sources as a reason for not requiring control. The reasons for not requiring control are based on the four statutory factors (see Section 9.5.1 of the SIP and our response to Comments 12B and 13). Since our analysis of the four statutory factors indicated additional controls were not reasonable, we had no reason to clarify our authority for these controls. Before the next review period, the NDDH's authority will be clarified.

Comment 21: Appendix A.2.2, AECOM's August 12, 2009 Response to Concerns Regarding BART Exemption Modeling for Heskett Unit 2:

(A) NDDH's 2006 CALPUFF BART exemption modeling indicated that baseline emission impacts would result in a visibility impact of 0.82 deciviews (dv) at TRNP and 0.58 at LWA. Predicted visibility impairment exceeding 0.5 dv would make the facility subject-to-BART. MDU then contracted with ENSR to make refinements to the State's analysis that included reducing the grid size from 3 km to 1 km and a number of other settings in the model that are not consistent with current EPA defaults settings for the CALFUFF model. To address this issue, in November 2009 NDDH, EPA, MDU, and the FLMS negotiated a modeling protocol that involved rerunning the model for BART applicability using the current EPA default model settings. MDU recently completed the revised modeling and provided the results in a December 17, 2009 report. The results show that the facility is exempt from the BART requirements. EPA has obtained and is reviewing the modeling files to verify these results. Given that this updated modeling was completed after the start of the current public comment period on the Regional Haze SIP, EPA will provide additional comments on this issue if the revised modeling fails to address our concerns. Please note that NDDH will need to revise the SIP to include the revised modeling and your related conclusions. The revision will need to follow North Dakota's public participation process for SIP revisions.

(B) We also note an inaccurate reference in Appendix A.2.2 stating that EPA accepted Rapid Update Cycle (RUC) prognostic meteorological data for use in NDDH's SO_2 Periodic Increment Review. EPA has not taken action to approve NDDH's Periodic Increment Review.

Response:

(A) The Department believes MDU Heskett Unit 2 is exempt from the BART requirements and apparently EPA now agrees with that determination. The source will be reviewed under the Reasonable Progress requirements. An initial review of this source indicates a 95% reduction in SO_2 (wet scrubber) and a 40% reduction in NO_x (SNCR) will produce a visibility improvement of only 0.009 deciviews at TRNP and 0.003 deciviews at LWA during the most impaired days. It is unlikely that any additional controls will be required.

(B) We acknowledge that final action has not been taken.

Comment 22: Appendix B.5, BART SCR Technical Feasibility Analysis for North Dakota Lignite:

(A) While we agree with your determination that Low Dust SCR and Tail-End SCR are technically feasible, we do not agree with all of the technical aspects or conclusions of the analysis, especially as they relate to High Dust SCR. As you know, we have done a thorough review of the technical feasibility analyses submitted by Minnkota for Units 1 and 2 at Milton R. Young Station and NDDH's preliminary BACT determination published for public notice on June 11, 2008. Our comments and supplemental information were provided in previous letters from EPA Region 8's Office of Enforcement, Compliance, and Environmental Justice, to the North Dakota Department of Health, Division of Air Quality. Our letters provided substantial information and evidence that all SCR technology, including High Dust SCR, is technically feasible at facilities burning North Dakota lignite, and we continue to stand by those comments.

(B) Please see p. 8 of the Institute of Clean Air Companies (ICAC) May 2009 White Paper on SCR Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants, contained in Enclosure 3 for your use. This paper addresses feasibility of SCR on lignite-fired boilers and, while noting "[l]ignite from different mines has some common characteristics but also differs in some significant ways," states that "[w]ith proper design, lignite applications can be successful." The ICAC paper addresses the technical issue of high sodium in lignite and states that "[t]hese poisons are not an issue as long as the catalyst stays above dew point conditions."

<u>Response</u>:

(A) We stand by our response that HDSCR is not technically feasible for North Dakota lignite. The preponderance of the evidence indicates HDSCR cannot be successfully operated on North Dakota lignite and is, therefore, not technically feasible.

(B) This White Paper was developed by companies that are in the business of selling air pollution control technology. Therefore, their statements must be evaluated carefully and proper consideration given to the source. The White Paper states "These poisons [Na/K] are not an issue as long as the catalyst stays above dew point conditions." This is in direct contrast to Zheng, et. al., (2008) that found that the submicron Na and K aerosols migrate into the catalyst pores by diffusion, most likely surface diffusion, with temperatures above the dew point. Zheng, et. al., found rapid catalyst deactivation under normal operation conditions. This statement is also in conflict to experience with biomass boilers. Under normal operating conditions (i.e. above the dew point) rapid catalyst deactivation has been found. Most, if not all, biomass boilers are now equipped with tail-end SCR (e.g. Amager Station). Ceram, in Minnkota's response to questions about the SCR cost estimate (2/11/10), states "Small aerosol particles can penetrate and neutralize active catalyst sites even in dry conditions." Ceram also stated "Catalyst installed in even low dust and tail-end locations are poisoned from the exposure to the flue gas" and "moreover, the high levels of phosphorus, sodium and potassium found in the mineral analysis will increase deactivation rates." It is also in direct conflict with the Minnkota efforts to secure a catalyst guarantee for a tail-end or low-dust SCR. Two companies, Ceram and Haldor Topsoe, refused to offer guarantees without previous pilot-scale testing.

The White Paper does not state which type of SCR (HDSCR, LDSCR, or TESCR) will be successful with proper design. The Department has determined that only LDSCR and TESCR will be successful. The Department's opinion may not be in conflict with the White Paper; the White Paper is just not specific enough for any determination to be made.

Comment 23: Appendix C.1, Leland Olds SCR Cost Estimate: We have numerous concerns with the May 2009 Leland Olds BART Update, Tail-End Selective Catalytic Reduction (TESCR) Cost Effectiveness Evaluation, as prepared by Sargent & Lundy for Basin Electric and utilized by NDDH in its BART determinations for Leland Olds. In summary, several unsubstantiated and likely inappropriate assumptions impact the cost effectiveness numbers relied upon by NDDH to eliminate SCR in its BART determinations for Leland Olds Units 1 & 2. These assumptions result in calculated costs for TESCR that are biased high. If a more reasonable set of assumptions are incorporated into this analysis, it will likely show SCR to be cost effective on the cyclone unit (Leland Olds Unit 2), and it may also be cost effective for the wall-fired unit (Leland Olds Unit 1). Please see our detailed comments in Enclosure 2.

Response: For making cost estimates for control technology review, the BART Guideline recommends the EPA Air Pollution Control Cost Manual (EPA/452/13-02-001). However, the manual cannot be used for determining the cost of TESCR (Section 2.4 for Selective Catalytic Reduction). Although the Control Cost Manual cannot be used for TESCR, it does provide a statement on the accuracy of the cost estimates generated by the manual. Chapter 2, Section 2.2 states "As mentioned in Chapter 1.1, the costs and estimating methodology in this Manual are directed toward the "Study" estimate with a nominal accuracy of ±30% percent." We believe Basin Electric's estimate is within ±30%. With the respect to the specific comments:

(A) Steam for reheat.

Basin Electric has indicated that using steam for reheat in North Dakota winters represents unique challenges that would greatly increase operation and maintenance costs and downtime. A steam reheat system would have to be designed for -40°F temperatures plus the operator must have the capability to service the system in the harsh conditions of a North Dakota winter. As indicated by Minnkota, their previous experience with the reheat of the flue gas from Unit 2 using steam was not positive and was abandoned. The Department believes this experience is directly applicable to Leland Olds Station.

There is no indication that the units at Leland Olds are turbine limited. Therefore, using steam could have an electrical penalty for the units. For Unit 2, this could amount to nearly 5 million dollars per year.

(B) Engineering calculations should be able to provide a reasonable estimation of the cost within an accuracy of +/-5%.

This statement is contrary to the BART Guideline which recommends using the Control Cost Manual which has an accuracy of ±30%. Perry's Chemical Engineer's Handbook describes five levels of cost estimates 1) Order of Magnitude, 2) Study with an accuracy of ±30%, 3) Preliminary with an accuracy of ±20%, 4) Definitive with an accuracy of ±10%, and 5) Detailed with an accuracy of ±5%. Detailed cost estimates require final drawings, specifications and site surveys. In order to achieve a ±5% accuracy, detailed engineering analyses including plans and specifications for the SCR system will have to be prepared. The BART Guideline does not require this level of detail.

(C) The operating life of TESCR catalyst can be expected to be in the range of 50,000 hours.

Minnkota was unable to secure any guarantee for the life of a TESCR catalyst. EPA's expected catalyst life appears inconsistent with at least two catalyst/SCR vendors. Without pilot scale testing, no definitive statement regarding catalyst life can be made.

(D) Only when the catalyst in the TESCR is being cooled down to below the water dew point, such poisoning will occur.

See response to Comment 22. In Haldor Topsoe's paper entitled "The Influence of Biomass Burning in the Design of an SCR Installation" they indicate that the tail-end installation after a wet FGD will only <u>minimize</u> the amount of poisoning species entering the SCR. To counter this poisoning, Haldor Topsoe used four counter measures to <u>minimize</u> risk. These included a "bio-optimized" catalyst with a high vanadium content and a high number of active sites to make the catalyst less susceptible to poisoning by alkali metals. All of this indicates that poisoning of TESCR catalyst is a real concern especially with organically associated sodium and potassium.

EPA claims that the wet scrubber will mostly absorb the sodium and potassium aerosols in the acidic scrubber slurry. This statement is in conflict with data from Markowski et. al. (1983). Markowski's data indicates the wet scrubber at M.R. Young Unit 2 does not remove the submicron sodium and potassium aerosols that cause SCR catalyst deactivation. The data actually suggests an increase in submicron aerosols. Based on this data, the Department believes a wet scrubber that is designed for sulfur dioxide control will have little effect on the sodium and potassium submicron aerosols. However, the Department agrees that the sodium and potassium aerosol concentration entering either a LDSCR or TESCR will be sufficiently low to allow successful operation.

(E) The Leland Olds LDSCR and TESCR systems would be similar to the M.R. Young systems. Minnkota, in their detailed response to questions by the NDDH and EPA (2/11/10), has responded to this same issue. The SCR process consultant for Minnkota calculated a temperature gradient of 43-45°F. The catalyst vendor recommended a design up to 600°F. Based on 50°F temperature gradient and a heat input of 5120 x 10^6 Btu/hr for Unit 2, Basin Electric has estimated that reheating the flue gas will consume approximately 115 x 10^6 Btu/hr. Minnkota has estimated, based on a temperature gradient of 43°F and a heat input of 4885 x 10^6 Btu/hr, that 96.2 x 10^6 Btu/hr will be required to reheat the flue gas for Unit 2. The difference is attributable to the 7°F temperature gradient difference and the difference in heat input to each unit. Since final design specifications are not required for this estimate ($\underline{+}$30% accuracy required), Basin Electric's estimate of a 50°F temperature gradient and a flue gas temperature of 600°F are reasonable.

EPA claims that the only relevant information from pilot testing would be the catalyst deactivation rate. The Department believes pilot scale testing will also help optimize the catalyst volume that is required; the catalyst surface area required, the required reagent injection rate, expected reagent slip, whether a wet ESP is required for ammonium bisulfate and/or ammonium sulfate emissions and an appropriate catalyst maintenance plan. All of these issues will affect the annualized cost. However, the NDDH believes the cost of LDSCR and TESCR can be estimated, without pilot testing, to within ±30 which is equivalent to the accuracy of EPA's Control Equipment Cost Manual which is recommended by the BART Guideline.

EPA has indicated that two weeks is too much time to replace the catalyst. EPA has suggested that five days would be more appropriate. Assuming 3 layers of catalyst, each layer would contain 177 m^3 of catalyst or approximately 85 modules. Schirmer et. al. in the paper In-Situ SCR Catalyst Replacement indicated it took 9 days to replace 90 modules at the TVA Allen Fossil Plant not including cool down and vacuuming of the reactor. Cool down of the reactor and vacuuming is expected to take 3-4 days. In addition, reheating of the SCR prior to startup will take another 1-2 days. Based on this data, the NDDH believes the S&L estimate of two weeks to replace the catalyst is reasonable.

EPA has questioned the catalyst replacement schedule. Basin Electric has estimated the cost based on a six-month and 12-month replacement schedule. The NDDH believes LDSCR and TESCR will have a replacement schedule that is probably greater than 12 months (10,000 hours equals 13.7 months). Although 12 months is slightly less than the 10,000 hours the Department suggested was necessary for technical feasibility, no one knows the actual deactivation rate without pilot scale testing. Because of the lack of vendor guarantees, a replacement schedule of 12 months appears reasonable. A replacement schedule of 13.7 months would decrease the cost effectiveness by approximately $52 per ton or 1.0 – 1.4%. The Department considers this insignificant. The Department has determined that the cost is excessive at both the low end and high end. The Department also considered the amount of visibility improvement in the BART determination. The amount of improvement between SCR and the next most efficient option is negligible.

Specific issues include:

(A) The catalyst volume of 530 m^3 seems high.

> Minnkota has projected a total initial catalyst volume of 768 m^3 for M.R. Young Unit 2 (256 m^3 per layer and 3 layers). M.R. Young Unit 2 is rated at 477 MWe and Leland Olds 2 is rated at 440 MWe. The M.R. Young Unit 2 design volume was provided by a vendor. The DOI, in their consultation comments, estimated that 645 m^3 of catalyst would be required for Leland Olds Unit 2 based on the EPA's Air Pollution Control Cost Manual. Given the Minnkota catalyst volume estimate, the DOI estimate and the uncertainties regarding the catalyst deactivation rate, the catalyst volume appears to be on the low side and therefore acceptable for the cost estimate.

(B) The selected NO_x Efficiency of 85% appears low – see response to Comment 25.

(C) A capacity factor of 92.3% is erroneous since it is based on catalyst replacement every six months.

From 2000-2008 Leland Olds Unit 2 had a capacity factor of 87.4% based on hours of operation. Catalyst maintenance will decrease this availability. Using a capacity factor of greater than 92.3% does not appear to be reasonable based on the operating history.

(D) The price of $7,500 per cubic meter appears high.

This is the same cost provided for the M.R. Young Station which the NDDH understands is based on a vendor quote plus shipping, handling and taxes. It appears the cost is reasonable.

(E) The power cost of five cents per kilowatt appears high.

The Energy Information Administration (EIA) reports that the average retail price of electricity in North Dakota is 6.89 center per kilowatt. They also report that the average wholesale price of electricity in the MRO (formerly MAPP) area was 4.86 cents per kilowatt hour which is the lowest in the country (5.72 cents/kilowatt hour average for the U.S.). The S&L estimate of five cents per kilowatt hour appears reasonable.

(F) Natural gas prices are currently between $3 to $5 MMBtu rather than $8 to $12 MMBtu (inferred that cost of natural gas is too high).

Wellhead natural gas prices have been as much as $14/MMBtu in the recent past. Projecting natural gas prices must take into account the U.S. economy, new legislation or rules for the control of greenhouse gases including the surge in demand for natural gas as a substitute for other fossil fuels to reduce GHG, market price speculation, the ability of supply to keep up with demand and inflationary pressures. The Energy Information Administration (EIA) has predicted that the commercial price will range from $10.65 - $12.12 per MMBtu from 2011-2030 (calculated as 2008 dollars). The NDDH believes $8 - $12/MMBtu is a reasonable estimate of average natural gas prices over the life of the SCR system given the many factors that can influence the cost.

(G) Ammonia costs are currently more in the range of $300-400 per ton rather than $450-700 per ton.

Ammonia costs are directly related to the cost of natural gas since most anhydrous ammonia is produced from natural gas. Based on the NDDH's expectation that natural gas prices will increase, the range of ammonia cost of $450 - $700 per ton is reasonable.

(H) EPA notes that SCR retrofits in the U.S. are well below the $/kw price range calculated by S&L.

EPA provided no details to support this claim. The NDDH notes that Basin Electric's estimate is for TESCR; most SCR installations in the U.S. are HDSCR which have a much lower cost. ERG has noted in their review of the PGE Boardman BART analysis that the cost of SCR has escalated rapidly since 2004. ERG found actual costs exceeding $267/kw for HDSCR (2007 dollars). For the Boardman Plant, ERG's estimate was $206 - $267/kw. The Black and Veatch estimate was $309/kw. S&L has used $376-$387/kw for TESCR which includes a reheat system and gas-to-gas heat exchangers not associated with HDSCR. The NDDH believes the capital cost estimate is reasonable given the uncertainties such as the design volume of the reactor.

Comment 24: Appendix C.4, November 2009 Minnkota Supplemental NO_x BACT Analysis Reports for Units 1 & 2: In response to Minnkota's Supplemental BACT Reports, NDDH sent a November 25, 2009, letter to Minnkota citing a lack of detailed and comprehensive cost data documentation in the Supplemental BACT Reports and the failure to address the use of main boiler steam for flue gas reheat. NDDH requested that this information be submitted, as well as a demonstration that the cost of NO_x removal for SCR is disproportionately high compared to the cost of NO_x control in other recent Best Available Control Technology (BACT) determinations for coal-fired power plants. EPA has reviewed the Supplemental BACT Reports and wholly supports the statements in NDDH's November 25, 2009 letter. Given the fact that you are not satisfied with Minnkota's analysis and have requested additional supplemental information, it is not appropriate to rely on this cost analysis in the BART context at this time. EPA has also identified additional problems and concerns with the Supplemental BACT Reports which must be addressed for BART purposes as well, in accordance with the requirements of 40 CFR 51.308(e)(1). (SIP must include documentation for BART analyses.) These additional problems and concerns are summarized as follows:

(A) The <u>additional</u> outage time estimated in the Supplemental BACT Reports for catalyst cleaning/replacement seems very high and is not supported. Considering there are regular planned outages for both units, these times should be attributed to catalyst cleaning/ replacement activities that would not otherwise be accommodated during these planned outage events.

(B) The estimated catalyst replacement schedule under both scenarios used in the Supplemental BACT Reports is much shorter than EPA would expect for Low-Dust Selective Catalytic Reduction (LDSCR) and TESCR systems. Furthermore, the assumption that one layer of catalyst would be replaced during each planned boiler cleaning outage is made without any justification and should therefore be given little to no credibility in the final conclusions of the BACT analysis.

(C) All vendor correspondence related to catalyst costs and replacement, as described in the Supplemental BACT Reports, must be provided. This includes the original requests submitted to the vendors by Minnkota and/or their consultants.

(D) While the Supplemental BACT Reports give a general description of how the pressure drops and parasitic loads were calculated, Minnkota or NDDH must provide more details, including calculations to justify these high values.

(E) No data is provided for the temperature gradient of the regenerative gas-to-gas heat exchanger, which is essential to determine the required reheat input for either a natural gas-fired or steam system. Furthermore, the assumed value of flue gas reheat of 600 º F must be justified. We would also expect this temperature to be different for a LDSCR and TESCR due to significantly different SO_2 and SO_3 concentrations.

(F) The Supplemental BACT Reports claim there were no similar projects "on coal-fired power plants in the United States that could be used, with adjustments, to properly represent total installed cost" for MRYS. Minnkota or NDDH should consider the data from the PSE&G Mercer and We Energies South Oak Creek facilities that have installed, or will be installing, LDSCR systems.

(G) The cost values used for catalyst, natural gas, and electricity appear higher than current prices and must be substantiated. Furthermore, the Supplemental BACT Reports assume urea would be used as opposed to anhydrous ammonia. Both options should be evaluated and the least costly option selected, unless there is a compelling reason to use the more expensive option.

Response: Minnkota has addressed the use of steam for reheat in their December 11, 2009 response to NDDH questions. The NDDH asked for additional support for Minnkota's position on steam for reheat and several other items. Minnkota has supplied a response to all of the questions the NDDH and EPA posed regarding the cost estimate (2/11/10). The NDDH has reviewed Minnkota's responses and finds them to be acceptable. The NDDH is confident that the range of costs provided by Minnkota have an accuracy of ±30%, which is the accuracy of EPA's Air Pollution Control Cost Manual that is recommended by the BART Guideline.

In determining BART for NO_x at M.R. Young Station, the NDDH considered all five statutory factors. Our analysis of the costs indicate that both costs calculated by the NDDH and by Minnkota are excessive over the entire range of the costs estimated. In addition, the incremental cost effectiveness of SCR (LDSCR and TESCR) + ASOFA is excessive when compared to SNCR + ASOFA. Finally, the incremental amount of visibility improvement of SCR + ASOFA versus SNCR + ASOFA is negligible. Each of these factors (i.e. cost effectiveness, incremental cost or visibility improvement) by themselves would dictate that SCR + ASOFA is not BART.

The NDDH also considered the uncertainties regarding the technical feasibility of LDSCR and TESCR. Since Minnkota was unable to secure a vendor guarantee, the successful application of LDSCR and TESCR is more questionable.

Having considered the cost effectiveness, incremental cost, the incremental visibility improvement, and the uncertainties regarding the successful application of SCR to a source combusting ND lignite, the NDDH has determined that BART is not represented by SCR.

Comment 25: Appendix J.1, Consultation with Federal Land Managers: We note that in several of your responses to FLM comments, you cite to EPA's August 28, 2009 Advanced Notice of Proposed Rulemaking (ANPR) regarding the Four Corners Power Plant BART analysis. The ANPR does not represent an Agency decision but rather includes information on which EPA

Region 9 seeks comment. At this point, no Agency position has even been proposed, much less finalized. It is not appropriate to rely on the August 28, 2009 ANPR to support your position regarding BART analyses in North Dakota.

<u>Response</u>: The Department has reviewed the EPA Air Pollution Control Cost Manual which states "In practice, SCR systems operate at efficiencies in the range of 70% to 90%." EPA's Air Pollution Control Technology Fact sheet for selective catalytic reduction (EPA-452F-03-032) states "SCR is capable of NO_x reduction efficiencies in the range of 70% to 90%." The Oregon DEQ hired Eastern Research Group, Inc. (ERG) to review the BART analysis for the PGE Boardman Plant. In their review, ERG stated "With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR of the Boardman Plant under year-round operation would need to be considered in selecting a permit level." The NDDH believes the use of 80% is a reasonable choice for a source that must meet a BART emission limit on a long-term continuous basis.

In addition to the ANPR estimate for SCR at the Four Corners Power Plant, the Department also reviewed the analysis commissioned by the Oregon DEQ for the cost of SCR at the PGE Boardman Plant. The analysis, which was prepared by Eastern Research Group, Inc. (ERG) states, "Nonetheless, all of these sources do point to a rapid escalation in SCR installed costs since 2004. ERG analyzed the 2007 cost-basis data by eliminating the three highest and one project that was known to be very dissimilar to the Boardman Plant characteristics. The remaining nine projects range from $207/kw to $267/kw, with an average of $227/kw. ERG believes that this is a reasonable representation of 2007 costs of large SCR installations under normal retrofit conditions." This cost is two to three times the amount that would be estimated using EPA's Control Cost Manual. Further, these costs are for HDSCR. The cost for LDSCR and TESCR will be substantially higher because of the capital cost for the reheat system (including heat exchangers) and the operating cost for reheating the flue gas.

<u>Comment 26</u>: SO_2 and NO_x analyses: In general, analyses of control options and proposed limits should not be based on worst-case coal scenarios and/or highest calendar year emission rates. Use of averages should allow for accommodation of worst-case situations and will ensure that the more common conditions are adequately limited.

<u>Response</u>: The BART guidelines states "the baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." Using worst-case emissions represents a realistic scenario because the scrubber will have to be designed for that coal and operation and maintenance costs will be higher with this higher sulfur coal. North Dakota lignite is extremely variable in both quality and sulfur content. Using an average sulfur content will not accommodate worst-case conditions. For Minnkota, one standard deviation of the sulfur content amounts to 0.53% sulfur or 57% of the average sulfur content. Prediction of future sulfur content has been based on a limited number of core samples. Using an annual average for the baseline eliminates some of this variability; however, it does not eliminate it all. The Department believes that a sulfur content at, or near, the maximum annual average provides a realistic depiction of emissions. This is the same as using the maximum two years of the last five or ten years to predict the baseline emission rate as suggested by EPA in the BART Guideline and in response to questions on BART (Question 7, August 3, 2006). The difference is that you have to look into the future to see what two years will provide the maximum emission rate.

For BART, EPA has indicated the limit must be on a 30-day rolling average. A 30-day rolling average emission rate is not equivalent to an annual average emission for North Dakota lignite which is highly variable. Our review of scrubber systems in North Dakota indicates as much as a one-third difference between these two emission rates. To account for this variability, the annual emission rate must be adjusted upward to get a 30-day rolling average. In addition, the Department has not allowed an exemption from the BART emission limits during startup/shutdown or malfunction (SSM). Therefore, SSM must be considered in setting the BART emission limit. Using a near maximum sulfur content allows the Department to set the BART limit without making an adjustment for SSM.

For NO_x, the average of the highest two years out of the last five years was used by the Department to establish a baseline. This is consistent with the BART Guideline (Section IV.D.4.d.1). It is also consistent with EPA's August 3, 2006, response to comments (Question 7) and consistent with BACT determinations.

Again, a 30-day rolling average NO_x emission rate is not equivalent to the annual average emission rate for boilers firing North Dakota lignite. Our analysis indicates the 30-day rolling average can be 15% or more higher than the annual average emission rate especially when SSM is considered.

Comment 27: NO_x analyses, Step 3: Evaluate Control Effectiveness of Remaining Control Technologies: Based on our comments #22-24 above and Enclosure 2, please ensure that inappropriate assumptions in the cost analyses for SCR were not carried over to the NDDH BART determinations for any of the facilities reviewed. In addition and as we have commented in previous correspondence, incremental cost analyses are intended to be a useful supplement, not a replacement, for standard $/ton calculations. It is not unusual that the incremental costs will be greater than the average cost effectiveness as the level of control increases, but this should not be an automatic basis for eliminating an option which has a reasonable average cost effectiveness.

Response: The Department believes that cost estimates are with ± 30% of the actual cost which is similar to the costs provided by EPA's Control Cost Manual (see Responses to Comments 22-24).

Incremental cost was considered in evaluating the various control options. As provided in the BART Guideline, "The greater the number of possible control options that exist, the more weight should be given to the incremental costs vs. average costs." The Department evaluated at least five different NO_x control options for each source subject to BART. As such, more weight was given to the incremental cost as recommended by the BART Guideline. The Department considered all five statutory factors in determining BART including average cost effectiveness and incremental cost.

<u>Comment 28</u>: The visibility impact analyses need to eliminate the reference to "3 units" for TRNP, as requested by the FLMs. We note that this change was made in the SIP text and should be carried over to these documents. TRNP was identified as a single national park under the Clean Air Act Amendments of 1977 (42 U.S.C. 7472); thus, there is only one mandatory Class I Federal area for this park. By dividing this Class I area into 3 units, there may be slight reductions in benefits predicted when modeling the visibility effects of applying controls.

***<u>Response</u>*:** North Dakota has two Class I areas within its boundaries: the Theodore Roosevelt National Park which consists of three separate and distinct units and the Lostwood National Wildlife Refuge Wilderness Area. The Department considers the three units of Theodore Roosevelt National Park to be three separate areas for modeling purposes for the following reasons:

A. Theodore Roosevelt National Park (TRNP) as a PSD Class I area consists of three units (see 44 FR (November 30, 1979) at 69125 and 69127, 40 CFR § 81.423 and NDAC § 33-15-15-01.2 (Scope) relating to 40 CFR 52.21(e)). The areas are not contiguous. The North Unit and South Unit are separated by approximately 38 miles.

B. Federal regulation, 40 CFR 51.301, states "*Adverse impact on visibility* **means, for purposes of section 307, visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent,** intensity, duration, frequency and time of visibility impairments and how these factors correlate with (1) times of visitor use of the Federal Class I areas, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas." (Emphasis added) Combining the three units of TRNP into a single area for visibility analysis fails to address the "geographic extent" of any visibility impairment.

C. The North Unit is not visible from the South Unit and vice versa. The commingling of receptors from the units for a visibility analysis misrepresents the ability of a park visitor to observe features in another unit.

   Any viewable scenes outside any unit of TRNP from within the unit are "integral vistas". The effects on integral vistas are not considered when determining whether an adverse impact on visibility will occur. There are no geological features, terrain or structures in any unit of TRNP that are viewable from another unit across the land regions separating the units. For example, terrain peaks in the South Unit would have to rise at least 900 feet above terrain in the North Unit, due to the Earth's curvature, to be seen by a visitor in the North Unit. So the visual range of visitors in one unit does not include aspects of another unit.

D. The Department has treated the units as separate Class I areas for 30+ years for purposes of PSD increment consumption without objection from EPA or the FLMs prior to 2006.

E. Treating the three units as a single Class I area effectively extends Class I status to areas between the units which are classified as Class II by rule and law.

F. The units have three different names, the South Unit, the North Unit and the Elkhorn Ranch Unit.

Comment 29: Section II.A.2., Compliance Date: The last phrase "…approves this permit as part of the BART SIP" needs to be revised to "…approves this permit as part of the Regional Haze SIP."

Response: Agreed

Comment 30: Unit 1 SO_2 BART evaluation, p. 5: As we have commented in previous correspondence, we have concerns with the use of 35(s) as an alternative emission factor for SO_2. NDDH's response did not adequately justify the use of the alternative. The alternative factor was based on a study contained in NDDH's periodic review of PSD SO_2 increment consumption. In that study, an emission factor of 37.4(s) was proposed. For the Leland Olds BART determination, an emission factor of 35(s) was used to provide a conservative estimate of the uncontrolled emission rate. In the periodic review, NDDH apparently used CEM data from recent years to derive an alternative emission factor to estimate sulfur emissions. The EPA AP-42 emission factors were developed in the mid-1970s and include test data gathered at lignite burning power plants in North Dakota and elsewhere. EPA has concerns about using recent CEM data to adjust emission factors given that coal quality may have changed over the years, or may change in the future. However, in this instance it does not appear that the use of this alternative emission factor affects the results of the SO_2 BART determination.

Response: AP-42 makes several statements about the use of the emissions factors in the document. These include:

- Data from source-specific emission tests or continuous emission monitors are usually preferred for estimating a source's emissions because those data provide the best representation of the tested source's emissions.

- Use of these factors as source-specific permit limits and/or as emission regulation compliance determinations is not recommended by EPA. Because emission factors essentially represent an average of a range of emission rates, approximately half of the subject sources will have emission rates greater than the emission factor and the other half will have emission rates less than the factor. As such, a permit limit using an AP-42 emission factor would result in half of the sources being in noncompliance.

- Average emissions differ significantly from source to source and, therefore, emission factors frequently may not provide adequate estimates of the average emissions for a specific source. The extent of between-source variability that exists, even among similar individual sources, can be large depending on process, control system, and pollutant.

AP-42, in the Introduction-Figure 1, indicates that CEM data provides the best reliability for estimating emissions.

Based on the above, the Department believes an emission factor based on actual CEM data is far superior to the AP-42 emission factors. The baseline emissions that were estimated based on an emission factor derived from CEM data provides the most accurate data available. Using an inferior AP-42 emission factor would degrade the BART process. No changes were made based on this comment.

Comment 31: Units 1 and 2 NO_x BART evaluations:

(A) NDDH has revised its analysis and determines that LDSCR and TESCR are technically feasible and includes separate cost estimates for both systems. However, there is no explanation as to how the LDSCR cost values were obtained. Please clarify and include all supporting documentation in the SIP. See 40 CFR 51.308(e)(1).

(B) Based on our review of Basin Electric's May 29, 2009 supplemental TESCR cost analysis and NDDH's July 2009 SCR Technical Feasibility Analysis for North Dakota Lignite, we do not agree with certain assumptions used in the TESCR cost analysis. Please see Enclosure 2 for more detail, as well as our comments #22-23 above. Step 3 of the BART determination needs to be revised to address these concerns. These revisions are likely to considerably improve the cost effectiveness of TESCR for each unit, making it a reasonable selection for BART. In addition, this version of the draft BART determination includes new cost estimates for LDSCR. As explained above, it is unclear how the cost values for LDSCR were derived.

Response:

(A) The costs for LDSCR at Leland Olds were based on the cost estimate for M.R. Young 2 Station. The cost of TESCR was reduced proportionately to arrive at a cost for LDSCR. The smallest differential was used for the public comment period. The Department has revised the estimate based on the average of the "stand-alone" costs using M.R. Young 1 data for Leland Olds 1 and M.R. Young 2 data for Leland Olds 2. The detailed calculations are included in Appendix C.1.

(B) See our response to comments 22-23, we believe the cost estimate is within ±30% as would be estimated using the Control Cost Manual.

This comment seems to ignore the other four factors that are involved in making a BART determination, especially the amount of visibility improvement. Our cumulative modeling for Unit 2 shows only a 0.01 deciview improvement, in the most impaired days for SCR & ASOFA versus RRI & SNCR. The Department has the flexibility to weigh each factor as it chooses. The Department weighed visibility improvement fairly heavily in this analysis because the costs were very high. The Department has determined that the costs are excessive and the visibility improvement is so small that selection of SCR as BART is unwarranted.

Comment 32: Unit 1 NO_x BART evaluation, Step 3, p. 13: We note your reference to EPA's August 28, 2009 Advanced Notice of Proposed Rulemaking (ANPR) regarding the Four Corners Power Plant BART analysis to support the use of an 80% control efficiency for SCR with reheat. The ANPR does not represent an Agency decision but rather includes information for which Region 9 seeks comment. At this point, nothing has even been proposed much less finalized. It is not appropriate to rely on the ANPR to support your position regarding BART analyses in North Dakota. NDDH needs to explain why the more commonly accepted figure of 90% control efficiency is not warranted. For more information, please see the proposed and final Standards for Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units (70 FR 9713, February 29, 2005 and 71 FR 9869, February 27, 2006) and the May 2009 ICAC White Paper, pp. 4 and 7 (contained in Enclosure 3 of this letter).

Response: Although the ANPR was cited, that was not the only document that was relied on. The EPA Air Pollution Control Cost Manual states, "In practice, SCR systems operate at efficiencies in the range of 70% to 90%". EPA's Air Pollution Control Technology Fact Sheet for SCR (EPA-452F-03-032) states that SCR is capable of NO_x reduction efficiencies in the range of 70% to 90%. The Arizona DEQ determined that SCR with LNB could achieve 75% reduction. The Oregon DEQ commissioned Eastern Research Group (ERG) to evaluate the BART analysis for the PGE Boardman Plant. In their Technical Memorandum #2 (copy attached), ERG states "With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR at the Boardman Plant under year-round operation would need to be considered in selecting a permit level." The Department stands by its decision to use 80% efficiency for SCR alone on a retrofit.

Comment 33: Unit 2 NO_x BART evaluation, pp. 23-31:

(A) Per the BART Guidelines, EPA has found that the use of SCRs at large cyclone units burning lignite enables the units to cost-effectively meet NO_x rates of 0.10 lbs/MMBtu. A revised cost analysis, using the necessary adjustments we have described in comment #23 and Enclosure 2, will most likely show that SCR is cost effective at this large boiler.

(B) For BART determinations, visibility improvement must be based on the 98th percentile day results, not the 20% worst days. We do not agree that single source modeling under the BART Guidelines overestimates visibility improvement. See comment #4 above for more detail. NDDH did not use this approach in the visibility analysis for Unit 1 and it must not be used for Unit 2.

(C) There appears to be a typographical error at the beginning of the last paragraph on p. 30 – should be "BART" instead of "BACT?"

<u>Response</u>:

(A) EPA did not evaluate the flue gas characteristics of North Dakota lignite when it established the presumptive BART NO_x levels for cyclone boilers. This is in direct opposition to the statements in the BART Guideline regarding technical feasibility of a control option (i.e. technical feasibility is based on an evaluation of the flue gas characteristics and the potential for successful application of the technology). Had EPA evaluated the flue gas characteristics of North Dakota lignite, they may have concluded that HDSCR is not technically feasible; however, no such EPA analysis is available. This failure of EPA will affect the estimated cost of achieving the presumptive levels. Had EPA conducted this analysis, the presumptive levels for cyclone boilers combusting North Dakota lignite may have been quite different.

(B) The Leland Olds Station is not subjected to the BART Guideline (i.e. <750 MWe). 40 CFR 51, Appendix Y states, "For sources other than 750 MW power plants, however, states retain the discretion to adopt approaches that differ from the guidelines". As demonstrated is the Response to Comment 4, single source modeling, as recommended in the BART Guideline, over predicts the amount of visibility improvement. The Department's cumulative modeling provides a more accurate estimate of the visibility improvement that is reasonably expected to occur and is more compliant with the requirements of Section 169A(g)(2) of the Clean Air Act than the BART single source modeling. We have exercised our discretion to use this approach for Unit 2 since the costs for SCR on a dollar per ton of NO_x removed and the incremental costs are very high.

(C) Agreed

<u>Comment 34</u>: The "References" section includes NDDH's 2005 Proposed Alternative Air Quality Modeling Protocol to examine the status of attainment of PSD Class I increments. This protocol was never approved by EPA, and contested elements of this protocol cannot be relied upon in your BART determinations.

<u>Response</u>: The reference only refers to emission factors that were calculated for the increment consumption analysis. These factors were not used in the BART analysis; a more conservative factor of 35(s) was used. As explained in the Response to Comment 30, we believe this factor provides a better estimate of sulfur dioxide emissions than the AP-42 factors because it more closely matches actual CEM data.

<u>Comment 35</u>: SO_2 evaluation, Step 2, 2nd paragraph, p. 8: There appears to be a typographical error in the 2nd to last sentence – should be Falkirk Mine instead of Center Mine?

<u>Response</u>: Agreed

<u>Comment 36</u>: SO_2 analyses, Step 5, p. 11: The reader is referred to the Great River Energy (GRE) BART Analysis, pp. 47-51, for visibility improvement analyses. While the 98th percentile results are provided in the GRE report, it is nearly impossible to understand the tables since results are combined for SO_2 and NO_x and there are no specifics provided for each scenario.

NDDH needs to extract the relevant 98th percentile results from the GRE analysis - by pollutant and by specific scenario – and incorporate them directly into the BART determination document. We note that this information has been added to the NO_x evaluation section but was still omitted from this SO_2 evaluation.

<u>Response</u>: Appendix Y to Part 51, Guidelines for BART Determinations Under the Regional Haze Rule states in part: "As long as these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section, including the visibility analysis in step 5. Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section." In the case of Coal Creek SO_2, the most stringent control available was selected as BART and it will be made federally enforceable in the Permit to Construct. The amount of visibility improvement can be discerned from GRE's analysis.

<u>Comment 37</u>: NO_x analyses, Step 2: Eliminate Technically Infeasible Options, p. 15: As noted above in comment #22, we have provided substantial information and evidence that all SCR technology, including High Dust SCR, is technically feasible at facilities burning North Dakota lignite, and we continue to stand by those comments.

<u>Response</u>: The Department believes the preponderance of evidence indicates that HDSCR cannot be successfully operated when North Dakota lignite is combusted making this option technically infeasible.

<u>Comment 38</u>: NO_x analyses, Step 3: Evaluate Control Effectiveness of Remaining Control Technologies, pp. 15-16: NDDH needs to explain why it accepted GRE's suggested 80% control efficiency for LDSCR instead of using the generally accepted 90% efficiency. For more information, please see the proposed and final Standards for Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units (70 FR 9713, February 29, 2005 and 71 FR 9869, February 27, 2006) and the May 2009 ICAC White Paper, pp. 4 and 7 (contained in Enclosure 3 of this letter).

<u>Response</u>: See response to Comment 32.

<u>Comment 39</u>: NO_x analyses, Step 4: Evaluate Impacts and Document Results, p. 17:

(A) The elimination of SCR and SNCR based on uncertainty surrounding "potential" ammonia contamination of fly ash is not appropriate. The BART determination should be based on the 5-factor analysis, including any necessary data to address this question. GRE claims that installation of SCR or SNCR may negatively impact fly ash sales due to ammonia slip and may result in an ash disposal problem, but does not provide any manufacturer's data, vendor information, or other technical or commercial data to support its claims. See 40 CFR 51.308(e)(1). (SIP must include documentation for BART analyses.) It is our understanding that installation of SCR and SNCR result in very little, if any, impacts to fly ash sales since the ammonia slip for each control is now very low – less than 2 ppm for SCR and less than 5-10 ppm for SNCR. Given that this concern

> wasn’t raised at the other BART sources where you have proposed SNCR, we know of no reason for it to apply to Coal Creek. We note that you cite to an example from Nebraska to support your decision. Please be advised that the cited example is from a draft BART determination analysis. The State of Nebraska has not submitted to EPA Region 7 its BART determination analysis as part of a final Regional Haze SIP. EPA Region 7 has not, and will not, make a determination regarding the approvability of Nebraska's BART determinations until it reviews all components of the final Nebraska Regional Haze SIP and acts on the revision through its own public notice and comment rulemaking.

Response: The commenter requested additional vendor information to support the determination that SCR and SNCR will result in ammonia slip and ash contamination that may reasonably be expected to negatively impact future ash sales. Additional information to support that conclusion is contained in a 2/9/10 GRE email that has been added to the supplemental information considered for the BART determination (copy attached to this response). This email contains recent testimonials from ash marketers, buyers and end product users that provide clear evidence of negative impact on ash sales and use when the ash is contaminated with ammonia by SCR and SNCR systems. The commenter statement that “It is our understanding that installation of SCR and SNCR result in very little, if any, impacts to fly ash sales”... is contradicted by these testimonials.

The commenter stated that EPA/R8 knows of no reason to apply the ash-ammonia contamination concern to Coal Creek since it was not a concern raised in NDDH BART determinations for other plants. The reason is simple: Coal Creek is the only North Dakota plant that has developed a market for ash, that has invested in the infrastructure to sell ash, and that is currently selling ash. It should be no surprise to anyone that companies do not raise the issue of lost sales for products that they do not market.

The commenter stated that NDDH could not use the Nebraska DEQ determination that SCR was not BART in part due to ash contamination by ammonia as supporting evidence because EPA has not yet approved the draft Nebraska Regional Haze SIP. It appears EPA fails to realize that evidence can be considered credible to NDDH even if EPA has not rendered an opinion on it. This evidence has weight with NDDH because the State of Nebraska has considered it and found it to be credible. Nebraska’s BART determination analysis is proof that at least one other state has come to the same conclusion on this matter as NDDH.

Comment 40: Evaluate Visibility Impacts, Step 5, pp. 17-19: We note that you have extracted the visibility impacts data from the GRE BART analysis to include in the NO_x BART evaluation. However, it appears that you have presented the combined results for SO_2 and NO_x controls, not just the NO_x results. Please clarify.

Response: See response to Comment 36.

Comment 41: Summary, p. 23: Please correct typographical errors in the SO_2 BART limits for Unit 1 and Unit 2 – should be 95% instead of 94%.

Response: Agreed

Comment 42: II.A.4.a.: Please correct the typographical error in the first paragraph – should be 95% reduction limit instead of 94%.

Response: Agreed

Comment 43: Unit 1 and Unit 2 NO_x BART evaluation:

(A) In addition to objecting to selection of SNCR as BART based on the North Dakota record, we also object to your determination that separate NO_x limits are appropriate for startup. The record does not justify the need for such separate limits, nor does it justify that the selected values represent BART. As you know, the BART Guidelines contemplate pounds per million Btu limits that apply continuously, with a 30-day rolling average period to accommodate, among other things, potential short-term fluctuations in the emissions rate that may result during startups and other conditions.

As we have noted previously, separate startup limits have not been sought by, or provided to, other facilities (Leland Olds and Stanton) for which SNCR is proposed as BART, and we know of no reason M.R. Young warrants special treatment. NDDH alludes to the Consent Decree as a basis for special treatment and a need to harmonize the "BACT limits" under the Consent Decree and the BART limits. First, the Consent Decree terms with respect to startup were the result of a negotiated compromise in the context of an enforcement action. The Consent Decree terms are not binding in the context of this BART determination, and Paragraph 66 of the Consent Decree in no way settles whether separate startup BART limits are necessary or appropriate at M.R. Young. At this time, no BACT limit has been established at M.R. Young.

NDDH also alludes to the fact that SNCR, and perhaps the overfire air system, will not work optimally during startup. Of course, this is also true for the other facilities mentioned above. This fact alone is not convincing.

NDDH then references Minnkota's claim that startup has lasted up to 61 hours for Unit 1 and that noncompliance of this length will make compliance with the 30-day rolling average emission limit "extremely difficult." From your analysis, we cannot determine whether Minnkota was exercising good air pollution control practices to minimize emissions during this period or to minimize the duration of the startup, whether this length of startup was an anomaly, or what the average emissions rate was during this period. There is no mention of startups at Unit 2 or whether the same parameters can or should be applied. Also, we cannot determine from the analysis what the expected "normal" emissions rate is using SNCR and overfire air. Presumably, your proposed BART limits already include some margin of safety for operational variation.

Also, NDDH has not evaluated potential impacts of the separate startup limits on visibility or why the separate limits represent BART. We have found no indication that the proposed startup limits represent the most stringent level of control for those periods. Furthermore, there is virtually no explanation in your BART determination for the separate startup limit for Unit 2 or why it differs so greatly from the proposed startup limit for Unit 1, or why the other terms that apply to the startup limit for Unit 2 in the permit differ from those for Unit 1 or are warranted.

Even if we found the separate startup limits to be justified, we do not believe the permit is sufficiently clear with respect to determining compliance with the normal 30-day limits and the 24-hour startup limits. In calculating 30-day averages, how will days be accounted for that include some, but not all, hours of startup? How will startups that are less than 24 hours be accounted for in calculating 24-hour averages? Finally, we question the use of heat input levels to define the end of startup as opposed to using temperatures. The latter would be more directly related to SNCR performance.

(B) As we have commented in previous correspondence, the presumptive limits should apply as the control floor since the total generating capacity is actually greater than the reported nameplate capacity of 734 MW, in fact, > 750 MW. In a November 20, 1995 letter, Minnkota advised NDDH that M.R. Young was operating at levels above nameplate and requested a change in the permit description of each unit to 277 MW for Unit 1 and 517 MW for Unit 2. These changes reflected the capabilities of the units as they "are currently with respect to generator output" and result in a total generating capacity of at least 794 MW. Per the BART Guidelines, EPA has found that the use of SCRs at cyclone units burning lignite should enable these large units to cost-effectively meet NO_x emission rates of 0.10 lbs/MMBtu.

(C) We assume that NDDH has revised its cost estimates based on Minnkota's November 2009 Supplemental NO_x BACT Analysis Reports for Units 1 & 2. Minnkota's revised cost analyses are unsubstantiated and highly questionable in many regards, as discussed in comment #24 above. Based on our review of Minnkota's supplemental reports and this BART determination, the NO_x BART determinations need to be revised to address these issues. Revisions, per our comments, are likely to considerably improve the cost effectiveness of SCR for each unit, making it a reasonable selection for BART. In addition, we have the following concerns specific to the BART determination document:

(1) NDDH has assumed a control efficiency of 90% (combined) for ASOFA with SCR. EPA expects that NO_x emissions can be reduced by 90% with SCR alone. Please see the proposed and final Standards for Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units (70 FR 9713, February 29, 2005 and 71 FR 9869, February 27, 2006) and the May 2009 ICAC White Paper, pp. 4 and 7 (contained in Enclosure 3 of this letter). Minnkota's own cost analysis uses 93.8% combined control and 90% control beyond ASOFA with SCR. The BART determination simply states that NDDH believes a reduction of 90% for ASOFA and SCR is "more appropriate on a long-term basis" without providing any rationale. Using a lower control efficiency results in significantly inflated $/ton values.

(2) The footnote on the cost tables (p. 14 and p. 29) indicates that the cost range provided is based on the difference in applying SCR to each unit as a stand alone retrofit (high end cost) and applying SCR to both Units 1 & 2 with shared facilities (low end cost). Minnkota provided these scenarios in its cost analysis. However, it appears the difference between the low and high end of the annualized cost range in NDDH's BART determination is based on "Scenarios A & B" in Minnkota's cost analysis. Scenario A (the lower cost) assumes a catalyst layer replacement (and unit outage time) every 16,000 hours, while Scenario B (the higher cost) assumes a catalyst layer replacement (and additional unit outage time) at each scheduled boiler cleaning outage. For Unit 1, this is three times a year and for Unit 2 this is four times per year. EPA believes that Scenario B is not realistic for a LDSCR or TESCR and should be completely disregarded. It appears as though NDDH is in agreement, but inadvertently used the Scenario B values for the high end of the cost range, rather than using the stand-alone values. In addition to mistakenly using the Scenario B values from Minnkota's cost analysis, it appears that NDDH used the Scenario A & B costs from the "shared facility" Table 4-7SF for Unit 1, while using the Scenario A & B costs from the "stand alone" Table 4-7SA for Unit 2. Correcting these values significantly reduces the higher annualized cost estimate (based on a stand alone unit instead of Scenario B) leading to a much smaller range between the low-end and high end estimates. The lower cost estimate (representing shared costs between Unit 1 and Unit 2 for Scenario A) and the higher cost estimate (representing Scenario A stand alone unit) should be as follows:

Unit 1 LDSCR: $31,749,000/$36,872,000
Unit 1 TESCR: $39,307,000/$44,465,000
Unit 2 LDSCR: $57,351,000/$59,881,000
Unit 2 TESCR: $66,506,000/$69,057,000

(3) Combining the higher 93.8% control efficiency for SCR + ASOFA (as submitted by Minnkota) and the worst case scenario cost described by NDDH in the BART Determination (stand alone unit costs, Scenario A), the following represents the <u>high-end</u> costs for Units 1 & 2:

Scenario A Stand Alone Costs:	Annual NOx Tons Removed	Levelized Total Cost ($1000)	Average Control Cost ($/ton)
Unit 1 (LDSCR)	9,348	36,872	3,944
Unit 1 (TESCR)	9,345	44,465	4,758
Unit 2 (LDSCR)	14,862	59,881	4,029
Unit 2 (TESCR)	14,857	69,057	4,648

On p. 17 of the BART Determination for Unit 1, NDDH “considers the cost effectiveness and incremental cost of SCR + ASOFA at the low end of the cost range to be reasonable,” while the higher end of the range was considered excessive. However, NDDH made this determination based on an error in the calculation of the high-end cost ranges (based on the Scenario B assumption that catalyst is replaced every time the unit is down for a planned outage). NDDH's low-end cost effectiveness values (\$/ton) range from \$3906/ton to \$4948/ton. Given that the corrected high-end cost estimates are not dissimilar from NDDH's reasonable low-end estimates, these high-end costs should be considered reasonable at present.

As described earlier (and apparently supported by NDDH's narrative in the BART Determination, as well as NDDH's criteria for technical feasibility, *i.e.*, a catalyst replacement schedule of 3-4 times per year would not have been considered technically feasible by NDDH), Scenario B should be dismissed. When the high-end cost range becomes the intended "Stand Alone" facility costs, and more appropriate NO_x removal efficiencies are assumed (as provided by Minnkota), the high-end costs become very similar to (and in some cases lower than) what the NDDH BART Determination calculated as low-end costs deemed to be reasonable. There is little difference in these high-end cost effectiveness values for Units 1 and 2. As such, EPA concludes that even without examining the concerns and problems with Minnkota's initial cost values, as discussed in comment #24 above, the existing information for the BART Determination demonstrates that SCR is cost effective. Once appropriate adjustments are made to reflect more realistic costs, these values will become even more reasonable.

(D) As noted above in comment #4, BART visibility improvement analyses must be based on the 98th percentile day results, not the 20% worst days. We do not agree that modeling based on the BART Guidelines overpredicts the visibility improvement in North Dakota.

Response:

(A) The BART Guideline, Section IV.C states "unless there are new technologies which would lead to cost-effective increases in the level of control, you may rely on the MACT standards for purposes of BART. We believe that the same rationale holds true for emissions standards developed for municipal waste incinerators under CAA Section 111(d), and for many NSR/PSD determinations and **NSR/PSD settlement** agreements." [emphasis added]. Clearly, the terms of Consent Decrees, such as the one with Minnkota, can be used in determining BART limits including startup limits that are separate from normal operation limits.

Minnkota did not include emissions from startups in their proposed BART limit because the Consent Decree indicates they must be addressed separately. Other sources have included these emissions in their proposed BART limit. Leland Olds Unit 2 has a baseline emission rate of 0.67 $lb/10^6$ Btu with a BART limit of 0.35 $lb/10^6$ Btu. The Minnkota Unit 1 baseline is 0.85 $lb/10^6$ Btu while Unit 2 is 0.79 $lb/10^6$ Btu. We have proposed a BART limit for Unit 1 of 0.36 $lb/10^6$ Btu and 0.35 for unit 2 (same as Leland Olds Unit 2). It is obvious that the Leland Olds Unit 2 limit has startups included in the rate.

The maximum 24-hour NO_x emission rates for M.R. Young that were used to determine BART applicability were 2,855 lb/hr and 5,364 lb/hr for Units 1 and Unit 2, respectively.

These values excluded startup, shutdown and malfunctions. The proposed startup limits are 2,070 lb/hr and 3,996 lb/hr for Unit 2 (24-hr average). This represents a 25-30% reduction from the baseline emission rate based on the proposed BART limits for startup. This clearly indicates there will be an improvement in visibility in the Class I areas even under the startup limits. When comparing the proposed startup limits to normal baseline emissions, it is evident that Minnkota will have to take steps to minimize emissions. Startup emissions can exceed 1 lb/10^6 Btu. The proposed startup limits represent 0.83 lb/10^6 Btu that must be averaged over the startup period. This is considerably less than the baseline emission rates (excluding SSM) which are 1.14 and 1.12 lb/10^6 Btu based on the heat input at the end of the startup period. Minnkota's justification is in Sections 3.5.2 of their analysis for each unit. The justification is virtually the same for each unit. The Department saw no reason to repeat its analysis for the similar units in its BART determination.

The Department will be making a BACT determination for the units for NO_x. That BACT determination will include startup limits. If the BACT limits are more stringent than the BART limits, the Department will reopen the Regional Haze SIP and incorporate the more stringent limits into the BART Permit to Construct.

The startup limit for Unit 2 is much higher than Unit 1 since it is a much larger unit (i.e. 477 MWe versus 257 MWe). However, the average lb/10^6 Btu emission rate during the startup is the same (0.83 lb/10^6 Btu) for both units.

Compliance with the NO_x BART limit will be determined based on the average of all hours in the 30 successive boiler operating dates except that only startups will be excluded from the 30-day rolling average. Malfunctions and shutdowns will be included. Any hours of startup will be excluded from calculating the 30-day rolling average emission rate. For startups that equal or exceed 24 hours, the average emission rate is calculated as the arithmetic average of 24 consecutive hourly emission rates. For startups that are less than 24 hours, compliance will be determined based on the arithmetic average for the duration of the startup period. The Permit to Construct has been modified to include this compliance determination method.

(B) The November 20, 1995 letter lists an URGE rating which is a three hour test. This rating does not represent a long-term rating or one that can be sustained more than three hours. The Acid Rain database lists M.R. Young Station as having a capacity of 734 MWe. The Energy Information Administration of the Department of Energy lists M.R. Young as having a summer time capacity of 697 MWe. Although Section 169A(b)(2) of the Clean Air Act does not define "total generating capacity", Section 169A(c) does discuss exempting power plants from the BART requirements if the <u>total design capacity</u> is less than 750 megawatts and it does not significantly contribute to visibility impairment. "Total design capacity" is equal to or less than the nameplate rating of the generators. In addition, the presumptive BART limits for NO_x were based on the nameplate capacity of the sources (see Technical Support Document; Methodology for Developing BART NO_x Presumptive Limits). Therefore, we believe M.R. Young Station is not subject to the BART Guidelines or the presumptive BART limits.

(C)(1) See response to Comment 25.

The 80% removal efficiency expected for SCR is in the middle of the range of efficiencies indicated in two EPA documents (see response to Comment 25) and ERG's analysis for the PGE Boardman Plant (see response to Comment 25). The BART Guideline in Step 4 states "The value selected for the design parameter should ensure that the control option will achieve the level of emission control being evaluated." The NDDH is confident that SCR + ASOFA will achieve 90% control; however, the amount of time an SCR will achieve this level of control (i.e. catalyst life) is unknown. Whether SCR will achieve 93.8% reduction efficiency over an extended period of time at M.R. Young is debatable.

The NDDH has included Minnkota's cost effectiveness and incremental cost results in our BART determination analysis. These calculations are based on 93.8% reduction efficiency. The NDDH considers the cost effectiveness and incremental costs calculated by Minnkota to be excessive over the entire range of costs.

(C)(2) The costs that are now shown represented the full range of costs provided by Minnkota. The footnote at the bottom of the cost tables has been changed to indicate that the entire cost range is provided. The NDDH has included all scenarios to show that the cost effectiveness and incremental cost is excessive regardless of the catalyst changeout schedule or whether cost should be calculated based on standalone facilities or shared facilities. Based on both the NDDH's and Minnkota's estimate cost effectiveness and incremental cost, the cost of SCR is considered excessive.

(C)(3) The cost estimate in the FLM review version of the BART determination analysis was updated by using Minnkota's cost estimate instead of one based on the cost estimate for Leland Olds Unit 2 which indicated lower costs. However, some of the discussion on cost effectiveness for M.R. Young Unit 1 from the FLM review version was not updated. This error has been corrected and EPA should not draw any conclusions regarding cost effectiveness or incremental cost effectiveness from this erroneous text.

The NDDH has included Minnkota's calculation of cost effectiveness and incremental cost in its BART determination analysis. These costs are based on 93.8% reduction efficiency. The cost effectiveness and incremental cost effectiveness are considered excessive over the entire range of costs.

Minnkota has been unable to obtain a vendor guarantee for the catalyst for either LDSCR or TESCR. This indicates that no one can predict with any reasonable accuracy the life of the catalyst. Therefore, the costs over the entire range were considered and found to be excessive.

The Department considered all five factors in determining BART for the M.R. Young Station. The incremental improvement in visibility of SCR + ASOFA versus SNCR + ASOFA is negligible (0.01 deciviews at TRNP and LWA for Unit 1 and 0.01 and 0.02 deciviews respectively at TRNP and LWA for Unit 2). This incremental improvement in visibility would cost at least $2,605,400,000 per deciview at Unit 1 and at least $2,286,700,000 per deciview for Unit 2 based on the cumulative modeling. The NDDH considers this amount of visibility improvement to be negligible and the cost unreasonable.

Even using 93.8% removal efficiency will not create much additional visibility improvement (approximately 4% additional reduction of emissions). Modeling by the NDDH indicates that SCR + ASOFA operating at 93.8% efficiency will only improve visibility 0.001 deciviews in the most impaired days when compared to SCR + ASOFA operating at 90% efficiency. The incremental visibility improvement between SCR + AOFA and SNCR + ASOFA would still be negligible.

As part of the BART process, the NDDH had to determine if LDSCR and TESCR were technically feasible. When this determination was made, the NDDH had information that a vendor guarantee could be secured for TESCR at M.R. Young Station. More recent information provided by Minnkota indicates this is not true. The uncertainty whether LDSCR or TESCR can be successfully applied at M.R. Young was weighed in the decision not to require LDSCR or TESCR. The BART Guideline states "there may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology." Requiring the use of SCR that cannot be successfully applied at M.R. Young Station would have severe economic effects on Minnkota Power Coop.

The NDDH considers the cost effectiveness of SCR + ASOFA to be excessive. The NDDH considers the incremental cost of SCR + ASOFA versus SNCR to be excessive. This determination is applicable to both the NDDH's calculated cost values and Minnkota's values and is applicable to the entire range of costs. The NDDH considers the amount of visibility improvement of SCR + ASOFA versus SNCR + ASOFA to be negligible. The NDDH also considered the uncertainties of the technical feasibility of LDSCR and TESCR to M.R. Young Station Units 1 and 2 which is highlighted by the lack of a vendor guarantee. The NDDH stands by its determination that SCR + ASOFA is not BART.

(D) See response to Comment 4.

Comment 44: Unit 2 SO_2 Evaluation, Step 3, p. 21: We note the baseline SO_2 emissions have been revised from 16,728 tons/year upward to 18,090 tons/year in this draft. Please explain why this revision was necessary at this late date.

Response: The baseline was revised to match the expected average sulfur content for future coal. The previous baseline was based on historical data which represented coal with a lower sulfur content. The change was made in response to an FLM comment. The Department believes the use of future coal sulfur content is more consistent with the discussion on baseline emissions in the BART Guideline since it represents anticipated emissions from the unit. It did not affect the BART decision since the most efficient control option was selected both in the public comment version and the final version.

Comment 45: II.A.1.c., NO_x limits: The alternative limits for startup are not acceptable. See comment #43(A) above.

Response: See response to Comment 43.

Comment 46: II.A.1.e.: The condition that SO_2 and PM limits apply at all times, including startup, shutdown, emergency and malfunction should also apply to NO_x limits.

Response: Minnkota did not request a different limit for SO_2 or PM during startup. Therefore, we did not consider it.

Comment 47: II.A.4.b.(8): This language regarding averaging the emissions of Unit 1 and Unit 2 is not consistent with the language in the BART determination document, Section IX. The BART determination includes a formula and definition for Average Allowable Emission Rate (AER), which is not included in the permit. Please clarify.

Response: The formula for Average Allowable Emission Rate (AER) is unnecessary since averaging is only allowed if Unit 2 is basing compliance on percent reduction. Since both Unit 1 and Unit 2 have an AER of 95% reduction, the Average Allowable Emission Rate is 95%; no calculation is needed. This is specified in Condition IX.A.3(a).

Comment 48: SO_2 BART evaluation in general: NDDH notes that a circulating dry scrubber was eliminated from consideration due to excessive incremental costs. However, EPA would not find the cost effectiveness of this option ($1631/ton) unreasonable compared with other BART determinations reviewed.

Response: EPA states that the cost effectiveness of a circulating dry scrubber ($1,631/ton) is not unreasonable. However, as EPA is aware, the Department eliminated a circulating dry scrubber from consideration as BART based upon the high incremental cost of greater than $10,600/ton. It is the Department's position that both cost effectiveness and incremental cost must be considered in the analysis in accordance with long-standing EPA policy. The New Source Review Workshop Manual states, "This type of analysis should demonstrate that a technically and economically feasible control option is nevertheless, by virtue of the magnitude of its associated costs and limited application, unreasonable or otherwise not "achievable" as BACT in the particular case. Average and incremental cost effectiveness numbers are factored into this type of analysis." It is our understanding that EPA's policy (i.e., that both cost effectiveness and incremental cost should be considered) remains as stated in the Manual. The Department considered both cost effectiveness and incremental cost in accordance with long-standing EPA policy and determined that the incremental cost is excessive for a circulating dry scrubber. The Department maintains the position that the incremental cost of a circulating dry scrubber is excessive and this excessive incremental cost is a sufficient reason to eliminate a circulating dry scrubber from consideration.

Comment 49: SO_2 BART evaluations for lignite and PRB coal, pp. 8 and 22: In an effort to assess the coal quality basis for NDDH's proposed SO_2 BART determinations for Stanton, we conducted an independent analysis, using lignite and PRB coal data contained in EPA's Clean Air Markets Division (CAMD) database. The 30-day average SO_2 emission potentials (in lb/MMBtu and percent sulfur) of lignite and PRB coal are available for a wide variety of sources through CAMD, and for most (if not all) of the large coal mines in the region. We would be happy to share this information with NDDH, if desired. Since these data are readily available, we see no need for the use of a 33% multiplication factor to adjust an annual average emission rate to a 30-day rolling average emission rate.

Based upon our review of the lignite coal quality data in the CAMD database for 2007-2009, it appears that NDDH's proposed SO_2 BART limit of 0.24 lb/MMBtu when burning lignite is in the range of what we'd expect to see at a 90% control efficiency. However, we wish to note that if NDDH believes that the proposed Spray Dryer Absorber and Fabric Filter will be able to achieve 90% reduction of SO_2 emissions while burning low sulfur PRB coal, the control devices should be able to achieve greater than 90% control when burning higher sulfur content lignite coal.

Based on our review of the PRB coal quality data in the CAMD database for 2007-2009, NDDH's proposed SO_2 BART limit of 0.16 lb/MMBtu when burning PRB coal appears to be too high. The NDDH based its proposed limit on an estimate of 1.2 lb/MMBtu for the annual average SO_2 emission potential of PRB coal, then applied 90% control efficiency to yield 0.12 lb/MMBtu controlled SO_2 on an annual average, then multiplied by 1.33 to convert to a 30-day average limit of 0.16 lb/MMBtu. The NDDH's estimate of 1.2 lb/MMBtu emission potential for PRB coal was apparently based on coal sulfur content of about 0.64%. The NDDH's BART Determination document does not indicate which mines were averaged together to yield 0.64%. Data we obtained from CAMD's database for 15 of the largest PRB coal mines reveal that PRB coal typically has much lower sulfur content on a 30-day average, about half of the 0.64% used by NDDH. Our analysis of that data yielded an average SO_2 emission potential of 0.78 lb/MMBtu, on a 30-day basis, for all of the PRB coal mines together.

It appears that NDDH wishes to use the high end of a 95% confidence interval rather than an average value to set the 90% reduction limit. Therefore, we have averaged all the high end values of all the 95% confidence intervals for all the PRB mines for which we obtained data. The average of these 95% confidence intervals is 0.95 lb/MMBtu, again on a 30-day average basis. The resulting SO_2 BART limit when burning PRB coal at a 90% control efficiency would most likely be in the vicinity of 0.095 lb/MMBtu, on a 30-day rolling average.

Response: EPA states, "we see no need for the use of a 33% multiplication factor to adjust an annual average emission rate to a 30-day rolling average emission rate." The EPA provides no data to support this position and only refers to an "independent analysis" conducted by EPA. As EPA is well aware, a party (including EPA) wishing to comment during a comment period is under an obligation to submit any data that the party wishes the Department to consider. Since EPA failed to submit any data during the comment period, the Department is unable to conduct a review of EPA's data. It should be noted that EPA has been aware of the use of the 33% adjustment factor at least since August 4, 2008, did not comment on the use of the factor in EPA's October 23, 2009 comment letter and only now comments on the use of the factor. In a response to a direct request from EPA Region 8 for more information regarding the use of the 33% adjustment factor, the Department sent a December 2, 2009 email to EPA Region 8 showing that the adjustment factor is based upon actual operating data at two North Dakota facilities. EPA did not ask for further data regarding the use of the 33% factor and apparently chose instead to move directly to an “independent analysis.” Given that EPA failed to submit this “independent analysis”, the Department cannot determine if EPA even considered the Department’s data as part of the analysis.

It is common practice to establish higher short-term limits to allow for short-term emissions variability inherent to facility operations. The EPA RACT/BACT/LAER Clearinghouse contains numerous examples of short-term BACT limits which are higher than longer-term BACT limits. For example, a permit issued to Omaha Public Power District (RBLC ID NE-0031) on March 9, 2005 establishes a 3-hour average SO_2 BACT emission limit of 0.48 lb/MM Btu compared to the 24-hour SO_2 BACT limit of 0.163 lb/MM Btu and a 30-day rolling average SO_2 BACT limit of 0.095 lb/MM Btu. A permit issued to Wellington Development / Greene Energy (RBLC ID PA-0248) on July 8, 2005 establishes a 3-hour average SO_2 BACT limit of 0.234 lb/MM Btu and a 30-day rolling average SO_2 BACT limit of 0.156 lb/MM Btu. A permit issued to River Hill Power Company (RBLC ID PA-0249) on July 21, 2005 establishes a 24-hour average SO_2 BACT limit of 0.274 lb/MM Btu and a 30-day rolling average SO_2 BACT limit of 0.20 lb/MM Btu. Two examples where annual and 30-day rolling average BACT limits were established include permits issued to Associated Electric Cooperative (RBLC ID MO-0077) and Western Farmers Electric Cooperative (RBLC ID OK-0118). The permit issued on February 22, 2008 to Associated Electric Cooperative establishes a 30-day rolling average NO_x limit of 0.065 lb/MM Btu and an annual average NO_x limit of 0.05 lb/MM Btu. The permit issued on February 9, 2007 to Western Farmers Electric Cooperative establishes a 30-day rolling average NO_x limit of 0.07 lb/MM Btu and an annual average NO_x limit of 0.05 lb/MM Btu. In addition, a permit issued by EPA on July 31, 2008 for the Desert Rock facility establishes a 30-day rolling average NO_x limit of 0.05 lb/MM Btu and an annual average NO_x limit of 0.0385 lb/MM Btu. Clearly, it is common practice to establish short-term BACT limits which are higher than longer-term BACT limits.

The Department has reliable data based upon actual facilities operating in North Dakota to support the use of the 33% adjustment factor. In addition, adjustment factors (to adjust from an annual average limit to a 30-day rolling average limit) calculated from Associated Electric Cooperative, Western Farmers Electric Cooperative and Desert Rock limits are approximately 30%, 40% and 30%, respectively. These adjustment factors are very close to the adjustment factor of 33% used by the Department. Since the Department has reliable data to support the use of the 33% adjustment factor and no data has been submitted indicating that the factor is not appropriate, the Department maintains the position that the 33% adjustment factor is appropriate.

EPA states that “the control devices should be able to achieve greater than 90% control when burning higher sulfur lignite coal”; however, EPA provides no data to support this statement. The Department is aware that higher control efficiencies are thought to be attained when high sulfur coal is burned; however, EPA provides no data indicating that a higher control efficiency can be attained when burning lignite (with an assumed uncontrolled SO_2 emission rate of approximately 1.8 lb/MM Btu) as compared to PRB (with an assumed uncontrolled SO_2 emission rate of approximately 1.2 lb/MM Btu). Given that some facilities in the U.S. burn coal which results in uncontrolled SO_2 emission rates in excess of 4 lb/MM Btu, neither lignite nor PRB would be considered to be a “high sulfur coal” in comparison. Based on the available data, the Department maintains the position that a SD/FF at Stanton Station #1 is capable of an average sulfur dioxide control efficiency of 90%.

EPA states that “Data we obtained from CAMD’s database for 15 of the largest PRB coal mines reveal that PRB coal typically has much lower sulfur content on a 30-day average, about half of the 0.64% used by NDDH. Our analysis of that data yielded an average SO_2 emission potential of 0.78 lb/MMBtu, on a 30-day basis, for all of the PRB coal mines together.” The EPA submits no actual data and just refers to “data we obtained…for 15 of the largest PRB coal mines…”. EPA does not indicate which coal mines were studied and why certain mines were apparently not included in the study. EPA is under an obligation to submit any applicable data that EPA wishes the Department to consider. Unfortunately, since EPA failed to submit any data during the comment period, the Department is unable to conduct a review of EPA’s data. However, the Department did consult the U.S. Geological Survey (USGS) Coal Quality Database (available at www.usgs.gov) and found that the database currently includes over 700 samples of Wyoming and Montana subbituminous for which sulfur was analyzed. The Department has analyzed this data and has determined that the average sulfur content based on all of the samples is approximately 0.83%. In addition, the GRE BART submittal includes actual data from three mines from which GRE could potentially receive coal. The average coal sulfur contents for the three mines are 0.34%, 0.64% and 0.80%, for an average sulfur content of approximately 0.59% (on a heat input basis, the average uncontrolled SO_2 emission rate is calculated to be approximately 1.17 lb/MM Btu compared to the SO_2 emission rate assumed in the analysis of 1.2 lb/MM Btu). Based upon the available data the Department maintains the position that the uncontrolled SO_2 emission rate of 1.2 lb/MM Btu used to calculate emissions when burning PRB coal is reasonable.

Comment 50: NO_x BART evaluation: As we have commented in previous correspondence, the 45% control efficiency assumed for the alternative of combining combustion controls plus SNCR is lower than we’ve seen elsewhere. Please explain why NDDH accepted this control efficiency number from GRE. In addition, as noted above in comment #22, we have provided substantial information and evidence that all SCR technology, including High Dust SCR, is technically feasible at facilities burning North Dakota lignite.

Response: EPA states that the 45% control efficiency assumed for the alternative of combining combustion controls plus SNCR “is lower than we’ve seen elsewhere” and asks the Department to “explain why NDDH accepted this control efficiency from GRE.” EPA provides no data to support the EPA’s contention that the control efficiency “is lower than we’ve seen elsewhere.”

In the response to public comments for the Desert Rock Energy Facility dated July 31, 2008, EPA states, “A BACT determination involves judgment and balancing, and does not involve simply picking the lowest numerical emission limit or the highest observed control efficiency. The design of a wet FGD system and the resulting control efficiency depends on a variety of parameters, including the characteristics of the fuel, boiler operating data and tolerances, emission requirements…, limestone availability and quality, and economic factors.” In the Desert Rock case, EPA clearly recognizes that a number of factors must be taken into account when determining if a control efficiency is acceptable. However, in the above comment the EPA appears to ask the Department to increase an assumed control efficiency based on no data and only a vague, unverifiable statement from EPA regarding what EPA has "seen elsewhere." EPA does not even discuss if the control efficiencies EPA has "seen elsewhere" are for sources that are comparable to Stanton Station #1.

In a technical memorandum dated June 26, 2008 prepared by Eastern Research Group, Inc. (ERG) regarding the estimation of costs and impacts of NO_x control technologies applied to the PGE Boardman Plant (a coal-fired facility), ERG conservatively estimates an 18 percent SNCR control efficiency for the PGE Boardman Plant. The same memorandum references an estimate by Black and Veatch of a 20 to 25 percent SNCR control efficiency. The memorandum also states, "With regard to SNCR performance, although SNCR installations on boilers have been demonstrated to achieve between 25 and 50 percent reduction in NO_x, very large boilers (>300 MW) generally are limited to lower SNCR removal efficiencies."

The EPA Air Pollution Control Cost Manual states, "SNCR can achieve NO_x reduction efficiencies of up to 75 percent (%) in selected short-term demonstrations. In typical field applications, however, it provides 30% to 50% NO_x reduction." A table in the Manual labeled "SNCR NO_x Reduction Efficiency for Various Boiler Sizes" indicates that the SNCR reduction efficiency for the size of a boiler at Stanton Station #1 (1,800 MM Btu/hr) would be expected to be less than 40%.

GRE has described the rationale for the control efficiency selected and the EPA has not identified any actual concerns with GRE's rationale, has not provided any actual data relating to SNCR control efficiencies at Stanton Station #1 and can only offer a vague, unverified statement regarding SNCR control efficiencies. The available data indicates that a 45% control efficiency is reasonable and may in fact be on the higher end of achievable control efficiencies for SNCR applied to a coal-fired unit of the size at Stanton Station #1 as a retrofit. Given that the available data clearly indicates that the assumed 45% control efficiency is reasonable and EPA has offered no data to the contrary, the Department maintains the position that the 45% control efficiency is reasonable.

Comment 51: II.A.3., Continuous Emission Monitoring (CEM): Based on GRE's comments, this section of the permit was revised to eliminate the phrase "Main Stack" from "Unit 1 (Main Stack)" as the location for the CEM. For clarity, the permit needs to be revised to specify that the CEM location for a particular pollutant is downstream of controls for that pollutant (unless control efficiency is being measured by a combination of upstream and downstream CEMs, in which case one of the CEMs for that pollutant would be upstream of controls).

Response: The Department believes is inherently obvious that the pollutant concentration will be measured downstream of the control equipment since the CEM is meant to establish compliance with the emission limits. However, to address EPA's concern, the Department has added language to clarify that the CEMs must be located downstream of the control equipment.

Comment 52: Based on your discussions with Otter Tail Power Company, it appears that this level of minimal control is considered reasonable at this time. Therefore, even if you disagree with our other comments regarding Reasonable Progress, at least this level of NO_x control should be included in the SIP as a required Reasonable Progress control measure. As such, the permit should more closely mirror the BART permit format, including the appropriate 30-day rolling average emission limit, compliance date no later than 2018 (or sooner if reasonable), and compliance determination, monitoring, recordkeeping, and reporting requirements.

Response: The Department has found through its reasonable progress analysis that additional controls on Coyote are not reasonable. Nevertheless, in an effort to demonstrate that North Dakota continues to work with companies to make further reductions, NO_x reductions at the Coyote Station are being included in the SIP. We have relocated the write-up on the Coyote Station to Section 10.6.1, Emission Reductions Due to Ongoing Air Pollution Control Programs. Since this source is not subject to BART, we believe the Permit to Construct is appropriate. The equipment will be installed by July 1, 2018.

Comment 53: II.A.2, Compliance Date: There appears to be a typographical error in the heading – should be "Date" instead of "Data."

Response: Agreed

Attachments

1. ERG Technical Memorandum on PGE Boardman Plant.

2. October 6, 2008 email from Steve Weber to Kevin Golden.

3. Minnkota response to questions on SCR Cost Estimate; February 11, 2010.

4. GRE Response on Ammonia in Flyash; February 9, 210.

Technical Memorandum #2

To: David Collier, Oregon Department of Environmental Quality
Brian Finneran, Oregon Department of Environmental Quality
Mark Fisher, Oregon Department of Environmental Quality

From: Roger Christman, Roy Oommen, and Paula Fields

Subject: Estimation of Costs and Impacts of NO_x Control Technologies Applied to the PGE Boardman Plant

Date: June 26, 2008

INTRODUCTION

In response to the U.S. EPA final rule on Regional Haze and Best Available Retrofit Technology (BART) determinations, and at the request of the Oregon Department of Environmental Quality (DEQ), Portland General Electric Company (PGE) submitted their proposed BART analysis for the Boardman Plant (PGE Proposal) on November 5, 2007. The PGE proposal was prepared by Black & Veatch (B&V) and CH2M Hill.

In December 2007, Eastern Research Group, Inc. (ERG) was engaged by the DEQ to assist in the evaluation of the PGE Proposal and to conduct an independent feasibility assessment of select options for control of nitrogen oxides (NO_x) from the coal-fired Boardman Plant. ERG's scope of work (SOW), as contained in Contract 055-08, includes the following tasks:

- Task 1: Participate in a kick-off meeting in Portland with PGE, DEQ, and key stakeholder groups
- Task 2: Participate in a site visit to the Boardman Plant
- Task 3: Submit a trip report documenting the results of Tasks 1 and 2
- Task 4: Evaluate the PGE Proposal and submit memo of findings (Memo #1)
- Tasks 5 and 6: Evaluate NO_x control technologies (i.e., low NO_x burners with overfire air and selective noncatalytic reduction, low NO_x burners with overfire air and selective catalytic reduction, and other control options as identified by DEQ), and submit a memo of findings (Memo #2)
- Task 7: Participate in a meeting to discuss findings of Memos #1 and #2 with DEQ, PGE, and other stakeholder groups
- Tasks 8, 9, and 10: Prepare outline of draft report, submit draft report, and meet with DEQ, PGE, and stakeholder groups to discuss draft report
- Task 11: Participate in meeting with DEQ's BART rulemaking Advisory Committee
- Task 12: Submit final report
- Task 13: Provide "as needed" assistance to DEQ within the constraints of the project budget

Tasks 1 and 2 were completed on February 4 and 5, 2008, and the Task 3 trip report was submitted to DEQ on February 15, 2008. The Task 4 preliminary evaluation of the PGE Proposal (Memo #1) was submitted to DEQ on February 25, 2008. This evaluation focused on the NO_x control technologies that were examined by B&V for the Boardman Plant; however, the evaluation was considered preliminary because answers to most of the questions asked of PGE and B&V at the February meetings had not as yet been provided. The memo cited selective catalytic reduction (SCR) installed costs as the major issue to be resolved and most other comments were fairly minor (i.e., not likely to substantially change the BART determination).

This Task 6 memorandum (Memo #2) documents the results of ERG's complete evaluation of the PGE Proposal, as well as our own feasibility assessment of select technologies for controlling NO_x at the Boardman Plant (Task 5). Memo #2 is organized as follows:

- Summary of Methods and Findings: This section contains a brief overview of the method used by ERG to evaluate the PGE Proposal and assess the various characteristics of each NO_x control technology (i.e., performance, energy and non-air quality impacts, and cost).
- Section 1.0, Control Technologies Selected for Analysis: This section lists and describes the NO_x control technologies reviewed by ERG and contained in the PGE Proposal for the Boardman Plant. Also, the impact of the NO_x controls on the DEQ's requirements pertaining to mercury for Boardman is discussed.
- Section 2.0, ERG's Cost Estimation Methodology: This section describes the inputs and outputs of the cost estimates developed by ERG using the CUECost model. Conclusions are presented regarding the appropriateness of this method for use on Boardman's NO_x control retrofit options.
- Section 3.0, Comparison of PGE Proposed Costs and ERG Costs Estimates for NO_x Control: This section compares the results contained in the PGE Proposal for the range of NO_x controls, to ERG's estimates. This section addresses the significant issue of how best to estimate SCR installed costs for the Boardman Plant in view of widely varying costs that results from various approaches.
- Section 4.0, Conclusions: This section provides ERG's findings with regard to the PGE Proposal for the Boardman Plant's NO_x and mercury control technologies.

SUMMARY OF METHODS AND FINDINGS

Based on the experience of ERG's NO_x control expert and relevant literature, ERG evaluated the performance and energy and non-air quality impacts of the NO_x control technologies identified by DEQ for this analysis, and evaluated in the PGE Proposal for the Boardman Plant, including (combinations of): new low NO_x burners (NLNB), advanced overfire air (AOFA), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). Our findings are as follows:

- With regard to the performance of NLNB with AOFA, ERG acknowledges that the unusual furnace internals at the Boardman Plant (i.e., wing or division walls extending well below the boiler nose) will limit the effectiveness of these controls in reducing NO_x, and finds that the B&V estimate of 0.28 lb/MMBtu does not seem unreasonable.

- With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR at the Boardman Plant under year-round operation would need to be considered in selecting a permit level.
- With regard to SNCR performance, although SNCR installations on boilers have been demonstrated to achieve between 25 and 50 percent reduction in NO_x, very large boilers (>300 MW) generally are limited to lower SNCR removal efficiencies. The Boardman Plant is large and has division walls, noted above, that limit upper furnace mixing. In Memo #1, ERG expressed concern that SNCR might not achieve the 20 to 25 percent that B&V was predicting for Boardman. B&V has since requested a more detailed assessment of the unit by Fuel Tech, the country's leading SNCR vendor and has reduced the estimated performance to18 percent to be conservative.
- With regard to energy and non-air quality impacts, ERG finds that there are no significant impacts from existing/new LNB, AOFA, or SNCR. In general, ERG agrees with the PGE Proposal that SCR has three (potential) adverse impacts as compared to SNCR: an SCR unit requires at least 36 times as much electricity to operate as SNCR; disposal of spent catalysts create hazardous waste (although ERG believes evolving catalyst management practices may minimize this impact); and anhydrous ammonia releases create an additional accidental release hazard. In some cases, utilities have chosen to avoid this hazard by generating ammonia "on demand" from urea, although this involves added capital and operating expense.

ERG's method for evaluating cost of the NO_x control technologies included use of the CUECost estimation program. The CUECost program is widely accepted and used by the utility industry and government agencies for estimating costs for controls applied to coal-fired power plants. While ERG believes that CUECost is appropriate for estimating cost for relatively small construction projects (e.g. NLNB, AOFA and SNCR retrofits for coal-fired power plants), we do not believe that CUECost accurately reflects installed costs for major construction projects, such as SCR and flue gas desulfurization (FGD), for reasons that evolved through this study. These findings are described below.

From the outset, the majority of ERG's attention and effort focused on the probable installed cost of SCR at the Boardman Plant. In our preliminary evaluation (Memo #1), ERG believed that the SCR installed cost estimate provided on page D-9 of the PGE Proposal overstated the likely cost (2007 cost-basis), possibly by as much as a factor of two. We focused on the SCR installed cost because:

- SCR is widely and successfully applied on Powder River Basin (PRB) coal units throughout the country;
- SCR is effective in reducing NO_x to very low levels; and
- SCR represents a substantial increase in installed cost as compared to SNCR (which is the BART technology proposed by PGE).

For quite some time, the power plant NO_x control community has used \$100/kW as a rule-of-thumb installed cost for SCR installed on coal-fired power plants. This was based on costs reported for some early installations in the 1990s and early cost studies by the U.S. Environmental Protection Agency (U.S. EPA) and others. As we started this analysis of the PGE Proposal, ERG was aware of three literature papers that addressed SCR installed costs (Hoskins, 2003; Cichanowicz, 2004; Marano and Sharp, 2006) with cost-basis years of 2002, 2003 and 2005, respectively. These papers provided evidence that the $100/kW rule-of-thumb did not correspond to the costs being experienced by utilities installing SCR in the 2002–2005 timeframe. In an initial conference call with DEQ personnel, ERG expressed an opinion that SCR installed costs for Boardman may be on the order of $150/kW or about one half the $309/kW that was contained in the PGE Proposal.

Section 3.0 of this memo contains a discussion of three avenues of analysis that ERG has pursued to evaluate the probable installed cost of SCR at Boardman. These are:

- Bottom-Up installed cost using the CUECost Model with the Chemical Engineering Construction Cost Index for 2007 applied.
- Top-Down literature values obtained from the SCR installed costs as reported in various Internet and subscription sources.
- A current B&V "real" project cost that ERG was permitted to examine (under terms of a confidentiality agreement) in the B&V offices in Overland Park, Kansas.

ERG supplemented these cost sources with literature papers and relevant study findings concerning the general escalation in heavy construction cost resulting from the world-wide commodities bubble and construction labor shortages.

The CUECost program generates an installed cost of $70/kW to $130/kW; however, we feel this does not represent the probable cost of SCR applied to the Boardman Plant.

The top-down literature values analysis is based on a large number of data points including 33 SCR project installed costs provided by PGE and B&V in an April 6, 2008 submission to DEQ. Although there are many data points in this dataset, the quality of the individual points is difficult, and in some cases impossible, to assess. Nonetheless, all of these sources do point to a rapid escalation in SCR installed costs since 2004. ERG analyzed the 2007 cost-basis data by eliminating the three highest and three lowest cost projects and one project that was known to be very dissimilar to the Boardman Plant characteristics. The remaining nine projects range from $207/kW to $267/kW, with an average of $227/kW. ERG believes that this is a reasonable representation of 2007 costs of large SCR installations under normal retrofit conditions.

ERG examined the actual cost data (i.e., both the bid cost developed for the project proposal and the actuals from the B&V project accounting system) for a recent SCR project performed by B&V. The total installed cost for this project was $221/kW on a 2007 cost-basis. This project cost falls near the middle of the costs resulting from the analysis of the 2007 top-down literature values described above and thus provides confirmation that the range of $207/kW to $267/kW is reasonable.

Certain retrofit conditions at the Boardman plant tend to increase the installed cost, and others tend to reduce costs. The fact that some boiler modifications will be needed (due to the high flue gas temperature at the economizer outlet) that are not typical of SCR retrofit projects, tends to offset some of the cost-lowering factors present at the Boardman Plant. With all of these factors taken into consideration, ERG concludes that the Boardman Plant SCR installed cost would be at the high end of the \$207/kW to \$267/kW range cited above (a detailed analysis of this finding is in Section 3.4 of this memo). However, since no detailed design of the Boardman Plant SCR has been carried out, there is a fairly broad uncertainty band associated with all of these cost estimates.

Table 1 of this memo provides a side-by-side comparison of the costs for all NO_x control technologies evaluated in the PGE Proposal, and by ERG using the research and methods described above. Differences in costs range from less than 1 percent (for NLNB) to 100 percent for existing LNB with OFA and SNCR. Differences between PGE and ERG cost estimates for SCR range from 24 percent (SCR with existing LNB and OFA) to 27% (SCR with NLNB and AOFA).

1.0 CONTROL TECHNOLOGIES SELECTED FOR ANALYSIS

DEQ directed ERG to review several specific NO_x controls for potential use at the Boardman Plant. These controls, listed below, were also contained in the PGE Proposal and initially reviewed by ERG in Memo #1 (submitted to the Oregon DEQ on February 25, 2008):

- New low NO_x burners (NLNB)
- NLNB with advanced overfire air (AOFA)
- Existing LNB with OFA and selective catalytic reduction (SCR)
- Existing LNB with OFA and selective noncatalytic reduction (SNCR)
- NLNB with AOFA and SCR
- NLNB with AOFA and SNCR

The remainder of this section discusses the performance (i.e., percent reductions and emission rates in pounds per million BTU [lbs/MMBtu]) and energy and non-air quality environmental impacts for each of the NO_x controls. Also, the potential impacts of each NO_x control on DEQ's existing mercury control requirement for the Boardman Plant are discussed.

1.1 Performance of NO_x Controls

New Low NO_x Burners

Improvements to LNB design since development of the first generation of LNBs have achieved an additional 20 to 40% reduction in NO_x in comparison to first generation LNBs. The PGE Proposal indicates that the Boardman Plant was issued a construction permit in 1977. As part of the permit, PGE utilized first generation low NO_x burners (LNB) in combination with overfire air (OFA) to reduce NO_x emissions. This combination of controls is discussed below.

New Low NO_x Burners with Advanced Overfire Air

Since the early to mid-1990s, boosted overfire air systems (referred to as advanced overfire air or AOFA) began to be operated. This OFA system can be installed over the existing wind boxes for retrofit installations. Advanced OFA systems add air ports to several walls of the furnace, in addition to just the burner walls. Due to fan systems and extra air ports, more flow can be diverted than in the original OFA system. The extensive placement of ports in the AOFA system also allows air to be diverted to a greater area of the furnace interior. The NO_x removal efficiency of the AOFA system ranges from 15 to 25 percent compared to the baseline case. New LNBs in combination with AOFA systems have been demonstrated to achieve NO_x emission levels as low as 0.15 lbs/MMBtu for some wall-fired boilers firing PRB coal. However, for reasons discussed below, ERG does not believe that 0.15 lbs/MMBtu is achievable at the Boardman Plant.

There are a number of instances of NLNB/AOFA retrofits on units that burn PRB coal where the resulting NO_x emission level is reported to be 0.15 lbs/MMBtu. An examination of the individual units involved shows that all but one of the units are tangential-fired with very low pre-retrofit NO_x emission levels. The single wall-fired unit is discussed in a paper prepared by the vendor, Riley Power (Penterson, 2003). The specific unit is not identified in the paper, nor is the owning utility identified. The paper does discuss some characteristics of the unit which are not typical of most wall-fired boilers. Specifically, when the unit was originally started up, it was determined that it could not be fired at its intended full rating. Sixteen of the original burners were removed resulting in a substantial derating and a very low initial NO_x of 0.30 lbs/MMBtu. The initial NO_x at Boardman (0.43 lbs/MMBtu) is more than 40 percent higher than the unit described in the Penterson paper and the achievement of 0.15 lbs/MMBtu at Boardman Plant by retrofitting NLNB and AOFA does not appear feasible.

Also, the furnace internals at the Boardman Plant appear to be rather unusual in that the wing (or division) walls extend well below the boiler nose. More typically, in-furnace pendant pressure parts would extend down to the nose. The Boardman Plant upper furnace has wing-walls that suspend from the furnace roof to about midway down to the furnace floor. They appear also to extend from the front wall to about midway to the back wall and will present problems both in getting good mixing of the AOFA and possible rapid tube corrosion due to the strongly reducing flue gas conditions, if deep-staging is attempted in the Boardman furnace.

The non-typical situation at Boardman Plant will, in the opinion of ERG, limit the effectiveness of NLNB and AOFA in reducing NO_x. Determining exactly how much reduction could be achieved would require detailed computational fluid dynamics (CFD) modeling; however, the B&V prediction of 0.28 lb/MMBtu does not seem unreasonable.

Low NO_x Burners with Overfire Air and Selective Catalytic Reduction

Recent installations on utility boilers have shown that SCR can achieve 70 to more than 90 percent efficiency, and NO_x emission levels as low as 0.05 lbs/MMBtu. Similarly, SCR in combination with LNB with OFA or NLNB with AOFA have been demonstrated to achieve NO_x emissions as low as 0.05 lbs/MMBtu. Most of this experience is with ozone-season units that have a substantial opportunity for off-season maintenance and catalyst cleaning; therefore, the impact of year-round operation would have to be considered in selecting a permit level for the Boardman Plant.

Low NO_x Burners with Overfire Air and Selective Noncatalytic Reduction

SNCR installations in combination with LNB with OFA or NLNB with AOFA on utility boilers have been demonstrated to achieve between 25 and 50 percent reduction. The reduction percentage that can be achieved is extremely unit-specific and fairly large units generally achieve reductions at the low end of the range. ERG has expressed concern that high upper furnace temperatures at the Boardman Plant, and the effect of the wing walls on upper furnace mixing mentioned earlier, might severely limit reductions achievable at the plant. During a meeting at B&V offices in Kansas on April 24, 2008, B&V indicated that they have had Fuel Tech (a leading SNCR vendor) conduct further examination of the Boardman unit. Fuel Tech confirmed that there was an appropriate injection location (in the upper backpass, rather than the usual upper furnace location), and that 25 percent reduction is feasible. B&V said that they were assuming 18 percent in their estimates to be conservative.

1.2 Energy and Non-Air Quality Environmental Impacts

Existing/New Low NO_x Burners, Existing/Advanced Overfire Air, Selective Noncatalytic Reduction

There are no significant energy or non-air quality environmental impacts from use of existing or NLNB, existing or AOFA, or SNCR.

Selective Catalytic Reduction

The PGE Proposal cites three energy and non-air quality environmental impacts for which SCR is disadvantaged when compared to SNCR:

- B&V calculates that the SCR unit will require 36 times as much electric power as SNCR, due to the additional fan power needed to overcome the catalyst bed pressure drop. ERG believes that this figure may be low. CUECost generates a differential of about 100 times for the same SCR-to-SNCR comparison.
- The PGE Proposal cites the disposal of spent catalyst as a hazardous waste as being a non-air quality environmental impact. This may be of little significance, based on evolving catalyst management practices. Catalyst regeneration processes potentially allow for reuse of the catalyst modules for several cycles, making the disposal cost and environmental impact much less than earlier industry estimates.
- The PGE Proposal cites the additional accidental release hazard associated with anhydrous ammonia (for SCR) versus urea solution for SNCR. Although the remote location of Boardman makes this less of an issue when compared to urban and suburban power plants, nevertheless, there is added hazard for plant personnel and the few people that may live or be present in the path of an ammonia plume from the plant. This hazard can be remedied for a price. Today, there are commercially available systems that convert urea to ammonia "on demand", with no significant ammonia inventory present at the facility at any time. As noted, this is an additional capital and operating cost for the SCR installation. It should also be noted that ammonia is a fairly common industrial chemical and refrigerant and there are established safeguards and procedures for its handling and storage.

In general, ERG agrees with the PGE Proposal assessment of these impacts, at least qualitatively.

1.3 Mercury Control Technologies

Additionally, the effect of the NO_x controls on reducing mercury emissions was also evaluated. PGE proposes to retrofit a fabric filter downstream of the existing electrostatic precipitator (ESP) to enhance the control of particulate matter at the Boardman Plant. The PGE Proposal states that this technology selection was driven, in part, by the future need to control mercury emissions with dry sorbent injection. This approach is consistent with the approach taken throughout the industry for power plants burning PRB coal. Because mercury contained in PRB coal flue gas is not readily oxidized by SCR catalysts for subsequent collection in a flue gas desulfurization (FGD) system, virtually all near-term mercury control for PRB units will be through the use of activated carbon injection (or injection of enhanced activated carbon). In a very recent study by The Shaw Group (Wedig et al., 2008) published in the May 2008 issue of Power Magazine, the authors identified a total of 51 PRB plants (8 new and 43 retrofit) that have committed to mercury control, all proposing activated carbon injection.

None of the other NO_x controls considered (i.e., NLNB, AOFA, SNCR) would have any impact on the Boardman baseline mercury emissions. Also, for reasons stated in the previous paragraph, capture of mercury in an FGD system (wet, dry, or semi-dry, would be very small and Boardman, like other PRB coal-fired units, will need to rely on some form of carbon injection for mercury control.

2.0 ERG'S COST ESTIMATION METHODOLOGY

The U.S. EPA's BART guidance (www.epa.gov/air/visibility/pdfs/guidelines_2005_6_24.pdf) recommends: "The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, EPA 453/B-96-001)." Consequently, ERG reviewed the procedures in the available cost estimation methodologies, the OAQPS Cost Manual, and also the CUECost estimation program to determine the most appropriate methodology for providing capital and annual costs. Initially, ERG decided that the CUECost estimation program was more appropriate because it provided costs separated into elements which could be compared to the specific cost elements used by B&V in developing the PGE Proposal. Also, the CUECost program is widely accepted and used by the utility industry and government agencies to provide cost estimates, and it is tailored to air pollution controls applied to coal-fired power plants.

The remainder of this section describes the CUECost input data used by ERG, and provides our conclusions related to CUECost's ability to predict "real world" costs for projects requiring major heavy construction (e.g., SCR) as compared to smaller projects (e.g., NLNB, AOFA, and SNCR) that do not require major structural work or large process equipment. Based on our conclusions, we deviate from a CUECost approach when preparing an independent estimate for SCR installed cost; this is explained in detail below in Section 3.4 of this memo.

2.1 Cost Algorithm Inputs

The CUECost program provides cost estimates for new LNB, SCR, and SNCR. The cost factors for AOFA provided in an earlier analysis conducted by ERG for the Western Regional Air Partnership (WRAP) were used to calculate the capital costs. The WRAP report indicates that in 2005, the installed capital cost for AOFA was $8.80/kW. The total capital investment for the combinations of NO_x controls using AOFA were calculated by adding the AOFA capital costs.

Attachment A lists the inputs necessary to run the CUECost program for NO_x control technologies, and the rationale for use of the different inputs. The attachment also provides the inputs used in the analysis and the source of the input data. After reviewing the PGE Proposal CUECost inputs, ERG concludes that most of the inputs that were used for PGE's CUECost runs were appropriate for the analysis. Consequently, where possible, we used inputs provided by PGE for our assessment. Attachment B contains detailed cost outputs from CUECost for NLNB, AOFA, SNCR, and SCR. Attachment C shows a detailed comparison of the PGE and ERG CUECost estimates for total capital investment of SCR, which is a main area of disagreement (see Section 3.4 for more details on this comparison).

The CUECost program was last updated in 2002. For the outputs to be relevant, ERG escalated the costs to 2007 using Chemical Engineering magazine cost factors.

2.2 Conclusions Regarding the Use of CUECost for the Boardman Analysis

As discussed later in detail in Section 3.4 of this memo, ERG's investigation of SCR installed costs for the 2007 cost-basis year has led us to the conclusion that CUECost does not provide "real world" costs for SCR in the current environment for major construction projects. Similarly, based on a study prepared for the National Lime Association (Sargent and Lundy, 2007) and a study by Cichanowicz for the Utility Air Regulatory Group (Cichanowicz, 2007), there is good evidence that FGD (i.e., another technology requiring heavy construction) installed costs have escalated at an unprecedented rate since about 2004. CUECost, even when inflation-adjusted by applying the current Chemical Engineering Construction Cost Index, appears to produce installed costs that are well below those that appear in the recent literature. However, for relatively "smaller" projects, such as LNB, AOFA, and SNCR retrofits, we believe that estimates developed using CUECost are reasonable.

ERG was not able to determine why CUECost seems unable to generate costs corresponding to current experience; however, Cichanowicz, et al. (Cichanowicz et al., 2006), speculated that early SCR installations may have been misleading due to under-design (that resulted in failure to meet performance objectives) and selection of favorable retrofit units for early installations. Also, some features now considered more or less standard (e.g., large pitch catalyst, popcorn ash screens, static mixers, and provision of a great deal of sootblower capability) were not part of early system designs. Finally, vendors were clearly positioning for the surge of installations in 2002, 2003 and 2004, and substantial cost overruns may have been absorbed by the vendors and constructors, and would not necessarily be reported by the utilities or appear in the literature. In the recent worldwide high-demand environment for industrial construction services and equipment, the opposite effect may be taking place, where engineering firms, constructors and equipment manufactures are bidding with high profit margins and large contingency factors, driving up installed costs.

Although ERG is convinced that CUECost fails to provide "real world" installed costs for major construction projects such as SCR retrofits, we are not able to necessarily extend this to projects that do not require extensive "construction" (e.g., extensive foundations and structural works, ductwork modifications, etc.) and projects where retrofit issues do not heavily influence installed costs. For smaller projects such as NLNB, AOFA and SNCR, largely because we have no evidence to the contrary, we have used CUECost results escalated to 2007 by applying the 2007 Chemical Engineering Construction Cost Index.

3.0 COMPARISON OF PGE PROPOSED COSTS AND ERG COST ESTIMATES FOR NO_x CONTROL

This section compares the PGE proposed costs with the ERG costs for the NO_x control technologies selected for this analysis. Table 1 summarizes the total capital cost in units of $/kW from the PGE Proposal and as estimated by ERG for each NO_x control technology. A discussion of each of the comparisons is provided below for NLNB (Section 3.1), NLNB with AOFA (Section 3.2), SNCR (Section 3.3), and SCR (Section 3.4).

3.1 NLNB Comparison

The capital cost estimates for NLNB from ERG's CUECost run differs by less than 1% of the estimate provided by PGE. This difference was not considered significant and, therefore, not analyzed further.

3.2 NLNB with AOFA Comparison

The difference in total capital cost of NLNB with AOFA between the PGE Proposal and ERG's estimates is due to PGE's use of handling and erection cost factors that are higher than those in CUECost to estimate direct installation costs. The handling and erection factor (50 percent of the purchased equipment cost) is approximately 20 to 30 percent higher than cost factors used in CUECost and in EPA's OAQPS Cost Manual. These additional costs then propagate further when calculating Indirect Costs and Total Capital Investment. The PGE Proposal included costs for the following ancillary equipment: neural network system, NO_x monitoring equipment, water cannon, and modulating orifice for burners. These additional cost items add approximately $8/kW to the total installed cost.

ERG agrees that certain upgrades such as neural networks and burner air controls are part of general system upgrades that allow NLNB with AOFA to achieve and maintain optimum performance. Also, PGE reported that slagging has been a recurring problem when the current OFA system is operated continuously. Water cannons have been used extensively for PRB units throughout the country. ERG's cost is based on a combination of the CUECost result ($28/kW) and the cost of the ancillary equipment noted above ($8/kW) for a total of $36/kW. The PGE Proposal cost is $53/kW, or about 47% higher.

Table 1. Comparison of PGE Proposed Costs and ERG Costs for NO_x Control at the Boardman Plant

Control Technology	Cost Estimate in $/kW		% Difference	Notes
	PGE	ERG		
NLNB	18	18	< 1%	CUECost and PGE estimates are essentially the same.
NLNB with AOFA	53	36	47%	PGE cost is much higher than CUECost results. PGE added equipment items not included in CUECost. ERG agrees that these items are warranted and that the probable cost is about $8/kW. This cost was added to the CUECost result to arrive at the ERG estimate.
Existing LNB with OFA + SNCR	28	14	100%	ERG cost is based on CUECost and confirmed by leading SNCR vendor public statement. ERG does not know the basis of PGE's estimate and cannot duplicate it.
NLNB with AOFA + SNCR	81	50	62%	Cost is based on adding the NLNB with AOFA cost to the SNCR cost, above.
Existing LNB with OFA + SCR	309	250	24%	ERG cost is based on the high end of the range of costs ($207/kW to $267/kW) that ERG found to be reasonable based in the analysis described in Section 3.4 of this memo.
NLNB with AOFA + SCR	362	286	27%	Costs are based on summing the cost of "stand-alone" SCR with the cost of NLNB/AOFA. Probably costs should be slightly lower because of reduced inlet NO_x.

ERG does not have information that would support the higher erection factor used by PGE as compared to the CUECost default values. However, we do note again that there has been rapid escalation in construction costs in recent years for SCR that does not seem to be captured by CUECost using the Chemical Engineering Cost index.

3.3 SNCR Comparison

For the option of using the existing LNB with OFA along with a new SNCR, PGE's Proposal indicated that CUECost was used to calculate costs of the SNCR system. However, PGE's CUECost outputs could not be duplicated using the inputs provided in the PGE Proposal. Insufficient information was provided to fully assess the reason for the differences. The costs estimated by PGE for reagent storage, handling, injection and controls were $5,100,000 compared to the CUECost output of $1,730,000. Air heater modifications calculated by PGE were $2,835,000 compared to the CUECost output of $1,400,000. These additional costs then propagate further when calculating indirect costs and total capital investment.

Fuel Tech's Dr. Bill Sun, a longtime expert on SNCR, recently placed SNCR installed costs at \$5 to \$20/kW (Sun, 2007). The CUECost estimate of \$14/kW falls comfortably within the range indicated by Fuel Tech. This cost would apply to both the existing LNB with OFA and NLNB with AOFA, as SNCR capital costs are relatively insensitive to initial NO_x emissions levels. The PGE Proposal contains an installed cost of \$28/kW for SNCR (which we cannot reproduce); this is at least 50 percent higher than the CUECost estimate for SNCR.

3.4 SCR Comparison

ERG reviewed the SCR installed cost contained in the PGE Proposal. The review has involved a number of information-gathering steps and discussions with DEQ, PGE and B&V. The following activities have taken place since the start of the project in January 2008:

- January 18 - After a brief review of the BART Proposal, ERG and DEQ conducted a conference call to plan initial steps. During this call ERG gave its initial reaction to the PGE Proposal and cited the SCR installed costs as, in our opinion, well above costs appearing in the literature.
- February 4 - ERG attended the Stakeholder Meeting at Stoel Rives LLP. B&V presented the main points of the BART Proposal and ERG provided 14 questions in writing. These questions were combined with dozens of other questions raised by the stakeholders attending the meeting.
- February 5 - ERG attended a tour of the Boardman Plant.
- February 15 - ERG submitted a trip report covering the February 4 meeting and the February 5 plant tour.
- February 15 - ERG received and reviewed the B&V response to ERG question #2, which asked for the plant, economic, and NO_x inputs used for the CUECost model runs that were used in the PGE Proposal. In some ways, the response confused these issues rather than clarifying them, since the data and discussion in the response did not correspond to the discussion in the PGE Proposal (i.e., different inlet NO_x, different percent removal).
- February 25 - ERG submitted Memo #1 to DEQ, discussing the ERG review of the PGE Proposal. SCR installed cost was identified as the primary concern. Most other comments were relatively minor.
- March 23 - ERG received and reviewed the PGE/B&V responses to 101 questions that were recorded at the February 4 and 5 meetings.
- April 6 - ERG received and reviewed a B&V discussion of current and historical SCR installed costs. This submission included installed costs for 33 SCR projects (both single unit and multiple unit projects) with the cost-basis year, unit size, and installation year. These were obtained from the open literature and subscription sources. Both actual completed projects and future (estimated cost) installations are included.
- April 24 - ERG attended a meeting and discussion at B&V offices in Kansas. At this meeting, B&V presented a detailed cost estimate for a current SCR project that is similar enough in size as to be relevant to the potential Boardman installed cost.

The primary issue is: ***How to estimate SCR installed cost for the Boardman Plant in view of widely varying costs that result from various sources and approaches?***

We examined three fundamentally different costing approaches to address this issue:

- Bottom-up installed cost using the CUECost Model
- Top-down literature values
- B&V "real" project cost

In addition, we examined the general escalation of construction costs due to the commodities bubble and labor shortages. These approaches and the general escalation of construction costs as related to SCR are discussed in detail below.

Bottom-Up Installed Cost Using the CUECost Model

CUECost is a widely-used, U.S. EPA-developed cost model for air pollution controls applied to coal-fired power plants. When the model is run with Boardman-specific technical inputs, the default economic inputs, a "difficult" retrofit factor and escalated to 2007 dollars, the result for Boardman is about $100/kW. Since the developers of CUECost specifically caution that the level of detail involved results in a plus-or-minus 30 percent estimate, the CUECost estimate for the Boardman Plant would actually be $70/kW to $130/kW. However, a number of recent studies of actual installed costs for completed installations and estimates for near-term future installations call into question the direct use of CUECost in today's construction environment. For reasons noted below, it is ERG's opinion that the CUECost model does not generate "real world" SCR installed cost estimates.

Top-Down Literature Values

There are three fairly recent literature papers that address SCR installed costs (Hoskins, 2003; Cichanowicz, 2004; Marano and Sharp, 2006). In a paper prepared for the Utility Air Regulatory Group, Cichanowicz compiled SCR installed costs from the same three papers (Cichanowicz, 2007). Also, Internet searches produced a number of other anecdotal examples of recent plant-specific costs. Although there are many data points in this dataset, the quality of the individual points is difficult, and in some cases impossible, to assess. Nonetheless, all of these sources do point to a rapid escalation in SCR installed costs since 2004.

In their April 6 submission, B&V compiled installed costs for 33 SCR projects, including both single unit and multiple unit installations. The average SCR installed cost for the 2007 projects was $242/kW, and B&V concluded that these data are consistent with their Boardman Plant estimate of $309/kW when the proposed Boardman boiler modifications, at $65/kW, are added. (Note: the Boardman Proposal [at page D-9] includes the cost of NLNB and AOFA along with the SCR cost, resulting in a total of $362/kW for the combined technologies.)

ERG examined the 33 individual data points (installed cost, cost-basis year) and determined that several of the critical (2007 cost-basis) data points are skewed somewhat to the high side. For example, 6 of the data points for 2006 represent projects at Progress Energy's Ancolote and Crystal River plants. The data for cost-basis year 2007 contains these same projects, escalated by 70 percent based on a blanket statement by a Progress Energy official that the cost of new air pollution controls have "jumped 70% from their 2006 submission" (to the Florida Public Service Commission). An examination of the source document shows that the 2006 submission actually contained estimates with a 2005 cost-basis. Also, the implied 70 percent escalation from 2006 to 2007 is in conflict with a statement by Kentucky Utilities (before the Kentucky Public Services Commission) that the installed cost estimate of SCR for Ghent Unit 2 had increased by 21 percent from 2006 to 2007. The 70 percent escalation figure is also inconsistent with a number of other papers (see below) that address the general cost escalation for various types of utility construction in the current environment.

Two of the critical 2007 cost-basis data points were contained in the BART proposals for Gerald Gentleman Units 1 and 2 ($334/kW) and Nebraska City Unit 1 ($376/kW). In both cases, the estimate was provided by architectural and engineering firm HDR. The estimates were described as based on 2002 vendor quotes for major equipment, adjusted for capacity (the quotes were not for the specific plants involved), escalated to 2007 (by applying a 68 percent escalation factor), doubled to account for construction costs, and multiplied by a 25 percent contingency factor. ERG does not accept that these very crudely developed costs represent useful data in evaluating cost of the Boardman Plant retrofit.

Finally, an examination of the year-to-year escalation implied by the 33 data points provided by B&V calls into question the quantitative use of the data (though it is certainly useful in a qualitative sense.). For the B&V dataset, the year-to-year changes in historical average installed costs are:

- 2002 to 2003 = +80 percent
- 2003 to 2004 = +76 percent
- 2004 to 2005 = +25 percent
- 2005 to 2006 = -37 percent
- 2006 to 2007 = +62 percent

Obviously, these year-to-year variations, including a drop in cost of 37 percent from 2005 to 2006, are an indication that these data are not useful in any given year in a quantitative sense. They do, however, support the contention that the last several years have seen construction cost escalation that is significantly above the general consumer inflation rate in recent years.

To more closely examine these data in a quantitative sense, ERG eliminated the three highest (including the afore mentioned HDR estimates) and three lowest estimates contained in the 16 projects which make up the 2007 basis-year data. We also eliminated the WE Energies' Oak Creek Units 5 and 6 project since these are small, tail-end systems. The remaining nine projects are fairly tightly grouped, providing some comfort that they represent "typical" installations, rather than outliers. **These projects range from $207/kW to $267/kW, with an average of $227/kW.** The fact that the average is very close to the B&V "real" project cost discussed below tends to confirm that this range ($207/kW to $267/kW) is a reasonable representation of 2007 costs of large SCR systems and normal retrofit conditions.

B&V "Real" Project Cost

At an April 24, 2008, meeting at the B&V offices, an ERG engineer was presented with detailed estimates for two very recent B&V SCR installations. After examining the "specifics" of one of the projects, ERG concluded that it was too different (i.e., much smaller, hot-side ESP, low-dust SCR) to provide a relevant data point for the Boardman Plant retrofit. The second plant was sufficiently close in "specifics" to the Boardman Plant to be relevant. Clearly, the cost details were based on B&V actual costs, and were not prepared specifically for ERG's visit. They correspond roughly to 2007 dollars since the project start was mid-2006 and it is now just wrapping up. B&V provided the estimate for this same unit, reformatted to correspond to the line items on page D-9 of the PGE Proposal.

The B&V "real" project cost of $221/kW that was provided in the D-9 format exhibits some line-by-line differences when compared to the Boardman Plant SCR estimate prepared by B&V for PGE. These differences include higher total purchased equipment costs, lower total direct installation costs, and a much higher cost for site preparation and buildings at the Boardman Plant. The most significant difference the Boardman Plant estimate and the B&V "real" project cost is the $65/kW added to account for boiler modifications to reduce the SCR flue gas inlet temperature. Also, the Boardman BART Proposal SCR estimate includes an additional $53/kW for NLNB with AOFA. ERG believes that the benefit of the NLNB with AOFA system (i.e., lower SCR inlet NO_x) is not properly reflected in the PGE Proposal's SCR cost estimate.

In spite of some of the differences cited above, ERG believes the "real" project cost data that were reviewed at the B&V offices on April 24, 2008, support the PGE/B&V position that CUECost, when run with default values and an escalation factor, does not generate "real world" SCR installed costs for a 2007 cost-basis year.

General Escalation of Construction Costs due to the Commodities Bubble and Labor Shortages

In addition to the three costing approaches described above, ERG considered a fourth factor in analyzing the Boardman Plant SCR estimate contained in the PGE Proposal. In their April 6, 2008 submission of historical SCR installed cost data, B&V included two recent articles that deal with rapidly escalating construction in the utility industry (Chupka and Basheda, 2007; Schimmoller, 2007). Although these articles do not address SCR specifically, they do give a clear sense that construction costs are escalating at a rate well above historical norms. In a report prepared for the National Lime Association, Sargent and Lundy pegged the recent escalation of FGD installed costs at 25 percent per year (Sargent and Lundy, 2007) (Note: FGD retrofits involve the same type of major structural work, large process equipment and retrofit issues that are present with SCR installations.). As noted earlier, Kentucky Utilities estimated an increase of 21 percent for the Ghent Unit 2 SCR cost from a 2006 to a 2007 cost basis. All of these are indications that the effect of world demand for construction materials, equipment, and labor are exerting a strong upward pressure that has impacted SCR installed costs in the U.S.

Summary of SCR Cost Analysis

It is ERG's opinion, based on a distillation of the three cost approaches discussed above and the general rapid cost escalation environment, that the 2007 installed costs for SCR range from $207/kW to $267/kW, barring any extremely favorable or unfavorable site-specific conditions.

In the Boardman case, there are factors that would tend to push costs toward the high end of the range and other factors that would tend to reduce costs. Some of the factors that tend toward higher cost include:

- Use of PRB coal (as compared to bituminous coal);
- The Boardman Plant's remote location and its impact on labor availability and cost;
- The higher-than-normal structural bridge needed to span the ESP; and
- The boiler modifications needed to adjust inlet flue gas temperatures.

Some of the cost-reducing factors include:

- A unit size that is large enough to provide economy of scale, but small enough to fit the catalyst box between the unit and the stack;
- A single-unit plant with much clear space around the rear of the plant; and
- (Importantly) the low inlet NO_x and low removal efficiency specified in the PGE Proposal.

Although some of the site-related factors are favorable (e.g., clear space, single unit plant), the major complicating factor is the boiler modifications for flue gas temperature adjustment, which B&V places at $65/kW. ERG believes, based on conversations with B&V personnel, that B&V has not analyzed this cost in detail (nor has ERG). ERG notes that, in general, all SCR retrofits require ductwork modifications at the rear of the boiler and in many cases, an economizer bypass is included, thus some of the costs associated with fitting the SCR into the boiler/airheater train are already contained in SCR estimates. Anecdotal information on pressure part replacement projects (from the Internet) gives us the impression that the B&V estimate is high, but in the absence of design and cost details, ERG is unable to quantitatively assess this. ERG does agree that some significant cost is involved and that it would tend to push the Boardman installed cost toward the upper end of the range cited above ($207/kW to $267/kW). Bearing in mind the broad uncertainty band associated with all of the estimates, ERG selected a "round number" cost of $250/kW as our Boardman Plant SCR installed cost.

4.0 CONCLUSIONS

The following are ERG's conclusions regarding the NO_x control technologies in the PGE Proposal:

- Appropriate NO_x technologies were included in the analysis.
- The control level estimate for NLNB with AOFA is reasonable. PGE and B&V enlisted Fuel Tech to more closely examine the Boardman Plant and confirm SNCR performance. The resulting B&V estimate of 18 percent control is reasonable. SCR units can achieve control to the 0.05 lbs/MMBtu level, but not necessarily meet a 0.05 limit. Most of SCR experience is with ozone-season units that are afforded significant off-season opportunity for maintenance and catalyst cleaning. The impact of year-round operation would have to be considered in selecting a permit limit for Boardman.
- NLNB with AOFA costs are reasonable.
- ERG finds that the B&V's estimated installed cost for SNCR is high by at least 50 percent. ERG's estimate (based on CUECost) is $14/kW versus the B&V cost of about $28/kW.

- ERG finds that the contention by PGE and B&V that SCR installed costs have escalated extremely rapidly in recent years is supported by a number of literature sources. For reasons not fully clear, CUECost does not capture this recent surge in installed cost, even when the most recent Chemical Engineering Cost Index is applied.
- ERG's analysis of the 2007 cost for retrofitting SCR at the Boardman Plant is based on literature information and on data provided by PGE and B&V. We find a cost of about $250/kW versus the PGE and B&V estimate of $309/kW to be reasonable in view of recent similar installations and literature estimates.
- Future mercury control is appropriately addressed by the proposed fabric filter. Since mercury oxidation across an SCR and subsequent collection in an FGD system is relatively ineffective for PRB coal, mercury control at Boardman will likely entail activated carbon injection (or some other dry sorbent) followed by collection in a fabric filter. The other NO_x technologies considered (NLNB, AOFA, SNCR) will not influence the Boardman baseline mercury emissions or future mercury controls.

5.0 REFERENCES

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Attachment A

Inputs Used for CUECost

CUECost INPUTS			
Description	**Units**	**Input 1**	**Source**
General Plant Technical Inputs			
Location – State	Abbrev.	OR	PGE report
MW Equivalent of Flue Gas to Control System	MW	584	PGE report
Net Plant Heat Rate	Btu/kWhr	9,817	PGE report
Plant Capacity Factor	%	85%	PGE report
Total Air Downstream of Economizer	%	117%	PGE report
Air Heater Leakage	%	11%	PGE report
Air Heater Outlet Gas Temperature	▯	297	PGE report
Inlet Air Temperature	▯	80	PGE report
Ambient Absolute Pressure	In. of Hg	29.18	PGE report
Pressure After Air Heater	In. of H_2O	-13	PGE report
Moisture in Air	lb/lb dry air	0.01362	PGE report
Ash Split:			
Fly Ash	%	80%	PGE report
Bottom Ash	%	20%	PGE report
Seismic Zone	Integer	1	PGE report
Retrofit Factor	Integer	1.6	PGE report
(1.0 = new, 1.3 = medium, 1.6 = difficult)			
Select Coal	Integer	8	PGE report
Is Selected Coal a Powder River Basin Coal?	Yes / No	Yes	PGE report
Economic Inputs			
Cost Basis -Year Dollars	Year	2007	
Service Life (levelization period)	Years	15	
Inflation Rate	%	3%	CUECost default
After Tax Discount Rate (current $'s)	%	9%	CUECost default
AFDC Rate (current $'s)	%	11%	CUECost default
First-year Carrying Charge (current $'s)	%	22%	CUECost default
Levelized Carrying Charge (current $'s)	%	17%	CUECost default
First-year Carrying Charge (constant $'s)	%	16%	CUECost default
Levelized Carrying Charge (constant $'s)	%	12%	CUECost default
Sales Tax	%	6%	CUECost default
Escalation Rates:			
Consumables (O&M)	%	3%	CUECost default
Capital Costs:			
Is Chem. Eng. Cost Index available?	Yes / No	Yes	
If "Yes" input cost basis CE Plant Index.	Integer	525.4	CE Cost Index
If "No" input escalation rate.	%	3%	
Construction Labor Rate	$/hr	$35	PGE report
Prime Contractor's Markup	%	3%	PGE report
Operating Labor Rate	$/hr	$30	PGE report
Power Cost	Mills/kWh	65.3	DOE website for 2006
Steam Cost	$/1000 lbs	3.5	PGE report
NO_x Control Inputs			

CUECost INPUTS

Description	Units	Input 1	Source
Selective Catalytic Reduction (SCR) Inputs			
NH_3/NO_x Stoichiometric Ratio	NH_3/NO_x	1.05	PGE report
NO_x Reduction Efficiency	Fraction	0.90	
Inlet NO_x	lbs/MMBtu	0.426	PGE report
Space Velocity (Calculated if zero)	1/hr	0	PGE report
Overall Catalyst Life	years	3	PGE report
Ammonia Cost	$/ton	400	Price for 2007
Catalyst Cost	$/ft3	169.9	PGE report
Solid Waste Disposal Cost	$/ton	10	PGE report
Maintenance (% of installed cost)	%	1.5%	CUECost default
Contingency (% of installed cost)	%	20%	CUECost default
General Facilities (% of installed cost)	%	5%	CUECost default
Engineering Fees (% of installed cost)	%	10%	CUECost default
Number of Reactors	integer	2	PGE report
Number of Air Preheaters	integer	1	PGE report
Selective NonCatalytic Reduction (SNCR) Inputs			
Reagent	1:Urea 2:Ammonia	1	PGE report
Number of Injector Levels	integer	3	PGE report
Number of Injectors	integer	18	PGE report
Number of Lance Levels	integer	0	PGE report
Number of Lances	integer	8	PGE report
Steam or Air Injection for Ammonia	integer	1	PGE report
NO_x Reduction Efficiency	Fraction	0.50	
Inlet NO_x	lbs/MMBtu	0.426	PGE report
NH_3/NO_x Stoichiometric Ratio	NH_3/NO_x	1.2	PGE report
Urea/NO_x Stoichiometric Ratio	Urea/NO_x	1.2	PGE report
Urea Cost	$/ton	315	PGE report
Ammonia Cost	$/ton	450	PGE report
Water Cost	$/1,000 gal	2	PGE report
Maintenance (% of installed cost)	%	1.5%	CUECost default
Contingency (% of installed cost)	%	20%	CUECost default
General Facilities (% of installed cost)	%	5%	CUECost default
Engineering Fees (% of installed cost)	%	10%	CUECost default
Low NO_X Burner Technology Inputs			
NO_x Reduction Efficiency	fraction	0.35	
Boiler Type	T:T-fired, W:Wall	W	PGE report
Retrofit Difficulty	L:Low, A:Average, H:High	A	
Maintenance Labor (% of installed cost)	%	0.8%	CUECost default
Maintenance Materials (% of installed cost)	%	1.2%	CUECost default

Attachment B

CUECost Outputs

SCR (high-dust) – Preliminary		**Case1**
Ammonia Injection Rate	lb/hr	949
Space Velocity	1/hr	1,873
Gross Catalyst Volume	ft^3	39,736
SCR Capital Costs		Case1
Cost Basis (Year)	→	***2007***
Reactor Housing and Installation	$	6,933,702
Ammonia Handling and Injection	$	2,034,420
Flue Gas Handling:Ductwork and Fans	$	7,222,232
Air Preheater Modifications	$	1,828,819
Misc. Other Direct Capital Costs	$	604,355
Equipment Capital Cost Subtotal	$	$18,623,527
Instruments & Controls	$	$372,471
Taxes	$	$1,117,412
Freight	$	$931,176
Total Direct Cost		$21,044,586
Total Direct Cost with Retrofit Factor	$	$33,671,337
General Facilities	$	$1,683,567
Engineering Fees	$	$3,367,134
Contingency	$	$6,734,267
Total Plant Cost (TPC)	$	$45,456,305
Total Plant Cost (TPC) w/ Prime Contractor's Markup	$	$46,819,994
Total Cash Expended (TCE)	$	$45,469,545
Allow. for Funds During Constr. (AFDC)	$	$4,985,542
Total Plant Investment (TPI)	$	$50,455,086
Preproduction Costs	$	$1,215,710
Inventory Capital		
Initial Ammonia(60 days)	$	$232,401
Initial Catalyst	$	$6,751,206
Total Capital Requirement (TCR)	$	**$58,654,404**
	$/kW	$100
SCR O&M Costs		Case1
Cost Basis (Year)	→	***2007***
Ammonia	$/yr	1,413,774
Catalyst Replacement	$/yr	2,250,402
Catalyst Disposal	$/yr	3,179
Electricity	$/yr	1,041,331
High-dust SCR Steam	$/yr	93,969
Operating Labor	$/yr	134,190
Supervisory labor	$/yr	***20,128***
Maintenance	$/yr	681,845
Total O&M Costs	$/yr	**5,618,690**
taxes, insurance, administrative	$/yr	$2,346,176
capital recovery	$/yr	$6,439,938
Total Annual Cost	**$/yr**	**$12,078,756**

SNCR - Preliminary		**Case1**
Number of Wall Injectors	integer	18
Number of Lances	integer	8
Urea Injection Rate	lb/hr	1905
Ammonia Injection Rate	lb/hr	1085
SNCR Capital Costs		Case1
Cost Basis (Year)	→	***2007***
Urea Based SNCR Costs		
Urea Storage & Handling	$	$485,138
Urea Injection	$	$983,103
Controls/Miscellaneous	$	$260,286
Air Heater Modifications	$	$1,394,942
Ammonia Based SNCR Costs		
Ammonia Storage, Handling, Injection, Controls	$	$0
Air Heater Modifications	$	$0
Total Direct Cost	$	$3,123,469
Total Direct Cost with Retrofit Factor	$	$4,997,551
General Facilities	$	$249,878
Engineering Fees	$	$499,755
Contingency	$	$999,510
Total Plant Cost (TPC)	$	$6,746,693
Total Plant Cost (TPC) w/ Prime Contractor's Markup	$	$6,949,094
Total Cash Expended (TCE)	$	$6,748,659
Allow. for Funds During Constr. (AFDC)	$	$739,962
Total Plant Investment (TPI)	$	$7,488,620
Preproduction Costs	$	$386,037
Inventory Capital	$	$367,247
Freight		
Total Capital Requirement (TCR)	$	**$8,241,904**
	$/kW	$14.1
SNCR O&M Costs		Case1
Cost Basis (Year)	→	***2007***
Operating and Supervisory Labor	$/yr	65,700
Maintenance Labor and Materials	$/yr	101,200
Reagent	$/yr	2,234,084
Electricity	$/yr	8,825
Water	$/yr	33,954
Steam (for steam atomization)	$/yr	-
Total O&M Costs	$/yr	**2,443,763**
CR		**904,917**
Total Annual Cost		**3,348,680**

Low NO$_x$ Burner Technology Capital Costs		Case1
Cost Basis (Year)		***2007***
Total Capital Requirement with Retrofit (TCR)	**$**	**$10,445,451**
	$/kW	$17.9
Low NO$_x$ Burner Technology O&M Costs		Case1
Cost Basis (Year)		***2007***
Maintenance Labor	$/yr	83,564
Maintenance Materials	$/yr	125,345
Control, Administration, Overhead	$/yr	25,069
Total O&M Costs	$/yr	**233,978**
CR		**1,146,854**
Total Annual Cost		1,380,833

Attachment C

Comparison of PGE Proposal Using CUECost and ERG CUECost Results for SCR

Cost Category	Subcategory	Cost Item	PGE	CUECost (2007)	Comment
Direct Costs	**Purchased Equipment Cost (PEC)**	Reactor Housing	$5,580,000	$6,933,702	
		Ammonia Handling and Injection	2,589,000	2,034,420	
		Initial Catalyst and Ammonia	4,750,000	6,983,607	
		Flue Gas Handling System	6,500,000	7,222,232	
		Air Preaheater Mod.	2,835,000	1,828,819	
		Electical System Mod.	2,261,000		
		ID Fans	3,658,000		
		Ash Handling System	3,100,000		
		Miscellaneous Direct Capital costs		604,355	
		Total Capital Cost	*$31,273,000*	*$25,607,134*	
		Instruments and Controls	3,127,300	372,471	PGE used 10% of Capital Cost, CUECost uses 2%
		Freight	1,563,650	931,176	
		Taxes		1,117,412	
		Total PEC	**$35,963,950**	**$28,028,193**	
	Direct Installation Costs (DIC)	Foundation and Support	$13,666,301		
		Handling and erection	13,306,662		
		Electrical	8,990,988		
		Piping	2,697,296		
		Insulation	3,596,395		
		Painting	359,640		
		Demolition	6,113,872		
		Relocation	4,315,674		
		Retrofit Cost		$12,626,751	

Cost Category	Subcategory	Cost Item	PGE	CUECost (2007)	Comment
		Total DIC	**$53,046,826**	**$12,626,751**	
		Site Preparation	**2,000,000**		
		Buildings	**500,000**		
		Total Direct Costs	***$91,510,776***	***$40,654,944***	
Indirect Costs	Engineering		$10,981,293	$3,367,134	
	Owner's Cost		4,575,539		
	Construction Management		9,151,078		
	Start-up and spare parts		2,745,323		
	Performance Test		200,000		
	Contingencies		13,726,616	6,734,267	
	Contractors Markup			1,363,689	
	General Facilities			1,683,567	
		Total Indirect Costs	***$13,148,657***	***$13,148,657***	
		Allowance for Funds During Construction	***17,926,000***	***4,985,542***	
		Boiler Heat Transfer Surface Area Replacement	***$40,000,000***		
		Preproduction Costs		***$1,215,710***	
Total Capital Investment Cost			**$190,816,626**	**$60,004,853**	

Weber, Steve F.

From: Weber, Steve F.
Sent: Monday, October 06, 2008 11:15 AM
To: Golden.Kevin@epamail.epa.gov; Tim Allen (tim@den.nps.gov); John_Notar@nps.gov
Cc: O'Clair, Terry L.; Mount, Dana K.; White, Rob J.
Subject: Updated ND Regional Haze Modeling Protocol (Draft)

Hello Kevin, John, Tim

Attached is an updated draft of the proposed North Dakota modeling protocol for RH reasonable progress goals. Note that recent changes are highlighted with blue text.

We would appreciate your review and comments on the updated protocol.

Thanks.

Steve

Steve Weber
ND Dept of Health
(701) 328-5188

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MINNKOTA POWER COOPERATIVE, Inc. and SQUARE BUTTE ELECTRIC COOPERATIVE

FOLLOWUP RESPONSES TO PRESENTATION and NDDH REQUEST FOR ADDITIONAL INFORMATION SUPPLEMENTAL NOx BACT ANALYSIS STUDY MILTON R. YOUNG STATION UNIT 1 and UNIT 2 REGARDING SCR ECONOMIC FEASIBILITY

February 11, 2010

North Dakota Department of Health's Environmental Health Section, Division of Air Quality has requested[1] that Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") provide additional information clarifying the written response submitted December 11, 2009[2] that provided detailed and comprehensive cost data following the NDDH's and U.S. EPA's reviews of the Best Available Control Technology (BACT) Analysis Study – Supplemental Reports[3] submitted on November 12, 2009 for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 at Milton R. Young Station (MRYS).

Burns & McDonnell (B&McD) was retained by MPC as an independent consultant to perform the referenced 2006 NO_X BACT Analysis Study[4] of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station in accordance with the requirements of a Consent Decree (CD)[5]. Burns & McDonnell also performed the November 2009 Supplemental NO_X BACT Analysis Study and generated the referenced reports for each MRYS boiler in response to the NDDH's request[6] to see Steps 3 and 4 of the BACT analysis process[7] include low-dust and tail end SCR alternatives, assuming that they are technically feasible to apply at MRYS as NDDH has recently advised[8].

Information supplementing the previously-provided detailed breakdown of capital costs and operation and maintenance costs for hypothetical applications of low-dust and tail end SCR alternatives, and their subsequent presentation to NDDH, are attached.

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[1] See Reference number 1, January 11, 2010.

[2] See Reference number 2, December 11, 2009.

[3] See Reference number 3, November 12, 2009.

[4] See Reference number 4, October 2006.

[5] See Reference number 5, April 24, 2006.

[6] See Reference number 6, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

[7] See Reference number 7, October 1990.

[8] Ibid Reference number 6, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

NOx BACT Analysis Study Supplemental Reports:

NDDH Request #1: How were the SCR reactors sized and the catalyst volume determined and what target NOx control efficiency was used to size the catalyst? How was the cost of the catalyst determined?

BMcD Response:

The same SCR system supplier that is providing the low-dust SCR equipment for the WE Energies South Oak Creek project in Wisconsin was asked to provide a budgetary equipment proposal for both low-dust and tail end SCR arrangements for each unit at MRYS. A lignite coal analysis (proximate, ultimate, and coal ash) and process design basis (boiler fuel heat input rates, excess air percentages, flue gas volumetric flows, temperatures and gas species contents) were included with the request. An assumed inlet and outlet NOx concentration was also provided, with a nominal 85% reduction from 0.5 lb/mmBtu requested. This SCR system supplier sized the SCR reactor, the SCR gas-to-gas heat exchange equipment (SCR GGH), and related ductwork. The initial catalyst charge for each reactor was included in the lump-sum equipment price proposal. The SCR system supplier did not disclose the specific volume of catalyst to be provided nor the specific manufacturer or type of catalyst (i.e. honeycomb, plate, etc.). Due to the proprietary nature of this SCR conceptual design and budgetary equipment pricing effort, this work was performed by the SCR system supplier with the understanding that it was confidential. Refer to Burns & McDonnell's response to NDDH Request #7 for additional information.

Two SCR catalyst suppliers provided budgetary replacement catalyst quotes, including catalyst volume, catalyst pitch, catalyst type, and arrangement of catalyst modules, based on preliminary process design provided by an SCR process design consultant. The design used for these catalyst supplier proposals was based on 90% overall NOx reduction across the SCR system. The catalyst suppliers also provided cost proposals for the replacement catalyst. One supplier provided a cost of replacement catalysts in terms of $\$/m^3$. Due to the proprietary nature of this SCR reactor sizing and budgetary catalyst pricing effort, this work was performed by the SCR catalyst suppliers with the understanding that it was confidential. Refer to Burns & McDonnell's response to NDDH Request #7 for additional information.

NDDH Request #2: Anhydrous ammonia appears to be a less expensive reagent than urea for the SCR system due to local availability. A justification must be supplied for electing urea over anhydrous ammonia.

BMcD Response:

Aqueous urea solution was selected because of health and safety issues related to the use of ammonia, including site constraints involving over-the-road transport, on-site unloading and storage. MRYS does not have rail access, and is adjacent to a lake used for condenser cooling water and process water supplies. Public access to the lake is allowed. Anhydrous ammonia and aqueous ammonia are classified as hazardous chemicals per Clean Air Act Section 112 (r). This requires extensive emergency planning. Transport and handling of ammonia is restricted by the United States Department of Homeland Security and the Department of Transportation through the Rail Security Act. The U.S. EPA has determined that a toxic radius of a spill to be between 5 and 7 miles for anhydrous ammonia and 1 to 2 miles for aqueous ammonia[9].

NDDH Request #3: Support must be provided for the catalyst cleaning/replacement outage periods. This should include an explanation of the method used to estimate the outage time and clarification whether the outage time includes the regular outage period.

BMcD Response:

Burns & McDonnell and Minnkota queried SCR catalyst suppliers, process design consultants, utility construction and maintenance contractors, and utility personnel at U.S. coal-fired plants with operating SCRs to provide input into the estimation of time associated with catalyst installation into the empty (spare) layer of the reactor, and to remove dirty catalyst and install fresh catalyst in its place. The responses indicated that there is a broad range of experiences based on limited amounts of user and vendor data on this issue. The range of experience is due to the site-specific conditions and design-specific features of the reactor catalyst access doors' locations and sizes, module arrangement, hoisting equipment, staging areas and platforms, labor availability and familiarity. The general lack of data is due to the relative newness of many SCR installations currently operating at coal-fired powerplants in the United States that have not accumulated significant operating time and so have not required significant numbers of catalyst changeouts.

Catalyst replacement activities by current coal-fired powerplant users are typically scheduled during major boiler outages that are 18-36 months apart. The SCR catalyst changeout is usually not a schedule-critical activity during such outages. The catalyst changeout time required depends on how many modules are involved, and whether a single shift of personnel or multiple shifts per day are engaged in the work.

For the hypothetical application of low-dust and tail end SCR technologies at MRYS, most of the catalyst changeouts were assumed to coincide with boiler fireside cleaning outages, which are historically approximately 4 days in duration, three or four times per year, depending on the boiler involved. Because of the use of high pressure water to remove boiler deposits during these cleanings, the air exhausted from the boilers through the flue gas ductwork to the chimneys during these times contains moisture and particulate.

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[9] See Reference 8.

Catalyst vendors have advised that this air stream is not suitable for passing through an SCR reactor filled with catalyst. This will require an SCR reactor bypass to be provided for use during these outages.

Before catalyst changeout operations can begin, the large volume of catalyst and supporting structural steel must be cooled down sufficiently to allow personnel to safely enter the reactor to gain access to remove any ash accumulations. The means and equipment required to remove the catalyst depends on the specific reactor design and module arrangements. The specific time and equipment requirements for catalyst changeouts are normally developed after the specific reactor and module details are established.

The SCR Cost Estimate study assumed that reactor isolation dampers and reactor maintenance bypass ductwork dampers would be required to avoid contamination of the catalyst by the air/water/particulate stream, and allow the reactors to be cooled while being isolated from the normal flue gas path to the chimney. The time estimated for catalyst installation into the empty (spare) layer of the reactor was 16 shifts, which, assuming two shifts per day, would be 8 days. The time estimated to remove dirty catalyst and install fresh catalyst in its place was 24 shifts, which, assuming two shifts per day, would be 12 days. The time assumed for reactor cooldown was previously estimated as 48-60 hours, which would elapse during the first half of the boiler cleaning process[10]. After the fresh catalyst is in place, and the reactor access doors closed, the entire volume of fresh and dirty catalyst remaining in the reactor must then be heated to above the moisture dewpoint to avoid possible moisture condensation during boiler startup. This would involve use of the supplemental catalyst outage heating system, not the flue gas reheat system nor flue gas from the boiler. Burns & McDonnell estimated that post catalyst changeout outage time will extend approximately 36-48 hours until the boilers are ready to begin the startup process to return to service.

The November 2009 Supplemental NOx BACT Analysis study assumed 1168 total hours and 1126 total hours of outage time per year associated with MRYS Unit 1's hypothetical application of low-dust and tail end SCR technologies (Scenario "B"), respectively. This is 980 hours and 938 hours of outage time in addition to the 188 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming three catalyst layer changeout outages per year for Unit 1, this works out to be approximately 13 extra days per outage. Unit 2's Scenario "B" assumed 1415 total hours of outage time for either hypothetical application of low-dust and tail end SCR technologies. This is 1234 hours of outage time in addition to the 181 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming four catalyst changeout outages per year for Unit 2, this works out to be approximately 13 extra days per outage.

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[10] See Reference 9, March 15, 2007, pages 12-14.

The November 2009 Supplemental NOx BACT Analysis study assumed 401 total hours and 443 total hours of outage time per year associated with MRYS Unit 1's, and 387 total hours and 428 total hours of outage time per year for Unit 2's, hypothetical application of tail end and low-dust SCR technologies (Scenario "A"), respectively. This is 213 or 256 hours of Unit 1 outage time and 206 or 247 hours of Unit 2 outage time in addition to the 181 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming one catalyst changeout outage every two years for each Unit 1 and Unit 2, this works out to be approximately between 8.6 and 10.7 extra days per outage, depending on the boiler and SCR technology studied.

The catalyst changeout outage times assumed in the November 2009 Supplemental NOx BACT Analysis study for MRYS Unit 1 and the similar study for MRYS Unit 2 are expected to be extensions to the boiler cleaning outages. Note that the estimated annual number of days for catalyst changeout outages is in addition to outage times included in the Advanced Separated Overfire Air alternative, which is also relative to baseline operation which include downtime for boiler cleanings. We believe the outage durations and frequency are reasonable assumptions to use for the purposes of showing possible economic outcomes that could result from the hypothetical application of low-dust and tail end SCR technologies at MRYS.

NDDH Request #4: The indirect capital costs associated with the project appear to be high. A detailed explanation of the estimation method must be supplied.

BMcD Response:
Burns & McDonnell used standard estimating practices to estimate direct, installation, and indirect capital costs for MRYS Unit 1's and Unit 2's hypothetical application of low-dust and tail end SCR technologies. To establish the context of estimated indirect costs, we note that several major assumptions were used by Burns & McDonnell in developing the capital cost estimates of the hypothetical applications of low-dust and tail end SCRs at Milton R. Young Station. These assumptions include the following:

- A multiple (parallel prime) contracting approach was selected (as opposed to single "turnkey" or Engineer-Procure-Construct contract). Although this approach may increase the project execution risk to the Owner, the execution risk is considered manageable. This contracting approach was recommended because it allows early award of major equipment procurements to allow detailed design engineering to proceed expeditiously to meet the project schedule, and offers the greatest flexibility for the Owner (Minnkota) to be involved in key decisions regarding design.
- Project will be executed to achieve completion in 2016 for Unit 2 and 2017 for Unit 1. It was assumed that the project will be executed with skilled workforce resources sufficient to meet the target project execution schedule while minimizing overtime. No additional overtime is included to accommodate a compressed work schedule.

Indirect Costs:

- Escalation based on historical data and Burns & McDonnell experience was assumed to average 5% per year for equipment, 9% per year for materials and 5% per year for labor. See additional general description of escalation included below.
- Contingency was calculated at 20% overall (10% for pricing and 10% for scope). Contingency was applied to Total Direct Capital Costs plus Indirect Capital Costs such as Engineering and Field Support, Construction Management and related indirects, Startup Expenses, and Cost Escalation during Project Execution. Owner Contingency was estimated at 7%. See additional general description of contingency included below.
- A performance bond is included for all subcontract work at the rate of 1.5% of the estimated project contract costs.
- Sales tax on construction consumables is included. No other tax is included.
- Owner will provide a builder's risk policy for the project. Cost for this is included in the estimate of Owner's costs.
- Interest During Construction (IDC) is included in the Owner's costs at 6% per year, assuming project execution-based monthly expenditures.

Escalation:

An estimate for escalation of project costs has been included in the capital cost estimate. Escalation of construction labor, materials, and indirects was estimated based on historical data and Burns & McDonnell experience.

Escalation of construction labor was estimated to be approximately 5% annually throughout the project. This estimate of escalation was based on the average increase in craft labor costs for the United States combined with known union labor contract costs in the next few years. The average annual escalation of union contracts for skilled and common labor rates over the last ten years in North Dakota has been approximately 5.0% per year.

Escalation of equipment and materials is included in the project estimate at a rate of 5% per year for equipment and 9% per year for materials. Since January 2004, steel pricing experienced rapid escalation equating to a nearly a 100% increase in rebar and structural steel costs, then dropped in late 2008 and early 2009. Within the past 6 months, steel prices have again started to rise. Pipe and electrical commodities have also seen a high overall escalation during this time, followed by a decline in late 2008. Due to this volatility, equipment and material suppliers have been providing pricing with short bid validity.

Contingency:

This project involves a significant amount of retrofit work in the existing plant. The SCR Cost Estimate study did not perform a thorough review of existing conditions and interfaces with the new work. It is anticipated that the scope of work will increase as unknown conditions are discovered during project execution. A contingency of 20% of the overall project costs is included in the project cost. Of this 20%, 10% covers accuracy of the pricing of the equipment and materials (commodities), and 10% covers omissions from the defined project scope. This contingency is not intended to cover changes in the general project scope (i.e. addition of buildings, addition of redundant equipment, addition of systems, etc.) nor major shifts in market conditions that could result in significant increases in contractor margins, major shortages of qualified labor, significant increases in escalation, or major changes in the cost of money (interest rate on loans).

In addition to the project contingency, an additional owner contingency is included to cover owner general project scope additions. Based upon the amount of preliminary design and project definition completed, a 7% scope contingency to cover such potential changes is included. However, this contingency level depends on the probability of additional scope and is typically determined by the Owner (Minnkota).

NDDH Request #5: Support must be supplied for the cost of natural gas and electricity.

BMcD Response:
Burns & McDonnell used estimated long-term average natural gas unit cost for the economics of conventional and fuel-lean gas reburn alternatives' annual operating costs included in the 2006 NOx BACT Analysis Study reports for MRYS Unit 1 and Unit 2. The annual cost of auxiliary power consumed by air pollution control equipment and the value of electric generator output not able to be sold ("lost") due to inability to produce electricity during outages related to the air pollution control equipment associated with particular control alternatives were also calculated. The long-term average unit costs for natural gas and electricity were provided by Minnkota. Burns & McDonnell's recent review of the forecast power industry's natural gas unit cost forecasts from 2006 confirm that the number used in the original NOx BACT Analysis Study calculations and reports submitted in October 2006 are reasonable, given the uncertainty and variability that is common with such forecasts.

In the November 2009 Supplemental NOx BACT Analysis study reports, Burns & McDonnell assumed the economics of hypothetical application of low-dust and tail end SCR technologies at MRYS should be also based on the same unit costs used for the 2006 NOx BACT Analysis study reports.

NDDH Request #6: More details, including calculations, must be supplied to justify the pressure drops and parasitic loads associated with the SCR configurations.

BMcD Response:
Burns & McDonnell used estimated flue gas pressure drops provided by the SCR supplier for the SCR reactor, and gas-to-gas heat exchangers (GGH), in the development of new induced draft booster fans' performance requirements and the alternatives' economics of hypothetical application of low-dust and tail end SCR technologies at MRYS for Unit 1 and Unit 2 in the November 2009 Supplemental NOx BACT Analysis study reports. The estimated flue gas pressure drops of the flue gas ductwork, which would be incurred upstream and downstream of the low-dust and tail end SCR reactors and GGHs, were calculated using a proprietary spreadsheet.

For low dust SCR cases, new ductwork would be connected downstream of the existing induced draft fans' outlets and a new booster fan for each reactor would follow the GGH outlet after the SCR reactor, discharging to the existing flue gas desulfurization (FGD) system absorber inlet duct[11].

In tail end SCR cases, new duct connections downstream of the existing induced draft fans' outlets would divert flue gas before the FGD absorbers' inlet ducts, through the hot side of the FGD GGH then back to the FGD absorber inlet duct. Additional duct connections downstream of the existing FGD absorbers' outlet ducts would reroute flue gas through the cold side of the FGD GGH, then to the cold side of the main (SCR) GGH upstream of the flue gas reheat section in the SCR reactor. After the reactor, flue gas would pass through the hot side of the main (SCR) GGH, continue to the new induced draft booster fans, and be discharged back to new duct connections near the existing inlets to the chimneys[12].

Horsepower required to drive the fans to produce pressure needed to overcome the cumulative ductwork and SCR equipment pressure losses for full load (maximum continuous rating) and "test block" flue gas flows was calculated from budgetary booster fan equipment quotes, which included preliminary pressure rise versus flow and mechanical efficiency curves, from two fan vendors. The horsepower required for the volumetric gas flow and pressure rise was then converted into electrical kilovolt-amperes (kVA) and kilowatts (kW) in order to calculate auxiliary power loads. An annual average load factor was applied, which was then multiplied by the assumed hours of annual operation to determine the annual megawatt-hours (MW-h) of consumed auxiliary power due to the SCRs' induced draft booster fans.

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[11] See attached sketch for low-dust SCR equipment and ductwork conceptual arrangement.
[12] See attached sketch for tail end SCR equipment and ductwork conceptual arrangement.

The parasitic loads associated with the SCR alternatives studied were determined by identifying known power-consuming auxiliary equipment serving the new air pollution control equipment. Estimates of design horsepower or kVA, based on vendor quotes or similar projects where information is available, were generated. Conversion to kW along with application of an annual average load factor resulted in estimated average annual auxiliary power loads, which were summed together to establish the total parasitic load. Annual megawatt-hours (MW-h) of consumed auxiliary power due to the various SCR cases studied were calculated by multiplying the total parasitic load by the assumed hours of annual operation.

The table below provides the results of these calculations.

Pressure Drop and Fan Power Calculation Results

Parameter	U1 LD	U1 TE	U2 LD	U2 TE
FGD GGH (hot side) pressure drop, in. w.g.	--	2.7	--	1.87
FGD GGH (cold side) pressure drop, in. w.g.	--	2.7	--	1.87
SCR GGH (cold side) pressure drop, in. w.g.	2.3	2.7	1.74	1.98
SCR reactor/catalyst press. drop, in. w.g.	2.0	2.0	2.0	2.0
SCR GGH (hot side) pressure drop, in. w.g.	2.3	2.7	1.74	1.98
SCR flue gas ducts/dampers/connections pressure drop, in. w.g.	5.4	6.2	4.5	6.3
Booster Fan Static Pressure Rise / Total Pressure[1] (Inches W.G.)	12.0 / 13.51	19.0 / 21.33	10.0 / 11.50	16.0 / 18.23
Booster Fan Motor Horsepower[2]	5000	7000	3500	5000
Load kVA / Demand kVA[3]	5000 /4500	7000 /6300	3500 /3150	5000 /4500
Quantity of Fans, capacity per fan, each case	One (1) x 100%		Two (2) x 50%	

1- Booster fan static pressure rise is the sum of the duct and SCR equipment pressure drops. Total fan pressure includes fan static pressure rise plus additional pressure rise required to overcome pressure drops within the fan equipment. These numbers do not include additional fan capacity (margin) above the amount required for full load (maximum continuous rating or MCR) operation, which allows for factors that reduce actual performance over sustained periods of running. Static pressure rise and Total pressure numbers are preliminary; final design may require values higher or lower than those shown.

2- Motor horsepower is greater than fan mechanical horsepower, and is based on available size larger than "Test Block" horsepower. Mechanical horsepower takes into account fan mechanical efficiency at the stated operating condition. Fans are sized based on mechanical efficiency and additional capacity (margin) above the MCR condition, referred to as "Test Block". The test block flow margin is 15% per fan, the test block pressure rise margin is 32.25% (1.15^2) above MCR values stated above. Test block fan mechanical efficiency is approximately 0.8. Fan Mechanical Horsepower = flue gas volumetric flow (actual cubic feet per minute) multiplied by pressure rise in inches w.g. divided by (6536 x efficiency). Fan efficiency varies with flow and pressure rise; values based on estimates/vendor quotes for full load (maximum continuous rating or MCR) conditions.

3- Horsepower (motor rating) is approximately equal to Connected Load kVA; Connected Load kVA x Estimated Annual Average Demand factor = Demand Load kVA.

Hypothetical applications of low-dust and tail end SCR technologies included estimates of auxiliary electrical power usage. It is important to note that some alternatives identified between 88 and 109 electricity-consuming items supplying or serving each SCR reactor system. Several pieces of auxiliary equipment with significant electrical power loads were included. These are: sootblowing air compressors with dryers; instrument/service air compressors with dryers; seal air fans for SCR reactor inlet and outlet flue gas isolation dampers; SCR flue gas reheat burner combustion air fans; drive gearboxes for rotary gas/gas heat exchangers; urea-to-ammonia dilution air/combustion air fans; auxiliary equipment service building ventilation/heating/lighting; and urea feed pumps. The instrument/service air and sootblowing air compressors are significant but necessary to supply dry compressed air used by equipment dedicated to control, maintain, and provide catalyst cleaning media for the SCR systems.

NDDH Request #7: All vendor correspondence related to SCR reactor sizing, catalyst volume, NOx control efficiency, catalyst cost, catalyst replacement schedule, and catalyst guarantees should be provided. This includes the original requests submitted to vendors and analyst [catalyst] suppliers by Minnkota and its consultants. This must also include the description of the gas stream that was supplied to the vendors.

BMcD Response:
Information responsive to this request by Minnkota, Burns & McDonnell and the SCR system supplier and SCR process design consultant, catalyst vendors, and flue gas particulate characterization consultant is being submitted (see Enclosures). Documents that include information considered as "trade secrets" per the NDDH's Air Pollution Control rules are being submitted and marked "confidential" (see Enclosures).

Minnkota developed agreements with the catalyst suppliers and flue gas particulate characterization consultant engaged in this effort, and has a general services agreement with Burns & McDonnell, which covers work done by the SCR system supplier and SCR process design consultant. Information provided under Enclosure C is considered non-confidential, and includes information for which no claim is being made for confidentiality, along with an index and summary of the information submitted which is suitable for release to the public. Enclosure D includes documents claimed to contain trade secrets which are requested to be treated as confidential, along with an affidavit stating how and why the information fulfills the conditions of confidentiality per the NDDH's Air Pollution Control rules describing this confidentiality procedure.

NDDH Request #8: Data must be provided for the temperature gradient of the regenerative heat exchanger to justify the reheat calculations. This must be provided for the both LDSCR and TESCR. The 600°F temperature for the reheated flue gas must be justified.

BMcD Response:

The preliminary design temperatures for the hypothetical applications of low-dust and tail end SCR technologies shown in the table below were calculated by the SCR process consultant. The temperature data tabulated below for the Unit 1 low dust (LD) case include corrections identified by the SCR process consultant as described further in the response to NDDH Request #11.b. The SCR system supplier, which provided pricing of SCR equipment, including GGHs for low-dust and tail end SCRs, did not provide estimates of the GGHs' process performance.

SCR Process Design Temperatures

Parameter	U1 LD	U1 TE	U2 LD	U2 TE
FGD GGH (hot side) inlet temperature, °F	--	335	--	331
FGD GGH (hot side) outlet / FGD Absorber Inlet temperature, °F	--	(1)	--	(1)
FGD GGH (cold side) inlet/ FGD Absorber Outlet temperature, °F	--	142	--	143
FGD GGH (cold side) outlet temperature, °F	--	150	--	151
SCR GGH (cold side) inlet temperature, °F	335	150	331	151
SCR GGH (cold side) outlet temperature, °F	535	520	535	520
Flue Gas Reheat Burner outlet / SCR Ammonia Injection Grid/Reactor inlet temperature, °F	580	563	580	563
SCR GGH (hot side) outlet temperature, °F	380	199	380	197
FGD Absorber Outlet temperature, °F	142	142	143	143

1- The temperature of the FGD GGH hot side outlet (discharges to FGD Absorber Inlet) was not provided by the SCR process consultant. It would be less than 330°F.

As can be seen in the table above, the flue gas is reheated by natural gas to either 580°F for low-dust SCR cases or 563°F for tail end SCR cases. Natural gas heat input rates used in the November 2009 Supplemental NOx BACT Analysis study reports assumed these flue gas temperatures. These preliminary process design temperatures have not been confirmed pending final design by the gas/gas heat exchanger manufacturer. The catalyst vendors recommended that the catalyst be designed for (able to withstand continuous exposure to) 600°F service operating temperature. The capacity of the reheat burner equipment was not specifically provided by the SCR system supplier, but was expected to be capable of raising the flue gas up to the recommended service temperature.

NDDH Request #9: A comparison of the SCR costs at M.R.Young Station versus PSE&G Mercer Station and We Energies Oak Creek Station should be provided or an explanation why such a comparison is not possible or inappropriate. We recognize that each plant has unique characteristics and there will be some design differences from plant-to-plant, but those differences should not necessarily dismiss making general comparison of costs unless there are unique or extenuating circumstances which would preclude a general cost comparison.

BMcD Response:

A BACT analysis is performed on a case-by-case, site-specific basis. It is inappropriate to compare the capital costs associated with the low-dust SCR installation at Mercer Station, or at South Oak Creek Station, against those developed for the hypothetical applications of low-dust and tail end SCR technologies at MRYS. Site conditions, boiler firing type, type and characteristics of fuels burned and resulting flue gas emissions and ash produced, and the limited amount of NOx reduction required for those referenced low-dust SCR cases that were not required to represent BACT, make the comparison not relevant to MRYS.

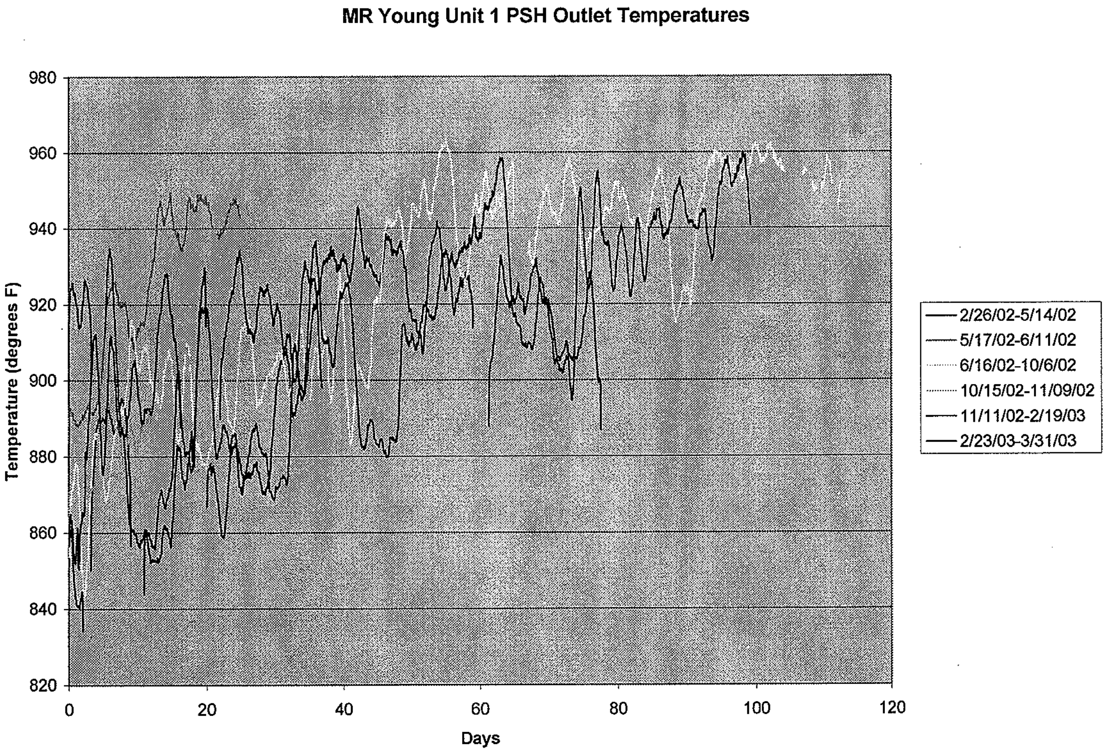
NDDH Request #10: Provide additional clarification and technical justification regarding Minnkota's determination that the units at MRYS are boiler limited and cannot generate additional steam for flue gas reheating purposes.

BMcD Response:

The steam turbine-generators at MRYS have a given output (gross megawatts) based on steam pressures, temperatures and flow rates related to the boilers. Removing high pressure/high temperature steam to use for flue gas reheating will directly cause a reduction in electrical output. This output reduction cannot be compensated for by increased boiler steam generation without unreasonable consequences. The boilers generate steam based upon their fuel heat input (firing) rates and capacities to absorb the heat created from the fuel combustion. The efficiency of converting fuel heat to steam to megawatts (heat rate or Btu per gross kilowatt) is limited by many factors. Fuel characteristics and boiler capacity are factors that impact heat rate (efficiency) that are not easily changed in the positive direction. The current fuel quality coming from the adjacent mine is not within the original design parameters of the boilers.

Because of the firing type (cyclone) and characteristics of North Dakota lignite burned and resulting flue gas emissions and ash produced at MRYS, the amount of fouling of the heat-absorbing surfaces within the boiler system is severe. These fouling conditions cause high exit flue gas temperatures that eventually reach the maximum limit recommended for maintaining the integrity of the air preheaters. This is indicated by the time-temperature graphs previously provided[13] and repeated below. The rate of boiler surface fouling increases significantly as more coal is fired, especially at maximum sustainable firing rates.

Due to the sticky character of the ash deposits, an "arsenal" of sootblower and water lance equipment is employed by Minnkota in an attempt to reduce the rate of fouling accumulations during boiler operations and remove these deposits during frequent boiler outages. These boiler cleaning outages occur every three to four months depending on the specific unit and the fuel quality delivered during the period. If the firing rate is increased to generate more steam for other heating purposes, the frequency of the cleaning outages must be increased. If the accumulated deposits are not removed, the frequency of the cleaning outages must be increased or the firing rates must be reduced and thus reduce the steam and electrical output of the boilers and steam turbine-generators. There is not "excess steam available for flue gas reheating" that would allow Minnkota to avoid reduced annual power generation.



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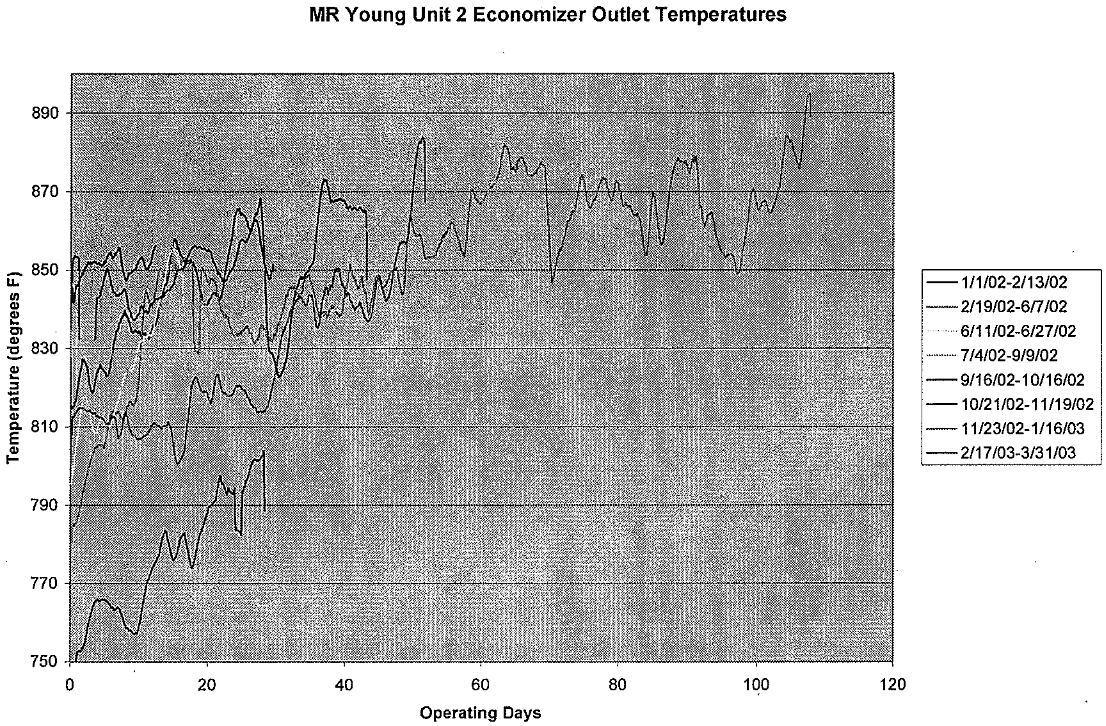
[13] See Reference number 11, April 18, 2007, pages 13-17.


MR Young Unit 2 Economizer Outlet Temperatures
Temperature (degrees F)
890
870
850
830
810
790
770
750
0
20
40
60
80
100
120
Operating Days
1/1/02-2/13/02
2/19/02-6/7/02
6/11/02-6/27/02
7/4/02-9/9/02
9/16/02-10/16/02
10/21/02-11/19/02
11/23/02-1/16/03
2/17/03-3/31/03

NDDH Request #11: There appear to be several discrepancies in the documents that must be addressed including:

a. **The catalyst volume for Unit 2 (p. 4-23) is listed as 256 m^3 per reactor or 512 m^3 per layer. This is 4-5 times more than Unit 1 yet Unit 2 is not twice as large. Please verify the Unit 2 catalyst volume.**

At page 4-23, the words "per reactor" should be deleted from the sentence describing Unit 2's catalyst volume. This will be shown on an "Errata Sheet" attached to this document.

For Unit 2, the total initial volume was 768 cubic meters for three layers, or 256 cubic meters per layer, based on catalyst vendor input. Subsequent installation of 342 cubic meters for the fourth layer was assumed, also based on catalyst vendor input. Total initial volume plus first fill of spare layer equaling 1110 cubic meters is for two SCR reactors for each case studied for Unit 2. The correct catalyst volumes were used in the annual operating and maintenance cost calculations that are a portion of the levelized total annual costs for NOx control alternatives provided in the referenced November 2009 Supplemental NOx BACT Analysis study reports.

The conceptual design of Unit 1 Low-Dust SCR Reactor, and Tail End SCR Reactor as provided by the catalyst supplier included in each layer a total of 104 catalyst modules (8 x 13 arrangement). There is one SCR reactor for each case studied for Unit 1. The conceptual design of Unit 2 Low-Dust SCR Reactor, and Tail End SCR Reactor included in each layer a total of 91 catalyst modules per reactor (7 x 13 arrangement). There are two SCR reactors for each case studied for Unit 2.

b. **The reheat for Unit 2 for TESCR is listed as 48.11 MMBtu/hr per reactor and for LDSCR is 45.55 MMBtu/hr per reactor. The differential between TESCR and LDSCR is much less than for Unit 1 (60.3 MMBtu/hr and 31 MMBtu/hr). Please explain this difference.**

The preliminary process design calculations were reviewed for the hypothetical applications of low-dust and tail end SCR technologies for Unit 1 and Unit 2. It was determined from this review that the temperature rise for the Unit 1 LDSCR flue gas reheat system was incorrectly assumed to be 25 degrees F instead of 25 degrees C (equivalent to 45 degrees F). The corrected 45 degrees F temperature rise for the Unit 1 LDSCR flue gas reheat system is shown in the table included with the response to NDDH Request #8. The correct natural gas heat input rate for Unit 1's low-dust SCR cases is 54.5 MMBtu/hr (instead of 31 MMBtu/hr).

The discovery of the underestimate of Unit 1's low-dust SCR flue gas reheat fuel requires revision to the MRYS Unit 1 November 2009 Supplemental NOx BACT Analysis study report for "Scenario A" and "Scenario B" cases. A revised version of the referenced November 2009 MRYS Unit 1 Supplemental NOx BACT Analysis Study report document and the December 2009 response document is being submitted with the corrected numbers and recalculated control costs (see Enclosures). The flue gas reheat fuel rates and costs assumed for the hypothetical applications of Unit 1's tail end and Unit 2's low-dust and tail end SCR alternatives included in the November 2009 Supplemental NOx BACT Analysis study reports will not change.

The temperature rise for the Unit 1 TESCR, Unit 2 LDSCR, and Unit 2 TESCR flue gas reheat systems are also shown in the table included with the response to NDDH Request #8. These are all preliminary numbers that would require confirmation after final cold-side outlet design temperatures are established by the FGD and SCR gas/gas heat exchanger manufacturer.

c. The capital costs for the "stand alone" SCR (p.3 of attachments to December 11, 2009 submittal) do not total correctly. Please check the numbers and revise the documents as necessary.

The numbers for "Pricing Contingency" shown in the table that provided "Estimates of Total Capital Investment for Low Dust and Tail End Selective Catalytic Reduction Alternatives Best Available Control Technology – Supplemental Analysis Stand Alone" cases submitted on December 11, 2009 were incorrect. They should match the "Scope Contingency" numbers above the "Pricing Contingency" line in the table. A revised version of the referenced document is being submitted containing the table with corrected data (see Enclosures).

d. The flue gas reheat burners and fans appear to be included in both "SCR system equipment" and "Auxiliaries" cost estimates (see p.4 of attachments to December 11, 2009 submittal, footnotes 1 and 3). Please check this and revise the documents as necessary.

There are two systems of natural gas-fired burners associated with each alternative studied for hypothetical application of low-dust and tail end SCR technologies in the November 2009 Supplemental NOx BACT Analysis study reports. The "flue gas reheat burner equipment" is correctly included as part of the "Purchased Capital Equipment SCR System Equipment" item (1) (a) under "Direct Capital Costs" denoted by footnote number1 in both tables of "Estimates of Total Capital Investment" for "Shared Facilities" and "Stand Alone" as submitted on December 11, 2009. Item (1) (b) "Auxiliaries/Balance of Plant" of both tables has footnote number 3. This footnote should be revised to read as follows: "Includes service air and sootblower air compressors, induced draft booster fan(s) and dampers, urea-to-ammonia conversion ~~flue gas reheat~~ equipment with natural gas-firing burners and fan(s), SCR bypass ducts and isolation dampers, interconnecting ductwork, equipment for active coal yard storage modifications, and catalyst standby heating auxiliary equipment costs as well as mechanical setting of this equipment". A revised version of the referenced document with the corrected footnotes is being submitted (see Enclosures).

REFERENCES

1. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter from Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: SCR Cost Estimate,* January 11, 2010.

2. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH Request NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, December 2009, submitted by Minnkota to North Dakota Department of Health on December 11, 2009.

3. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009; and a separate NO_X BACT Analysis Study – Supplemental Report for Milton R. Young Station Unit 2 for Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, November 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009.

4. "BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc." and a separate "BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc." Final Report, October 2006 submitted by Minnkota to North Dakota Department of Health.

5. Consent Decree filed in the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034, filed April 24, 2006.

6. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.

7. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").

8. Technical Information (brochure) FT-9200-AP involving anhydrous and aqueous ammonia versus urea for SCRs available from Fuel Tech's website www.ftek.com, dated November 17, 2008.

9. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to EPA Comments NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Technical Feasibility, March 15, 2007. [with regard to two documents: ERG Memorandum to EPA Region 8 and EPA Office of Regulatory Enforcement, *Review and Critique of the Burns & McDonnell* NO_X *BACT Analysis for the Milton R. Young Station Operated by Minnkota Power (October 2006),* written by Roger Christman, Eastern Research Group, Inc., January 8, 2007, faxed by North Dakota Department of Health to Minnkota, January 9, 2007. *EPA Region 8 Preliminary Analysis of Burns & McDonnell*

BACT Analysis For Nitrogen Oxide at Milton R. Young Station, Units 1 and 2 January 8, 2007 faxed by North Dakota Department of Health to Minnkota, January 9, 2007.]

10. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns, Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007. [with regard to two documents: North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: BACT Determination Milton R. Young Station*, dated February 1, 2007, with enclosure from United States Environmental Protection Agency Region 8, letter to Terry O'Clair, North Dakota Department of Health Division of Air Quality, *Re: Transmittal of EPA Non-SCR concerns and additional information required for Minnkota BACT Analysis Study*, dated January 26, 2007.]

ATTACHMENTS

1. Conceptual design sketch, for hypothetical application of Low Dust SCR technology to MRYS Unit 1 and Unit 2, Burns & McDonnell, 2009.

2. Conceptual design sketch, for hypothetical application of Tail End SCR technology to MRYS Unit 1 and Unit 2, Burns & McDonnell, 2009.

3. ERRATA Sheet:

   a. Corrections to Reference number 3 of this document "NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 2, Minnkota Power Cooperative, Inc. Operating Agent for Square Butte Electric Cooperative, Owner" November, 2009; (February, 2010).

ENCLOSURES:

A. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH Request NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, December 2009, submitted by Minnkota to North Dakota Department of Health on December 11, 2009, revised February, 2010.

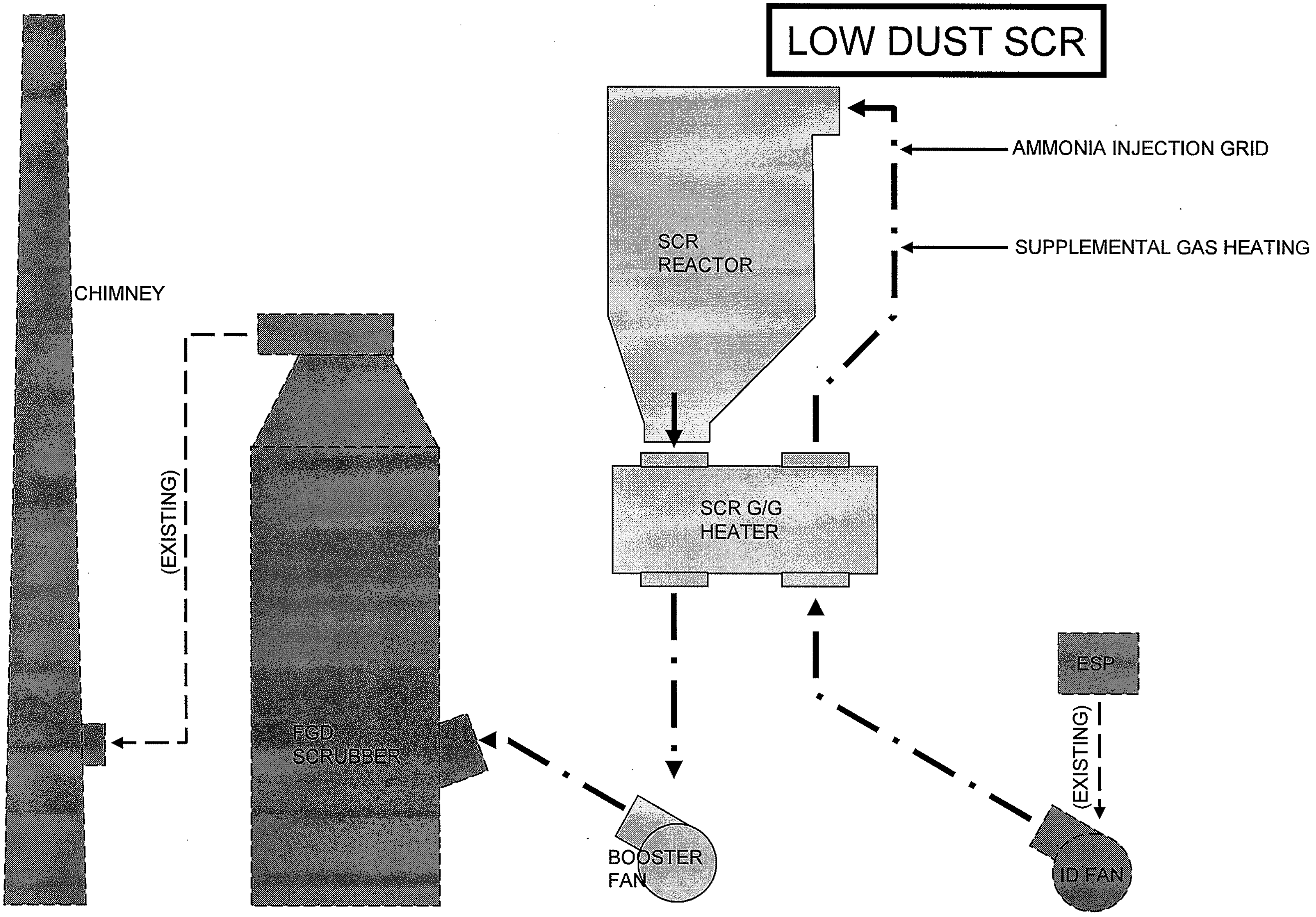
B. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009, revised February, 2010.

C. Non-confidential information related to response to NDDH Request #7 of this document (Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NOx BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, February 2010).

D. Confidential information related to response to NDDH Request #7 of this document (Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NOx BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, February 2010).

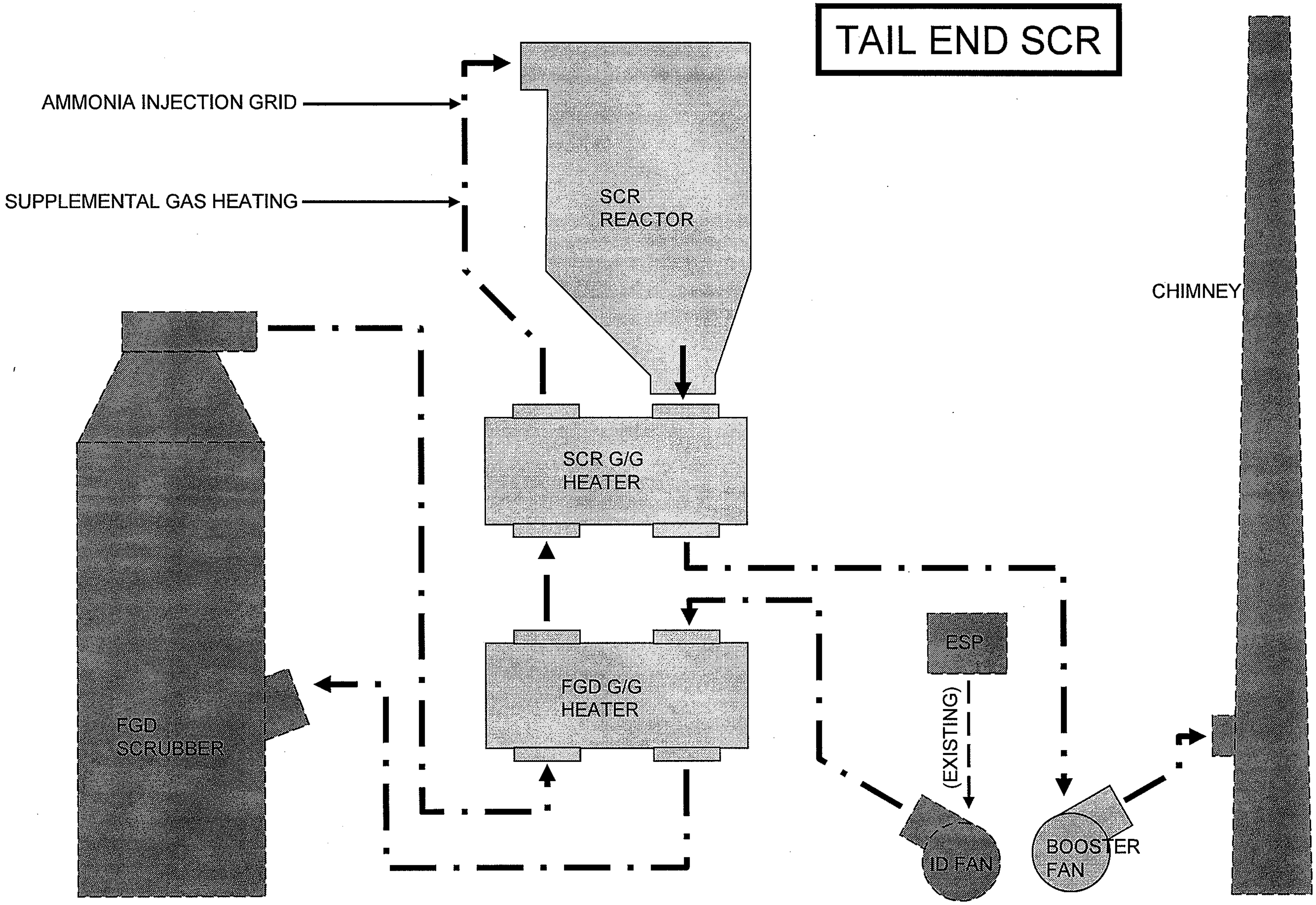
SKETCH SK - FD1

LOW DUST SCR



SKETCH SK – FD2

TAIL END SCR



ERRATA – MRYS Unit 2 Supplemental NOx BACT Analysis Study Report (November 2009)

Unit 2 Supplemental NOx BACT Analysis Study Report November 2009, page 4-23:

The second sentence of the paragraph should be revised to delete the words "per reactor":

> SCR catalyst replacements are additive to the general annual hypothetically-applied low-dust and tail end SCR equipment maintenance. Catalyst replacement costs are based on catalyst vendor quotation of volume of catalyst, estimated to be three layers initially (top, middle-upper and middle-lower) at 256 cubic meters per layer ~~per reactor~~ for two reactors in parallel. A fourth (bottom) layer at 342 cubic meters is expected to be required after initial operation of hypothetically-applied full-time tail end or low-dust SCR alternatives, as part of the catalyst replacement program. Catalyst replacement costs for the hypothetical application of SCR alternatives were estimated for the two different catalyst management scenarios described above.

GREAT RIVER
ENERGY℠

February 9, 2010

Lewis Dendy
North Dakota Department of Health
Division of Air Quality
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Dear Lew,

Great River Energy (GRE) respectfully submits our response to questions raised by US EPA concerning ammonia in fly ash relevant to our Coal Creek Station (CCS). To address the issues raised by Amy Platt of US EPA in a November 30, 2009 email message to Tom Bachman of NDDH, GRE provides the following responses:

1. Response to Amy Platt's email
2. Fly Ash usage and properties

Response to Amy Platt's email

Amy Platt's email references Dynegy's Baldwin Energy Complex and Progress Energy's Roxboro Generating Station as facilities that have post combustion NOx control and market their fly ash. Both facilities have Selective Catalytic Reduction (SCR) installed, not Selective Non-Catalytic Reduction (SNCR) technology. It is typical for SCR technology to operate with lower ammonia injection and slippage rates than comparable SNCR technology. With SCR technology additional mixing and chemical reaction assistance is introduced in the catalyst packing resulting in reduction in NOx emissions. SNCR technologies require additional ammonia injection to ensure contact with the NO_X molecules in the flue gas, as they do not benefit from additional mixing or the benefit of enhanced chemical reactions provided by the catalyst packing. Headwaters Resources, GRE's fly ash marketer, on average sees ammonia content in ash from 200-600 ppm for SNCR units and from 50-400 ppm for SCR units. *See Attachment 3 section.*

Dynegy's 1,800 MW Baldwin Energy Complex has 3 units burning Powder River Basin (PRB) coal. Two of the units have SCR installed, the third unit has no post-combustion NO_X control technology. Headwaters Resources, GRE's fly ash marketer, is also the ash marketer for the Baldwin Energy Complex. Headwaters only markets ash from the one pulverized coal unit that does not have either SCR or SNCR installed and therefore the ash sold does not contain ammonia. Please see attached letter from Herbert Moeckel of Headwaters Resources. *In Attachments 1 section.*

Currently there are no installations of SCR or SNCR burning North Dakota Fort Union lignite. As GRE does not have any data or experience with ammoniated ash we have asked our fly ash marketer, Headwaters Resources, to respond to Amy Platt's chemistry statement that alkaline ashes experience lower uptake of ammonia. Headwaters has extensive experience with ammoniated ash and they have observed higher ammonia odor emissions from a plant (East Lake Plant, OH) producing a higher alkaline ash. The mechanism for this higher evolution of ammonia has not been identified and is currently being investigated. *See email thread of December 29, 2009-in Attachment 2 section.* Without empirical evidence on uptake of ammonia on ash from ND lignite GRE cannot assume ammonia slippage rates or retention rates on fly ash. We have also presented the question about expected ammonia in ash for lignite units to Tony Facchiano, Sr. Program Manager at the Electric Power Research Institute (EPRI) and although they have done work for other types of coal they have not conducted research with ND lignite and would not be able to correlate the ammonia in ash with ammonia slip at this time.

As there are no data from Fort Union lignite on SNCR ammonia retention in ash we have provided testimony from GRE customers. As noted by our customers, ammonia-impregnated ash would have an economic impact not only on GRE but also to our marketers who sell the ash. *See enclosures from Lafarge and GCC of America in the Attachment 1 section.*

Fly Ash

Fly ash for use in concrete is classified in 3 classes: Class N – raw or calcined natural pozzolans that comply with ASTM C618-08; Class F - typically produced from burning anthracite or bituminous coal, but lignite also; Class C – typically produced from burning lignite's, but may also be produced from burning anthracite or bituminous coal as long as the total calcium contents are higher than 10% and the ash has some cementitious properties. CCS ash is classified as a Class F ash. Introduction of ammonia will not affect the class of our fly ash but will decrease the desirability and thus the marketability of our ash if the customer perceives a health risk or is able to procure the same material without the objectionable qualities.

The original investments made in the infrastructure for the marketing of fly ash was predicated on the fact that CCS is a mine mouth plant with a consistent coal source which is producing a high quality fly ash which is very desirable in the concrete market. The introduction of undesirable characteristics into the fly ash, such as an odor or inhalation risk, will force our concrete customers to pursue alternate marketers for their feedstock. *See testimonials from Headwaters Resouces, Lafarge, and GCC in the Attachments 1 section.*

Please contact me at 763-445-5208 regarding any questions or comments.

Sincerely,

GREAT RIVER ENERGY

Debra Nelson

Debra Nelson

c: Diane Stockdill
File

Attachment 1: Testimonials

HEADWATERS
RESOURCES

Adding Value to Energy

January 28, 2010

Mr. Al Christianson
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Dear Mr. Christianson:

I am writing in regards to the Dynegy Midwest Generation – Baldwin Energy Complex located in Baldwin, Illinois. Headwaters Resources is the marketing company for all five Dynegy Midwest Generation plants located in Illinois.

The Baldwin Energy Complex is composed of three – 600 MW units, totaling 1800 MW. Units 1 and 2 are cyclone fired boilers and Unit 3 is a pulverized coal boiler, all three units are burning PRB coal. Units 1 and 2 are equipped / operating with an SCR and Unit 3 has neither a SCR or SNCR installed.

Headwaters Resources has mainly marketed the cyclone boiler fly ash produced from Units 1 and 2 into the cement industry as a raw feed ingredient since 1998. Since 2000, we were able to market approximately 17,000 tons of this material into "flowable fill" on a few mine subsidence projects in the East St. Louis, Illinois area. We have performed ammonia testing on the fly ash produced from Unit 1 and 2 utilizing the Headwaters SOP using dragger tubes. This material fluctuates between 35 and 125 ppm ammonia in the fly ash. The ammonia odor was noticeable when used on the flowable fill mixes which contained high volumes of fly ash per yard. The ammonia odor did not have an impact on our sales agreement with Buzzi Unicem, since they were using the material as a raw feed ingredient in the production of cement. Starting in July 2009 new mercury regulation forced the power stations in Illinois to use activated carbon injection to reduce mercury emissions. Units 1 and 2 did begin activated carbon injection in July 2009 at which time the material was no longer allowed to be used in the production of cement. At this time 100% of the fly ash material produced from these units is being disposed of in an on site impoundment. Dynegy is constructing SDA scrubbers which should be complete by 2013, at which time the injection point of the activated carbon will be moved allowing the use of the fly ash material in cement production. The fly ash produced from these two units is not suitable for use in concrete.

Unit 3 at the Baldwin Energy Complex was granted a temporary variance which did not force this unit to inject activated carbon until the SDA / Bag house is operational at the end of 2010. Headwaters Resources has marketed the ASTM C618 Class C fly ash produced from unit 3 into ready mix concrete, concrete paving, and soil stabilization since 1998.

Please feel free to contact me at 612-963-7093 regarding any questions or comments.

Respectfully

Herbert Moeckel
Technical Sales Representative
Headwaters Resources
P.O. Box 566
Osage Beach, MO 65065
P: 612-963-7093
F: 866-449-8130

GCC
of America

January 21, 2010

Mr. Al Christianson
GREnergy
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Al,

We would like to take this opportunity to express concern about GRE's potential injection of ammonia into the flue gas during coal burning operations as an effort to reduce NOx emissions. As a wholesale marketer and end-user of your fly ash from the Coal Creek facility in North Dakota, our concern surrounds the impact this process will have on the fly ash when used in concrete.

The ammonia in fly ash is not present as ammonia gas. Rather, it is in the fly ash as ammonium sulfate. Once in the high alkaline environment of concrete the ammonia is released. This becomes a problem because of the odor, especially in enclosed spaces such as residential basements. The smell of ammonia is objectionable and would potentially impact external fly ash sales for GCC of America and internal use in the concrete operations owned by GCC Ready Mix..

Our professional experience with this situation in the past had been limited to the senses, i.e. eye and nose irritation and unpleasant odor. The corrective action taken was at the expense of the concrete producer, causing those customers to do business elsewhere.

We value our relationship with your company and prefer to use your product because of its quality and performance. Please do not allow these attributes to be compromised. If you should have any questions, or if we may be of further assistance, please contact either of us our Denver offices at (303) 739-5900.

Sincerely,

Joe Finnegan

Mark R. Lukkarila,
Technical Services Manager
GCC of America

Joseph E. Finnegan,
Regional Sale Manager
GCC of America

Building Together

Corporate Offces
130 Rampart Way, Suite 200
Denver, CO 80230

Telephone: 303-739-5900
Fax: 303-739-5938
www.gcc.com

HEADWATERS
RESOURCES

Adding Value to Energy™

January 11, 2010

Mr. Al Christianson
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Dear Mr. Christianson:

The Eastlake power plant in Eastlake, Ohio had a SNCR installed over 2 years ago. Prior to the installation the plant produced a high quality F-ash which was sold out every year during the construction season. The ammonia level was between 200-400 PPM after the installation which was when the problems started. Anything over 100 PPM seemed to be a noticeable at this plant.

We started shipping the material when it was in the 100-200 PPM range and the customers, batch plants and several contractors started calling with complaints especially in confined spaces such as buildings and basements. In one case a Ready Mix plant employee stuck his head in the back of the truck to add air entraining agent and it burned his eyes. He spent the night in the emergency room getting his eyes washed out not knowing it was the fly ash causing the ammonia smell.

We quit shipping anything over 100 PPM and business started dropping off; contractors did not want fly ash in their mixes. Since you're only checking a small amount of ammonia in the load it would test for less than 100 PPM but in some cases the Ready Mix producer still had problems which indicated the entire load was not less than 100 PPM. We shut down a block plant and the customer made us take the fly ash out of his silo and he quit buying fly ash from us.

Bill Newkirk

Bill Newkirk
Headwaters Resources
Technical Sales Rep
440-725-0088

2761 Port Neal Circle
Salix, IA 51052
P: 712.943.4049 F: 712.943.2876

LAFARGE
NORTH AMERICA

Cement

January 26, 2010

Mr. Al Christianson
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Subject: Ammonia Injection in Fly Ash

Lafarge has used fly ash from power sources where SNCR ammonia injection units have been installed. We have found that when the ammonia levels exceed 40 parts per million in the fly ash that the consumer notices the ammonia and find it to be objectionable.

Lafarge is concerned that if ammonia injection units are installed at Great River Energy's Coal Creek Station it may cause the fly ash that is produced to be unmarketable. Lafarge currently purchases a large percentage of the fly ash that is produced at this station and would be placed at an economic disadvantage if we were no longer able to market this high quality ash to our ready mix customers.

This would cause our customers in turn to be at an economic disadvantage if they had to use fly ash from another source that is further away or use slag cement that perhaps would be more expensive than Coal Creek ash.

Roy V. Sander, Jr.

Roy Sander/General Manager

LAFARGE Dakota.
684 15th Ave. SW. PO Box 757, Valley City, ND 58072
Telephone: (701) 845-2421 Fax: (701) 845-1849 Toll Free: 1-800-533-8662

Attachment 2: Email Thread Headwater to GRE

From: Stockdill, Diane GRE-CC
Sent: Tuesday, December 29, 2009 3:38 PM
To: Nelson, Debra GRE-MG
Subject: FW: Where are we at?
Attachments: STI ammonia removal.pdf

Let's talk tomorrow

-----Original Message-----
From: Christianson, Al GRE-BI
Sent: Tuesday, December 29, 2009 3:35 PM
To: Stockdill, Diane GRE-CC
Subject: FW: Where are we at?

Fyi, they are working on it. al

Al Christianson
Manager, North Dakota Business Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503
701-250-2164 Direct
701-442-7664 Direct
701-220-4881 Cell
701-202-8964 Car
achristianson@grenergy.com
www.greatriverenergy.com

-----Original Message-----
From: Jerry Smith [mailto:jsmith@headwaters.com]
Sent: Tuesday, December 29, 2009 3:34 PM
To: Christianson, Al GRE-BI
Subject: FW: Where are we at?

Al: Attached is Bruce's response to your latest inquiry. It appears that we are still waiting on Mr. O'Conner (EPRI) to review our data on Sammis and East Lake ash. The attached brochure from STI may be helpful in the comparison of SNCRs and SCRs in regard to ammonia being introduced into the ash. I don't know if this is sufficient for your needs. If not, I suggest that we (Diane, you, and I) get on a conference call with Bruce to discuss what else we may be able to provide. Just let me know. Thanks.

From: Bruce Boggs
Sent: Tuesday, December 29, 2009 2:35 PM
To: Jerry Smith
Subject: RE: Where are we at?

Jerry,

There was no official document generated by EPRI to circulate on this issue. The curious finding that the more alkaline ashes had higher ammonia odor emissions was reported to EPRI but the reason for the finding was never identified. Dave O'Connor at EPRI will review our data showing the data on Sammis and East Lake comparisons.
The data from our East Lake plant with SNCR and higher alkaline ash should be available shortly to compare with the much lower levels of ammonia from an SNCR associated with low alkalinity ash at Sammis.

STI found it necessary to develop an ammonia removal/treatment system in addition to the carbon removal system they operate at several locations. I do not know if the Roxboro plant uses this system but I would point out that with the storage dome at Coal Creek, the ammonia levels that could accumulate would be extremely hazardous. A little know fact is that ammonia is an explosive gas at certain levels when it accumulates with air present. See attached STI brochure on ammonia removal. In that brochure they support the fact that SNCR units will introduce much more ammonia to the ash than SCRs but both can prevent ash from being used in the market.

Bruce

From: Jerry Smith
Sent: Tuesday, December 29, 2009 2:46 PM
To: Bruce Boggs
Subject: FW: Where are we at?

Bruce: Please see Al's and Diane's comments below. Have we heard anything from EPRI on this issue? Thanks.

From: Christianson, Al GRE-BI [AChristianson@GREnergy.com]
Sent: Tuesday, December 29, 2009 1:22 PM
To: Jerry Smith
Subject: FW: Where are we at?

Anything new, people want to know?

Al Christianson
Manager, North Dakota Business Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503
701-250-2164 Direct
701-442-7664 Direct
701-220-4881 Cell
701-202-8964 Car
achristianson@grenergy.com<mailto:achristianson@grenergy.com>
www.greatriverenergy.com<http://www.greatriverenergy.com>

From: Stockdill, Diane GRE-CC
Sent: Tuesday, December 29, 2009 1:15 PM
To: Christianson, Al GRE-BI

Subject: Where are we at?

Where is Headwaters at on the SNCR justification documentation? I saw the waiting for EPRI response but when do they plan on having something to us?

Attachment 3: Headwaters information on SCR vs. SNCR

Ammonia Contamination Levels

Air Pollution Control Process	NH_3 "Slip" ppm$_v$	NH_3 in Ash mg/kg
SCR	2 to 10	50 to 400
SNCR	5 to 20	200 to 600
SO_3 Control	10 to 20	300 to 600
ESP Conditioning	20 to 30	600 to 1200

Actual ammonia concentrations will depend on ammonia injection rates, coal type, sulfur content, and other operating parameters.

Environmental Groups

Comment I: The Clean Air Act and Federal Regulations Require NDDH to Abate Visibility Improvement.

A) The BART limits fail to reflect the best degree of continuous emission reduction achievable.

Response: The determination of BART is based on five factors: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts; 4) the remaining useful life of the source; and 5) the degree of visibility improvement. The NDDH considered all five factors in determining BART. BART is not necessarily the lowest possible emission rate or the emission rate (or technology) that achieves the maximum visibility improvement. All of the five factors must be considered. The NDDH is free to determine the weight and significance assigned to each factor (40 CFR 50, Appendix Y, Section IV.D Step 5). A response to specific comments on the BART analyses follows.

B) North Dakota should actively encourage other states and Canada to reduce emissions that impair visibility.

Response: The NDDH has consulted with other states as part of WRAP and the Northern Class I Areas workgroup. Significant emissions reductions will come from sources in each state involved in these groups. Negotiations with a foreign country are reserved to the U.S. Government. The NDDH is hopeful that the U.S. EPA and the U.S. State Department will pursue reductions at Canadian sources; however, the State of North Dakota has no control over these agencies.

Minnesota asked for additional reductions from EGUs in North Dakota. However, Minnesota's request was not based on the four factors that must be evaluated for reasonable progress. The NDDH suggested that Minnesota consider the fourth factor (cost of compliance) in their analysis, especially dollar per deciview improvement.

Comment II: NDDH's Draft BART Determinations are Flawed

II.A. NDDH purported to do a case-by-case evaluation of BART, it appears the case-by-case analysis were simply written to support the presumptive levels.

Response: Each EGU was evaluated considering the five factors. Since the original BART submittals, the NDDH has required 95% removal at Leland Olds Unit 1 and M.R. Young Unit 2 compared to the 90% removal proposed by the companies. At Stanton Station, GRE originally proposed sorbent injection. The NDDH has required a dry scrubber. The NDDH's evaluation of BART indicates these sources may exceed the 0.15 lb/10^6 Btu presumptive limit when higher sulfur coal is encountered. Instead of establishing a higher lb/10^6 Btu limit, the NDDH maintained the 0.15 lb/10^6 Btu presumptive limit but gave the sources the option of complying with the 95% reduction requirement.

None of these sources are subject to the BART Guidelines in 40 CFR 50, Appendix Y for SO_2. All the plants except Coal Creek Station have a nameplate capacity less than 750 MWe. Coal Creek Station is not subject to the BART Guidelines for SO_2 since its existing scrubbers are achieving greater than 50% removal efficiency. The NDDH considered the five statutory factors and determined BART appropriately.

II.A.I: NDDH Cannot Take into Account Projected Worst-Case Sulfur Content of Coal in Setting BART Limits.

Response: The BART Guideline states "The baseline emissions rate should represent a realistic depiction of **anticipated** [emphasis added] annual emissions for the source." This statement clearly indicates future conditions should be utilized if it is different from historic conditions. EPA has allowed the use of the last 5 or 10 years for establishing the baseline (EPA – Additional Regional Haze Questions, August 3, 2006; Question 7). Because North Dakota lignite is extremely variable, using the highest 24-months out of the last 5 or 10 years may not give a realistic depiction of future conditions. Therefore, using the highest annual average sulfur content from a future period is consistent with the BART Guideline and EPA guidance.

In the case of Leland Olds, coal sulfur data was provided based on core sampling from the Freedom Mine (See Appendix B.2). The data shows an annual average sulfur content of 1.13% for 2019 and 1.12% for 2020. Since these are annual averages, they do not represent the maximum sulfur content that may be encountered during a given 30-day rolling average basis. For Coal Creek, the coal sulfur content selected was based on the 98th percentile of the coal sulfur data provided by GRE. The NDDH believes this is realistic for future emissions from Coal Creek.

For Milton R. Young Station, the average sulfur content from various core samples was used (see Table C.11, 4/18/07 Response to Comments). The maximum sulfur content is 5.5%.

For Unit 1 at the M.R. Young Station, the commenter is confusing the 2000-2004 average emission rate with the baseline emission rate. As noted earlier, the baseline emission rate, as suggested by EPA, is based on the maximum two years of emissions out of the last five years, not the entire five year period. Obviously, the five year average will be less than the maximum two year period. The commenter states that if actual emissions were reduced by the projected amount, Unit 1 would be emitting negative amounts of $SO_{2,}$ which is an impossibility. The commenter's statement is based on the 2000-2004 average SO_2 emission rate. Use of a five year average is contrary to the BART guideline and other guidance which indicates a two year average should be used. Had the Department used the 2000-2004 average emission rate as the baseline, an emissions reduction of 95% would have indicated emissions (after the wet scrubber) of 1007 tpy, not a negative emission rate.

For Stanton, the maximum uncontrolled emission rates expected are 2.4 $lb/10^6$ for lignite and 1.60 $lb/10^6$ Btu for subbitimunous coal (See Appendix E of GRE's analysis). In the NDDH BART analysis, 1.81 $lb/10^6$ Btu was used for lignite and 1.2 $lb/10^6$ Btu for subbituminous coal.

It is obvious the NDDH BART analysis did not use the maximum sulfur coal. The NDDH made a determination that the lower values would realistically depict future emissions.

II.A.2: The Proposed BART Limits Fail to Reflect the Degree of SO_2 Reduction Achievable with the BEST SO_2 Controls.

The commenter claims that 99% removal efficiency can be achieved using the Chiyoda CT-121 FGD or the Mitsubishi double contact flow scrubber.

<u>Response</u>: Regarding the Mitsubishi DCFS, literature by ADVATECH (copy attached to this response) for this scrubber indicates it can achieve very high sulfur removal efficiencies on high sulfur coal. However, tested performance on installed FGD systems indicate down to 90% removal efficiency for sulfur inlet concentrations of 1000 ppm or less. For North Dakota lignite, the inlet concentration is generally below 1000 ppm. The commenter also references two technical documents and a single sheet of information with no explanation of the source. These documents indicate high efficiencies at high inlet SO_2 concentrations (>1000 ppm), but low efficiencies (<95%) at most of the sources tested where the inlet sulfur concentration was less than 1000 ppm. The Department has proposed a wet scrubber that will achieve at least 95% removal under all inlet loadings. The NDDH is not convinced that this technology will provide any additional SO_2 removal.

The Chiyoda CT-121 FGS is a bubbling jet reactor which the commenters claim has achieved 99% SO_2 removal in Japan on coal fired boilers. The commenters provided several technical documents in an attempt to support their claim. The Black and Veatch brochure provides a list of installed and proposed facilities. The installed facilities have SO_2 removal efficiencies between 70-99%. However, for most of the facilities with lower inlet SO_2 concentrations, the removal efficiency is below 95%. This shows a wide range of efficiencies with little useful data.

The technical paper by Yasuhiko Shimoganci et.al. indicates an SO_2 removal efficiency of 99% at the Shinko-Kobe Power Plant in Japan. This paper provides no data on averaging times, the variability of the coal burned, or permittee emissions limits. It is also the NDDH's understanding that this plant has experienced operational problems with scaling of the FGD's sulfur gas fan which requires two days of maintenance every 2-3 months. The NDDH believes that it would be unreasonable to require this technology given the high outage time.

The commenters pointed out several facilities where this technology has been demonstrated or is to be deployed. This entire comment is nearly identical to one submitted on the Desert Rock BACT analysis. EPA investigated these claims and still rejected this technology as BACT (see attachments).

The commenter also refers to a "LADCO and MRPO" presentation that indicated the technologies could achieve 99.5% control for $1,240 to $2,875 per ton of SO_2 removal. Apparently, these figures were based on 2.5% sulfur which is twice as high as that proposed for any of the North Dakota BART sources. More detailed information would be required from the commenter to assess the cost for this lower sulfur coal.

As indicated earlier, this comment is nearly identical to one submitted for the Desert Rock Power Plant BACT determination. EPA's response to this comment for Desert Rock is attached to this response. The NDDH agrees with EPA's BACT determination which rejected this technology. The NDDH does not consider the Chiyoda CT-121 scrubber or the Mitsubishi DCFS to be BART.

II.A.4 a, b, c: The Proposed SO_2 BART Limits Should be Expressed Multiple Ways.

The commenter indicates that 98-99% removal efficiency should be required based on the technology discussed in Comment II.A.2. The NDDH believes this removal efficiency is not feasible on a continuous basis for lower sulfur lignite (<1.5% sulfur). New wet scrubbers generally achieve SO_2 removal efficiencies of 95% (Institute of Clean Air Companies, 2008; Federal Register Vol. 70, No. 28, P.9715). EPA (Air Pollution Control Technology Fact Sheet; EPA-451/F-03-034) indicates "Chlorine content improves SO_2 removal…" North Dakota lignite has some of the lowest chlorine levels of all the U.S. coals. Based on the low chlorine content and lower sulfur content, the NDDH believes that 95% is a reasonable removal efficiency for a scrubber to meet on a continuous long-term basis which includes startups, shutdowns and malfunctions.

The commenter also states the proposed BART limit of 0.15 lb/10^6 Btu should be lowered based on <u>current</u> coal sulfur content. The commenter does not acknowledge that higher sulfur coal will be burned in the future. The future coal sulfur content is based on actual core samples from future mining areas. As explained in the response to Comment II.A.1, the baseline for determining the BART limit is based on the <u>anticipated</u> emissions that are expected to occur. The NDDH considers the core samples of future mined coal to be strong evidence of anticipated emissions. Based on 95% removal, the M.R. Young plant would have an SO_2 emission rate of 0.60 lb/10^6 Btu when the maximum sulfur coal of 5.6% is burned. Using one standard deviation from the average sulfur content would yield a controlled emission rate of 0.17 lb/10^6 Btu.

At the Leland Olds Station, a maximum 30-day rolling average of 0.19 lb/10^6 Btu would be expected based on an <u>annual average</u> sulfur content of 1.13% and 95% reduction. At Coal Creek, a 30-day rolling average SO_2 emission rate of 0.18 lb/10^6 Btu would be expected based on an annual average sulfur content of 1.1%. The NDDH stands by its decision to limit emissions to 0.15 lb/10^6 Btu.

The commenter also wants a mass per unit of time emission limit included in the BART Permit to Construct. The NDDH contacted EPA Region 8 earlier in the BART process regarding this issue. In a November 21, 2005 email response from Laurel Dygowski of EPA Region 8, it was stated "We think a 24-hour limit is unnecessary and may not be of much value." Given the small amount of emissions coming from these sources after controls, a mass per unit of time emission rate will be easily calculated with very good accuracy.

The NDDH stands by its decision not to include a mass per unit of time emission rate.

II.A.4.d: Comments Regarding the Stanton Station Unit 1 SO_2 Emission Limits

The commenter states that "there is no valid justification for NDDH to increase the derived emission rate reflective of 90% control by 33%". The commenter refers to the 33% adjustment factor used by the Department to adjust from an annual average emission rate to a 30-day rolling average emission rate.

It is common practice to establish higher short-term limits to allow for short-term emissions variability inherent to facility operations. The EPA RACT/BACT/LAER Clearinghouse contains numerous examples of short-term BACT limits which are higher than longer-term BACT limits. For example, a permit issued to Omaha Public Power District (RBLC ID NE-0031) on March 9, 2005 establishes a 3-hour average SO_2 BACT emission limit of 0.48 lb/MMBtu compared to the 24-hour SO_2 BACT limit of 0.163 lb/MMBtu and a 30-day rolling average SO_2 BACT limit of 0.095 lb/MMBtu. A permit issued to Wellington Development / Greene Energy (RBLC ID PA-0248) on July 8, 2005 establishes a 3-hour average SO_2 BACT limit of 0.234 lb/MMBtu and a 30-day rolling average SO_2 BACT limit of 0.156 lb/MMBtu. A permit issued to River Hill Power Company (RBLC ID PA-0249) on July 21, 2005 establishes a 24-hour average SO_2 BACT limit of 0.274 lb/MMBtu and a 30-day rolling average SO_2 BACT limit of 0.20 lb/MMBtu. Two examples where annual and 30-day rolling average BACT limits were established include permits issued to Associated Electric Cooperative (RBLC ID MO-0077) and Western Farmers Electric Cooperative (RBLC ID OK-0118). The permit issued on February 22, 2008 to Associated Electric Cooperative establishes a 30-day rolling average NO_x limit of 0.065 lb/MMBtu and an annual average NO_x limit of 0.05 lb/MMBtu. The permit issued on February 9, 2007 to Western Farmers Electric Cooperative establishes a 30-day rolling average NO_x limit of 0.07 lb/MMBtu and an annual average NO_x limit of 0.05 lb/MMBtu. In addition, a permit issued by EPA on July 31, 2008 for the Desert Rock facility establishes a 30-day rolling average NO_x limit of 0.05 lb/MMBtu and an annual average NO_x limit of 0.0385 lb/MMBtu. Clearly, it is common practice to establish short-term BACT limits which are higher than longer-term BACT limits.

The Department has reliable data based upon actual facilities operating in North Dakota to support the use of the 33% adjustment factor. In addition, adjustment factors (to adjust from an annual average limit to a 30-day rolling average limit) calculated from Associated Electric Cooperative, Western Farmers Electric Cooperative and Desert Rock limits are approximately 30%, 40% and 30%, respectively. These adjustment factors are very close to the adjustment factor of 33% used by the Department. Since the Department has reliable data to support the use of the 33% adjustment factor and no data has been submitted indicating that the factor is not appropriate, the Department maintains the position that the 33% adjustment factor is appropriate.

The commenter states that spray dryers can achieve greater than 90% SO_2 removal and references permits issued for the Newmont Nevada TS, White Pine, Toquop Energy and Dry Fork facilities.

The Newmont Nevada TS power plant construction permit requires a 95% control efficiency when combusting coal with a sulfur content equal to or greater than 0.45% and a 91% control efficiency when combusting coal with a sulfur less than 0.45%. Based upon this permit, it is possible for the facility to operate with lower sulfur coal, maintain a control efficiency of 91% and meet the requirements of the permit. The Department does not consider a 91% control efficiency to be significantly different than a 90% control efficiency and the commenter provides no data indicating that a control efficiency greater than the 91% requirement has been routinely attained at the Newmont Nevada facility. The Department conducted the BART analysis for Stanton Station #1 when combusting PRB coal assuming an uncontrolled emission rate of 1.2 lb/MM Btu (on an annual average basis) and a control efficiency of 90%. If slightly higher sulfur coal is burned at Stanton Station #1, then the facility will need to attain a slightly higher removal efficiency than 90% to maintain compliance with the emission limit. Although a slightly higher control efficiency may be attainable on a short-term basis, the Department maintains the position that a standard spray dryer is routinely capable of a 90% SO_2 control efficiency, especially when periods of startup, shutdown and malfunction are included. The Department considered other control technologies (wet scrubber, circulating dry scrubber) with higher control efficiencies than 90% in the BART analysis and eliminated these technologies based upon cost and other environmental considerations.

The commenter references a "draft Toquop permit" as exhibit 22. However, as submitted, both exhibit 21 and 22 are the Desert Rock permit, so it appears the Toquop permit was excluded from the exhibits. The Department has reviewed the draft permit for the Toquop Energy, LLC facility on the Nevada Division of Environmental Protection web site and has found that the control technology proposed for the Toquop facility is a wet scrubber, not a spray dryer. Since the Toquop facility will be employing a wet scrubber, the draft permit for the facility does not support the commenter's position regarding the control efficiency of a spray dryer.

The commenter indicates that the White Pine power plant has not been constructed and is "indefinitely postponed", so this provides no evidence that a spray dryer can routinely attain SO_2 control efficiencies greater than 90%.

The commenter references the Dry Fork Station as evidence that a spray dryer can attain greater than 90% SO_2 control efficiency. However, the control technology to be used at the Dry Fork Station is a circulating dry scrubber, not a spray dryer. The Department did consider a circulating dry scrubber (at 93% SO_2 control efficiency) in the BART analysis for Stanton Station #1 and determined that the incremental cost of a circulating dry scrubber (compared to a spray dryer) is excessive.

The commenter argues that spray dryers can achieve greater than 90% SO_2 removal and presented four facilities (Toquop Energy, Dry Fork, White Pine and Newmont Nevada) to support this argument. The Toquop Energy and Dry Fork facilities are not proposing to use a spray dryer to control SO_2 emissions. The White Pine facility does not appear to have been issued a permit. The only facility which is employing a spray dryer and which has operated is the Newmont Nevada facility. However, as indicated above, the Department is not aware of any data from this facility demonstrating that a standard spray dryer can routinely attain SO_2 control efficiencies greater than 90%.

Based upon the above, the Department maintains the position that a standard spray dryer can be expected to routinely attain an SO_2 control efficiency of 90%.

The commenter states that the Department eliminated a wet scrubber from consideration as BART based only on the small amount of visibility improvement. The commenter argues that, since the cost of a wet scrubber is not prohibitive, the Department must require the use of a wet scrubber as BART at Stanton Station #1.

The BART determination for Stanton Station #1 clearly states that the Department chose a spray dryer as BART as opposed to a wet scrubber based upon both the additional environmental impacts and the small visibility improvement of a wet scrubber as compared to a spray dryer. The additional environmental impacts of a wet scrubber were outlined in the BART determination as follows:

- A wet scrubber is estimated by GRE to use as much as 20% more water or approximately 15 million gallons per year of additional water.
- It is assumed that a wet scrubber system will require additional on-site ponding. GRE has identified two potential areas on site that could be used for the additional ponding. The areas include the existing ash pile, which would have to be excavated and moved, or the abandoned ash disposal area adjacent to the river, which reportedly has geotechnical deficiencies.
- Dry scrubbers are purported to achieve a higher mercury control efficiency on lignite and PRB as compared to a wet scrubber. In addition, future mercury control requirements could result in high concentrations of mercury in the ponds and prove problematic to discharge.

Considering the additional environmental impacts and the fact that a wet scrubber will result in a small visibility improvement beyond the control achieved by a spray dryer, the Department maintains the position that BART for SO_2 at Stanton Station #1 should be established as a spray dryer with a fabric filter.

The commenter states that a wet scrubber can attain SO_2 removal efficiencies of 98-99%. See responses to comments for Sections II.A.4.a, b and c.

The commenter states that the Department should establish both a numerical emission limit and a minimum control efficiency for SO_2. The BART guidelines list the presumptive levels in units of lb/million Btu or a percent reduction. Given that the presumptive levels are listed in units of lb/million Btu or a percent reduction, the Department does not believe it is appropriate to establish emission limits on a lb/million Btu and percent reduction basis.

II.A.5: There Are Other Benefits to NDDH Requiring Stringent SO_2 BART Limits That NDDH Must Take Into Account.

The commenter indicated that the NDDH should control SO_2 to low levels to facilitate the capture of CO_2. There are currently no regulations that require CO_2 capture. There are only a few technologies that are in various stages of development from bench scale to testing at full scale. The NDDH cannot consider what may happen in the future regarding CO_2 capture. A cap and trade program may make purchasing CO_2 credits (allowances) more economically feasible than capture. New technologies may be developed which do not require low SO_2 concentrations.

The NDDH believes CO_2 capture is currently only in its infancy and future regulatory requirements are too uncertain at this time to be considered in the current BART determinations.

The commenter also indicates that $PM_{2.5}$ concentrations will also be lowered with lower SO_2 emissions and this should be considered in the BART determination. The commenter's statement is true that lower SO_2 emissions will probably lead to lower $PM_{2.5}$ concentrations. The entire state of North Dakota is in compliance with current NAAQS for $PM_{2.5}$. BART requirements will reduce SO_2 emissions by nearly 100,000 tons per year. This should reduce $PM_{2.5}$ concentrations significantly in affected areas. The small emissions reductions going from 95% SO_2 reductions to 98-99% reduction will have little effect on ambient $PM_{2.5}$ concentrations due to dispersion of the plumes. The NDDH considers this issue as insignificant in the BART determination process.

II.B.1: High Dust SCR (HDSCR) is Technically Feasible.

The commenter claims that high dust SCR is technically feasible for North Dakota lignite. The commenter expressed comments about several issues the NDDH discussed in the technical feasibility analysis. These include: 1) The variability of fuel composition; 2) Results for the Coyote Pilot testing; 3) Sodium in the ash; 4) Temperature variations, 5) Catalyst erosion and; 6) the Lack of vendor guarantees.

<u>Response</u>: The BART Guideline states "Where you conclude that a control option identified in Step 1 is technically infeasible, you should demonstrate that the option is either commercially unavailable, or that specific circumstances preclude its application to a particular emissions unit. Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are irresolvable technical difficulties with applying the control to the source (e.g. size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility)." The commenter did not supply any analyses of the flue gas from North Dakota lignite combustion to demonstrate that HDSCR is technically feasible. The commenter did address sodium in the flue gas by stating "At least one of the catalyst vender noted that sodium is not a poison to a catalyst at SCR operating temperatures." The commenter went on to say that proper operation will prevent catalyst deactivation and that if any condensation occurs, it can be mitigated by washing. The NDDH has concluded that moisture, or condensation, is not necessary to poison the catalyst. Zheng et.al (2008) concluded that the submicron aerosols of soluble potassium and sodium are transported into the catalyst pores by diffusion (i.e. surface diffusion). Several pilot and full scale tests have found rapid deactivation of SCR catalyst from potassium and sodium aerosols from biomass combustion when the catalyst was at normal operating temperatures. Haldor Topsoe (Crespi et.a.) in their paper, *The Influence of Biomass Burning in the Design on an SCR Installation* states "Submicron aerosols adhere to the catalyst surface or diffuse into the macro pores. The aerosols cannot diffuse into the clusters as primary TiO_2 support particles, which appear as islands at the catalyst surface. However, the alkalis are very mobile and are readily transported by surface diffusion into the clusters and react with the active sites. The reaction is not reversible:" The NDDH agrees that condensation will greatly enhance catalyst deactivation; however, severe catalyst deactivation from Na and K aerosols does occur at biomass boilers without condensation of moisture occurring.

Catalyst washing may help regenerate a catalyst that has been coated or the pores plugged. However, as Haldor Topsoe notes, when soluble Na or K reacts with the active sites, the reaction cannot be reversed by washing.

The commenter specifically addressed a) the variability of fuel composition, b) the Coyote Pilot testing, c) sodium, d) temperature variations, e) catalyst erosion, and f) lack of vendor guarantees.

a) Variability – The commenter indicated that the variability of North Dakota lignite was not an issue and that it can be overcome by proper design.

<u>Response</u>: The analyses that were conducted for the technical feasibility determination used an average ash content and average sodium and potassium content of that ash. Data supplied by the companies indicates that the ash content can be twice as high as the average and the Na_2O content can be 3-4 times the average (see Minnkota's 4/18/07 response to comments). The analyses indicate that average coal constituents will rapidly deactivate an SCR catalyst. If the amount of sodium is increased by a factor of 6-8, even more rapid catalyst deactivation is expected. The commenter has provided no evidence indicating that coals used at power plants that have HDSCR have such a high variability in the catalyst poisoning agents.

b) Results of the Coyote Pilot Testing – The commenter dismissed the results of the Coyote testing indicating that any conclusions from the testing should be rejected.

<u>Response</u>: The NDDH made only one conclusion from the testing. That is, there is a difference between subbituminous coal and North Dakota lignite when it comes to the design and operation of an SCR system. The Coyote testing showed much more severe plugging problems than at the Baldwin Station. This indicates the design may require a different pitch and a much larger reactor. As Sargent and Lundy (PowerPoint Presentation 5/2007) has noted, "Some important unanswered questions pose significant risk for an SCR design engineer."

- An unknown catalyst deactivation rate will prevent:
  - Optimum selection of a catalyst design
  - Selection of an appropriate reactor size

S&L also indicated "there are attributes of this fuel in an SCR environment that are not well understood today and need more investigation to predict its performance." The NDDH has concluded that pilot scale testing would be required before HDSCR could be deemed technically feasible. The BART sources are not required to do that testing.

c) Sodium: The commenter believes sodium is not an issue for SCR deactivation unless condensed water is available in the SCR reactor.

<u>Response</u>: See Response to Comment II.B.1

d) Temperature Variations – The commenter claims that high temperature variations should not preclude HDSCR from being technically feasible.

Response: High temperatures entering an SCR catalyst can quickly deactivate a catalyst through sintering. In order to determine if this problem can be overcome, expensive and lengthy engineering analysis will be required. The BART Guideline states "Alternatively, a demonstration of technical infeasibility may involve a showing that there are unreasonable technical difficulties with applying the control to the source (e.g. size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability and adverse side effects on the rest of the facility)." Until the engineering studies are completed, temperature swings must be a consideration in determining technical feasibility.

e) Catalyst Erosion – The commenter contends that ash erosion is not a concern that has been substantiated.

Response: Catalyst erosion is a significant concern. Ash from North Dakota lignite has different abrasive qualities from other coals. The experience from other coals may not be applicable to North Dakota lignite.

f) Lack of Vendor Guarantees – The commenter claims that both CERAM and Haldor Topsoe have stated that they would offer guarantees for HDSCR.

Response: The commenter is correct that CERAM and Haldor Topsoe initially indicated they would offer guarantees. However, Minnkota has approached these same two companies regarding a guarantee for LDSCR and TESCR which should be less susceptible to catalyst poisoning than HDSCR. Both companies have refused to offer a guarantee for LDSCR or TESCR without pilot testing first (see NO_x Best Available Control Technology Analysis Study – Supplemental Report, November 2009). If these companies will not offer a guarantee for LDSCR or TESCR, it is expected they would not offer one for HDSCR.

The NDDH stands by its determination that HDSCR is not technically feasible for North Dakota lignite at this time.

II.B.2: TESCR and LDSCR are Cost Effective

The commenter indicates both TESCR and LDSCR are cost effective. This comment is based on a few BACT determinations and the National Park Service's database of BART determinations (preliminary and final by the States) that have not been promulgated in an EPA approved SIP. BART determinations are not the same as BACT determinations. For BART determinations, the amount of visibility improvement must be considered. The Department's analysis of LDSCR and TESCR indicate cost effectiveness values above $3,581 per ton and incremental costs at $5,978/ton or greater. The comparison to the NPS database indicated that costs are as high or higher than anything approved for BART. In addition, the amount of visibility improvement is very low (≤ 0.02 deciviews on the most impaired days). The high cost and miniscule visibility improvement dictates that SCR is not BART.

The commenter also indicated there was a lack of transparency regarding the methodology for developing the costs estimates. The cost estimates were developed by engineering consultants who are experienced with SCR design and installation. The estimate provides as much detail as the EPA Air Pollution Control Cost Manual which is recommended by the BART Guideline. The NDDH believes the cost estimates are within the ± 30% accuracy of the Control Cost Manual. Given the very small visibility improvement, the costs are of less importance. The NDDH stands by the estimated costs.

II.B.3: Specific Comments on Each NO_x BART Analysis

A) Lelands Olds Unit 1 - The commenter believes LDSCR is cost effective.

Response: The cost effectiveness of LDSCR ranges from $7,849/ton to $11,313/ton with an incremental cost of $12,489/ton. This is 6-9 times more than the EPA estimated cost of the controls necessary to meet the BART presumptive limits for lignite fired dry bottom wall-fired units. The cost is nearly twice that of most recent BACT determinations for NO_x. The State of Wyoming recently rejected a lower NO_x emission rate (0.043 lb/10^6 Btu) for the Dry Fork plant based on a cost effectiveness of $1,751/ton and an incremental cost of $10,300/ton. The NDDH stands by its determination that LDSCR and TESCR are not cost effective for Leland Olds Unit 1. The NDDH has required Basin Electric to meet an NO_x emission limit that is below the presumptive BART limit.

B) Leland Olds Unit 2 – The commenter believes HDSCR is technically feasible and LDSCR was rejected based on erroneous cost criteria.

Response: Regarding HDSCR technical feasibility, see Response to Comment II.B.1.

The commenter has provided no technical analysis or evidence to show that the cost estimate is erroneous. The NDDH stands by the cost estimate for LDSCR and TESCR.

C) Coal Creek Units 1 and 2 – The commenter states that HDSCR was improperly rejected and the use of 80% control for SCR biased the cost effectiveness to the high side.

Response: Regarding HDSCR technical feasibility, see Response to Comment II.B.1.

The Department has reviewed the EPA Air Pollution Control Cost Manual which states "In practice, SCR systems operate at efficiencies in the range of 70% to 90%. EPA's Air Pollution Control Technology Fact sheet for the selective catalytic reduction (EPA-452F-03-032) states "SCR is capable of NO_x reduction efficiencies in the range of 70% to 90%." The Oregon DEQ hired Eastern Research Group, Inc. (ERG) to review the BART analysis for the PGE Boardman Plant. In their review, ERG stated "With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR of the Boardman Plant under year-round operation would need to be considered in selecting a permit level." The NDDH believes the use of 80% is a reasonable choice for a source that must meet a BART emission limit on a long-term continuous basis. In the ANPR for the Four Corners Power Plant (Federal Register 8/28/09), EPA states "APS estimated that SCR could achieve NO_x control of approximately 90% or greater from the baseline emissions. For new facilities, 90% or greater reduction in NO_x from the SCR can be reasonably expected. See May 2009 White Paper on SCR from Institute of Clean Air Companies. For SCR retrofits on an existing coal-fired power plant, Arizona Department of Environmental Quality (ADEQ) determined that 75% control from SCR (following upstream reductions by LNB) was appropriate for the Coronado Generating Station in Arizona. Based on this data, EPA has determined that an 80% control efficiency for SCR alone, rather than the 90% control assumed by APS, is appropriate."

The Department believes 80% is a reasonable estimate that allows the source to comply with the expected emission limit on a continuous basis.

D) Stanton Station Unit 1 – The commenter believes HDSCR was rejected improperly and a cost effectiveness of $6,475/ton is reasonable.

Response: Regarding the technical feasibility of HDSCR, see Response to Comment II.B.1

Regarding cost effectiveness, see Response to Comment II.B.3(a). The estimated cost effectiveness of $6,475/ton when burning lignite is five times the amount EPA found was cost effective for the presumptive limits for wall-fired lignite units. In addition, the incremental cost when burning lignite is $10,032/ton. This unit will meet the presumptive BART limits for both lignite and subbituminous coal.

E) M.R. Young Station Units 1 and 2 – The commenter states that the NDDH has done no more than is required by law and rolled it into the BART analysis. The commenter also states that HDSCR was rejected erroneously and the cost effectiveness of LDSCR and TESCR are reasonable.

Response: Although the Consent Decree requires the level of emissions that are proposed for BART, the NDDH conducted a BART analysis in accordance with the Five Step BART process. After considering the five factors, SCR was rejected as BART.

Regarding the technical feasibility of HDSCR, see the Response to Comment II.B.1.

With respect to cost effectiveness, see the Response to Comment II.B.3.A. The cost effectiveness of LDSCR and TESCR is three to five times the cost EPA had estimated for cyclone boilers to meet the BART presumptive emission rate. The Department believes these costs are excessive in comparison to EPA's analysis and are very high when compared to recent BACT determinations. However, the NDDH also considered the amount of visibility improvement and the other three factors in making its BART determination. The amount of visibility improvement (≤0.02 deciviews on the most impaired days) when compared to the next most efficient technology is trivial. The NDDH stands by its BART determination.

Comment III: NDDH Has Failed to Include Other Emission Reduction Requirements as Part of Its Long-Term Strategy to Meet Reasonable Progress Requirements which must be Designed to Meet the Goal of Natural Visibility Conditions by 2064.

The commenter indicated the following:

A) BART sources should have been reevaluated under the reasonable progress section of the SIP.
B) North Dakota is not doing its fair share to reduce visibility improvement.
C) SO_2 controls that achieve 98-99% efficiency should have been considered.
D) Costs alone should not eliminate controls on sources under BART.
E) The SIP does not go far enough to ensure that natural visibility conditions are achieved by 2064.

Response:

A) EPA has published guidance for determining Reasonable Progress for regional haze – Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, June 1, 2007. This document states "Also, as noted in Section 4.2, it is not necessary for you to reassess the reasonable progress factors for sources subject to BART for which you have already completed a BART analysis." Section 4.2 states "Since the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in establishing the RPG, it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first RPG planning period." In Section 9.5.1, the NDDH discussed the elimination of the BART sources from the reasonable progress goals analyses. The NDDH concluded that all controls that were reasonable were included as BART. The NDDH stands by this decision.

B) In the North Dakota Class I areas, visibility improvement is mostly due to sulfates and nitrates. The emission control requirements under the SIP will reduce SO_2 emissions by 60% and NO_x emissions by more than 25%. The uniform rate of progress goal for this planning period would only require a 23% (14 years – 60 years) reduction in visibility impairment.

The following table shows the expected change in emissions by 2018 from surrounding States and Canada.

Projected Change in Emissions 2002-2018 (%)					
	South Dakota	**Montana**	**Minnesota**	**Canada**	**North Dakota**
SO_2	-35.7	-11.8	-28.8	-6.8	-60.0
NO_x	-17.9	-26.0	-39.4	-0.8	-25.3
OC	-6.1	-3.3	-5.3	22.7	-19.4
EC	-51.1	-16.6	-28.9	75.2	-52.3
PMF	2.2	7.5	-1.3	34.8	2.0
PMC	5.2	8.8	-4.4	33.8	3.5
NH_3	0.3	1.2	33.9	-31.9	-0.3
VOC	-0.5	-0.6	2.9	-1.2	1.1
CO	-17.0	-15.9	-20.8	-11.7	-27.4

This table clearly shows that North Dakota is doing more to reduce the primary visibility impairing pollutants (SO_2 and NO_x) than the surrounding states. In addition, North Dakota is exceeding the 23% reduction calculated from the URP for this planning period for both SO_2 and NO_x. The NDDH believes that North Dakota is doing more than its fair share to address emissions reductions to reduce regional haze.

C) See Response to Comment II.A.2

D) The BART determinations were based on the five statutory factors which include: 1) cost of compliance, 2) the energy and non-air quality environmental impacts of compliance, 3) any existing air pollution control equipment in use at the source, 4) the remaining useful life of the source, and 5) the amount of visibility improvement expected from the use of the control technology. The NDDH evaluated all five factors and discussed them in the BART determinations. Cost alone was not the single factor that determined BART. For Coal Creek and Stanton Station, non-air environmental issues were a significant issue in the BART determination for NO_x and SO_2 respectively. Visibility improvement was a significant factor for NO_x at Leland Olds Station and M.R. Young Station. Existing control equipment was an important factor for determining BART for particulate matter at each BART source. The BART determinations were not made on cost alone.

Some technologies were obviously not cost effective. EPA addressed this issue in the preamble to the BART Guideline: “The interpretation of the requirements of the regional haze program reflected in the discussion above does not necessitate costly and time-consuming analyses. Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source’s impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible," (F.R. Vol. 70, No. 128, p.39116). The NDDH has taken this streamlined approach where the cost is obviously excessive.

E) The NDDH has included all reasonable control reduction measures in the SIP. The NDDH has shown that if all SO_2 and NO_x emissions in the State were eliminated, the uniform rate of progress for the first planning period could not be met (see Section 8.6.3.3 of SIP). This is because of the huge influence out-of-state sources have on the North Dakota Class I areas, especially Canadian sources. As noted in the SIP (Section 9.7), achieving natural conditions by 2064 is impossible without a new, zero emissions energy source. The Regional Haze SIP demonstrates that North Dakota is doing its fair share to secure reductions that will reduce visibility impairment.

Comment IV: North Dakota Must Also Propose Short-Term Average Emission Limits on SO_2 Emissions in Order to Ensure Protection of the SO_2 Increments of the State's Class I Areas.

The commenter believes that SO_2 increment is exceeded in the Class I areas of North Dakota and that short-term emission limits for SO_2 must be included in the BART permits to protect the increment.

Response: Modeling conducted by the Department (see Documents Relating to a Memorandum of Understanding between the State of North Dakota and the U.S. Environmental Protection Agency Regarding Computer Modeling Protocol for the State's PSD Program) indicates the increment for SO_2 is not exceeded. The NDDH stands by this analysis.

The SIP will reduce SO_2 emissions by nearly 106,000 tons by 2018. This will make actual emissions less than the baseline emissions. Therefore, SO_2 reductions in North Dakota will actually expand the amount of increment available for other new sources. There will be no question that emissions from sources in North Dakota (or surrounding states) do not cause concentrations of sulfur dioxide that exceed the increments.

Comment V: Other General Comments

1) Technical support is necessary to demonstrate that the Painted Canyon Improve Monitor is representative of Elkhorn Ranch Unit and the North Unit of TRNP.

2) The details of the baseline visibility calculations need to be included in the SIP.

3) The analysis of MDU Heskett cannot be putoff and must be included in the Regional Haze SIP.

Response:

1) The choice of the IMPROVE THRO1 monitor site was made by the federal agencies in 1999 when the IMPROVE network was expanded to 108 sites regionally representative of the 156 mandatory federal Class I areas. The existing monitoring site at the Painted

Canyon Overlook in the South Unit was selected to provide regionally representative coverage and data for the three units of Theodore Roosevelt National Park. Site selection followed the criteria in the Improve Particulate Monitoring Network Procedures For Site Selection, February 24, 1999, prepared by the Crocker Nuclear Laboratory of the University of California Davis, the IMPROVE contractor. The criteria included requirements that all areas represented by the site should be within 100 km of a current or potential site, whose elevation lies between the highest and lowest elevations of all areas, with a permitted variance of 100 feet or 10 percent. The site must avoid small valleys, should also avoid local pollution sources or areas with unusual meteorology and avoid nearby obstacles that could affect sample collection. The site also must be accessible for weekly sample change in all but the most severe weather. It was desirable to have existing electrical power available. The existing Painted Canyon Overlook monitoring site met all the criteria in the Procedures for Site Selection including being approximately 80 km away from the northern boundary of the North Unit and 45 km away from the Elkhorn Ranch Unit. The University of California Davis maintains the photographic and written documentation of the THRO1 site.

2) The baseline visibility calculations are taken from the WRAP TSS website. This is noted on p.34 of the SIP. The documentation for the calculations can be found in the 2006 Report for the Western Regional Air Partnership (WRAP) Regional Modeling Center (RMC) on pages 31-32. These pages will be included in an appendix to the SIP.

3) The analysis of the Heskett Station will be included in the Regional Haze SIP as a supplement. The NDDH’s analysis demonstrates that the Heskett Station is exempt from BART requirements and EPA has indicated that they agree with the Department’s determination. The supplement regarding the Heskett Station will be included in the SIP following proper adoption procedures.

Attachments

1. Environmental Groups' Complete Comments

2. EPA's Response on SO_2 Control Technology for the Desert Rock Power Plant BART Determination

3. ADVATECH Brochure

4. EPA response regarding Heskett Station BART Applicability

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RE: Comments on North Dakota's Regional Haze State Implementation Plan

Dear Mr. O'Clair:

On behalf of Dakota Resource Council, National Parks Conservation Association, Dakota Resource Council, Friends of the Boundary Waters Wilderness, Plains Justice, Dakotah Chapter of the Sierra Club, South Dakota Chapter of the Sierra Club, and Voyageurs National Park Association, we respectfully submit the following comments on the Draft North Dakota Regional Haze (RH) State Implementation Plan (SIP). Our organizations represent hundreds of North Dakotans and thousands of people throughout the nation that care deeply about protecting the air quality in our national parks and wilderness areas in the Dakotas and Midwest. We hope and strongly encourage the North Dakota Department of Health (NDDH) to revise its SIP by requiring further reductions in haze causing pollutants and otherwise advancing measures that will improve regional visibility.

For the reason stated herein, North Dakota's regional haze plan is both legally and technically deficient. The regional haze plan fails to require sufficient reductions in visibility impairing pollutants from its major polluting sources and fails to provide a long term strategy that would meet reasonable progress goals. As addressed below, the State can and must achieve much greater emission reductions in haze causing pollution with available control technologies and/or by imposing more stringent emission limits reflective of the best level of continuous emission reduction in its Best Available Retrofit Technology (BART) determinations. In addition, the long-term strategy must ensure appropriate BART requirements and other measures, including consideration of source retirement and replacement, to improve visibility in

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North Dakota and other downwind states' Class I areas to ensure that the SIP will meet its share of the emission reductions needed to meet the reasonable progress goals for the area.

Regional haze results from small particles in the atmosphere that impair a viewer's ability to see long distances, color and geologic formation. While some haze causing particles result from natural processes, most result from anthropogenic sources of pollution. Haze forming pollutants including sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), volatile organic compounds (VOCs), and ammonia (NH_3) contribute directly to haze or form haze after breaking down in the atmosphere. These air pollutants contribute to the deterioration of air quality and reduced visibility in our nation's national parks and wildlife refuges. Visibility impairment is measured in deciviews, which is understood as the perceptible change in visibility. The higher the deciview value is, the worse the impairment.

Through the Clean Air Act (CAA), Congress established "as a national goal the prevention of any future, and remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution." 42 U.S.C. §7491(a)(1). In order to meet this goal, a State is required to design an implementation plan to reduce and ultimately eliminate haze from air pollution sources within its borders that may reasonably be anticipated to cause or contribute to visibility impairment for any protected area located within or beyond that State's boundaries. In creating and implementing the plan the State has an unparalleled opportunity to protect and restore regional air quality by curbing visibility impairing emissions from some of its oldest and most polluting facilities.

Each SIP must provide "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal." 42 U.S.C. § 7491(b)(2). Two of the most critical features of a SIP are requirements for (1) the installation of BART for delineated major stationary sources of pollution and (2) a long-term strategy for making reasonable progress towards the national visibility goal. 42 U.S.C. § 7491(b)(2)(A) & (B).

There are two Class I areas in North Dakota—Theodore Roosevelt National Park and Lostwood National Wildlife Refuge Wilderness Area. Other Class I areas impacted by North Dakota sources of air pollution include: Badlands National Park and Wind Cave National Park in South Dakota, Medicine Lake National Wildlife Refuge Wilderness Area and U.L. Bend National Wildlife Refuge Wilderness Area in Montana, Boundary Waters Canoe Area Wilderness Area and Voyageurs National Park in Minnesota, and Isle Royale National Park and Seney National Wildlife Refuge Wilderness Area in Michigan. These Class I areas preserve the region's inspiring landscapes, rare geologic formations, breathtaking water country, and diverse wildlife and vegetation. They also serve as living museums of our nation's history. Visitors from across the nation and globe are drawn to these lands and their tourist dollars benefit state and local economies.

National parks and wilderness areas are of great natural and cultural value and also engines for sustainable local capital. For example, in 2008, National Park Service units received over 274 million visits accounting for over $2.5 billion in revenue.[1] National parks support $13.3

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[1] *See* http://www.census.gov/compendia/statab/2010/tables/10s1215.pdf, Ex. 1.

billion of local private-sector economic activity and 267,000 private-sector jobs.[2] They also attract businesses and individuals to the local area, resulting in economic growth in areas near parks that is an average of 1 percent per year greater than statewide rates over the past three decades.[3] National parks also generate more than four dollars in value to the public for every tax dollar invested.[4] Of the number of annual park visitors in 2008, approximately 516,804 people journeyed to Theodore Roosevelt National Park spending nearly half a million dollars. The same year 845,734 people visited Badlands National Park; 573,433 visited Wind Cave National Park; 221,585 visited Voyageurs National Park and 14,038 visited Isle Royale National Park.[5]

Excessive emissions from North Dakota not only obscure the region's scenic vistas Congress sought to protect, but also contribute to a host of public health problems as well as adverse impacts to wildlife and vegetation. For example, NO_x and VOCs are precursors to ground level ozone, or smog. Ground level ozone is associated with respiratory diseases, asthma attacks, and decreased lung function.[6] SO_2 pollution contributes to respiratory problems, particularly for children and the elderly, and aggravates existing heart and lung diseases. Exposure to particulate matter, made up of sulfates and nitrates, has been associated with reduced lung function, increased susceptibility to respiratory infections, chronic bronchitis, and premature death.[7] The U.S. Environmental Protection Agency (EPA) has found that in 2015, the Regional Haze Rule also will provide substantial health benefits valued at $8.4 - $9.8 billion annually -- preventing 1,600 premature deaths, 2,200 non-fatal heart attacks, 960 hospital admissions, and over 1 million lost school and work days. The total annual cost will range from 1.4 – 1.5 billion dollars.[8] These benefits are estimated under the assumption that the Regional Haze Rule will be implemented as intended-therefore these numbers may be lower if North Dakota does not revise its plan.

The regional haze program imposes a legal obligation on the State to abate the adverse visibility effects to which its haze causing facilities contribute in order to restore visibility levels to their natural conditions as mandated by the Clean Air Act. To prevent and remedy visibility impairment to the implicated Class I areas, North Dakota can and must revise and substantially improve the draft RH SIP. A strong regional haze program will not only help protect and restore treasured landscapes and the economies that rely on them but also benefit public health. With this in mind, we offer the comments below for consideration by the NDDH and strongly encourage the Department to strengthen its regional haze plan.

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[2] Hardner and Gullison, "The U.S. National Park System, An Economic Asset at Risk" (November 2006) [prepared for the National Parks Conservation Association]. Ex. 2.

[3] Id.

[4] Id.

[5] *See* http://www.nature.nps.gov/stats/index.cfm.

[6] 70 Fed. Reg. 25162, 25169 (May 12, 2005).

[7] U.S. EPA. Air Quality Criteria for Particulate Matter (Final Report, April 1996). U.S. Environmental Protection Agency, Washington, D.C., EPA 600/P-95/001.

[8] EPA, Fact Sheet, *Final Regional Haze Regulations for Protection of Visibility in National Parks and Wilderness Areas* (June 2, 1999) at http://www.epa.gov/visibility/fs_2005_6_15.html, Ex. 3.

In addition, we note that the public comment for North Dakota's SIP was open for 30 days. It is common in other jurisdictions to provide for 45 or 60 day comment period. Given the lengthy history and technical complexity of this SIP, such an abbreviated window is not conducive to a full and fair evaluation by the public. We understand that the EPA has requested states to submit SIPs by January 15, 2010. Understandably, North Dakota would like to abide by this suggested timeline, however, the short turnaround—five business days from the end of the public comment period to the EPA deadline—does not provide NDDH an adequate amount of time to genuinely consider public comments and make needed changes to the SIP. Accordingly, we request NDDH coordinate with EPA to submit the North Dakota SIP in a timely manner without compromising full consideration of public comments.

I. The Clean Air Act and Federal Regulation Require NDDH to Abate Visibility Impairment

In 1977, the Clean Air Act declared "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution[]" where visibility has been determined to be an important value. 42 U.S.C. § 7491(a)(1) &(2). "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities[.]" 42 U.S.C. §7491(g)(3). Congress adopted the visibility protection program to protect the "intrinsic beauty and historical and archeological treasures" of specific public lands.[9] To protect these treasures, the regional haze program establishes a regulatory floor and requires states to design and implement programs at least as stringent as the national floor to curb haze causing emissions located within their jurisdictions. States are required to submit State Implementation Plans or SIPs if they host federally protected areas or the emissions of a facility located within a State "may be reasonably be anticipated to cause or contribute to any impairment of visibility" for a protected area located beyond their borders. 42 U.S.C. §7491 (b)(2).

The SIP must contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal..." including BART requirements for all eligible sources and a long-term strategy for making reasonable progress towards meeting the national goal. 42 U.S.C. §7491(b)(2)(A) &(B).

BART is defined as an emission limitation

> ...**based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility**. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in

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[9] *See* H.R. REP. NO. 95-294, at 203–04 (1977).

> visibility which may reasonably be anticipated to result from the use of such technology.

40 C.F.R. §51.301, emphasis added. BART limits are required for major stationary sources that were in existence on August 7, 1977 and began operating after August 7, 1962 and emit air pollutants that may reasonable be anticipated to cause or contribute to any impairment of visibility is a Class I area. 42 U.S.C. § 7491(b)(2)(A). The term "major stationary source" is defined as sources that have the potential to emit 250 tons or more of any pollutant and fall within one of 26 categories of industrial sources defined by the Act. 42 U.S.C. § 7491(g)(7). A BART-eligible source is one that meets the above criteria and is responsible for an impact on visibility in a Class I area of 0.5 deciview or more. 40 C.F.R. Part 51, Appendix Y. BART must be installed and operated no later than five years after the SIP approval. 40 C.F.R.§51.302(c)(4)(iv).

The SIP must also provide a long-term strategy for achieving reasonable progress toward meeting natural visibility conditions at mandatory Class I areas by 2064. 40 C.F.R. §51.308(d)(1)(i)(B). If a state's reasonable progress goals do not anticipate restoring visibility to natural conditions by 2064 the state must demonstrate why the goal of attaining natural conditions by the established date is unreasonable. 40 C.F.R. §51.308(d)(1)(ii). The SIP must provide for improved visibility on the most impaired days and ensure no degradation in visibility for the least impaired days. 40 C.F.R. §51.308(d)(1)(i)(B). The long-term strategy is typically a 10-15 year plan containing enforceable measures designed to meet regional progress goals. In developing its plan, the State must document the technical basis for the SIP, including monitoring data, modeling, and emission information, including the baseline emission inventory upon which its strategies are based. 40 C.F.R. §51.308(d)(3)(iii).

In developing its long-term strategy, the State must consider all anthropogenic sources of visibility impairment and evaluate different emission reduction strategies beyond those prescribed by the BART provisions. 40 C.F.R §51.308(d). The state should consider "major and minor stationary sources, mobile sources and area sources." Id. At a minimum, the state must consider the following elements:

(A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
(B) Measures to mitigate the impacts of construction activities;
(C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
(D) Source retirement and replacement schedules;
(E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
(F) Enforceability of emission limitations and control measures; and
(G) The anticipated net effect on visibility due to projected changes in point, area, and mobile emissions over the period addressed by the long-term strategy.

40 C.F.R. 51.208(d)(3)(v)(A)-(G).

North Dakota's regional haze plan falls far short of meeting reasonable progress goals. In fact, North Dakotas's draft regional haze plan will only bring the state to, at most, 38% of its 2018 regional progress target at Theodore Roosevelt National Park and even less than that at Lostwood Wilderness Area. Table 8.11 of the draft North Dakota State Implementation Plan (SIP) for Regional Haze. The State appears to be claiming that the national visibility goal of returning to natural visibility conditions by 2064 is unattainable, because the the majority of regional haze pollution comes from sources in Canada and outside the state. Draft North Dakota SIP for Regional Haze at 44-45. While it may be true that some of the pollution responsible for haze in the State's Class I areas is due to sources outside of North Dakota's control, that does not relieve the State from requiring industrial sources within North Dakota to be subject to BART emission limits reflective of the best degree of continuous emission reduction achievable, nor does it relieve the State from adopting other measures to improve visibility in North Dakota and other downwind states' Class I areas.

Furthermore, to ensure that reasonable progress goals are met, North Dakota should actively encourage other states and Canada to reduce emissions impairing visibility in its state and region. State-to-state consultations are part of the regional haze process, and North Dakota is well within its rights to formally request reductions from other states where appropriate. The U.S. EPA, in comments on the FLM version of the draft SIP, suggests that a three-prong approach is appropriate: "NDDH needs to be addressing sources within its control in North Dakota, requesting reductions from contributing states, and asking EPA to address the Canadian emissions."[10] To the extent that North Dakota has not undertaken each of these actions, it should do so. While there are multiple opportunities for North Dakota to pursue to ensure reasonable progress goals are attained, the State may not use emissions from outside sources as a scapegoat to avoid in-state action.

Our review of North Dakota's proposed BART emission limits and controls shows that the State has clearly not required emissions controls and limits that reflect BART for the BART-eligible sources. This is discussed in detail below. Further, the State has not required any source emission reductions or source retirements other than its proposed BART requirements to meet reasonable progress requirements. Regardless of the impacts that other sources outside of North Dakota have on regional haze in North Dakota's Class I area, North Dakota has a responsibility under the federal regional haze requirements to reduce haze causing emissions from its own sources of air emissions to do its part to meet the reasonable progress goals. Under the Long Term Strategy regulations, North Dakota is required to demonstrate that "it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goals for the area" even when other states contribute to visibility impairment in the State's Class I areas. 40 C.F.R. §51.308(d)(3)(ii). Thus, the State cannot shirk its responsibility to address its sources of regional haze pollution by putting the blame on sources outside the state.

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[10] U.S. EPA Region 8 Comments on August 21, 2009 Draft Regional Haze SIP (FLM Consultation Version), Enclosure 1, p. 5.

Further, the State has a responsibility to reduce emissions from North Dakota sources that are reasonably anticipated to impact visibility in other states' Class I areas. Minnesota is one such state, and Minnesota submitted a letter to the North Dakota Department of Health (NDDH) indicating the need for North Dakota electrical generating units to meet an average SO_2 limit of 0.25 lb/MMBtu as well as the need for NO_x emission reductions from North Dakota sources. September 19, 2007 letter from the Minnesota Pollution Control Agency (MPCA) to NDDH and other states (Appendix J.2.1. of the draft North Dakota Regional Haze SIP). NDDH did not agree with these requests and stated that "[a]dditional reductions from Minnesota sources may provide much greater reduction of visibility impacts." August 22, 2008 letter from NDDH to MPCA at 2 (Appendix J.2.2. of the draft North Dakota Regional Haze SIP.)

North Dakota could achieve additional reductions in visibility impairing pollutants from its own sources, but this draft regional haze SIP and BART limits do not require such reductions. As we will show below, North Dakota could achieve much greater emission reductions in haze causing pollution with available control technologies and/or by imposing more stringent emission limits reflective of the best level of continuous emission reduction in its BART determinations.

II. NDDH's Draft BART Determinations are Flawed

A. The SO_2 BART Limits Fail to Reflect the Degree of SO_2 Emission Reduction Achievable with the Best System of Continuous Emission Reductions.

NDDH simply has proposed the EPA's presumptive BART limits as BART at most of the BART-eligible coal-fired electric utility steam generating units (EGUs) that NDDH determined were subject to BART. Specifically, NDDH proposed SO_2 BART limits for Leland Olds Units 1 and 2, Milton R Young Unit 2, and Coal Creek Units 1 and 2 of 0.15 lb/MMBtu or 95% control. While NDDH purported to do a case-by-case evaluation of BART for each EGU, it appears that the case-by-case analyses were simply written to support the imposition of EPA's presumptive BART limits rather than to truly reflect the best level of continuous SO_2 emission reduction at each EGU.

EPA's BART Guidelines include "presumptive BART" emission limits for EGUs which were based on EPA's broad review of the control technologies and emission limits that could be met cost effectively at a wide range of coal-fired power plants. *See* Sections IV.E.4 and 5 of the BART Guidelines in 40 C.F.R. Part 51, Appendix Y. However, it must be stated that EPA's presumptive BART limits do not negate the need for the State to determine BART for each BART-eligible source on a case-by-case basis through a five factor analysis. The regulations and the Clean Air Act require the determination of BART to be source-specific. *See* 40 C.F.R. § 51.308(e)(1)(ii)(A); § 169A(g) of the Clean Air Act.

The five steps of determining BART are:

STEP 1 -- Identify All [fn 12] Available Retrofit Control Technologies,

> STEP 2-- Eliminate Technically Infeasible Options,
> STEP 3-- Evaluate Control Effectiveness of Remaining Control Technologies,
> STEP 4-- Evaluate Impacts and Document the Results, and
> STEP 5 – Evaluate Visibility Impacts.
>
> Fn 12: In identifying "all" options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology – the list is complete if it includes the maximum level of control each technology is capable of achieving.

Section IV.D. of BART Guidelines at 40 C.F.R. Part 51, Appendix Y.

Clearly, EPA's BART Guidelines require an evaluation of the top level of pollution reduction achievable with each control system evaluated in a BART analysis. EPA's BART Guidelines provide that, if a control system can be operated at a wide range of control efficiencies, "the most stringent emissions control level that the technology is capable of achieving" must be evaluated. Section IV.D.3. of the BART Guidelines at 40 C.F.R. Part 51, Appendix Y. The BART Guidelines further require that "[y]ou should consider recent regulatory decisions and performance data (e.g., manufacturer's data, engineering estimates and the experience of other sources) when identifying an emissions performance level or levels to evaluate." *Id.*

The BART Guidelines also provide:

> In assessing the capability of the control alternative, latitude exists to consider special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative. However, you should explain the basis for choosing the alternate level (or range) of control in the BART analysis. Without a showing of differences between the source and other sources that have achieved more stringent emissions limits, you should conclude that the level being achieved by those other sources is representative of the achievable level for the source being analyzed.

Id.

Further, while one can consider varying levels of pollution control in evaluation of a particular control device, one "must consider the most stringent level as one of the control options." *Id.*

NDDH did not follow these guidelines or otherwise meet the intent of the BART requirements because it did not evaluate the most stringent option available for reducing SO_2 from the State's EGUs as is discussed further below.

1. NDDH Cannot Take Into Account Projected Worst Case Sulfur Content of Coal in Setting BART Limits

For all of the coal-fired EGU SO_2 BART determinations, NDDH relied on worst case projections of sulfur content of the coal to be burned in justifying the SO_2 emission limits as BART. For example, for Leland Olds, which currently has an uncontrolled SO_2 rate exiting the boilers of 1.82 to 1.83 lb/MMBtu (2000-2004 average)[11], NDDH assumed an uncontrolled SO_2 emission rate of 3.02 lb/MMBtu[12]. There is no justification for assuming such a high uncontrolled SO_2 emission rate. Similarly, Coal Creek Units 1 and 2 burned coal with a sulfur content of 0.61% during 2003-2004[13], and yet NDDH relied on a worst case coal sulfur content of 1.1%, close to double the 2003-2004 average coal sulfur content, in proposing a BART SO_2 limit.[14]

Milton R. Young Unit 1, which currently has no scrubber, had an uncontrolled SO_2 emission rate exiting the boiler of 1.83 lb/MMBtu (2000-2004 average)[15]. Yet, for Milton R. Young Unit 2, which presumably burned the same coal as Milton R. Young Unit 1, NDDH assumed an uncontrolled SO_2 emission rate of 3.48 lb/MMBtu in proposing BART limits for SO_2.[16] Although NDDH's BART Determination for Unit 1 did not include an uncontrolled SO_2 emission rate, it also appears that NDDH assumed a higher-than-actual SO_2 rate for Unit 1. NDDH assumed 95% SO_2 removal would result in an emission reduction of 20,443 tpy.[17] Yet, the 2000-2004 average SO_2 emissions from Unit 1 were only 20,148 tpy.[18] If actual average emissions were reduced by the projected amount, Unit 1 would be emitting negative amounts of SO_2, which is an impossibility.

This shows that, not only did NDDH improperly rely on the worst case sulfur content coal in proposing BART limits, NDDH also inflated the baseline actual emissions for some EGUs to reflect higher sulfur content coal, and then calculated SO_2 emission reductions based on assumed levels of SO_2 removal from baseline emissions that never actually occurred. Thus, NDDH greatly overstated the emission reductions that would occur from implementation of SO_2 BART controls. Presumably, this was also carried over into NDDH's modeling conducted for the BART analyses as well.

In evaluating SO_2 BART for Stanton Unit 1, NDDH's approach was slightly different but had the same result of artificially inflating the proposed limit. Two scenarios

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[11] See NDDH's BART Determination for Leland Olds at 2-3.

[12] *Id.* at 5.

[13] See NDDH's BART Determination for Coal Creek at 9.

[14] Id.

[15] See NDDH's BART Determination for Milton R. Young at 3.

[16] *Id.* at 24.

[17] *Id.* at 7.

[18] *Id.* at 3.

were evaluated for Stanton Unit 1, burning lignite and burning Powder River Basin, or PRB, coal. While developing a limit for burning lignite, NDDH did not rely on worst case coal. Instead, it used the average of the annual SO_2 emission rate from 2001-2004, applied its assumed SO_2 control factor for each control evaluated, [19] and then, for the proposed limit, increased the calculated controlled emission rate by 33% to arrive at a 30-day average emission limit.[20] While developing an SO_2 emission limit for burning PRB coal, however, NDDH did arbitrarily rely on higher sulfur Powder River Basin coal than currently burned at Stanton Unit 1, *and* NDDH also applied a 33% increase.[21]

The purpose of BART is to reduce emissions from current levels to improve visibility, and that purpose will be ignored if BART limits are determined based on worst case sulfur content coals of the future. As we have seen with Milton R. Young Unit 1, the nonsensical nature of this approach is highlighted when it leads to projected emission reductions that are greater than actual emissions. Because NDDH is proposing BART limits based on 30-day averages, the averaging time can allow the EGU owners to take into account variability in sulfur content of coal and still comply with the limit. Further, retrofitted and upgraded wet scrubbers can achieve much higher levels of SO_2 control than the 95% control assumed by NDDH, as is discussed further below. Thus, if an EGU owner anticipates burning a higher sulfur coal in the future, it can have its scrubber designed to achieve higher levels of SO_2 removal to meet a SO_2 BART emission limit that is set based on the coal currently burned at the EGU. There are also other options that the EGUs could use to address unusually high levels of sulfur in the coal, such as blending with a lower sulfur coal, rejecting high sulfur coal altogether, or coal drying, as has been demonstrated at the Coal Creek facility.[22] Thus, there is no justification to base SO_2 BART limits on the ultimate worst case sulfur content coal to be burned at these units.

2. The Proposed SO_2 BART Limits Fail to Reflect the Degree of SO_2 Reduction Achievable with the Best SO_2 Controls

All but one[23] of NDDH's SO_2 BART determinations requires the use of new or upgraded wet scrubbers, a technology capable of reducing SO_2 emissions by 99% or more. Despite this achievable control efficiency, NDDH simply proposed EPA's presumptive BART limits for SO_2: either 95% control or an emission limit of 0.15 lb/MMBtu. While wet scrubbers can routinely achieve the highest levels of SO_2 control, NDDH's proposed BART emission limits fail to reflect this.

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[19] See NDDH's BART Determination for Stanton Unit #1 at 4.

[20] *Id.* at 8. Note that NDDH did not adequately justify applying a 33% increase to the controlled SO2 emission rate based on annual average uncontrolled SO2 emission rates, as we will discuss further below.

[21] *Id.* at 17, 22.

[22] To the extent that it may be capable of additional reductions of NOx and SO2 above and beyond the proposed technologies, coal drying should have been evaluated as part of the BART determinations as well. http://www.greatriverenergy.com/makingelectricity/dryfining_factsheet.pdf, Ex. 4.

[23] As discussed below, a wet scrubber was not required for Stanton Unit 1.

Wet scrubbers can achieve 99% removal efficiency. A prime example is the Chiyoda CT-121 FGD. Vendor information for this technology indicates that this scrubber has achieved 98-99% SO_2 removal even with low sulfur coal.[24] For example, the Chiyoda's bubbling jet reactor has consistently achieved >99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb SO_2/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis and has consistently exceeded this level of control while treating gases with inlet SO_2 concentrations of 1.78 lb/MMBtu.[25] Based on actual SO_2 emissions data, the North Dakota BART-eligible EGUs have inlet SO_2 concentrations of this level or higher. This technology has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan.[26] It also has been demonstrated in the U.S. at the University of Illinois's Abbott power plant, Georgia Power's Plant Yates[27], Dayton Power & Light's Killen Unit 2,[28] and Plant Bowen Unit 3.[29] It has also been licensed for installation on several additional units in the US, including the other three units at Plant Bowen in Georgia, the other units at Dayton Power & Light's Killen plant, Dayton Power & Light's Stuart plant, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others.[30] Black & Veatch and Southern Company are both U.S. licensees. Further, this technology also has shown to be very effective in removing fine particulates, oxidized and elemental mercury, and acid gases, and the technology uses less energy compared to traditional wet scrubbers.

Further, Mitsubishi, another vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including for coal-fired boilers.[31, 32, 33]

Finally, a Lake Michigan Air Directors Consortium ("LADCO") and the Midwest Regional Planning Organization ("MRPO") presentation indicated that advanced FGD

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[24] *See* Black & Veatch vendor brochure on CT-121, Ex 5.

[25] Yasuhiko Shimogama, Hirokazu Yasuda, Naohiro Kaji, Fumiaki Tanaka, and David K. Harris, Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant, Paper No. 27, presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, Ex. 6.

[26] CT-121 FGD Process – Jet Bubbling Reactor, http://www.bwe.dk/fgd-ct121.html, Ex. 7.

[27] Emission-control Technologies Continue to Clear the Air, Power, May/June 2002.

[28] See Black & Veatch, First Black&Veatch/Chiyoda Wet Flue Gas Desulfurization System in North America Successfully Goes Operational, Ex. 8.

[29] Blankinship, Steve, Go Take a Bath, Power Engineering, October 2008, available at http://pepei.pennnet.com/display_article/342997/6/ARTCL/none/none/1/Go-Take-a-Bath/, Ex. 9.

[30] Chiyoda Licenses Its Flue Gas Desulfurization Technology in USA Newly for 5 Coal-Fired Generation Units, Press Release, May 2, 2005, Ex. 10; Chiyoda Licenses its Flue Gas Desulfurization Process in USA for Georgia Power Owned 4 FGD Units, January 26, 2005, Ex. 11.

[31] Jonas S. Klingspor, Kiyoshi Okazoe, Tetsu Ushiku, and George Munson, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, p.8, Table 4, Ex. 12.

[32] Yoshio Nakayama, Tetsu Ushiku, and Takeo Shinoda, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD, Ex. 13.

[33] Mitsubishi High SO2 Removal Experience, Ex. 14.

technologies could achieve 99.5% control for \$1,240 to \$2,875 per ton of SO_2 removed. Ex. 15. These costs are well within the range that EPA normally considers to be cost effective in best available control technology (BACT) analyses.[34] Further, these costs are also well within the range of what other states have found to be cost effective for SO_2 BART determinations.[35]

3. The Proposed SO_2 BART Limits Should Be Expressed Multiple Ways

Many of the proposed limits are listed either as lb/mmbtu OR as percent removal efficiency. To ensure continuous compliance with "the degree of reduction achievable through the application of the best system of continuous emission reduction" over the range of possible coal sulfur content, all the SO_2 BART limits should be expressed both ways. Without a minimum required removal efficiency, the achievable SO_2 removal efficiency will not be required at lower coal sulfur content.

Further, a maximum cap on emissions should be required. EPA guidance suggests that emission limits be expressed both as a maximum allowable emission rate per unit time (e.g., lb/hr, tons/year) to reflect application of emissions controls at maximum capacity *and* as an instantaneous emission limit (e.g., lb/mmbtu). NSR Manual, pp. B.56, H.5, I.2, I.4. This is good practice for compliance purposes, and also serves as an actual time-based limit for modeling purposes.

4. NDDH's Proposed SO_2 Emission Limits Fail to Reflect BART

Thus far, three general flaws have been noted in the NDDH SO_2 BART determinations: use of worst case coal sulfur content; failure to reflect the actual removal efficiency of wet scrubbers; and failure to express limits in multiple ways. These errors and others noted below on a case-specific basis combine to allow for significantly higher SO_2 emission rates from the EGUs evaluated for BART. Table 1 below highlights this impact.

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[34] \$10,000/ton in 2001, equivalent to over \$13,000/ton today. *See* expert report of Matt Haber - EPA, *Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois*, prepared for the United States in connection with United States v. Illinois Power Company and Dynegy Midwest Generation, Inc., Civil Action 99-883-MJR, in the U.S. District Court for the Southern District of Illinois, April 2002, p. 17, Ex. 16; Memorandum of John S. Seitz to Air Division Directors, BACT and LAER for emissions of nitrogen oxides and volatile organic compounds at Tier 2/Gasoline Sulfur Refinery Projects (Jan. 19, 2001), at 3, Ex. 17.

[35] See National Park Service Spreadsheet "EGUs with Proposed BART SO2 Controls" dated November 13, 2009, Ex. 18.

Table 1: Proposed and Appropriate BART Limits for EGUs Evaluated By NDDH

Facility	Proposed BART	Appropriate BART
Leland Olds Units 1 and 2	95% removal OR 0.15 lb/MMBtu	95 – 99% removal AND 0.03 – 0.091 lb/MMBtu
Milton R. Young Unit 1	95% removal	95 – 99% removal AND 0.035 – 0.094 lb/MMBtu
Milton R. Young Unit 2	95% removal OR 0.15 lb/MMBtu	95 – 99% removal AND 0.035 – 0.094 lb/MMBtu
Coal Creek Units 1 and 2	95% removal OR 0.15 lb/MMBtu	95 – 99% removal AND 0.03 – 0.087 lb/MMBtu
Stanton Unit 1	90% removal OR 0.24 lb/MMBtu	95 – 99% removal AND 0.02 – 0.085 lb/MMBtu

a. Leland Olds

For Leland Olds, NDDH proposed SO_2 BART limits for each unit of either 95% removal of the inlet SO_2 concentration to the scrubber or 0.15 lb/MMBtu on a 30-day average basis based on use of wet scrubbers. The proposed emission limitation of 0.15 lb/MMBtu only reflects 91.8% SO_2 removal at each unit based on the annual average of uncontrolled SO_2 emissions at each unit. Such an SO_2 removal efficiency falls far short of what is achievable with a wet scrubber at the Leland Olds units. A removal efficiency of 95% control reflects the minimum level of SO_2 removal that is achievable with a wet scrubber. Thus, at the minimum, the BART emission limit should be based on 95% removal from the annual average of the uncontrolled SO_2 emissions at each unit - or a limit of 0.091 lb/MMBtu. Because the proposed 95% removal is an alternate and not concurrent limit, the fact that NDDH has also proposed an alternative limit of 95% SO_2 removal will not ensure 95% removal is required until the uncontrolled SO_2 emissions increase significantly, to about 2.8 lb/MMBtu. Thus, it is imperative that the lb/MMBtu limit reflect no less than 95% control off of current coal in order for the BART limit to reflect at least the minimum level of SO_2 control efficiency of a wet scrubber.

Indeed, based on the discussion above regarding the SO_2 removal capabilities of a wet scrubber, a more appropriate BART limit would reflect 98-99% SO_2 removal. Even assuming the worst case uncontrolled SO_2 emissions identified by NDDH of 3.20 lb/MMBtu, 98% removal would reflect an emission limit of 0.064 lb/MMBtu. This SO_2 emission limit based on worst case coal and an achievable level of SO_2 removal would reflect 96.5% SO_2 removal from current coal – a control efficiency that is clearly achievable with a wet scrubber. Ninety-nine percent removal off of worst case coal at Leland Olds would equate to a SO_2 emission limit of 0.03 lb/MMBtu. With current coal, this would reflect 98.4% removal. This emission level and SO_2 removal efficiency has been shown to be achievable and has been achieved in practice.

The attached National Park Service spreadsheet of best available control technology (BACT) determinations for coal-fired power plants shows that BACT limits as high as the 0.15 lb/MMBtu SO_2 BART limits proposed for the Leland Olds units are unheard of. Ex. 19. The proposed permit for the Plant Washington facility requires as part of the facility's BACT limits a 97.5% SO_2 removal efficiency requirement that would apply on a 30-day rolling average regardless of the type of coal burned.[36] This facility may burn Powder River Basin coal or Central Appalachian coal or a combination of the two. The Desert Rock facility, which will burn low sulfur western coal, is subject to an SO_2 BACT limit of 0.060 lb/MMBtu on a 24-hour basis (Ex. 21), and the proposed Toquop (Ex. 22) and Ely Energy Center [37](Ex. 23) permits, both of which would burn Powder River Basin coal, also included BACT limits of 0.06 lb/MMBtu for SO_2. As Ex. 25 shows, there are numerous coal-fired units that are achieving SO_2 emission rates much lower than the 0.15 lb/MMBtu SO_2 BART limit proposed for the Leland Olds Units. The lowest SO_2 emission rates being achieved are at the Pleasant Prairie units which are emitting SO_2 at 0.021 to 0.027 lb/MMBtu with wet scrubbers.

Thus, for all of the reasons discussed above as supported by the attached documentation, BART emission limits of no higher than 0.091 lb/MMBtu and as low as 0.03 lb/MMBtu should have been evaluated as BART for the Leland Olds Units. Such limits should be readily met on a 30-day average basis, especially because higher SO_2 removal efficiencies than represented by this range of more appropriate BART limits could be met with a wet scrubber. There is no justification for increasing the emission rate determined from annual average coal characteristics to arrive at a higher 30-day average emission limit as NDDH has proposed. Thirty day average emission limits are long term average emission limits, and peaks in emissions can be smoothed out with increased SO_2 removal efficiencies and/or use of lower sulfur content coal. In addition to imposing a numerical emission limit, NDDH should also set a minimum control efficiency requirement not as an alternative limit but as a second BART limit, to ensure the achievable SO_2 removal efficiency is required regardless of the type of coal burned.

Thus, the proposed 0.15 lb/MMBtu SO_2 BART limits fall far short of reflecting the best system of continuous emission reduction at the Leland Olds units. In fact, a much more appropriate SO_2 BART limit would be in the range of 0.03 to 0.091 lb/MMBtu, 30-day average, along with an SO_2 removal efficiency requirement of no less than 95% control.

b. Milton R. Young

For Milton R. Young Unit 1, NDDH has proposed use of a wet scrubber and an SO_2 BART limit of a 95% removal efficiency from the inlet SO_2 concentration to the scrubber, to be achieved on a rolling 30-day average basis. For the reasons previously discussed and the documentation attached, 95% control does not reflect best system of continuous emission reduction of SO_2 emissions from Milton R. Young Unit 1. Instead, an SO_2 removal efficiency of 98 to 99% should be achievable with a wet scrubber and the coal to be burned at Milton R. Young Unit 1.

Along with an SO_2 removal requirement, NDDH should also impose an emissions limit. Otherwise, it is difficult for NDDH to project emissions from Milton R. Young Unit 1 for use in air modeling analyses such as PSD increment analyses or for the visibility modeling done for this regional haze SIP and subsequent SIP submissions. Based on the same reasoning provided

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[36] Proposed Plant Washington PSD Permit (Ex. 20) at Condition 2.14.

[37] NV Energy no longer plans to build the Ely Energy Center, and officially withdrew its application to the state Public Utilities Commission in June 2009. See http://www.lvrj.com/news/breaking_news/48923992.html, Ex. 24.

above, the numerical SO_2 BART limit should be based on no less than 95% removal from the current uncontrolled emission rate of 1.88 lb/MMBtu - 0.094 lb/MMBtu. However, as discussed above, higher SO_2 removal efficiencies are achievable. Even using NDDH's worst case uncontrolled SO_2 emission rate for Milton R. Young Unit 1 of 3.48 lb/MMBtu, 98% SO_2 removal would reflect an emissions limit of 0.070 lb/MMBtu. Ninety-nine percent removal would result in an emissions limit of 0.035 lb/MMBtu. As shown in the attachments to this letter, such emission rates have been required as BACT and/or have been met in practice.

Thus, the proposed 95% SO_2 removal efficiency requirement for Milton R. Young Unit 1 falls far short of reflecting the best system of continuous emission reduction at the unit. A much more appropriate SO_2 BART limit would be in the range of 0.035 to 0.094 lb/MMBtu, 30-day average, along with a 95% or higher SO_2 removal efficiency requirement.

Milton R. Young Unit 2 is already equipped with a wet scrubber which, according to NDDH, achieves approximately 65% SO_2 control. NDDH has proposed requiring upgrades to the scrubber to achieve 95% control or meet an SO_2 emission limit of 0.15 lb/MMBtu, 30-day average, as BART for Milton R. Young Unit 2. NDDH found the costs to upgrade the scrubber to 95% control to be quite reasonable. Given the low costs for upgrading the scrubber to achieve 95% removal, it should also be cost effective to require the scrubber to be upgraded to achieve the level of SO_2 control that is achievable with a wet scrubber – up to 98-99% SO_2 removal.

Along with an SO_2 removal requirement, NDDH should also impose an emissions limit as BART for Unit 2. Because the same coal is burned and the same control efficiencies can be expected, the same analysis applies to Unit 2 as that described for Unit 1 above.
Thus, the 95% removal efficiency requirement that would apply to Unit 2 does not satisfy BART. An SO_2 emission limit in the range of 0.035 – 0.094 lb/MMBtu along with a high SO_2 removal efficiency requirement should instead be required as BART for Unit 2.

Such limits should be readily met on a 30-day average basis, especially because higher SO_2 removal efficiencies than represented by this range of more appropriate BART limits could be met with a wet scrubber. There is no justification for increasing the emission rate determined from annual average coal characteristics to arrive at a higher 30-day average emission limit as NDDH has proposed. Thirty day average emission limits are long term average emission limits, and peaks in emissions can be smoothed out with increased SO_2 removal efficiencies and/or use of lower sulfur content coal.

c. Coal Creek

For Coal Creek Units 1 and 2, NDDH proposed SO_2 BART limits for each unit of either 95% removal of the inlet SO_2 concentration to the scrubber or 0.15 lb/MMBtu on a 30-day average basis based on use of wet scrubbers. Assuming each unit achieved 68% SO_2 removal efficiencies as claimed by NDDH, then the uncontrolled SO_2 emissions at the inlet to the scrubber averaged over 2000-2005 ranged from 1.59 to 1.71 lb/MMBtu. The 0.15 lb/MMBtu emission limit only reflects 90.6% to 91.4% SO_2 removal based on the annual average of uncontrolled SO_2 emissions at each unit. Such SO_2 removal efficiencies fall far short of what is achievable with a wet scrubber at the Coal Creek units. A removal efficiency of 95% control reflects the minimum level of SO_2 removal that is achievable with a wet scrubber. Thus, at the minimum, the BART emission limit should be based on 95% removal from the annual average of the uncontrolled SO_2 emissions at each unit - or a limit of 0.080 to 0.087 lb/MMBtu. Because the proposed 95% removal is an alternate and not concurrent limit, the fact that NDDH has also proposed an alternative limit of 95% SO_2 removal will not ensure 95% removal is required until the uncontrolled SO_2 emissions increase significantly, to about 2.8 lb/MMBtu. Thus, it is imperative that the lb/MMBtu limit reflect no less 95% control off of current coal.

Indeed, based on the discussion above regarding the SO_2 removal capabilities of a wet scrubber, a more appropriate BART limit would reflect 98-99% SO_2 removal. Even assuming the worst case uncontrolled SO_2 emissions identified by NDDH of 2.92 lb/MMBtu[38], 98% removal would reflect an emission limit of 0.058 lb/MMBtu. And this SO_2 emission limit based on worst case coal and an achievable level of SO_2 removal would reflect at most 96.6% SO_2 removal from current coal – a control efficiency that is clearly achievable with a wet scrubber. Ninety-nine percent removal off of worst case coal at Coal Creek would equate to a SO_2 emission limit of 0.03 lb/MMBtu. With current coal, this would reflect 98.2% removal. These emission rates and control efficiencies are achievable as evidenced by the previously referenced and attached documentation.

Thus, for all of the reasons discussed above as supported by the attached exhibits, SO_2 emission limits of no higher than 0.087 lb/MMBtu and as low as 0.03 lb/MMBtu should have been evaluated as BART for the Coal Creek Units. Such limits should be readily met on a 30-day average basis, especially because higher SO_2 removal efficiencies than represented by this range of more appropriate BART limits could be met with a wet scrubber. There is no justification for increasing the emission rate determined from annual average coal characteristics to arrive at a higher 30-day average emission limit as NDDH has proposed. Thirty day average emission limits are long term average emission limits, and peaks in emissions can be smoothed out with increased SO_2 removal efficiencies and/or use of lower sulfur content coal. In addition to imposing a numerical emission limit, NDDH should also impose a minimum control efficiency requirement not as an alternative limit but as a second BART limit, to ensure the achievable SO_2 removal efficiency is required regardless of the type of coal burned. Therefore, a SO_2 control efficiency requirement should also be imposed as BART, no less than 95% control.

d. Stanton Unit 1

For Stanton Unit 1, NDDH proposed as BART for SO_2 the use of a spray dryer with a fabric filter and an SO_2 emission limit of 0.24 lb/MMBtu or an SO_2 removal efficiency of 90%, both on a 30-day rolling average basis. This emission limit was derived assuming 90% removal from the highest calendar year average SO_2 emissions of 1.81 lb/MMBtu, increased by 33% to adjust from an annual average to a 30-day average. NDDH has provided absolutely no justification for this 33% increase. Given that the limit is based on the worst year of uncontrolled SO_2 emissions, that the assumed control efficiency of the spray dryer is much lower than what can actually be achieved in practice with a spray dryer, and that Stanton Unit 1 also

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[38] This was calculated from the table of future case emissions rates and the expected control efficiencies of the various options evaluated, Coal Creek BART Determination at 10.

burns Powder River Basin (PRB) coal which has much lower uncontrolled SO_2 emissions, there is no valid justification for NDDH to increase the derived emission rate reflective of 90% control by 33%.

Spray dryers can achieve greater than 90% SO_2 removal. There have been several proposed low sulfur PRB coal-fired power plants that have proposed to use dry scrubbers to meet PSD requirements and that are subject to much lower SO_2 BACT limits than 0.23 lb/MMBtu. Those facilities include the Newmont Nevada TS power plant, the proposed White Pine power plant[39], Toquop, and the Dry Fork power plant. The Newmont Nevada power plant is subject to a minimum 95% SO_2 removal efficiency requirement when burning coal with a sulfur content equal to or greater than 0.45% and is subject to a minimum 91% SO_2 removal efficiency when burning coal with sulfur content less than 0.45%.[40] This facility is currently operating in compliance with its limits. The Newmont Nevada plant is also subject to an SO_2 BACT limit of 0.065 lb/MMBtu when burning coal with less than 0.45% sulfur content. The proposed Toquop permit included an SO_2 BACT limit of 0.06 lb/MMBtu on a 24-hr average basis.[41] The Dry Fork power plant in Wyoming, which is also currently under construction, will burn Powder River Basin coal, will be equipped with a dry scrubber, and is subject to an SO_2 BACT limit of 0.07 lb/MMBtu.[42] Other examples of low SO_2 emission limits and high SO_2 removal rates being required as BACT can be found in the National Park Service's spreadsheet of BACT determinations for coal-fired electrical generating units, Ex. 19.

Regardless of whether NDDH underestimated the effectiveness of a spray dryer, a wet scrubber can remove an even greater amount of SO_2 than a spray dryer. Although NDDH did not find the costs of a wet scrubber at Stanton Unit 1 to be excessive, NDDH discounted the use of a wet scrubber because it determined the increased amount of SO_2 removed would not provide that much of a visibility improvement. The cost effectiveness of the wet scrubber at 95% removal for Stanton Unit 1 was actually quite reasonable at $1,480 per ton of SO_2 removed. Stanton BART Determination at 5. As shown in the National Park Service spreadsheet of BART determinations (Ex. 18), there are several instances where wet scrubbers were required to meet SO_2 BART requirements with similar or even higher costs on a $/ton of SO_2 removed basis, specifically Clay Boswell Unit 3 ($1,640/ton) and Naughton Units 1 ($1,707/ton) and 2 ($1,700/ton). There are also several instances of dry scrubbers being required as BART for SO_2 with even higher cost effectiveness values than $1,480 per ton, including Boardman ($3,053/ton), Martin Drake Units #6 ($2,765/ton) and #7 ($2,276/ton), Dave Johnston Units #3 ($1,848/ton) and #4 ($4,743/ton), and Silver Bay ($7,309/ton), among others. Thus, the cost of a wet scrubber at Stanton Unit 1 is cost effective and is well within the range of the costs required at other similar EGUs to meet BART for SO_2. Given that North Dakota is far from meeting reasonable progress goals in remedying existing visibility impairment, NDDH must require as BART the most effective SO_2 control – especially when it is as cost effective as a wet scrubber would be at Stanton Unit 1.

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[39] In March 2009, LS Power "indefinitely postpone[d]" plans to build the White Pine power plant. http://www.lasvegassun.com/news/2009/mar/05/second-coal-fired-plant-canceled-nevada/, Ex. 26.

[40] *See* Section V.A.2.a.8. of Newmont Nevada Permit, Ex. 27.

[41] *See* Section V.A.2..a.(8) of draft Toquop permit, Ex. 22.

[42] *See* Dry Fork PSD Permit, Ex. 28.

In addition, as discussed above and in the attached exhibits, wet scrubbers can achieve higher than NDDH's assumption of 95% removal, as high as 98-99% SO_2 removal. If a proper SO_2 removal efficiency was taken into account, the cost effectiveness of a wet scrubber at Stanton Unit 1 would be even lower and the benefit to visibility in the affected Class I areas would be even greater.

Because the cost of a wet scrubber at Stanton Unit 1 is cost effective and because a wet scrubber will reduce SO_2 emissions to a much greater extent than a dry scrubber, NDDH must require the use of a wet scrubber as BART for SO_2 at Stanton Unit 1.

Along the same lines as our previous comments, the SO_2 BART limit with a wet scrubber should be no less than 95% removal off of current coal, or an emission limit of 0.085 lb/MMBtu. As previously stated and shown by the attached exhibits, 98-99% SO_2 removal should be achievable with a wet scrubber, which would equate to emission limits of 0.034 lb/MMBtu to 0.02 lb/MMBtu. These emission rates and control efficiencies are achievable as evidenced by the previously referenced and attached documentation.

Thus, for all of the reasons discussed above, a wet scrubber should have been required as BART for Stanton Unit 1. SO_2 emission limits of no higher than 0.085 lb/MMBtu and as low as 0.02 lb/MMBtu should have been evaluated as BART for the Stanton Unit 1. Such limits should be readily met on a 30-day average basis, especially because higher SO_2 removal efficiencies than represented by this range of more appropriate BART limits could be met with a wet scrubber. Thirty day average emission limits are long term average emission limits, and peaks in emissions can be smoothed out with increased SO_2 removal efficiencies and/or with the use of lower sulfur content coal. In addition to imposing a numerical emission limit, NDDH should also set a minimum control efficiency requirement not as an alternative limit but as a second BART limit, to ensure the achievable SO_2 removal efficiency is required regardless of the type of coal burned. This is especially important for Stanton Unit 1 which may burn two different types of coal with different uncontrolled SO_2 emission rates. The minimum control efficiency requirement should be no less than 95% control for a wet scrubber.

5. There Are Other Benefits to NDDH Requiring Stringent SO_2 BART Limits that NDDH Must Take Into Account

Along with providing for improved visibility, there are also other environmental benefits to higher SO_2 removal requirements. Specifically, very low SO_2 emission rates, on the order of single digit parts per million (ppm) concentrations, will be needed for the effective removal of carbon dioxide (CO_2) from the gas stream. Many of the amine-based CO_2 control methods currently under development are very sensitive to sulfur and thus require very low SO_2 inlet concentrations, on the order of 1 to 2 ppm.[43] It will be more cost effective and operationally simpler to design and install controls in one retrofit program.

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[43] Chuck Dene, Lesley A. Baker, and Robert J. Keeth, FGD Performance Capability, Mega 2008, Ex. 29.

It is well recognized that it is not a matter of if but when Congress and/or EPA will mandate CO_2 reductions from industrial sources such as EGUs. Thus, if a more effective SO_2 control technology and more stringent control requirements will better prepare North Dakota's EGUs to be able to effectively remove CO_2 in the future, that must be taken into account in the BART analysis as another environmental benefit of a lower SO_2 emission limit. Indeed, as described above, there are wet scrubber technologies available that can remove 99+% of the SO_2.

Further, lower emissions of SO_2 that are achievable with wet scrubbers also equate to lower $PM_{2.5}$ concentrations since there will be less SO_2 in the air to contribute to sulfate formation. Studies have demonstrated that sulfate addition to sulfate-limited water bodies or wetlands can increase the transformation of mercury to its neurotoxic form, methylmercury.[44] Thus, with lower SO_2 emissions from North Dakota's EGUs, the result should be less sulfate deposition which should decrease methylization of mercury.

All of the above must be taken into account by NDDH in proposing SO_2 BART limits for the State's BART-eligible EGUs. NDDH must require the best designed and most effective SO_2 controls on its BART-eligible EGUs – i.e., wet scrubbers designed to achieve 98-99% SO_2 removal – to meet the regional haze requirements of the Clean Air Act for the State's Class I areas.

B. NO_x BART Comments

The following comments are provided with respect to the proposed NO_x BART levels in the draft RH SIP proposed by NDDH. At the outset, it must be noted that technical issues pertaining to NO_x BART for the various coal-fired electric utility units, which are the major NO_x sources affecting visibility and regional haze in Class I areas in North Dakota and neighboring states, have been under discussion, in one form or another going back to roughly 2006. As such, it is impossible to provide meaningful comments on all aspects of NO_x BART in the allowed 30-day time period for public comment. This is particularly so given that the public comment period (ending January 8, 2010) coincided with major holidays and year end vacation periods, minimizing the ability to fully flesh out important aspects of the proposed BART. As such, the focus of the comments is on the following most important issues:

(a) The erroneous determination that high dust Selective Catalytic Reduction (HDSCR) is technically infeasible at each and any of the coal-fired electric utility units under consideration;
(b) The erroneous determination that tail end or low dust SCR (TESCR or LDSCR) are rejected based on cost ineffectiveness considerations at each and any of the coal-fired utility units under consideration.

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[44] *See, e.g.*, Jeremiason, Jeff D. et al., Sulfate Addition Increases Methylmercury Production in an Experimental Wetland, Environ. Sci. Technol., 2006, 40, 3800-3806 (Ex. 30); See also Krabbenhoft, David P. *et al.*, Unravelling the Complexities Mercury Methylation in the Everglades: The Use of Mesocosms to Test the Effects of "New" Mercury, Sulfate, Phosphate, and Dissolved Organic Carbon, available at http://sofia.usgs.gov/projects/merc_carbon/hgmeso_geer03abs.html, Ex. 31.

The net result of rejection of SCR of any design at the coal fired units is that otherwise large NO_x reductions from these major sources, which could have accrued, and benefitted air quality in North Dakota and neighboring states, will not occur. That this outcome is based on erroneous regulatory and technical reasoning is untenable.

It should be noted that, due to the lack of time, the following issues could not be extensively commented upon. However, they are noted in summary or brief form below. We reserve the right to provide additional comments on these and related topics at a later date:

(a) The process by which North Dakota selected the NO_x sources to be analyzed as part of the SIP.
(b) The process by which certain emission units were selected at sources and source categories which were found to significantly impact visibility, either as part of being BART-eligible sources or under the Reasonable Progress provisions of the applicable regulations.
(c) The lack of technical basis for the assumed control efficiencies in most of the NO_x control options. For example, in the case of SCR, efficiencies of 80% or 90% or 93% are variously assumed, without basis or consistency.
(d) The lack of any support whatsoever for the level of cost-effectiveness which appears to be the basis for rejection of technologies (such as TESCR and LDSCR) on cost-ineffectiveness grounds. Nothing in the EPA guidelines for BART determinations established a bright-line cap on the cost-effectiveness expressed on \$/ton reduced grounds. References to EPA's presumptive limits (\$1,300/ton reduced) as a cap in this regard is fatally flawed. Numerous BART determinations in other states RH SIPs have accepted NO_x controls at levels higher than this level.[45]
(e) The improper use of incremental cost-effectiveness, as a tool to reject technologies (such as TESCR and HDSCR) which are otherwise cost-effective, even under the flawed and worst-case analyses presented by the utilities (and accepted by the State). EPA has noted the error in relying on this metric in its comments. However, such direct and express criticism seems to have had no effect in ND's analysis and proposal.
(f) The lack of discussion and analysis of cost-effectiveness expressed in terms of \$/dv improved. This metric, clearly relevant in this regard, will allow comparisons of cost-effectiveness for North Dakota sources with those from other sources in other states subject to RH NO_x reductions.
(g) The lack of explicit discussion of how each of the 5 statutory factors was used or weighed in the BART determinations.
(h) The lack of support for how details such as the BART limits themselves were arrived at in terms of their averaging time. In other words, why shorter averaging times (such as 7-day or 24-hour averages) were not considered – especially given that visibility impacts can occur on short durations.
(i) The exception accorded to startup and shutdown periods, even though 30-day averaging time periods are used for the recommended BART limits. This is without technical and regulatory basis.

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[45] See National Park Service Spreadsheet "EGUs with Proposed BART NOx Controls" dated November 13, 2009, Ex. 32.

Finally, it should be noted that there was insufficient time to properly critique NO_x BART for the other NO_x sources (other than the utility boilers).

1. High Dust SCR (HDSCR) is Technically Feasible

As noted earlier, the applicability of SCR as NO_x control – universally agreed to by all parties as being the technology with the highest degree of NO_x reduction potential (upwards of 90%, after consideration of in-boiler NO_x controls such as low NO_x burners or over-fire air etc.) – has been the subject of technical discussion in North Dakota since at least 2006. Not only were such discussions central to the consent decree implementation at the Milton R. Young units, but they were also part of the initial BART submittals of the various affected companies.

It appears that after opposing any type of SCR (high dust, tail end or low dust) for years on technical infeasiblity grounds, the State of North Dakota finally revised its position recently that tailend and low dust SCR were technically feasible after all. While this is a positive shift, we believe that the State has not provided a technical or regulatory basis for continuing to reject the even most promising (and likely more cost-effective) option that HDSCR is also technically feasible.

Since the State's position regarding HDSCR is the same in the case of any of the BART analyses (see Appendix B.5), comments on this aspect are provided in general, without particular reference to specific units. It should be noted that the State's position is an amalgam of all of the arguments that have been pushed consistently by the affected units, their owners, their technical consultants (Burns and MacDonnell, Sargent and Lundy, and others) with regards to SCR for the last many years.

The central issue seems to be the use (or lack of use) of technical judgment on the part of the State. An important secondary issue seems to be the State's rejection of technical arguments and support from a most important source – namely the vendors of SCR catalysts themselves.

The State's technical infeasibility rejection of HDSCR boils down to a circular argument. Basically, the State has taken the following position:

(a) that each of the boilers at issue burns some form of North Dakota lignite coal (either exclusively or in combination with other fuels such as Powder River Basin (PRB) sub-bituminous coal);
(b) that North Dakota lignite is both unique and highly variable in its properties – such as heating value, ash content, sodium content, sulfur content, moisture content, etc. In fact, in the State's view, it is so unique that there are no other similar or comparable aspects to any other lignites or brown coals anywhere in the world nor any other fuels such as biomass or wood;
(c) that HDSCR has not been applied at any North Dakota lignite fired units (which are only used in North Dakota utility units) to date (with the one, flawed exception at Coyote back many years ago, which will be discussed shortly);

(d) that since HDSCR has not been applied at any North Dakota lignite fired units successfully and for many years, there is no basis to conclude that it can be used successfully.

The circular argument is obvious. NDDH basically wants proof that HDSCR will work successfully before allowing HDSCR to be implemented – yet it demands that this proof be obtained from the very universe of sources (and only those) which are the subject of its analysis. This is akin to saying that a control technology will not work at a particular facility because it has not been tried there yet.

It is not unusual for "new" technologies to be faced with such first-time applicability challenges in a particular source category. Of course, HDSCR is not "new" in any traditional sense - it has been demonstrated successfully in other, closely related source types. In fact, implementation of BART[46] relies on the fact that emissions reductions will often accrue from first-time application of "new" technologies to various source categories. Otherwise the inherent "technology-forcing" aspect of BACT and BART would not be realized.

There is no debate that HDSCR has been successfully to all boiler types in other coal-fired applications including bituminous coals, sub-bituminous coals, other lignites, brown coals, biomass, and combinations of these fuels. There is also no debate that HDSCR has been successfully applied to all of the boiler technologies at issue here – namely cyclone, tangential fired and wall fired boilers.

Thus, the only issue is whether, in light of its widespread and continued successful use in closely related sources types such as other coal-fired applications, HDSCR can be successfully "transferred" to North Dakota lignite fired units that are either cyclone or tangential fired or wall fired (which is the universe at issue at the present time)? We believe that the overwhelming evidence in the record suggests that the answer to this question is Yes.

Typically, first-time applicability is the result of careful and proper technical consideration by the regulatory agency of the following:

(a) reliance on technology-transfer from other similar sources, broadly construed;
(b) proper reliance on pilot tests, if such tests were properly designed and conducted;
(c) reliance on key technology suppliers such as vendors, who bear the risk of failure – commercially, and reputationally; and
(d) fundamental assessment of the likely risk factors that may make the technology a failure.

Of course there will be risks inherent in the first-time application of any technology (new or old) to a new source category. We do not believe that demanding zero-risk as a pre-requisite is proper. Yet, we believe that this is exactly what North Dakota seems to want in its circular argument discussed above.

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[46] We note that implementation of BART can and should necessarily encompass a review of relevant BACT analysis.

We believe that North Dakota has improperly disregarded key aspects of the above considerations, in particular the rejection of explicit assurances from at least two experienced and reputable SCR catalyst vendors, as far back at 2007/2008, that HDSCR could be installed at the units at issue. Substituting its own judgment in place of such vendors was improper. Relying only on industry-funded researchers, engineering companies and consultants (who are not technology providers) is also improper.

Basically, for the last 4 years, and in spite of much evidence to the contrary, North Dakota has chosen to disregard the plain fact that HDSCR can be successfully applied to each and every unit at issue. Of course, such application will require case-by-case design and analysis. Of course, such application will inherently involve some technical risk. To the extent that such risks can be mitigated by coupon tests, or pilot tests, these should be conducted either at the units or at vendor locations. That each utility was vehemently opposed to any such tests, relying on false regulatory arguments that these somehow violate how BART is determined, underscores the outcome-determinative nature of the present proposed analysis. The fact is that BART allows for technology transfer. We know of no successful technology transfer that is not preceded by prudent engineering judgment, supported by appropriate testing. Thus, excluding the possibility of any such type of testing equates to reading-out technology transfer from the definition of BART – which directly contradicts EPA guidance and Congressional intent.

Below, we provide some comments on key technical concerns raised by the State in attempting to support its position that HDSCR is not technically feasible.

a. Variability of Fuel Composition

The State notes that North Dakota lignites (or lignite from a particular mine, such as the Center Mine, the source of the Milton R. Young units) are highly variable in heat and ash content and in the constituents that make ash, and that such variability will affect SCR design and operation. While this may be true, it is true of all coals, worldwide. We know of no coal-fired boiler designer/operator or SCR designer/operator who does not face fuel variability. However, such variability is no reason to conclude that HDSCR will be precluded from successful application. In fact, designers routinely factor in such variability such that equipment can operate over a wide range of variability. Thus, it is a matter of proper design, anticipating such variability, which is required by a case-by-case analysis. Frankly, pointing to such variability as a reason for technical infeasibility of HDSCR shows the weakness of the State's argument.

b. Results of the Coyote Pilot Testing

The State correctly states that "the only pilot testing that has ever been conducted on a unit firing North Dakota lignite was at the Coyote stations. The pilot scale SCR was plugged after 2 months and little useful data was obtained." In fact, the failure of the Coyote stations test is noted as a central point in the State's determination that HDSCR cannot be successful. Yet, in key respects, the State intentionally or otherwise misrepresents these tests and their conclusions. This is puzzling because the State correctly notes that "the pilot testing....in hind-sight, was ill-designed for a unit combusting North Dakota lignite..." In fact, it is undisputed that this test was poorly designed and executed for the following reasons:

(a) The catalyst used at the Coyote station test was previously used at the Baldwin station. While it was supposedly cleaned between tests, the nature of such cleaning and its effectiveness are unknown. It is more than likely that the catalyst was impaired before tests even began at Coyote station. At any rate, it is undisputed that it was not new or fresh catalyst;

(b) The catalyst design was improper with regard to pitch, measure of cell spacing that influences gas flow and ash deposit. That resulted in rapid plugging in a short amount of time. As a result, no deactivation data were obtained. There is no support whatsoever that this type of catalyst or the same pitch would be proper or be used in any of the HDSCRs at issue. Improperly disregarding the specific aspects of why these tests failed but continuing to make general statements, is the very definition of poor judgment.

Just on this basis alone, the Coyote station "tests" and any conclusions therefrom should be rejected. It is a simple data validation issue. In particular, any conclusions relating to catalyst blinding or plugging etc., which depend on catalyst geometry, from these flawed tests, should definitely be rejected. Knowing these flaws and purposely choosing to ignore them while relying on these tests points to poor technical judgment on the part of the State.

In fact, as the State well knows, the prior Baldwin tests also concluded that HDSCR would not work for those cyclone boilers. Yet, after proper evaluation, the Baldwin station proceeded to install HDSCR and such units have been operating successfully, now for many years. This provides further support for rejection of the Coyote tests.

Finally, several of the SCR and catalyst vendors (Alstom, Babcock Power, CERAM, Halder-Topsoe), who were aware of the Coyote tests, were still willing to provided proper guarantees for HDSCR. The State chose to disregard this.

To the extent that the State is worried about popcorn ash plugging, these issues have been widely and successfully addressed in numerous other HDSCR installations using simple technologies such as ash removal systems (e.g. mechanical screens).

c. Sodium

The State notes that the combustion of North Dakota lignite produces or can produce soluble sodium compounds, which cause more severe catalyst deactivation than insoluble sodium compounds. However, the State fails to show how, under the actual operating temperatures in a HDSCR location, such compounds can penetrate or deposit on the catalyst and if they did so, why they could not be addressed by mitigation measures such as washing (since they are soluble). At least one of the catalyst vendor has noted that "sodium is not a poison to catalyst at SCR operating temperatures..." The critical issue is not whether, as a general matter, sodium can cause deactivation, but whether, under actual operating conditions, it would do so. Without factoring in the operating temperatures, such a statement or concern is meaningless. Since, at the expected operating temperatures, such sodium compounds will generally not condense, this mechanism is speculative and unlikely. At under conditions where such condensation is an issue (such as during shutdown), proper design such as by-pass, can be used. Finally, even if some condensation occurred, it can be mitigated using water washing.

d. Temperature Variations

In some units (such as the Milton Young cyclone unit), the State is concerned that the temperature variation of the flue gas entering a HDSCR will adversely affect its performance. We note that this, again, is a matter of proper design and evaluation. Why there are such large temperature variations and what is causing them are legitimate design issues that need to be resolved on a case-by-case basis. Perhaps additional boiler changes in the backpass, air preheater, or economizer may be needed. But the need for such changes does not eliminate HDSCR. No regulation or guidance contemplates that application of air pollution control technology would be so seamless as to preclude any other changes to the emissions source. To provide this argument in support for technical infeasibility for HDSCR has no merit.

e. Catalyst Erosion

The State is concerned that HDSCR catalysts can erode and that there are "unresolved issues regarding catalyst erosion…." Notwithstanding that all SCR catalysts erode to some extent and that this is accounted for as part of the design of any SCR, the State's position is not substantiated by any data. SCRs have been exposed to bituminous coal combustion ash as high as 40%. Ash contents in coal comparable to that of North Dakota lignite have used SCR for many years.

f. Lack of Vendor Guarantees

The Department states that "vendors cannot without further pilot testing, guarantee SCR system performance for M.R. Young Station boilers firing North Dakota lignite." This statement is simply incorrect as both CERAM and Haldor Topsoe clearly stated, way back in 2007 and 2008, that they would be willing to offer industry standard guarantees for an HDSCR system installed at the Milton R. Young Station, which includes a cyclone boiler. The guarantees that were offered were consistent with those that are typical in the utility industry (i.e., up to contract value), in spite of claims to the contrary by the State and consultants to the utility companies. Making an issue of guarantees in the face of explicit guarantees already being offered by the actual catalyst suppliers underscores the nature and weakness of the State's argument against HDSCR.

In summary, we believe that it is grossly erroneous to conclude the HDSCRs are technically infeasible for any of the utility boilers that are at issue in the RH SIP. For this reason alone, the draft SIP and all of the NO_x limits proposed as BART are flawed and the analysis needs to be redone. In redoing the analysis, the following approach should be followed:

(a) Request engineering quotes for HDSCR systems from experienced SCR and catalyst vendors, capturing up-to-date developments in catalyst design and mitigation strategies for the potential problems that may arise in installation. Determine a range of HDSCR control effectiveness values and associated costs, as appropriate for each unit;

(b) Do the above in a public process so that the problematic and procedural issues inherent in the prior process (in which vendors were essentially brow-beaten by industry consultants) when vendors were contacted, are avoided. Involve U.S. EPA, the National Park Service, and other relevant regulatory agencies in this process;
(c) Lay out clear guidelines for the cost-effectiveness criteria that will be used in a comparison of cost effectiveness of HDSCR. At a minimum, this should include the absolute cost effectiveness expressed as \$/ton NO_x reduced and \$/deciview of visibility improvement (considering all of the unit's impacts at all affected Class I areas). Secondarily, this can include considerations of incremental cost-effectiveness. However, incremental cost-effectiveness is a secondary and not a primary criterion. These guidelines should be clearly stated independently of the HDSCR analysis and should be supported. Some comments on this aspect are provided later.
(d) Conclude whether HDSCR is cost-effective at each unit and therefore whether it is BART or not.

2. TESCR and LDSCR Are Cost Effective.

As noted above, in rejecting HDSCR, we believe that the State has fatally compromised its NO_x BART analysis and, therefore, the analysis should be redone.

Separately from that, although the State did require that TESCR and LDSCR be considered since they are technically feasible (after incorrectly arguing that they are not for years), these technologies were rejected on cost-effectiveness grounds. We believe that this rejection was in error for the following reasons:

(a) A lack of transparency of how the costs were developed. In no case were detailed cost-estimates provided in the record, along with the associated design of the SCRs. Rather, gross values of SCR in \$/kW terms were assumed along with numerous other assumptions, stated and unstated. Without this information, there is insufficient data for analysis of cost effectiveness by the public or any agency. The SIP should be considered incomplete without this information. Thus, the cost figures arrived at (and the associated control efficiencies) are unreliable and are assumed to be higher than actual.
(b) An incorrect reliance on incremental cost-effectiveness as the metric for cost effectiveness;
(c) A lack of stated and defensible cost-effectiveness metrics by the State.

We believe that higher values of total (not incremental) cost-effectiveness are appropriate. Higher measures of cost-effectiveness than those used by the State have been used in both BART analyses and rule-making instances, over \$10,000/ton in some instances.[47] As

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[47] See National Park Service Spreadsheet "EGUs with Proposed BART NOx Controls" and "EGUs with Proposed BART SO2 Controls" dated November 13, 2009, Ex. 32 and Ex. 18, demonstrating BART determinations at cost effectiveness up to \$7,309/ton (SO2) and \$3,778/ton (NOx); \$10,000/ton was determined to be cost effective for BACT in 2001, equivalent to over \$13,000/ton today. *See* expert report of Matt Haber - EPA, *Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois*, prepared for the United States in connection with United States v. Illinois Power Company and Dynegy Midwest Generation, Inc., Civil Action 99-883-MJR, in the U.S. District Court for the Southern District of Illinois, April 2002, p. 17, Ex. 16; Memorandum of John S. Seitz

noted by EPA itself in its comments in the present instance, there is no justification to limit the cost-effectiveness to just those values considered in the examples of presumptive-BART, as has been done by the utilities and the State.

Considering a higher range of cost-effectiveness, the application of TESCR and/or LDSCR is cost-effective in many cases in the instances where considered. This is in spite of the lack of transparency in the costs themselves as noted above. In other cases where it is not cost-effective at this metric, we stand by our comment on the lack of transparency. We also note that at this level of cost-effectiveness, other NO_x control technologies that were incorrectly rejected (such as SNCR) are also cost-effective.

Thus, there is no justification for rejecting TESCR or LDSCR as NO_x BART. Therefore, the proposed BART limits are flawed and the analysis should be rejected.

3. Specific Comments on Each NO_x BART Analysis

Our additional comments on the seven specific BART utility boilers NO_x BART analyses are noted below. However, these are not extensive in view of the lack of time provided for public comment. The brevity of these comments should not be interpreted as an indicator of agreement with the analyses or the conclusions presented in the proposed RH SIP. As such, we stand by comments made by others including the U.S. EPA in specific instances, particularly as related to the incorrect assumptions in the design and cost analyses present by industry consultants including Sargent and Lundy.

Basin Electric Power Cooperative Leland Olds Station Unit 1 - This unit is a wall-fired pulverized coal boiler combusting primarily lignite coal (80-100%) and PRB subbituminous coal (20-0%). The existing nitrogen oxides control equipment is low NO_x burners installed in 1995. The BART selected by the State is a limit of 0.19 pounds per million Btu of heat input on a 30-day rolling average basis. This limit is to be achieved by the installation of selective noncatalytic reduction (SNCR) and basic separated overfire air (SOFA). We believe that these technologies do not constitute BART and that HDSCR was improperly rejected in the analysis. We also believe that LDSCR with reheat that was considered in the analysis was improperly rejected given that its cost-effectiveness, as calculated with non-transparent cost data, was in line with the range of other cost-effectiveness decisions.

Basin Electric Power Cooperative Leland Olds Station Unit 2 - This unit is a cyclone boiler combusting primarily lignite coal (80-100%) and PRB subbituminous coal (20-0%). The unit has no existing nitrogen oxides control equipment. The BART selected by the State is a limit of 0.35 pounds per million Btu of heat input on a 30-day rolling average basis. This limit is to be achieved by the installation of selective noncatalytic reduction (SNCR) and advanced separated overfire air (ASOFA). We believe that these technologies do not constitute BART and that HDSCR was improperly rejected in the analysis. As noted above for Unit 1 for this station, LDSCR was improperly rejected as BART based on erroneous cost criteria.

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to Air Division Directors, BACT and LAER for emissions of nitrogen oxides and volatile organic compounds at Tier 2/Gasoline Sulfur Refinery Projects (Jan. 19, 2001), at 3, Ex. 17.

Great River Energy Coal Creek Station Unit 1 and Unit 2 - Unit 1 and Unit 2 are identical tangentially-fired pulverized coal boilers combusting lignite coal. The existing nitrogen oxides control equipment is low NO_x burners (LNB) and separated overfire air (SOFA). The BART selected by the Department for each unit is a limit of 0.17 pounds per million Btu of heat input on a 30-day rolling average basis. This limit is to be achieved by the use of the existing low NO_x burners (LNB) and modified/additional separated overfire air (SOFA). We believe that these technologies do not constitute BART and that HDSCR was improperly rejected in the analysis. We also believe that an improper value (80%) was used as the control efficiency for LDSCR, resulting in an erroneously high cost-effectiveness for LDSCR.

Great River Energy Stanton Station Unit 1 - Unit 1 is a wall-fired pulverized coal boiler combusting PRB subbituminous coal and lignite coal. The existing nitrogen oxides control equipment is low NO_x burners. The BART selected by the State is a limit of 0.29 pounds per million Btu of heat input on a 30-day rolling average basis when burning only lignite coal, a limit of 0.23 pounds per million Btu of heat input on a 30-day rolling average basis when burning subbituminous coal, and a weighted average emission limit when burning a combination of lignite and subbituminous coal. These limits are to be achieved by the installation of low NO_x burners (LNB), overfire air (OFA), and selective noncatalytic reduction (SNCR). We believe that these technologies do not constitute BART and that HDSCR was improperly rejected in the analysis. We also believe that LDSCR, which was considered technically feasible, was improperly rejected given its cost-effectiveness of $6,475 is in the range of appropriate cost-effectiveness values.

Minnkota Power Cooperative Milton R. Young Station Unit 1 and Unit 2 - Unit 1 and Unit 2 are both cyclone boilers burning lignite coal. The units have no existing nitrogen oxides control equipment. The BART selected by the State for Unit 1 is a limit of 0.36 pounds per million Btu of heat input on a 30-day rolling average basis and for Unit 2 is a limit of 0.35 pounds per million Btu of heat input on a 30-day rolling average basis. These limits will be achieved by the installation of selective noncatalytic reduction (SNCR) and advanced separated overfire air (ASOFA). These technologies and the limits contained in the draft SIP are identical to the provisions in the consent decree. The State has done nothing more than take what has already been required by law and rolled that into the BART analysis. We believe that this does not constitute an adequate BART analysis.

Specifically, we believe that the selected technologies do not constitute BART and that HDSCR was improperly rejected in the analysis. We also believe that LDSCR and TESCR, which were considered technically feasible, were improperly rejected given cost-effectiveness values of $3,906/$5,591 (LDSCR) and $4,835/$6,266 (TESCR) for Unit 1 and $4291/$6382 (LDSCR) and $4,948/$7081 (TESCR) for Unit 2 are in the range of appropriate cost-effectiveness values.

II. NDDH Has Failed to Include Other Emission Reduction Requirements as Part of Its Long Term Strategy to Meet Reasonable Progress Requirements Which Must Be Designed to Meet the Goal of Natural Visibility Conditions by 2064

Although NDDH evaluated additional controls at Antelope Valley Units 1 and 2, Coyote Station, the Great Plains SynFuel Plant, and the Tioga Gas Plant, NDDH did not ultimately propose any additional emission reductions as part of its long term strategy to meet reasonable progress goals. NDDH placed heavy focus on these additional controls based on costs, and NDDH discounted all additional controls at these facilities due to its determination of a limited visibility benefit to be gained from the controls. Draft North Dakota SIP for Regional Haze at 185.

NDDH has not adequately met the regional haze requirements of developing a long term strategy to show how it would meet reasonable progress goals to attain natural visibility conditions by 2064, as required by 40 C.F.R. §51.308(d)(1) and (d)(3). First, NDDH should not have limited its analysis of additional measures to provide for reasonable progress to facilities not already controlled by BART. As shown above, NDDH's proposed BART emission limits and requirements do not reflect the maximum emission reductions that could be achieved at the State's EGUs. For those controls or more stringent control efficiencies that NDDH determines are not required to meet BART, NDDH must still evaluate use of those control technologies and/or methods as part of its long term strategy to meet reasonable progress goals. For example, if NDDH determined SCR is not BART for an EGU, it could still require SCR at that EGU to meet reasonable progress requirements. Further, NDDH also excluded the Heskett EGU from evaluation of long term strategy requirements. While NDDH postponed a determination of whether Heskett was subject to BART, that should not exclude the unit from evaluation of pollution controls as part of the State's long term strategy.

Second, in evaluating additional control measures to meet the national visibility goal, NDDH should not just place emphasis on the benefit to visibility achieved by the reductions at each emissions unit. Instead, NDDH should evaluate the cumulative effective of the State's strategy to meet reasonable progress goals to attain natural visibility conditions by 2064. 40 C.F.R. §51.308(d)(3)(iv)(G).

Further, 40 C.F.R. §51.302(d)(3)(ii) provides:

> Where other States cause or contribute to impairment in a mandatory Class I Federal area, *the State must demonstrate that it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area.*

[Emphasis added.]

Thus, NDDH must evaluate all available measure to reduce North Dakota's share of visibility impairing pollution as part of its long term strategy. Such available measures include emission reduction programs, imposition of emission limitations, and source retirement and replacements.

NDDH did not evaluate the potential for any EGU retirements in its draft regional haze SIP. Given the age of the State's coal-fired EGUs along with the fact that North Dakota's draft SIP falls far short of meeting reasonable progress goals for regional haze, NDDH must consider EGU retirements to meet reasonable progress goals as part of its long term strategy.

For the sources for which NDDH did evaluate controls, it did not evaluate the most stringent levels of control achievable. For example, for Antelope Valley Units 1 and 2, NDDH only evaluated a wet scrubber that could achieve 95% SO_2 removal even though, as we have shown above, wet scrubbers can achieve 98-99% SO_2 removal. Further, NDDH did not conduct any modeling to show the visibility improvement from use of a wet scrubber at the Antelope Valley units because it found the costs to be too high. As shown in the National Park Service SO_2 BART Summary spreadsheet (Ex. 11), the costs of wet scrubbers at Antelope Valley Units 1 and 2 ($5,899-$6,780/ton) are not out of the range of SO_2 BART control costs. A new wet scrubber at the Coyote Station is quite cost effective at $2,593/ton.

Even if the costs were more than previously required as BART, that should not be a reason alone to discount use of a control technology. This is especially true with North Dakota's regional haze SIP which fails to meet the uniform rate of progress necessary to attain natural visibility conditions by 2064. Further, given the fact that North Dakota sources cause and contribute to visibility impairment in other states, it is imperative that NDDH include all emission reduction measures in its long term strategy to meet reasonable progress goals. While it is true there will be costs to reducing visibility impairing pollution from North Dakota sources, such costs do not allow North Dakota to ignore the national visibility goal of the Clean Air Act and the requirements for regional haze SIPs. Thus, cost of controls alone should not be a determining factor in evaluating additional emission reduction options in the State's long term strategy. Accordingly, NDDH should evaluate the use of SCR at units such as Antelope Valley and Coyote, as well as at those EGUs for which NDDH determines SCR is not BART, for inclusion in its long term strategy.

In summary, North Dakota's draft SIP for regional haze fails to include adequate reasonable progress goals and fails to include an adequate long term strategy to meet reasonable progress goals. While North Dakota's proposed BART determinations will greatly reduce SO_2 emissions and, to a lesser extent, NO_x emissions from the State's BART-eligible EGUs, the State's plan does not go far enough to ensure that North Dakota's Class I areas and the Class I areas in other states that are impacted by North Dakota sources will achieve natural visibility conditions by 2064. Thus, North Dakota must adopt additional measures or requirements, including consideration of source retirements, as part of its long term strategy to achieve reasonable progress toward the national visibility goal.

III. North Dakota Must Also Propose Short Term Average Emission Limits on SO_2 Emissions in Order to Ensure Protection of the SO_2 Increments of the State's Class I Areas

The SO_2 emission reductions that North Dakota has proposed as BART for the State's BART-eligible EGUs should greatly help the State address the SO_2 increment violations that have been occurring at the North Dakota Class I areas.[48] And we recently learned that the State

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[48] See 5/24/99 North Dakota Class I Area Calpuff Analysis; see also 5/8/03 EPA Dispersion Modeling Analysis.

has issued a draft plan for updating and evaluating a new modeling protocol and that the State plans on conducting a new periodic assessment of increment consumption in the near future.[49] However, in order for the State to be able to count on the SO_2 emission reductions proposed to meet BART in its new periodic assessment of SO_2 increment consumption or in other increment modeling analyses (such as those conducted for PSD permits), NDDH must propose for public comment short term average emission limits in addition to the 30-day average BART emission limits for the State's EGUs that are installing pollution controls. A long term average limit does not ensure 3-hour average or 24-hour average emissions will be reduced to the same levels, especially given that NDDH's proposed SO_2 BART limits are based on worst case sulfur content assumptions that are not reflective of the coal the units are currently burning.

The visibility protection program falls under the same part of the Clean Air Act that the increments do – that is, the prevention of significant deterioration program of Part C of the Clean Air Act. One of the mandates of the prevention of significant deterioration program is to preserve, protect, and enhance the air quality in national parks and wilderness Class I areas. CAA §160(2). For Class I areas, the Clean Air Act provides protection for Class I areas by requiring compliance with stringent PSD increments *and* by requiring protection of air quality related values including visibility. CAA §§162, 165(d), and 169A.

Because air quality modeling analyses that comply with EPA policies for increment consumption have shown that violations of the 3-hour and 24-hour average SO_2 increment are occurring in the State's Class I areas, it is imperative that North Dakota harmonize the SO_2 emission reductions that the State is requiring as part of its regional haze SIP with the requirement for the State's Class I areas to comply with the 3-hour and 24-hour average SO_2 increments. Thus, North Dakota must impose short term average SO_2 emission limits reflective of the SO_2 controls and emission reductions being required in its draft regional haze plan (primarily through BART) in order to be able to rely on the emission reductions in analyses of compliance with the 3-hour and 24-hour average SO_2 Class I increments.

Such emission limits must be reflective of the capabilities of the SO_2 controls being installed, in order to be consistent with the general purpose of the North Dakota regulations to "state such requirements as shall be required to achieve and maintain the best air quality possible, consistent with the best available control technology… and to facilitate the enjoyment of the natural attractions of this state." ND Reg. 33-15-01-01. The definition of "best available control technology" under the State's PSD regulations is defined as an emission limitation "based on the maximum degree of reduction" of a pollutant that is achievable. ND Reg. 33-15-15-01.2 incorporating by reference 40 C.F.R. 52.21(b)(12). And "emission limitation" is defined under the Clean Air Act as a requirement established by a state or EPA which limits emissions "on a continuous basis." CAA §302(k). Thus, in establishing short term average emission limits that can be relied upon in analyses of compliance with the PSD increments, North Dakota must set limits consistent with the maximum degree of emission reductions that is achievable with the BART SO_2 controls and that reflect operation of the SO_2 controls on a continuous basis. Without such short term average emission limits, NDDH cannot rely on the planned SO_2

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[49] As discussed in NDDH's "A Plan for Updating and Testing the North Dakota Department of Health's CALMET and CALPUFF Protocol," Draft Final, December 29, 2009, available at http://www.ndhealth.gov/AQ/NoticesPSDStatusIncrementConsumption.htm.

reductions at the State's EGUs in any increment analyses until the BART controls have been installed and normal operation has resumed for at least two years.

As we stated above, we understand from the NDDH's draft plan to revise the State's modeling protocol that the State plans to conduct a new periodic assessment of SO_2 increment consumption soon. Not only is such an analysis required under 40 C.F.R. §51.166(a)(4), but a new analysis is also required because, in its previous assessment of increment consumption, NDDH relied on techniques and methods that are inconsistent with EPA policy and the intent of the Clean Air Act. Although EPA proposed revisions to its regulations that would have allowed for many of North Dakota's increment modeling techniques and approaches[50], EPA never finalized that rulemaking and has indicated it will not finalize that rulemaking. Therefore, North Dakota cannot rely on those techniques and approaches that are inconsistent with EPA policy and with the intent of the PSD program of the Clean Air Act in evaluating increment consumption. Because prior analyses by NDDH (in 1999) and by EPA (in 2003) that more closely complied with EPA policy showed numerous violations of the 3-hour and 24-hour SO_2 increments in the State's Class I areas, it is imperative that NDDH conduct a new assessment of SO_2 increment consumption following EPA policy and consistent with the PSD mandates of the Clean Air Act. And, for NDDH to rely on the BART SO_2 reductions in such an analysis, the State must propose and adopt short term average emission limits.

IV. Other General Comments

1. The proposed RH SIP notes that the visibility monitor (IMPROVE THRO1 monitor) is located at the Painted Canyon Overlook in the South Unit of Theodore Roosevelt National Park. It also notes that this one monitor is "representative" of haze conditions in the separate North Unit and the separate Elkhorn Ranch Unit of the THRO Park. However, why and how a single monitor can be or is representative of haze conditions at these other, distant locations is never discussed. We believe that without technical support, the assumption that THRO1 is representative of conditions elsewhere in the THRO are unsupported. It is not enough to simply assert that this one monitor is representative, without basis (see page 31 of the proposed RH SIP). To the extent that the RH SIP relies on this TR-North Unit and TR-Elkhorn Ranch Unit. This is a fundamental flaw of the analysis.[51]

2. The RH SIP does not provide the details of its calculations for baseline visibility including all input assumptions. Thus, the values used cannot be verified. This is especially important since the values used are greater than EPA recommended values.

3. The proposed SIP (page 68) notes that "The FLMs and EPA have expressed concerns about the modeling that was conducted. MDU has agreed to remodel using a revised

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[50] 72 Fed.Reg. 31372, June 6, 2007.

[51] This critique is not in conflict with our support for treating THRO as it was designated: one mandatory Class I area, not three. In this case, THRO is one Class I area spread out over significant distance, and multiple monitors are appropriate in the same way that they would be for one large contiguous Class I area (e.g. Yellowstone National Park).

> modeling protocol. The Department will reassess the determination to exclude Heskett Station Unit 2 following review of the revised modeling. Heskett Unit 2 will be addressed in a supplement to this SIP revision." This analysis cannot be put off to the future and must be part of the regional haze plan. Without this analysis, the SIP is incomplete. In the alternate, if the Heskett analysis is not now included, the supplement should be subject to full public review.

Thank you for the opportunity to comment on the draft Regional Haze State Implementation Plan.

Sincerely,

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EPA Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility

US Environmental Protection Agency Region 9

July 31, 2008

c. **Comment:** Further, 98% is not the highest achievable SO_2 control efficiency for low sulfur coal similar to Navajo's coal. The

Application and AAQIR rely on other permitted sources, corrupting the BACT process. Many other sources of information, other than just permitted levels, must be consulted to determine BACT...The top control option is a wet FGD designed to achieve 99%+ SO_2 control. This level of control has been achieved at the Mitchell Station in Pennsylvania using magnesium enhanced lime, a type of wet FGD...It has also been achieved at several coal-fired power plants in Japan and is proposed for several U.S. coal fired power plants.

Chiyoda's bubbling jet reactor (a type of wet FGD) has consistently achieved >99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb SO_2/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis and has consistently exceeded this level while treating gases with inlet SO_2 concentrations within the range proposed for DREF (1.78 lb SO_2/MMBtu compared to 1.84 lb SO_2/MMBtu for DREF). This technology has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan. It also has been demonstrated in the U.S. at the University of Illinois's Abbott power plant and Georgia Power's Plant Yates and recently was licensed for use on several additional plants in the US, including Plant Bowen in Georgia, Dayton Power & Light's Killen and Stuart plants, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others. Black & Veatch and Southern Company are both U.S. licensees.

Mitsubishi, a vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including four coal-fired boilers.

Finally, a recent Lake Michigan Air Directors Consortium ("LADCO") and the Midwest Regional Planning Organization ("MRPO") presentation indicated that advanced FGD technologies could achieve 99.5% control for $1,240 to $2,875 per ton of SO_2 removed and wet FGD could achieve 99% SO_2 control for $1,881 to $3,440 per ton of SO_2 removed. [23]

Response: With respect to the claims that EPA's and the Applicant's reliance on other permitted sources has corrupted the BACT process and that higher levels of control have been achieved at other sources, the commenters are first referred to the responses to comments II.C.1.e and II.C.1.g. A BACT determination involves judgment and balancing, and does not involve simply picking the lowest numerical emission limit or the highest observed control efficiency. The design of wet a FGD system and the resulting control efficiency depends on a variety of parameters, including the characteristics of the fuel, boiler operating data and tolerances, emission requirements (not only for SO_2 but also for particulate, dust, temperature, and waste water), limestone availability and quality, and economic factors.[3] As discussed in the permit application, a comparison of relative control efficiencies of add-on SO_2 control equipment must take into account the amount of uncontrolled SO_2 to be treated. For example, for a given heat input, a facility with a BACT limit of 0.06 lb/MMBtu that achieves 95% control will result in fewer emissions to the atmosphere than a facility with a limit of 0.1 lb/MMBtu that achieves 98% control. It is therefore misleading for the commenters to cite to other facilities that achieve greater control efficiencies than proposed for the DREF while ignoring differences in site specific factors.

Moving to the commenters' specific claims, the commenters first assert that the Mitchell Power Station in Courtney, PA has achieved greater than 99% SO_2 control. In support of the statement, the commenters submitted data which purportedly represents daily emissions from the facility.[4] The commenters' assertion is misleading because the information submitted contains only 88 days worth of monitoring data collected over a span of 17 months between July 1983 and December 1984. As previously discussed, the EAB has recognized the distinction between measured emissions data at one point in time and an emissions limitation placed into a PSD permit which must be met continuously for the entire life of the facility. Actual emissions data reported by the facility pursuant to the Acid Rain program reveal that the emissions are much higher in recent years than they were for the brief period from 1983-1984. The following statistics reflect actual SO_2 emissions from the Mitchell Power Station in 2006:[5]

Total Number of Days Monitored:	312
Lowest Daily Average Emission Rate:	0.01 lb/MMBtu
Highest Daily Average Emission Rate:	0.36 lb/MMBtu
Frequency Analysis	
Range	**Number of Days**
$X \leq 0.06$ lb/MMBtu	29

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[3] See *Alstom Environmental Control Systems Wet FGD Design Criteria*, included as Attachment 2.

[4] The data submitted by the commenters is on plain paper with no markings or other indications whatsoever that it represents the actual emissions from this facility. However, for the sake of the comment, EPA will consider the data to be legitimate.

[5] The facility had several startups, shutdowns, and process upsets in 2006. Emissions data from these periods were generally higher than for normal operations and were excluded from the statistical review. The raw data from EPA's Clean Air Markets database is included in Attachment 3.

0.07 lb/MMBtu $\leq X \leq$ 0.09 lb/MMBtu	125
0.10 lb/MMBtu $\leq X \leq$ 0.19 lb/MMBtu	138
0.20 lb/MMBtu $\leq X \leq$ 0.29 lb/MMBtu	16
0.30 lb/MMBtu $\leq X \leq$ 0.39 lb/MMBtu	4

It is clear from this data that the Mitchell Power Station has achieved a daily average emission rate equal to or less than the limit proposed for the DREF for only 29 days out of the year. The actual emissions were moderately higher for the remainder of the year. By comparison, the DREF would never be allowed to exceed 0.060 lb/MMBtu over a 24-hour average and would thus perform far better than the Mitchell Power Station on a heat input basis. Thus EPA does not agree with the commenters that the Mitchell Power Station provides evidence that the proposed DREF limit is not BACT.

The commenters' next claim that the Chiyoda's bubbling jet reactor has consistently achieved greater than 99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan and that it has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan. In support of its claim regarding the three boilers in Japan, the commenters referred to a website operated by Burmeister & Wain Energy, which has the license for the CT-121 FGD process on the European market. This site contains two promotional documents. The first document, *CT-121 FGD Process* (included as Attachment 4), contains an elementary description of the CT-121 process and its purported advantages, including a generic statement that removal efficiencies up to 99%+ are possible. It does not, however, provide any technical information regarding the conditions under which such efficiencies can be achieved nor does it provide any information about actual guaranteed emission rates (see earlier discussion regarding comparison of control efficiencies versus actual emission rates). The second document, *Flue Gas Desulphurization Reference list CT-121*(included as Attachment 5), is simply a list of facilities in which the CT-121 process has been or will be installed, the installation dates, and the SO_2 control efficiencies, which range from 82% to 99%. This list clearly shows that this technology has a wide range of efficiencies and as with the first document, it provides no information about the conditions under which the higher efficiencies can be achieved nor does it state what the guaranteed emission rates are for the facilities that are achieving high removal efficiencies. It is also worth noting that many of the facilities in the list with higher control efficiencies are not in operation as the dates provided in the table are 2008 and beyond. The lack of any useful technical information in these documents provides EPA with no basis for a more detailed response. The commenters did cite to one technical paper by Yasuhiko Shimogama and others. Though this paper indicates that 99% control is being achieved at the Shinko-Kobe plant, EPA can not rely on this document alone to establish BACT. Other pertinent information such as the permitted emission limits, averaging periods, and actual emissions data should be submitted. It is the commenters' burden to provide that information and the commenters have failed to meet that burden in this case. Nonetheless, EPA attempted to contact the Japan Ministry of the Environment for additional information but to date, our request for information has not been answered. EPA did, however, receive a response to a request for information from Kobe Steel, Ltd., the company that owns and operates the Shinko-Kobe plant. Specifically, EPA asked about Kobe Steel's general experience using the technology. In his reply, the manager of the Power Plant Technology Section stated that the SO_2 removal efficiency has never dropped below the guaranteed performance level, that their experience with the CT-121 process has been positive, and that their decision to use the CT-121 at that plant was the correct one. However, they also noted that they have been experiencing problems with the system's sulfur gas fan. Specifically, they have been experiencing degradation of fan efficiency by gypsum deposits during normal operation of the plant. They stated that an attempt has been made to remedy the problem by installing a washing system but that has not been sufficient and the problem still remains unresolved by the supplier. As a result, they are required to conduct periodic preventive maintenance every two to three months. During a planned outage over a weekend, they stop plant operations for two days and wash the fan blades. See Attachment 6, *July 31, 2007 e-mail from Gary Tsuchida*. EPA does not believe it is reasonable to require the use of a technology with unresolved operational issues that require such frequent shutdowns of the plant. Thus while the technology appears promising for certain situations, it may not be suitable for all situations and EPA cannot simply require its use in every instance. As the commenters later note in their comments, this technology is being planned for use at other plants. Those installations will likely provide additional data and operating experience that does not currently exist but that is needed to fully evaluate this technology in future BACT analyses.

The commenters also claim that Chiyoda's bubbling jet reactor has been demonstrated in the U.S. at the University of Illinois's Abbott power plant and Georgia Power's Plant Yates and recently was licensed for use on several additional plants in the US, including Plant Bowen in Georgia, Dayton Power & Light's Killen and Stuart plants, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek.

The commenters are correct that the Chiyoda's CT-121 FGD system is used at the University of Illinois's Abbott Power Plant and Georgia Power's Plant Yates. However, a review of the actual emissions data from these facilities again demonstrates that the DREF would have lower emissions than these facilities on a heat input basis. The following statistics reflect actual SO_2 emissions data from Plant Yates in 2006. The raw data from the Clean Air Markets database is included in Attachment 7

Total Number of Days Monitored:	346
Lowest Daily Average Emission Rate:	0.02 lb/MMBtu
Highest Daily Average Emission Rate:	0.38 lb/MMBtu
Frequency Analysis	
Range	**Number of Days**
$X \leq 0.06$ lb/MMBtu	48
0.07 lb/MMBtu $\leq X \leq$ 0.09 lb/MMBtu	28
0.10 lb/MMBtu $\leq X \leq$ 0.19 lb/MMBtu	140
0.20 lb/MMBtu $\leq X \leq$ 0.29 lb/MMBtu	97
0.30 lb/MMBtu $\leq X \leq$ 0.39 lb/MMBtu	33

It is again clear from this data that while Plant Yates has achieved a daily average emission rate equal to or less than the limit proposed for the DREF for short periods of time, for the majority of the time the emission rates were significantly higher. Furthermore, information obtained from the Illinois Environmental Protection Agency (IEPA) shows that the actual measured control efficiency of the FGD system at the Abbott Power Plant is 92.3%. See Attachment 8, *6/14/2007 fax from Joe Kotas*, IEPA. In addition, the Abbott Power Plant includes three boilers of approximately 200 MW each. To the extent that boiler characteristics affect emissions and control technology design, these units do not serve as a good reference for the DREF, which has much larger units. EPA thus disagrees with the commenters that the use of Chiyoda's equipment at another facility is an indication the proposed limit for the DREF is not BACT.

The commenters are also correct that Chiyoda's FGD system is being installed on several other plants. However, most of those referred to by the commenters are not yet constructed or operating. According to the Kentucky Department for Environmental Protection, Division for Air Quality, the Big Sandy project has been postponed until 2014; it is thus not useful for establishing BACT for the DREF. See Attachment 9, *e-mail from Candy Montgomery, Kentucky DAQ*, June 8, 2007. The Conesville, Cardinal and Kyger

Creek projects are proceeding but are currently in various stages of construction. According to the Ohio EPA, the control efficiency for these systems is estimated at 98%. However, even with 98% control, the emission limits (in terms of lb/MMBtu heat input) for these facilities will be significantly higher than the proposed limit for the DREF, further supporting EPA's conclusion that the DREF limit represents BACT. The current status of these facilities and their emission limits are summarized in the following table:

Facility/Unit	**Stage of Construction**	**Emission Limit**
AEP Conesville #4	Early stage of construction	0.90 lb/MMBtu (30-day rolling average)
AEP Muskingum River #5	Construction halted	1.5 lb/MMBtu (30-day rolling average)
AEP Kyger Creek Units 1-5	Early stages of construction	1.20 lb/MMBtu (30-day rolling average)
AEP Cardinal Units 1&2	Construction nearing completion	2.5 lb/MMBtu (30-day rolling average)

See Attachment 10, *e-mail from Dean Ponchak*, Ohio EPA, June 8, 2007. The emission limits for Dayton Power & Light's Killen and Stuart plants are similarly higher than the DREF limit:

Facility/Unit	**Emission Limit**
Killen Station #2	1.2 lb/MMBtu
Stuart Unit #4	1.77 lb/MMBtu (30-day average)
Stuart Unit #3	1.77 lb/MMBtu (30-day average)
Stuart Unit #1	1.77 lb/MMBtu (30-day average)
Stuart Unit #2	1.77 lb/MMBtu (30-day average)

See Attachment 11, *e-mail from Cindy Charles*, Ohio EPA, June 8, 2007. FGD systems on Units 1-4 at Plant Bowen are also in the construction phase. However, these systems are being installed for purposes of compliance with the Clean Air Interstate Rule and at the time this document was written the facility has not yet received its allocation. Until the allocations are received, the permits to install these systems have no emission limits or other operating requirements.

The commenters further claim that Mitsubishi reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including four coal-fired boilers. The commenters are again misleading in their statements because they point to control efficiencies without respect to inlet pollutant loading. In support of their statements, the commenters refer to two technical papers and a page on Mitsubishi Heavy Industries' website. Both technical papers explicitly state that the highest SO_2 control efficiencies are associated with high inlet SO_2 concentrations:

> In this paper, performance test data for the latest single-tower coal-fired application (a 600MW module) that started commercial operation on July 12, 2004 are reported. In addition, **super high SO_2 removal efficiency (99-99.9%) <u>under high inlet SO_2 conditions</u>** (2,000-3,000ppm) achieved by a single DCFS module and an extraordinary space-saving design related to its compactness feature are also introduced here...
>
> Nakayama et. al. at 1 (emphasis added).

> The twin tower design, which is the combination of co- and counter-current designs, is selected when both high particulate removal and **extremely high desulfurization performance requirement (98% and over) <u>for high sulfur coal</u>** are required...In the past 2 or 3 years, we have been successful in achieving **ultra-high SO_2 removal efficiency (e.g., 99.9%) <u>with a high inlet SO_2</u>** using a single tower DCFS.
>
> Nakayama et. al. at 2 (emphasis added).

> This paper provides a detailed description of the DCFS FGD system including operating data from recent installations...Recent operating experience is reviewed in detail. In particular, the paper highlights design requirements to achieve **SO_2 removal efficiencies as high as 99.9 percent <u>on high sulfur coals</u>**.
>
> Klingspor et. al. at 1 (emphasis added).

High inlet concentrations tend to make high removal efficiencies more practical and economical. Also, as previously discussed, having the lowest emission rate on a heat input basis does not necessarily require achieving the highest control efficiency if the use of low-sulfur coal results in lower uncontrolled emissions to begin with. EPA thus remains convinced that the proposed limit represents BACT in this instance.

Finally, the commenters note that a recent Lake Michigan Air Directors Consortium (LADCO) and Midwest Regional Planning Organization (MRPO) presentation indicated that advanced FGD technologies could achieve 99.5% control for \$1,240 to \$2,875 per ton of SO_2 removed and wet FGD could achieve 99% SO_2 control for \$1,881 to \$3,440 per ton of SO_2 removed. According to the engineering analysis for boilers referenced in the presentation, the cost estimates referred to by the commenters were developed assuming a fuel sulfur content of 2.5%. This is 2-3 times higher than the sulfur content of the coal to be used at the DREF and thus the LADCO example does not necessarily reflect the true economics for this or other facilities that use low sulfur coal. Furthermore, the LADCO report cautions that these estimates are intended to provide a general indication of the technical and economic feasibility of each control technology and that a unit-specific evaluation must still be performed. The report further recognizes the likelihood that site-specific vendor quotes will be required to get accurate cost analysis results. See Attachment 12, *LADCO Report* at 20.

d. **Comment:** Japan regulates SO_2 emissions to about 10 ppm (0.02 lb/MMBtu) from new industrial facilities locating in polluted areas. There are currently two Japanese vendors who supply wet FGD systems in the U.S. market that are able to achieve 99% SO_2 control on low sulfur coals. These are Chiyoda and Mitsubishi, as discussed supra. These two wet FGD systems are more cost effective, require less water and electricity, generate less wastes, and remove more mercury and particulate matter than the type of wet FGD selected for DREF. They do not have any adverse energy, environmental, or economic impacts.

This Japanese experience is supported by two facilities in the U.S. The U.S. EPA issued a PSD permit to AES Puerto Rico to construct and operate a 454-MW coal-fired CFB project. The permit requires the unit to meet an SO_2 limit of 0.022 lb/MMBtu or 9.00 ppmvd corrected to 7% oxygen on a 3-hour basis, compared to 0.09lb/MMBtu on a 3-hour basis and 0.06 lb/MMBtu on a 24-hour basis for DREF. The much lower AES Puerto Rico limit has been achieved. Further, Utah issued a permit for the Nevco Sevier project in October 2004. Its SO_2 limits are: 0.022 lb/MMBtu based on a 30-day average and 0.05 lb/MMBtu based on a 24-hour average. We are not advocating CFBs for DREF, but rather that the emission limits proposed for these CFB units should be included in the top down BACT analysis for PC boilers, as set out below. [23]

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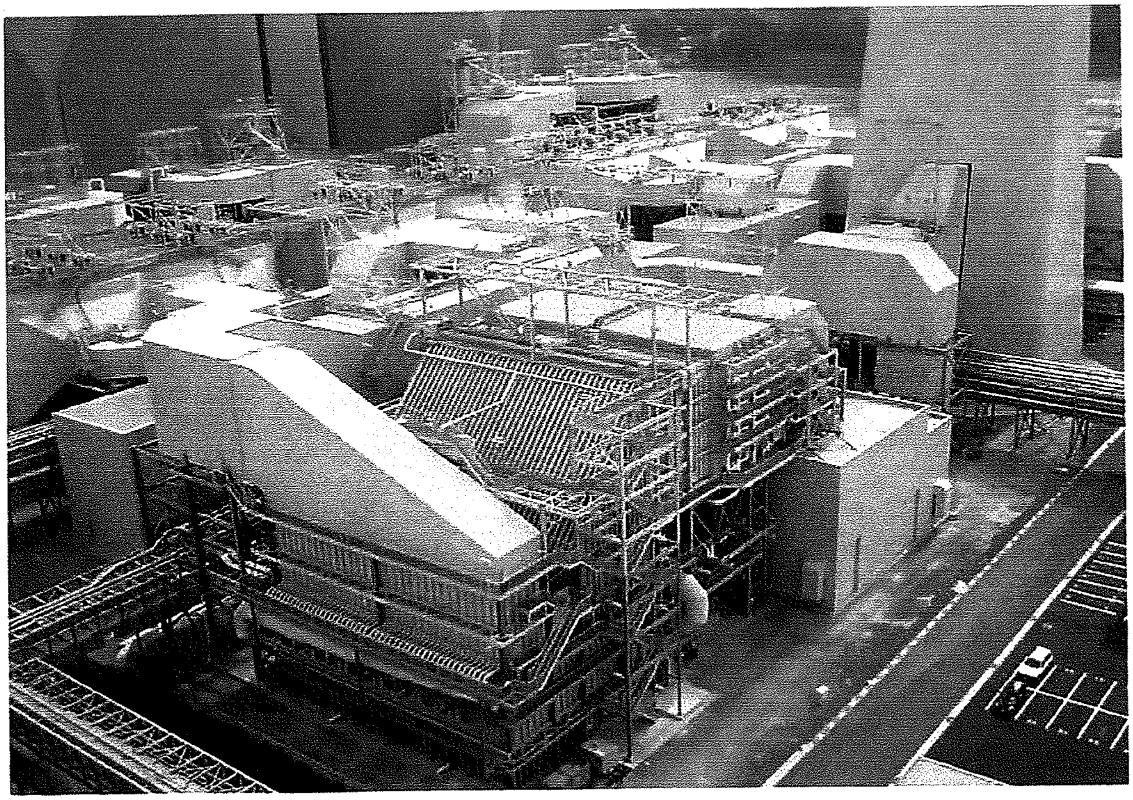
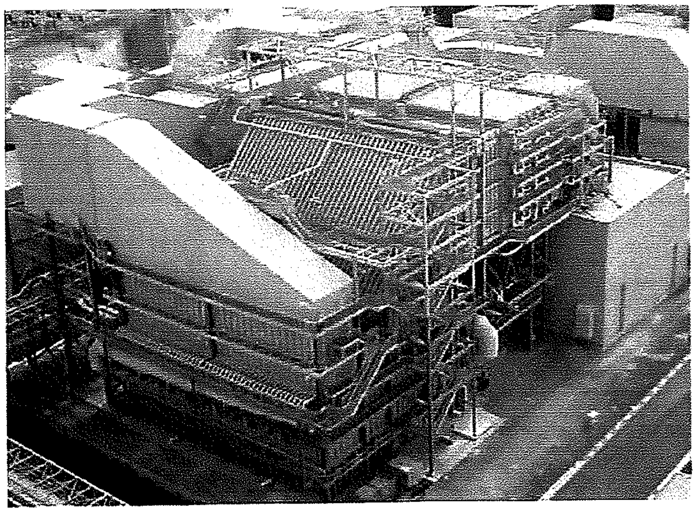
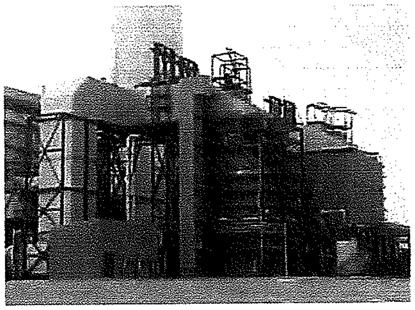
Advanced Flue Gas Desulfurization



The Next Generation



The EPDC Tachibanawan Power Station has a single 1,050 MWe DCFS module that is the largest FGD module in the world. The unit has operated at 100 percent availability since startup in 2000. The SO_2 removal is in excess of 95 percent and can be tuned for greater removal by optimizing recycle pump operation.



The twin tower DCFS FGD system installed at the Rathaburi Power Station in Thailand operates at 97 percent SO_2 removal efficiency.

The plant is designed with close-coupled gas-to-gas regenerative reheat located on top of the absorber.

Unrivaled Experience

Highlights of Our Worldwide FGD Experience

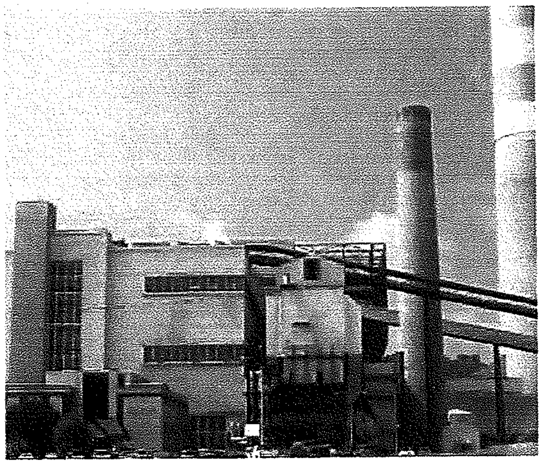
Installed FGD Capacity	~56,000 MWe
FGD Orders Last 10 Years	~30,000 MWe
Highest SO_2 Guaranteed Removal	99.80%
Highest SO_2 Removal w/o Additives	99.90%
Highest SO_2 Concentration	7,800 ppm
Largest Single Absorber	1,060 MWe
Longest Time Between Outages	2 yrs
Spare Modules Installed	None
Highest Availability, Single Module	100% / 12yrs

Advatech was formed jointly by URS and Mitsubishi Heavy Industries America (MHIA) to provide flue gas desulfurization (FGD) systems to American utilities. Advatech combines the Mitsubishi Heavy Industries (MHI) Double Contact Flow Scrubber (DCFS) advanced FGD technology and the comprehensive engineering, procurement, and project implementation services of URS.

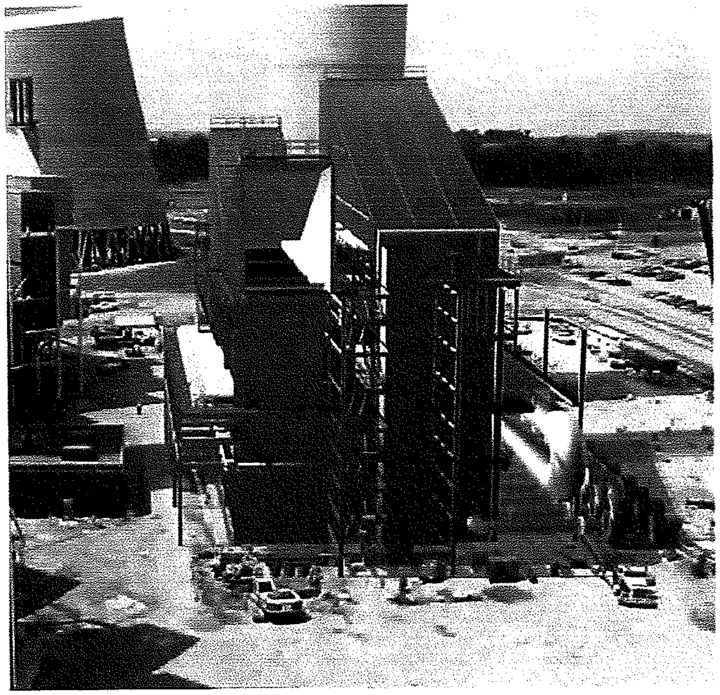
Through Advatech, URS and MHIA bring unsurpassed technology, engineering, design, procurement and project implementation services backed by strong parent companies. Radian Corporation, now a part of URS, began offering FGD services over 30 years ago.

The first MHI FGD system was installed in 1964. Today, MHI is the world's leading supplier of FGD systems with over 56,000 MWe installed on more than 160 boilers in 14 countries.

Available in the US through Advatech, the DCFS system is highly reliable, and the uniqueness of its design allows it to operate at 100 percent availability with no spare



Advatech is currently designing a single-module DCFS FGD system for Alabama Power's 1,151 MWe Plant Gorgas which will achieve 98 percent SO_2 removal efficiency with ultra-high reliability.



The twin-tower DCFS FGD system currently being installed at the Paradise Power Station will be the largest single-module FGD system in the world. The system is designed to achieve 98 percent SO_2 removal burning 3.5 percent sulfur coal and will produce wallboard-quality gypsum. The unit is slated for commercial operation in 2006.

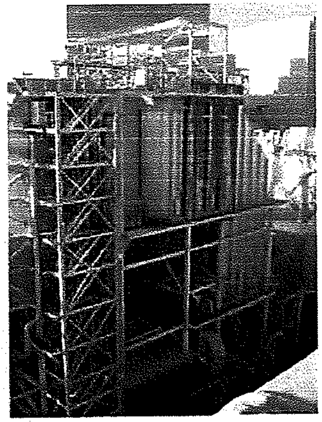
module required. SO_2 removal efficiencies as high as 99.8 percent have been guaranteed and achieved on a 3 percent sulfur fuel while producing wallboard-grade gypsum.

The DCFS FGD system is particularly robust, can tolerate dramatic changes in operating conditions, and is designed to operate two to four years between scheduled outages.

All Advatech's limestone-based FGD systems produce a gypsum byproduct. The majority of these installations sell their gypsum to either wallboard or cement plants.

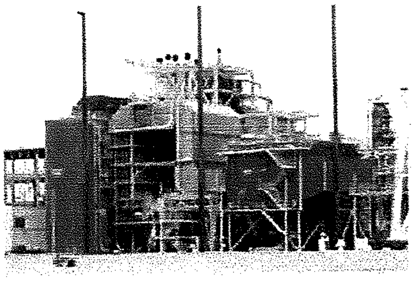
FGD Projects in the U.S.

NiSource Bailly (Pure Air)	530 MWe	95% SO_2 Removal
TVA Paradise	1,060 MWe	98% SO_2 Removal
TVA Widows Creek	500 MWe	96% SO_2 Removal
TVA Colbert	500 MWe	97-98% SO_2 Removal
TVA Bull Run	920 MWe	95-98% SO_2 Removal
Alabama Power Gorgas	1,151 MWe	98% SO_2 Removal



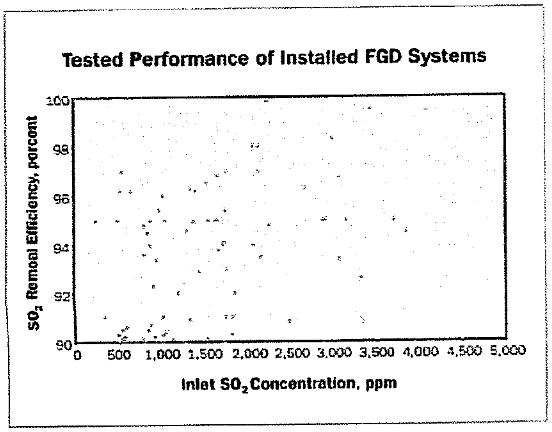
With over two years of continuous operation, this DCFS unit cleans flue gas at Hokkaido Electric's 700 MWe Tomatoazuma station.

Started in early 2002, the 600 MW Kansai Electric Gobo Power Station processes 1 percent sulfur with more than 99 percent SO_2 removal.



The twin tower DCFS FGD system installed at the KOA refinery operates at 99.9 percent SO_2 removal efficiency (without additives), with an inlet SO_2 at 2,100 ppm and less than 2 ppm in the stack. The system produces wallboard-grade gypsum, and has operated at 100 percent availability with four years between scheduled outages since its startup in 1995.

Multipollutant Control Capabilities



In addition to SO_2, the DCFS FGD system is capable of reducing emissions of particulates, acid mist and mercury. The DCFS design which provides the ability to achieve ultra-high (above 99 percent) removal efficiencies of SO_2 without additives is beneficial for the control of other pollutants. Particulate emissions can be reduced by up to 95 percent after locating a high efficiency ESP upstream of the FGD system, and by up to 99.6 percent without a particulate control device. In tandem with a reagent injection process to control acid mist emissions, opacity levels can be reduced to single digits. The DCFS FGD system is also efficient in removing oxidized mercury. In combination with a mercury oxidation

Exceptional Performance—No Lost Megawatts

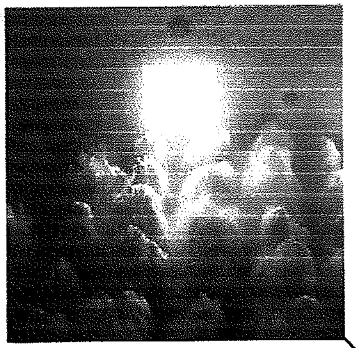
Client			Performance		
Year	***Customer (Location)***	***Capacity (MW)***	***Removal Efficiency (%)***	***Availability (Cumulative) (%)***	***Operating Time Between Outages (years)***
2004	Tokyo Electric Power Company (Hirono, Japan)	600x1	98.3	100	2
2004	Nippon Petroleum Refining Co., Ltd. (Muroran, Japan)	99x1	99.6	100	1
2004	Nippon Petroleum Refining Co., Ltd. (Marifu, Japan)	149x1	99.9	100	1
2003	Kashima Northern Electric Power Co. (Kashima-kita #3,Japan)	300x½	99.4	100	1
2003	COSMO OIL Co., Ltd. (Yokkaichi, Japan)	223x1	99.9	100	1
2003	Sumitomo Joint Thermal Electric Power Co., Ltd. (Nyuugawa, Japan)	250x1	92.8	100	2
2002	Kansai Electric Power Co., Inc. (Gobo #3, Japan)	600x1	99.1	100	2
2002	Hokkaido Electric Power Co., Inc. (Tomatoh-atsuma #4, Japan)	700x1	96.4	100	2
2001	Chugoku Electric Power Co., Inc. (Shimonoseki, Japan)	400×1	97.2	100	2
2000	Nakayama Nagoya Joint Thermal (Nagoya, Japan)	149×1	95.2	100	1
2000	Shikoku Electric Power Co., Ltd. (Tachibanawan, Japan)	700×1	95.0	100	2
2000	Electric Power Development Co., Ltd. (Tachibanawan, Japan)	1,050×1	95.0	100	2
1998	Nippon Petroleum Refining Co., Ltd. (Osaka, Japan)	149×1	99.9	100	1
1998	Chugoku Electric Power Co., Inc. (Misumi, Japan)	1,000×1	90.2	100	2
1997	Sumitomo Osaka Cement Co., Ltd. (Ako, Japan)	100×1	99.3	99.9	1
1997	Fukui Joint Thermal Power Co., Ltd. (Mikuni, Japan)	250×1	96.6	100	2
1992	Kashima South Joint Power Corporation (Kashima, Japan)	146×1	97.1	100	1

Advatech, through MHI, has extensive experience with FGD systems operating at 100 percent availability on low-and high-sulfur fuels.

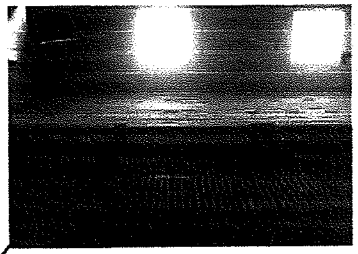
This table shows recent operating experience with DCFS FGD units for a wide range of boiler size, fuel sulfur content and SO_2 removal performance. In total, MHI has more than 160 FGD units worldwide including the world's largest.

catalyst, most of the elemental mercury can be captured as well. More importantly, the efficient forced oxidation systems incorporated in the DCFS design avoids reemitting of oxidized mercury. Advatech is working on providing oxidation catalysts for control of elemental mercury and current pilot plant tests show promising results.

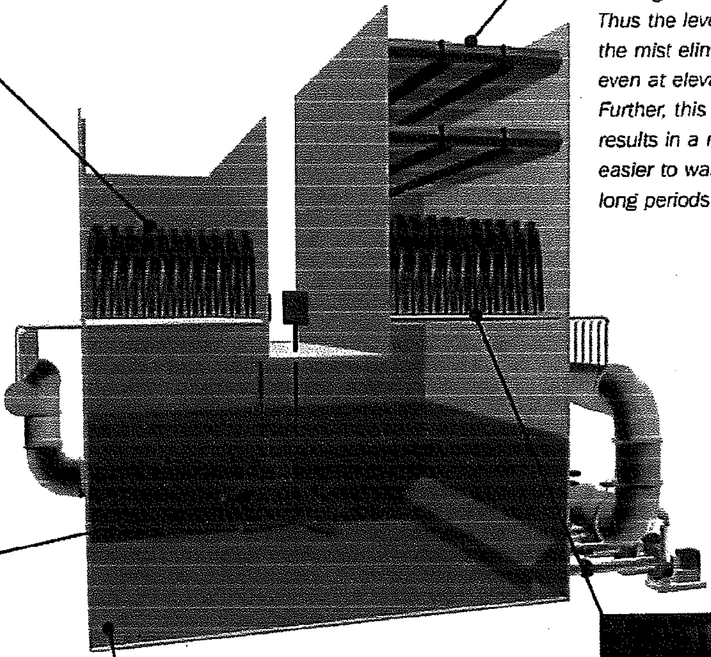
The Advatech DCFS Design

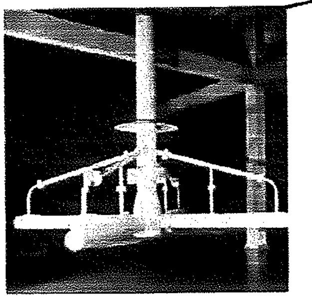


Multiple fountains provide for exceptional gas liquid contact ensuring SO_2 removal efficiencies of up to 99.9 percent! The gas is contacted twice as the liquid sprays upward and as it falls downward. This double contact provides a more efficient mass transfer and higher SO_2 removal per unit of L/G.

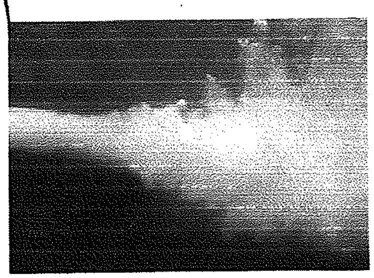


Use of the DCFS fountains for gas liquid contact minimizes the droplet loading on the mist eliminators. Thus the level of liquid loading to the mist eliminators is much less even at elevated gas velocities. Further, this lower liquid loading results in a mist eliminator which is easier to wash and keep clean for long periods between outages.

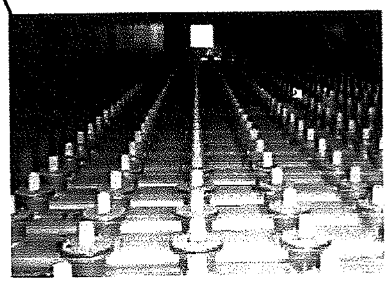




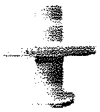
Powerful Air Rotary Sparger (ARS) provides excellent agitation simultaneously distributing fine bubbles used in complete oxidation of calcium sulfite to calcium sulfate. The patented ARS provides an ultra efficient use of oxidation air while ensuring that sufficient gypsum solids exist throughout the module thus minimizing any scaling potential.



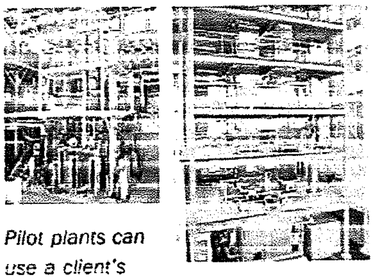
The patented Jet Air Sparger (JAS) was developed to provide oxidation air to the vessel using an eductor to pull atmospheric air (or compressor enhanced air) for oxidation of calcium sulfite to calcium sulfate. The JAS produces very fine air bubbles which enhance the mass transfer and minimize capital and operating costs.



The Advatech DCFS introduces the slurry in a single always-operating spray level. The single level eliminates header-to-header erosion and allows for operation of slurry solids concentration of 30 wt%. The higher solids concentration and the continuous operation ensure the tower stays exceptionally clean and scale free. All recycle pump motors and gear boxes are identical, with a spare recycle pump usually provided to ensure availability.

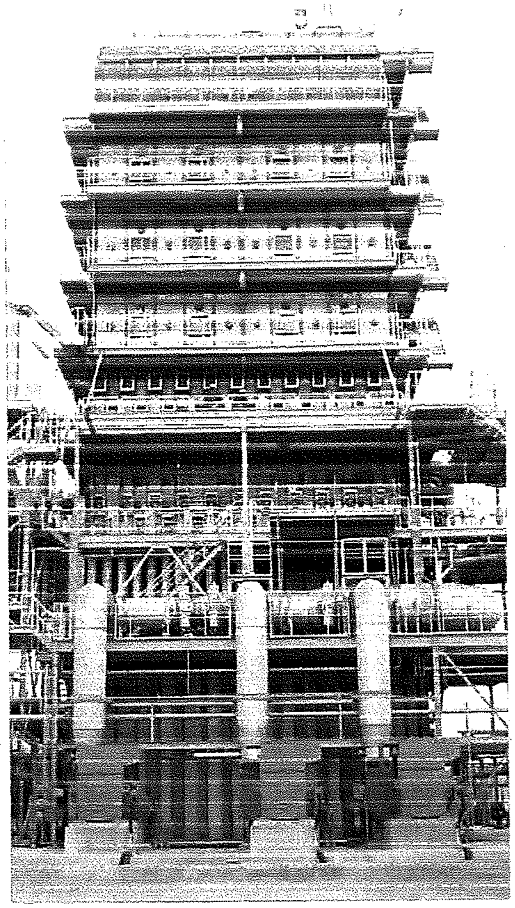


SIC spray nozzle



Pilot plants can use a client's coal, limestone and make-up water to simulate desired conditions.

100 MWe absorber fluid dynamics model



400 MW single-tower DCFS test facility used to improve the single tower design to achieve ultra-high removal capability

Relentless Improvement

Advatech, through MHI and URS, is strongly committed to research and development and to bringing continuous improvements to the utility industry. We have large modern research facilities dedicated to air pollution control.

Advatech's wet FGD system has evolved to a very simple, reliable and highly efficient single loop, double contact flow scrubber. During recent years, prominent technology improvements have included the single stage DCFS spray header design, air rotary sparger for combined slurry mixing and gypsum-oxidation, and jet air sparger for gypsum oxidation without use of oxidation compressors.

A full-featured wet FGD pilot plant which can use site-specific coal, limestone and water sources is available to model client-specific operating conditions.

Recent developments have focused on control of trace emissions such as sulfuric acid mist (SO_3) and mercury (Hg). URS has introduced a new process for control of SO_3 emissions by use of sodium by-sulfite injection. When injected upstream of the air preheater, the acid dew point is lowered sufficiently, which can result in a significant increase in boiler efficiency. Mercury control technologies are being studied vigorously by both URS and MHI, and technologies for control of mercury emissions will be introduced to the market in the near future.

Advatech brings the full talent and capabilities of MHI and URS research and development to the market. We design our control technologies to account for future emissions control requirements. Our technologies will help you bridge the gap to future emissions control legislation.

Corporate Strength

Advatech combines the strength of two world-class organizations—URS and Mitsubishi Heavy Industries America—to bring the best FGD systems to the United States. With Advatech, you get not only the DCFS technology, but also all the R&D, engineering and implementation experience, and the corporate commitment from both companies. Advatech is providing design and construction services to the Tennessee Valley Authority for up to five FGD systems. Advatech is now designing the first large FGD system for the Southern Company—at Alabama Power's Plant Gorgas.

MHIA URS

ADVATECH™

The Next Generation

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Bachman, Tom A.

From:	Platt.Amy@epamail.epa.gov
Sent:	Monday, February 08, 2010 9:51 AM
To:	Bachman, Tom A.; Morales.Monica@epamail.epa.gov
Cc:	Golden.Kevin@epamail.epa.gov
Subject:	Re: Heskett Unit 2

Tom:

Based on our review of AECOM's December 17, 2009 "Updated BART Modeling Results for R.M. Heskett Station Unit 2," our preliminary conclusions are that an EPA-approved protocol was used, and the results indicate that Heskett Unit 2's impact was less than the subject-to-BART threshold of 0.5 deciviews. Therefore, it appears appropriate for the State to determine that the source is not subject to BART. However, the source may still qualify for potential emission reductions under the Reasonable Progress requirements of the Regional Haze Rule. In addition, please note that we can only reach a final decision regarding the modeling and its results, and any other aspect of the Regional Haze SIP, through our own notice and comment rulemaking.

Thanks for your follow-up on this one......Amy

Amy Platt, Environmental Scientist, 8P-AR
EPA Region 8, Air Program
1595 Wynkoop Street
Denver, CO 80202

303-312-6449 (voice), 303-312-6064 (fax)
Platt.Amy@epa.gov

-----"Bachman, Tom A." <tbachman@nd.gov> wrote: -----

To: Amy Platt/R8/USEPA/US@EPA
From: "Bachman, Tom A." <tbachman@nd.gov>
Date: 02/01/2010 10:23AM
Subject: Heskett Unit 2

Amy:

Will we be getting a letter from you indicating that EPA concurs that Heskett Unit 2 is not subject to BART? We would like to have it for our records.

Tom Bachman
Sr. Env. Engr.
ND Dept. of Health
(701) 328-5188

General Comments

Comment 1: The Department received 30 nearly identical emails from various individuals. The emails asked the Department to require additional control on the power plants and more aggressively pursue identified emissions reductions from all sources of pollutants. This was also reiterated in two additional emails and the oral testimony by Jim Kambeitz.

Response: The Department has required all emissions reductions that are required by rule or law. The SIP will reduce SO_2 emissions from power plants by approximately 68% and nitrogen oxides emissions by approximately 39% (based on 2000-2004 average emission rate). Overall, sources in North Dakota will reduce total sulfur dioxide emissions by approximately 106,000 tons/yr (60%) and nitrogen oxides by 58,000 tons/yr (25%). The uniform rate of progress for this planning period would only require a 23.3% improvement in visibility. The Department believes the reductions that will be achieved represent North Dakota's fair share of emissions reductions for the planning period. None of the commenters provided any technical argument that the Department was not complying with the Clean Air Act or the rules promulgated thereunder. The Department stands by its decision.

Comment 2: Two email commenters suggested that the Department needed to require additional emissions reductions in order to protect public health.

Response: The Department has reviewed ambient monitoring data in the Beulah area which is the most heavily affected area by power plants and a coal gasification plant. Five ambient monitors are operated in the immediate area. In 2008, the maximum 3-hr SO_2 concentration was 39 ppb (7.8% of the NAAQS), the maximum 24-hour SO_2 concentration was 9 ppb (6.4% of the NAAQS), and the maximum annual average SO_2 concentration was 1.8 ppb (6% of the NAAQS). For NO_2, the maximum annual average concentration was 2.7 ppb (5.1% of the NAAQS). The NAAQS were established by EPA to protect public health and welfare, including young individuals, with an adequate margin of safety. The reduction in emissions from the power plants and the other sources should reduce these ambient concentrations. The Department believes the public health and welfare is protected and air quality only will improve with the proposed reductions in emissions.

Montana Dakota Utilities Comments

Comment 1: Montana Dakota Utilities (MDU): MDU recalculated the expected SO_2 reductions at Heskett Station Unit 2 from limestone injection into the boiler. They excluded 2002 from the calculation and calculated a 474 tons per year reduction.

Response: The Department has reevaluated its calculation of the expected reduction. To be consistent with calculations for other sources, 2002 data was not eliminated. Based on the reevaluation, the Department expects a 553 ton/yr reduction from the 2000-2004 average emission rate.

Comment 2: MDU wanted the latest BART applicability modeling analysis and EPA's approval of the modeling protocol included in the final SIP revision.

Response: These documents will be included in the final SIP revision.

Comment 3: MDU asked the Department to consider the amount of visibility improvement that could be achieved by adding controls to Heskett Unit 2 when determining the reasonable progress goals.

Response: The visibility improvement will be considered in the calculation of cost (i.e., dollar per deciview). The other three factors for determining reasonable progress will also be considered.

Department of Interior (DOI) Comments

The DOI comments took the form of a response to the Department's response to the DOI comments of October 23, 2009.

Comment 1: The DOI still contends that TRNP should be treated as one area for visibility modeling.

Response: The Department still believes that the three units of TRNP should be treated as three distinct areas. Our reasons are stated in our response to the October 23, 2009 comments. We stand by our comments.

Comment 2: Regenerative Selective Catalytic Reduction (RSCR) should be evaluated.

Response: As pointed out by the commenter, this type of system requires much more space than a conventional TESCR system. Both the M.R. Young Station and Leland Olds Station have limited space and could not accommodate RSCR. The commenter indicated that RSCR has a high capital cost when compared to conventional SCR. The Department rejected TESCR and LDSCR at all four stations due to an excessive cost and/or lack of significant improvement in visibility. This unit will not provide any improvement in visibility over conventional TESCR and LDSCR. No technical details were provided so that the Department could make a comparison; therefore, it is not considered BART.

Comment 3: Follow up to October 23, 2009 comment 6.

DOI suggested that the Department should explain how it considered the benefits of reducing emissions with respect to visibility improvements at multiple Class I areas.

Response: The Department provided visibility modeling results for LWA and the three units of TRNP. We looked at both the maximum improvement at each of the four areas; the average for each area and the average for all of the areas (see tables in each BART analysis). We believe we have complied with the Clean Air Act.

As pointed out previously, only the Coal Creek Station is subject to the BART Guideline (40 CFR 51, Appendix Y) and only for NO_x. EPA has stated that "… states are not required to follow these guidelines for EGUs located at power plants with a generating capacity of less than 750 MW" (FR Vol. 70, No. 128, 39131). Within the Guideline, EPA states "For sources other than 750 MW power plants, however, States retain the discretion to adopt approaches that differ from the guidelines" (Appendix Y to Part 61, Section I.H.). The NDDH has exercised this discretion when evaluating the various BART options.

Comment 4: Follow up to Comment 8 from October 23, 2009

DOI stated that they had commented to EPA Region 9 that they had underestimated the efficiency of SCR in the ANPR for the Four Corners Plant.

Response: The Department has reviewed the EPA Air Pollution Control Cost Manual which states "In practice, SCR systems operate at efficiencies in the range of 70% to 90%". EPA's Air Pollution Control Technology Fact sheet for selective catalytic reduction (EPA-452F-03-032) states "SCR is capable of NO_x reduction efficiencies in the range of 70% to 90%". The Oregon DEQ hired Eastern Research Group, Inc. (ERG) to review the BART analysis for the PGE Boardman Plant. In their review, ERG stated "With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR of the Boardman Plant under year-round operation would need to be considered in selecting a permit level." The NDDH believes the use of 80% is a reasonable choice for a source that must meet a BART emission limit on a long-term continuous basis.

Comment 5: Follow up to Comment 9 from October 23, 2009

DOI indicated they had commented to EPA Region 9 that the cost of SCR had been overestimated.

Response: In addition to the EPA estimate for SCR at the Four Corners Power Plant, the Department also reviewed the analysis commissioned by the Oregon DEQ for the cost of SCR at the PGE Boardman Plant. The analysis, which was prepared by Eastern Research Group, Inc. (ERG) states, "Nonetheless, all of these sources do point to a rapid escalation in SCR installed costs since 2004. ERG analyzed the 2007 cost-basis data by eliminating the three highest and one project that was known to be very dissimilar to the Boardman Plant characteristics. The remaining nine projects range from \$207/kw to \$267/kw, with an average of \$227/kw. ERG believes that this is a reasonable representation of 2007 costs of large SCR installations under normal retrofit conditions." DOI's estimate of the Total Direct Capital costs for SCR was less than \$150/kw for all facilities and substantially less for most units (i.e. \$101/kw at Stanton Unit 1). The NDDH <u>continues</u> to believe DOI has severely underestimated the cost of SCR. Since high dust SCR is not technically feasible for North Dakota lignite; the DOI cost estimates are even more erroneous since they do not include a reheat system or reheat annual costs. Based on the above, we believed the EPA Control Cost Manual is inappropriate for estimating the cost of

SCR. The manual states in Section 2.4 that the costs for tail-end SCR cannot be estimated from this report because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements.

Comment 6: Follow up to comment 10 on October 23, 2009

DOI believes the NDDH is placing too much emphasis upon incremental differences in visibility improvement. NDDH should support their claim that single source modeling overpredicts the actual improvement by a factor of 5-7.

Response: The preamble to the BART Guideline states "Because each Class I area is unique, we believe states should have flexibility to assess visibility improvements due to BART controls by one or more methods, and we agree with commenter's suggestions to do so." (FR Vol. 70, No. 128, p.39129). The NDDH has looked at the difference in improvement for each control option. This is the same as looking at the total improvement for each control option and determining the difference in visibility improvement. Indirectly, the total improvement of each option is considered.

The difference between cumulative and BART single-source modeling results starts with the logarithmic relationship between deciview and light extinction, which is based on the proven concept that an observer will detect visibility changes more easily in clean air than in dirty air. Deciview is related to light extinction using the equation

$$dv = 10 \times \ln(b_{ext} / 10)$$

where

dv = deciview

b_{ext} = light extinction in units of inverse mega-meters (Mm^{-1})

In BART single-source modeling, the incremental impact of the subject source is based on a background of natural visibility conditions only. In cumulative modeling, as conducted by WRAP, the incremental impact of the subject source is based on a background of natural visibility conditions plus the impact of a complete inventory of all other source emissions which affect visibility. Therefore, calculated delta-deciview for the subject source for the cumulative case will be lower than for the single-source case.

A simple hypothetical example can illustrate the difference in single-source and cumulative visibility modeling. Assume that a subject source is contributing 5 Mm^{-1} to total light extinction and that the natural visibility background is 20 Mm^{-1}. Under single-source modeling, delta-deciview for the subject source would be calculated:

$$\text{delta-dv} = [10 \times \ln(25 / 10)] – [10 \times \ln(20 / 10)] = 9.16 – 6.93 = 2.23$$

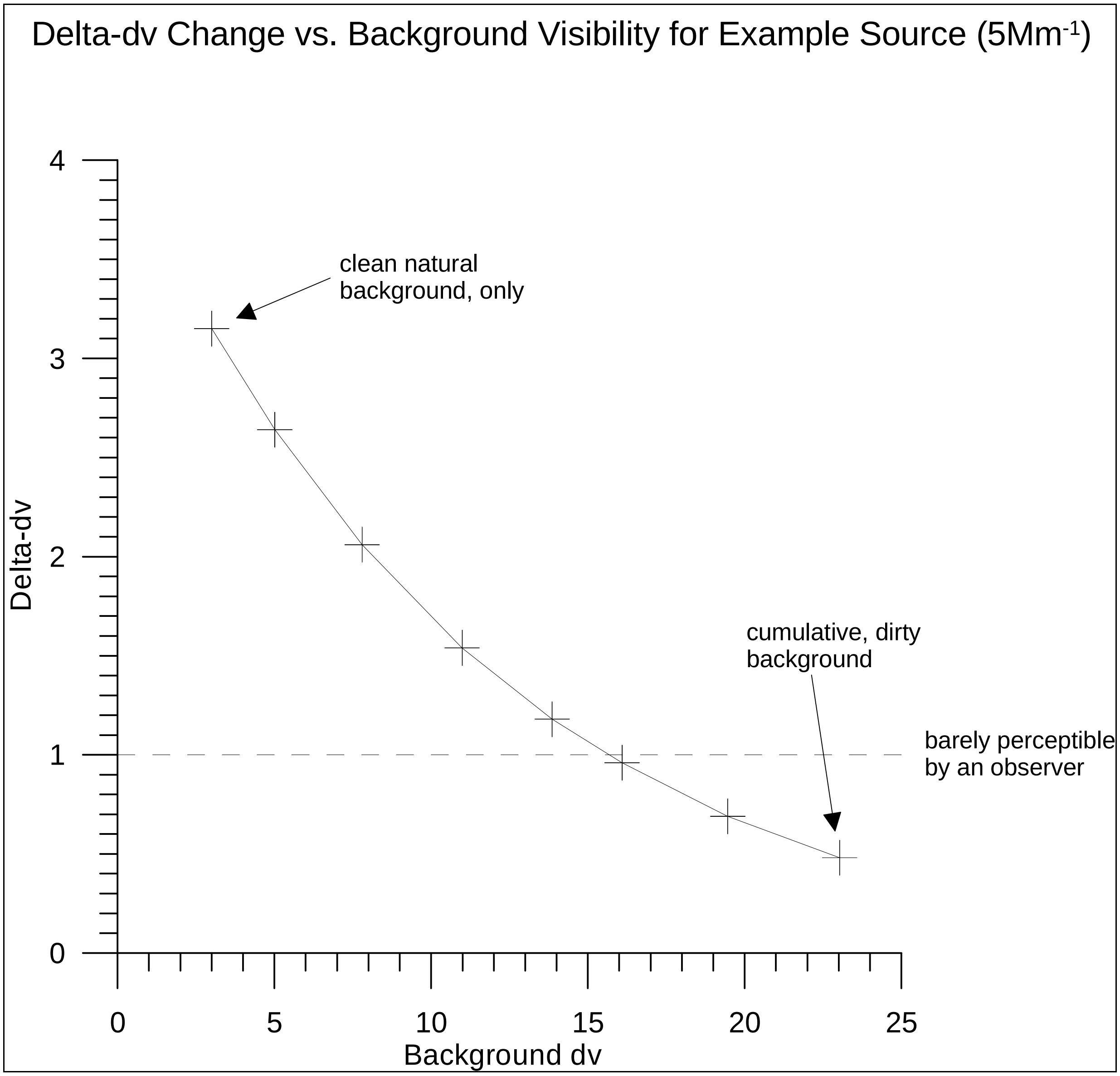
WRAP and the NDDH have found that adding a complete emissions inventory in the cumulative modeling will typically result in a background more than double the natural visibility conditions.

So to complete the example for the cumulative modeling case, we assume a background of 50 Mm^{-1} and the same subject source. Delta-deciview for the subject source would be calculated:

delta-dv = [10 x ln(55 / 10)] – [10 x ln(50 / 10)] = 17.05 – 16.09 = 0.96

Therefore, inclusion of the complete visibility-affecting emissions inventory in the cumulative modeling produces a smaller, but more realistic, observer-detected difference of 0.96 deciview from the subject source. In fact, for this example, the cumulative modeling result falls below the generally recognized observer-detectable threshold of about 1.0 deciview. Thus, the example illustrates that the impact of the subject source plume against a clean background would be much more noticeable to an observer than the impact of the same plume against the more realistic dirtier background. And, obviously, any change in visibility-affecting emissions from the subject source would have a smaller impact on the observer under the cumulative modeling scenario.

In the figure below, delta-deciview has been plotted for several background deciview levels, based on the subject source above. The included background levels range from a clean natural background to a dirty background representing the cumulative effect of many visibility-affecting sources. The plot includes the two points calculated above. The plot illustrates the general dependency of the observed visibility change (delta-deciview) on the background level, and the fact that an observer’s perception of visibility change can vary greatly depending on the background deciview level. In fact, for this example, there is a factor of 6.6 difference in delta-deciview for the cleanest background compared with the dirtiest background (3.15 / 0.48 = 6.56).



To further illustrate the difference in single-source and cumulative visibility analyses, the NDDH conducted additional modeling using actual sources. For this illustration, the NDDH grouped the BART-applicable Coal Creek, Leland Olds, and Milton R Young Generating Stations (in North Dakota) as an effective single source. Single-source and cumulative modeling analyses were conducted to determine the incremental visibility improvement at Theodore Roosevelt National Park from the 3-source group, based on BART controls. Calpuff system versions 5.8, the new IMPROVE equation, annual average natural background, and consistent annual emission rates (for the three noted sources) were applied for both analyses. The 90th percentile visibility day from the single-source modeling results was used to emulate the 20% worst day average from the cumulative modeling results. (Given that the typical distribution of 20% worst day visibilities tends to be skewed toward the high end, the 90th percentile day may somewhat understate the

20% worst day average). Note that the post-BART emissions inventory for the cumulative analysis included changes only to the three sources referenced above.

Results of the NDDH modeling analyses are summarized in the table below. The modeling analyses discussed above are compared in the first two columns of results.

	20% Worst Day Avg. Cumulative Modeling	90th Percentile Day Single-Source Modeling	90th Percentile Day Single-Source Modeling Using 2005 ND BART Protocol
Baseline (dv)	16.954	6.552	5.583
Post-BART (dv)	16.493	5.641	3.288
Improvement (delta-dv)	0.461	0.911	2.295

As shown in the table, visibility improvement from the addition of BART controls to the three generating stations based on single-source modeling is about twice that found from cumulative modeling. These results are consistent with the hypothetical example discussed above.

Also shown in the table are results of a third modeling scenario, i.e., single-source modeling based on the North Dakota BART modeling protocol. Consistent with EPA recommendations at the time (2005), the North Dakota BART protocol specified the use of Calpuff Version 5.7, the old IMPROVE equation, and a natural background reflecting cleanest days. In addition, the protocol specified use of maximum 24-hour emission rates, per the BART Rule. As indicated in the table, use of this protocol resulted in a much greater "apparent" improvement in visibility, about a five-fold increase in the result from the cumulative modeling. This illustration, therefore, is another basis for the NDDH statement in the SIP that BART single-source modeling over predicts by a factor of 5 to 7.

All BART modeling conducted by the NDDH and industry was based on the North Dakota BART protocol. Given differences in the North Dakota BART protocol (compared to later protocols), combined with the logarithmic nature of the relationship between deciview and light extinction, it becomes clear that BART single-source modeling could have greatly overstated the more realistic results obtained from recent cumulative modeling for North Dakota.

Note that use of the ND BART single source modeling produces a visibility improvement at Theodore Roosevelt National Park (2.295 dv) which achieves compliance with the uniform rate of progress goal (2.3 dv as discussed in Section 5 of the North Dakota SIP). If one was to accept the premise that these single-source modeling results are realistic, it would logically follow that North Dakota has met the uniform rate of progress based on BART controls for the three modeled sources, and that the need to address additional (non-BART) visibility-affecting emissions reductions in North Dakota is therefore less compelling.

The 20% worst-day average metric from cumulative modeling and the 90th percentile day metric from single-source modeling have been compared in this illustration as they constitute a comparable moment of the annual distribution of daily visibility predictions. Obviously, the 98th percentile day metric from single-source modeling would provide an even greater exaggeration of actual visibility change than the 90th percentile, in the context of the 20% worst-day average metric required to measure progress with respect to visibility goals under the regional haze rule.

Comment 7: Follow up comment 10C from October 23, 2009

DOI still believes that modeling should be based on the future conditions instead of the year that match the meteorology.

Response: As pointed out previously, the BART Guideline states that the emission rates for determining visibility for the precontrol scenario, the highest emission rates from the meteorological period modeled should be used. When determining visibility improvement, the comparison is made from a baseline, not a future scenario. This affords consistency from state-to-state and allows emissions data to be paired with meteorological data to produce the best prediction of baseline visibility conditions.

Comment 8: Follow up to comment 11 from October 23, 2009

DOI still believes NO_x reductions improve visibility more than SO_2 reductions.

Response: The Department agrees that NO_x reductions may be more effective than SO_2 reductions in reducing some visibility-affecting species' concentrations under some conditions, especially at a generally cooler, northern location versus a warmer, southern location. This is especially true because of the strong temperature dependence of the chemical reaction that forms NO_3 from HNO_3. The following table illustrates the strong temperature and relative humidity dependence of the reaction that forms ammonium nitrate from HNO_3 and the extreme values that can occur given typical values for $[NH_3]$ and $[HNO_3]$ of 1 ppb each. The equilibrium constant of the reaction is K and has an inverse relationship with $[NH_4NO_3]$.

T(deg.C)	T(deg.F)	RH(%)	K(ppb)	$[NH_4NO_3]$(ppb)
40	104	50	1000	0.001
30	86	40	100	0.01
30	86	90	20	0.05
20	68	40	8	0.13
20	68	90	2	0.5
10	50	40	0.6	1.7
10	50	90	0.2	5
0	32	40	0.03	33
0	32	90	0.01	100
<0	<32	<80	<0.01	>100

It is recognized that lower temperatures favor production of ammonium nitrate, for example, over production of HNO_3 from NO_x emissions. Conversely, warmer temperatures favor production of HNO_3 over NO_3, including during warmer months in North Dakota. During winter months in North Dakota, lower temperatures produce more potential for higher NO_3 concentrations than in the summer, when potential NO_3 concentrations are relatively low because of warmer temperatures. This temperature effect can be seen in the time-series plots of nitrate concentrations over an annual cycle, displayed in Figure 8.11 of the SIP document. Note the relatively low NO_3 concentrations during the summer and adjacent warmer periods and the higher NO_3 concentrations during the rest of the year.

Nevertheless, potentially higher NO_3 concentrations are only favored in the winter and colder days in spring and fall in North Dakota, and only then when NH_3 and NO_x emissions are high enough, and when winds transport NO_x plumes toward Class I areas and dispersion of plumes is not favorable. During the summer and about half of the spring and fall in North Dakota, ambient temperatures are warmer, similar to the rest of the U.S., and thus high NO_3 concentrations would not be favored then.

It may be true that it is easier to obtain lower NO_3 concentrations from NO_x reductions in a generally cooler, northern location than at a warmer, southern location, because of the temperature dependence in the chemistry. Nevertheless, obtaining visibility improvement by lowering SO_4 concentrations through SO_2 reductions is a reliable, effective way of improving visibility in North Dakota, somewhat because of the less complex chemistry involving SO_2. Reducing SO_2 emissions to improve visibility has the advantage of being effective year round, whereas NO_x reductions would be less effective during warmer months because of the lower potential NO_3 production from the temperature dependence in the chemistry.

Comment 9: Follow up to comment 12 from October 23, 2009

DOI still believes the dollar per deciview improvement is still the metric to emphasize when determining BART.

Response: As far as the emphasis on incremental differences between controls options, see response to comment 6.

DOI apparently did not understand the NDDH response when it pointed out that accuracy of single source modeling when compared to cumulative modeling can vary from state-to-state. As such, the accuracy of a dollar per deciview calculation will vary from state-to-state. This is due to a variation in the number of sources that affect the Class I area, the amount of emissions that affect the area and the location of the sources that affect the area. This makes this metric of very little value.

Comment 10: Follow up to comment 13 from October 23, 2009

DOI believes the proposed SO_2 control technology could meet the lower lb/MMBtu limit (assumed 0.15 lb/10^6 Btu) even if coal quality deteriorates.

<u>Response</u>: The Department did not use the maximum sulfur content in determining the BART limits. The Department used an annual average sulfur content. In the case of Minnkota's M.R. Young Station, the maximum sulfur content is 5.6% with an average of 0.93%. In order to comply with a 0.15 lb/10^6 Btu standard when burning the maximum sulfur coal, the scrubber would have to achieve 98.9% efficiency. This is extremely difficult with a wet scrubber.

<u>Comment 11</u>: Follow up to comment 25 from October 23, 2009

The DOI continues to assert that the WYGEN3 permit should be used as a basis for requiring Stanton Unit 1 to meet a 93% control for SO_2 and an emission limit of 0.09 lb/MM Btu on a 30-day rolling average basis.

<u>Response</u>: The DOI continues to ignore the fact that the WYGEN3 permit does not establish any minimum SO_2 control efficiency, let alone a 93% control efficiency. The WYGEN3 permit only establishes SO_2 emission limits on a lb/hr, lb/MW-hr and lb/MM Btu basis. As stated in the Department's initial response, the WYGEN3 facility could burn low-sulfur coal and still comply with the emission limits with SO_2 control efficiencies below 90%. As also indicated in the Department's initial response, it is the Department's understanding that the WYGEN3 facility has yet to demonstrate that the SO_2 emission limits can be achieved.

The Department maintains the position that a SD/FF operating at Stanton Station Unit 1 is capable of achieving an average SO_2 control efficiency of 90%.

<u>Comment 12</u>: Follow up to comment 26 from October 23, 2009

The DOI states that the "NDDH should show how it arrived at the conclusion that 'based upon the average sulfur content of the coal burned the SO_2 removal efficiency at Stanton Unit 10 is estimated to be approximately 90%.'"

<u>Response</u>: The Department estimated the control efficiency based upon data contained in the annual emission inventory report for the Stanton Unit 10 facility. Uncontrolled emissions were calculated based upon AP-42 emission factors. Actual (controlled) emissions are measured by the CEM at Stanton Unit 10. This data is public information which will be provided to the DOI upon request.

<u>Comment 13</u>: Follow up to comment 29 from October 23, 2009

The DOI asserts that it may be possible that SOFA with SCR with reheat may be less expensive than just SCR with reheat since the additional capital cost of adding SOFA may be offset by reduced annual operating costs.

<u>Response</u>: The DOI provides no data to support this position. The BART analysis for the M.R. Young facility estimates the annualized cost for SCR with reheat with ASOFA to be approximately \$99,600 to \$143,570 per MWe. The estimated annualized cost for SCR with reheat at Stanton Unit 1 is approximately \$66,435 per MWe. Based upon this data, the cost of adding ASOFA is expected to significantly increase the annualized cost. Although adding SOFA may be somewhat less expensive than adding ASOFA, in the Department's judgment it is very likely that the cost of SOFA with SCR with reheat will be higher than the cost of SCR with reheat alone.

In the specific case of the BART analysis for Stanton Unit 1 the incremental cost of applying SCR with reheat is $10,032 per ton of NO_x controlled when burning lignite and $12,894 per ton of NO_x controlled when burning PRB. It would be necessary for the addition of SOFA to reduce the incremental costs considerably for the application of SOFA with SCR with reheat to not be considered cost prohibitive. As indicated above, it is very likely that the addition of SOFA would increase costs significantly and not decrease costs significantly. Therefore, in the Department's judgment an analysis of SOFA with SCR with reheat would not alter the conclusion that SOFA with SCR with reheat is cost prohibitive at Stanton Unit 1.

Comment 14: Follow up to comment 30 from October 23, 2009

The DOI continues to question the cost estimates for SCR with reheat included in the BART analysis.

Response: In previous comments submitted by DOI, the DOI questioned GRE's estimate of the capital cost of SCR with reheat of $301/kW based upon the fact that the cost exceeded what the DOI deemed to be an acceptable range of $50-$267/kW. The DOI bases the acceptable range on a cost survey and one of the documents referenced by DOI includes a June 26, 2008 technical memorandum prepared by Eastern Research Group, Inc. (ERG) regarding the PGE Boardman Plant. In this document, ERG references an acceptable cost range for SCR (apparently without reheat or gas-to-gas heat exchanges – GGHE) of $207-$267/kW. However, the ERG memorandum also references a cost estimate prepared by Black & Veatch and CH2M Hill for the PGE Boardman Plant of $309/kW (apparently for SCR without reheat). The Black and Veatch / CH2M Hill cost estimate was not referenced by the DOI. Based on the GRE BART submittal, the capital cost estimate for addition of the thermal oxidizer necessary to reheat the flue gas is approximately $1.275 million (approximately $7 per kW). Adding this to the above-referenced ERG cost ranges results in a range of approximately $214-$274/kW. Adding the $7 per kW cost to the Black and Veatch / CH2M Hill cost estimate results in a cost estimate of approximately $316/kW.

Based on the above, it can be seen that the GRE capital cost estimate for SCR with reheat of $310/kW is approximately 10% higher than the highest cost value of $274/kW prepared by ERG (adjusted for SCR with reheat but without the GGHE). The GRE capitol cost estimate for SCR with reheat is approximately 2% lower than the cost estimate of $316/kW prepared by Black and Veatch / CH2M Hill for the PGE Boardman Plant (adjusted for SCR with reheat but without the GGHE). Based upon this data, the GRE cost estimates appear to be in the range of similar cost estimates. This is especially true considering the inherent difficulty in calculating actual costs. Both the New Source Review Workshop Manual and the EPA Air Pollution Control Cost Manual state that control cost estimates are typically accurate within ± 20 to 30 percent. Based upon the above, the GRE cost estimate for SCR with reheat appears to be reasonable.

The DOI also continues to question how the Department verified the cost estimates. An example of how the Department verifies cost estimates is shown above. As can be seen from the above, the Department verified the cost estimates by comparing the calculated costs with all relevant data. The Department also verifies the actual calculations to determine if the values used are reasonable. Based on the ongoing comments, it appears that the DOI has relied on outdated models to estimate costs. As the Department has demonstrated in previous responses to DOI comments, the DOI cost estimates for other projects have been found to be significantly lower than EPA cost estimates for the same projects.

Comment 15: Follow up to comment 34 from October 23, 2009

DOI is suggesting a higher efficiency for SCR.

Response: See response to comment 4.

Comment 16: Follow up to comment 35 from October 23, 2009

DOI claims that the NDDH cannot simply halt the BART process by determining that a technically feasible option is too expensive on a cost per ton basis.

Response: The preamble to the BART guideline states "The interpretation of the requirements of the regional haze program reflected in the discussion above does not necessitate costly and time-consuming analyses. Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach [emphasis added] to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source's impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible." (F.R. Vol. 70, No. 128, p.39116). The cost of SCR is obviously excessive. Based on the visibility modeling results from Unit 2, the amount of improvement is visibility in any Class I area will be less than 0.01 deciviews in the most impaired days or approximately 0.10 deciviews (overall average) based on the 98th percentile value from the single source modeling when compared to the next best control technology. This amount of visibility improvement is negligible.

The Department is free to weigh the five factors as we choose (FR Vo. 70, No. 120, p.39130). As we have indicated, visibility improvement has been given little weight in the BART process. In the case of a control technology that is obviously excessive in cost on a dollar per ton basis, visibility improvement was given even less weight. That is, a control option that has an excessive cost on a dollar per ton basis, there is no reason to model the visibility improvement because visibility improvement will be a small part of the decision making process. There are literally dozens of control options with varying degrees of removal efficiency that could be analyzed. To make a workable BART process, not all options can be modeled to determine the amount of visibility improvement.

Comment 17: Follow up to comment 37 from October 23, 2009

DOI believes visibility modeling must be done for SOFA + SCR and SCR.

Response: See response to comment 16.

Comment 18: Follow up to comment 49 from October 23, 2009

DOI is advocating a startup limit (lb/hr) based on the BART allowable and the maximum rated heat input of the unit.

Response: For wall and tangentially fired boilers, the DOI suggestion may work. Because cyclone boilers emit at such a high rate during startup (>1.0 lb/10^6 Btu), limiting the emissions based on DOI suggestion does not provide the relief necessary. The unit would exceed the lb/hr limitation when the heat input is only 1/3 of the rated capacity or less. This would lead to extended periods of noncompliance. The NDDH believes the proposed limit is necessary for Minnkota since they did not include startups in the proposed BART limit. The Consent Decree for Minnkota requires these limits to be established separately.

Comment 19: Follow up to comment 54 from October 23, 2009

Same comment as comment 23 except for M.R. Young Unit 2.

Response: See response to comment 18.

Comment 20: Follow up to comment 63 from October 23, 2009

DOI indicated that NDDH should seriously evaluate all significant sources of human-caused impairment. They also questioned whether cumulative visibility improvement cited in the SIP included controls on Coyote and AVS.

Response: The NDDH considered all the significant sources of visibility impairing pollutants including any source that emits more than 100 tons per of sulfur dioxide and nitrogen oxides combined, oil and gas production facilities, prescribed burning, agricultural tillage operations and mobile sources. The NDDH believes this represents nearly all of the SO_2 and NO_x emissions from anthropogenic sources. The analysis that was conducted indicates it is not reasonable to control these sources.

The cumulative visibility modeling shown in the SIP did include controls for Coyote and AVS. For Coyote Station, this included a new wet scrubber plus ASOFA + SNCR. For AVS, this included LNB + SNCR.

Attachments

1. Email and other general comments
2. Montana Dakota Utilities complete comments
3. Department of Interior complete comments

From: odinwan@cableone.net
Sent: Wednesday, December 16, 2009 6:42 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

My grandfather homesteaded in the badlands, and my dad grew up there. My sister and I spent most weekends there, and I have a deep appreciation for the beauty, and also the pollution free air there. Thank you for the opportunity to comment on North Dakota's proposed regional haze plan. As a national park visitor and advocate for the parks, I value the beauty of Badlands, Theodore Roosevelt, and Wind Cave National Parks. I understand that the state's haze plan offers an unprecedented opportunity to clean up the air in these parks, which are affected by pollution from power plants and other industry. Air pollution from North Dakota's coal plants and industry also impacts national parks in Minnesota and Michigan, as well as four large wilderness areas.

The Clean Air Act requires old power plants and factories to reduce haze-causing pollutants. Technology exists to reduce this pollution--technology that will protect our national parks and wilderness areas, and public health. It is important that the Act and other air quality regulations are followed, so that we can enjoy these parks now and preserve them for our children and grandchildren.

The State of North Dakota can and should do more to protect our air quality as it implements the Regional Haze Rule. I request that the haze plan impose stricter limits on pollution from power plants and other industrial sources. In particular, North Dakota should require all appropriate coal plants to install more effective pollution control devices, and more aggressively pursue identified emission reductions from all sources.

Without this and other measures, North Dakota's coal plants will continue to unnecessarily obscure views in our national parks and wilderness areas for decades to come and deter tourists, including me and my family, from visiting the state of North Dakota and the beloved parks in the region. North Dakota must do its part to ensure that the air in our parks, and throughout the region, will indeed be restored to natural conditions.

Thank you for considering my comments.

Sincerely,
Alice Christianson
2807 25 Av S
Fargo, ND 58103

From: larrett@gwtc.net
Sent: Wednesday, December 16, 2009 5:52 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Penny Larrett
13019 Lakeview Dr.
Hot Springs, SD 57747

From: ron@cattletech.com
Sent: Wednesday, December 16, 2009 4:58 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
ron ragsdale
613 Main St
Rapid City, SD 57701

From: jannrayg@gwtc.net
Sent: Wednesday, December 16, 2009 5:35 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

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North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Ray Gellerman
12349 Moss Rock Lane
Custer, SD 57730

Bachman, Tom A.

From: a.goering@sio.midco.net
Sent: Wednesday, December 16, 2009 4:05 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

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North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Arden Goering
3305 E 33rd Street
Sioux Falls, SD 57103

Bachman, Tom A.

From: gbloomer@gwtc.net
Sent: Wednesday, December 16, 2009 3:47 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Jerry Bloomer
2146 Minnekahta Avenue
Hot Springs, SD 57747

Bachman, Tom A.

From: tinker1447@aol.com
Sent: Wednesday, December 16, 2009 3:36 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

Thank you for the opportunity to comment on North Dakota's proposed regional haze plan. As a national park visitor and advocate for the parks, I value the beauty of Badlands, Theodore Roosevelt, and Wind Cave National Parks. I understand that the state's haze plan offers an unprecedented opportunity to clean up the air in these parks, which are affected by pollution from power plants and other industry. Air pollution from North Dakota's coal plants and industry also impacts national parks in Minnesota and Michigan, as well as four large wilderness areas.

The Clean Air Act requires old power plants and factories to reduce haze-causing pollutants. Technology exists to reduce this pollution--technology that will protect our national parks and wilderness areas, and public health. It is important that the Act and other air quality regulations are followed, so that we can enjoy these parks now and preserve them for our children and grandchildren.

The State of North Dakota can and should do more to protect our air quality as it implements the Regional Haze Rule. I request that the haze plan impose stricter limits on pollution from power plants and other industrial sources. In particular, North Dakota should require all appropriate coal plants to install more effective pollution control devices, and more aggressively pursue identified emission reductions from all sources.

Without this and other measures, North Dakota's coal plants will continue to unnecessarily obscure views in our national parks and wilderness areas for decades to come and deter tourists, including me and my family, from visiting the state of North Dakota and the beloved parks in the region. North Dakota must do its part to ensure that the air in our parks, and throughout the region, will indeed be restored to natural conditions.

Thank you for considering my comments.

Sincerely,
Linda Meilink
2040 W Main St
Ste 210- #1656
Rapid City, SD 57702

From: jahag74@yahoo.com
Sent: Wednesday, December 16, 2009 3:27 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
Jamie Hagen
37989 138th Street
Aberdeen, SD 57401

From: agayken75@yahoo.com
Sent: Wednesday, December 16, 2009 3:19 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Aaron Gayken
310 W. 21st St. #9
Sioux Falls, SD 57105

From: tall_n_silvery@yahoo.com
Sent: Wednesday, December 16, 2009 3:19 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

Thank you for the opportunity to comment on North Dakota's proposed regional haze plan. As a citizen of North Dakota, a national park visitor and advocate for the parks, I value the beauty of Badlands, Theodore Roosevelt, and Wind Cave National Parks. I understand that the state's haze plan offers an unprecedented opportunity to clean up the air in these parks, which are affected by pollution from power plants and other industry. Air pollution from North Dakota's coal plants and industry also impacts national parks in Minnesota and Michigan, as well as four large wilderness areas.

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Thank you for considering my comments.

Sincerely,
Linda Jagielo
166 Boise Ave
Bismarck, ND 58504

From:	sheridar@gmail.com
Sent:	Wednesday, December 16, 2009 3:19 PM
To:	O'Clair, Terry L.
Subject:	Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
Sherida Ribordy
1806 Rushmore St.
Rapid City, SD 57702

From: harming@rushmore.com
Sent: Wednesday, December 16, 2009 3:19 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
W. Harming
P.O. 9402
Rapid City, SD 57709-9402

From: scotthed@hotmail.com
Sent: Thursday, December 17, 2009 8:03 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

Thank you for the opportunity to comment on North Dakota's proposed regional haze plan. As a resident of South Dakota as well as a national park visitor and advocate for the parks, I value the beauty of Badlands, Theodore Roosevelt, and Wind Cave National Parks. I understand that the state's haze plan offers an unprecedented opportunity to clean up the air in these parks, which are affected by pollution from power plants and other industry. Air pollution from North Dakota's coal plants and industry also impacts national parks in Minnesota and Michigan, as well as four large wilderness areas.

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Thank you for considering my comments.

Sincerely,
Scott Hed
713 S. Holt Avenue
Sioux Falls, SD 57103

From: jewels17_17@hotmail.com
Sent: Thursday, December 17, 2009 7:38 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
Julie Landkamer
208 N 3rd Street
Drayton, ND 58225

Bachman, Tom A.

From: pcw577@hotmail.com
Sent: Thursday, December 17, 2009 6:49 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
Charles Wirth
605 Judson Ave
Hurley, SD 57036

From: gjturner@westriv.com
Sent: Thursday, December 17, 2009 2:31 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

Thank you for the opportunity to comment on North Dakota's proposed regional haze plan. As an advocate for the parks, I value the beauty of Badlands, Theodore Roosevelt, and Wind Cave National Parks. I understand that the state's haze plan offers an unprecedented opportunity to clean up the air in these parks, which are affected by pollution from power plants and other industry. Air pollution from North Dakota's coal plants and industry also impacts national parks in Minnesota and Michigan, as well as four large wilderness areas.

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Thank you for considering my comments.

Sincerely,
Julie Turner
28759 127th St.
Mobridge, SD 57601-5000

From: bessythree@yahoo.com
Sent: Thursday, December 17, 2009 1:42 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
Ron Ratner
3700 S Westport Ave #3769
Sioux Falls, SD 57106

From: hawkins_j_m@hotmail.com
Sent: Wednesday, December 16, 2009 10:30 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Ran Zirasri
423 W. Century Ave. Apt. 201
Bismarck, ND 58501

From:	mantyfan@yahoo.com
Sent:	Wednesday, December 16, 2009 8:56 PM
To:	O'Clair, Terry L.
Subject:	Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Pamela Kjono
1146 McKinley Avenue
Grand Forks, ND 58201

From: ndhockeyfan87@yahoo.com
Sent: Wednesday, December 16, 2009 7:19 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Elaine Matthew
216 Windward Hills Ave
Grand Forks, ND 58201

From: O'Clair, Terry L.
Sent: Friday, December 18, 2009 11:40 AM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: staceydohn@cableone.net [mailto:staceydohn@cableone.net]
Sent: Friday, December 18, 2009 11:39 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Stacey Dohn
905 7th street south
Fargo, ND 58103

From: O'Clair, Terry L.
Sent: Friday, December 18, 2009 4:28 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: ann.nelson@gmail.com [mailto:ann.nelson@gmail.com]
Sent: Friday, December 18, 2009 3:34 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
Ann Nelson
10338 S Wood St.
Apt 1B
Chicago, IL 60643

From: O'Clair, Terry L.
Sent: Monday, December 21, 2009 4:53 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: amp_2010@msn.com [mailto:amp_2010@msn.com]
Sent: Monday, December 21, 2009 4:47 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Without this and other measures, North Dakota's coal plants will continue to unnecessarily obscure views in our national parks and wilderness areas for decades to come and deter tourists, including me and my family, from visiting the state of North Dakota and the beloved parks in the region. North Dakota must do its part to ensure that the air in our parks, and throughout the region, will indeed be restored to natural conditions.

Thank you for considering my comments.

Sincerely,
Adam Petty
1902 26 1/2 Court S
Fargo, ND 58103

Bachman, Tom A.

From: O'Clair, Terry L.
Sent: Friday, December 18, 2009 10:28 AM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: stewart.m.preston@gmail.com [mailto:stewart.m.preston@gmail.com]
Sent: Thursday, December 17, 2009 10:34 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

Thank you for the opportunity to comment on North Dakota's proposed regional haze plan. As a national park visitor and advocate for the parks, I value the beauty of Badlands, Theodore Roosevelt, and Wind Cave National Parks. I understand that the state's haze plan offers an unprecedented opportunity to clean up the air in these parks, which are affected by pollution from power plants and other industry. Air pollution from North Dakota's coal plants and industry also impacts national parks in Minnesota and Michigan, as well as four large wilderness areas.

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Thank you for considering my comments.

Sincerely,
Stewart Preston
PO Box 301
Medora, ND 58645

From: O'Clair, Terry L.
Sent: Thursday, December 17, 2009 4:26 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: twotails100@hotmail.com [mailto:twotails100@hotmail.com]
Sent: Thursday, December 17, 2009 1:05 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
marcella gilbert
910 brooklawn dr
brookings, SD 57006

From: O'Clair, Terry L.
Sent: Thursday, December 17, 2009 4:25 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: rcsailer@beu.midco.net [mailto:rcsailer@beu.midco.net]
Sent: Thursday, December 17, 2009 11:24 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
randy sailer
1018 cherry lane
beulah, ND 58523

Bachman, Tom A.

From: O'Clair, Terry L.
Sent: Thursday, December 17, 2009 4:24 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: dborman@att.net [mailto:dborman@att.net]
Sent: Thursday, December 17, 2009 10:48 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Darold Borman
1508 N Oakridge Place
Sioux Falls, SD 57110

From: O'Clair, Terry L.
Sent: Thursday, December 17, 2009 4:24 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: pjacobs289@aol.com [mailto:pjacobs289@aol.com]
Sent: Thursday, December 17, 2009 9:37 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
Paul Jacobs
11001 221st Ave.
Morristown, SD 57645

From: O'Clair, Terry L.
Sent: Monday, December 28, 2009 8:23 AM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: act3@goldenwest.net [mailto:act3@goldenwest.net]
Sent: Saturday, December 26, 2009 6:43 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
Andrea Yarger
26914 Battle Mountain Pkwy
Hot Springs, SD 57747

JAN 2010
Received
Air Quality

Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave
Bismarck, ND 58501-1947

8 January 2009

Dear Terry O'Clair:

I'm writing to submit a comment regarding the recent draft of the North Dakota State Implementation Plan (SIP) to reduce haze. Given the fact that the Theodore Roosevelt National Park is protected from man-made haze in the Clean Air Act and that man-made pollution from North Dakota power plants and industry is contributing to the haze in our national parks, it is very important that the ND SIP be revised to strengthen the regulations on our local coal-fired power plants. Burning approximately 30 million tons of coal each year, they are a major source of haze for our state and a substantial risk to our citizens' health.

The Clean Air Act requires ND to create a plan to reduce air pollution contributing to that haze, however ND's draft plan released last week fails to require strict enough limits for our state's largest pollution sources: the eight aging power plants, many of which were grandfathered in, therefore they have been allowed to pollute much more than the Clean Air Act's standards target. It is crucial for our state to use this moment to make the long-needed change and be more aggressive about protecting our people and natural resources, especially the quality of our air, land and water. Reducing air pollution from burning coal is the crucial step in protecting all three of these areas, since what goes up into the air inevitably ends up in our soil and water, thus in our citizens' bodies.

I ask that you revise and increase the controls in the SIP not only to protect our land and citizens, but also to protect and stimulate our sustainable economy. In every way, moving away from fossil fuels will benefit our state economically. It will force coal plants to move into sustainable- and in the long run- more inexpensive and profitable sources of energy. The price of burning fossil fuels will continue to rise as we start to pay for the externalities and as the international and national laws become stronger, which they are and are projected to continue to do. The income from green and sustainable energies, which ND has an abundant supply of, is continually rising and projected to rise. ND has already seen millions and even hundreds of millions of dollars invested in its wind farms, which needs to be further encouraged. A PEW study in 2009 stated that jobs in renewable energy outnumber jobs in the regular sector in ND by a margin of 3-to-1. So, raising the limits on coal may appear to be an economic loss in the short term, but it will certainly stimulate greater economic benefits, and a more stable future economy for our state in the long term.

Tourism is another aspect of our ND economy that we have to remember when considering revisions to the SIP. Tourism is such a large part of our ND economy, so we really need to protect our natural ecosystems from pollution in order to preserve these areas, as well as protect the people's health who visit them and keep the visibility as clear as possible so people can experience the majesty of these beautiful views. Every year I camp and hike in the Theodore Roosevelt National Park. The park is very important to me and many people I know. The friends I've taken there from out-of-state are always impressed by the visibility and "how far they can see", so it is really something we need to take seriously and protect from haze. In closing, I'd like to reiterate that this is both a health issue as well as an economic issue for our state, and the coal plants' pollution threatens them both.

For these and many other common sense reasons, I urge the ND State Health Department to revise and strengthen the air pollution controls in the ND SIP.

Thank you for hearing my request.

Sincerely,

James Kambeitz

Sickler
235+5w
ing ND 58642

BISMARCK ND 585
09 JAN 2010 PM 1 T

ND DH Division of air qu.
918E. Divide Ave
Bismarck, ND 58501

5850131947

HANDYMAN
CLUB OF AMERICA

Dear Sir!

I Feel there is no problem with the air qu. in N Dak.

thank you

JAN 2010
Received
Air Quality

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

JAN 2010
Received
Air Quality

January 7, 2010

Mr. Terry O'Clair
Director
Division of Air Quality – 2nd Floor
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, ND 58501-1947

Re: Comments on the North Dakota Department of Health Proposed Amendment to the State Implementation Plan (SIP) for Reducing Regional Haze

Dear Mr. ~~O'Clair~~ Terry:

Montana Dakota Utilities Co. (Montana-Dakota) submits the following comments on the North Dakota Department Health's (NDDH) proposed amendment to the State Implementation Plan (SIP) for reducing Regional Haze.

Montana-Dakota generates, transmits and distributes electricity and distributes natural gas in North Dakota, South Dakota, Montana and Wyoming. The company owns and operates electric steam generating facilities which are subject to extensive regulation under the Federal Clean Air Act. The following comments concern issues pertaining to R.M. Heskett Station Unit 2 (Heskett Unit 2) in the draft Regional Haze SIP.

Level of Emission Reduction from Voluntary Commitment

The NDDH included language in the last paragraph of Section 7.3.4 of the SIP, page 68, discussing a voluntary commitment by Montana-Dakota to reduce potential sulfur dioxide emissions in the future from Heskett Unit 2 by a minimum of 70 percent. The NDDH states in the SIP document that this commitment will reduce sulfur dioxide emissions to 1,660 tons per year at Heskett Unit 2 from its 2000-2004 emissions of 2,400 tons per year, yielding a 740 tons per year reduction. Montana-Dakota has calculated a projected average annual reduction of sulfur dioxide emissions of 474 tons per year that better represents the 70 percent reduction of sulfur from coal to stack during a normal operating year when adding limestone. This value, instead of 740 tons per year, should be used and is further explained in the following paragraphs.

The 2,400 tons per year NDDH cited in the SIP is an average sulfur dioxide emissions rate over the 2000-2004 time period. During this period, emissions varied from a minimum of 1,778 tons per year in year 2000 to a maximum of 2,754 tons per year in year 2004. The lower annual emissions are mainly due to plant shut downs, while the higher annual emissions are due to increased demand growth over time.

Montana-Dakota calculates the expected sulfur dioxide emission reduction by comparing emissions projected for a normal operating year when adding limestone to Heskett Unit 2 to the average sulfur dioxide emissions resulting from the higher operating years in 2000-2004. The higher emissions years are 2001 at 2,625 tons, 2003 at 2,650 tons, and 2004 at 2,754 tons, yielding an average of 2,676 tons of sulfur dioxide for a baseline annual average emissions rate.

To calculate the projected annual average sulfur dioxide emission rate for a normal operating year when adding limestone, Montana-Dakota made the following determinations and calculations. First, the average sulfur in coal from the 2000-2004 time period was approximately 0.72 percent, with an average heat content of the coal at 7,176 btu/lb. We then used Equation 19-25 from EPA Method 19 to calculate an average uncontrolled sulfur dioxide emission rate of approximately 2.01 lb/mmbtu. With limestone addition, Heskett Unit 2 could achieve a sulfur dioxide emission rate of approximately 0.60 lb/mmbtu, which assumes a 70 percent level of control from the uncontrolled emission rate of 2.01 lb/mmbtu. During a normal operating year with limestone addition, and assuming an approximate 91% availability (representing the average availability in 2001, 2003 and 2004), Heskett Unit 2 would be expected to emit approximately 2,202 tons of sulfur dioxide per year (2.01 lb/mmbtu x 916.5 mmbtu/hr x 7,971 hr/year (annual 91% availability) / 2000 lb/ton x 30% = 2,202 ton/year).

Based on the above, Heskett Unit 2 would expect to achieve an average annual sulfur dioxide emissions reduction of approximately 474 tons per year, which reflects the baseline emissions of 2,676 tons per year less the projected 2,202 tons per year with limestone control. If the NDDH should choose to include in the Regional Haze SIP a projected sulfur dioxide emission reduction associated with Montana-Dakota's voluntary commitment, Montana-Dakota could only support a projected average annual reduction of 474 tons per year.

Supporting SIP Documentation for Heskett Unit 2

We assume that the Appendices A.2 and A.3 to the final Regional Haze SIP will be updated and revised to include copies of: (1) the document titled, "CALPUFF Visibility Modeling Protocol: MDU Heskett Unit 2 BART Analysis" prepared by AECOM and dated November 25, 2009; (2) the NDDH and EPA Region 8 approvals of the November 25, 2009 BART modeling protocol for Heskett Unit 2, which include an e-mail from S. Weber, NDDH, to B. Paine, AECOM dated December 1, 2009, an e-mail from S. Weber, NDDH to K. Golden, EPA Region 8, dated December 1, 2009, and an e-mail from K. Golden, EPA Region 8, to S. Weber, NDDH, dated December 10, 2009); (3) a copy of the document titled "Updated BART CALPUFF Visibility Modeling Analysis for Montana-Dakota Utilities Heskett Station Unit 2," dated December 17, 2009, which sets forth the most recent visibility modeling analysis for Heskett Unit 2 (this document is currently included in the draft Regional Haze SIP documents, however, it is located at the bottom of the NDDH's webpage http://www.ndhealth.gov/AQ/RegionalHaze/); and (4) the December 21, 2009 NDDH correspondence to EPA Region 8 which states that Heskett Unit 2 is exempt from BART.

Reasonable Further Progress Goals

The federal Regional Haze Rules require NDDH to set reasonable progress goals (RPGs) toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064. The federal rules identify four factors that must be considered in evaluating potential added emission control measures to meet RPGs, including: (1) the cost of compliance; (2) the time necessary for compliance; (3) energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any existing source subject to such requirements. See e.g., "Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota," dated May 18, 2009, Revised Draft Report Prepared by: B. Nelson, W. Battye, and J. Hou, EC/R Incorporated.

As part of applying the RPG analysis to Heskett Unit 2, Montana-Dakota expects the NDDH to consider the degree of visibility improvement on a deciview (dv) basis and a cost per deciview improvement basis ($/dv) that would result from additional controls, since this is the approach the NDDH followed when evaluating emissions from other RPG sources in the State. At the public hearing held today on the proposed Regional Haze SIP, we understood NDDH to confirm that Heskett Unit 2 has been subject to RPG analysis. The analysis considered the degree of deciview improvement that would result from a 95 percent level of sulfur dioxide emission control. The analysis showed inconsequential deciview improvements at Theodore Roosevelt National Park (0.009 dv) and at Lostwood National Wildlife Refuge (0.003 dv). Based on the outcome of the analysis, NDDH stated that it would not require additional controls for Heskett Unit 2 under the RPG element of the SIP. While Montana-Dakota endorses this outcome, analyzing the incremental costs of control per deciview improvement would further support the NDDH's RPG conclusions with respect to Heskett Unit 2.

If you have any questions or would like to discuss our comments, please contact me at 222-7844.

Sincerely,

Abbie Krebsbach
Environmental Manager

cc: Andrea Stomberg, Vice President Electric Supply
Alan Welte, Generation Manager
Tony Stroh, R.M. Heskett Station Manager

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

January 8, 2010

N3615 (2350)

Mr. Terry L. O'Clair, P.E.
Director
Division of Air Quality
North Dakota Department of Health
Environmental Health Section
918 E. Divide Avenue
Bismarck, North Dakota 58501-1947

Dear Terry ~~Mr. O'Clair~~:

We appreciate the effort you and your staff have devoted to responding to the comments we provided during consultation on your State Implementation Plan (SIP) revision to address regional haze requirements of 40 CFR 51.300-308. However, after reviewing your "Response to DOI Comments" document, we believe that there are still some outstanding issues that warrant further consideration as you prepare the SIP revision for submittal to EPA Region 8. Specifically, we still contend that Theodore Roosevelt National Park (NP) should be treated in all impact assessments as one Class I area (not three separate areas), and that additional controls (e.g., Selective Catalytic Reduction) is Best Available Retrofit Technology (BART) for some BART-eligible units. Our follow-up comments are discussed in more detail below and in the enclosed document.

Treatment of Theodore Roosevelt NP

We appreciate your acknowledgement that Theodore Roosevelt NP is only one Class I area under the Clean Air Act. However, we disagree that units of the park can be separated when assessing visibility impairment for the purposes of determining if an existing source causes or contributes to visibility impairment under the Regional Haze Rule. Your response cites the definition of "adverse impact on visibility" which is a definition that applies for assessment under Section 51.307 regarding impacts of new sources. For purposes of applying Best Available Retrofit Technology (BART) to existing sources, or determining if an existing source could be controlled to aid in "reasonable progress" toward the national visibility goal of no human-caused impairment, a State should consider if a source contributes to "visibility impairment." Section 51.301 (x) defines visibility impairment as "any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions." U.S. Environmental Protection Agency rules for applying BART establish a test for "contribution" of sources as 0.5 deciview impact for the 98th percentile day over a three-year period. That impact applies to all locations (i.e., receptors) within a Class I area for the modeled three-year period. In the case of Theodore Roosevelt NP, modeling receptors are only located within the boundaries of the three individual units of the Class I area. Since lands outside of the Class I area are not included in assessing the 0.5 deciview impact, there is no misrepresentation of impacts for park visitors, and there is no extension of Class I status to areas outside of the park.

If receptors within the total park boundary show 0.5 or more deciview impacts (98th percentile day) over the three-year period, a BART-eligible source's emissions contribute to "visibility impairment" and must be assessed under EPA's regional haze BART guidance. We believe that this test is useful for any stationary source to identify those sources or groups of sources that should be evaluated for reasonable progress as well.

Best Available Retrofit Technology (BART) Analyses

We have reviewed the responses you provided to our comments on assessing BART controls. The enclosed follow-up comments supplement the concerns we have raised in light of your responses.

We have received a letter dated December 21, 2009, regarding new results of air quality modeling to determine if the Heskett Power Plant is subject to BART. We are coordinating with U.S. EPA Region 8 staff in their efforts to verify the new modeling results. Pending the outcome of the review, we may provide additional comments on these new modeling results.

Finally, we have recently become aware that Regenerative Selective Catalytic Reduction (SCR) is an available technology that is applicable to Electric Generating Units and has the potential to allow SCR to be installed on a relatively cool gas stream (e.g., following a scrubber) with relatively little auxiliary heat required. The primary drawbacks to this Regenerative SCR are the capital cost and space requirement, but this technology warrants further evaluation as possible BART for North Dakota sources.

Again, we appreciate your State's efforts to build a foundational SIP for the purposes of addressing regional haze and visibility protection in general for our national treasures. We look forward to working with the State to continue progress toward the national visibility goal.

Sincerely,

John Bunyak

for Christine L. Shaver
Chief, Air Resources Division
National Park Service

Sincerely,

Sandra V. Silva

Sandra V. Silva
Chief, Branch of Air Quality
U.S. Fish & Wildlife Service

Enclosure

cc:
Tom Bachman
Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, ND 58501-1947

Callie Videtich
U.S. EPA Region 8
1595 Wynkoop Street
Mail Code: 8P-AR
Denver, CO 80202-1129

Department of the Interior (DOI) Follow-up Comments on North Dakota Department of Health (NDDH) Best Available Retrofit Technology (BART) Analyses
January 8, 2010

DOI Comment 6: (Purpose of the BART Program)
The core purpose of the BART program is to improve visibility in our Class I areas. BART is not necessarily the most cost-effective solution. Instead, BART represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. We believe that it is essential to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected.

NDDH Response: In determining BART, visibility improvement was generally not weighted as heavily as the cost of compliance because we believe the single source modeling required by the BART guideline does not give a true representation of the degree of improvement in visibility **which may reasonably be anticipated to result from the use of the technology.**

We believe the cumulative visibility effects analysis promoted by DOI is scientifically unsound and not in accordance with rule or law. Adding the maximum improvement value (or 98th percentile) at one Class I area to the maximum improvement at another Class I area does not account for these maximums happening at different times. In addition, DOI has not defined which Class I areas should be added together to achieve the cumulative impact. This makes the analysis arbitrary. The single source modeling under BART does not provide a realistic estimate of visibility improvement of a given technology. Creating a "cumulative effects" analysis based on the flawed BART analysis only compounds the inaccuracy and misleads the reader of the SIP.

In addition, the BART Guideline only requires an evaluation of the change at each receptor. It does not require adding these changes together.

DOI Follow-up: In light of the NDDH's perceived problems with the suggested DOI approach, the NDDH should explain how it considered the benefits of reducing emissions with respect to visibility improvements at multiple Class I areas.

DOI Comment 8: The ability of SCR to reduce emissions, as assumed by NDDAQ, was inconsistent and sometimes underestimated.

NDDH Response: In the ANPR for the Four Corners Power Plant (Federal Register 8/28/09) EPA states "APS estimated that SCR could achieve NO_x control of approximately 90% or greater from the baseline emissions. For new facilities, 90% or greater reduction in NO_x from the SCR can be reasonably expected. See May 2009 White Paper on SCR from Institute of Clean Air

Companies. For SCR retrofits on an existing coal-fired power plant, Arizona Department of Environmental Quality (ADEQ) determined that 75% control from SCR (following upstream reductions by LNB) was appropriate for the Coronado Generating Station in Arizona. Based on this data, EPA has determined that an 80% control efficiency for SCR alone, rather than the 90+% control assumed by APS, is appropriate". The Department believes 80% is a reasonable estimate that allows the source to comply with the expected emission limit on a continuous basis.

DOI Follow-up: We have advised EPA Region 9 that it has underestimated the ability of SCR to reduce NO_x emissions from the sources in question and supported our comments with real-world data from actual retrofits to coal-fired EGUs. Our comments can be found in the same docket accessed by NDDH.

DOI Comment 9: The cost of SCR was consistently overestimated.

NDDH Response: The DOI used the EPA Air Pollution Control Cost Manual (February 1996) to estimate the capital cost and operating costs for the SCR system. The DOI did not use the most current version of this manual which is dated January 2002.

DOI Follow-up: We used the current version of the Cost Manual as it pertains to SCR.

NDDH Response: The EPA Air Pollution Control Cost Manual (both versions) is significantly out-of-date for estimating costs for SCR. This can be seen from the recently published results of EPA's review of the Four Corners Power Plant BART analysis. In the Advanced Notice of Proposed Rulemaking (August 28, 2009), EPA published the Consultant's, EPA's and the National Park Service's estimate of the cost for NO_x controls.

DOI Follow-up: We have advised EPA Region 9 that it has overestimated the cost of SCR to reduce NO_x emissions from the sources in question. Our comments can be found in the same docket accessed by NDDH.

NDDH Response: It would appear the NPS is underestimating annualized SCR costs by as much as a factor of 6 and cost effectiveness by as much as a factor of 3. The discrepancy between the annualized cost and the cost effectiveness is apparently due to the NPS overestimating the effectiveness of SCR. Based on this apparent underestimation, it appears the costs provided by the consultants and the Department's estimates are similar to EPA estimates and are reasonable. Any estimate by the FLM of cost on a dollar per deciview basis would be similarly flawed.

DOI Follow-up: NDDH should conduct an independent analysis by applying the EPA-recommended OAQPS Control Cost manual.

NDDH Response: As pointed out earlier, the OAQPS Control Cost Manual is out-of-date. EPA accepted estimates based on the CUE Cost Model for the Four Corners Power Plant BART analysis. Since the OAQPS Control Cost Manual is out-of-date and drastically underestimates control costs, we believe the CUE Cost Model provides a more realistic estimate of the costs.

DOI Follow-up: EPA Region 8 recommended that NDDH use the OAQPS Control Cost manual, and we support the EPA position on this matter.

DOI Comment 10: (Step 5: Visibility Improvement)
A) DOI believes it is appropriate to consider both the degree of visibility improvement as well as cumulative effects.
B) DOI is concerned that the Department did not provide the total improvement for each BART option.

NDDH Response: The total improvement under BART is not the best metric for addressing visibility associated with each option since the single source modeling under BART over predicts (by a factor of 5-7) the actual improvement in North Dakota. Incremental differences in improvement provides an easy way to evaluate the visibility improvement benefits of one option over another. The difference is equivalent to the total improvement of one option minus the total improvement of the other option. Providing the total improvement will mislead the reader of the SIP because of the over prediction. However, this information can be extracted from the analyses conducted by the operators of the BART sources. .

DOI Follow-up: NDDH is placing too much emphasis upon incremental differences; NDDH should provide the total improvement. In addition, we do not understand how NDDH can claim that the BART modeling over predicts (by a factor of 5-7) because in the Leland Olds Station Unit 1 and 2, and the Milton R. Young Unit 1 and 2 BART protocols, NDDH itself states: "The NDDH modeling protocol recommends a specific version of the CALPUFF modeling system as modified by the NDDH to specifically address terrain, climate, and emission characteristics of LOS / MRYS. ... The input files contained the specific coordinate grid points, wind field options, terrain, dispersion options, receptor coordinates and plume characteristics and other model parameters that the NDDH has determined best represents the region. The NDDH version of CALPUFF was used for modeling." Therefore, NDDH should support its claims that "the single source modeling under BART over predicts (by a factor of 5-7) the actual improvement in North Dakota."

DOI Comment 10: C) DOI is concerned about the difference in their modeling for Leland Olds Unit 2 and the Department's and Basin Electric's modeling results (the latter two sets of results agree closely).

NDDH Response: There are bound to be differences in modeling results when different model settings and options are used as well as different receptor grids. One error noted in the DOI modeling results was the input for the maximum 24-hour SO_2 emission rate for Unit 2. DOI used 17,610 lb/hr plus 1,581 lb/hr for sulfate. Unit 2 had a maximum 24-hour SO_2 (includes SO_4) of 12,205 lb/hr during the baseline period (2000-2004). DOI apparently used an SO_2 + SO_4 emission rate based on maximum future sulfur content. This is incorrect since current visibility conditions (12,205 lb/hr) are compared to conditions after controls are applied. The BART Guideline states "Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario)". The meteorological data used by the Department is from 2000-2004. Use of potential future uncontrolled emissions for the precontrol scenario is inconsistent with the BART guideline. The Department also noted that this error carried over into the emission rates for other pollutants. This error will provide a much greater improvement in visibility as found by the DOI.

DOI Follow-up: We agree with NDDH's method of assessing future emissions and control costs and effectiveness based upon anticipated changes in coal quality. We, therefore, believe that it is appropriate to model changes in visibility impairment on the same bases. The SO_2 emission rate was provided by Basin Electric in "Table 1.3-2 – Leland Olds Station Future PTE Emissions for BART Analysis". The sulfate emissions were derived from our PM speciation workbook and account for all condensible inorganic emissions. We invite NDDH to discuss this matter further.

DOI Comment 11: It appears to be more beneficial to reduce NO_x than to reduce SO_2 in this cool climate.

NDDH Response: The Department does not necessarily agree with this statement. There are situations in North Dakota where reduction in NO_x has very little impact on visibility. This can be seen from the AVS I analysis. A 65% reduction NO_x (2,356 tpy) only provided a 0.01 deciview improvement in the average of the 20% worst days.

DOI Follow-up: AVS 1 was not subject to BART, and thus not reviewed in that context. If one considers the relative visibility benefits of reducing SO_2 versus NO_x (on a per-ton basis) <u>at a given EGU that was subject to BART</u>, it appears to be more beneficial to reduce NO_x than to reduce SO_2 in this cool climate.

DOI Comment 12: DOI recommends more emphasis on the dollar per deciview metric.

NDDH Response: There was no established data base for this metric when the BART analyses were developed and when the Department was making its decisions. Even the DOI's data is not very useful since the EPA has not approved the BART determinations in that database. Again, the single source modeling does not reflect the true visibility improvement. It may be more realistic in some states than in others. Therefore, the comparison of $/deciview in North Dakota to $/deciview in another State is not an apples-to-apples comparison. The Department has considered the incremental visibility improvement between BART options. We believe this is the best metric given the limitations of single source modeling to provide realistic estimates of visibility improvement.

DOI Follow-up: NDDH has placed too much emphasis upon incremental differences and should explain what benchmarks or thresholds it used to make its decisions. As for the differences among state modeling procedures, the cost-per-deciview criterion we have suggested is simply the estimated cost divided by the estimated improvement—how that value is derived is irrelevant in this context—it is how the value is used that matters.

DOI Comment 13: For several units, NDDOH is proposing alternative sulfur dioxide (SO_2) limits that are similar to the presumptive BART limits because they allow a source to choose between a limit in terms of pounds of emissions per million Btu of heat input, or percent reduction of that pollutant. While EPA presented its BART Guidelines for SO_2 in that format, we do not believe that it was EPA's intention to allow the source to choose the more favorable limit. By definition, BART represents the highest degree of control that meets the five-factor test. Where NDDOH has determined that a lb/mmBtu limit is reasonable, it should require that that limit be met.

Similarly, where NDDOH has determined that a percent reduction limit is reasonable, it should require that that limit be met. If both limits are determined to be reasonable, then to allow the source to choose only one clearly does not represent the most stringent reasonable degree of control. Therefore, where NDDOH has proposed alternative limits, both should be required.

NDDH Response: The DOI has requested that the sulfur dioxide limitations be written as 95% reduction and 0.15 lb/10^6 Btu instead of 95% reduction or 0.15 lb/10^6 Btu. Coal quality data suggests that the source may not be able to comply with the 0.15 lb/10^6 Btu limit when the maximum sulfur coal is received. This would make the requested standard impossible to meet for high sulfur coal. The BART guidelines (40 CFR 51, Appendix Y, Section IV.E.4) states "you must require 750 MW power plants to meet specified levels of SO_2 of either 95 percent control or [emphasis added] 0.15 lb/10^6 Btu". The guidance does not indicate both standards apply. In addition, the BART presumptive levels are not applicable to any source in North Dakota except for NO_x at Coal Creek Station.

DOI Follow-up: There is also a fundamental problem with setting only a percent-reduction limit on SO_2 emissions. If fuel sulfur content increases, emissions can increase correspondingly. Unless sulfur content is limited, or a cap is placed on mass emissions (e.g., lb/hr, tons/yr as proposed by Wyoming, for example), the actual amount of SO_2 emitted is unlimited.

NDDH Response: The DOI has also asked that a mass per unit of time limit be placed on the permit for SO_2. The Department believes this is unnecessary since the Department's evaluation of visibility impacts was based on full load and worst case sulfur (i.e. highest 24-hour emissions). The Department asked the EPA if a mass per unit of time limit (24-hour basis to ensure the accuracy of the modeling) was necessary in the permit that establishes the BART limits. In a November 21, 2005 response from Laurel Dygowski of Region 8, it was stated "we think that a 24-hour limit is unnecessary and may not be of much value". Based on EPA's guidance and the Department's determination that mass per unit of time units are not necessary, the Department will not include such limits in the permit that establishes the BART limits.

DOI Follow-up: As we noted previously, even if coal quality deteriorates to the anticipated worst-case, the proposed control technology would still be capable of meeting the lower lb/mmBtu limit.

DOI Comment 25: On page 16 of the comments, the DOI states, "We believe that higher control efficiency is warranted for both the lignite and PRB sub-bituminous scenarios". The DOI goes on to state that a facility burning coal with an uncontrolled SO_2 emission rate of 2.4 lb/MM Btu for lignite and 1.6 lb/MMBtu on PRB "should be capable of at least 93% control and achieve an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis[11]". Footnote 11 in the DOI comments states, "Please see the entry in Appendix D for the permit issued by Wyoming to Black Hills Power for its WYGEN3 project".

NDDH Response: The DOI states a SD/FF at Stanton #1 "should be capable of" at least 93% control and an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis. The DOI attempts to support this position by referencing the WYGEN3 facility permit. Although the WYGEN3 facility does have a 0.09 lb/MMBtu SO_2 emission limit, according to the EPA RACT/BACT/LAER clearinghouse, the 0.09 lb/MM Btu SO_2 emission limit is on a 12-month rolling average basis, not a 30-day rolling average basis. Also, the RACT/BACT/LAER clearinghouse does not list a required SO2 removal efficiency. If the WYGEN3 facility burns low-sulfur coal, the facility could comply with the 0.09 lb/MMBtu emission limit with SO_2 control efficiencies below 90%. Furthermore, it is the Department's understanding that the WYGEN3 facility has yet to operate and demonstrate that the SO_2 emission limit can be achieved. Based upon these facts, the WYGEN3 facility permit does not support the DOI position that a SD/FF at Stanton Station Unit 1 "should be capable of" at least 93% control and an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis. The Department maintains the position that a SD/FF operating at Stanton Station Unit 1 is capable of achieving an SO_2 control efficiency of 90%.

DOI Follow-up: The WYGEN3 permit[1] limits the EGU to 117 lbSO_2/hr on a 30-day rolling average basis. At a heat input of 1,300 mmBtu/hr, this corresponds to 0.09 lb SO_2/mmBtu on a 30-day rolling average.

DOI Comment 26: On page 16 of the DOI comments, the DOI states, "Because the larger Stanton Unit #10 also located at this site is achieving less than 0.06 lb/MMBtu on an annual basis (presumably burning PRB coal) using the same SD/FF technology proposed for Stanton Unit #1, NDDAQ should explain why a newer installation of that technology at Stanton #1 cannot perform as well, at least on PRB coal".

NDDH Response: The DOI incorrectly states that Stanton #10 is larger than Stanton #1. In fact, Stanton #10 (with a heat input of approximately 642 MM Btu/hr) is approximately 2.8 times smaller than Stanton #1 (with a heat input of approximately 1,800 MM Btu/hr). The DOI states that Stanton #10 emitted SO_2 at an emission rate of 0.06 lb/MM Btu and asks the Department to explain why Stanton #1 cannot perform as well as Stanton #10 when burning PRB coal. Although the Stanton #10 facility has recently emitted SO_2 at an emission rate of 0.06 lb/MM Btu, based upon the average sulfur content of the coal burned the SO_2 removal efficiency at Stanton #10 is estimated to be approximately 90%. The dry scrubber technology proposed as BART for Stanton #1 is expected to achieve an SO_2 control efficiency of 90%, so Stanton #1 will be expected to perform as well as Stanton #10.

DOI Follow-up: We appreciate NDDH's correction of our error with respect to the relative sizes of the two EGUs. However, this does not change our contention that Stanton #1 should be able to perform as well as Stanton #10, both on lb/MMBtu and control efficiency bases. NDDH should show how it arrived at the conclusion that "based upon the average sulfur content of the coal burned the SO_2 removal efficiency at Stanton #10 is estimated to be approximately 90%."

DOI Comment 29: On page 17, the DOI states, "We believe that NDDAQ should have included SOFA with tail-end SCR with reheat in its analysis".

NDDH Response: The Department analyzed SCR with reheat in the BART analysis. A 90% control efficiency for SCR with reheat was assumed. For retrofits, the Department believes that a 90% control efficiency for SCR with reheat is highly optimistic and that 80% control is

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[1] http://deq.state.wy.us/eqc/orders/Air%20Closed%20Cases/07-2801%20Dry%20Fork%20Station/DEQ's%20Dispositive%20Response.63-Ex.16.pdf

reasonable. It should be noted that conducting the BART analysis using an 80% control efficiency would make the cost of SCR with reheat even more cost prohibitive.

In the Department's judgment, SOFA with SCR with reheat would not attain greater than 90% NO_x control at Stanton #1. Since SOFA with SCR with reheat would be more expensive than SCR with reheat (which has already been determined to be cost prohibitive assuming a 90% control efficiency), it can be concluded that an analysis of SOFA with SCR with reheat would also be considered to be cost prohibitive.

DOI Follow-up: NDDH cannot assume that "SOFA with SCR with reheat would be more expensive than SCR with reheat" on a total annual cost basis without doing a proper cost analysis. It is possible that the additional capital cost (on an annual basis) of adding SOFA would be more than offset by reduced annual operating costs.

DOI Comment 30: On pages 18 and 20 the DOI indicates that the expected costs for SCR with reheat included in the BART analysis for Stanton #1 are higher than the cost estimates prepared by the DOI. The DOI requests that NDDH document and justify the SCR-with-reheat cost estimate.

NDDH Response: The DOI requests that the Department document and justify the SCR with reheat cost estimate for Stanton #1. The Department considers the cost estimate of SCR with reheat submitted with the GRE BART analysis to be extensively documented and the Department has verified the cost estimates.

DOI Follow-up: NDDH should explain how it "verified the cost estimates".

DOI Comment 34: DOI believes SOFA + SCR can achieve 83% NO_x removal.

NDDH Response: As pointed out in the Advanced Notice of Proposed Rulemaking for the Four Corners Power Plant, the Arizona DEQ determined that 75% control was appropriate following low NO_x burners at the Coronado Generating Station. Leland Olds 1 is equipped with low NO_x burners. We believe 75% reduction for the retrofit of a 43 year old plant is appropriate. Reducing the emission rate to 0.05 $lb/10_6$ Btu achieves 212 tons per year additional NO_x reduction. The cost effectiveness is then $8,888/ton to $12,784/ton. These costs are still considered excessive and SCR + SOFA is not BART.

DOI Follow-up: We have advised EPA Region 9 that it has underestimated the ability of SCR to reduce NO_x emissions from the sources in question and supported our comments with real-world data from actual retrofits to coal-fired EGUs. Our comments can be found in the same docket accessed by NDDH. Furthermore, NDDH cannot simply halt the BART

process by determining that a technically feasible option is too expensive on a cost-per-ton basis. A full five-factor BART analysis is required.

DOI Comment 35: NDDAQ did not evaluate the visibility benefits of any of the technically feasible options except for the proposed basic SOFA + SCR.

NDDH Response: The cost analysis eliminated SCR, coal reburn + SCR, coal reburn + SOFA and SNCR + boosted SOFA on either a very high cost effectiveness basis or a very high incremental cost basis. This left SOFA + SNCR as the most efficient control option. This option was then modeled to determine the visibility effects.

DOI Follow-up: NDDH cannot simply halt the BART process by determining that a technically feasible option is too expensive on a cost-per-ton basis. A full five-factor BART analysis is required.

DOI Comment 37: Based upon NDDAQ's analysis, addition of the proposed basic SOFA+SNCR to LOS #1 yields a cost-effectiveness of $25.6 million per dv at Theodore Roosevelt NP and $13.2 million per dv cumulatively when Lostwood WA is included. NDDAQ has not adequately considered the visibility benefits of the control strategies it evaluated. NPS' analysis of addition of basic SOFA+SCR with reheat yields a cost-effectiveness of $12.6 – $32.3 million per dv cumulatively. We would normally consider costs above $20 million/dv to be above the average that most states/source are proposing, but believe that these results warrant further analysis, as we will discuss in more detail with respect to LOS #2.

NDDH Response: SOFA + SCR has an estimated cost of $8,888 - $12,784/ton of NO_x removed. The incremental cost would be approximately $15,748/ton to $25,319/ton over the next most efficient option. It is clear that SOFA + SCR, or SCR alone, is not cost effective for this unit.

DOI Follow-up: NDDH cannot simply halt the BART process by determining that a technically feasible option is too expensive on a cost-per-ton basis. A full five-factor BART analysis is required.

M.R. Young Station Unit 1

DOI Comment 49: NDDAQ proposes that NO_x emissions be limited to 2,070.2 lb/hr on a 24-hour rolling average basis during startup. We recommend that NDDAQ limit the mass emission rate (e.g., lb/hr) to the rate under normal operation.

NDDH Response: The proposed limit is under normal operating conditions without the ASOFA and SNCR, since the SNCR cannot be operated until the proper boiler temperature is reached. The actual startup emissions will be much higher (>1.0 lb/10^6 Btu). Therefore, limiting startup emissions based on normal operations with SNCR (<0.35 lb/10^6 Btu) will provide no relief to the source during startup.

DOI Follow-up: To clarify our initial comment, we are suggesting that NDDH limit emissions on a lb/hr basis (not lb/mmBtu) to a rate equal to the maximum lb/hr that would be allowed were MRYS #1 to meet its BART limit under normal operation (e.g., BART limit in lb/mmBtu * maximum allowable heat input in mmBtu/hr). Thus, as load (and furnace temperature) increases, the effectiveness of the NO_x control technology also increases so as to stay under the lb/hr limit.

DOI Comment 51: NDDAQ overestimated the costs associated with adding SCR. In the absence of supporting documentation by NDDAQ, we also estimated a total annual cost for ASOFA + SCR with reheat at $9.7 million and a corresponding cost effectiveness of $1,028 per ton.

NDDH Response: Minnkota has provided its own estimate of the cost of SCR as part of the BACT process under their Consent Decree. Minnkota's estimate has been included in the BART determination.

DOI Response: We have not had sufficient time to properly evaluate the materials posted on or after November 25, 2009, by NDDH.

<u>M.R. Young Station Unit 2</u>

DOI Comment 54: NDDAQ proposes that NO_x emissions be limited to 3,995.6 lb/hr on a 24-hour rolling average basis during startup. We recommend that NDDAQ limit the mass emission rate (e.g., lb/hr) to the rate under normal operation.

NDDH Response: See response to Comment 49.

DOI Follow-up: To clarify our initial comment, we are suggesting that NDDH limit emissions on a lb/hr basis (not lb/mmBtu) to a rate equal to the maximum lb/hr that would be allowed were MRYS #2 to meet its BART limit under normal operation (e.g., BART limit in lb/mmBtu * maximum allowable heat input in mmBtu/hr). Thus, as load (and furnace temperature) increases, the effectiveness of the NO_x control technology also increases so as to stay under the lb/hr limit.

DOI Comment 56: NDDAQ overestimated the costs associated with adding SCR. In the absence of supporting documentation by NDDAQ, we estimated total annual costs for ASOFA+tail-end SCR with reheat at $15.6 million and a corresponding cost effectiveness of $898 per ton.

NDDH Response: Minnkota has provided a much more detailed cost estimate of SCR with reheat as part of their BACT process under their Consent Decree. This estimate has been used in the Department's BART determination.

DOI Follow-up: We have not had sufficient time to properly evaluate the materials posted on or after November 25, 2009, by NDDH.

DOI Comment 63: Table 9.9 summarizes the results of assessing the costs and visibility improvement associated with possible controls on these facilities. The two power generation facilities, Coyote and AVS, have emissions and Q/d impacts that are similar, if not greater than, BART sources that will be required to add controls. The methodology to calculate visibility improvements noted in Table 9.9 are not explained in this section but appear to be some calculation of changes in the long-term metric of the 20 percent worst visibility days. These sources likely contribute to higher impacts on a daily basis, and a reduction in their emissions would be part of a broad strategy to reach natural conditions at the Class I areas. As such NDDAQ should examine the total improvement from the suite of sources as part of its reasonable progress assessment, not a simple unit by unit approach.

NDDH Response: The improvement in the 20% worst days was used to indicate the amount of visibility improvement. The SIP was revised to better explain this. Addressing individual days under reasonable progress is inconsistent with the reasonable progress goals in 40 CFR 51.308(d)(1) which states "The reasonable progress goals must provide for improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 CFR 51.301 defines the most impaired days as meaning "the average visibility impairment (measured in deciviews) for the 20% of monitored days in a calendar year with the highest amount of visibility impairment." 40 CFR 51.301 defines the least impaired days as the average visibility impairment (measured in deciviews) for the 20% of monitored days in a calendar year with the lowest amount of visibility impairment." It is clear that reasonable progress goals should be established based on the average of the "most impaired days" and the "least impaired day", not individual days.

The Department did evaluate the cumulative effects of the most efficient remaining options. As stated on p. 182, the cumulative visibility improvement was 0.11 deciviews at LWA and 0.03 deciviews at TRNP. The less efficient control options would provide even less improvement.

DOI Follow-up: The use of daily impacts is a good means to identify those sources that have the largest impact on the 20 percent worst days. Since North Dakota is not meeting the uniform rate of progress for visibility improvement under EPA's guidance, it should seriously evaluate all significant sources of human-caused impairment. It is unclear if cumulative visibility improvement cited in the SIP included controls at Coyote and AVS.

Basin Electric Power Cooperative

Comment 1: Basin Electric believes LDSCR and TESCR are not technically feasible. They believe the Department should not rely on historical operating data of biomass boilers and should not rely on vendor's statements that they will provide performance guarantees for LDSCR and TESCR. Basin Electric believes LDSCR and TESCR are not commercially available for boilers that combust North Dakota lignite.

Response: The Department's analysis of this issue indicates that electrostatic precipitators, such as those at the Leland Olds Station, are capable of removing up to 99% of the sodium that is in the lignite combusted. The analysis also indicates that control of the submicron sodium and potassium aerosols will be greater than 90%. This indicates the flue gas characteristics will be no worse than cyclone boilers burning subbituminous coal in a high dust SCR configuration. It also indicates the concentration of potassium and sodium aerosols are less than pilot scale testing for biomass combustion which indicates an SCR can be successfully operated (Zheng et. al. 2008, Kling et. al. 2007). The commenter provided no evidence to dispute this point. Biomass contains soluble sodium and potassium just like North Dakota lignite. TESCR is being operated successfully on several biomass boilers.

Regarding vendor guarantees, the BART Guideline states "Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, we do not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Generally, you should make decisions, about technical feasibility based on chemical, and engineering analyses (as discussed above), in conjunction with information about vendor guarantees." The information on vendor guarantees was only one portion of the evidence that was considered in making the technical feasibility determination. The commenter also suggested that pilot scale testing is necessary before LDSCR and TESCR can be determined to be technically feasible. The flue gas characteristics after an ESP when compared to pilot testing at biomass-fired boilers (Zheng et. al. and Kling et. al.) indicate LDSCR and TESCR can be successfully operated on North Dakota lignite. Pilot testing will help optimize the design of LDSCR or TESCR and provide a better estimate of catalyst life; however, the NDDH believes it is unnecessary for determining technical feasibility.

Comment 2: The commenter believes that BART NO_x controls that have a cost effectiveness greater than $1,350 per ton are unreasonable.

Response: The EPA has not established a "bright line" for determining whether BART controls are cost effective or reasonable. In the preamble to the proposed BART Guideline (F.R. Vol. 69, No. 87, p. 25198) EPA discussed this issue. This discussion indicates the WRAP technical support document for the Grand Canyon visibility Transport Report Annex listed control options are "low" below $500 per ton, "moderate" from $500 per ton to $3,000 per ton and "high" if over $3,000 per ton. This is a 1999 document and costs must be adjusted accordingly for inflation. The CAIR rule, which could have been used as a substitute for BART, had an estimated cost of up to $2,700 per ton (this rule has now been vacated). Based on the information cited, the NDDH believes the $1,350 per ton cost effectiveness is a reasonable BART cost.

Comment 3: The Department's conclusion (in the SIP), that the elimination of every in-state emissions source would still not achieve the 2018 reasonable progress (glide path) goal, is counterintuitive and is misleading on several fronts.

Response: Because the commenter provided no specific information on why this conclusion is "counterintuitive or misleading," the Department cannot directly respond. However, the Department believes that the modeling analysis supporting this conclusion makes a very strong and intuitive point about the relatively low contribution of North Dakota visibility-affecting emissions sources to visibility degradation in North Dakota Class I areas. Therefore, the Department stands by the conclusion.

Basin Electric, Great River Energy and Minnkota Power Coop.

Comment 1: The commenters want the SIP revised to redefine natural visibility conditions and reset the glide path for reasonable progress goals.

Response: For the current planning period and SIP, the Department does not have the time or resources to adjust natural visibility conditions and reset the uniform rate of progress glide path as suggested. However, the Department finds merit in this suggestion and will consider such adjustments in the next planning period.

Great River Energy

Comment 1: GRE agreed with the NDDH's modeling approach and encouraged the NDDH to use the most up-to-date modeling science and to calibrate these models with actual monitored data to ensure their relative accuracy.

Response: Agreed

Comment 2: GRE believes the NDDH must preserve its ability to adjust the glide path for non-manmade and international emissions.

Response: See response to Comment No. 1 under Basin Electric, Great River Energy and Minnkota Power Coop.

Comment 3:

(a) GRE believes site specific cost estimates provided by various consulting firms are more accurate than from cost manuals which are adjusted for inflation.

Response: Agreed

(b) GRE believes that approximately $1,000 per ton cost effectiveness should be used as a cutoff for BART determinations.

Response: See response to Basin Electric’s Comment No. 2.

Attachments

1. Basin Electric’s Comments.
2. Combined Comments of Basin Electric, Great River Energy and Minnkota Power Coop.
3. Great River Energy Comments.

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Air Quality

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RE: Basin Electric Power Cooperative Comments on proposed Amendments to the State Implementation Plan for Air Pollution Control relating to the Reduction of Regional Haze

Dear Mr. O'Clair:

Basin Electric Power Cooperative (Basin Electric) appreciates this opportunity to offer comments on the proposed Amendments to the State Implementation Plan for Air Pollution Control relating to the Reduction of Regional Haze. Basin Electric agrees, in general, with your individual BART Determination for our two generating units at the Leland Olds Facility. We also support the Department's determination of technical infeasibility relating to High-Dust Selective Catalytic Reduction (SCR) as applied to cyclone boilers combusting North Dakota Lignite.

We do, however, believe that the Department is in error in its applicability determination that Low-Dust and TE SCRs are technically feasible for reduction of Nitrogen oxides (NOx) from a cyclone boiler firing North Dakota Lignite. The determination was seemingly based on transference of historical operating data of biomass fired boilers whose boiler type, size, and flue gas properties do not represent a similar enough application to justify its extension to North Dakota Lignite-fired cyclone boilers. Most concerning was a reliance on vendor statements alleging their willingness to consider offering guarantees of NOx reduction performance outside the framework of binding contractual obligations to back up these statements, or evidence that these promises of potential guarantees had any guaranteed performance levels that would make them meaningful. This sets a dangerous precedent of vendor puffing serving as a basis for claiming commercial availability. The clear path forward was to do the needed pilot testing, and then base the determination on this actual performance testing in future phases of the regional haze program. EPA guidance is clear that when pilot testing is needed, the application is not commercially available. When this bright-line test is ignored, where the line is drawn becomes arbitrary and unsupportable. When a decision has hundreds of millions of dollars of potential impacts on electrical customers throughout the Midwest, the evidence supporting commercial availability needs to be placed on a firmer technical, legal and factual foundation. Although we agree with your determination that Low-Dust and TE SCRs are not economically feasible, we ask you to re-consider your determination that Low-Dust and TE SCRs are commercially available for high-sodium-lignite cyclone boilers.

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Sargent and Lundy (S&L) is an independent engineering and construction management service organization who has been a leader in the design, construction, and operation of selective catalytic reduction within the energy industry. Furthermore, S&L has participated in the development of the only two tail-end configured SCRs on coal-fired boilers in the United States. S&L provided significant input as to what is known and what is unknown from their previous experience of SCR design on Texas Lignite, Sub-bituminous, and Bituminous fired boilers. S&L presented extensive evidence showing that pilot testing is required to design Low and Tail-end SCR systems for several reasons, including that the chemical and physical properties of the flue gas from combusting North Dakota Lignite in a cyclone boiler is unique and not well enough understood—based on S&L's previous experiences of SCR applications—to make it a commercially available technology.

The cost of this pilot testing is estimated to be $1.5 to 2.0 million and would take 18 to 24 months to complete. This need for pilot testing provides, under EPA guidance, the bright-line test that demonstrates that Low-Dust and Tail-end configured SCR are not a commercially available technology for high-sodium-lignite burning cyclone boilers. We are disappointed that EPA continues to encourage you to ignore EPA's own bright-line test; Low-Dust and TE SCRs require pilot testing before they can be applied to high-sodium-lignite-burning cyclones, which precludes a determination that those applications are commercially available under any reasonable interpretation of EPA's own guidance.

The NDDH requested that Basin Electric prepare a cost effectiveness determination for a Tail-End SCR application. As explained previously, it is impractical to provide a definitive cost determination for a Tail End SCR application without completing the additional testing described above. In May 2009, at the NDDH's request, a hypothetical cost effectiveness determination as developed by S&L and submitted to the Department. Hypothetical cost effectiveness were developed under five various scenarios of various catalyst life, and other input costs, i.e. natural gas, ammonia and subsequent sorbent control. The hypothetical cost effectiveness ranged from a low of $4,170 per ton up to $5,976 per ton.

The hypothetical cost effectiveness determination as determined by S&L should then be compared to the NOx control and cost impact data published by EPA as part of the Regional Haze Rule rulemaking process, including EPA's "Technical Support Document – Methodology for Developing BART NOx Presumptive Limits" (EPA Clean Markets Division, June 15, 2005). This review would indicate that EPA established the presumptive BART limits under the Regional Haze Rule of $1,350 per ton as being cost effective for all boilers other than cyclones while control technologies that had a cost impact greater than $1,350 were not cost effective. SCR were determined to be cost effective on Cyclone Boilers. The average cost effectiveness of SCR on Cyclone Boilers was determined to be $901per ton.

Attached for your consideration is S&L's report of this regulatory evaluation. The estimated cost effectiveness of $4,170 to $5,976 per ton for Tail End SCR on a cyclone boiler is significantly higher than EPA established reasonable cost threshold for NOx Controls under BART of $1,350 per ton.

Basin Electric also suggests that the Department revise what is defined as the natural background visibility and then re-setting the glide path for reasonable progress. Emission sources that are beyond the control of the Department (international point sources and particulate matter such as windblown dust and wildfires) should be removed from the reasonable progress determination. Multiple significant modeling efforts have been completed for North Dakota Class I areas that indicate the significant role the international source and the non-point source particulate matter. The conclusion that with the elimination of every in-state emissions would still not achieve the 2018 reasonable progress goal is counterintuitive and is misleading on several fronts. This discussion (Jan 2010) was submitted collaboratively to the Department under separate cover by Great River Energy, Minnkota Power Cooperative and Basin Electric Power Cooperative.

Basin Electric has now completed most of the construction of its new sulfur dioxide scrubber for its Leland Olds station several years before when construction would have commenced if Basin Electric had waited for the NDDH's BART determination. A couple months ago, the NDDH asked if Basin Electric would consider offering further early action under Reasonable Progress for non-BART-eligible sources in North Dakota. This request came too late for Basin Electric to advance it to its management and board. This does not preclude consideration of this possibility at some point in the future.

Sincerely,

Cris Miller

Cris Miller
Senior Environmental Project Administrator

/gmj
Enclosure: Sargent and Lundy Letter to Mr. Cris Miller (January 2010)

Sargent & Lundy LLC

William DePriest
Senior Vice President
312-269-6678
312-269-2499 (fax)

January 6, 2010

Mr. Cris Miller
Senior Environmental Project Administrator
Basin Electric Power Cooperative
1717 E. Interstate Avenue
Bismarck, ND 58503-0564

Project: Basin Electric Power Cooperative – Leland Olds Station
Subject: BART Cost Effectiveness Thresholds

Dear Mr. Miller:

The purpose of this letter report is to present the U.S. Environmental Projection Agency's (EPA's) determination of cost-effectiveness thresholds for retrofit emission control technologies under the Regional Haze Rule.[1] Basin Electric Power Cooperative asked Sargent & Lundy (S&L) to perform this evaluation to supplement the Best Available Retrofit Technology Determination prepared for Leland Olds Station Units 1 and 2, and submitted to the North Dakota Department of Health (NDDH) in August 2006.

S&L provides comprehensive consulting, engineering, design, and analysis for electric power generation and power delivery projects throughout the U.S., and we are very familiar with all of the major environmental rules regulating emissions from electric generating units, including the Regional Haze Rule. We are experienced with all aspects of air pollution control, and have prepared a number of control technology evaluations, cost-estimates, and cost-effectiveness evaluations for electric generating units. To complete this analysis, we reviewed nitrogen oxide (NOx) control and cost impact data published by EPA as part of the Regional Haze Rule rulemaking process, including EPA's "Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet" and "Technical Support Document – Methodology for Developing BART NOx Presumptive Limits" (EPA Clean Air Markets Division, June 15, 2005).

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[1] The Regional Haze Rule was published on July 6, 2005, "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations," 70 FR 39104. Unless otherwise noted, all references to EPA's Regional Haze Rule in this document mean the preamble and rule published on July 6, 2005.

Based on our review of the cost impact evaluation prepared by EPA to establish the presumptive BART limits under the Regional Haze Rule, it can be concluded that a threshold of $1,350/ton should be used to establish the cost-effectiveness of NOx retrofit controls. In general, EPA concluded that NOx control technologies that had a cost impact of less than $1,350/ton were cost-effective (e.g., combustion controls on all boiler types other than cyclones), while control technologies that had a cost impact greater than $1,350 were not cost-effective (e.g., SCR on all boiler types other than cyclones).

Background

Basin Electric Power Cooperative's (BEPC's) Leland Olds Station (LOS) Unit 2 is a B&W cyclone-fired unit with a turbine-generator nameplate rating of 440 MW. The unit was identified by NDDH as a BART-eligible source under the Regional Haze Rule. As such, BEPC is required to control emissions from LOS Unit 2 using Best Available Retrofit Technology (or "BART"). In August 2006, BEPC submitted its BART evaluation for the Leland Olds Station, including an evaluation of NOx emission controls on LOS Unit 2 (the "BART Determination Study"). The BART Determination Study concluded that selective non-catalytic reduction (SNCR) with advanced separated overfire air (ASOFA) represented BART for NOx control on LOS Unit 2, and proposed a BART NOx emission limit of 0.35 lb/mmBtu (30-day rolling average).

Tail-end selective catalytic reduction (TE-SCR) was identified in the BART Determination Study as a potentially available post-combustion NOx retrofit control technology for LOS Unit 2. However, the study determined that TE-SCR would be susceptible to unacceptable catalyst deactivation from soluble alkalis in the unit's lignite fuel (most notably sodium). The study concluded that TE-SCR was not a technically feasible NOx retrofit control technology due to the flue gas characteristics associated with the North Dakota lignite fired in LOS Unit 2.

Subsequently, NDDE requested additional analysis of the cost effectiveness of the TE-SCR technology assuming the technology was determined to be technically feasible and commercially available. In response to the Department's request, BEPC submitted a cost effectiveness evaluation of the TE-SCR on LOS Unit 2. That evaluation, dated May 27, 2009, calculated a cost effectiveness for TE-SCR (assuming technical feasibility) to be in the range of $4,170 and $5,976/ton depending on the rate of catalyst degredation and the cost of consumables (ammonia and natural gas). This letter report reviews the economic impact evaluation prepared by EPA to support the final Regional Haze Rule, which established a cost-effectiveness threshold for retrofit control technologies.

BART Cost Effectiveness

The Regional Haze Rule requires that a determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable, taking into consideration: (1) the technology available; (2) the costs of compliance; (3) the energy and non-air-quality environmental impacts of compliance; (4) any pollution control equipment in use at the source; (5) the remaining useful life of the source; and (6) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[2] BART is determined on a case-by-case basis. Guidelines for making BART determinations are included in Appendix Y of 40 CFR Part 51 (Guidelines for BART Determinations Under the Regional Haze Rule). The Appendix Y guidelines for BART determinations identify the following five steps in a case-by-case BART analysis:

Step 1. Identify All Available Retrofit Control Technologies.
Step 2. Eliminate Technically Infeasible Options.
Step 3. Evaluate Control Effectiveness of Remaining Control Technologies.
Step 4. Evaluate Impacts and Document the Results.
Step 5. Evaluate Visibility Impacts.

Step 4 of the BART determination process involves an evaluation of potential impacts associated with the technically feasible retrofit technologies. Impact evaluations should be conducted to assess: (1) costs of compliance; (2) energy impacts; and (3) non-air quality environmental impacts. The economic analysis performed in Step 4 of the BART determination examines the cost-effectiveness of each control technology, on a dollar-per-ton of pollutant removed basis. Annual emissions using a particular control device are subtracted from baseline emissions to calculate tons of pollutant controlled per year. Annual costs are calculated by adding annual operating and maintenance (O&M) costs to the annualized capital cost of an option. Cost effectiveness of an option is simply the annual cost ($/yr) divided by the annual pollution controlled (ton/yr).

Presumptive BART Limits

In the Regional Haze Rule EPA established presumptive BART emission limits for SO_2 and NOx for certain electric generating units (EGUs) based on fuel type, unit size, cost effectiveness, and the presence or absence of pre-existing controls.[3] The presumptive levels were intended to reflect "highly cost-effective technologies," while providing flexibility to States to consider source specific characteristics when evaluating BART.

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[2] See, 70 FR 39105 col. 2.

[3] See, 40 CFR 51 Appendix Y Part IV, and 70 FR 39131.

Methodology for Developing BART NOx Presumptive Limits

To develop the presumptive BART NOx limits, EPA analyzed costs and emission reductions associated with the installation of various NOx control systems at BART-eligible EGUs including combustion control and post-combustion control systems. A detailed cost impact evaluation was developed using different combinations of boiler design, fuel, and control technology. Results of the NOx cost impact evaluation, including control costs and controlled NOx emission rates used in the evaluation, are presented in EPA's "Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet" ("BART Excel Spreadsheet"). The methodology used by EPA to prepare the BART Excel Spreadsheet is described in EPA's "Technical Support Document – Methodology for Developing BART NOx Presumptive Limits" (EPA Clean Air Markets Division, June 15, 2005).

The cost-effectiveness of each retrofit technology was calculated based on: (1) capital cost ($/kW); (2) fixed O&M ($/kW); (3) variable O&M (mills/kW-hr); and (4) controlled NOx emissions (lb/mmBtu). Capital and fixed O&M costs were adjusted based on boiler capacity to account for economies-of-scale achievable with larger units. Variable O&M costs were calculated using each individual units' baseline heat input to account for individual capacity factors. Costs were developed for bituminous, lignite and subbituminous-fired units for the following five boiler configurations: (1) Cyclones; (2) Cell Burners; (3) Dry-Bottom (DB) Wall-Fired; (4) DB Turbo-Fired; and (5) Tangentially (T) Fired units.[4]

Three coal-fired control cases were used by EPA to evaluate the cost-effectiveness of combustion and post-combustion NOx control technologies on coal-fired EGUs. A description of the three control cases, designated as Cases 1a, 1d, and 1e, is provided in Table 1.

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[4] EPA also prepared cost effectiveness calculations Stoker, Wet-Bottom, and "Other" boiler configurations; however, because of the limited number of boilers in each of those groups (5, 6, and 1, respectively) those boilers have not been included in this summary.

Table 1
BART Cost-Effectiveness Evaluation
Coal-Fired EGU Control Cases

Control Case	Control Action Taken	Major Assumptions/Notes
1a	Installation of current NOx combustion controls for unit with no prior controls, or which had controls installed before 1997. For unit with controls installed in or after 1997, install incremental controls if a complete set of combustion controls was not installed (low NOx Burners and Overfire Air). For Cyclone units, apply coal reburn if no prior controls installed. For Cell Burners, install current combustion controls if the unit had no controls or controls were installed before 1997. Do not include existing SCR or SNCR units in the Control Case NOx Rate.	If the 2004 NOx rate was less than the floor rate established for each NOx control technology, no controls added. Used average heat input from 2002 – 2004 to calculate an Average NOx Rate. Assumed 10,000 Btu/kWh heat rate for coal-fired boilers.
1d	Install SCR, unless unit already has SCR installed or the 2004 NOx rate is already at or below the SCR floor rate.	
1e	Install rotating overfire air (ROFA) unless unit already has SCR or the 2004 NOx Rate is already at or below the ROFA floor rate, or the calculated ROFA rate is greater than or equal to the 2004 NOx rate. Also, for Cyclone boilers install SCR. Do not include units with existing SCR/SNCR in the Control Case NOx rate.	

Presumptive NOx BART Limits

For all types of boilers, other than cyclone units and units already equipped with post-combustion controls (i.e., SCR and SNCR), the NOx presumptive BART limits were based on the use of current combustion control technologies. EPA established the presumptive BART levels for each subcategory based on control strategies determined to be generally cost-effective for all units within the subcategory.[5] For sources without post-combustion controls EPA established a presumption as to the appropriate BART limits based on boiler design, coal type, and combustion controls. The BART NOx presumptive emission limits are summarized in Table 2.

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[5] See, 70 FR 39134 col. 2.

Table 2
Presumptive NOx Emission Limits for BART-Eligible Coal-Fired Units*

Unit Type	Coal Type	Presumptive NOx Limit
Dry-Bottom Wall-Fired	Bituminous Subbituminous Lignite	0.39 0.23 0.29
Tangential Fired	Bituminous Subbituminous Lignite	0.28 0.15 0.17
Cell Burners	Bituminous Subbituminous	0.40 0.45
Dry-Turbo-Fired	Bituminous Subbituminous	0.32 0.23
Wet-Bottom Tangential-Fired	Bituminous	0.62
Cyclone Boilers	All	0.10

* 70 FR 39135 Table 2.

Presumptive BART Cost-Effectiveness

EPA developed the presumptive NOx BART limits listed in Table 2 based on an evaluation of the cost-effectiveness of each control technology. A summary of the average cost-effectiveness for each control case (calculated as the total control cost for all units within the subcategory divided by the total annual tons of NOx removed) by boiler type is provided in Table 3.

Table 3
Average Cost Effectiveness of NOx Controls for BART-Eligible Coal-Fired Units by Boiler Type[6]

Boiler Type	Unit Average Cost Per Ton Removed		
	Case 1a	Case 1d	Case 1e
Cyclone – All	$1,330	$901	$901
Cell Burner – All	$1,198	$1,383	$722
DB Wall Fired-All	$723	$1,554	$853
DB Turbo Fired – All	$622	$1,483	$733
T-Fired – All	$376	$2,012	$875

Case 1a = current combustion controls (LNB+OFA for all boiler types) and coal reburn on cyclone boilers.
Case 1d = SCR on all units.
Case 1e = advanced combustion controls (ROFA on all boiler types) and SCR on cyclones.

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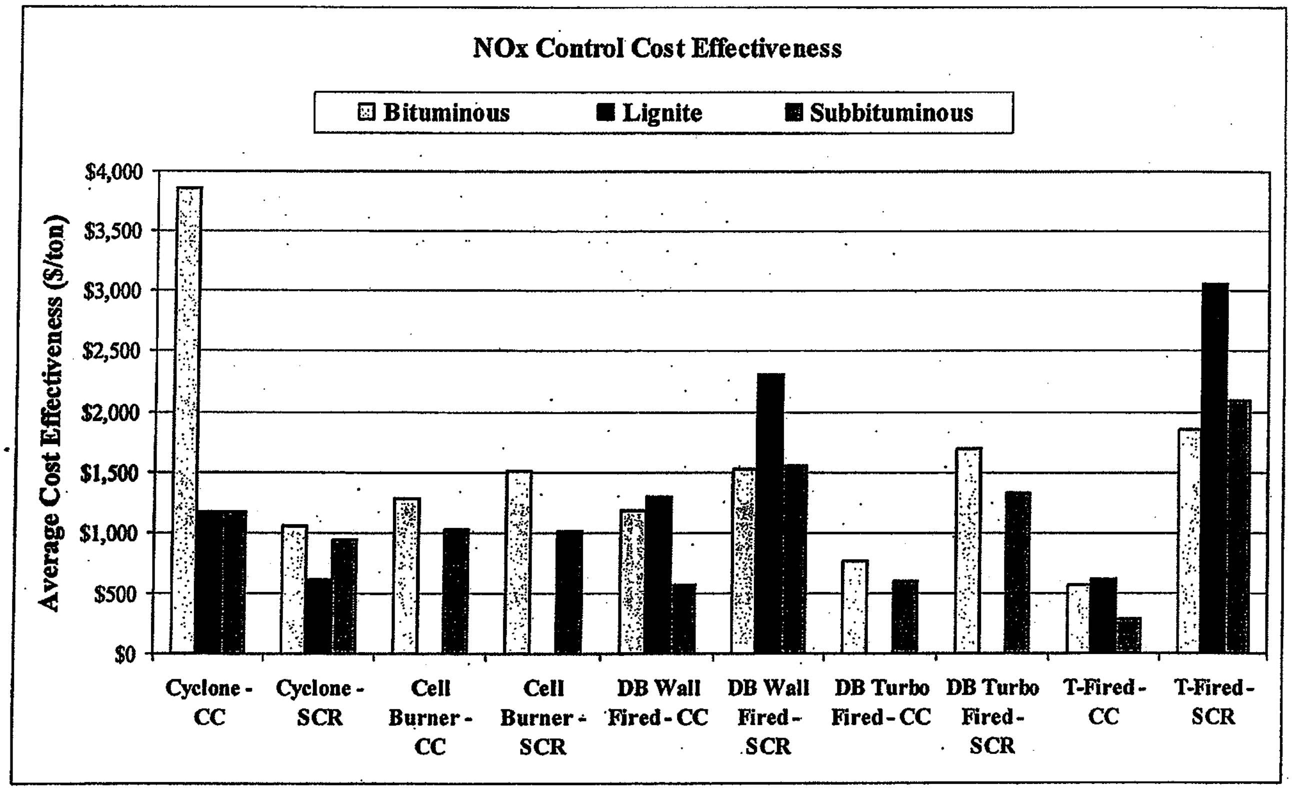
[6] See, 70 FR 39135,Table 3. For EGUs currently using post-combustion controls such as SCR or SNCR to reduce NOx during part of the year, EPA established a presumption that use of these same controls year-round is BART. EPA's cost impact assessment showed year-round operation of existing SCRs, compared to operation during the 5-month ozone season only, to be highly cost effective with an average cost-effectiveness of $170/ton (70 FR 39134).

For all the boiler types (except cyclones) the NOx BART limits were based on the use of current combustion control technologies. EPA's cost impact analysis found that combustion controls (Case 1a) were generally, but not always, more cost-effective than post-combustion controls such as SCRs (Case 1d). The cost-effectiveness of combustion control systems (for boiler types other than cyclones) averaged between $376/ton (T-Fired Units) and $1,198/ton (Cell Burners). Combustion controls on Cyclone Boilers (i.e., coal reburn) were determined to be less cost-effective, averaging $1,330/ton removed.

SCR control systems were found to be less cost-effective on all boiler types except Cyclone Boilers. The cost-effectiveness of SCR for all boiler types other than cyclones averaged between $1,383/ton (Cell Burners) and $2,012/ton (T-Fired units). The cost-effectiveness of SCR control on Cyclone Boilers was determined to average $901/ton. The average cost effectiveness of combustion controls and SCR for each boiler type and fuel (i.e., bituminous, lignite, and subbituminous) are shown in Figure 1.

Figure 1
Average Cost Effectiveness of NOx Combustion Controls and SCR



Based on the cost impact results summarized in Figure 1 EPA concluded that combustion controls could cost-effectively reduce NOx emissions on all boiler types other than cyclones, while post-combustion controls, including SCR, were excluded from EPA's presumptive BART determination based on cost impacts.

Cyclone Cost Evaluation

EPA's cost impact evaluation concluded that SCR was more cost-effective than combustion controls on Cyclone Boilers. SCR was determined to be more cost-effective on Cyclone Boilers for several reasons, including: (1) relatively high baseline NOx emission rates; (2) relatively low combustion control efficiencies; (3) high SCR control efficiencies; (4) high combustion control capital costs (compared to combustion controls on other boiler types); and (5) high combustion control O&M costs. Some of the control and cost assumptions used by EPA to develop the BART NOx presumptive limits are summarized in Tables 4 and 5.

Table 4
BART NOx Control Assumptions - Summary

NOx Rate or Control Efficiency	**Unit**	**Boiler Type**				
		Cyclone	**Cell Burner**	**DB Wall-Fired**	**DB Turbo-Fired**	**T-Fired**
Baseline 2004 NOx Rate (units w/o combustion controls)	lb/mmBtu	0.79	0.47	0.40	0.41	0.34
Baseline 2004 NOx Rate (all units)	lb/mmBtu	0.68	0.40	0.37	0.39	0.29
Controlled NOx Rate (combustion controls)	lb/mmBtu	0.47	0.37	0.27	0.22	0.19
Average Combustion Control Efficiency*	%	40.5%	21.2%	32.5%	46.3%	44.1%
Controlled NOx Rate (SCR)	lb/mmBtu	0.073	0.060	0.060	0.060	0.060
Average SCR Control Efficiency**	**%**	**89.3%**	**85.0%**	**83.8%**	**84.6%**	**79.%**

* Average combustion control efficiency was calculated based on the 2004 baseline NOx emission rate associated with units without current combustion controls.

** Average SCR control efficiency was calculated based on the 2004 Baseline NOx emission rate for all units not currently equipped with SCR control.

Table 5
BART Cost Assumptions - Summary

Control Technology	Cost	Unit	Boiler Type				
			Cyclone	Cell Burner	DB Wall-Fired	DB Turbo-Fired	T-Fired
Combustion Controls	Capital Costs	$/kW	$72.66	$23.43	$23.43	$23.43	$14.52
	Fixed O&M	$/kW	$1.10	$0.35	$0.36	$0.36	$0.22
	Variable O&M	mill/kWh	0.26	0.07	0.07	0.07	0.02
	Total Cost	mill/kWh	1.80	0.50	0.47	0.50	0.27
SCR	Capital Costs	$/kW	$100	$100	$100	$100	$100
	Fixed O&M	$/kW	$0.66	$0.66	$0.66	$0.66	$0.66
	Variable O&M	mill/kWh	0.60	0.60	0.60	0.60	0.60
	Total Cost	mill/kWh	2.66	2.41	2.25	2.25	2.18

Based on a review of the control and cost assumptions summarized in Tables 4 and 5, it appears that the most significant variable contributing to the cost effectiveness of SCR on Cyclone Boilers is the relatively high cost of combustion controls. Combustion controls were significantly more expensive on Cyclone Boilers than on other boiler types. Capital costs for combustion controls (i.e., coal reburn) on cyclones averaged $72.66/kW compared to capital costs of $23.43/kW for combustion controls on Cell Burners, DB Wall-Fired, and DB Turbo-Fired units, and $14.52/kW on T-Fired units. Similarly, both fixed and variable O&M costs were significantly higher for Cyclone Boiler combustion controls. As a result, total annual costs for combustion controls on Cyclone Boilers averaged 1.80 mill/kWh, compared to 0.50 mill/kWh for Cell Burners and DB Turbo-Fired units, 0.47 mill/kWh for DB Wall-Fired units and only 0.27 mill/kWh for T-Fired units.

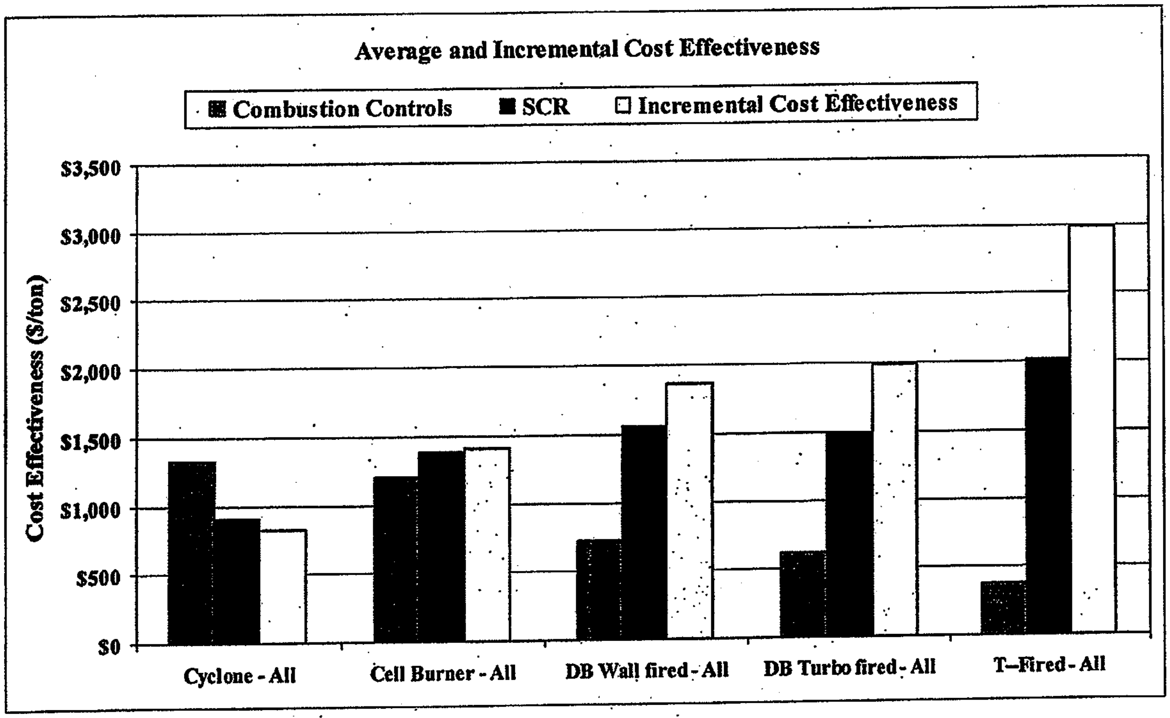
On the other hand, the same cost assumptions were used for SCR retrofit controls regardless of boiler type (i.e., $100/kW Capital Costs-adjusted for boiler size, $0.66/kW Fixed O&M, and 0.60 mill/kWh Variable O&M). Overall annual costs of an SCR system were similar for all boiler types, averaging between 2.18 mill/kWh (T-Fired units) and 2.66 mill/kWh (Cyclone Boilers).

Due to the relatively low control effectiveness and the high cost of combustion controls (including both capital and O&M), combustion controls were determined to be less cost effective on Cyclone Boilers than SCR. SCR control was assumed to achieve significantly lower controlled NOx emissions (0.073 lb/mmBtu compared to 0.47 lb/mmBtu with combustion controls) at a relatively low incremental increase in capital costs ($100/kW compared to $72.66/kW for combustion controls). Based on these assumptions SCR was found to be more cost effective on Cyclone Boilers than combustion controls.

BART Cost Effectiveness Conclusions

Regardless of the assumptions used in the BART cost impact evaluation, EPA concluded that post-combustion controls were not cost effective for all boiler types other than Cyclone Boilers. Thus, the cost effectiveness of SCR controls on those boiler types can be used to determine the cost-effectiveness threshold used by EPA to conclude that post-combustion controls were not cost-effective. In addition to the average cost effectiveness of a control technology (i.e., relative to the base case), the incremental cost-effectiveness to go from one level of control to the next more stringent level of control (i.e., from combustion controls to SCR) may be used to evaluate the cost impact of the more stringent control. Figure 2 summarizes the average cost effectiveness of combustion controls, the average cost effectiveness of SCR, and the incremental cost effectiveness of SCR (compared to combustion controls) for each boiler type

Figure 2
Average and Incremental Cost Effectiveness of NOx Retrofit Controls

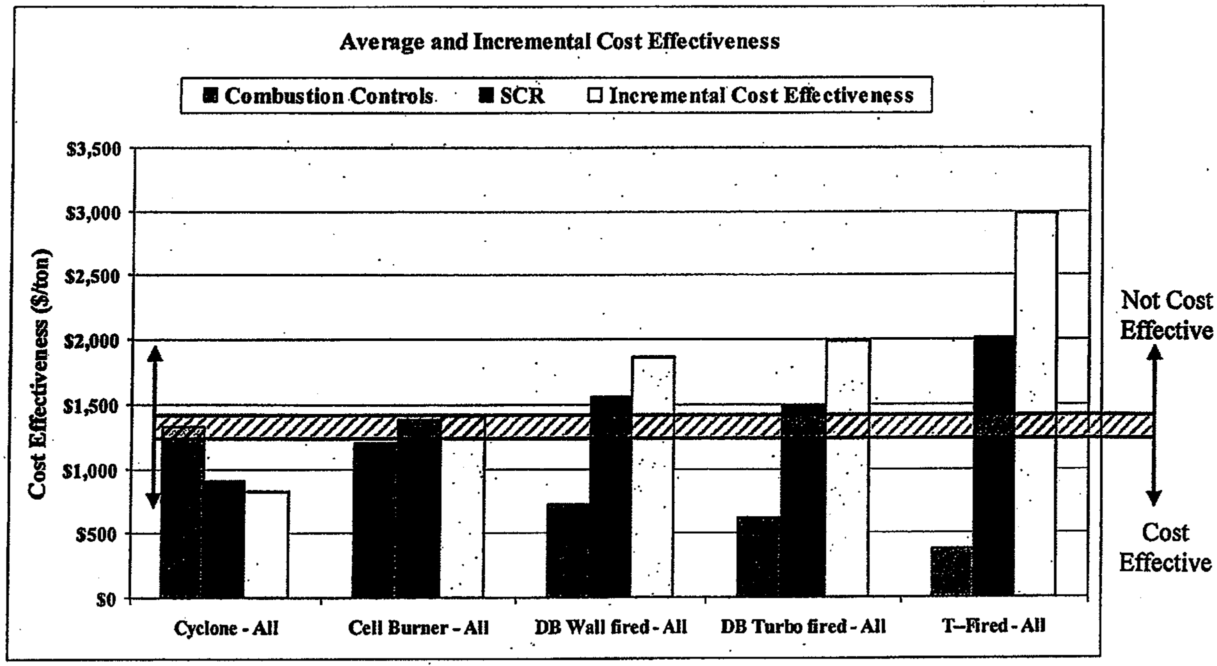


For all boiler types other than cyclones, combustion controls were determined to be a cost-effective NOx retrofit control option while post-combustion SCR was not considered to be cost-effective. Combustion controls had an overall average cost effectiveness (calculated by dividing total annual costs by total annual tons of NOx removed for all boiler categories other than cyclones) of approximately $535/ton, and ranged from $281/ton (T-Fired subbituminous units) to $1,296/ton (DW Wall-Fired lignite units). SCR had an overall average cost effectiveness of $1,749/ton, ranging from $1,016/ton (Cell Burner – subbituminous) to $3,060/ton (T-Fired lignite units). Other than Cyclone Boilers, the Cell Burner category had the highest combustion control cost-effectiveness and the lowest SCR cost-effectiveness at $1,198/ton and $1,383/ton, respectively.

Conversely, SCR, rather than combustion controls, were determined to be cost-effective on Cyclone Boilers. The average cost-effectiveness of combustion controls and SCR on Cyclone Boilers was determined to be $1,330/ton and $901/ton, respectively.

Figure 3 shows the average and incremental cost-effectiveness for combustion controls and SCR on each boiler type, and shows the approximate thresholds used by EPA to establish cost-effectiveness.

Figure 3
Average and Incremental Cost Effectiveness of NOx Retrofit Controls
Showing Cost-Effectiveness Thresholds



Based on the cost impact evaluation prepared by EPA to establish the presumptive BART limits, it can be concluded that a threshold of $1,350/ton should be used to establish the cost-effectiveness of NOx retrofit control technologies. In general, control technologies that had a cost impact of less than $1,350/ton were determined to be cost-effective (e.g., combustion controls on all boiler types other than cyclones), while control technologies that had a cost impact greater than $1,350 were determined not to be cost-effective (e.g., SCR on all boiler types other than cyclones).[7]

Again, the purpose of this letter report is to summarize EPA's determination of cost-effectiveness thresholds for retrofit emission control technologies under the Regional Haze Rule. This evaluation of EPA's cost-effectiveness threshold for retrofit emission control technologies was based on a review of EPA documents published to support the Regional Haze Rule, and should be directly applicable to cost-effectiveness evaluations included in the Leland Olds BART Determination Study.

Should you need additional information, please do not hesitate to contact me.

Very Truly Yours,

William DePriest
Sr. Vice President and
Director Environmental Services

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[7] EPA's cost impact evaluation included a couple of notable exceptions to this general statement. For example, combustion controls on both lignite- and subbituminous-fired Cyclone Boilers had a cost-effectiveness of $1,161/ton and $1,167/ton (which is below the $1,350/ton threshold). Similarly, post-combustion SCR on subbituminous-fired Cell Burners had a cost impact of $1,016/ton (which is below the $1,350/ton threshold).

January 7, 2010

JAN 2010
Received
Air Quality

North Dakota Department of Health
Attn: Terry O'Clair
Second Floor
918 East Divide Avenue
Bismarck, ND
58501-1947

Re: Comments on Notice of Intent to Amend the State Implementation Plan for Air Pollution Control Relating to Reduction of Regional Haze

Please accept the attached document that was developed by Bob Paine, from AECOM, on behalf of the undersigned Electric Cooperatives. Mr. Paine presents valid arguments for re-visiting natural background conditions and re-setting the glide path. He recommends additional modeling to exclude uncontrollable particulate matter (PM) emissions, such as windblown dust and wildfires, as well as international SO2 and NOx emissions, which are not within the jurisdiction of the North Dakota Department of Health. The North Dakota Department of Health should also consider Mr. Paine's recommendations as part of their weight of evidence for determining reasonable progress under the Regional Haze Requirements.

//s//Lyle Wytham
Manager, Environmental
Services

BASIN ELECTRIC
POWER COOPERATIVE
A Touchstone Energy® Cooperative

//s//Mary Jo Roth
Manager, Environmental
Services

GREAT RIVER
ENERGY®
A Touchstone Energy® Cooperative

//s// John Graves,
Environmental Manager

Minnkota Power
Cooperative, Inc.

Enc: "Visibility Projections at North Dakota Class 1 Areas with Consideration of Uncontrollable Emissions" dated January 6, 2010

Visibility Projections at North Dakota Class I Areas with Consideration of Uncontrollable Emissions

(Comments provided for revisions to the North Dakota State Implementation Plan for Air Pollution Control Relating to the Reduction of Regional Haze)

Robert Paine, AECOM Environment
January 6, 2010

Introduction

The purpose of this document is to comment on the use of the default natural visibility conditions defined by the United States Environmental Protection Agency (USEPA)[1] to assess progress in attaining the goals of the Regional Haze Rule (RHR), which is the subject of the North Dakota State Implementation Plan (SIP). In its December 2, 2009 draft SIP, North Dakota notes in Section 8.6.3.3 that,

> "Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO_2 and NO_x emissions in North Dakota will not achieve the uniform rate of progress for this [2018], or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources."

It is clear that the use of USEPA default natural conditions leads to unworkable and absurd results for North Dakota's ability to determine the rate of progress toward an unattainable goal. The definition of natural conditions that can be reasonably attained for a reasonable application of USEPA's Regional Haze Rule must be revised. USEPA provides each state with ability to do this, and North Dakota should seriously consider this option.

The objective of this memorandum is to summarize recent modeling studies of natural visibility conditions and to suggest how such studies can be used in evaluating the uniform rate of progress in reducing haze to attain natural visibility levels. In addition, the distinction between natural visibility and policy relevant background visibility is discussed. Treatment of this issue by other states who are also considering what to do for their Regional Haze Rule SIPS is also discussed.

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[1] USEPA, 2003. *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule.* EPA-454/B03-005. http://www.epa.gov/ttn/oarpg/t1/memoranda/rh_envcurhr_gd.pdf.

Natural Haze Levels

The Regional Haze Rule establishes the goal that natural visibility conditions should be attained in Federal Class I areas by the year 2064. Additionally, the states are required to determine the uniform rate of progress (URP) of visibility improvement necessary to attain the natural visibility goal by 2064. Finally, each state must develop a SIP identifying reasonable control measures that will be adopted well before 2018 to reduce source emissions of visibility-impairing particulate matter (PM) and its precursors (SO_2 and NO_x).

Estimates of natural haze levels have been developed by the USEPA for visibility planning purposes and are described in the above-referenced USEPA 2003 document. The natural haze estimates were based on ambient data analysis of selected PM species for days with good visibility and are shown in Table 1. These estimates were derived from Trijonis (1990)[2] and use two different sets of natural concentrations for the eastern and western U.S. Tombach (2008)[3] provides a detailed review and discussion of uncertainty in the USEPA natural PM estimates. Natural visibility can be calculated using the IMPROVE equation which calculates the light scattering caused by each component of PM. Objections have been raised both in the assumed natural concentrations of PM and in the method by which the IMPROVE equation is used to calculate visibility (EPRI, 2004). In response, changes in the IMPROVE equation and in the method for calculating natural visibility were developed in 2005 and are described by Pitchford et al.[4]

The USEPA guidance also makes provision for refined estimates of site-specific natural haze that differ from the default values using either data analysis or model simulations. However, most states have continued to use the default natural haze levels for calculating the progress toward natural visibility conditions. Tombach and Brewer (2005)[5] reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach (2008) also reviewed estimates of natural haze levels and proposed that, instead of using two sets of default natural PM concentrations for the eastern and western US, a large number of sensitivity zones should be developed that reflect regional variability in natural PM sources. Tombach (2008) also suggested that modeling studies are a possible approach to further revise estimates of natural PM concentrations.

Previous modeling studies have shown that the estimates of natural visibility described above for "clean" days will differ from the results of model simulations when United States anthropogenic emissions are totally eliminated (Tonnesen et al., 2006[6]; Koo et al., 2009[7]), especially when natural wild fire emissions are

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[2] Trijonis, J. C. Characterization of Natural Background Aerosol Concentrations. Appendix A in Acidic Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions -- Causes and Effects. J. C. Trijonis, lead author. National Acid Precipitation Assessment Program: Washington, DC, 1990.

[3] Tombach, I., (2008) *Natural Haze Levels Sensitivity -- Assessment of Refinements to Estimates of Natural Conditions,* Report to the Western Governors Association, January 2008, available at http://www.wrapair.org/forums/aamrf/projects/NCB/index.html.

[4] Pitchford, M., Malm, W., Schichtel, B., Kumar, N., Lowenthal, D., Hand, J., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, J. Air & Waste Manage, Assoc. 57: 1326 – 1336, 2007.

[5] Tombach, I., and Brewer, P. (2005). Natural Background Visibility and Regional Haze Goals in the Southeastern United States. *J. Air & Waste Manage. Assoc. 55,* 1600-1620.

[6] Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside,

included in the model simulation. Because the URP is calculated using model simulations of PM on the 20% of days with the worst visibility, wild fires and other extreme events can result in modeled levels of natural haze (even without any contribution of US anthropogenic sources) that are significantly greater than the natural levels used in the USEPA guidance for URP calculation. This could make it difficult or impossible for states to identify emissions control measures sufficient to demonstrate the URP toward attaining visibility goals because the endpoint is unachievable even if all US anthropogenic emissions are eliminated, as North Dakota has already determined even for the interim goal in 2018.

Modeling studies for natural ozone and PM have been completed at the global scale with the GEOS-CHEM model (Fiore et al., 2003[8]; Park et al., 2004[9]). Park et al. (2006)[10] estimated the contribution of both natural PM and international transport of PM in the eastern and western U.S. and compared their results to the USEPA default natural concentrations. They found significantly less difference in the natural concentrations between the east and west compared to the USEPA default values. Their modeled western concentrations were greater than the USEPA default values, while their modeled eastern concentrations were lower than the default values.

Tonnesen et al. (2006)[11] performed visibility modeling simulations for the WRAP using a "clean emissions" scenario in which all (US and international) anthropogenic emissions were removed from the model, and the GEOS-CHEM natural simulation was used to provide boundary conditions for CMAQ. This CMAQ simulation was not considered an adequate representation of natural conditions because some natural emissions data were not available. However, it did include natural fire emissions and was useful for showing the maximum visibility possible when all US and international anthropogenic emissions were totally eliminated. The model results were evaluated for annual average visibility and extinction coefficient, shown in Figure 1. The largest source of natural emissions in this model simulation was from wildfires, which were predominantly located in the Western US.

Riverside, California, November. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

[7] Koo B., C.J. Chien, G. Tonnesen, G.Yarwood, J. Johnson, T. Sakulyanontvittaya, P. Piyachaturawat, and R. Morris, (2009). Revised Natural Components for Regional Modeling of Background Ozone and Particulate Matter and their Impacts on Emissions Control Strategies, manuscript under preparation.

[8] Fiore, A., D. J. Jacob, H. Liu, R. M. Yantosca, T. D. Fairlie, and Q. Li (2003) Variability in surface ozone background over the United States: Implications for air quality policy, J. Geophys. Res., 108, ACH 19-1 - ACH 19-12.

[9] Park, R. J., D. J. Jacob, B. D. Field, R. M. Yantosca, and M. Chin (2004) Natural and transboundary pollution influences on sulfate-nitrate-ammonium aerosols in the United States: Implications for policy, *J. Geo-phys Res., 109*, D15204, doi:10.1029/2003JD004473.

[10] Park, R. J., D. J. Jacob, N. Kumar, R. M. Yantosca (2006) Regional visibility statistics in the United States: Natural and transboundary pollution influences, and implications for the Regional Haze Rule, *Atmos. Env., 40*: 5405-5423.

[11] Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside, Riverside, California, November. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

More recently, Koo et al. (2009) have completed CMAQ model simulations of natural ozone and haze levels using a more complete natural emissions inventory. The updated Koo et al. natural visibility modeling is currently the best available estimate of natural visibility for the worst 20% model days. It represents the absolute maximum visibility conditions possible in the model when all anthropogenic US and international emissions are controlled. However, those results have not yet been evaluated to identify the modeled natural concentrations for the worst 20% visibility days.

Policy Relevant Background Visibility

The use of natural haze levels is an unattainable goal for U.S. domestic planning purposes because the Regional Haze Rule does not have jurisdiction over international emissions. A more appropriate goal would be based on the background concentration resulting from a combination of natural PM and international transport of PM.

For air quality planning purposes, the USEPA has identified the policy-relevant background (PRB) ozone concentration as that which would occur in the United States in the absence of anthropogenic emissions of VOC and NO_x in continental North America (USEPA, 2007). The PRB ozone concentration represents the contribution of international transport of ozone and photochemical production from biogenic VOC and NO_x precursors within North America. The PRB is useful for ozone planning using air quality models because it defines the minimum level of ozone that can be simulated in the model when all anthropogenic emissions of VOC and NO_x are controlled 100% in North America. Similarly, PRB levels could be defined for $PM_{2.5}$ and for haze, and this would be useful for estimating the rate of progress that the states are making through the control of domestic sources of visibility impairing species.

PRB levels of haze can be evaluated in air quality model simulations by excluding all anthropogenic emissions within North America, or more appropriately, excluding all anthropogenic emissions within the US only (especially relevant for North Dakota). Such model simulations have not yet been completed; however, existing RPO data sets could be modified to perform new CMAQ simulations for use in this analysis.

The RPOs have completed modeling studies using source apportionment tools to evaluate individual sources that contribute to visibility impairment at Class I Areas. Both WRAP and CENRAP have performed CAMx simulations using the Particulate Source Apportionment Tool (PSAT) to evaluate emissions sources that contribute to sulfate and nitrate at receptor sites. Figure 2 shows the CAMx PSAT results for major contributors to sulfate for the 20% worst visibility days at the Lostwood Wilderness Area (LWA) and Theodore Roosevelt National Park (TRNP) Class I areas. The source apportionment results provide some of the same information that would be obtained from model simulations to evaluate PRB haze. For example, the contribution of boundary conditions in the CAMx PSAT results represent contributions of international transport from areas outside the model domain, although parts of in Canada and Mexico are included within the model domain and are represented explicitly in the PSAT results. Figure 2 shows that in the PSAT results, Canadian point sources of SO_2 (PT_CN) and international transport were the two largest sources of sulfate at both the LWA and TRNP Class I areas, producing approximately 1.6 ug/m^3 of sulfate of the total of 2.48 ug/m^3 at LWA, and approximately 0.93 ug/m^3 of sulfate of the total of 1.61 ug/m^3 at TRNP. For both sites, point sources of SO_2 within North Dakota were ranked below these sources as the third largest source of sulfate in the PSAT results.

While the PSAT results are useful for identifying the relative important of different source regions and emissions source categories at individual Class I Areas, there would be advantages to also performing a model simulation that included only international transport (including Canadian and Mexican emissions) and natural emissions to more accurately estimate PRB haze levels that North Dakota could then adopt as a refined natural background visibility goal for the Regional Haze Rule.

Texas and Colorado SIP Issues

There are many similarities between the Regional Haze Rule (RHR) challenges for North Dakota and Texas in that both states have significant international and natural contributions to regional haze in Class I areas in their states. The Texas Commission on Environmental Quality (TCEQ) has introduced alternative RHR glide paths to illustrate their rate of progress toward the RHR goals. Since TCEQ has already gone through the process of a RHR State Implementation Plan (SIP) development and comment period, it is instructive for the North Dakota to look at the TCEQ approach, the comments provided to TCEQ, and TCEQ's reaction to the comments.

In addition, Colorado's approach to Reasonable Further Progress prudently focuses upon source groups and particulate species for which Colorado sources contribute significantly to regional haze for the worst 20% haze days. This approach, consistent with that of Texas, concludes that some of the particulate species that contribute to regional haze are highly variable, not principally from anthropogenic sources, difficult to model, and difficult to control.

Similarities Between North Dakota and Texas

Similarities to be considered for the RHR SIP development in both North Dakota and Texas include the items listed below.

- Both states have Class I areas for which a considerable fraction of the regional haze is due to international transport
- Both states have Class I areas in their western portion, which results in the prevailing winds taking emissions from within their states away from those Class I areas.
- The distance to the nearest Class I areas associated with the prevailing winds is many hundreds of kilometers.
- The impact of the large haze precursor emitters in each state is noticeable when the wind directions advect their plumes toward the Class I areas, but this happens only a small fraction of the time.
- As a result, there is a substantial reduction in SO_2 and NO_x emissions from the BART-eligible sources in each state, but this reduction results in a relatively small impact on regional haze mitigation. Additional emission reductions that are advocated by some commenters would, therefore, have a minimal benefit on visibility improvement at substantial cost.
- In the RHR SIP development, both states have attempted to account for the effects of anthropogenic emissions that they can control in alternative analyses. These analysis result in a finding that the in-state emission reductions come closer to meeting the Uniform Rate of Progress glide path goals for 2018. However, due to the low probability of impact of these sources on the worst 20% days, the effectiveness of in-state emission controls on anthropogenic sources subject to controls is inherently limited.

Differences Between RHR SIP Approaches: North Dakota and Texas

Although both North Dakota and Texas have presented alternative analyses that attempt to present the effect of emissions that each state can control and discount the rest, the two states have used different approaches. The nature of these differences and a discussion of the approaches taken by each state are noted below.

- North Dakota appears to have not reduced the deciview value of the natural condition endpoint, but instead altered the beginning point. On the other hand, TCEQ appears to have altered the endpoint. It is my opinion that altering the endpoint to reflect haze components that are currently affecting visibility but which cannot be controlled by the Regional Haze Rule has its merits. The beginning point is set by observations, so it should not be altered.

- TCEQ decided that coarse and fine PM measured at the Class I areas were due to natural causes (especially on the worst 20% days), and adjusted the natural conditions endpoint accordingly. The Federal Land Managers (FLMs) agreed with this approach for the most part[12], but suggested that only 80% of these concentrations would be due to natural causes, and 20% would be due to anthropogenic causes. TCEQ determined from a sensitivity analysis that the difference in these two approaches was too small to warrant a re-run of their analysis, but it is important that the FLMs agreed to a state-specific modification of the natural conditions endpoint, and this substantially changed the perceived rate of progress of the SIP plan toward the altered natural conditions endpoint.

- Although the TCEQ did not address other particulate matter components in this same way, our independent analysis of the worst 20% haze days in 2002 for Class I areas in North Dakota suggest that other components, such as organic matter due to wildfires, could be substantially due to natural causes, so that this component should also be considered as at least partially natural.

- The TCEQ discussed the issue of how emissions from Mexico could interfere with progress on the RHR, but they did not appear to adjust the glide path based upon Mexican emissions. On the other hand, North Dakota did make adjustments based upon anthropogenic emissions that could be controlled, but did not take into account any specific particulate species that are generally not emitted by major anthropogenic sources of SO_2 and NO_x.

Colorado RHR Issues Consistent with Texas

Similar to Texas, Colorado[13] has determined that SO_2 and NO_x are precursors to important visibility PM species, are predominantly due to anthropogenic sources, and can be effectively controlled for stationary sources. The other four PM species that affect visibility are coarse and fine matter as well as organic and

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[12] See Appendix 2-2 at http://www.tceq.state.tx.us/implementation/air/sip/bart/haze_appendices.html.

[13] Colorado has posted stakeholder presentations at http://www.cdphe.state.co.us/ap/RegionalHaze/RHFeb08reasonableprogress.pdf and http://www.cdphe.state.co.us/ap/RegionalHaze/stakepresentation02-27-08.pdf.

elemental carbon. Colorado has determined that sources of these constituents are mostly natural and difficult to quantify, model, and control. This is consistent with Texas in that the focus should be on the progress made in controlling emissions from stationary sources of SO_2 and NO_x. In North Dakota, the recommended BART reductions for SO_2 and NO_x sources go well beyond the fractional progress toward zero emissions by the first milestone year of 2018, which represents less than 25% of the time period of the RHR implementation.

Recommendations and Conclusions

I recommend that North Dakota consider alternative endpoints to the natural conditions glide path for progress on the worst 20% haze days in order to indicate a more rational analysis. The use of the natural conditions provided by the default EPA approach to the RHR results in an outcome that is counterintuitive and frustrating because it indicates that even with a total shutdown of in-state emissions, not even the 2018 goal is met.

North Dakota could accomplish this goal in one of two ways. It could, similar to what was done in Texas, identify particulate matter components that are inherently dominated by natural emission sources such as windblown dust and wildfires on the worst 20% haze days. For example, the FLMs have already agreed with Texas that 80% of the coarse and fine particulate matter for these days could be considered to be uncontrollable and due to natural causes. I recommend that organic matter be added to this list, for which well over 50% would likely be attributable to natural causes (wildfires) on the 20% worst haze days when this particulate matter component is dominant. However, this approach does not address the issue of uncontrollable international emissions.

Therefore, a better approach that I recommend[14] would be to combine the effects of the uncontrollable particulate matter components and the SO_2 and NO_x emissions from international sources to determine a new glide path endpoint that is achievable by controlling anthropogenic emissions within the USA only. To compute this new endpoint, I recommend that CMAQ modeling be conducted for the base case (already done) and then for a future endpoint case with no USA anthropogenic emissions, but with particular matter emissions associated with uncontrollable coarse matter, fine matter, and organic carbon, as well as for SO_2 and NO_x emissions associated with all non-USA sources set to the current baseline levels. Then, North Dakota could use a relative reduction factor (RRF) approach to determine the ratio of the haze impacts between the base case and the reasonable future case, and then apply the RRF values to the baseline haze to obtain a realistic "natural conditions" haze endpoint.

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[14] These comments and recommendations were discussed with Gail Tonneson, who has provided helpful input and review for this document.

Table 1: Average Natural Levels of Aerosol Components from Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA, 2003)

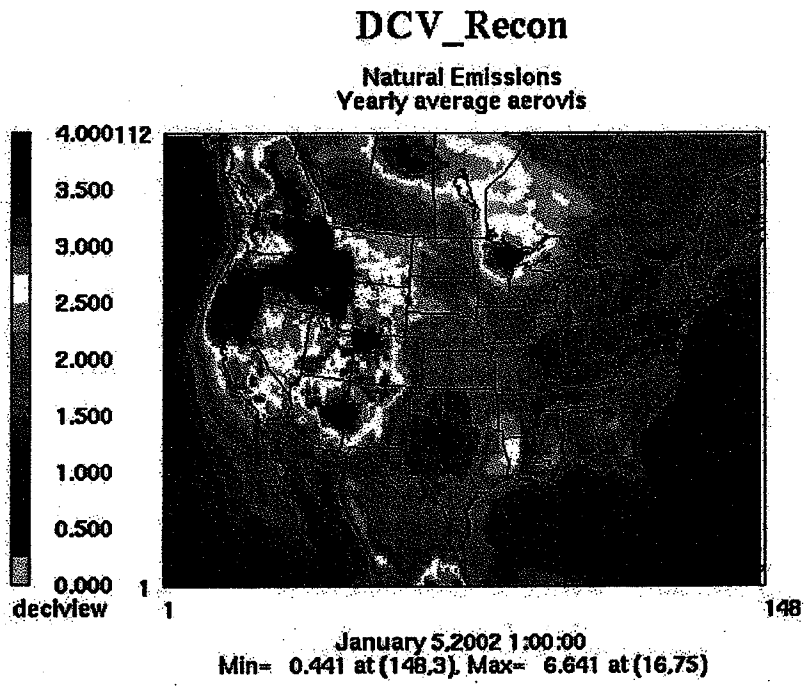
	Average Natural Concentration		Error Factor	Dry Extinction Efficiency (m^2/g)
	West ($\mu g/m^3$)	East ($\mu g/m^3$)		
Ammonium sulfate [b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass [c]	0.47	1.40	2	4
Elemental carbon	0.02	0.02	2-3	10
Soil	0.50	0.50	1½ - 2	1
Coarse Mass	3.0	3.0	1½ - 2	0.6

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1 $\mu g/m^3$ and 0.2 $\mu g/m^3$ of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 $\mu g/m^3$ and 1.5 $\mu g/m^3$ of organic compounds.

Figure 1: WRAP Clean Model Simulation Annual Average for Visibility (top) and Extinction Coefficient (bottom) from Tennessee et al. (2006)



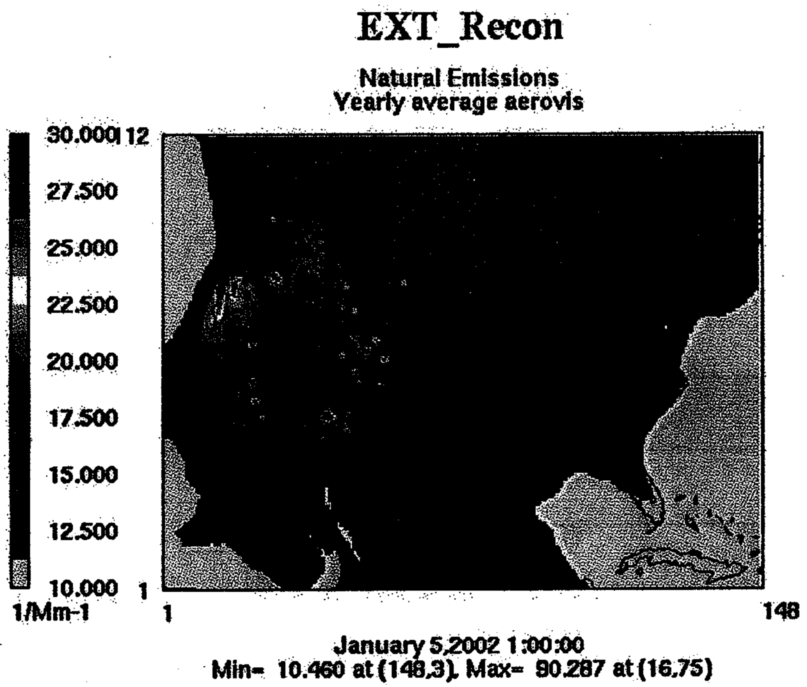
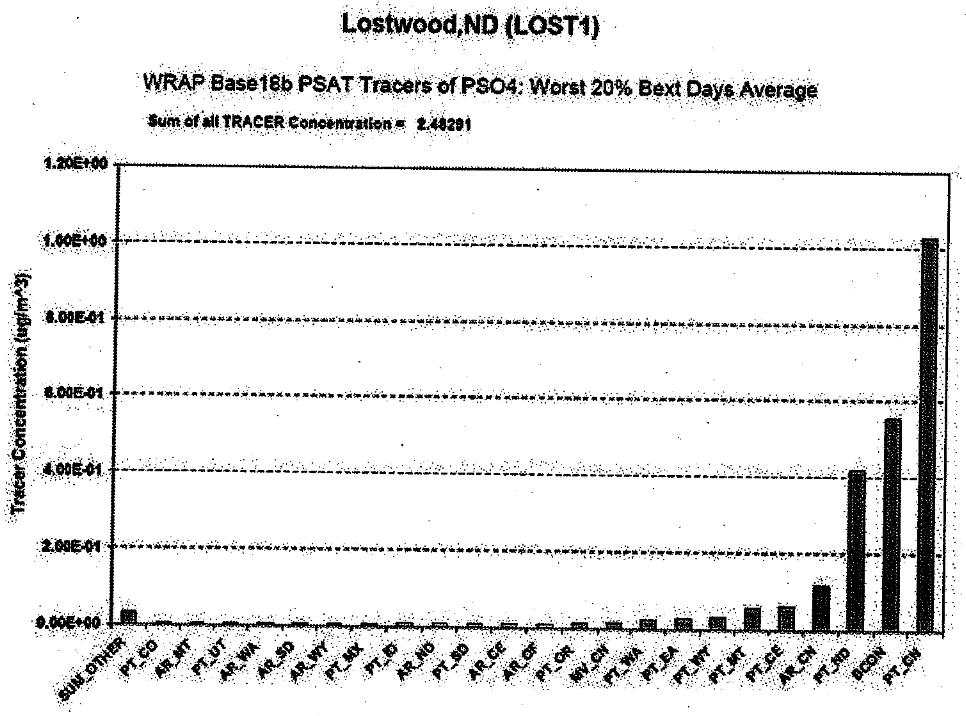
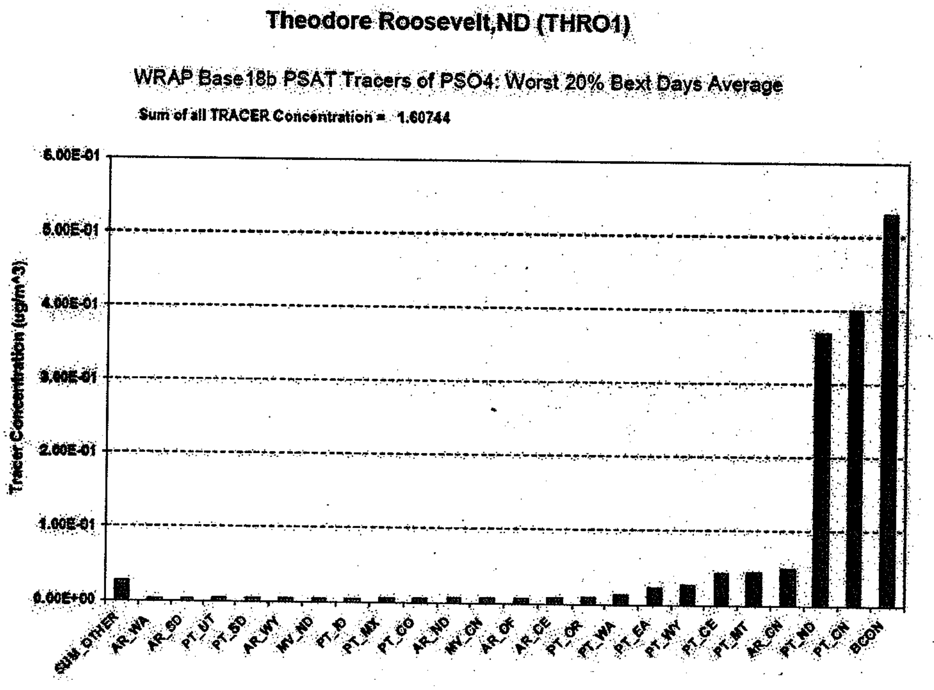


Figure 2: CAMx Source Apportionment Results for Major Contributors to Sulfate for the 20% Worst Visibility Days at Lostwood (top) and TNRP (bottom) Class I Areas





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Received
JAN 2010
Air Quality

January 7, 2010

North Dakota Department of Health
Attn: Terry O'Clair
Second Floor
918 East Divide Avenue
Bismarck, ND
58501-1947

Re: Comments on Notice of Intent to Amend the State Implementation Plan for Air Pollution Control Relating to Reduction of Regional Haze

Great River Energy is a generation and transmission electric cooperative based in Maple Grove, Minnesota. Our two coal-fired power plants are located in North Dakota: Coal Creek Station, a 1,129-megawatt plant located near Underwood; and Stanton Station, a 190-megawatt plant located near Stanton. Great River Energy respectfully provides the following general comments to North Dakota's Regional Haze State Implementation Plan ("SIP").

Since 2005, Great River Energy has been working with the North Dakota Department of Health ("NDDH") to define Best Available Retrofit Technologies ("BART") for three of our coal-fired units in North Dakota. Both Coal Creek Units 1 and 2, as well as Stanton Station Unit 1, are BART affected sources due to their dates of construction and their modeled contributions to visibility impairment in North Dakota Class 1 areas, Lostwood Wilderness Area and Theodore Roosevelt National Park's North, South and Elkhorn Units.

Great River Energy originally submitted detailed BART analyses for our affected units, Stanton and Coal Creek stations, in June and August, respectively, of 2006. Each BART submittal was amended several times in response to Environmental Protection Agency ("EPA"), Federal Land Manager and NDDH comments. Stanton's final BART submittal was provided in January 2008 and Coal Creek's in December 2007. These documents were the foundations for the NDDH BART determinations, and draft Title V permits-to-construct, which were issued in May of 2008, and act as reference materials in the NDDH Regional Haze Rule SIP.

NDDH technical modeling appropriately utilizes the most up-to-date modeling science as grounded by actual monitored data to ensure relative accuracy.

Great River Energy supports using the best and most current science as part of regulatory decision making. Specifically, Great River Energy strongly believes that "models" must be calibrated to actual monitored data, as much as technically feasible. It is clear that models must be "tuned" to meet local conditions in order to provide more accurate results. Otherwise, uncalibrated modeled results will not provide the necessary foundation for regulatory decision making. Modeling science continues to develop as new chemistry and better meteorology are incorporated.

With respect to regional haze modeling, NDDH spent significant technical resources and time "calibrating" EPA's default model, by nesting CALPUFF within CMAQ for more refined treatment of plume dispersion than would have otherwise been accomplished with the CMAQ model. The hybrid CMAQ-CALPUFF model was "tuned" to local monitored results and then used to project emissions for the glide path. It was clear that the NDDH's technical efforts provided a more accurate model in most situations. For future modeling, Great River Energy encourages NDDH to continue to use the most up-to-date modeling science, and to continue to calibrate these models with actual monitored data to ensure their relative accuracy.

The glide path is a "goal" and not an absolute, as defined by rule. "Natural," or non-manmade, and international sources are both significant and outside of NDDH control.

NDDH must preserve its ability to adjust the glide path for non-manmade and international emissions, which are completely outside of its control. As part of the weight of evidence, NDDH has modeled a scenario that eliminates all North Dakota emission sources that were used in the baseline. Even "zero"ing these emissions, NDDH demonstrates that the state cannot hit the first reasonable progress goal in 2018. In short, the international and non-manmade emissions are more significant in achieving "natural background" conditions than ND sources contained in the modeling database. By adjusting the glide path to exclude non-manmade and international emissions, as part of its weight of evidence, NDDH can more accurately demonstrate reasonable progress towards natural background conditions in 2064 through reductions over which it has control.

The BART rule treats smaller, non-presumptive sources (less than 750 MW) differently. EPA determined that these smaller sources should not be held to presumptive limits, unless the state exercises its discretion in order to meet reasonable progress goals.

It is important to note that significant technical and financial resources were spent to provide the complete BART evaluations and other supporting documentation. National emission control experts, including but not limited to Alstom, URS, and the Washington Group, were hired to provide engineering estimates based on their knowledge of recently installed controls, material costs, and site specific limitations. Their site specific recommendations should be considered more accurate than comparable information that could have been derived from older cost manuals, which are then adjusted for inflation, as suggested by the Federal Land Managers.

EPA clearly established presumptive BART emission rates for sources greater than 750 MW. These emission rates were deemed cost effective based on EPA's cost per ton estimates. NDDH BART determinations represent higher cost effective determinations than the BART rule. As an example, NDDH appears to use a somewhat arbitrary and largely unsubstantiated $3600/ton cost effectiveness threshold, as compared to ~$1000/ton in the BART rule. Great River Energy provided an analysis of cost effective controls as supported by the BART rule in our Cost Effectiveness Memo, dated July 3, 2007, which was included as an appendix in Coal Creek and Stanton stations' final BART determinations.

Given the inaccuracy of the model(s), as discussed, and the costly control of emissions, it is imperative that reasonable, cost effective determinations be consistently applied, not only in North Dakota but in the region, to ensure competitive energy production. The Regional Haze and BART rules have distinct requirements to make reasonable progress towards a goal of natural background conditions, in a cost effective manner, as deemed appropriate by the North Dakota Department of Health.

Although more than the rule requires, Great River Energy generally supports NDDH BART determinations as being within their statutory discretion to meet glide path goals.

Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services
Great River Energy

Cc: Greg Archer, GRE
Deb Nelson, GRE
Diane Stockdill, GRE
Steve Smokey, GRE

ATTORNEY GENERAL'S OPINION
Statement of Authority

State Plan for Implementing 40 C.F.R. § 51.308, Regional Haze Program Requirements

At the request of the North Dakota Department of Health (Department), I have reviewed the relevant elements of the Regional Haze State Implementation Plan (SIP) submitted by the Department to the Environmental Protection Agency (EPA) for approval in accordance with Section 110 of the Clean Air Act (CAA). As discussed in more detail below, it is my opinion that North Dakota law currently provides adequate authority for the Department to adopt and implement the Regional Haze SIP, including the Permits to Construct issued as part of the SIP. This opinion includes a review of the statutes, rules, and other legal authority for the SIP. Attached to this opinion are the relevant sections of North Dakota law.

I. Authority to Adopt the Plan

North Dakota's legislature has designated the Department as "the agency to administer and coordinate a statewide program of air pollution control." N.D.C.C. § 23-25-02(1). The Department has the authority to cooperate with EPA and to "develop and implement" federal air pollution prevention and control programs. N.D.C.C. § 23-25-03(4), (12). In order to implement and enforce a federal program, the Department may adopt rules, including rules setting ambient standard and emission limitations. N.D.C.C. § 23-25-03(8), (12). A person must obtain a permit from the Department to "construct, install, modify, use, or operate an air contaminant source" and the Department may impose requirements on the issuance of such permits. N.D.C.C. § 23-25-04.1(1)-(3); see N.D. Admin. ch. 33-15-14. The Department properly adopted rules implementing the Regional Haze Requirements, which became effective January 1, 2007. See N.D. Admin. ch. 33-15-25. Accordingly, the Department has the authority to adopt the Regional Haze SIP.

II. Authority to Implement the Plan

The Department also has the legal authority to carry out the Regional Haze SIP, as required by 40 C.F.R. § 51.230. Specifically, the Department has the authority to:

- Adopt emission standards and limitations and any other measures necessary for attainment and maintenance of national standards: N.D.C.C. § 23-25-03(8), (12).
- Enforce applicable laws, regulations, and standards, and seek injunctive relief: N.D.C.C. §§ 23-25-03(5) and 23-25-10.
- Abate pollutant emissions on an emergency basis to prevent substantial endangerment to the health of persons: N.D.C.C. §§ 23-25-03(5), 23-25-08, and 23-25-10(5).
- Prevent construction, modification, or operation of a facility, building, structure, or installation, or combination thereof, which directly or indirectly results or may result in emissions of any air pollutant at any location which will prevent the attainment or maintenance of a national standard: N.D.C.C. §§ 23-25-03(5)-(6), 23-25-04.1(1)-(2), and 23-25-10(5); N.D. Admin. §§ 33-15-14-02, 33-15-14-06, and 33-15-25-02.
- Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require recordkeeping and to make inspections and conduct tests of air pollution sources: N.D.C.C. §§ 23-25-03(10), 23-25-04.1(2), and 23-25-05(1)-(2); N.D.

Admin. §§ 33-15-14-02(9), 33-15-14-06(4)-(5), 33-15-25-04.

- Require owners or operators of stationary sources to install, maintain, and use emission monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; also authority for the State to make such data available to the public as reported and as correlated with any applicable emission standards or limitations: N.D.C.C. §§ 23-25-03(10) and 23-25-04.1(2); N.D. Admin. §§ 33-15-14-02(9), 33-15-14-06(5), and 33-15-25-04.

III. The Department Complied with State Law Procedural Requirements in Issuing the Permits to Construct

In addition to the above, I have reviewed the Department's Public Hearing Notice and other relevant information. Based on this review, it is my opinion that the Permits to Construct were issued in compliance with state procedural requirements. See N.D.C.C. § 23-01-23; N.D. Admin. § 33-15-14-02(6).

Dated this 26th day of February, 2010.

State of North Dakota

Wayne Stenehjem
ATTORNEY GENERAL

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Relevant Sections of the North Dakota Century Code

23-01-23. Permit or investigatory hearings - Exemption from chapters 28-32 and 54-57. A permit hearing conducted for purposes of receiving public comment or an investigatory hearing conducted under chapters 23-20.1, 23-20.3, 23-25, 23-29, 61-28, and 61-28.1 is not an adjudicative proceeding under chapter 28-32 and is not subject to the requirements of chapter 54-57.

23-25-02. State air pollution control agency - Advisory council.

1. The state department of health, hereinafter referred to as the department, is hereby designated as the agency to administer and coordinate a statewide program of air pollution control consistent with the provisions of this chapter.

23-25-03. Power and duties of the department. The department shall:

1. Encourage the voluntary cooperation of persons or affected groups to achieve the purposes of this chapter.
2. Determine by scientifically oriented field studies and sampling the degree of air pollution in the state and the several parts thereof.
3. Encourage and conduct studies, investigations, and research relating to air pollution and its causes, effects, prevention, abatement, and control.
4. Advise, consult, and cooperate with other public agencies and with affected groups and industries.
5. Issue such orders as may be necessary to effectuate the purposes of this chapter and enforce the same by all appropriate administrative and judicial procedures.
6. Provide rules and regulations relating to the construction of any new direct or indirect air contaminant source or modification of any existing direct or indirect air contaminant source which the department determines will prevent the attainment or maintenance of any ambient air quality standard, and require that prior to commencing construction or modification of any such source, the owner or operator thereof shall submit such information as may be necessary to permit the department to make such determination.
7. Establish ambient air quality standards for the state which may vary according to appropriate areas.
8. Formulate and promulgate emission control requirements for the prevention, abatement, and control of air pollution in this state including achievement of ambient air quality standards.

9. Hold hearings relating to any aspect or matter in the administration of this chapter, and in connection therewith, compel the attendance of witnesses and the production of evidence.

10. Require the owner or operator of a regulated air contaminant source to establish and maintain such records; make such reports; install, use, and maintain such monitoring equipment or methods; sample such emissions in accordance with such methods, at such locations, intervals, and procedures; and provide such other information as may be required.

11. Provide by rules and regulations a procedure for the handling of applications for the granting of a variance to any person who owns or is in control of any plant, establishment, process, or equipment. The granting of a variance is not a right of the applicant but must be in the discretion of the department.

12. Provide by rules any procedures necessary and appropriate to develop, implement, and enforce any air pollution prevention and control program established by the Federal Clean Air Act, as amended, and the authorities and responsibilities of which are delegatable to the state by the United States environmental protection agency. Such rules may include any and all enforceable ambient standards, emission limitations, and other control measures, means, techniques, or economic incentives such as fees, marketable permits, and auctions of emissions rights as provided by the Act. The department shall develop and implement such federal programs if the department determines there is a benefit to the state.

13. Provide by rules a program for implementing lead-based paint remediation training, certification, and performance requirements in accordance with title 40, Code of Federal Regulations, part 745, sections 220, 223, 225, 226, 227, and 233.

After consultation with the advisory council, the department is empowered to adopt, amend, and repeal rules and regulations implementing and consistent with this chapter.

23-25-04.1. Permits or registration.

1. No person shall construct, install, modify, use, or operate an air contaminant source designated by regulation, capable of causing or contributing to air pollution, either directly or indirectly, without a permit from the department or in violation of any conditions imposed by such permit.

2. The department shall provide for the issuance, suspension, revocation, and renewal of any permits which it may require pursuant to this section.

3. The department may require that applications for such permits shall be accompanied by plans, specifications, and such other information as it deems necessary.

4. Possession of an approved permit or registration certificate does not relieve any person of the responsibility to comply with applicable emission limitations or with any other provision of law or regulations adopted pursuant thereto and does not relieve any person from the requirement that that person possess a valid contractor's license issued under chapter 43-07.

5. The department by rule or regulation may provide for registration and registration renewal of certain air contaminant sources in lieu of the permit required pursuant to this section.

6. The department may exempt by rule and regulation certain air contaminant sources from the permit or registration requirements set forth in this section when the department makes a finding that the exemption of such sources of air contaminants will not be contrary to section 23-25-01.1.

23-25-05. Right of onsite inspection.

1. Any duly authorized officer, employee, or agent of the department may enter and inspect any property, premise, or place on or at which an air contaminant source is located or is being constructed, installed, or established at any reasonable time for the purpose of ascertaining the state of compliance with this chapter and rules and regulations enforced pursuant thereto. If requested, the owner or operator of the premises shall receive a report setting forth all facts found which relate to compliance status.

2. The department may conduct tests and take samples of air contaminants, fuel, process material, and other materials which affect or may affect emission of air contaminants from any source, and shall have the power to have access to and copy any records required by department rules or regulations to be maintained, and to inspect monitoring equipment located on the premises. Upon request of the department, the person responsible for the source to be tested shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities exclusive of instruments and sensing devices as may be necessary for proper determination of the emission of air contaminants. If an authorized representative of the department, during the course of an inspection, obtains a sample of air contaminant, fuel, process material, or other material, that representative shall issue a receipt for the sample obtained to the owner or operator of, or person responsible for, the source tested.

3. For the purpose of ascertaining the state of compliance with this chapter and any applicable rules, any duly authorized officer, employee, or agent of the

department may enter and inspect, at any reasonable time, any property, premises, or place on or at which a lead-based paint remediation activity is ongoing. If requested, the department shall provide to the owner or operator of the premises a report that sets forth all facts found which relate to compliance status.

23-25-08. Administrative procedure and judicial review. Any proceeding under this chapter for:

1. The issuance or modification of rules and regulations including emergency orders relating to control of air pollution; or

2. Determining compliance with rules and regulations of the department,

must be conducted in accordance with the provisions of chapter 28-32, and appeals may be taken as therein provided. When an emergency exists requiring immediate action to protect the public health and safety, the department may, without notice or hearing, issue an order reciting the existence of such emergency and requiring that such action be taken as is necessary to meet this emergency. Notwithstanding any provision of this chapter, such order must be effective immediately, but on application to the department an interested person must be afforded a hearing before the state health council within ten days. On the basis of such hearing, the emergency order must be continued, modified, or revoked within thirty days after such hearing. Except as provided for in this section, notice of any hearing held under this chapter must be issued at least thirty days prior to the date specified for the hearing.

23-25-10. Enforcement - Penalties - Injunctions.

1. Any person who willfully violates this chapter, or any permit condition, rule, order, limitation, or other applicable requirement implementing this chapter, is subject to a fine of not more than ten thousand dollars per day per violation, or by imprisonment for not more than one year, or both. If the conviction is for a violation committed after a first conviction of such person under this subsection, punishment must be by a fine of not more than twenty thousand dollars per day per violation, or by imprisonment for not more than two years, or both.

2. Any person who violates this chapter, or any permit condition, rule, order, limitation, or other applicable requirement implementing this chapter, with criminal negligence as defined by section 12.1-02-02, is subject to a fine of not more than ten thousand dollars per day per violation, or by imprisonment for not more than six months, or both.

3. Any person who knowingly makes any false statement, representation, or certification in any application, record, report, plan, or other document filed or required to be maintained under this chapter or any permit condition, rule,

order, limitation, or other applicable requirement implementing this chapter, or who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this chapter or any permit condition, rule, order, limitation, or other applicable requirement implementing this chapter, upon conviction, is subject to a fine of not more than ten thousand dollars per day per violation, or by imprisonment for not more than six months, or both.

4. Any person who violates this chapter, or any permit condition, rule, order, limitation, or other applicable requirement implementing this chapter, is subject to a civil penalty not to exceed ten thousand dollars per day per violation.

5. Without prior revocation of any pertinent permits, the department, in accordance with the laws of this state governing injunction or other process, may maintain an action in the name of the state against any person to enjoin any threatened or continuing violation of any provision of this chapter or any permit condition, rule, order, limitation, or other applicable requirement implementing this chapter.

CHAPTER 33-15-14
DESIGNATED AIR CONTAMINANT SOURCES, PERMIT TO CONSTRUCT, MINOR SOURCE PERMIT TO OPERATE, TITLE V PERMIT TO OPERATE

Section

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33-15-14-01. Designated air contaminant sources. Pursuant to subsection 1 of North Dakota Century Code section 23-25-04, stationary sources within the following source categories are designated as air contaminant sources capable of causing or contributing to air pollution, either directly or indirectly.

1. The following chemical process facilities:

   a. Adipic acid.

   b. Ammonia.

   c. Ammonium nitrate.

   d. Carbon black.

   e. Charcoal.

   f. Chlorine.

   g. Chlor-alkali manufacturing.

   h. Detergent and soap.

   i. Explosives (trinitrotoluene and nitrocellulose).

   j. Hydrochloric acid.

   k. Hydrofluoric acid.

   l. Nitric acid.

   m. Paint and varnish manufacturing.

n. Phosphoric acid.

o. Phthalic anhydride.

p. Plastics manufacturing.

q. Printing ink manufacturing.

r. Sodium carbonate.

s. Sulfur production and recovery.

t. Sulfuric acid.

u. Synthetic fibers.

v. Synthetic rubber.

w. Terephthalic acid.

x. Alcohol.

y. Cresylic acids.

z. Phenol.

aa. Polymer manufacturing and coating operations.

2. The following food and agricultural facilities:

   a. Agricultural drying and dehydrating operations.

   b. Ammonium nitrate.

   c. Cheese whey drying and processing.

   d. Coffee roasting.

   e. Cotton ginning.

   f. Feed, grain, and seed handling and processing.

   g. Fermentation processes.

   h. Fertilizers.

    i. Fishmeal processing.
    j. Meat smokehouses.
    k. Orchard heaters.
    l. Potato processing.
    m. Rendering plants.
    n. Starch manufacturing.
    o. Sugarbeet processing.

3. The following metallurgical facilities:
    a. Primary metals facilities:
        (1) Aluminum ore reduction.
        (2) Copper smelters.
        (3) Ferroalloy production.
        (4) Iron and steel mills.
        (5) Lead smelters.
        (6) Metallurgical coke manufacturing.
        (7) Zinc.
    b. Secondary metals facilities:
        (1) Aluminum operations.
        (2) Brass and bronze smelting.
        (3) Ferroalloys.
        (4) Ferrous foundries.
        (5) Gray iron foundries.
        (6) Lead smelting.
        (7) Magnesium smelting.

        (8) Nonferrous foundries.

        (9) Steel foundries.

        (10) Zinc processes.

    c. Electrolytic plating operations.

4. The following mineral products facilities:

    a. Asphalt roofing.

    b. Asphaltic concrete plants.

    c. Bricks and related clay refractories.

    d. Calcium carbide.

    e. Ceramic and clay processes.

    f. Clay and fly ash sintering.

    g. Coal cleaning.

    h. Coal drying.

    i. Coal mining.

    j. Coal handling and processing.

    k. Concrete batching.

    l. Fiberglass manufacturing.

    m. Frit manufacturing.

    n. Glass manufacturing.

    o. Gypsum manufacturing.

    p. Leonardite mining, drying, and processing.

    q. Lime manufacturing.

    r. Mineral wool manufacturing.

    s. Paperboard manufacturing.

   - t. Perlite manufacturing.
   - u. Phosphate rock preparation.
   - v. Portland cement manufacturing, bulk handling, and storage.
   - w. Rock, stone, gravel, and sand quarrying and processing.
   - x. Uranium mining, milling, and enrichment.
   - y. Calciners and dryers.

5. The following energy and fuel facilities:
   - a. Coal gasification.
   - b. Coal liquefaction.
   - c. Crude oil and natural gas production.
   - d. Fossil fuel steam electric plants.
   - e. Fuel conversion plants.
   - f. Natural gas processing.
   - g. Petroleum refining and petrochemical operations.
   - h. Petroleum storage (storage tanks and bulk terminals).
6. The following wood processing facilities:
   - a. Plywood veneer and layout operations.
   - b. Pulpboard manufacturing.
   - c. Wood pulping.
   - d. Sawmills.
   - e. Wood products manufacturing.
7. The following waste management units or facilities:
   - a. Afterburners.
   - b. Automobile body incinerators.

  c. Conical burners.
  d. Flares.
  e. Gaseous and liquid organic compounds incinerators.
  f. Industrial waste incinerators.
  g. Open burning.
  h. Open pit incinerators.
  i. Infectious waste incinerators.
  j. Refuse incinerators.
  k. Salvage incinerators.
  l. Sewage sludge incinerators.
  m. Wood waste incinerators
  n. Municipal waste combustors.

8. The following miscellaneous facilities:
  a. Drycleaning and laundry operations.
  b. Fuel burning equipment.
  c. Internal combustion engines.
  d. Surface coating operations.
  e. Wastewater treatment plants.
  f. Water cooling towers and water cooling ponds.
  g. Stationary gas turbines.
  h. Lead acid battery manufacturing.
  i. Hydrocarbon contaminated soil remediation projects.

9. Any category of sources to which a federal standard of performance applies [40 CFR 60].

10. Any source which emits a contaminant subject to a national emission standard for hazardous air pollutants [40 CFR 61].

11. Any source which is subject to review under federal prevention of significant deterioration of air quality regulations [40 CFR 51.166].

12. Any source which is determined by the department to have an emission which affects state ambient air quality standards or the other provisions of chapter 33-15-02.

13. Any source subject to title V permitting requirements in section 33-15-14-06.

14. Any major source to which a national emission standard for hazardous air pollutants for source categories [40 CFR 63] would apply.

15. Other sources subject to a standard or requirement under the Federal Clean Air Act as amended.

History: Amended effective October 1, 1987; March 1, 1994; August 1, 1995.
General Authority: NDCC 23-25-03, 23-25-04, 23-25-04.1
Law Implemented: NDCC 23-25-04, 23-25-04.1

33-15-14-01.1. Definitions. For the purposes of this chapter:

1. "Complete" means, in reference to an application for a permit, that the application contains all the information necessary for processing the application. Designating an application complete for purposes of permit processing does not preclude the department from requesting or accepting any additional information.

2. "Construction, installation, or establishment" means:

   a. For sources subject to a standard or requirement under chapters 33-15-13, 33-15-15 (excluding increment consumption by nonmajor sources), and 33-15-22, it shall have the meaning given for construction in each of the respective chapters.

   b. For all other sources it means the placement or erection, including fabrication, demolition, or modification, of an air contaminant emissions unit and any equipment, process, or structure that will be used to reduce, physically or chemically change, or transmit to the atmosphere any air contaminant. This does not include the building that houses the source, site work, foundations, or other equipment which does not affect the amount, ambient concentration, or type of air contaminants that are emitted. With respect to a physical change or a change in the method of operation it means those onsite activities which will affect an existing emissions unit or establishment of a new unit that emits to the atmosphere.

3. "Emissions unit" has the meaning given to it in section 33-15-14-06.

4. "Minor source" means any designated air contaminant source under section 33-15-14-01 which is not required to obtain a title V permit to operate under section 33-15-14-06.

5. "Potential to emit" has the meaning given to it in section 33-15-14-06.

6. "Stationary source" has the meaning given to it in section 33-15-14-06.

History: Effective March 1, 1994; amended effective January 1, 1996.
General Authority: NDCC 23-25-03
Law Implemented: NDCC 23-25-03

33-15-14-02. Permit to construct.

1. **Permit to construct required.** No construction, installation, or establishment of a new stationary source within a source category designated in section 33-15-14-01 may be commenced unless the owner or operator thereof shall file an application for, and receive, a permit to construct in accordance with this chapter. This requirement shall also apply to any source for which a federal standard of performance has been promulgated prior to such filing of an application for a permit to construct. A list of sources for which a federal standard has been promulgated, and the standards which apply to such sources, must be available at the department's offices.

   The initiation of activities that are exempt from the definition of construction, installation, or establishment in section 33-15-14-01.1, prior to obtaining a permit to construct, are at the owner's or operator's own risk. These activities have no impact on the department's decision to issue a permit to construct. The initiation or completion of such activities conveys no rights to a permit to construct under this section.

2. **Application for permit to construct.**

   a. Application for a permit to construct a new installation or source must be made by the owner or operator thereof on forms furnished by the department.

   b. A separate application is required for each new installation or source subject to this chapter.

   c. Each application must be signed by the applicant, which signature shall constitute an agreement that the applicant will assume responsibility for the construction or operation of the new installation or source in accordance with this article and will notify the department, in writing, of the startup of operation of such source.

3. **Alterations to source.**

   a. The addition to or enlargement of or replacement of or alteration in any stationary source, already existing, which is undertaken pursuant to an approved compliance schedule for the reduction of emissions therefrom, shall be exempt from the requirements of this section.

   b. Any physical change in, or change in the method of operation of, a stationary source already existing which increases or may increase the emission rate or increase the ambient concentration by an amount greater than that specified in subdivision a of subsection 5 of any pollutant for which an ambient air quality standard has been promulgated under this article or which results in the emission of any such pollutant not previously emitted must be considered to be construction, installation, or establishment of a new source, except that:

      (1) Routine maintenance, repair, and replacement may not be considered a physical change.

      (2) The following may not be considered a change in the method of operation:

         (a) An increase in the production rate, if such increase does not exceed the operating design capacity of the source and it is not limited by a permit condition.

         (b) An increase in the hours of operation if it is not limited by a permit condition.

         (c) Changes from one operating scenario to another provided the alternative operating scenarios are identified and approved in a permit to operate.

         (d) Trading of emissions within a facility provided:

            [1] These trades have been identified and approved in a permit to operate; and

            [2] The total facility emissions do not exceed the facility emissions cap established in the permit to operate.

(e) Trading and utilizing acid rain allowances provided compliance is maintained with all other applicable requirements.

c. Any owner or operator of a source who requests an increase in the allowable sulfur dioxide emission rate for the source pursuant to section 33-15-02-07 shall demonstrate through a dispersion modeling analysis that the revised allowable emissions will not cause or contribute to a violation of the national ambient air quality standards for sulfur oxides (sulfur dioxide) or the prevention of significant deterioration increments for sulfur dioxide. The owner or operator shall also demonstrate that the revised allowable emission rate will not violate any other requirement of this article or the Federal Clean Air Act. Requests for emission limit changes shall be subject to review by the public and the environmental protection agency in accordance with subsection 6.

4. **Submission of plans - Deficiencies in application.** As part of an application for a permit to construct, the department may require the submission of plans, specifications, siting information, emission information, descriptions and drawings showing the design of the installation or source, the manner in which it will be operated and controlled, the emissions expected from it, and the effects on ambient air quality. Any additional information, plans, specifications, evidence, or documentation that the department may require must be furnished upon request. Within twenty days of the receipt of the application, the department shall advise the owner or operator of the proposed source of any deficiencies in the application. In the event of a deficiency, the date of receipt of the application is the date upon which all requested information is received.

a. Determination of the effects on ambient air quality as may be required under this section must be based on the applicable requirements specified in the "Guideline on Air Quality Models (Revised)" (United States environmental protection agency, office of air quality planning and standards, Research Triangle Park, North Carolina 27711) as supplemented by the "North Dakota Guideline for Air Quality Modeling Analyses" (North Dakota state department of health, division of air quality). These documents are incorporated by reference.

b. When an air quality impact model specified in the documents incorporated by reference in subdivision a is inappropriate, the model may be modified or another model substituted provided:

(1) Any modified or nonguideline model must be subject to notice and opportunity for public comment under subsection 6.

(2) The applicant must provide to the department adequate information to evaluate the applicability of the modified or nonguideline model. Such information must include, but is not limited to, methods like those outlined in the "Interim Procedures for Evaluating Air Quality Models (Revised)" (United States environmental protection agency, office of air quality planning and standards, Research Triangle Park, North Carolina 27709).

(3) Written approval from the department must be obtained for any modification or substitution.

(4) Written approval from the United States environmental protection agency must be obtained for any modification or substitution prior to the granting of a permit under this chapter.

5. **Review of application - Standard for granting permits to construct.** The department shall review any plans, specifications, and other information submitted in application for a permit to construct and from such review shall, within ninety days of the receipt of the completed application, make the following preliminary determinations:

a. Whether the proposed project will be in accord with this article, including whether the operation of any new stationary source at the proposed location will cause or contribute to a violation of any applicable ambient air quality standard. A new stationary source will be considered to cause or contribute to a violation of an ambient air quality standard when such source would, at a minimum, exceed the following significance levels at any locality that does not or would not meet the applicable ambient standard:

Contaminant		Averaging Time (hours)			
	Annual ($\mu g/m^3$)	24 ($\mu g/m^3$)	8 ($\mu g/m^3$)	3 ($\mu g/m^3$)	1 ($\mu g/m^3$)
SO_2	1.0	5		25	25
PM_{10}	1.0	5			
NO_2	1.0				25
CO			500		2000

b. Whether the proposed project will provide all necessary and reasonable methods of emission control. Whenever a standard of performance is applicable to the source, compliance with this criterion will require provision for emission control which will, at least, satisfy such standards.

6. **Public participation - Final action on application.**

a. The following source categories are subject to the public participation procedures under this subsection:

(1) Those affected facilities designated under chapter 33-15-13.

(2) New sources that will be required to obtain a permit to operate under section 33-15-14-06.

(3) Modifications to an existing facility which will increase the potential to emit from the facility by the following amounts:

(a) One hundred tons [90.72 metric tons] per year or more of particulate matter, sulfur dioxide, nitrogen oxides, hydrogen sulfide, carbon monoxide, or volatile organic compounds;

(b) Ten tons [9.07 metric tons] per year or more of any contaminant listed under section 112(b) of the Federal Clean Air Act; or

(c) Twenty-five tons [22.68 metric tons] per year or more of any combination of contaminants listed under section 112(b) of the Federal Clean Air Act.

(4) Sources which the department has determined to have a major impact on air quality.

(5) Those for which a request for a public comment period has been received from the public.

(6) Sources for which a significant degree of public interest exists regarding air quality issues.

(7) Those sources which request a federally enforceable permit which limits their potential to emit.

b. With respect to the permit to construct application, the department shall:

(1) Within ninety days of receipt of a complete application, make a preliminary determination concerning issuance of a permit to construct.

(2) Within ninety days of the receipt of the complete application, make available in at least one location in the county or counties in which the proposed project is to be located, a copy of its preliminary determinations and copies of or

a summary of the information considered in making such preliminary determinations.

(3) Publish notice to the public by prominent advertisement, within ninety days of the receipt of the complete application, in the region affected, of the opportunity for written comment on the preliminary determinations. The public notice must include the proposed location of the source.

(4) Within ninety days of the receipt of the complete application, deliver a copy of the notice to the applicant and to officials and agencies having cognizance over the locations where the source will be situated as follows: the chief executive of the city and county; any comprehensive regional land use planning agency; and any state, federal land manager, or Indian governing body whose lands will be significantly affected by the source's emissions.

(5) Within ninety days of receipt of a complete application, provide a copy of the proposed permit and all information considered in the development of the permit and the public notice to the regional administrator of the United States environmental protection agency.

(6) Allow thirty days for public comment.

(7) Consider all public comments properly received, in making the final decision on the application.

(8) Allow the applicant to submit written responses to public comments received by the department. The applicant's responses must be submitted to the department within twenty days of the close of the public comment period.

(9) Take final action on the application within thirty days of the applicant's response to the public comments.

(10) Provide a copy of the final permit, if issued, to the applicant, the regional administrator of the United States environmental protection agency, and anyone who requests a copy.

c. For those sources subject to the requirements of chapter 33-15-15, the public participation procedures under section 33-15-15-01.2 shall be followed.

7. **Denial of permit to construct.** If, after review of all information received, including public comment with respect to any proposed project, the department makes the determination of any one of subdivision a or b of subsection 5 in the negative, it shall deny the

permit and notify the applicant, in writing, of the denial to issue a permit to construct.

If a permit to construct is denied, the construction, installation, or establishment of the new stationary source shall be unlawful. No permit to construct or modify may be granted if such construction, or modification, or installation, will result in a violation of this article.

8. **Issuance of permit to construct.** If, after review of all information received, including public comment with respect to any proposed project, the department makes the determination of subdivision a or b of subsection 5 in the affirmative, the department shall issue a permit to construct. The permit may provide for conditions of operation as provided in subsection 9.

9. **Permit to construct - Conditions.** The department may impose any reasonable conditions upon a permit to construct, including conditions concerning:

   a. Sampling, testing, and monitoring of the facilities or the ambient air or both.

   b. Trial operation and performance testing.

   c. Prevention and abatement of nuisance conditions caused by operation of the facility.

   d. Recordkeeping and reporting.

   e. Compliance with applicable rules and regulations in accordance with a compliance schedule.

   f. Limitation on hours of operation, production rate, processing rate, or fuel usage when necessary to assure compliance with this article.

   The violation of any conditions so imposed may result in revocation or suspension of the permit or other appropriate enforcement action.

10. **Scope.**

    a. The issuance of a permit to construct for any source does not affect the responsibility of an owner or operator to comply with applicable portions of a control strategy affecting the source.

    b. A permit to construct shall become invalid if construction is not commenced within eighteen months after receipt of such permit, if construction is discontinued for a period of eighteen months or more; or if construction is not completed within a reasonable time. The department may extend the eighteen-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within eighteen months of the projected and approved commencement date. In cases of major construction projects involving long lead times and substantial financial commitments, the department may provide by a condition to the permit a time period greater than eighteen months when such time extension is supported by sufficient documentation by the applicant.

11. **Transfer of permit to construct.** To ensure the responsible owners or operators, or both, are identified, the holder of a permit to construct may not transfer such permit without prior approval of the department.

12. **[Reserved]**

13. **Exemptions.** A permit to construct is not required for the following stationary sources provided there is no federal requirement for a permit or approval for construction or operation and there is no applicable new source performance standard, or national emission standard for hazardous air pollutants.

    a. Maintenance, structural changes, or minor repair of process equipment, fuel burning equipment, control equipment, or incinerators which do not change capacity of such process equipment, fuel burning equipment, control equipment, or incinerators and which do not involve any change in the quality, nature, or quantity of emissions therefrom.

    b. Fossil fuel burning equipment, other than smokehouse generators, which meet all of the following criteria:

        (1) The heat input per unit does not exceed ten million British thermal units per hour.

        (2) The total aggregate heat input from all equipment does not exceed ten million British thermal units per hour.

        (3) The actual emissions, as defined in chapter 33-15-15, from all equipment do not exceed twenty-five tons [22.67 metric tons] per year of any air contaminant and the potential to emit any air contaminant for which an ambient air quality standard has been promulgated in chapter 33-15-02 is less than one hundred tons [90.68 metric tons] per year.

    c. (1) Any single internal combustion engine with less than five hundred brake horsepower, or multiple engines with a combined brake horsepower rating less than five hundred brake horsepower.

(2) Any single internal combustion engine with a maximum rating of less than one thousand brake horsepower, or multiple engines with a combined brake horsepower rating of less than one thousand brake horsepower, and which operates a total of five hundred hours or less in a rolling twelve-month period.

(3) Any internal combustion engine, or multiple engines at the same facility, with a total combined actual emission rate of five tons [4.54 metric tons] per year or less of any air contaminant for which an ambient air quality standard has been promulgated in section 33-15-02-04.

(4) The exemptions listed in paragraphs 1, 2, and 3 do not apply to engines that are a utility unit as defined in section 33-15-21-08.1 or are subject to a standard under chapter 33-15-22.

d. Bench scale laboratory equipment used exclusively for chemical or physical analysis or experimentation.

e. Portable brazing, soldering, or welding equipment.

f. The following equipment:

(1) Comfort air-conditioners or comfort ventilating systems which are not designed and not intended to be used to remove emissions generated by or released from specific units or equipment.

(2) Water cooling towers and water cooling ponds unless used for evaporative cooling of process water, or for evaporative cooling of water from barometric jets or barometric condensers or used in conjunction with an installation requiring a permit.

(3) Equipment used exclusively for steam cleaning.

(4) Porcelain enameling furnaces or porcelain enameling drying ovens.

(5) Unheated solvent dispensing containers or unheated solvent rinsing containers of sixty gallons [227.12 liters] capacity or less.

(6) Equipment used for hydraulic or hydrostatic testing.

g. The following equipment or any exhaust system or collector serving exclusively such equipment:

   (1) Blast cleaning equipment using a suspension of abrasive in water.

   (2) Bakery ovens if the products are edible and intended for human consumption.

   (3) Kilns for firing ceramic ware, heated exclusively by gaseous fuels, singly or in combinations, and electricity.

   (4) Confection cookers if the products are edible and intended for human consumption.

   (5) Drop hammers or hydraulic presses for forging or metalworking.

   (6) Diecasting machines.

   (7) Photographic process equipment through which an image is reproduced upon material through the use of sensitized radiant energy.

   (8) Equipment for drilling, carving, cutting, routing, turning, sawing, planing, spindle sanding, or disc sanding of wood or wood products, which is located within a facility that does not vent to the outside air.

   (9) Equipment for surface preparation of metals by use of aqueous solutions, except for acid solutions.

   (10) Equipment for washing or drying products fabricated from metal or glass; provided, that no volatile organic materials are used in the process and that no oil or solid fuel is burned.

   (11) Laundry dryers, extractors, or tumblers for fabrics cleaned with only water solutions of bleach or detergents.

h. Natural draft hoods or natural draft ventilators.

i. Containers, reservoirs, or tanks used exclusively for:

   (1) Dipping operations for coating objects with oils, waxes, or greases, if no organic solvents are used.

   (2) Dipping operations for applying coatings of natural or synthetic resins which contain no organic solvents.

    (3) Storage of butane, propane, or liquefied petroleum or natural gas.

    (4) Storage of lubricating oils.

    (5) Storage of petroleum liquids except those containers, reservoirs, or tanks subject to the requirements of chapter 33-15-12.

j. Gaseous fuel-fired or electrically heated furnaces for heat treating glass or metals, the use of which does not involve molten materials.

k. Crucible furnaces, pot furnaces, or induction furnaces, with a capacity of one thousand pounds [453.59 kilograms] or less each, unless otherwise noted, in which no sweating or distilling is conducted, nor any fluxing conducted utilizing chloride, fluoride, or ammonium compounds, and from which only the following metals are poured or in which only the following metals are held in a molten state:

    (1) Aluminum or any alloy containing over fifty percent aluminum; provided, that no gaseous chlorine compounds, chlorine, aluminum chloride, or aluminum fluoride are used.

    (2) Magnesium or any alloy containing over fifty percent magnesium.

    (3) Lead or any alloy containing over fifty percent lead, in a furnace with a capacity of five hundred fifty pounds [249.48 kilograms] or less.

    (4) Tin or any alloy containing over fifty percent tin.

    (5) Zinc or any alloy containing over fifty percent zinc.

    (6) Copper.

    (7) Precious metals.

l. Open burning activities within the scope of section 33-15-04-02.

m. Flares used to indicate some danger to the public.

n. Sources or alterations to a source which are of minor significance as determined by the department.

o. Oil and gas production facilities as defined in chapter 33-15-20 which are not a major source as defined in subsection 1 of section 33-15-14-06.

14. **Performance and emission testing.**

    a. Emission tests or performance tests or both shall be conducted by the owner or operator of a facility and data reduced in accordance with the applicable procedure, limitations, standards, and test methods established by this article. Such tests must be conducted under the owner's or operator's permit to construct, and such permit is subject to the faithful completion of the test in accordance with this article.

    b. All dates and periods of trial operation for the purpose of performance or emission testing pursuant to a permit to construct must be approved in advance by the department. Trial operation shall cease if the department determines, on the basis of the test results, that continued operation will result in the violation of this article. Upon completion of any test conducted under a permit to construct, the department may order the cessation of the operation of the tested equipment or facility until such time as a permit to operate has been issued by the department.

    c. Upon review of the performance data resulting from any test, the department may require the installation of such additional control equipment as will bring the facility into compliance with this article.

    d. Nothing in this article may be construed to prevent the department from conducting any test upon its own initiative, or from requiring the owner or operator to conduct any test at such time as the department may determine.

15. **Responsibility to comply.**

    a. Possession of a permit to construct does not relieve any person of the responsibility to comply with this article.

    b. The exemption of any stationary source from the requirements of a permit to construct by reason of inclusion in subsection 13 does not relieve the owner or operator of such source of the responsibility to comply with any other applicable portions of this article.

16. **Portable sources.** Sources which are designated to be portable and which are not subject to the requirements of chapter 33-15-15 are exempt from requirements to obtain a permit to construct. The owner or operator shall submit an application for a permit to operate prior to initiating operations.

17. **Registration of exempted stationary sources.** The department may require that the owner or operator of any stationary source exempted under subsection 13 shall register the source with the department within such time limits and on such forms as the department may prescribe.

18. **Extensions of time.** The department may extend any of the time periods specified in subsections 4, 5, and 6 upon notification of the applicant by the department.

19. **Amendment of permits.** The department may, when the public interest requires or when necessary to ensure the accuracy of the permit, modify any condition or information contained in the permit to construct. Modification shall be made only upon the department's own motion and the procedure shall, at a minimum, conform to any requirements of federal and state law. In the event that the modification would be a major modification as defined in chapter 33-15-15, the department shall follow the procedures established in chapter 33-15-15. For those of concern to the public, the department will provide:

    a. Reasonable notice to the public, in the area to be affected, of the opportunity for comment on the proposed modification, and the opportunity for a public hearing, upon request, as well as written public comment.

    b. A minimum of a thirty-day period for written public comment, with the opportunity for a public hearing during that thirty-day period, upon request.

    c. Consideration by the department of all comments received in its order for modification.

    The department may require the submission of such maps, plans, specifications, emission information, and compliance schedules as it deems necessary prior to the issuance of an amendment. It is the intention of the department that this subsection shall apply only in those instances allowed by federal rules and regulations and only in those instances in which the granting of a variance pursuant to section 33-15-01-06 and enforcement of existing permit conditions are manifestly inappropriate.

History: Amended effective March 1, 1980; February 1, 1982; October 1, 1987; June 1, 1990; March 1, 1994; August 1, 1995; September 1, 1997; September 1, 1998; June 1, 2001; March 1, 2003; February 1, 2005; January 1, 2007; April 1, 2009.
General Authority: NDCC 23-25-03, 23-25-04, 23-25-04.1, 23-25-04.2
Law Implemented: NDCC 23-25-04, 23-25-04.1, 23-25-04.2

33-15-14-03. Minor source permit to operate.

1. **Permit to operate required.**

    a. Except as provided in subdivisions c and d, no person may operate or cause the routine operation of an installation or source designated in section 33-15-14-01 without applying for and obtaining, in accordance with this section, a permit to operate. Application for a permit to operate a new installation or source must be made at least thirty days prior to startup of routine operation. Those sources that received a permit to construct under section 33-15-14-02, need only submit a thirty-day prior notice of proposed startup to satisfy the requirement to apply for a permit to operate under this subdivision.

b. No person may operate or cause the operation of an installation or source in violation of any permit to operate or any condition imposed upon a permit to operate or in violation of this article.

c. Sources that are subject to the title V permitting requirements of section 33-15-14-06 are exempt from the requirements of this section except during the transitional period from a minor source permit to operate to a title V permit to operate. Existing sources shall comply with all the requirements of this section until a title V permit to operate is issued. Fees for sources that meet the applicability requirements of section 33-15-14-06 shall be assessed based on section 33-15-23-04.

d. Sources that are exempt from the requirement to obtain a permit to construct under subsection 13 of section 33-15-14-02 are exempt from this section.

e. Sources which are subject to the title V permitting requirements in section 33-15-14-06 based solely on their potential to emit may apply for a federally enforceable minor source permit to operate which would limit their potential to emit to a level below the title V permit to operate applicability threshold.

f. Permits which are issued under this section which do not conform to the requirements of this section, including public participation under subdivision a of subsection 5 of section 33-15-14-03, and the requirements of any United States environmental protection agency regulations may be deemed not federally enforceable by the United States environmental protection agency.

g. General permits: The department may issue a general permit covering numerous similar sources. Any general permit shall comply with all requirements applicable to other minor source permits to operate and shall identify criteria by which sources may qualify for the general permit. To sources that qualify, the department shall grant the conditions and terms of the general permit. Sources that would qualify for a general permit must apply to the department for coverage under the terms of the general permit or apply for an individual minor source permit to operate. Without repeating the public participation procedures under subsection 5 of section 33-15-14-03, the department may grant a source's request for authorization to operate under a general permit.

2. **Application for permit to operate.**

   a. Application for a permit to operate must be made by the owner or operator thereof on forms furnished by the department.

   b. Each application for a permit to operate must be accompanied by such performance tests results, information, and records as may be required by the department to determine whether the requirements of this article will be met. Such information may also be required by the department at any time when the source is being operated to determine compliance with this article.

   c. Each application must be signed by the applicant, which signature shall constitute an agreement that the applicant will assume responsibility for the operation of the installation or source in accordance with this article.

3. **Standards for granting permits to operate.** No permit to operate may be granted unless the applicant shows to the satisfaction of the department that the source is in compliance with this article.

4. **Performance testing.**

   a. Before a permit to operate is granted, the applicant, if required by the department, shall conduct performance tests in accordance with methods and procedures required by this article or methods and procedures approved by the department. Such tests must be made at the expense of the applicant. The department may monitor such tests and may also conduct performance tests.

   b. Emission tests or performance tests or both shall be conducted by the owner or operator of a facility and data reduced in accordance with the applicable procedure, limitations, standards, and test methods established by this article. Issuance of a minor source permit to operate is subject to the faithful completion of the test in accordance with this article.

   c. All dates and periods of trial operation for the purpose of performance or emission testing pursuant to a permit to operate must be approved in advance by the department. Trial operation shall cease if the department determines, on the basis of the test results, that continued operation will result in the violation of this article. Upon completion of any test conducted under a permit to construct, the department may order the cessation of the operation of the tested equipment or facility until such time as a permit to operate has been issued by the department.

d. Upon review of the performance data resulting from any test, the department may require the installation of such additional control equipment as will bring the facility into compliance with this article.

e. Nothing in this article may be construed to prevent the department from conducting any test upon its own initiative or from requiring the owner or operator to conduct any test at such time as the department may determine.

5. **Action on applications.**

a. Public participation: This subdivision is applicable to only those sources which apply for a federally enforceable minor source permit to operate which limits their potential to emit an air contaminant. The department shall:

(1) Within ninety days of receipt of a complete application:

(a) Make a preliminary determination concerning issuance of the permit to operate.

(b) Make available in at least one location in the county or counties in which the source is located, a copy of the proposed permit and copies of or a summary of the information considered in developing the permit.

(c) Publish notice to the public by prominent advertisement, in the region affected, of the opportunity for written comment on the proposed permit. The public notice must include the proposed location of the source.

(d) Deliver a copy of the proposed permit and public notice to any state or federal land manager, or Indian governing body whose lands will be significantly affected by the source's emissions. For purposes of this subparagraph, lands will be considered to be significantly affected if the source is located within thirty-one and seven hundredths miles [50 kilometers] of such land.

(e) Provide a copy of the proposed permit, all information considered in the development of the permit and the public notice to the regional administrator of the United States environmental protection agency.

(2) Allow thirty days for public comment.

(3) Consider all public comments properly received, in making the final decision on the application.

(4) Allow the applicant to submit written responses to public comments received by the department. The applicant's responses must be submitted to the department within twenty days of the close of the public comment period.

(5) Take final action on the application within thirty days of the applicant's response to the public comments.

(6) Provide a copy of the final permit, if issued, to the applicant, the regional administrator of the United States environmental protection agency, and anyone who requests a copy.

b. For those sources not subject to public participation under subdivision a, the department shall act within thirty days after receipt of an application for a permit to operate a new installation or source, and within thirty days after receipt of an application to operate an existing installation or source, and shall notify the applicant, in writing, of the approval, conditional approval, or denial of the application.

c. The department shall set forth in any notice of denial the reasons for denial. A denial must be without prejudice to the applicant's right to a hearing before the department or for filing a further application after revisions are made to meet objections specified as reasons for the denial.

6. **Permit to operate - Conditions.** The department may impose any reasonable conditions upon a permit to operate. All emission limitations, controls, and other requirements imposed by conditions on the permit to operate must be at least as stringent as any applicable limitation or requirement contained in this article. Permit to operate conditions may include:

a. Sampling, testing, and monitoring of the facilities or ambient air or both.

b. Trial operation and performance testing.

c. Prevention and abatement of nuisance conditions caused by operation of the facility.

d. Recordkeeping and reporting.

e. Compliance with applicable rules and regulations in accordance with a compliance schedule.

f. Limits on the hours of operation of a source or its processing rate, fuel usage, or production rate when necessary to assure compliance with this article.

7. **Suspension or revocation of permit to operate.**

   a. The department may suspend or revoke a permit to operate for violation of this article, violations of a permit condition, or failure to respond to a notice of violation or any order issued pursuant to this article.

   b. Suspension or revocation of a permit to operate shall become final ten days after serving notice on the holder of the permit.

   c. A permit to operate which has been revoked pursuant to this article must be surrendered forthwith to the department.

   d. No person may operate or cause the operation of an installation or source if the department denies or revokes a permit to operate.

8. **Transfer of permit to operate.** The holder of a permit to operate may not transfer it without the prior approval of the department.

9. **Renewal of permit to operate.**

   a. Every permit to operate issued by the department after February 9, 1976, shall become void upon the fifth anniversary of its issuance. Applications for renewal of such permits must be submitted ninety days prior to such anniversary date. The department shall approve or disapprove such application within ninety days. If a source submits a complete application for a permit renewal at least ninety days prior to the expiration date, the source's failure to have a minor source permit to operate is not a violation of this section until the department takes final action on the renewal application.

   b. The department may amend permits issued prior to February 9, 1976, so as to provide for voidance upon the fifth anniversary of its issuance.

10. **[Reserved]**

11. **[Reserved]**

12. **Responsibility to comply.**

   a. Possession of a minor source permit to operate does not relieve any person of the responsibility to comply with this article.

b. The exemption of any stationary source from the requirements to obtain a minor source permit to operate does not relieve the owner or operator of such source of the responsibility to comply with any other applicable portions of this article.

13. **Portable sources.** Sources which are designed to be portable and which are operated at temporary jobsites across the state may not be considered a new source by virtue of location changes. One application for a permit to operate any portable source may be filed in accordance with this chapter, and subsequent applications are not required for each temporary jobsite. The permit to operate issued by the department shall be conditioned by such specific requirements as the department deems appropriate to carry out the provisions of sections 33-15-01-07 and 33-15-01-15.

14. **Registration of exempted stationary sources.** The department may require that the owner or operator of any stationary source exempted from the requirement to obtain a minor source permit to operate to register the source with the department within such time limits and on such forms as the department may prescribe.

15. **Extensions of time.** The department may extend any of the time periods specified in this section upon notification of the applicant by the department.

16. **Amendment of permits.** When the public interest requires or when necessary to ensure the accuracy of the permit, the department may modify any condition or information contained in a minor source permit to operate. Modification shall be made only upon the department's own motion and the procedure shall, at a minimum, conform to any requirements of federal and state law. In the event that the modification would be a major modification as defined in chapter 33-15-15, the department shall follow the procedures established in chapter 33-15-15. For those of concern to the public, or modify a condition which limits the potential to emit of a source which possesses a federally enforceable permit, the department will provide:

    a. Reasonable notice to the public, in the area to be affected, of the opportunity for comment on the proposed modification and the opportunity for a public hearing, upon request, as well as written public comment.

    b. A minimum of a thirty-day period for written public comment with the opportunity for a public hearing during that thirty-day period, upon request.

    c. Consideration by the department of all comments received.

The department may require the submission of such maps, plans, specifications, emission information, and compliance schedules as it deems necessary prior to the issuance of an amendment. It is the intention of the department that this subsection shall apply only in those instances allowed by federal rules and regulations and only in those instances in which the granting of a variance pursuant to section 33-15-01-06 and enforcement of existing permit conditions are manifestly inappropriate.

History: Amended effective February 1, 1982; October 1, 1987; March 1, 1994; August 1, 1995; June 1, 2001; March 1, 2003.
General Authority: NDCC 23-25-03, 23-25-04.1, 23-25-04.2
Law Implemented: NDCC 23-25-03, 23-25-04.1, 23-25-04.2

33-15-14-04. Permit fees. Repealed effective March 1, 1994.

33-15-14-05. Common provisions applicable to both permit to construct and permit to operate. Repealed effective March 1, 1994.

33-15-14-06. Title V permit to operate.

1. **Definitions.** For purposes of this section:

   a. "Affected source" means any source that includes one or more affected units.

   b. "Affected state" means any state that is contiguous to North Dakota whose air quality may be affected by a source subject to a proposed title V permit, permit modification, or permit renewal or which is within fifty miles [80.47 kilometers] of the permitted source.

   c. "Affected unit" means a unit that is subject to any acid rain emissions reduction requirement or acid rain emissions limitation under title IV of the Federal Clean Air Act.

   d. "Applicable requirement" means all of the following as they apply to emissions units at a source that is subject to requirements of this section (including requirements that have been promulgated or approved by the United States environmental protection agency through rulemaking at the time of issuance but have future-effective compliance dates):

      (1) Any standard or other requirement provided for in the North Dakota state implementation plan approved or promulgated by the United States environmental protection agency through rulemaking under title I of the Federal Clean Air Act that implements the relevant requirements of the Federal Clean Air Act, including any revisions to that plan.

(2) Any term or condition of any permit to construct issued pursuant to this chapter.

(3) Any standard or other requirement under section 111 including section 111(d) of the Federal Clean Air Act.

(4) Any standard or other requirement under section 112 of the Federal Clean Air Act including any requirement concerning accident prevention under section 112(r)(7) of the Federal Clean Air Act.

(5) Any standard or other requirement of the acid rain program under title IV of the Federal Clean Air Act.

(6) Any requirements established pursuant to section 504(b) or section 114(a)(3) of the Federal Clean Air Act.

(7) Any standard or other requirement governing solid waste incineration, under section 129 of the Federal Clean Air Act.

(8) Any standard or other requirement for consumer and commercial products, under section 183(e) of the Federal Clean Air Act.

(9) Any standard or other requirement for tank vessels under section 183(f) of the Federal Clean Air Act.

(10) Any standard or other requirement of the program to control air pollution from outer continental shelf sources, under section 328 of the Federal Clean Air Act.

(11) Any standard or other requirement of the regulations promulgated to protect stratospheric ozone under title VI of the Federal Clean Air Act, unless the administrator of the United States environmental protection agency has determined that such requirements need not be contained in a title V permit.

(12) Any national ambient air quality standard or increment or visibility requirement under part C of title I of the Federal Clean Air Act, but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Federal Clean Air Act.

e. "Designated representative" means a responsible natural person authorized by the owners and operators of an affected source and of all affected units at the source, as evidenced by a certificate of representation submitted in accordance with subpart B of 40 CFR 72, to represent and legally bind each owner and operator, as a matter of federal law, in matters pertaining to the acid rain program. Whenever the term "responsible official" is used in this section, or in any other regulations implementing title V of the Federal Clean Air Act, it shall be deemed to refer to the "designated representative" with regard to all matters under the acid rain program.

f. "Draft permit" means the version of a permit for which the department offers public participation or affected state review.

g. "Emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the title V permit to operate, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

h. "Emissions allowable under the permit" means a federally enforceable permit term or condition determined at issuance to be required by an applicable requirement that establishes an emissions limit (including a work practice standard) or a federally enforceable emissions cap that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject.

i. "Emissions unit" means any part or activity of a stationary source that emits or has the potential to emit any regulated air contaminant or any contaminant listed under section 112(b) of the Federal Clean Air Act. This term does not alter or affect the definition of unit for purposes of title IV of the Federal Clean Air Act.

j. "Environmental protection agency" or the "administrator" means the administrator of the United States environmental protection agency or the administrator's designee.

k. "Federal Clean Air Act" means the Federal Clean Air Act, as amended [42 U.S.C. 7401 et seq.].

l. "Final permit" means the version of a title V permit issued by the department that has completed all review procedures required in this section.

m. "Fugitive emissions" are those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

n. "General permit" means a title V permit to operate that meets the requirements of subdivision d of subsection 5.

o. "Major source" means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person (or persons under common control)) belonging to a single major industrial grouping and that are described in paragraph 1 or 2. For the purposes of defining "major source", a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the contaminant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same major group (i.e., all have the same two-digit code) as described in the standard industrial classification manual, 1987.

(1) A major source under section 112 of the Federal Clean Air Act, which is defined as:

(a) For contaminants other than radionuclides, any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit, in the aggregate, ten tons [9.07 metric tons] per year (tpy) or more of any hazardous air contaminant which has been listed pursuant to section 112(b) of the Federal Clean Air Act, twenty-five tons [22.67 metric tons] per year or more of any combination of such hazardous air contaminants, or such lesser quantity as the administrator of the United States environmental protection agency may establish by rule. Notwithstanding the preceding sentence, emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources.

(b) For radionuclides, "major source" shall have the meaning specified by the administrator of the United States environmental protection agency by rule.

(2) A major stationary source of air contaminants, that directly emits or has the potential to emit, one hundred tons [90.68 metric tons] per year or more of any air contaminant (including any major source of fugitive emissions of any such contaminant, as determined by rule by the administrator of the United States environmental protection agency).

The fugitive emissions of a stationary source shall not be considered in determining whether it is a major stationary source for the purposes of this section, unless the source belongs to one of the following categories of stationary source:

(a) Coal cleaning plants (with thermal dryers).

(b) Kraft pulp mills.

(c) Portland cement plants.

(d) Primary zinc smelters.

(e) Iron and steel mills.

(f) Primary aluminum ore reduction plants.

(g) Primary copper smelters.

(h) Municipal incinerators capable of charging more than two hundred fifty tons [226.80 metric tons] of refuse per day.

(i) Hydrofluoric, sulfuric, or nitric acid plants.

(j) Petroleum refineries.

(k) Lime plants.

(l) Phosphate rock processing plants.

(m) Coke oven batteries.

(n) Sulfur recovery plants.

(o) Carbon black plants (furnace process).

(p) Primary lead smelters.

(q) Fuel conversion plants.

(r) Sintering plants.

(s) Secondary metal production plants.

(t) Chemical process plants.

(u) Fossil-fuel boilers (or combination thereof) totaling more than two hundred fifty million British thermal units per hour heat input.

(v) Petroleum storage and transfer units with a total storage capacity exceeding three hundred thousand barrels.

(w) Taconite ore processing plants.

(x) Glass fiber processing plants.

(y) Charcoal production plants.

(z) Fossil-fuel-fired steam electric plants of more than two hundred fifty million British thermal units per hour heat input.

(aa) Any other stationary source category which as of August 7, 1980, is being regulated under section 111 or 112 of the Federal Clean Air Act.

p. "Permit modification" means a revision to a title V permit that meets the requirements of subdivision e of subsection 6.

q. "Permit program costs" means all reasonable (direct and indirect) costs required to develop and administer a permit program, under this section (whether such costs are incurred by the department or other state or local agencies that do not issue permits directly, but that support permit issuance or administration).

r. "Permit revision" means any permit modification or administrative permit amendment.

s. "Potential to emit" means the maximum capacity of a stationary source to emit any air contaminant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air contaminant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable by the administrator of the United States environmental protection agency and the department.

t. "Proposed permit" means the version of a permit that the department proposes to issue and forwards to the administrator of the United States environmental protection agency for review.

u. "Regulated air contaminant" means the following:

(1) Nitrogen oxides or any volatile organic compounds.

(2) Any contaminant for which a national ambient air quality standard has been promulgated.

(3) Any contaminant that is subject to any standard promulgated under section 111 of the Federal Clean Air Act.

(4) Any class I or II substance subject to a standard promulgated under or established by title VI of the Federal Clean Air Act.

(5) Any contaminant subject to a standard promulgated under section 112 or other requirements established under section 112 of the Federal Clean Air Act, including sections 112(g), (j), and (r) of the Federal Clean Air Act, including the following:

    (a) Any contaminant subject to requirements under section 112(j) of the Federal Clean Air Act. If the administrator fails to promulgate a standard by the date established pursuant to section 112(e) of the Federal Clean Air Act, any contaminant for which a subject source would be major shall be considered to be regulated on the date eighteen months after the applicable date established pursuant to section 112(e) of the Federal Clean Air Act; and

    (b) Any contaminant for which the requirements of section 112(g)(2) of the Federal Clean Air Act have been met, but only with respect to the individual source subject to section 112(g)(2) of the Federal Clean Air Act requirement.

v. "Regulated contaminant" for fee calculation, which is used only for chapter 33-15-23, means any "regulated air contaminant" except the following:

(1) Carbon monoxide.

(2) Any contaminant that is a regulated air contaminant solely because it is a class I or II substance subject to a standard promulgated under or established by title VI of the Federal Clean Air Act.

(3) Any contaminant that is a regulated air contaminant solely because it is subject to a standard or regulation under section 112(r) of the Federal Clean Air Act.

w. "Renewal" means the process by which a permit is reissued at the end of its term.

x. "Responsible official" means one of the following:

(1) For a corporation: a president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy or decisionmaking functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(a) The facilities employ more than two hundred fifty persons or have gross annual sales or expenditures exceeding twenty-five million dollars (in second quarter 1980 dollars).

(b) The delegation of authority to such representatives is approved in advance by the department.

(2) For a partnership or sole proprietorship: a general partner or the proprietor, respectively.

(3) For a municipality, state, federal, or other public agency: either a principal executive officer or ranking elected official. For the purposes of this section, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a regional administrator of the United States environmental protection agency).

(4) For affected sources:

(a) The designated representative insofar as actions, standards, requirements, or prohibitions under title IV of the Federal Clean Air Act or the regulations promulgated thereunder are concerned.

(b) The designated representative for any other purposes under this section.

y. "Section 502(b)(10) changes" are changes that contravene an express permit term. Such changes do not include changes that would violate applicable requirements or contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.

z. "Stationary source" means any building, structure, facility, or installation that emits or may emit any regulated air contaminant or any contaminant listed under section 112(b) of the Federal Clean Air Act.

aa. "Title V permit to operate or permit" (unless the context suggests otherwise) means any permit or group of permits covering a source that is subject to this section that is issued, renewed, amended, or revised pursuant to this section.

bb. "Title V source" means any source subject to the permitting requirements of this section, as provided in subsection 2.

2. **Applicability.**

a. This section is applicable to the following sources:

(1) Any major source.

(2) Any source, including an area source, subject to a standard, limitation, or other requirement under section 111 of the Federal Clean Air Act.

(3) Any source, including an area source, subject to a standard or other requirement under section 112 of the Federal Clean Air Act, except that a source is not required to obtain a permit solely because it is subject to regulations or requirements under section 112(r) of the Federal Clean Air Act.

(4) Any affected source.

(5) Any source in a source category designated by the administrator of the United States environmental protection agency.

b. The following source categories are exempt from the requirements of this section:

(1) All sources listed in subdivision a that are not major sources, affected sources, or solid waste incineration units required to obtain a permit pursuant to section 129(e) of the Federal Clean Air Act, are exempt from the obligation to obtain a title V permit until such time as the administrator of the United States environmental protection agency completes a rulemaking to determine how the program should be structured for nonmajor sources and the appropriateness of any permanent exemptions.

(2) In the case of nonmajor sources subject to a standard or other requirement under either section 111 or 112 of the Federal Clean Air Act after July 21, 1992, those the

administrator of the United States environmental protection agency determines to be exempt from the requirement to obtain a title V source permit at the time that the new standard is promulgated.

(3) Any source listed as exempt from the requirement to obtain a permit under this section may opt to apply for a title V permit. Sources that are exempted by paragraphs 1 and 2 and which do not opt to apply for a title V permit to operate are subject to the requirements of section 33-15-14-03.

(4) The following source categories are exempted from the obligation to obtain a permit under this section.

(a) All sources and source categories that would be required to obtain a permit solely because they are subject to 40 CFR 60, subpart AAA - standards of performance for new residential wood heaters.

(b) All sources and source categories that would be required to obtain a permit solely because they are subject to 40 CFR 61, subpart M - national emission standard for hazardous air pollutants for asbestos, section 61.145, standard for demolition and renovation.

c. For major sources, the department will include in the permit all applicable requirements for all relevant emissions units in the major source.

For any nonmajor source subject to the requirements of this section, the department will include in the permit all applicable requirements applicable to the emissions units that cause the source to be subject to this section.

d. Fugitive emissions from a source subject to the requirements of this section shall be included in the permit application and the permit in the same manner as stack emissions, regardless of whether the source category in question is included in the list of sources contained in the definition of major source.

3. **Scope.** Nothing within this section shall relieve the owner or operator of a source of the requirement to obtain a permit to construct under section 33-15-14-02 or to comply with any other applicable standard or requirement of this article.

4. **Permit applications.**

a. Duty to apply. For each title V source, the owner or operator shall submit a timely and complete permit application in accordance with this subdivision.

(1) Timely application.

(a) A timely application for a source applying for a title V permit for the first time is one that is submitted within one year of the source becoming subject to this section.

(b) Title V sources required to meet the requirements under section 112(g) of the Federal Clean Air Act, or to have a permit to construct under section 33-15-14-02, shall file a complete application to obtain the title V permit or permit revision within twelve months after commencing operation. Where an existing title V permit would prohibit such construction or change in operation, the source must obtain a permit revision before commencing operation.

(c) For purposes of permit renewal, a timely application is one that is submitted at least six months, but not more than eighteen months, prior to the date of permit expiration.

(2) Complete application. To be deemed complete, an application must provide all information required pursuant to subdivision c, except that applications for a permit revision need supply such information only if it is related to the proposed change. Information required under subdivision c must be sufficient to evaluate the subject source and its application and to determine all applicable requirements. A responsible official must certify the submitted information consistent with subdivision d. Unless the department determines that an application is not complete within sixty days of receipt of the application, such application shall be deemed to be complete, except as otherwise provided in paragraph 3 of subdivision a of subsection 6. If, while processing an application that has been determined or deemed to be complete, the department determines that additional information is necessary to evaluate or take final action on that application, it may request such information in writing and set a reasonable deadline for a response. The source's ability to operate without a permit, as set forth in subdivision b of subsection 6, shall be in effect from the date the application is determined or deemed to be complete until the final permit is issued, provided that the applicant

submits any requested additional information by the deadline specified by the department.

(3) Confidential information. If a source has submitted information to the department under a claim of confidentiality, the source must also submit a copy of such information directly to the administrator of the United States environmental protection agency when directed to do so by the department.

b. Duty to supplement or correct application. Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a draft permit.

c. Standard application form and required information. All applications for a title V permit to operate shall be made on forms supplied by the department. Information as described below for each emissions unit at a title V source shall be included in the application. Detailed information for emissions units or activities that have the potential to emit less than the following quantities of air contaminants (insignificant units or activities) need not be included in permit applications:

Particulate: 2 tons [1.81 metric tons] per year

Inhalable particulate: 2 tons [1.81 metric tons] per year

Sulfur dioxide: 2 tons [1.81 metric tons] per year

Hydrogen sulfide: 2 tons [1.81 metric tons] per year

Carbon monoxide: 2 tons [1.81 metric tons] per year

Nitrogen oxides: 2 tons [1.81 metric tons] per year

Ozone: 2 tons [1.81 metric tons] per year

Reduced sulfur compounds: 2 tons [1.81 metric tons] per year

Volatile organic compounds: 2 tons [1.81 metric tons]

All other regulated contaminants including those in section 112(b) of the Federal Clean Air Act: 0.5 tons [0.45 metric tons] per year.

Where a contaminant could be placed in more than one category, the smallest emission level applies.

However, for insignificant activities or emissions units, a list of such activities or units must be included in the application. An applicant may not omit information needed to determine the applicability of, or to impose, any applicable requirement, or to evaluate the fee amount required under section 33-15-23-04. The application, shall, as a minimum, include the elements specified below:

(1) Identifying information, including company name and address (or plant name and address if different from the company name), owner's name and agent, and telephone number and names of plant site manager or contact.

(2) A description of the source's processes and products (by Standard Industrial Classification Code) including any associated with each alternate scenario identified by the source.

(3) The following emissions-related information:

  (a) All emissions of contaminants for which the source is major, and all emissions of regulated air contaminants. A permit application shall describe all emissions of regulated air contaminants emitted from any emissions unit, except when such units are exempted under this subdivision.

  (b) Identification and description of all points of emissions described in subparagraph a in sufficient detail to establish the basis for fees and applicability of requirements of the Federal Clean Air Act and this article.

  (c) Emissions rates in tons per year, in terms of the applicable standard, and terms that are necessary to establish compliance with the applicable compliance method.

  (d) Fuels, fuel use, raw materials, production rates, and operating schedules.

  (e) Identification and description of air pollution control equipment and compliance monitoring devices or activities.

(f) Limitations on source operation affecting emissions or any work practice standards, when applicable, for all regulated contaminants.

(g) Other information required by any applicable requirement including information related to stack height limitations developed pursuant to chapter 33-15-18.

(h) Calculations on which the information in subparagraphs a through g is based.

(4) The following air pollution control requirements:

(a) Citation and description of all applicable requirements; and

(b) Description of or reference to any applicable test method for determining compliance with each applicable requirement.

(5) Other specific information that may be necessary to implement and enforce other applicable requirements of the Federal Clean Air Act or of this article or to determine the applicability of such requirements.

(6) An explanation of any proposed exemptions from otherwise applicable requirements.

(7) Information that the department determines to be necessary to define alternative operating scenarios identified by the source or to define permit terms and conditions.

(8) A compliance plan for all title V sources that contains all the following:

(a) A description of the compliance status of the source with respect to all applicable requirements.

(b) A description as follows:

[1] For applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements.

[2] For applicable requirements that will become effective during the permit term, a statement that

the source will meet such requirements on a timely basis.

[3] For requirements for which the source is not in compliance at the time of permit issuance, a narrative description of how the source will achieve compliance with such requirements.

(c) A compliance schedule as follows:

[1] For applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements.

[2] For applicable requirements that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis. A statement that the source will meet in a timely manner applicable requirements that become effective during the permit term shall satisfy this provision, unless a more detailed schedule is expressly required by the applicable requirement.

[3] A schedule of compliance for sources that are not in compliance with all applicable requirements at the time of permit issuance. Such a schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.

(d) A schedule for submission of certified progress reports no less frequently than every six months for sources required to have a schedule of compliance to remedy a violation.

(e) The compliance plan content requirements specified in this paragraph shall apply and be included in the acid rain portion of a compliance plan for an affected source, except as specifically superseded by regulations promulgated under title IV of the Federal Clean Air Act with regard to the schedule and method or methods the source will use to achieve compliance with the acid rain emissions limitations.

(9) Requirements for compliance certification, including the following:

(a) A certification of compliance with all applicable requirements by a responsible official consistent with subdivision d and section 114(a)(3) of the Federal Clean Air Act;

(b) A statement of methods used for determining compliance, including a description of monitoring, recordkeeping, and reporting requirements and test methods;

(c) A schedule for submission of compliance certifications during the permit term, to be submitted annually, or more frequently if specified by the underlying applicable requirement; and

(d) A statement indicating the source's compliance status with any applicable enhanced monitoring and compliance certification requirements of the Federal Clean Air Act.

(10) The use of nationally standardized forms for acid rain portions of permit applications and compliance plans, as required by regulations promulgated under title IV of the Federal Clean Air Act.

d. Any application form, report, or compliance certification submitted pursuant to these rules shall contain certification by a responsible official of truth, accuracy, and completeness. This certification and any other certification required under this section shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

5. **Permit content.**

a. Standard permit requirements. Each permit issued under this section shall include, as a minimum, the following elements:

(1) Emissions limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance.

  (a) The permit must specify and reference the origin of and authority for each term or condition, and identify any difference in form as compared to the applicable requirement upon which the term or condition is based.

  (b) The permit must state that, if an applicable requirement of the Federal Clean Air Act is more stringent than an applicable requirement of regulations promulgated under title IV of the Federal Clean Air Act, both provisions shall be incorporated into the permit and shall be enforceable by the administrator of the United States environmental protection agency and the department.

  (c) If the state implementation plan allows a determination of an alternative emissions limit at a title V source, equivalent to that contained in the plan, to be made in the permit issuance, renewal, or significant modification process, and the department elects to use such process, any permit containing such equivalency determination shall contain provisions to ensure that any resulting emissions limit has been demonstrated to be quantifiable, accountable, enforceable, and based on replicable procedures.

(2) Permit duration. Each title V permit to operate shall expire upon the fifth anniversary of its issuance.

(3) Monitoring and related recordkeeping and reporting requirements.

  (a) Each permit shall contain the following requirements with respect to monitoring:

    [1] All monitoring and analysis procedures or test methods required under applicable monitoring and testing requirements, including subsection 10 and any procedures and methods promulgated pursuant to sections 504(b) or 114(a)(3) of the Federal Clean Air Act. If more than one monitoring or testing requirement applies, the permit may specify a streamlined set of monitoring or testing provisions provided the specified monitoring or testing is adequate to

assure compliance at least to the same extent as the monitoring or testing applicable requirements that are not included in the permit as a result of such streamlining;

[2] If the applicable requirement does not require periodic testing or instrumental or noninstrumental monitoring (which may consist of recordkeeping designed to serve as monitoring), periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit, as reported pursuant to subparagraph c. Such monitoring requirements shall assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirement. Recordkeeping provisions may be sufficient to meet the requirements of this item; and

[3] As necessary, requirements concerning the use, maintenance, and, if appropriate, installation of monitoring equipment or methods.

(b) With respect to recordkeeping, the permit shall incorporate all applicable recordkeeping requirements and require, if applicable, the following:

[1] Records of required monitoring information that include the following:

[a] The date, place as defined in the permit, and time of sampling or measurements;

[b] The dates analyses were performed;

[c] The company or entity that performed the analyses;

[d] The analytical techniques or methods used;

[e] The results of such analyses; and

[f] The operating conditions as existing at the time of sampling or measurement;

[2] Retention of records of all required monitoring data and support information for a period of at

least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

(c) With respect to reporting, the permit shall incorporate all applicable reporting requirements and require the following:

[1] Submittal of reports of any required monitoring at least every six months. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with subdivision d of subsection 4.

[2] Prompt reporting of deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. The department shall define "prompt" in the permit consistent with chapter 33-15-01 and the applicable requirements.

(4) A permit condition prohibiting emissions exceeding any allowances that the source lawfully holds under title IV of the Federal Clean Air Act or the regulations promulgated thereunder.

(a) No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to title IV of the Federal Clean Air Act, or the regulations promulgated thereunder, provided that such increases do not require a permit revision under any other applicable requirement.

(b) No limit shall be placed on the number of allowances held by the source. The source may not, however, use allowances as a defense to noncompliance with any other applicable requirement.

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under title IV of the Federal Clean Air Act.

(5) A severability clause to ensure the continued validity of the various permit requirements in the event of a challenge to any portions of the permit.

(6) Provisions stating the following:

  (a) The permittee must comply with all conditions of the title V permit. Any permit noncompliance constitutes a violation of the Federal Clean Air Act and this article and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

  (b) It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

  (c) The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

  (d) The permit does not convey any property rights of any sort, or any exclusive privilege.

  (e) The permittee must furnish to the department, within a reasonable time, any information that the department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the department copies of records required to be kept by the permit or, for information claimed to be confidential, the permittee must also furnish such records directly to the administrator of the United States environmental protection agency along with a claim of confidentiality.

(7) A provision to ensure that the source pays fees to the department consistent with the fee schedule in chapter 33-15-23.

(8) Emissions trading. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or

processes for changes that are provided for in the permit and the state implementation plan.

(9) Terms and conditions for reasonably anticipated operating scenarios identified by the source in its application as approved by the department. Such terms and conditions:

  (a) Shall require the source, contemporaneously with making a change from one operating scenario to another, to record in a log at the permitted facility a record of the scenario under which it is operating;

  (b) Shall extend the permit shield described in subdivision f to all terms and conditions under each such operating scenario; and

  (c) Must ensure that the terms and conditions of each such alternative scenario meet all applicable requirements and the requirements of this section.

(10) Terms and conditions, if the permit applicant requests them, for the trading of emissions increases and decreases in the permitted facility, to the extent that the applicable requirements, including the state implementation plan, provide for trading such increases and decreases without a case-by-case approval of each emissions trade. Such terms and conditions:

  (a) Shall include all terms required under subdivisions a and c to determine compliance;

  (b) Shall extend the permit shield described in subdivision f to all terms and conditions that allow such increases and decreases in emissions; and

  (c) Must meet all applicable requirements and requirements of this section.

(11) If a permit applicant requests it, the department shall issue permits that contain terms and conditions, including all terms required under subdivisions a and c to determine compliance, allowing for the trading of emissions increases and decreases in the permitted facility solely for the purpose of complying with a federally enforceable emissions cap that is established in the permit independent of otherwise applicable requirements provided the changes in emissions are not modifications under title I of the Federal Clean Air Act and the changes do not exceed the emissions allowable under the permit. The permit applicant shall include in

its application proposed replicable procedures and permit terms that ensure the emissions trades are quantifiable and enforceable. The department shall not be required to include in the emissions trading provisions any emissions units for which emissions are not quantifiable or for which there are no replicable procedures to enforce the emissions trades. The permit shall also require compliance with all applicable requirements. The permittee shall supply written notification at least seven days prior to the change to the department and the administrator of the United States environmental protection agency and shall state when the change will occur and shall describe the changes in emissions that will result and how these increases and decreases in emissions will comply with the terms and conditions of the permit. The permit shield described in subdivision f shall extend to terms and conditions that allow such increases and decreases in emissions.

b. Federally enforceable requirements.

(1) All terms and conditions in a title V permit, including any provisions designed to limit a source's potential to emit, are enforceable by the administrator of the United States environmental protection agency and citizens under the Federal Clean Air Act.

(2) Notwithstanding paragraph 1, the department shall specifically designate as not being federally enforceable under the Federal Clean Air Act any terms and conditions included in the permit that are not required under the Federal Clean Air Act or under any of its applicable requirements. Terms and conditions so designated are not subject to the requirements of subsections 6 and 7, or of this subsection, other than those contained in this subdivision.

c. Compliance requirements. All title V permits shall contain the following elements with respect to compliance:

(1) Consistent with paragraph 3 of subdivision a, compliance certification, testing, monitoring, reporting, and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit. Any document, including reports, required by a title V permit shall contain a certification by a responsible official that meets the requirements of subdivision d of subsection 4.

(2) Inspection and entry requirements that require that, upon presentation of credentials and other documents as may be

required by law, the permittee shall allow the department or an authorized representative to perform the following:

(a) Enter upon the permittee's premises where a title V source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

(d) As authorized by the Federal Clean Air Act and this article, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

(3) A schedule of compliance consistent with paragraph 8 of subdivision c of subsection 4.

(4) Progress reports consistent with an applicable schedule of compliance and paragraph 8 of subdivision c of subsection 4 to be submitted at least semiannually, or at a more frequent period if specified in the applicable requirement or by the department. Such progress reports shall contain the following:

(a) Dates for achieving the activities, milestones, or compliance required in the schedule of compliance, and dates when such activities, milestones, or compliance were achieved; and

(b) An explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

(5) Requirements for compliance certification with terms and conditions contained in the permit, including emissions limitations, standards, or work practices. Permits shall include each of the following:

(a) The frequency, which is annually or such more frequent periods as specified in the applicable requirement or by the department, of submissions of compliance certifications;

(b) In accordance with paragraph 3 of subdivision a, a means for monitoring the compliance of the source with its emissions limitations, standards, and work practices. The means for monitoring shall be contained in applicable requirements or United States environmental protection agency guidance;

(c) A requirement that the compliance certification include all of the following (provided that the identification of applicable information may cross-reference the permit or previous reports, as applicable):

[1] The identification of each term or condition of the permit that is the basis of the certification;

[2] The identification of the methods or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the methods and means required under paragraph 3 of subdivision a;

[3] The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the method or means designated in item 2. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under subsection 10 occurred; and

[4] Such other facts as the department may require to determine the compliance status of the source;

(d) A requirement that all compliance certifications be submitted to the administrator of the United States environmental protection agency as well as to the department; and

(e) Such additional requirements as may be specified pursuant to sections 114(a)(3) and 504(b) of the Federal Clean Air Act.

(6) Such other provisions as the department may require.

d. General permits.

(1) The department may, after notice and opportunity for public participation provided under subdivision h of subsection 6, issue a general permit covering numerous similar sources. Any general permit shall comply with all requirements applicable to other title V permits and shall identify criteria by which sources may qualify for the general permit. To sources that qualify, the department shall grant the conditions and terms of the general permit. Notwithstanding the shield provisions of subdivision f, the source shall be subject to enforcement action for operation without a title V permit to operate if the source is later determined not to qualify for the conditions and terms of the general permit. General permits shall not be authorized for affected sources under the acid rain program unless otherwise provided in regulations promulgated under title IV of the Federal Clean Air Act. The department is not required to issue a general permit in lieu of individual title V permits.

(2) Title V sources that would qualify for a general permit must apply to the department for coverage under the terms of the general permit or must apply for a title V permit to operate consistent with subsection 4. The department may, in the general permit, provide for applications which deviate from the requirements of subsection 4, provided that such applications meet the requirements of title V of the Federal Clean Air Act, and include all information necessary to determine qualification for, and to assure compliance with, the general permit. Without repeating the public participation procedures required under subdivision h of subsection 6, the department may grant a source's request for authorization to operate under a general permit, but such a grant shall not be a final permit action for purposes of judicial review.

e. Temporary sources. The department may issue a single permit authorizing emissions from similar operations by the same source owner or operator at multiple temporary locations. The operation must be temporary and involve at least one change of location during the term of the permit. No affected source shall be permitted as a temporary source. Permits for temporary sources shall include the following:

(1) Conditions that will assure compliance with all applicable requirements at all authorized locations;

(2) Requirements that the owner or operator notify the department at least ten days in advance of each change in location; and

(3) Conditions that assure compliance with all other provisions of this section.

f. Permit shield.

(1) Except as provided in this section, upon written request by the applicant, the department shall include in a title V permit to operate a provision stating that compliance with the conditions of the permit shall be deemed compliance with any applicable requirement as of the date of permit issuance, provided that:

(a) Such applicable requirements are included and are specifically identified in the permit; or

(b) The department, in acting on the permit application or revision, determines in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or a concise summary thereof.

(2) A title V permit that does not expressly state that a permit shield exists shall be presumed not to provide such a shield.

(3) Nothing in this subdivision or in any title V permit shall alter or affect the following:

(a) The provisions of section 303 of the Federal Clean Air Act (emergency orders), including the authority of the administrator of the United States environmental protection agency under that section;

(b) The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

(c) The applicable requirements of the acid rain program, consistent with section 408(a) of the Federal Clean Air Act; or

(d) The ability of the United States environmental protection agency to obtain information from a source pursuant to section 114 of the Federal Clean Air Act.

g. Emergency provision.

(1) An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emissions limitation under the title V permit to operate, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

(2) Effect of an emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emissions limitations if the conditions of paragraph 3 are met.

(3) The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

(a) An emergency occurred and that the permittee can identify the causes of the emergency;

(b) The permitted facility was at the time being properly operated;

(c) During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in the permit; and

(d) The permittee submitted notice of the emergency to the department within one working day of the time when emissions limitations were exceeded due to the emergency. This notice fulfills the requirement of item 2 of subparagraph c of paragraph 3 of subdivision a. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(4) In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

(5) This provision is in addition to any emergency or upset provision contained in any applicable requirement and the malfunction notification required under subdivision b of subsection 2 of section 33-15-01-13 when a threat to health and welfare would exist.

6. **Permit issuance, renewal, reopenings, and revisions.**

a. Action on application.

(1) A permit, permit modification, or permit renewal may be issued only if all of the following conditions have been met:

(a) The department has received a complete application for a permit, permit modification, or permit renewal, except that a complete application need not be received before issuance of a general permit under subdivision d of subsection 5;

(b) Except for modifications qualifying for minor permit modification procedures under paragraphs 1 and 2 of subdivision e, the department has complied with the requirements for public participation under subdivision h;

(c) The department has complied with the requirements for notifying and responding to affected states under subdivision b of subsection 7;

(d) The conditions of the permit provide for compliance with all applicable requirements and the requirements of this section; and

(e) The administrator of the United States environmental protection agency has received a copy of the proposed permit and any notices required under subdivisions a and b of subsection 7, and has not objected to issuance of the permit under subdivision c of subsection 7 within the time period specified therein.

(2) Except for applications received during the initial transitional period described in 40 CFR 70.4(b)(11) or under regulations promulgated under title IV or title V of the Federal Clean Air Act for the permitting of affected sources under the acid rain program, the department shall take final action on each

permit application, including a request for permit modification or renewal, within eighteen months after receiving a complete application.

(3) The department shall provide notice to the applicant of whether the application is complete. Unless the department requests additional information or otherwise notifies the applicant of incompleteness within sixty days of receipt of an application, the application shall be deemed complete. For modifications processed through the minor permit modification procedures, in paragraphs 1 and 2 of subdivision e, a completeness determination is not required.

(4) The department shall provide a statement that sets forth the legal and factual basis for the draft permit conditions, including references to the applicable statutory or regulatory provisions. The department shall send this statement to the United States environmental protection agency and to any other person who requests it.

(5) The submittal of a complete application shall not affect the requirement that any source have a permit to construct under section 33-15-14-02.

b. Requirement for a permit.

(1) Except as provided in the following sentence, paragraphs 2 and 3, subparagraph e of paragraph 1 of subdivision e, and subparagraph e of paragraph 2 of subdivision e, no title V source may operate after the time that it is required to submit a timely and complete application under this section, except in compliance with a permit issued under this section. If a title V source submits a timely and complete application for permit issuance, including for renewal, the source's failure to have a title V permit is not a violation of this section until the department takes final action on the permit application, except as noted in this subsection. This protection shall cease to apply if, subsequent to the completeness determination made pursuant to paragraph 3 of subdivision a, and as required by paragraph 2 of subdivision a of subsection 4, the applicant fails to submit by the deadline specified in writing by the department any additional information identified as being needed to process the application. For timely and complete renewal applications for which the department has failed to issue or deny the renewal permit before the expiration date of the previous permit, all the terms and conditions of the permit, including the permit shield that was granted pursuant

to subdivision f of subsection 5 shall remain in effect until the renewal permit has been issued or denied.

(2) A permit revision is not required for section 502(b)(10) changes provided:

(a) The changes are not modifications under chapters 33-15-12, 33-15-13, and 33-15-15 or title I of the Federal Clean Air Act.

(b) The changes do not exceed the emissions allowable under the title V permit whether expressed therein as a rate of emissions or in terms of total emissions.

(c) A permit to construct under section 33-15-14-02 has been issued, if required.

(d) The facility provides the department and the administrator of the United States environmental protection agency with written notification at least seven days in advance of the proposed change. The written notification shall include a description of each change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change.

The permit shield described in subdivision f of subsection 5 shall not apply to any change made pursuant to this paragraph.

(3) A permit revision is not required for changes that are not addressed or prohibited by the permit provided:

(a) Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition.

(b) The source must provide contemporaneous written notice to the department and the administrator of the United States environmental protection agency of each such change, except for changes that qualify as insignificant under the provisions of subdivision c of subsection 4. Such written notice shall describe each such change, including the date, any change in emissions, contaminants emitted, and any applicable requirement that would apply as a result of the change.

(c) The permittee shall keep a record describing changes made at the source that result in emissions of a regulated air contaminant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

(d) The changes are not subject to any requirements under title IV of the Federal Clean Air Act.

(e) The changes are not modifications under chapters 33-15-12, 33-15-13, and 33-15-15 or any provision of title I of the Federal Clean Air Act.

(f) A permit to construct under section 33-15-14-02 has been issued, if required.

The permit shield described in subdivision f of subsection 5 shall not apply to any change made pursuant to this paragraph.

c. Permit renewal and expiration.

(1) Permits being renewed are subject to the same procedural requirements, including those for public participation, affected state and the United States environmental protection agency review, that apply to initial permit issuance; and

(2) Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted consistent with subdivision b of subsection 6 and subparagraph c of paragraph 1 of subdivision a of subsection 4.

d. Administrative permit amendments.

(1) An "administrative permit amendment" is a permit revision that:

(a) Corrects typographical errors;

(b) Identifies a change in the name, address, or telephone number of any person identified in the permit, or provides a similar minor administrative change at the source;

(c) Requires more frequent monitoring or reporting by the permittee;

(d) Allows for a change in ownership or operational control of a source if the department determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the department;

(e) Incorporates into the title V permit the requirements from a permit to construct, provided that the permit to construct review procedure is substantially equivalent to the requirements of subsections 6 and 7 that would be applicable to the change if it were subject to review as a permit modification, and compliance requirements substantially equivalent to those contained in subsection 5; or

(f) Incorporates any other type of change which the administrator of the United States environmental protection agency has approved as being an administrative permit amendment as part of the approved title V operating permit program.

(2) Administrative permit amendments for purposes of the acid rain portion of the permit shall be governed by regulations promulgated under title IV of the Federal Clean Air Act.

(3) Administrative permit amendment procedures. An administrative permit amendment may be made by the department consistent with the following:

(a) The department shall take no more than sixty days from receipt of a request for an administrative permit amendment to take final action on such request, and may incorporate such changes without providing notice to the public or affected states provided that it designates any such permit revisions as having been made pursuant to this subdivision.

(b) The department shall submit a copy of the revised permit to the administrator of the United States environmental protection agency.

(c) The source may implement the changes addressed in the request for an administrative amendment immediately upon submittal of the request provided a permit to construct under section 33-15-14-02 has been issued, if required.

(4) The department may, upon taking final action granting a request for an administrative permit amendment, allow coverage by the permit shield in subdivision f of subsection 5 for administrative permit amendments made pursuant to subparagraph e of paragraph 1 of subdivision d which meet the relevant requirements of subsections 5, 6, and 7 for significant permit modifications.

e. Permit modification. A permit modification is any revision to a title V permit that cannot be accomplished under the provisions for administrative permit amendments under subdivision d. A permit modification for purposes of the acid rain portion of the permit shall be governed by regulations promulgated under title IV of the Federal Clean Air Act.

(1) Minor permit modification procedures.

(a) Criteria.

[1] Minor permit modification procedures may be used only for those permit modifications that:

[a] Do not violate any applicable requirement;

[b] Do not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in the permit;

[c] Do not require or change a case-by-case determination of an emissions limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

[d] Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include a federally enforceable emissions cap assumed to avoid classification as a modification under any provision of title I of the Federal Clean Air Act; and an alternative emissions limit approved pursuant to regulations

promulgated under section 112(i)(5) of the Federal Clean Air Act;

[e] Are not modifications under chapters 33-15-12, 33-15-13, and 33-15-15 or any provision of title I of the Federal Clean Air Act; and

[f] Are not required to be processed as a significant modification.

[2] Notwithstanding item 1 and subparagraph a of paragraph 2 of subdivision e, minor permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in the state implementation plan, or in applicable requirements promulgated by the United States environmental protection agency.

(b) Application. An application requesting the use of minor permit modification procedures shall meet the requirements of subdivision c of subsection 4 and shall include the following:

[1] A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

[2] The source's suggested draft permit;

[3] Certification by a responsible official, consistent with subdivision d of subsection 4, that the proposed modification meets the criteria for use of minor permit modification procedures and a request that such procedures be used; and

[4] Completed forms for the department to use to notify the administrator of the United States environmental protection agency and affected states as required under subsection 7.

(c) United States environmental protection agency and affected state notification. Within five working days of receipt of a complete permit modification application, the department shall notify the administrator of the United States environmental protection agency and affected states of the requested permit modification. The department shall promptly send any notice required under paragraph 2 of subdivision b of subsection 7 to the administrator of the United States environmental protection agency.

(d) Timetable for issuance. The department may not issue a final permit modification until after the United States environmental protection agency forty-five-day review period or until the United States environmental protection agency has notified the department that the United States environmental protection agency will not object to issuance of the permit modification, whichever is first, although the department can approve the permit modification prior to that time. Within ninety days of the department's receipt of an application under minor permit modification procedures or fifteen days after the end of the administrator's forty-five-day review period under subdivision c of subsection 7, whichever is later, the department shall:

[1] Issue the permit modification as proposed;

[2] Deny the permit modification application;

[3] Determine that the requested modification does not meet the minor permit modification criteria and should be reviewed under the significant modification procedures; or

[4] Revise the draft permit modification and transmit to the administrator the new proposed permit modification as required by subdivision a of subsection 7.

(e) Source's ability to make change. A source may make the change proposed in its minor permit modification application only after it files such application and the department approves the change in writing. If the department allows the source to make the proposed change prior to taking action specified in items 1, 2, and 3 of subparagraph d, the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time period, the source need not comply with the existing permit terms and conditions it seeks to modify. However, if the source fails to comply with its proposed permit terms and conditions during this time period, the existing permit terms and conditions it seeks to modify may be enforced against it.

(f) The permit shield under subdivision f of subsection 5 shall not extend to minor permit modifications.

(2) Group processing of minor permit modifications. Consistent with this paragraph, the department may modify the procedure outlined in paragraph 1 to process groups of a source's applications for certain modifications eligible for minor permit modification processing.

(a) Criteria. Group processing of modifications may be used only for those permit modifications:

[1] That meet the criteria for minor permit modification procedures under item 1 of subparagraph a of paragraph 1 of subdivision e; and

[2] That collectively are below the threshold level which is ten percent of the emissions allowed by the permit for the emissions unit for which the change is requested, twenty percent of the applicable definition of major source in subsection 1, or five tons [4.54 metric tons] per year, whichever is least.

(b) Application. An application requesting the use of group processing procedures shall meet the requirements of subdivision c of subsection 4 and shall include the following:

[1] A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs.

[2] The source's suggested draft permit.

[3] Certification by a responsible official, consistent with subdivision d of subsection 4, that the proposed modification meets the criteria for use of group processing procedures and a request that such procedures be used.

[4] A list of the source's other pending applications awaiting group processing, and a determination of

whether the requested modification, aggregated with these other applications, equals or exceeds the threshold set under item 2 of subparagraph a of paragraph 2 of subdivision e.

[5] Certification, consistent with subdivision d of subsection 4, that the source has notified the United States environmental protection agency of the proposed modification. Such notification need only contain a brief description of the requested modification.

[6] Completed forms for the department to use to notify the administrator of the United States environmental protection agency and affected states as required under subsection 7.

(c) United States environmental protection agency and affected state notification. On a quarterly basis or within five business days of receipt of an application demonstrating that the aggregate of a source's pending applications equals or exceeds the threshold level set under item 2 of subparagraph a of paragraph 2 of subdivision e, whichever is earlier, the department shall meet its obligation under paragraph 1 of subdivision a of subsection 7 and paragraph 1 of subdivision b of subsection 7 to notify the administrator of the United States environmental protection agency and affected states of the requested permit modifications. The department shall send any notice required under paragraph 2 of subdivision b of subsection 7 to the administrator of the United States environmental protection agency.

(d) Timetable for issuance. The provisions of subparagraph d of paragraph 1 of subdivision e shall apply to modifications eligible for group processing, except that the department shall take one of the actions specified in items 1 through 4 of subparagraph d of paragraph 1 of subdivision e within one hundred eighty days of receipt of the application or fifteen days after the end of the administrator's forty-five-day review period under subdivision c of subsection 7, whichever is later.

(e) Source's ability to make change. The provisions of subparagraph e of paragraph 1 apply to modifications eligible for group processing.

(f) The permit shield under subdivision f of subsection 5 shall not extend to group processing of minor permit modifications.

(3) Significant modification procedures.

(a) Criteria. Significant modification procedures shall be used for applications requesting permit modifications that do not qualify as minor permit modifications or as administrative amendments. Every significant change in existing monitoring permit terms or conditions and every relaxation of reporting or recordkeeping permit terms or conditions shall be considered significant. Nothing herein shall be construed to preclude the permittee from making changes consistent with this subsection that would render existing permit compliance terms and conditions irrelevant.

(b) Significant permit modifications shall meet all requirements of this section, including those for applications, public participation, review by affected states, and review by the United States environmental protection agency, as they apply to permit issuance and permit renewal. The department shall complete review of significant permit modifications within nine months after receipt of a complete application.

f. Reopening for cause.

(1) Each issued permit shall include provisions specifying the conditions under which the permit will be reopened prior to the expiration of the permit. A permit shall be reopened and revised under any of the following circumstances:

(a) Additional applicable requirements under the Federal Clean Air Act become applicable to a major title V source with a remaining permit term of three or more years. Such a reopening shall be completed not later than eighteen months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended.

(b) Additional requirements, including excess emissions requirements, become applicable to an affected source under title IV of the Federal Clean Air Act or the regulations promulgated thereunder. Upon approval by the administrator of the United States environmental protection agency, excess emissions offset plans shall be deemed to be incorporated into the permit.

(c) The department or the United States environmental protection agency determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

(d) The administrator of the United States environmental protection agency or the department determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(2) Proceedings to reopen and issue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Such reopening shall be made as expeditiously as practicable.

(3) Reopenings under paragraph 1 shall not be initiated before a notice of such intent is provided to the title V source by the department at least thirty days in advance of the date that the permit is to be reopened, except that the department may provide a shorter time period in the case of an emergency.

g. Reopenings for cause by the United States environmental protection agency.

(1) If the administrator of the United States environmental protection agency finds that cause exists to terminate, modify, or revoke and reissue a permit pursuant to subdivision f, within ninety days after receipt of such notification, the department shall forward to the United States environmental protection agency a proposed determination of termination, modification, or revocation and reissuance, as appropriate.

(2) The administrator of the United States environmental protection agency will review the proposed determination from the department within ninety days of receipt.

(3) The department shall have ninety days from receipt of the United States environmental protection agency objection to resolve any objection that the United States environmental protection agency makes and to terminate, modify, or revoke and reissue the permit in accordance with the administrator's objection.

(4) If the department fails to submit a proposed determination or fails to resolve any objection, the administrator of the United States environmental protection agency will terminate, modify, or revoke and reissue the permit after taking the following actions:

  (a) Providing at least thirty days' notice to the permittee in writing of the reasons for any such action.

  (b) Providing the permittee an opportunity for comment on the administrator's proposed action and an opportunity for a hearing.

h. Public participation. Except for modifications qualifying for minor permit modification procedures, all permit proceedings, including initial permit issuance, significant modifications, and renewals, shall be subject to procedures for public notice including offering an opportunity for public comment and a hearing on the draft permit. These procedures shall include the following:

(1) Notice shall be given by publication in a newspaper of general circulation in the area where the source is located or in a state publication designed to give general public notice; to persons on a mailing list developed by the department, including those who request in writing to be on the list; and by other means if necessary to assure adequate notice to the affected public;

(2) The notice shall identify the affected facility; the name and address of the permittee; the name and address of the department; the activity or activities involved in the permit action; the emissions change involved in any permit modification; the name, address, and telephone number of a person from whom interested persons may obtain additional information, including copies of the permit draft, the application, all relevant supporting materials, and all other materials available to the department that are relevant to the permit decision; a brief description of the comment procedures required by this subsection; and the time and place of any hearing that may be held, including a statement of procedures to request a hearing, unless a hearing has already been scheduled;

(3) The department shall provide such notice and opportunity for participation by affected states as is provided for by subsection 7;

(4) The department shall provide at least thirty days for public comment and shall give notice of any public hearing at least thirty days in advance of the hearing; and

(5) The department shall keep a record of the commenters and also of the issues raised during the public participation process. These records shall be available to the public.

7. **Permit review by the United States environmental protection agency and affected states.**

a. Transmission of information to the administrator.

(1) The department shall provide a copy of each permit application including any application for a permit modification (including the compliance plan), to the administrator of the United States environmental protection agency except that the applicant shall provide such information directly to the administrator of the United States environmental protection agency when directed to do so by the department. The department shall provide a copy of each proposed permit and each final title V permit to operate to the administrator of the United States environmental protection agency. To the extent practicable, the preceding information shall be provided in computer-readable format compatible with the United States environmental protection agency's national data base management system.

(2) The department may waive the requirements of paragraph 1 and paragraph 1 of subdivision b for any category of sources (including any class, type, or size within such category) other than major sources upon approval by the administrator of the United States environmental protection agency.

(3) The department shall keep these records for at least five years.

b. Review by affected states.

(1) The department shall give notice of each draft permit to any affected state on or before the time that the notice to the public under subdivision h of subsection 6 is given, except to the extent paragraphs 1 and 2 of subdivision e of subsection 6 require the timing of the notice to be different.

(2) As part of the submittal of the proposed permit to the administrator of the United States environmental protection agency (or as soon as possible after the submittal for minor permit modification procedures allowed under paragraphs 1 and 2 of subdivision e of subsection 6) the department shall notify the administrator of the United States environmental protection agency and any affected state in writing of any refusal by the department to accept all recommendations

for the proposed permit that the affected state submitted during the public or affected state review period. The notice shall include the department's reasons for not accepting any such recommendation. The department is not required to accept recommendations that are not based on applicable requirements or the requirements of this section.

c. United States environmental protection agency objection. No permit for which an application must be transmitted to the administrator of the United States environmental protection agency under subdivision a shall be issued if the administrator of the United States environmental protection agency objects to its issuance in writing within forty-five days of receipt of the proposed permit and all necessary supporting information.

d. Public petitions to the administrator of the United States environmental protection agency. If the administrator of the United States environmental protection agency does not object in writing under subdivision c, any person may petition the administrator of the United States environmental protection agency within sixty days after the expiration of the administrator's forty-five-day review period to make such objection. Any such petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided for in subdivision h of subsection 6, unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objection arose after such period. If the administrator of the United States environmental protection agency objects to the permit as a result of a petition filed under this subdivision, the department shall not issue the permit until the United States environmental protection agency's objection has been resolved, except that a petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the forty-five-day review period and prior to the United States environmental protection agency's objection. If the department has issued a permit prior to receipt of the United States environmental protection agency's objection under this subdivision, the department may thereafter issue only a revised permit that satisfies the United States environmental protection agency's objection. In any case, the source will not be in violation of the requirement to have submitted a timely and complete application.

e. Prohibition on default issuance. The department shall issue no title V permit to operate, including a permit renewal or modification, until affected states and the United States environmental protection agency have had an opportunity to review the proposed permit as required under this subsection.

8. **Judicial review of title V permit to operate decisions.**

   a. The applicant, any person who participated in the department's public participation process, and any other person who could obtain judicial review under North Dakota Century Code section 28-32-42 may obtain judicial review provided such appeal is filed in accordance with North Dakota Century Code section 28-32-42 within thirty days after notice of the final permit action.

   b. The department's failure to take final action on an application for a permit, permit renewal, or permit revision within the timeframes referenced in this section shall be appealable in accordance with North Dakota Century Code section 28-32-42 within thirty days after expiration of the applicable timeframes.

   c. In accordance with North Dakota Century Code chapter 28-32, the mechanisms outlined in this subsection shall be the exclusive means for judicial review of permit decisions referenced in this section.

   d. Solely for the purpose of obtaining judicial review in state court, final permit action shall include the failure of the department to take final action on an application for a permit, permit renewal, or permit revision within the timeframes referenced in this section.

   e. Failure to take final action within ninety days of receipt of an application requesting minor permit modification procedures (or one hundred eighty days for modifications subject to group processing requirements) shall be considered final action and subject to judicial review in state court.

9. **Enforcement.** The department may suspend, revoke, or terminate a permit for violations of this article, violation of any permit condition or for failure to respond to a notice of violation or any order issued pursuant to this article. A permit to operate which has been revoked or terminated pursuant to this article must be surrendered forthwith to the department. No person may operate or cause the operation of a source if the department denies, terminates, revokes, or suspends a permit to operate.

10. **Compliance assurance monitoring.** Except as noted below, title 40, Code of Federal Regulations, part 64 compliance assurance monitoring, as it exists on January 31, 2004, is incorporated by reference.

    a. "Administrator" means the department except for those duties that cannot be delegated by the United States environmental protection agency. For those duties that cannot be delegated, administrator means the department and the administrator of the United States environmental protection agency.

b. "Part 70 permit" means a title V permit to operate.

c. "Permitting authority" means the department.

History: Effective March 1, 1994; amended effective December 1, 1994; August 1, 1995; January 1, 1996; September 1, 1997; September 1, 1998; March 1, 2003; February 1, 2005.
General Authority: NDCC 23-25-03, 23-25-04, 23-25-04.1
Law Implemented: NDCC 23-25-03, 23-25-04, 23-25-04.1, 23-25-10

33-15-14-07. Source exclusions from title V permit to operate requirements.

1. **Purpose.** The purpose of this section is to clarify which sources are minor sources with respect to section 33-15-14-06. The owner or operator of any source that would be classified as a major source under section 33-15-14-06 and which is not specifically excluded by this section shall comply with the requirements of section 33-15-14-06.

2. **Definitions.** For purposes of this section:

   a. "Bulk gasoline plant" means any bulk gasoline distribution facility that has a gasoline throughput less than or equal to twenty thousand gallons [75700 liters] per day and that receives gasoline by truck rather than by rail.

   b. "Coatings" means coatings plus diluents plus cleanup solvents.

   c. "Fountain solution additives" includes isopropyl alcohol, n-propyl alcohol, n-butanol, and alcohol substitutes.

   d. "Hazardous air contaminant" means any air contaminant listed pursuant to subsection 112(b) of the Federal Clean Air Act.

   e. "Refueling positions" means the number of vehicles that could be dispensing simultaneously at a gasoline service station.

3. **Applicability.**

   a. The owner or operator of the following stationary sources is not required to obtain a title V permit to operate under section 33-15-14-06 if the conditions of this section are met:

      (1) Gasoline service stations.

      (2) Gasoline bulk plants.

      (3) Coating sources.

    (4) Printing, publishing, and packaging operations.

    (5) Degreasers using volatile organic solvents.

    (6) Hot mix asphalt plants.

b. Any facility obtaining coverage under this section must submit a notification in writing to the department within ninety days of publication of this section unless specifically exempted from this requirement in the applicable subdivision of this section. The notification must contain the following information:

    (1) Facility name, location, and nature of business.

    (2) A list of all the sources of air contaminants at the facility.

    (3) The condition of this section which is applicable to the facility.

    (4) Total material usage, source capacity, or throughput for the previous month or twelve months at the facility, in accordance with the subdivision that is applicable to the facility.

    (5) A signed statement accepting the throughput or usage limitation.

c. Complying with the conditions of this section does not exempt the owner or operator of a facility from the obligation to apply for and obtain a permit to construct or a minor source permit to operate unless specifically exempted in section 33-15-14-02 or 33-15-14-03.

d. The owner or operator of any facility listed in subdivision a which has potential emissions that would classify it as a major source even after the conditions of this section are met, or are not able to comply with the applicable conditions, shall obtain a title V permit to operate or a minor source permit to operate which limits the potential to emit of the source to a level below the major source threshold.

e. Complying with the conditions of this section does not relieve the owner or operator of a source of the responsibility to comply with any other applicable requirements of this article.

f. If the facility deviates from any condition, limit, or requirement of this section, a report must be submitted to the department within thirty days of the deviation containing the following information:

    (1) The facility's name and location.

(2) Applicable condition, limit, or requirement for the facility for which a deviation occurred.

(3) A summary of the records showing the deviation, accompanied by an explanation of the deviation.

(4) A plan of action to prevent future occurrences of any deviation at the facility.

g. All records required by this section must be maintained for a period of five years from the last date of entry. The records must be available for inspection or submittal to the department upon request. If a facility is limited by a material usage, capacity, or throughput based on a twelve-month rolling period, a log must be updated monthly to include the previous twelve months' total material usage, capacity, or throughput.

4. **Exclusion standards.**

a. Gasoline service stations. The owner or operator of sources where gasoline dispensing operations account for more than ninety percent of all emissions from the facility is not required to obtain a title V permit to operate if the following conditions are met:

(1) No vapor recovery is used:

(a) The source's total sales of gasoline must not exceed three hundred eighty thousand gallons [1438300 liters] per month in any calendar month. To demonstrate compliance with this limit, monthly records of throughput must be maintained at the source.

(b) If the number of refueling positions is no more than seventeen at the source, then the source is exempt from formal application to the department under subdivision b of subsection 3.

(2) Stage I vapor recovery is used:

(a) The source's total sales of gasoline must not exceed six hundred thirty thousand gallons [2384800 liters] per month in any calendar year. To demonstrate compliance with this limit, monthly records of throughput must be maintained at the source.

(b) If the number of refueling positions is no more than twenty-nine at the source, then the source is exempt from formal application to the department under subdivision b of subsection 3.

b. Gasoline bulk plants. The owner or operator of gasoline bulk plants where gasoline loading and unloading operations account for more than ninety percent of all emissions from the source are covered by this subdivision. To demonstrate compliance with the twenty thousand gallons [75700 liters] per day of gasoline definition of a bulk plant, monthly records of throughput must be maintained at the source.

c. Coating sources.

  (1) The owner or operator of sources where surface coating operations account for more than ninety percent of all hazardous air contaminant emissions from the facility is not required to obtain a title V permit to operate if the conditions in subparagraph a or b are met.

    (a) The source's total usage of surface coatings must not exceed two hundred fifty gallons [946.25 liters] of coatings per month in any calendar month nor exceed three thousand gallons [11355 liters] of coatings per twelve-month period. The coatings are limited to six pounds per gallon [719 grams per liter] of any individual hazardous air contaminant. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

    (b) The source's total hazardous air contaminant emissions shall not exceed ten tons per twelve-month period. Hazardous air contaminant emissions must be calculated by multiplying the surface coating material usage in gallons by the individual hazardous air contaminant content in pounds per gallon. To demonstrate compliance with the emissions limitation, the emissions must be calculated on a monthly basis and recorded in a log. All records of material usage, hazardous air contaminant content, and emissions must be maintained at the facility.

  (2) The owner or operator of an automobile refinishing shop where operations account for more than ninety percent of volatile organic compound emissions and hazardous air contaminant emissions is not required to obtain a title V permit to operate if the usage of coatings is less than two hundred fifty gallons [946.25 liters] per month or three thousand gallons [11355 liters] of coatings per twelve-month period. This item does not apply to facilities capable of refinishing vehicles other than automobiles or trucks. Sources are exempt from the notification requirements under subdivision b of subsection 3 if:

(a) The auto refinishing shop business is entirely, or almost entirely, for collision repairs and the business has two or fewer bays;

(b) Substantial portions of the auto refinishing shop business are devoted to repainting entire vehicles and the business only has one bay devoted to painting; or

(c) The auto refinishing shop business does not have the physical or operational capability to do more than fifty jobs per week.

d. Printing, publishing, and packaging operations.

(1) The owner or operator of facilities where sheetfed (nonheatset) offset lithography or nonheatset web offset lithography printing operations are conducted is not required to obtain a title V permit to operate if the conditions in subparagraphs a, b, and c are met.

(a) The facility must use less than fourteen thousand two hundred seventy-five gallons [54030 liters] of cleaning solvent and fountain solution additives in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(b) The facility must use less than three thousand three hundred thirty-three gallons [12615 liters] of materials containing multiple hazardous air contaminants in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(c) The facility must use less than one thousand three hundred thirty-three gallons [5045 liters] of material containing any individual hazardous air contaminant in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(2) The owner or operator of facilities where heatset web offset lithography printing operations are conducted is not required to obtain a title V permit to operate if the conditions in subparagraphs a, b, and c are met.

(a) The facility must use less than one hundred thousand pounds [45.36 megagrams] of ink, cleaning solvent, and fountain solution additives in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(b) The facility must use less than three thousand three hundred thirty-three gallons [12615 liters] of materials containing multiple hazardous air contaminants in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(c) The facility must use less than one thousand three hundred thirty-three gallons [5045 liters] of material containing any individual hazardous air contaminant in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(3) The owner or operator of facilities where screen printing operations are conducted is not required to obtain a title V permit to operate if the conditions in subparagraphs a, b, and c are met.

(a) The facility must use less than fourteen thousand two hundred seventy-five gallons [54030 liters] of the sum of solvent-based inks, cleaning solvents, adhesives, and coatings in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(b) The facility must use less than three thousand three hundred thirty-three gallons [12615 liters] of materials containing multiple hazardous air contaminants in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(c) The facility must use less than one thousand three hundred thirty-three gallons [5045 liters] of material containing any individual hazardous air contaminant in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(4) The owner or operator of facilities, where flexography, or rotogravure printing operations with water-based or ultraviolet-cured inks, coatings, and adhesives are

conducted, is not required to obtain a title V permit to operate if the conditions in subparagraphs a, b, and c are met.

(a) The facility must use less than four hundred thousand pounds [181 megagrams] of the sum of solvent-based inks, cleaning solvents, and adhesives in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(b) The facility must use less than three thousand three hundred thirty-three gallons [12615 liters] of materials containing multiple hazardous air contaminants in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(c) The facility must use less than one thousand three hundred thirty-three gallons [5045 liters] of material containing any individual hazardous air contaminant in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(5) The owner or operator of facilities where flexography or rotogravure printing operations with solvent inks are conducted is not required to obtain a title V permit to operate if the conditions in subparagraphs a, b, and c are met.

(a) The facility must use less than one hundred thousand pounds [45.36 megagrams] of the sum of ink, coatings, adhesives, dilution solvents, and cleaning solvents in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(b) The facility must use less than three thousand three hundred thirty-three gallons [12615 liters] of materials containing multiple hazardous air contaminants in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

(c) The facility must use less than one thousand three hundred thirty-three gallons [5045 liters] of material containing any individual hazardous air contaminant in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of material usage must be maintained at the facility.

e. Degreasers using volatile organic solvents. The owner or operator of facilities where degreasing operations account for more than ninety percent of all volatile organic compound emissions and hazardous air contaminant emissions from the facility is not required to obtain a title V permit to operate if the conditions in paragraph 1 or 2 are met.

   (1) If non-halogenated solvents are used, the usage is limited to two thousand two hundred gallons [8327 liters] of any one solvent-containing material and five thousand four hundred gallons [20439 liters] of any combination of solvent-containing materials in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of solvent usage must be maintained at the facility.

   (2) If halogenated solvents are used, including methyl chloroform, trichloroethane, and methylene chloride, the usage is limited to one thousand two hundred gallons [4542 liters] of any one solvent-containing material and two thousand nine hundred gallons [10976 liters] of any combination of solvent-containing materials in any twelve-month rolling period. To demonstrate compliance with the usage limit, monthly records of solvent usage must be maintained at the facility.

f. Hot mix asphalt plants. The owner or operator of facilities where hot mix asphalt production operations account for more than ninety percent of all emissions from the facility is not required to obtain a title V permit to operate if the amount of hot mix asphalt produced does not exceed two hundred fifty thousand tons [226757 metric tons] in any twelve-month rolling period. To demonstrate compliance with this limit, monthly records of hot mix asphalt produced must be maintained at the facility. Sources that are excluded under this subdivision must obtain a minor source permit to operate under section 33-15-14-03.

History: Effective June 1, 2001.
General Authority: NDCC 23-25-03
Law Implemented: NDCC 23-25-03, 23-25-04, 23-25-04.1

CHAPTER 33-15-25
REGIONAL HAZE REQUIREMENTS

Section

33-15-25-01 Definitions
33-15-25-02 Best Available Retrofit Technology
33-15-25-03 Guidelines for Best Available Retrofit Technology Determinations Under the Regional Haze Rule
33-15-25-04 Monitoring, Recordkeeping, and Reporting

33-15-25-01. Definitions. The definitions in title 40, Code of Federal Regulations, part 51, section 301, as they exist on October 1, 2005, are incorporated by reference into this chapter. For purposes of this chapter only:

1. "Boiler operating day" means any twenty-four-hour period between midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

2. "Contributes to visibility impairment" means a change in visibility impairment in a class I federal area of five-tenths deciviews or more (twenty-four-hour average) above the average natural visibility baseline. A source exceeds the threshold when the ninety-eighth percentile (eighth highest value) of the modeling results based on any one year of the three years of meteorological data modeled exceeds five-tenths deciviews.

History: Effective January 1, 2007.
General Authority: NDCC 23-25-03, 23-25-04
Law Implemented: NDCC 23-25-03, 23-25-04

33-15-25-02. Best available retrofit technology.

1. **Submission of best available retrofit technology analysis.** The owner or operator of any existing stationary facility as defined in title 40, Code of Federal Regulations, part 51, section 301, that contributes to visibility impairment in a class I federal area shall submit a best available retrofit technology analysis to the department. The analysis shall be submitted within nine months after being notified by the department that the existing stationary facility contributes to visibility impairment.

2. **Installation of best available retrofit technology.** The owner or operator of any existing stationary facility as defined in title 40, Code of Federal Regulations, section 301, which contributes to visibility impairment in a class I federal area shall install and operate best available retrofit technology. The equipment shall be installed and operating as expeditiously as practicable but in no event later than five years after the United States environmental protection agency's

approval of North Dakota's state implementation plan revision for best available retrofit technology.

3. **Operation and maintenance of best available retrofit technology.** The owner or operator of a facility required to install best available retrofit technology under subsection 1 shall establish procedures to ensure such equipment is properly operated and maintained.

History: Effective January 1, 2007.
General Authority: NDCC 23-25-03, 23-25-04
Law Implemented: NDCC 23-25-03, 23-25-04

33-15-25-03. Guidelines for best available retrofit technology determinations under the regional haze rule. Title 40, Code of Federal Regulations, part 51, appendix y, as published in the federal register on July 6, 2005, is incorporated by reference into this chapter.

The owner or operator of a fossil-fuel-fired steam electric plant with a generating capacity greater than seven hundred fifty megawatts of electricity shall comply with the requirements of appendix y. All other facility owners or operators shall use appendix y as guidance for preparing their best available control retrofit technology determinations.

History: Effective January 1, 2007.
General Authority: NDCC 23-25-03, 23-25-04
Law Implemented: NDCC 23-25-03, 23-25-04

33-15-25-04. Monitoring, recordkeeping, and reporting. The owner or operator of any existing stationary facility that is required to install best available retrofit technology shall conduct monitoring, recordkeeping, and reporting sufficient to show compliance or noncompliance. Monitoring for sulfur dioxide and nitrogen oxides from the main stack of a fossil-fuel-fired steam electric plant shall be conducted using continuous emissions monitoring systems which comply with the requirements of section 33-15-21-09. Particulate monitoring shall be in accordance with the requirements of subsection 10 of section 33-15-14-06. Recordkeeping and reporting shall comply with the requirements of section 33-15-14-06. Monitoring, recordkeeping, and reporting for other source units shall comply with the requirements of section 33-15-14-06.

History: Effective January 1, 2007.
General Authority: NDCC 23-25-03, 23-25-04
Law Implemented: NDCC 23-25-03, 23-25-04

CHAPTER 33-15-25
REGIONAL HAZE REQUIREMENTS

Section

33-15-25-01 Definitions
33-15-25-02 Best Available Retrofit Technology
33-15-25-03 Guidelines for Best Available Retrofit Technology Determinations Under the Regional Haze Rule
33-15-25-04 Monitoring, Recordkeeping, and Reporting

33-15-25-01. Definitions. The definitions in title 40, Code of Federal Regulations, part 51, section 301, as they exist on October 1, 2005, are incorporated by reference into this chapter. For purposes of this chapter only:

1. "Boiler operating day" means any twenty-four-hour period between midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

2. "Contributes to visibility impairment" means a change in visibility impairment in a class I federal area of five-tenths deciviews or more (twenty-four-hour average) above the average natural visibility baseline. A source exceeds the threshold when the ninety-eighth percentile (eighth highest value) of the modeling results based on any one year of the three years of meteorological data modeled exceeds five-tenths deciviews.

History: Effective January 1, 2007.
General Authority: NDCC 23-25-03, 23-25-04
Law Implemented: NDCC 23-25-03, 23-25-04

33-15-25-02. Best available retrofit technology.

1. **Submission of best available retrofit technology analysis.** The owner or operator of any existing stationary facility as defined in title 40, Code of Federal Regulations, part 51, section 301, that contributes to visibility impairment in a class I federal area shall submit a best available retrofit technology analysis to the department. The analysis shall be submitted within nine months after being notified by the department that the existing stationary facility contributes to visibility impairment.

2. **Installation of best available retrofit technology.** The owner or operator of any existing stationary facility as defined in title 40, Code of Federal Regulations, section 301, which contributes to visibility impairment in a class I federal area shall install and operate best available retrofit technology. The equipment shall be installed and operating as expeditiously as practicable but in no event later than five years after the United States environmental protection agency's

approval of North Dakota's state implementation plan revision for best available retrofit technology.

3. **Operation and maintenance of best available retrofit technology.** The owner or operator of a facility required to install best available retrofit technology under subsection 1 shall establish procedures to ensure such equipment is properly operated and maintained.

History: Effective January 1, 2007.
General Authority: NDCC 23-25-03, 23-25-04
Law Implemented: NDCC 23-25-03, 23-25-04

33-15-25-03. Guidelines for best available retrofit technology determinations under the regional haze rule. Title 40, Code of Federal Regulations, part 51, appendix y, as published in the federal register on July 6, 2005, is incorporated by reference into this chapter.

The owner or operator of a fossil-fuel-fired steam electric plant with a generating capacity greater than seven hundred fifty megawatts of electricity shall comply with the requirements of appendix y. All other facility owners or operators shall use appendix y as guidance for preparing their best available control retrofit technology determinations.

History: Effective January 1, 2007.
General Authority: NDCC 23-25-03, 23-25-04
Law Implemented: NDCC 23-25-03, 23-25-04

33-15-25-04. Monitoring, recordkeeping, and reporting. The owner or operator of any existing stationary facility that is required to install best available retrofit technology shall conduct monitoring, recordkeeping, and reporting sufficient to show compliance or noncompliance. Monitoring for sulfur dioxide and nitrogen oxides from the main stack of a fossil-fuel-fired steam electric plant shall be conducted using continuous emissions monitoring systems which comply with the requirements of section 33-15-21-09. Particulate monitoring shall be in accordance with the requirements of subsection 10 of section 33-15-14-06. Recordkeeping and reporting shall comply with the requirements of section 33-15-14-06. Monitoring, recordkeeping, and reporting for other source units shall comply with the requirements of section 33-15-14-06.

History: Effective January 1, 2007.
General Authority: NDCC 23-25-03, 23-25-04
Law Implemented: NDCC 23-25-03, 23-25-04

Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota

May 18, 2009

Revised Draft Report

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Scope of Document

This document provides an initial analysis of the four factors which must be considered in establishing a reasonable progress goal toward achieving natural visibility conditions in mandatory Class I areas. These factors were examined for several candidate control measures for priority pollutants and emission sources. The results of this report are intended to inform policymakers in setting reasonable progress goals for the Class I areas in the Western Regional Air Partnership (WRAP) region.

This document does not address policy issues, set reasonable progress goals, or recommend a long-term strategy for regional haze. Separate documents will be prepared by the States which address the reasonable progress goals, each state's share of emission reductions, and coordinated emission control strategies.

Disclaimer

The analysis described in this document has been funded by the Western Governors' Association. It has been subject to review by the WGA and the WRAP. However, the report does not necessarily reflect the views of the sponsoring and participating organizations, and no official endorsement should be inferred.

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Abbreviations

ACT	Alternative Control Techniques
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CBA	Cold Bed Adsorption
CO_2	Carbon Dioxide
DSI	Duct Sorbent Injection
EC	Elemental Carbon
EDMS	Emissions Data Management System
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulfurization
FF	Fabric Filters
ICAC	Institute of Clean Air Companies
LAER	Lowest Achievable Emission Rate
LEC	Low-Emission Combustion
LNB	Low-NOx Burners
MRPO	Midwest Regional Planning Organization
MW	Megawatt
NACAA	National Association of Clean Air Agencies
NEI	National Emissions Inventory
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
OC	Organic Carbon
OFA	Overfire Air
PM	Particulate Matter
PM_{10}	Particulate Matter Particles of 10 Micrometers or Less
$PM_{2.5}$	Particulate Matter Particles of 2.5 Micrometers or Less
RACT	Reasonably Available Control Technology
SCR	Selective Catalytic Reduction
SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
SRU	Sulfur Recovery Unit
TGTU	Tail Gas Treatment Units
WRAP	Western Regional Air Partnership

Units

acfm	Actual Cubic Feet per Minute
cfm	Cubic Feet per Minute
kWh	Kilowatt Hour
MM-BTU/hr	Million British Thermal Units per Hour
MW	Megawatt
ppmv	Parts per Million by Volume
scfm	Standard Cubic Feet per Minute

1. Introduction

The Regional Haze Rule requires States to set reasonable progress goals toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064. The first reasonable progress goals will be established for the planning period 2008 to 2018. The Western Regional Air Partnership (WRAP), along with its member states, tribal governments, and federal agencies, are working to address visibility impairment due to regional haze in Class I areas. The Regional Haze Rule identifies four factors which should be considered in evaluating potential emission control measures to meet visibility goals. These are as follows:

1. Cost of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of any existing source subject to such requirements

This report has been prepared as part of a project to evaluate the above factors for possible control strategies intended to improve visibility in the WRAP region. We have identified control measures for emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2), which can react in the atmosphere to produce visibility-obscuring particulate matter on a regional scale, and also for direct emissions of particulate matter. For direct particulate matter emissions (PM), we have evaluated the impacts of control measures on various particulate matter components, including $PM_{2.5}$, PM_{10}, elemental carbon (EC) particulate matter, and organic carbon (OC) particulate matter. A number of emission source categories have been addressed, including:

1. Reciprocating internal combustion engines and turbines
2. Oil and natural gas exploration and production field operations
3. Natural gas processing plants
4. Industrial boilers
5. Cement manufacturing plants
6. Sulfuric acid manufacturing plants
7. Pulp and paper plant lime kilns
8. Petroleum refinery process heaters

The four-factor analyses for these emission categories are documented in a separate report, entitled “Assessing Reasonable Progress for Regional Haze in the WRAP Region – Source Category Analysis.”

The current report presents the results of a four-factor analysis of potential control measures for selected emission sources in North Dakota. The emission sources addressed in this current report were selected by the North Dakota Department of Health, and include two electric generating units, three industrial boilers at a coal gasification facility, a sulfur recovery unit and several compressor engines at a natural gas processing facility, and a sulfur recovery unit at another gas processing facility. This report is organized in 4 sections, including this introduction. Section 2 presents the methodology employed to conduct the following analyses and Section 3 results of the four-factor analysis for boilers, including the electric generating units and the industrial boiler at the coal gasification facility. Section 4 gives the results of the four-factor analysis for the natural gas processing facilities.

2. Methodology

The first step in the technical evaluation of control measures for a source category was to identify the major sources of emissions from the category. Emissions assessments were initially based on 2002 emissions inventory in the WRAP Emissions Data Management System (EDMS),[1] which consists of data submitted by the WRAP states in 2004. The states then reviewed the emissions data and parameters from the EDMS used for this analysis and provided updated data when applicable. In some cases, detailed data on PM_{10} and $PM_{2.5}$ emissions were not available from the WRAP inventory. Therefore, PM_{10} and $PM_{2.5}$ data from the U.S. Environmental Protection Agency's (EPA) 2002 National Emissions Inventory (NEI) were used to supplement the WRAP inventory where necessary.

Once the important emission sources were identified within a given emission source category, a list of potential additional control technologies was compiled from a variety of sources, including control techniques guidelines published by the EPA, emission control cost models such as AirControlNET[2] and CUECost,[3] Best Available Retrofit Technology (BART) analyses, White Papers prepared by the Midwest Regional Planning Organization (MRPO),[4] and a menu of control options developed by the National Association of Clean Air Agencies (NACAA).[5] The options for each source category were then narrowed to a set of technologies that would achieve the emission reduction target under consideration. The following sections discuss the methodology used to analyze each of the regional haze factors for the selected technologies.

2.1 Factor 1 – Costs

Control costs include both the capital costs associated with the purchase and installation of retrofit and new control systems, and the net annual costs (which are the annual reoccurring costs) associated with system operation. The basic components of total capital costs are direct capital costs, which includes purchased equipment and installation costs, and indirect capital expenses. Direct capital costs consist of such items as purchased equipment cost, instrumentation and process controls, ductwork and piping, electrical components, and structural and foundation costs. Labor costs associated with construction and installation are also included in this category. Indirect capital expenses are comprised of engineering and design costs, contractor fees, supervisory expenses, and startup and performance testing. Contingency costs, which represent such costs as construction delays, increased labor and equipment costs, and design modification, are an additional component of indirect capital expenses. Capital costs also include the cost of process modifications. Annual costs include amortized costs of capital investment, as well as costs of operating labor, utilities, and waste disposal. For fuel switching options, annual costs include the cost differential between the current fuel and the alternate fuel.

The U.S. EPA's *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program*[6] indicates that the four-factor analyses should conform to the methodologies given in the *EPA Air Pollution Control Cost Manual*.[7] This study draws on cost analyses which have followed the protocols set forth in the Cost Manual. Where possible, we have used the primary references for cost data. Cost estimates have been updated to 2007 dollars using the Marshall & Swift Equipment Cost Index or the Chemical Engineering Plant Cost Index, both of which are published in the journal, *Chemical Engineering.*

For Factor 1, results of the cost analysis are expressed in terms of total cost-effectiveness, in dollars per ton of emissions reduced. A relevant consideration in a cost-effectiveness calculation is the economic condition of the industry (or individual facility if the analysis is performed on that basis). Even though a given cost-effectiveness value may, in general, be considered "acceptable," certain industries may find such a cost to be overly burdensome. This is particularly true for well-established industries with low profit margins. Industries with a poor economic condition may not be able to install controls to the same extent as more robust industries. A thorough economic review of the source categories selected for the factor analysis is beyond the scope of this project.

2.2 Factor 2 – Time Necessary for Compliance

For Factor 2, we evaluated the amount of time needed for full implementation of the different control strategies. The time for compliance was defined to include the time needed to develop and implement the regulations, as well as the time needed to install the necessary control equipment. The time required to install a retrofit control device includes time for capital procurement, device design, fabrication, and installation. The Factor 2 analysis also included the time required for staging the installation of multiple control devices at a given facility.

2.3 Factor 3 – Energy and Other Impacts

Table 2-1 summarizes the energy and environmental impacts analyzed under Factor 3. We evaluated the direct energy consumption of the emission control device, solid waste generated, wastewater discharged, acid deposition, nitrogen deposition, and climate impacts (e.g., generation and mitigation of greenhouse gas emissions).

In general, the data needed to estimate these energy and other non-air pollution impacts were obtained from the cost studies which were evaluated under Factor 1. These analyses generally quantify electricity requirements, steam requirements, increased fuel requirements, and other impacts as part of the analysis of annual operation and maintenance costs.

Costs of disposal of solid waste or otherwise complying with regulations associated with waste streams were included under the cost estimates developed under Factor 1, and were evaluated as to whether they could be cost-prohibitive or otherwise negatively affect the facility. Energy needs and non-air quality impacts of identified control technologies were aggregated to estimate the energy impacts for the specified industry sectors. However, indirect energy impacts were not considered, such as the different energy requirements to produce a given amount of coal versus the energy required to produce an equivalent amount of natural gas.

Table 2-1 Summary of Energy and Environmental Impacts Evaluated Under Factor 3

Energy Impacts
Electricity requirement for control equipment and associated fans
Steam required
Fuel required
Environmental Impacts
Waste generated
Wastewater generated
Additional carbon dioxide (CO_2) produced
Reduced acid deposition
Reduced nitrogen deposition
Benefits from reductions in $PM_{2.5}$ and ozone, where available
Impacts Not Included
Impacts of control measures on boiler efficiency
Energy required to produce lower sulfate fuels
Secondary environmental impacts to produce additional energy (except CO_2) produced

2.4 Factor 4 – Remaining Equipment Life

Factor 4 accounts for the impact of the remaining equipment life on the cost of control. Such an impact will occur when the remaining expected life of a particular emission source is less than the lifetime of the pollution control device (such as a scrubber) that is being considered. In this case, the capital cost of the pollution control device can only be amortized for the remaining lifetime of the emission source. Thus, if a scrubber with a service life of 15 years is being evaluated for a boiler with an expected remaining life of 10 years, the shortened amortization schedule will increase the annual cost of the scrubber.

The ages of major pieces of equipment were determined where possible, and compared with the service life of pollution control equipment. The impact of a limited useful life on the amortization period for control equipment was then evaluated, along with the impact on annualized cost-effectiveness.

2.5 References for Section 2

1. WRAP (2008), *Emissions Data Management System*, Western Regional Air Partnership, Denver, CO, http://www.wrapedms.org/app_main_dashboard.asp.

2. E.H. Pechan & Associates (2005), *AirControlNET, Version 4.1 - Documentation Report*, U.S. EPA, RTP, NC, http://www.epa.gov/ttnecas1/AirControlNET.htm.

3. *Coal Utility Environmental Cost (CUECost) Model Version 1.0*, U.S. EPA, RTP, NC, http://www.epa.gov/ttn/catc/products.html.

4. MRPO (2006), *Interim White Papers-- Midwest RPO Candidate Control Measures*, Midwest Regional Planning Organization and Lake Michigan Air Directors Consortium, Des Plaines, IL, www.ladco.org/reports/control/white_papers/.

5. NACAA (formerly STAPPA and ALAPCO) (2006), *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, National Association of Clean Air Agencies, www.4cleanair.org/ PM25Menu-Final.pdf.

6 EPA (2007), *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program*, http://www.epa.gov/ttncaaa1/t1/memoranda/reasonable_progress_guid071307.pdf.

7. EPA (2002), *EPA Air Pollution Control Cost Manual*, *6th ed.*, EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP, NC, Section 5 - SO_2 and Acid Gas Controls, pp 1-30 through 1-42, http://www.epa.gov/ttncatc1/products.html#cccinfo.

3. Boilers

A four factor analysis was performed on three coal-fired boilers; two units at Antelope Valley Station (Units B1 & B2), and one unit at Coyote Station, and three waste gas/liquid boilers at the Dakota Gasification Company. The boilers at Antelope Valley and Coyote are used to produce steam from the combustion of lignite coal to generate electricity in a steam turbine. The units at the Antelope Valley Station are rated at 450 megawatts (MW), and the unit at Coyote Station is rated at 427 MW. Pollutant emissions from the boilers include: nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). The boilers at Dakota Gasification are used to combust off-gas and waste liquids to provide process steam for the facility. Each of the boilers is rated at 763 MMBtu/hr and is vented to a common exhaust stack. In addition to the emissions from the three boilers, two superheaters rated at 169 MMBtu/hr are also vented to this common exhaust stack.

Table 2-1 summarizes the NO_X and SO_2 emissions from each of the boilers, as well as the control measures used to reduce these pollutant emissions.[1] The pollutant emission rates shown in Table 2-1 were obtained from the North Dakota Department of Health, Division of Air Quality.[2] The pollutant emissions are the based on the average of the two highest annual emission rates from the last five years. For the Dakota Gasification facility, the annual emissions were presented for the common exhaust stack, which includes the pollutant emissions from the three boilers and two superheaters. To estimate the emissions from each boiler, the total emission for each pollutant was divided by the total heat input and hours of operation of the boilers and superheaters to develop emission factors for each pollutant. The emission factors were used to estimate the pollutant emissions for each of the boilers based on the heat input to the boiler and the average hours of operation. Emissions of EC and OC can be estimated using speciation factors from EPA's SPECIATE database.[3] The EC and OC components are estimated to comprise 0.021% and 0.012% of PM_{10} emissions from the coal-fired boilers, respectively. There is not enough information to determine the speciation weight percentages for the Dakota Gasification facility, because the facility combusts waste liquid and gas streams from the facility processes.

Table 3-1. Emissions from Selected Boilers - North Dakota

Source Name	Facility Name	Unit ID	Unit Type	Boiler Size (MMBtu/hr)	NO_X Annual Emissions (tons/yr)	SO_2 Annual Emissions (tons/yr)	PM Annual Emissions (tons/yr)
Basin Electric Power	Antelope Valley Station	Unit B1	Lignite coal-fired boiler equipped with OFA, dry scrubber, FF	6,275	7,625	8,117	397
		Unit B2	Lignite coal-fired boiler equipped with OFA, dry scrubber, FF	6,275	6,764	7,298	390
Otter Tail Power Company	Coyote Station	Unit 1	Lignite coal-fired cyclone boiler equipped with dry scrubber, FF	5,800	13,058	14,864	273
Dakota Gasification Co.	Great Plains Synfuels Plant	Unit A[1]	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	763	935	723	65
		Unit B[1]	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	763	935	723	65
		Unit S[1]	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	763	935	723	65

[1] The available pollutant emissions included the emissions for all three boilers rated at 763 MMBtu/hr and two superheaters rated at 169 MMBtu/hr. To estimate the pollutant emissions for each of the boilers the heat inputs and annual operation of the boilers and superheaters were used to develop emission factors. The emission factors were then used to estimate the individual boiler pollutant emissions.

Currently, the Antelope Valley units are equipped with overfire air, dry scrubber and fabric filter to reduce pollutant emissions. The dry scrubber is used to reduce emissions of SO_2 from the exhaust gas and the FF is used to reduce PM, EC, and OC emissions. The units at Antelope Valley are also equipped with OFA to reduce emission of NO_X from the boilers. The Coyote Station boiler is a cyclone unit equipped with a dry scrubber (DSI) and fabric filter (FF). The Dakota Gasification facility is equipped with wet flue gas desulfurization (FGD) and wet electrostatic precipitator (ESP). A list of potential NO_X and SO_2 control strategies are presented in Table 2-2. The table provides the potential emission reductions for each of the control options.[4,5] For NO_X, the emissions reductions assumes the control option is used in conjunction with the current NO_X control technology. For SO_2, the potential emission reduction is calculated assuming a Wet FGD replaces the current SO_2 control technology. These control options have been applied to many electrical generating unit boilers in the U.S. to reduce emissions of NO_X and SO_2. In Table 2-2, the baseline emissions for NO_X are presented as the average of the two highest annual emission rates over the past five years. The uncontrolled emissions for SO_2 are estimated using an AP-42 emission factor of 30S, and assuming a heat rate of 10,400 Btu/Kw-hr for Antelope Valley and 11,400 Btu/Kw-hr for Coyote Station, a coal sulfur content of 0.6%, and operating 8760 hr/yr. The SO_2 emissions at Dakota Gasification are presented as controlled. The boilers are already equipped with wet FGD which achieves the highest potential SO_2 reduction of any of the control options.

Table 3-2. Control Options for Selected Boilers - North Dakota

Facility Name	Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1] (tons/yr)	Annual Emissions (tons/yr)	Estimated control efficiency (%)	Potential emissions reductions[2] (tons/yr)
Antelope Valley Station - Unit B1	Lignite coal-fired boiler equipped with OFA, dry scrubber, FF	NO_X	LNB	12,093	7,625	30 - 75	5,719
			SNCR			30 - 75	5,719
			SCR			40 - 90	6,863
		SO_2	Wet FGD	31,057	8,117	90	5,011
Antelope Valley Station - Unit B2	Lignite coal-fired boiler equipped with OFA, dry scrubber, FF	NO_X	LNB	12,093	6,764	30 - 75	9,070
			SNCR			30 - 75	9,070
			SCR			40 - 90	10,884
		SO_2	Wet FGD	31,057	7,298	90	4,192
Coyote Station - Unit 1	Lignite coal-fired cyclone boiler equipped with dry scrubber, FF	NO_X	SNCR	13,058	13,058	30 - 75	9,794
			SCR			40 - 90	11,752
		SO_2	Wet FGD	28,707	14,864	90	11,993
Great Plains Synfuels Plant - Unit A	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	NO_X	SNCR	935	935	30 - 75	701
			SCR			40 - 90	842
Great Plains Synfuels Plant - Unit B	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	NO_X	SNCR	935	935	30 - 75	701
			SCR			40 - 90	842
Great Plains Synfuels Plant - Unit S	Waste gas/liquid boiler equipped with wet ESP, and wet FGD	NO_X	SNCR	935	935	30 - 75	701
			SCR			40 - 90	842

[1] NO_X uncontrolled emissions calculated using AP-42 emission factors for lignite combustion. SO_2 uncontrolled emissions were calculated using an AP-42 SO_2 emission factor of 30S and assuming 0.6% Sulfur coal.

[2] Potential NO_X emission reductions were calculated assuming the addition of the control options with the existing control technology and assuming the highest percent reduction in the estimated control efficiency range. Potential SO_2 emission reductions were calculated assuming the replacement of the current SO_2 control system with a more effective SO_2 control system.

3.1 Factor 1 – Costs

Table 2-3 provides cost estimates for the emission control options which have been identified for each of the electrical generating unit boilers. Each of the boilers are already equipped with effective PM control, therefore additional PM options were not explored for these boilers. For the NO_X and SO_2 options, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The capital cost values are expressed in terms of the cost per MW size of the boiler using EPA cost information.[6,7] The capital cost data was extrapolated to determine the capital cost for the larger sized boilers. The annual cost was calculated by amortizing the capital cost over 30 years at an interest rate of 7% and multiplying that value by an O&M factor. Table 2-3 also estimates the cost effectiveness for each control measure, in terms of the cost per ton of emission reduction. Table 2-3 also estimates the cost effectiveness for each control measure, in terms of the cost per ton of emission reduction. Recent literature[8] has indicated that the cost of SCR for electric generating units can vary from $150 to $300 per kilowatt, therefore due to this variability, the capital and annual costs for SCR are presented as a range.

Emissions used to estimate the cost effectiveness of the control options were obtained from Table 3-2. For NO_X, the emissions used for the cost effectiveness calculations were the controlled emission rates. The NO_X controlled emission rates were used because the currently installed NO_X controls can be used in conjunction with the listed control options to reduce NO_X emissions from the current levels. For SO_2, uncontrolled emission levels were estimated for the coal-fired boilers to compare the current SO_2 emission levels with potential SO_2 emission reductions using the listed control technologies.

It should be noted that the application of high dust SCR may not be technically feasible for use on the lignite coal-fired boilers. The lignite coal contains a higher ash content which causes catalyst deactivation and air heater corrosion/blockage. In addition, the higher organically associated sodium in the lignite coal also deactivates the catalyst rapidly. Therefore, each boiler should be evaluated to determine the technical feasibility of applying high dust SCR to control emissions of NO_X.

3.2 Factor 2 – Time Necessary for Compliance

Once a State decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 18 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control, and approximately 30 months to design, build, and install SO_2 scrubbing technology.[9] Additional time of up to 12 months may be required for staging the installation process if multiple boilers are to be controlled at a single facility. Based on these figures, the total time required to achieve emission reductions for industrial boilers is estimated at a total of 5½ years for NO_X strategies, and 6½ years for SO_2 strategies.

3.3 Factor 3 – Energy and Other Impacts

Table 2-4 shows the estimated energy and non-air pollution impacts of control measures for industrial boilers. The values were obtained the EPA report listing the performance impacts of each of the control technology options.[10,11] In general, the combustion modification technologies (LNB, OFA) do not require steam or generate solid waste, or wastewater. They also do not require additional fuel to operate, and in some cases may decrease fuel usage because of the optimized combustion of the fuel.

Retrofitting of a SNCR requires energy for compressor power and steam for mixing. This would produce a small increase in CO_2 emissions to generate electricity; however the technology itself does not produce additional CO_2 emissions.

Installation of SCR on an industrial boiler is not expected to increase fuel consumption. However, additional energy is required to operate the SCR, which will produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal. However, many catalyst companies accept the return of spent catalyst material.

Table 3-3. Estimated Costs of Control for Selected Boilers - North Dakota

Facility Name	Pollutant controlled	Control Technology	Estimated control efficiency (%)	Estimated capital cost ($1000)	Estimated annual cost ($1000/yr)	Cost effectiveness ($/ton)
Antelope Valley Station - Unit B1	NO_X	LNB	51	14,530	2,280	586
		SNCR	40	15,020	8,960	2,938
		SCR	80	67,500 - 135,000	16,966 - 33,932	2,781 - 5,563
	SO_2	Wet FGD	90	170,100	32,170	6,420
Antelope Valley Station - Unit B2	NO_X	LNB	51	14,530	2,280	661
		SNCR	40	15,020	8,960	3,312
		SCR	80	67,500 - 135,000	16,966 - 33,932	3,135 - 6,271
	SO_2	Wet FGD	90	170,100	32,170	7,674
Coyote Station - Unit 1	NO_X	SNCR	40	14,270	8,520	1,631
		SCR	80	64,050 - 128,100	16,099 - 32,198	1,541 - 3,082
	SO_2	Wet FGD	90	161,700	30,580	2,550
Great Plains Synfuels Plant - Unit A	NO_X	SNCR	40	2,840	1,690	4,519
		SCR	80	10,950 - 21,900	2,752 - 5,505	3,680 - 7,359
Great Plains Synfuels Plant - Unit B	NO_X	SNCR	40	2,840	1,690	4,519
		SCR	80	10,950 - 21,900	2,752 - 5,505	3,680 - 7,359
Great Plains Synfuels Plant - Unit S	NO_X	SNCR	40	2,840	1,690	4,519
		SCR	80	10,950 - 21,900	2,752 - 5,505	3,680 - 7,359

[1] The annual cost was calculated using a 30-year equipment life and 7% interest.

[2] NO_X cost effectiveness is calculated from annual emissions using the estimated control efficiency and assumes that the control option is used in conjunction with the current NO_X control. SO_2 cost effectiveness is calculated using the potential emission reductions and reflects the replacement of the current SO_2 control with a Wet FGD.

Retrofitting of the SO_2 control options increase the usage of electricity, and produce both a solid waste and wastewater stream. In addition, increases of CO_2 emission will occur due to the increased energy usage for material preparation (e.g., grinding), materials handling (e.g., pumps/blowers), flue gas pressure loss, and steam requirements. Power consumption is also affected by the reagent utilization of the control technology, which also affects the control efficiency of the control technology.

3.4 Factor 4 – Remaining Equipment Life

Electric generating units do not have a set equipment life. Since many of the strategies are market-based reductions applied to geographic regions, it is assumed that control technologies will not be applied to units that are expected to be retired prior to the amortization period for the specific control equipment. Therefore, the remaining life of an industrial boiler is not expected to affect the cost of control technologies for industrial boilers.

Table 3-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Selected Boilers - North Dakota

			Energy and non-air pollution impacts				
Source Type	Control Technology	Pollutant controlled	Electricity requirement (kW)	Steam requirement (lb/hr)	Solid waste produced (ton/hr)	Wastewater produced (gal/min)	Additional CO_2 emitted (tons/yr)
Antelope Valley Station - Unit B1	LNB	NO_X	21.2				0.0212
	SNCR	NO_X	122	1,522			0.122
	SCR	NO_X	3,256	1,826			3.26
	Wet FGD	SO_2	9,423		27.8	585	9.4
Antelope Valley Station - Unit B2	LNB	NO_X	21.2				0.0212
	SNCR	NO_X	122	1,368			0.122
	SCR	NO_X	3,256	1,642			3.26
	Wet FGD	SO_2	9,423		27.8	585	9.4
Coyote Station - Unit 1	SNCR	NO_X	116	3,344			0.1161
	SCR	NO_X	3,089	3,344			3.09
	Wet FGD	SO_2	8,941		26.4	555	8.9
Great Plains Synfuels Plant - Unit A	LNB	NO_X	3.4				0.0034
	LNB w/ OFA	NO_X	3.4				0.0034
	SNCR	NO_X	20	136			0.020
	SCR	NO_X	528	163			0.53
Great Plains Synfuels Plant - Unit B	LNB	NO_X	3.4				0.0034
	LNB w/ OFA	NO_X	3.4				0.0034
	SNCR	NO_X	20	136			0.020
	SCR	NO_X	528	163			0.53
Great Plains Synfuels Plant - Unit S	LNB	NO_X	3.4				0.0034
	LNB w/ OFA	NO_X	3.4				0.0034
	SNCR	NO_X	20	136			0.020
	SCR	NO_X	528	163			0.53

NOTES:
A blank cell indicates no impact is expected.

3.5 References for Section 3

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4. MRPO (2006), *Interim White Paper - Midwest RPO Candidate Control Measures Source Category: Industrial, Commercial, and Institutional (ICI) Boilers*. http://www.ladco.org/reports/control/white_papers/

5. NESCAUM (2009), *Applicability and Feasibility of NO_X, SO_2, and PM Emission Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers*.

6. Khan, Sikander (2003), *Methodology, Assumptions, and References: Preliminary NO_X Controls Cost Estimates for Industrial Boilers*.

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8. Power Magazine (2006), *Estimating SCR Installation Costs*. http://www.powermag.com/instrumentation_and_controls/Estimating-SCR-installation-costs_506_p3.html

9. Institute of Clean Air Companies (2006), *Typical Installation Timelines for NO_X missions Control Technologies on Industrial Sources*.

10. Reference 6.

11. Reference 7.

4. Natural Gas Processing Facilities

Four-factor analyses have been conducted for selected emission sources at the Hess Corporation Tioga Gas Plant, in Williams County, North Dakota, and the Petro Hunt Little Knife Gas Plant in Billings County, North Dakota. The following emission sources have been evaluated:

- Petro Hunt Little Knife Gas Plant
  - Sulfur recovery unit (SRU) for amine treatment unit #1
- Hess Corporation Tioga Gas Plant
  - SRU for amine treatment unit #1
  - Seven lean-burn natural gas-fired compressor engines – five at 1,920 horsepower (hp) and two at 2,350 hp

Table 4-1 outlines the emission control measures that have already been applied to these sources, the baseline levels of emissions with these current controls, and potential additional control measures that could be adopted to further reduce emissions. The table also gives the estimated control efficiency and annual emission reduction for each potential future control measure.

Information on existing control measures and baseline emission levels for the North Dakota facilities was obtained from the North Dakota Department of Health.[1] The baseline emission level for each source reflects the average of the two highest annual emission rates over the past five years.

The Petro Hunt Little Knife plant has a 3-stage SRU with a cold bed adsorption (CBA) control system. The SRU has a capacity of 120 long tons sulfur per day and an estimated overall recovery efficiency of over 98%. The Hess Tioga plant has a 2-stage Claus SRU, also with a CBA control system. This unit has a capacity of 225 long tons of sulfur per day and an overall recovery efficiency of over 97%.

The New Source Performance Standards (NSPS) for sulfur recovery units at petroleum refineries limit SO2 emissions to 250 ppm, which corresponds to an overall efficiency of 99.98% (from the uncontrolled flow rate of sulfur compounds in the SRU feed stream).[2] This emission rate is generally achieved using tail gas treatment technologies.[3] EPA's RACT/BACT/LAER Clearinghouse indicates that tail gas treatment units (TGTU) installed on sulfur recovery units at petroleum refineries in recent years typically are required to achieve a controlled SO_2 emission concentration of 150 ppm,[4] which corresponds to an overall efficiency of 99.988%. Therefore, it is expected that TGTUs applied to the Petro Hunt and Hess SRUs could achieve an overall sulfur removal efficiency of between 99.98% and 99.988%. This would correspond to a reduction of

Table 4-1. Existing Control Measures and Potential Additional Control Options for Selected Natural Gas Processing Operations in North Dakota

Company	Source	Pollutant	Existing controls	Baseline emissions (tons/yr)	Potential additional control measures	Estimated control efficiency (%)	Potential emission reduction (tons/year)	Refer-ences
Petro Hunt, Little Knife Gas Plant	Sulfur recovery unit, 3-stage, 4-bed, 120 long tons/day sulfur	SO_2	3-stage unit with cold bed adsorbtion, >98% efficient	432	Tail-gas treatment unit - Amine absorption	87 - 92	370 - 400	2,3
Hess Corp., Tioga Gas Plant	Sulfur recovery unit, 2-bed Claus, 225 long tons/day sulfur	SO_2	2-stage Claus unit with cold bed adsorbtion, >97% efficient	1,221	Tail-gas treatment unit - Amine absorption	92 - 95	1,120 - 1,160	2,3
	Natural gas fired reciprocating engines, 1,920 hp, 2-stroke lean burn (Clark Model HLA-8, 5 engines)	NO_X	None	1,566	Air-fuel ratio controllers	10 - 40	160 - 630	5
					Ignition timing retard	15 - 30	230 - 470	5
					Low Emission Combustion (LEC) technology retrofit	80 - 90	1,300 - 1,400	8
					SCR	80 - 90	1,300 - 1,400	5,6,8
					Replacement with electric motors	100	1,600	7
		PM_{10}	None	10	Replacement with electric motors	100	10	7
		$PM_{2.5}$		10			10	
		EC		3.8			3.8	
		OC		2.5			2.5	
	Natural gas fired reciprocating engines, 2,350 hp, 2-stroke lean burn (Clark Model HLA-8, 2 engines)	NO_X	Recently refurbished, NO_X emissions reduced by about 70%	216	SCR	33 - 67	71 - 140	5,6,8
					Replacement with electric motors	100	220	7
		PM_{10}	None	6	Replacement with electric motors	100	6	7
		$PM_{2.5}$		6			6	
		EC		2.3			2.3	
		OC		1.5			1.5	

about 87 to 92% for the Petro Hunt facility (assuming a baseline efficiency of 98.5%), 92 to 95% for the Hess facility (assuming a baseline efficiency of 97.5%).

The Hess Tioga facility uses five 1,920 hp reciprocating engines and two 2,350 hp reciprocating engines, all fueled by natural gas in a under lean-burn fueling mode. The two 2,350 hp engines have recently been refurbished, and the reported NO_X emissions from these engines are about 70% lower than the reported emissions from the 1,920 hp engines, or a mass per hp-hour basis.

A number of options have been identified for stationary reciprocating engines in an Alternative Control Techniques (ACT) guidance document written by the U.S. EPA in 1993, and in more recent analyses for New Source Performance Standards.[5,6] In addition, the WRAP sponsored a study of control options for engines used in the oil and gas industry.[7] Reciprocating engines can be designed to operate under rich fuel mixture, or lean fuel mixture conditions. Air-to-fuel-ratio adjustments and ignition retarding technologies can be used to control emissions under either fuel mixture condition. Low-Emission Combustion (LEC) retrofit technology which can also reduce emissions from reciprocating engines by an average of 89%.[8] LEC involves modifying the combustion system to achieve very lean combustion conditions (high air-to-fuel ratios). SCR can also be used either alone or in conjunction with the above technologies to reduce NO_X emissions from reciprocating engines or turbines by 90%. EPA prepared an update to the ACT guidance for reciprocating engines in 2002 which focused on LEC technology and also updated the analysis of SCR.

For the two 2,350 hp engines, we have adjusted the estimated efficiencies of potential future control measures to reflect the emission reduction which appears to have already achieved by the recent refurbishment. We have assumed that air-to-fuel ratio adjustments, ignition timing retarding, and LEC retrofit technology would not achieve further emission reductions, since the estimated emission reductions for these measures are less than the reductions which appear to have already been achieved.

4.1 Factor 1 – Costs

Table 4-2 provides cost estimates for the emission control options which have been identified for the North Dakota gas processing facilities. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

Costs for the SRU tail gas treatment units were estimated using data given capital and annual cost data provided a review of the NSPS for Claus SRUs.[2] The NSPS analysis gives costs for three model plant sizes, which were interpolated to estimate costs for plants in the size ranges of the Petro Hunt and Hess SRUs (120 and 225 long tons per day, respectively).

Table 4-2. Estimated Costs of Control for Selected Natural Gas Processing Operations in North Dakota

Company	Source	Control option	Pollutant	Estimated control efficiency (%)	Potential emission reduction (tons/year)	Estimated capital cost ($1000)	Estimated annual cost ($1000/year)	Cost effectiveness ($/ton)	Refer-ences
Petro Hunt, Little Knife Gas Plant	Sulfur recovery unit, 3-stage, 4-bed, 120 long tons/day sulfur	Tail gas treatment unit - amine absorption	SO_2	87 - 92	370 - 400	9,400	3,200	8,060 - 8,560	2,3
Hess Corp., Tioga Gas Plant	Sulfur recovery unit, 2-bed Claus, 225 long tons/day sulfur	Tail gas treatment unit - amine absorption	SO_2	92 - 95	1,120 - 1,160	15,000	5,800	5,000 - 5,180	2,3
	Five natural gas fired reciprocating engines, 1,920 hp each, 2-stroke lean burn (Clark Model HLA-8)	Air-fuel ratio	NO_X	10 - 40	160 - 630	116	260	410 - 1,630	5
		Ignition timing retard	NO_X	15 - 30	230 - 470	116	140	300 - 610	5
		LEC retrofit	NO_X	80 - 90	1,300 - 1,400	2,300	560	400 - 430	8
		SCR	NO_X	80	1,300 - 1,400	450 - 940	380 - 1,600	270 - 1,230	5,6,8
		Replacement with electric motors	NO_X	100	1,600	900	280	180	7
			PM_{10}	100	10			28,000	
			$PM_{2.5}$	100	10			28,000	
			EC	100	4			73,680	
			OC	100	3			112,000	
			Overall	100	1,610			170	
	Two natural gas fired reciprocating engines, 2,350 hp each, 2-stroke lean burn (Clark Model HLA-8, recently refurbished)	SCR	NO_X	33 - 67	71 - 140	180 - 460	190 - 500	1,360 - 7,040	5,6,8
		Replacement with electric motors	NO_X	100	220	400	140	636	7
			PM_{10}	100	6			23,330	
			$PM_{2.5}$	100	6			23,330	
			EC	100	2			60,870	
			OC	100	2			93,330	
			Overall	100	226			619	

Costs for the reciprocating engine controls were estimated using data provided in the EPA ACT document, the ACT update, and the WRAP analysis for oil and gas production.[5,7,8] These sources give equations which relate capital and annual costs of emission controls to engine size in hp. The equations were applied to the engine sizes at the Hess Tioga plant.

4.2 Factor 2 – Time Necessary for Compliance

Once the regional haze control strategy is formulated for North Dakota, up to 2 years will be needed for the state to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The ICAC has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[9] However, state regulators' experience indicates that closer to 18 months is required to install this technology.[10] In the Clean Air Interstate Rule (CAIR) analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[11] The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility.

Based on these figures, the total time required achieve emission reductions for the Petro Hunt facility would be up to 6½ years. This includes 2 years for regulatory development, 1 year for capital acquisition, and 2½ years for designing, building and installing the TGTU. The time to achieve emission reductions for the Hess facility would also be up to 6½ years. This estimate includes the same components as the estimate for Petro Hunt, with an additional year for staging the installation of controls for multiple emission sources (the SRU and the reciprocating engines.)

4.3 Factor 3 – Energy and Other Impacts

Table 4-3 shows the estimated energy and non-air pollution impacts of control measures for sources at the Petro Hunt and Hess facilities. The table shows the additional fuel, electricity, and steam requirements resulting required to operate the control equipment; and the additional solid waste would be produced. CO_2 emissions associated with the generation of the additional electricity and steam are also estimated in the table.

The electricity and steam requirements for sulfur recovery TGTUs are based operating parameters from the 1982 NSPS review analysis.[2] These energy requirements are high in relation to the SO_2 emission reduction. Operating parameters were not readily available for newer TGTU designs; however, the energy requirement of these systems may be lower than the 1982 design.

Table 4-3. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Selected Natural Gas Processing Operations in North Dakota

Source Type		Control Technology	Pollutant controlled	Potential emission reduction (tons/year)	Additional fuel requirement (%)	Energy and non-air pollution impacts (per ton of emission reduced)			
						Electricity requirement (kW-hr)	Steam requirement (tons steam)	Solid waste produced (tons waste)	Additional CO_2 emitted (tons)
Petro Hunt, Little Knife Gas Plant	Sulfur recovery unit, 3-stage, 4-bed, 120 long tons/day sulfur	Amine absorption	SO_2	370 - 400		2,200	210	0.01	57
Hess Corp., Tioga Gas Plant	Sulfur recovery unit, 2-bed Claus, 225 long tons/day sulfur	Amine absorption	SO_2	1,120 - 1,160		700	120	0.004	32
	Five natural gas fired reciprocating engines, 1,920 hp each, 2-stroke lean burn (Clark Model HLA-8)	Air-fuel ratio	NO_X	160 - 630	2.5				1.9
		Ignition timing	NO_X	230 - 470	2.5				1.9
		LEC retrofit	NO_X	1,300 - 1,400	a				
		SCR	NO_X	1,300 - 1,400	0.5				0.4
		Replacement with electric motors	NO_X	1,600	(100)	66,000			b
			$PM_{2.5}$, PM_{10}, EC, OC	10					b
			Total	1,610					b
	Two natural gas fired reciprocating engines, 2,350 hp each, 2-stroke lean burn (Clark Model HLA-8, recently refurbished)	SCR	NO_X	71 - 140	0.5				0.0
		Replacement with electric motors	NO_X	220	(100)	66,000			b
			$PM_{2.5}$, PM_{10}, EC, OC	6					b
			Total	226					b

NOTES:

a - The measure is expected to improve fuel efficiency.

b - CO_2 from the generation of electricity would be offset by avoided emissions due to replacing the diesel engine

blank indicates no impact is expected.

For gas-fired reciprocating engines and diesel engines, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value of about 2.5%.[12,13] This increased fuel consumption would result in increased CO_2 emissions. LEC technology is not expected to increase fuel consumption; and may provide some fuel economy.[12]

Installation of SCR on the reciprocating engines would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed.[12] This would produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[14]

4.4 Factor 4 – Remaining Equipment Life

The startup dates for the emission sources at the Petro Hunt and Hess natural gas facilities are as follows:

- Petro Hunt Little Knife Plant
  - SRU – 1983
- Hess Tioga Plant
  - SRU – 1991
  - 1,920 hp engines – 1954
  - 2,350 hp engines – 1954

It is not possible to compute the remaining service lifetimes of these sources since emission sources at industrial facilities are often refurbished. For instance, the 2,300 hp engines at Hess were recently refurbished, although they are over 50 years old. Therefore, the remaining lifetimes of the SRUs and compressors are expected to be longer than 15 year figure which has been used to amortize the capital costs of add-on emission controls or equipment modifications to reduce emissions.

If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1-(1+r)^{-m}}{1-(1+r)^{-n}}$$

where:

A_1 = the annual cost of control for the shorter equipment lifetime ($)
A_0 = the original annual cost estimate ($)
C = the capital cost of installing the control equipment ($)

r = the interest rate (0.07)
m = the expected remaining life of the emission source (years)
n = the projected lifetime of the pollution control equipment

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June 19, 2009

JUN 2 2 2009

Mr. Lee Gribovicz
Western Regional Air Partnership (WRAP)
1600 Broadway, Suite 1700
Denver, CO 80202

Dear Mr. Gribovicz:

Basin Electric Power Cooperative (Basin Electric) is a consumer-owned, regional cooperative headquartered in Bismarck, North Dakota. Basin Electric has reviewed the Draft Report titled *"Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota"* dated May 18, 2009, and have the following comments for your consideration.

Page ii: You state in your Scope of Document Section that:

"This document provides an initial analysis of the four factors which must be considered in establishing a reasonable progress goal toward achieving natural visibility conditions in mandatory Class I areas".

We would like to point out that there is regulatory defined fifth factor that must be a part of this analysis. Any determination for the application of additional controls to reduce primary pollutants must further consider the degree of visibility improvement on a deciview (dv) and cost per deciview basis ($/dv) that would occur by the implementation of any controls. We recognize the document may have been directed to address the first four aspects of the evaluation process. We feel the fifth fact is of greater importance and is more consistent with the language and intent of the law. Further, the analysis must consider the impacts of all sources impacting visibility, and must be fair and non-discriminatory between source types, and should not simply tart energy generation units.

Page 3-2,3-5 and 3-6: Mismatch of text and titles of Table's 3-1, 3-2 and 3-3. They should be Table 2-1, 2-2 and Table 2-3 or correct text.

Page 3-3 Table 3-2 Control Options for Selected Boilers – North Dakota indicates the SO_2 control technology to be evaluated over and above the existing technology of Dry Scrubber would be Wet FGD technology. Basin Electric believes there are potential intermediate improvements steps associated with Dry FGD technology that should also be evaluated.

Page 3-4 We agree on your discussion on the application of SCR on North Dakota Lignite coal-fired boilers may not be technically feasible. You further state that each boiler should be evaluated to determine this technical feasibility. At the point in time where the utilities are required to perform the case-by-case technical evaluation for all additional pollution control equipment, the current body of knowledge will be utilized to make this technical and economic evaluation. Again the actual amount of visibility improvement on an incremental basis (both on dv and $/dv) from the next level of control technology will need to apart of the final evaluation process.

Page 3-4 Time Necessary for Compliance: We generally agree with your assessment of the five to six years to achieve emission reductions; however our units' major unit outages (6-8 weeks) are scheduled every three years. Depending on how the regulatory process unfolds with the outage schedules, the overall implementation timeline may need to be increased.

Basin Electric appreciates the opportunity to comment on your efforts.

Sincerely,

Cris Miller for

Lyle Witham
Manager of Environmental Services

crm/lw/gmj

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June 19, 2009

JUN 2009
Received
Air Quality

Mr. Lee Gribovicz, Project Manager
Western Regional Air Partnership
1600 Broadway, Suite 1700
Denver, Colorado 80202

Dear Mr. Gribovicz:

Thank you for the opportunity to provide comments on the document created for Western Regional Air Partnership (WRAP) entitled "Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota." The Four-Factor Analyses, hereafter referred to as the WRAP document, references the Riley boilers at the Great Plains Synfuels Plant (GPSP) and makes a case for why Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR) should be considered in setting reasonable progress goals to reduce NO_x emissions and improve regional haze. Dakota Gasification Company (DGC) supports the document presumption that the facility already meets the requirements for sulfur reduction technologies.

DGC is concerned about the high capital and operating costs associated with the NO_x removal technologies outlined in the WRAP document. Additionally, DGC is concerned that the capital cost and operating cost outlined in this report may be somewhat underestimated because it has not accounted for the unique operation at the GPSP. Finally, DGC is concerned that the estimated control efficiency may be overstated relative to the capital expended.

Theoretically, SCR and SNCR appear to be good technologies for controlling NO_x from the Riley boilers; however, neither has been proven to work with DGC's unique boiler fuels. The Riley boilers are fired with a variety of liquid *and* gaseous lignite-derived fuels. The capital and operating cost referenced in the WRAP document is based on either liquid-fired *or* gas-fired boilers. The reference does not address the cost implications for the unique combination of fuels fired at the GPSP.

DGC is not certain that SCR is technically feasible with the existing process at the GPSP. Furthermore, DGC has information that the cost may be significantly higher than reported in the WRAP document. In 1996, DGC installed a Flue Gas Desulfurization Unit as Best Achievable Control Technology (BACT) for sulfur dioxide. During the evaluation process leading up to the BACT installation, DGC evaluated a proposal for SCR on the Riley boilers. The proposal would have required modifications to the heat recovery section of the Riley boilers to increase the temperature of the flue gas entering the SCR. Presumably, the current operating temperature is not sufficient for effective SCR operation.

The required modifications would have reduced the capability of the boilers to make enough steam to operate the facility at full production. Therefore, the cost estimates in the WRAP document for installing SCR at DGC are too low because they do not account for the capital costs associated with modifying the Riley boilers and the production lost during that effort. Additionally, the operating cost estimates do not account for the continuing plant production losses directly related to the reduction in steam capacity from the Riley boilers.

Regarding SNCR, DGC has information that suggests it may not be technically feasible at DGC's GPSP. In 1997, DGC experimented with SNCR as a NO_x control on the Riley boilers. The injection of ammonia during this testing resulted in the rapid accumulation of ammonium sulfate particulate deposits in the heat recovery section of the boiler. The uniqueness of the flue gas (high SO_2 and CO_2) is believed to have contributed to the formation of ammonium sulfate in the boilers. This highly undesirable side effect combined with a much lower than predicted NO_x reduction prompted DGC to immediately discontinue testing. Further testing was not performed due to the likelihood of interfering with the long-term reliability and performance of the Riley boilers.

In addition to the typical cost of the control technologies themselves, other costs of installing SCR or SNCR will include engineering challenges of finding a place to install equipment in an area with limited space available. DGC has the concern that a retrofit installation for SNCR or SCR would drive the costs higher than the costs noted in the high level overview provided in the WRAP document. The reference for the WRAP document does not clearly indicate if a congested work site comparable to that at DGC has been considered in the capital cost estimate.

The WRAP document based the capital cost, operating cost, and overall effectiveness of the control technology by applying control technology only to the Riley boilers and not the two liquid-fired superheaters. This is an understandable approach by the author because the superheaters are equivalent to only 10% of the Riley boiler heat load. However, DGC's sampling indicates that the superheaters could contribute over 20% of the total NO_x produced. In order to achieve the maximum NO_x control referenced in the WRAP document, DGC would have to expend additional costs for controls on the superheaters.

Any new technology that is considered for NO_x controls will require an evaluation. Depending on the technology chosen, time and resources may need to be allotted to construct and operate a pilot plant to prove a chosen technology will work in this application.

Before requiring expenditure of significant amounts of capital to install new emission controls, consideration should be given to the overall impact of any required emission reduction. The NO_x emissions from the GPSP are a small part of the state inventory. Therefore, it does not seem cost-effective that DGC should bear the expense of adding costly controls. Good emission control strategies should target regional sources that are more cost-effective and feasible.

In addition to the four-factor analysis, a fifth factor needs to be part of this analysis. Any determination for the application of additional controls to reduce primary pollutants must further consider the degree of visibility improvement on a deciview (dv) and cost per dv ($/dv) basis that would be incurred by the implementation of any controls. This factor is of great importance and should be a major consideration.

If an emission reduction is required for a facility, DGC suggests that the agency issuing the requirement explain what reductions are needed and how those reductions are considered to be possible based on technology available. The agency should also allow facilities the flexibility to identify new and innovative ways to achieve those reductions that may not have been initially considered in the WRAP document.

DGC appreciates your consideration of our comments. Given the reasons detailed in this letter, DGC believes the control technologies for SCR and SNCR on the GPSP Riley boilers should not be considered within the first State Implementation Plan (SIP) on Regional Haze.

Sincerely,

David W Peightal

David W. Peightal, P.E.
Environmental Manager

dwp/paw
c: Terry O'Clair, NDDH
Tom Bachman, NDDH
9850-DWP-09-008

From: Ford, Michael [MFord@hess.com]
Sent: Saturday, June 20, 2009 6:40 PM
To: lg@westgov.org
Cc: Nelson, Rory; Chandra, Ajey; Dittus, Myles; Williams, Robert; Bachman, Tom A.
Subject: Comments - EC/R Inc. Four Factors Analysis - Hess Corporation Tioga Gas Plant

Mr. Gribovicz,

A review of the Hess Corporation Tioga Gas Plant data contained in the Four-Factor Analyses for Selected Individual Facilities in North Dakota report was recently completed. Our comments regarding the Tioga Plant analyses follow:

SO2 Emissions - Sulfur Recovery Unit (SRU):

The average sulfur recovery efficiency for the Tioga Gas Plant SRU is 98.8%. The baseline sulfur recovery efficiency stated in the report and used in the economic analysis is 97.5%. This difference in the recovery efficiency impacts the cost analyses. The cost per ton of sulfur dioxide emissions reduced by requiring additional control technology would increase substantially.

The Tioga Gas Plant SRU was designed for 225 long tons per day of sulfur production. The SRU currently recovers less than 100 long tons per day due to a lower sulfur concentration in the plant’s inlet gas. Expectations are the amount of sulfur in the inlet gas will continue to drop as more sweet gas is processed by the plant in conjunction with the Bakken Field development.

The cost estimate for installing a TGTU-amine absorption unit appears to be based on a 1982 report and extrapolating the costs up from a 100 ton per day unit. This could lead to significant error in the cost analysis.

NOx Emissions - Clark Engines:

The configuration of the Clark engine/compressor does not allow for replacement of the engine with an electric motor. The compressor cylinders connecting rods are an integral part of the engine’s main crankshaft.

Selective Catalytic Reduction (Catalytic Converter) will not work to control NOx emissions from a two-cycle lean burn engine without the injection of ammonia upstream. The use of ammonia has additional safety concerns.

If you should have any questions regarding these comments or need additional data, my contact information follows.

Michael Ford

Environmental Advisor

Hess Corporation

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Mobile: 713-829-6076

OtterTail Comments ECR Inc. Four Factors Analysis

From: TGraumann@otpco.com
Sent: Wednesday, May 27, 2009 9:01 AM
To: lg@westgov.org
Cc: Bachman, Tom A.
Subject: EC/R Inc. Four Factors Analysis
Attachments: ND DOH Regional Haze Progress Goals.xls; ND DOH Regional Haze Progress Goals.xls

Mr. Gribovicz:

Based on previous correspondence from Tom Bachman of the North Dakota Department of Health, it is my understanding that North Dakota must develop Regional Haze Reasonable Progress Goals for the Class I areas in North Dakota. As part of developing the Reasonable Progress Goals, North Dakota is required to evaluate the potential for air pollution controls (or additional controls) at sources that were not subject to Best Available Retrofit Technology (BART) requirements. EC/R, Inc. prepared a draft analysis of those facilities for the WRAP.

One of the facilities that is included in the analyses is Coyote Station, which is a co-owned facility that is operated by Otter Tail Power Company.

I have reviewed the draft report "Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota" and I offer the following comments for your consideration.

Section 3 Page 3-2. The fourth line from the bottom of the page references a coal sulfur content of 0.6% as a basis for estimating uncontrolled emissions. The average coal sulfur content for fuel burned at Coyote Station during the last five years (2004-2008) is 1.01%. We suggest using 1.01% for estimating the uncontrolled emissions for Coyote Station.

Section 3 Page 3-3 Table 3-2. The table reflects unrealistically low uncontrolled SO2 emissions and, when compared to the annual emissions, it gives the appearance that Coyote Station is removing less than 50% of the uncontrolled emissions. The table also attributes a greater incremental potential emissions reduction based a 90% control efficiency when compared to current removals. The attached table illustrates our concern. The SO2 uncontrolled of 48,323 tons more accurately reflects estimated historical conditions as does a removal of approximately 69%. The incremental benefit of 90% SO2 removal is reduced from 11,993 tons to 10,032 tons. Note that the methodology for calculating the uncontrolled emissions remains as you have proposed. The revised uncontrolled SO2 was simply based on a ratio of the fuel sulfur content (0.6% to 1.01%).

Section 3 Page 3-4. The second paragraph of the page accurately captures industry concerns with the feasibility of a high duct SCR on a lignite fired boiler. It might be helpful to include a reference supporting that concern. Because of its size I will forward the reference under a separate e-mail.

Section 3 Page 3-5 Table 3-3. As noted above, the incremental benefit of 90% SO2 removal is
reduced from 11,993 tons to 10,032 tons. The cost effectiveness of the wet FGD control
efficiency would increase in inverse proportion to the decrease in the tons of SO2 removed, all
other assumptions remaining equal. Thus the cost effectiveness ($/ton) of 90% SO2 removal
would be $3048 rather than $2550.

I have not reviewed the document for table text references and the like. I did notice that several
of the tables referenced in the text in Section 3 were incorrectly referenced.

Thank you for the opportunity of submitting comments.

Regards,

Terry

<<ND DOH Regional Haze Progress Goals.xls>>

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EVALUATION OF POTENTIAL SCR CATALYST BLINDING DURING COAL COMBUSTION AND ADD-ON: IMPACT OF SCR CATALYST ON MERCURY OXIDATION IN LIGNITE-FIRED COMBUSTION SYSTEMS

Final Report

(for the period of November 1, 2000 – June 30, 2004)

Prepared for:

Mr. Harvey Ness

Director
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04-EERC-11-09

November 2004

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JV 31 – EVALUATION OF POTENTIAL SCR CATALYST BLINDING DURING COAL COMBUSTION AND ADD-ON: IMPACT OF SCR CATALYST ON MERCURY OXIDATION IN LIGNITE-FIRED COMBUSTION SYSTEMS

ABSTRACT

Lignite and subbituminous coals from the United States of America have characteristics that impact the performance of catalysts used in selective catalyst reduction (SCR) for nitrogen oxide removal and mercury oxidation. Typically, these coals contain ash-forming components that consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. The alkali and alkaline-earth elements are partitioned between reactions with minerals and reactions to form alkali and alkaline-earth-rich oxides during combustion. The particles resulting from the reaction with minerals produce low-melting-point phases that cause a wide range of fireside deposition problems. The alkali and alkaline-earth-rich oxides consist mainly of very small particles (<5 µm) that are carried into the backpasses of the combustion system and react with flue gas to form sulfates and, possibly, carbonates. These particles cause low-temperature deposition, blinding, and plugging problems in SCR systems. These coals also lack sufficient levels of chlorine needed to oxidize mercury. Slipstream testing was conducted at two subbituminous-fired power plants and one lignite-fired power plant to determine the impacts of ash on SCR plugging, blinding, and mercury oxidation. The results indicated a high potential for blinding and plugging because of the formation of sulfate-bonded deposits but no evidence of mercury oxidation.

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JV 31 – EVALUATION OF POTENTIAL SCR CATALYST BLINDING DURING COAL COMBUSTION AND ADD-ON: IMPACT OF SCR CATALYST ON MERCURY OXIDATION IN LIGNITE-FIRED COMBUSTION SYSTEMS

EXECUTIVE SUMMARY

The goal of this project by the Energy & Environmental Research Center (EERC) is to determine the potential of low-rank coal ash to cause blinding or masking of selective catalytic reduction (SCR) catalysts. The primary goal of the add-on is to determine the effects of new and aged catalyst on the oxidation of mercury at full-scale power plants.

Two SCR slipstream reactors were constructed to accomplish the goals of this project. The test chambers are approximately 19 cm (7.5 inches) square and are able to accommodate catalyst sections up to 1 meter (3.3 feet) in length. The chambers are electrically heated and fully instrumented to limit heat loss and to maintain a catalyst face velocity of 5 m/s (16.4 ft/s).

The SCR reactors were installed at three different plant locations and operated until the catalyst had 6 months of operating time. The units that were chosen for this study are the Columbia Station (pulverized coal-fired), the Baldwin Station (cyclone-fired), and the Coyote Station (cyclone-fired). The Coyote Station fires North Dakota lignite, while the other two stations burn Powder River Basin (PRB) coal. The catalyst was sampled every 2 months and analyzed with scanning electron microscopy (SEM).

Bench-scale and Facility for Analysis of Chemical Thermodynamics (FACT) modeling studies were also conducted in the laboratory prior to the reactors being installed at the host utilities. Experiments were carried out in a thermogravimetric analyzer (TGA) system at 315°C (600°F), 370°C (700°F), and 427°C (800°F) with simulated flue gas. Ash samples created from the test coals were placed on the TGA pan with and without catalyst. The rate of sample weight gain was then monitored. The ash was then analyzed with SEM techniques to identify the species that were present.

The results of the bench-scale analysis indicate that the rate of weight gain increases with increasing temperature, and calcium sulfates were the predominant species formed. The rate of sulfate formation could increase as much as tenfold with the addition of catalyst to the system. Low-sulfur bituminous and PRB blends exhibited a higher rate of sulfate formation and, therefore, would have a higher blinding potential than a 100% PRB or lignite. Results of the FACT modeling indicate that there is a high potential to form alkali and alkaline-earth sulfates, carbonates, and phosphates while SCRs are operated at utilities burning lignite and PRB coals.

The data collected during the three slipstream reactor tests indicate that the pressure drop across the catalyst was found to be the most significant for the lignite-fired plant as compared to the subbituminous-fired plants. Both lignite and PRB coals had significant accumulations of ash on the catalyst, on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst

sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation.

The deposits on the surfaces and within the pores of the catalyst consisted of mainly alkali and alkaline-earth element-rich phases that have been sulfated. The mechanism for the formation of the sulfate materials involves the formation of very small particles rich in alkali and alkaline-earth elements, transport of the particles to the surface of the catalyst, and reactions with SO_2/ SO_3 to form sulfates. X-ray diffraction analysis identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements, including sodium, magnesium, calcium, and potassium in addition to mineral phases. During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component and their association in the coal and combustion system design and operating conditions. The results of this testing found that the smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-µm size fraction.

This study suggests the careful evaluation of each SCR installation on applications using subbituminous and lignite coals. Improvements are needed to ensure technical feasibility, especially with lignite-fired units. Installations involving lignite fuels will need advanced cleaning techniques to handle the high sodium and high dust loads associated with burning most lignite fuels.

The ability of mercury to be oxidized across the SCR catalyst was investigated at the Coyote Station. The Coyote Station is fired on North Dakota lignite, and the flue gases are dominated by elemental mercury. Measurement of mercury speciation was conducted using the Ontario Hydro (American Society for Testing and Materials D6784-02) method at the inlet and the outlet of the SCR reactor. These results show limited oxidation of mercury across the SCR catalyst when lignite coals are fired. The reasons for the lack of mercury oxidation include the following: no chlorine present in the coal and flue gas to catalytically enhance the oxidation of Hg^0, higher levels of alkali and alkaline-earth elements acting as sorbents for any chlorine present in the flue gas, and lower levels of acid gases present in the flue gas.

JV 31 – EVALUATION OF POTENTIAL SCR CATALYST BLINDING DURING COAL COMBUSTION AND ADD-ON: IMPACT OF SCR CATALYST ON MERCURY OXIDATION IN LIGNITE-FIRED COMBUSTION SYSTEMS

INTRODUCTION

The Energy & Environmental Research Center (EERC) investigated selective catalytic reduction (SCR) for NO_x control and mercury oxidation using a slipstream reactor at power plants firing subbituminous and lignite coals to determine the potential for ash plugging and blinding and mercury oxidation. SCR units lower NO_x emissions by reducing NO_x to N_2 and H_2O. Ammonia (NH_3) is the most common reducing agent used for the SCR of NO_x. The SCR process involves the use of a metal oxide catalyst such as titanium dioxide (TiO_2)-supported vanadium pentoxide (V_2O_5). These units are operated at about 340°–370°C (650°–700°F). Subbituminous and lignitic coals are known for their ability to produce alkali and alkaline-earth sulfate-bonded deposits at low temperature (<1000°C) in utility boilers. The mechanisms of the formation of low-temperature sulfates have been extensively examined and modeled by the EERC in work termed Project Sodium and Project Calcium in the early 1990s (1, 2). Deposit buildup of this type blinds or masks the catalyst, diminishing its reactivity for converting NO_x to N_2 and water and potentially creating increased NH_3 slip (3). Elemental mercury oxidation has been observed in laboratory-, pilot-, and full-scale testing using SCR catalysts (4–6). In these studies, the metal oxides, V_2O_5 and TiO_2, have been shown to promote the conversion of elemental mercury to oxidized and/or particulate-bound mercury. Full-scale tests in Europe (7) and the United States (8) have indicated that the V_2O_5 and TiO_2 catalyst may promote the formation of oxidized mercury. The ability to oxidize mercury is largely dependent on the composition of the coal (8).

Lignite and subbituminous coals produce ash that plug and blind catalysts (9–12). The problems currently being experienced on SCR catalysts include the formation of sulfate- and phosphate-based blinding materials on the surface of catalysts and the carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing them on top of the SCR catalysts (3). The most significant problem that limits the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates, phosphates and, possibly, carbonates on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (3, 11–14). The degree of the ash-related impacts on SCR catalyst performance depends upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (11, 12, 14, 15).

Licata and others (13) conducted tests on a South African and a German Ruhr Valley coal and found that the German Ruhr Valley coal significantly increased the pressure drop across the catalyst because of the accumulation of ash. They found that the German coal produced a highly adhesive ash consisting of alkali (K and Na) sulfates. In addition, they reported that the alkali elements are in a water-soluble form and highly mobile and will migrate throughout the catalyst material, reducing active sites. The water-soluble form is typical of organically associated alkali elements in coals. The German Ruhr Valley coal has about 9.5% ash and 0.9% S on an as-received basis, and the ash consists mainly of Si (38.9%), Al (23.2%), Fe (11.6%), and Ca (9.7%), with lower levels of K (1.85%) and Na (0.85%) (13). Cichanosicz and Muzio (14) summarized the experience in Japan and Germany and indicated that the alkali elements (K and Na) reduced the acidity of the catalyst sites for total alkali content (K + Na + Ca + Mg) of 8%–15% of the ash in European power plants. Licata et al. also found that alkaline-earth elements such as calcium react with SO_3 on the catalyst, resulting in plugging of pores and a decrease in the ability of NH_3 to bond to catalyst sites. The levels of calcium in the coals that caused blinding ranged from 3% to 5% of the ash. Studies conducted on the impact of alkali elements associated with biomass found that, when biomass is fired, poisoning and blinding of SCR catalysts occurred (16, 17).

This study took a three-pronged approach to solve the issues involving low-rank fuels and the SCR catalyst. Studies were conducted at both the pilot and bench scales and were compared to a thermodynamic equilibrium model. In order to facilitate the pilot-scale study, two slipstream SCR systems were constructed. The slipstream reactors were installed at three power plants. Two of the plants were cyclone-fired: one with lignite and one with subbituminous coal. The third plant was a pulverized-coal (pc), tangentially fired unit using subbituminous coal. The slipstream reactors were designed to expose SCR catalysts to flue gas and particulate matter under conditions that simulate gas velocities, temperatures, and NH_3 injection of a full-scale pilot plant. The control system maintains catalyst temperature, pulse air to remove accumulated deposits, and a constant gas flow across the catalyst; it logs pressure drops and temperatures. The reactor was operated in an automated mode and could be remotely controlled via modem. Testing at each power plant was conducted over 6 months. The reactor was inspected and cleaned at 2-month intervals, and a catalyst section was removed for analysis. The catalysts and associated ash deposits were analyzed to determine the characteristics of the ash on the surface and in the pores. In addition, mercury speciation in the flue gas upstream and downstream of the catalyst was conducted at 2-month intervals during the testing at the lignite-fired plant. The ability of the SCR catalyst to catalyze gaseous elemental mercury (Hg^0[g]) to more soluble and chemically reactive $Hg^{2+}X$(g) forms was evaluated, along with the potential increase in particle-associated mercury (Hg[p]). Increasing the oxidized and particulate fractions of mercury has the potential to increase the efficiency of mercury capture by conventional control devices such as wet flue gas desulfurization scrubbers and electrostatic precipitators.

EXPERIMENTAL

Thermochemical Equilibrium Modeling

The Facility for the Analysis of Chemical Thermodynamics (FACT) is a digital thermodynamic equilibrium model that assesses fuel quality effects on ash behavior in a boiler. It predicts molar fractions (partial pressures) of all gas, liquid, and solid stable components in a system by using the principle of Gibbs free energy minimization. FACT output includes quantities, compositions, and viscosities of liquid and solid mineral phases; the model accurately predicts the behavior of fuel ash, including biomass-derived ash, for different boiler temperature regimes.

In this study, the bulk ash composition and the atmosphere used in the thermogravimetric analyzer (TGA) testing were input to the FACT model. In this model, each reaction is considered independent of all other reactions. For example, the FACT model may predict that species X will dominate while the empirical results show that species Y tends to form (i.e., selectivity and kinetics are not considered by the model).

Bench-Scale TGA Study

Fuels were first combusted in the EERC's conversion and environmental process simulator. Ash resulting from the combustion of these fuels was collected and size-fractionated. Tests were carried out on the size-fractionated ash in a TGA under atmospheric conditions that mimic a combustion environment. The simulated flue gas atmosphere consisted of CO_2, SO_2, NH_3, N_2, O_2, H_2O, and P_2O_5. The flue gas makeup is presented in Table 1. The weight gain of the ash or ash–catalyst mixtures was measured as a function of time and temperature. The tests were conducted at 316°, 371°, and 427°C (600°, 700°, and 800°F). The resulting mixtures were analyzed to determine the influence of SCR catalysts on ash behavior.

Table 1. Flue Gas Makeup

N_2	74%
H_2O	8%
CO_2	14%
O_2	4%
NH_3	100–300 ppm
SO_2	0.04%
P	1–1000 ppm

Slipstream Reactor Installation and Operation

Upon installation at each utility boiler unit, flue gas temperature, composition, and velocity measurements were obtained using portable equipment. Shakedown testing of the unit was conducted to ensure that all components were operating properly and that data were being logged and could be retrieved. After installation and shakedown were completed, the reactor was operated in a computer-controlled, automated mode and monitored on a daily basis to ensure proper operation and data quality. During operation of the SCR slipstream system, catalyst temperature, sootblowing frequency, and pressure drop across the catalyst were monitored and logged. Samples of the exposed SCR catalyst and associated deposits were obtained after exposure to flue gas and particulate for 2, 4, and 6 months. The samples of the catalyst were analyzed to determine the components that were bonding and filling pores, resulting in decreased reactivity.

SEM Ash Characterization

The characteristics of the ash that accumulated on the catalyst were examined using scanning electron microscopy (SEM)–x-ray microanalysis and x-ray diffraction (XRD) (18). The samples were either placed on double-stick tape for surface analysis or mounted in epoxy for cross-section analysis. Correlations between the physical and chemical characteristics of any ash deposits on the SCR test section and entrained-ash sample collected at the chamber inlet and the coal inorganic composition will be made to discern mechanisms of SCR blinding. Entrained ash was collected at the Columbia Station only and characterized with respect to composition and size.

Mercury Measurement

At the Coyote Station, the Ontario Hydro (OH) mercury speciation sampling train was used to determine mercury forms across the SCR test section. The OH extractive mercury speciation sampling technique was used to measure potential mercury conversion across the SCR system over a period of several hours after fresh installation of the SCR test chamber and again just prior to removal of SCR catalyst sections.

The procedure used to conduct the mercury speciation sampling was American Society for Testing and Materials Method D6784-02 entitled “Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro method)” (19).

The OH method follows standard U.S. Environmental Protection Agency (EPA) methods for isokinetic flue gas sampling (EPA Methods 1–3 and EPA Method 5/17). A sample is withdrawn from the flue gas stream isokinetically through the filtration system, which is followed by a series of impingers in an ice bath. Particulate-bound mercury is collected on the filter; Hg^{2+} is collected in impingers containing 1 N potassium chloride solution; and elemental mercury is collected in one impinger containing a 5% nitric acid and 10% peroxide solution and in three impingers containing a solution of 10% sulfuric acid and 4% potassium permanganate. An impinger containing silica gel collects any remaining moisture. The filter media is quartz fiber filters. The filter holder is glass or Teflon-coated. An approximate 2-hour sampling time was used, with a target sample volume of 1 standard cubic meter.

RESULTS AND DISCUSSION

Task 1 – Identification of Test Coals and Utility Host Sites

Three host utility sites were chosen for the installation of the SCR reactors. The utilities were chosen based on their ability to provide all of the necessary support and hardware for the operation of the SCR reactors. The electric utility units selected for testing are shown in Table 2. The plants where the SCR slipstream system was installed included Alliant Energy’s Columbia Station, Dynegy’s Baldwin Station, and Otter Tail Power Company’s Coyote Station.

Table 2 describes the plants, and Table 3 summarizes the characteristics and selection criteria. The selection criteria that were most important to the success of this project were geographic location, a base load plant, and a consistent supply of one fuel for the duration of the study.

Table 2. Description of Power Plants Tested

	Baldwin	Columbia	Coyote
Unit No.	1	2	1
Utility	Dynegy	Alliant	Otter Tail
Boiler Type	Cyclone	T-fired	Cyclone
Fuel type	Antelope – subbituminous	Caballo – subbituminous	Beulah – Zap lignite
Load	Base	Base	Base
Location	Baldwin, IL	Portage, WI	Beulah, ND
MW	600	520	425

Table 3. Key Selection Criteria

Field Test 1 – Columbia Station

- Tangentially fired boiler to show differences in ash partitioning as compared to cyclone-fired systems.
- High-potential-blinding coal in Caballo, which can be burned nearly 100% for the entire test.

Field Test 2 – Baldwin Station

- Plant is cyclone fired.
- Units already are equipped to do slipstream testing.
- Plant currently fires a blend of Antelope coal and tires; plant is willing to fire 100% Antelope.
- High-potential-blinding coal in Antelope.

Field Test 3 – Coyote Station

- Cyclone-fired with lignite.
- High-potential-blinding coal with high alkali and alkaline-earth elements. Coal can have very high sodium content and is known to cause significant low-temperature deposition.

The units tested were selected based on the fuels fired, boiler type, and availability of the unit for sampling. The average composition of the coals fired during the testing is listed in Tables 4 and 5. The subbituminous coals were typically low ash, nominally 4.5%–5.5% with very high levels of calcium in the ash. In comparison, the lignite contains higher levels of ash and lower calcium but higher levels of sodium. The alkali and alkaline-earth elements are primarily associated with the organic matrix of the coal as salts of carboxylic acid groups (18). The portion of the ash-forming components that are associated with the organic matrix of the coal for subbituminous coal ranges from 30% to 60% (18); for the lignite coal, the portion is about 20% to 40%. The remaining ash-forming components consist of mineral grains. For these coals, the percentage organically associated is 29% for the Antelope, 36% for Caballo, and 19% for Beulah. The minerals present in the coals as determined by computer-controlled scanning electron microscopy (CCSEM) analyses are listed in Table 6. The primary minerals present in the subbituminous coals include quartz and various clay minerals with some pyrite and a mineral that is rich in Ca, Al, and P. This mineral has been identified in some coals as crandalite. The primary minerals found in the Beulah coal include clay minerals (kaolinite), pyrite, and quartz.

Table 4. Ultimate Analysis Results (dry basis), wt%

	Antelope	Caballo	Beulah
Ash Content	7.28	6.59	11.62
Total Sulfur	0.33	0.51	1.49
Carbon	69.97	67.88	61.50
Hydrogen	4.77	4.83	3.96
Nitrogen	1.05	1.24	1.08
Oxygen (by difference)	16.61	18.96	20.35

Table 5. Ash Composition (wt% equivalent oxide)

Oxide	Antelope	Caballo	Beulah
SiO_2	24.82	26.70	16.50
Al_2O_3	13.55	16.60	13.30
TiO_2	1.39	1.10	0.80
Fe_2O_3	7.52	5.10	16.60
CaO	26.68	25.10	19.50
MgO	7.14	8.00	7.40
K_2O	0.17	0.30	0.20
Na_2O	1.47	1.00	5.20
P_2O_5	0.90	1.70	0.00
SO_3	16.33	14.40	19.80

Task 2 – Bench-Scale Testing and FACT Modeling

Bench-Scale Testing

The goal of the bench-scale testing was to determine the effect catalyst would have on the conversion of SO_2 to SO_3 and the resulting increase in catalyst blinding. Tests were conducted with and without catalyst on the following fuels: Nanticoke Powder River Basin (PRB), Beulah lignite, and Nanticoke PRB and a low-sulfur U.S. (LSUS) bituminous blend.

The results of the study indicate that the addition of the catalyst to the ash and increased temperature increased the rate of weight gain by as much as tenfold. The weight gain can be directly linked to the rate of sulfation. The test results in Figures 1–3 were compiled using the gas concentrations noted in Table 1 minus the NH_3 and phosphorus compounds (baseline tests). Table 7 contains the ash analysis of the coals used in the bench-scale testing. Figure 1 contains the weight gain curves for the Nanticoke PRB test. The rate of weight gain increased as the temperature increased from 316° to 427°C (600° to 800°F).

Figure 2 contains the weight gain curve for the Beulah lignite. Again the weight gain increased as the temperature was increased from 316° to 427°C (600° to 800°F). The rate of weight gain was similar to what was seen with the Nanticoke PRB test.

Table 6. CCSEM Analysis Results for Beulah, Antelope, and Caballo (values are wt% on a mineral basis)

	Caballo	Antelope	Beulah
Total Mineral wt% on a Coal Basis:	2.8	3.2	8.4
Quartz	40.4	31.5	11.0
Iron Oxide	0.0	2.4	4.4
Periclase	0.0	0.0	0.0
Rutile	2.4	0.3	0.0
Alumina	0.0	0.0	1.1
Calcite	0.0	0.4	0.1
Dolomite	0.0	0.5	0.0
Ankerite	0.0	0.0	0.2
Kaolinite	23.7	17.1	4.9
Montmorillonite	0.4	6.5	6.6
K Al-Silicate	0.0	1.6	7.2
Fe Al-Silicate	0.0	0.8	9.0
Ca Al-Silicate	0.1	1.0	2.6
Na Al-Silicate	0.0	0.0	0.1
Aluminosilicate	0.7	3.3	3.2
Mixed Al-Silicate	0.0	1.0	5.5
Fe Silicate	0.0	0.0	0.0
Ca Silicate	0.0	0.4	0.0
Ca Aluminate	0.0	0.0	0.0
Pyrite	16.2	0.0	0.8
Pyrrhotite	0.0	4.8	18.4
Oxidized Pyrrhotite	0.0	0.5	0.5
Gypsum	0.4	0.0	0.5
Barite	0.8	0.5	3.0
Apatite	0.0	0.2	0.0
Ca Al-P	8.5	13.5	0.1
KCl	0.0	0.0	0.0
Gypsum/Barite	0.0	0.1	0.0
Gypsum/Al-Silicate	0.1	0.9	4.0
Si-Rich	0.3	3.7	4.9
Ca-Rich	0.0	0.0	0.0
Ca-Si-Rich	0.0	0.1	0.0
Unclassified	3.2	8.7	11.9
Totals	100.0	100.0	100.0

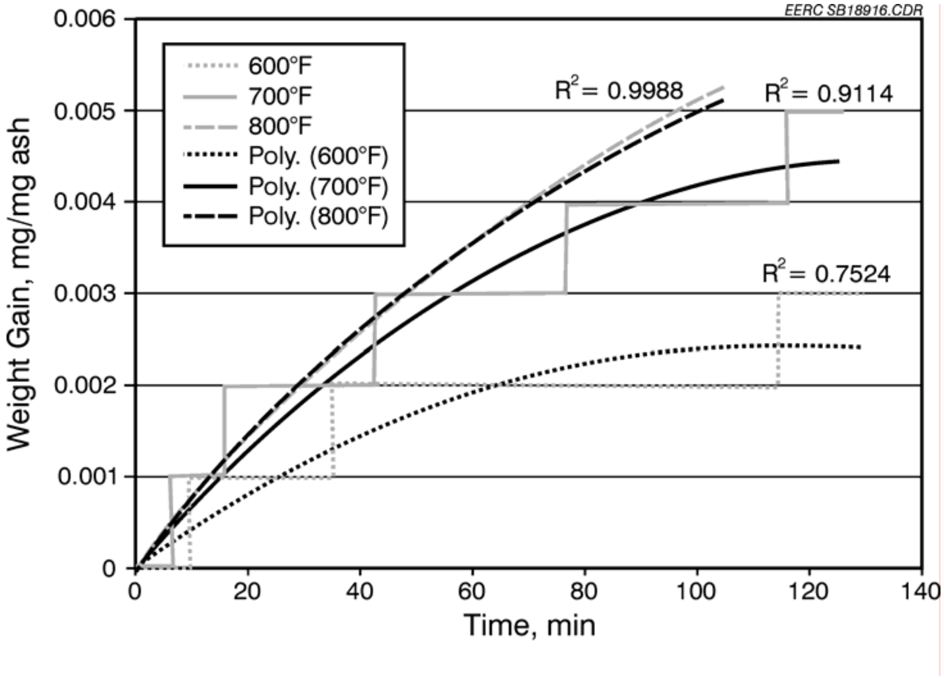


Figure 1. Weight gain curves for Nanticoke PRB (less than 3 µm), no catalyst.

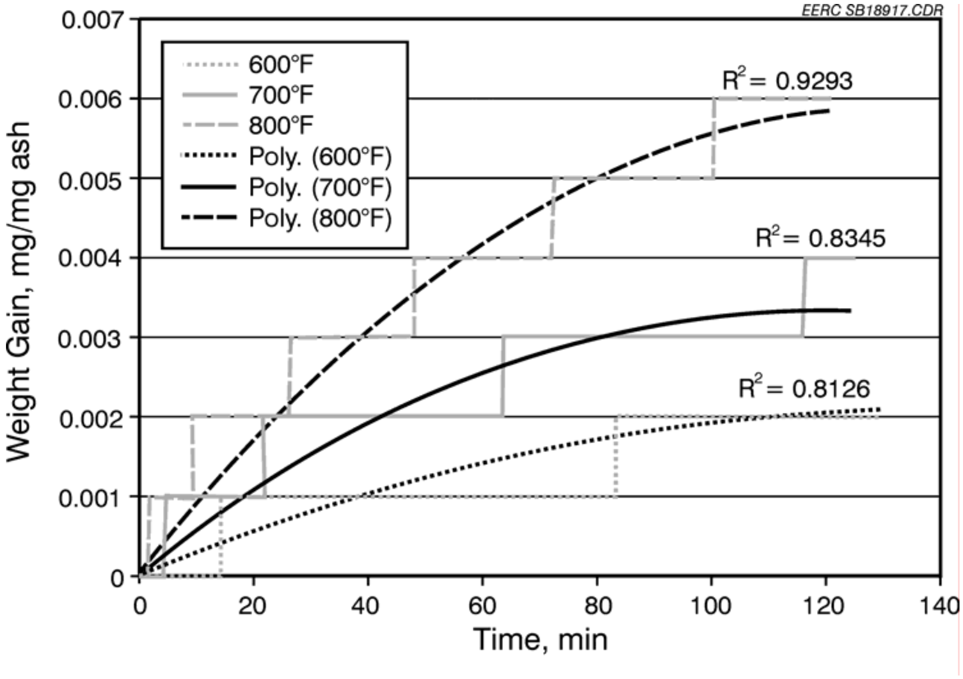


Figure 2. Weight gain curves for Beulah lignite (less than 3 µm), no catalyst.

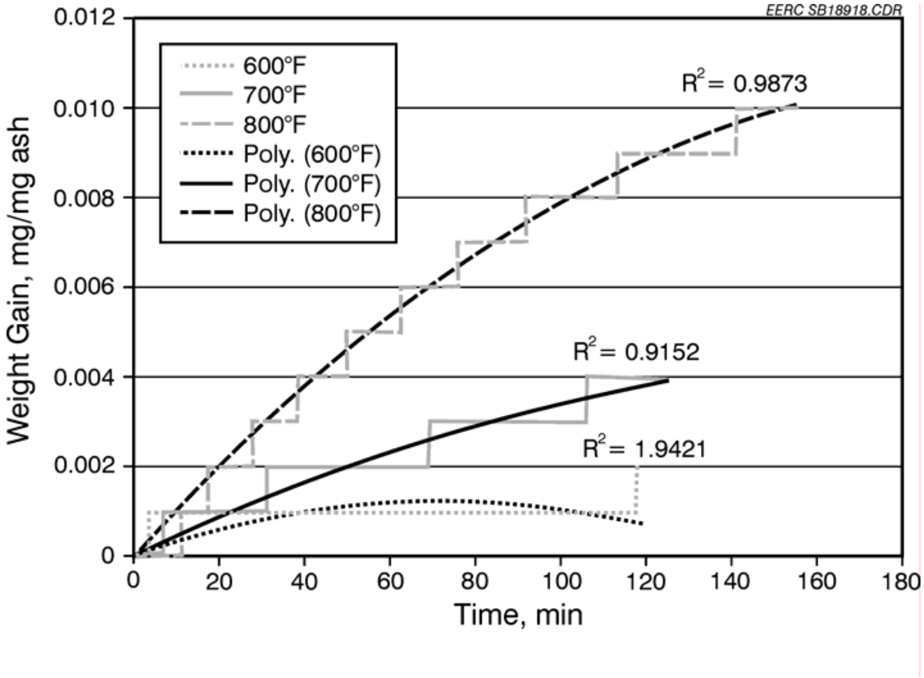


Figure 3. Weight gain curves for Nanticoke PRB–LSUS blend (less than 3 µm), no catalyst.

Table 7. Composition of Coal Ashes Used in Bench-Scale Testing

	Nanticoke 100% PRB		Nanticoke 52% PRB–48% LSUS		Beulah	
Oxides, wt%	(a)[1]	(b)[2]	(a)	(b)	(a)	(b)
SiO_2	27.9	32.0	43.4	48.4	31.5	39.7
Al_2O_3	17.7	20.3	26.7	29.7	14.2	17.9
Fe_2O_3	6.2	7.1	4.8	5.3	7.3	9.2
TiO_2	1.5	1.8	1.6	1.8	0.8	1.0
P_2O_5	1.0	1.2	0.4	0.4	0.2	0.2
CaO	24.8	28.5	8.5	9.4	15.8	19.9
MgO	6.6	7.6	2.6	2.9	5.8	7.3
Na_2O	1.0	1.2	0.7	0.7	3.1	3.9
K_2O	0.4	0.5	1.2	1.3	0.8	1.0
SO_3	12.9	—	10.2	—	20.6	—

[1] Oxide concentrations normalized to a closure of 100%.
[2] Oxide concentrations renormalized to an SO_3-free basis.

A blend of the Nanticoke PRB and an LSUS bituminous coal was tested at a 52–48 blend (PRB–LSUS). The weight gain curves for this test are in Figure 3. The results of this experiment are again similar to those obtained in the previous two cases, with the exception of the 427°C (800°F) test. The 427°C (800°F) test in this case gains slightly more weight than the previous two experiments. At high temperatures, this blend had almost double the weight gain from the straight PRB case. This indicates that there is likely more sulfur available from the bituminous coal.

More testing was completed on the Nanticoke PRB and the PRB–LSUS blend. In Figures 4–5, the gas used in the study now contains the NH_3 and phosphorus compounds in addition to the gas used in the previous three tests. Figure 4 contains the data for the Nanticoke PRB test with NH_3 and phosphorus. The addition of the NH_3 and phosphorus compounds increased the rate of weight gain in the 427°C (800°F) test. The difference in rates as temperature was increased became less pronounced.

Figure 5 contains the weight gain curves for the PRB–LSUS test. The rate of weight gain was also increased; however, the temperature effect was still present (increased weight gain with increased temperature).

The baseline tests (without NH_3 and phosphorus compounds) were repeated with the addition of SCR catalyst to the mixture. The results of these tests are in Figures 6–7. Figure 6 contains the weight gain curves for the Nanticoke PRB test with catalyst and the Nanticoke PRB test at baseline conditions and 427°C (800°F). The rate of weight gain with the addition of catalyst at 427°C (800°F) increased approximately 7-fold in this case. The addition of the catalyst will increase the amount of SO_2 that is oxidized to a more reactive form (SO_3), which will in turn increase the rate of sulfate formation.

Figure 7 contains the weight gain curves for the PRB–LSUS blend with catalyst. In this test, the rate of weight gain increased almost tenfold. Again, the increased rate can be attributed to more SO_3 in the system.

FACT Modeling

FACT thermodynamic equilibrium modeling was conducted on each of the ash and flue gas systems tested in the bench-scale screening. The FACT modeling will give an indication of what chemical species are thermodynamically favored at the temperature present in the SCR. Figures 8–13 contain the results of the FACT modeling on the Nanticoke PRB, Beulah lignite, and the Nanticoke PRB–LSUS blend. The gas composition used for the modeling is the same as what was used for the bench-scale analysis in Table 1.

Figures 8–10 have the results for the Nanticoke PRB, Nanticoke PRB–LSUS blend, and the Beulah lignite with 300 ppm NH_3 and 1000 ppm phosphorus pentoxide added. The model predicts that in all three cases the alkali/alkaline-earth phosphates and sulfates will be the predominant species formed. Trace amounts of phosphoric and sulfuric acid will also be present at lower temperatures (232°C [450°F]).

Figures 11–13 have the results for the Nanticoke PRB, the Nanticoke PRB–LSUS blend, and the Beulah lignite with 100 ppm NH_3 and 1 ppm phosphorus pentoxide added. With less phosphorus present, the model predicts that sulfates will dominate. In the case of the Nanticoke PRB, the formation of carbonate compounds is also predicted.

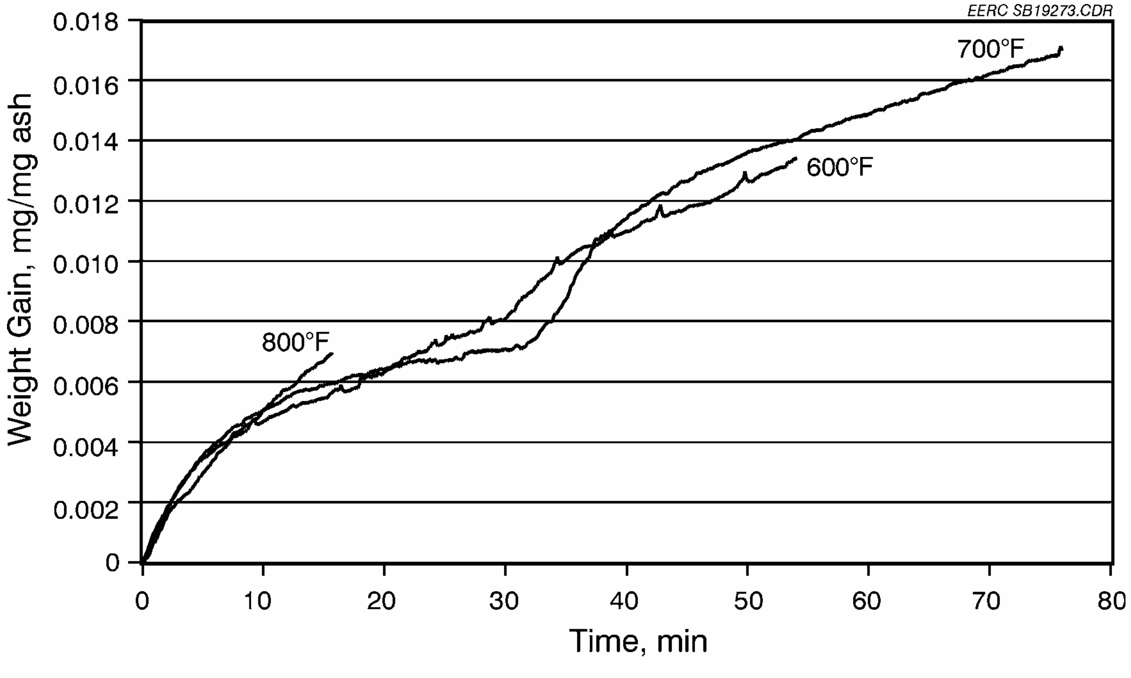


Figure 4. Weight gain curves for Nanticoke PRB (less than 3 µm) with ammonia and phosphorus compounds, no catalyst.

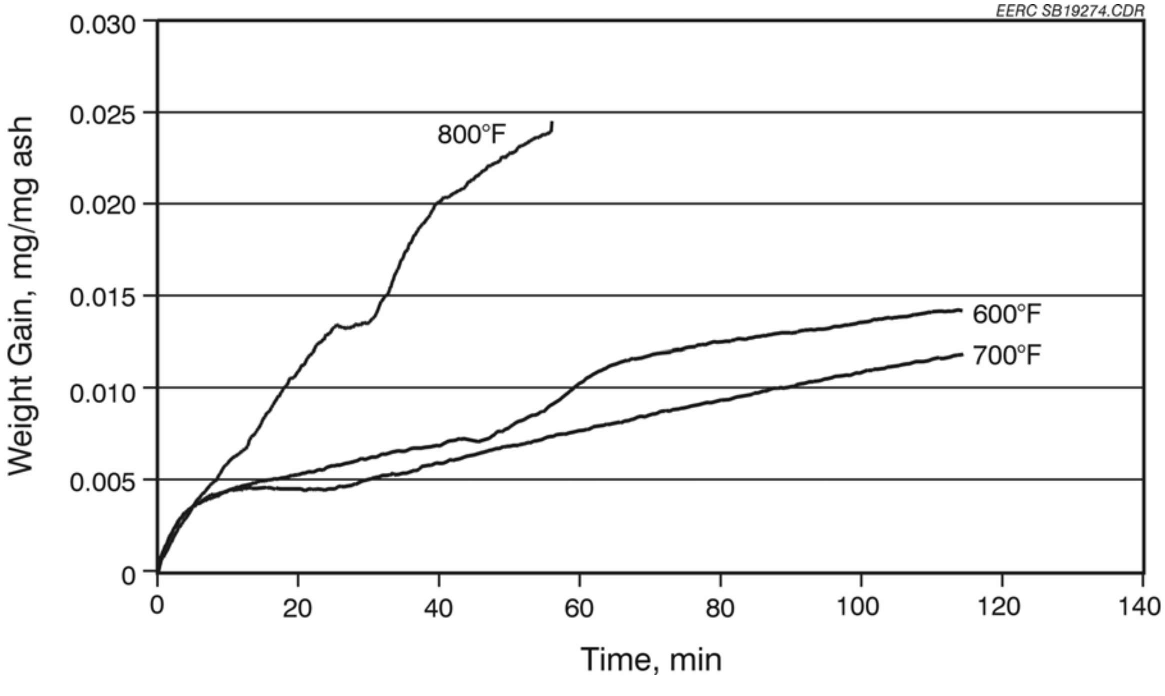


Figure 5. Weight gain curves for Nanticoke PRB–LSUS blend (less than 3 µm) with ammonia and phosphorus compounds, no catalyst.

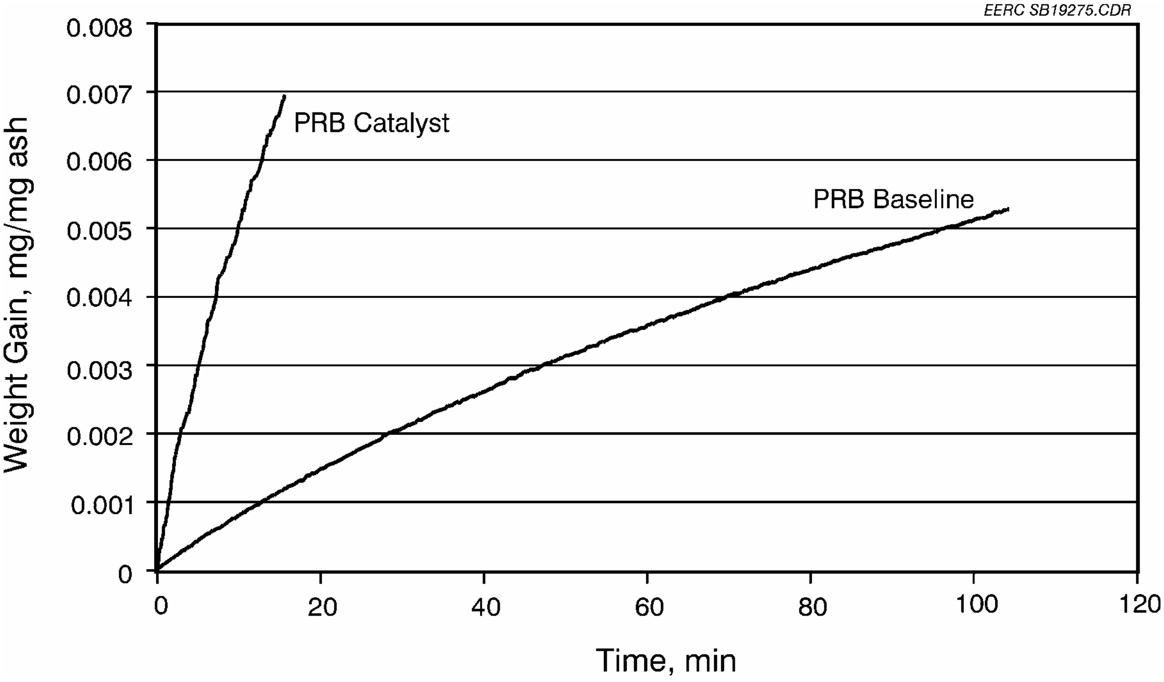


Figure 6. Weight gain curves for baseline Nanticoke PRB and Nanticoke PRB with catalyst.

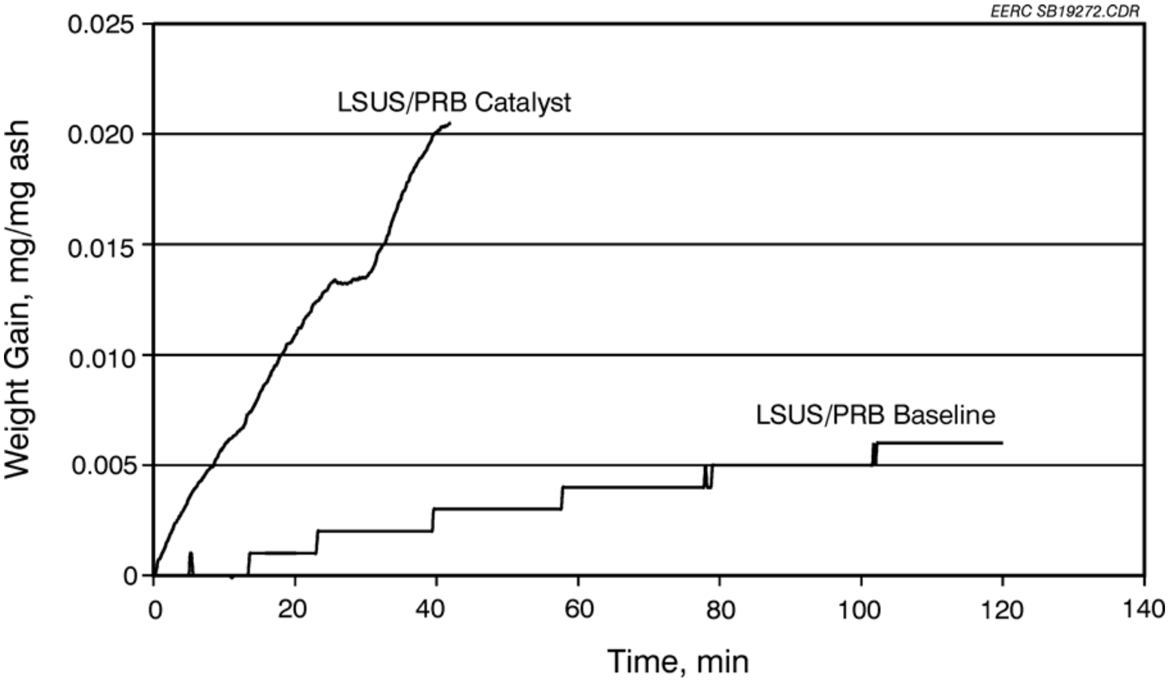


Figure 7. Weight gain curves for baseline LSUS–Nanticoke PRB blend and LSUS–Nanticoke PRB blend with catalyst.

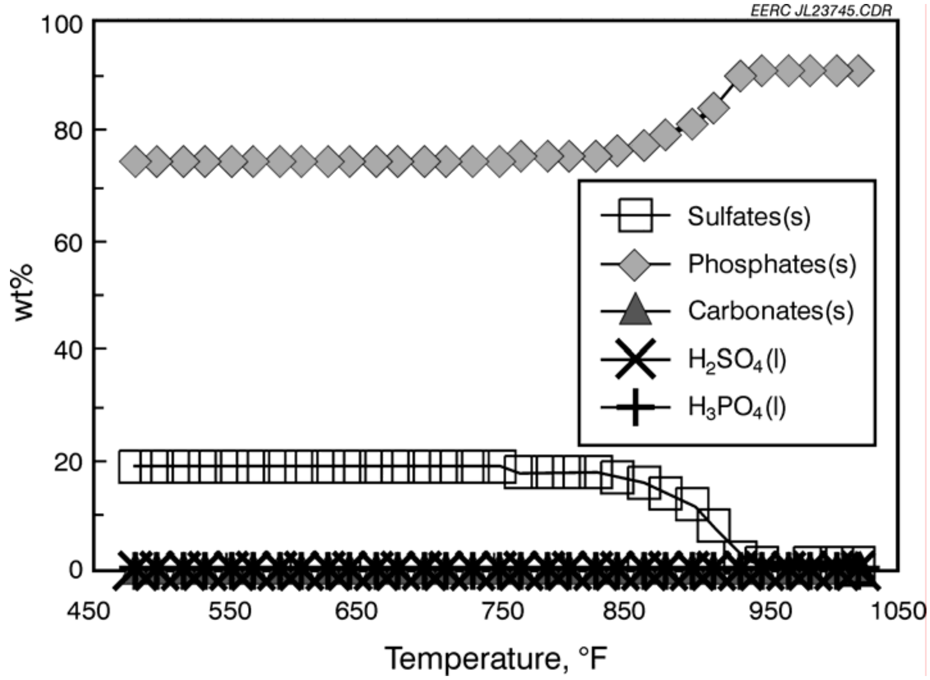


Figure 8. FACT modeling results for Nanticoke PRB with 300 ppm ammonia and 1000 ppm P_2O_5.

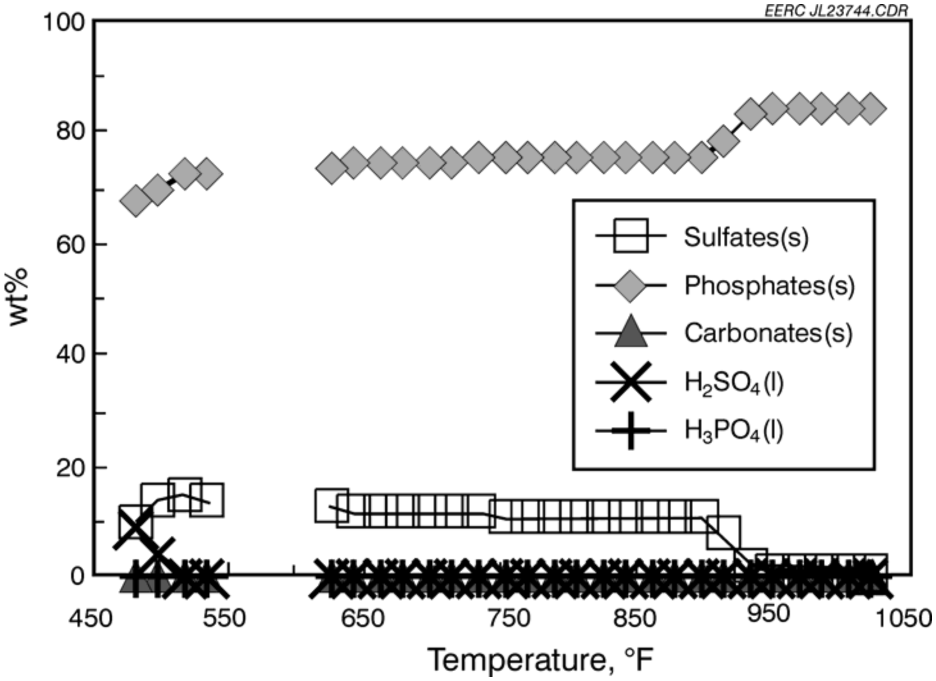


Figure 9. FACT modeling results for Nanticoke PRB–LSUS blend with 300 ppm ammonia and 1000 ppm P_2O_5.

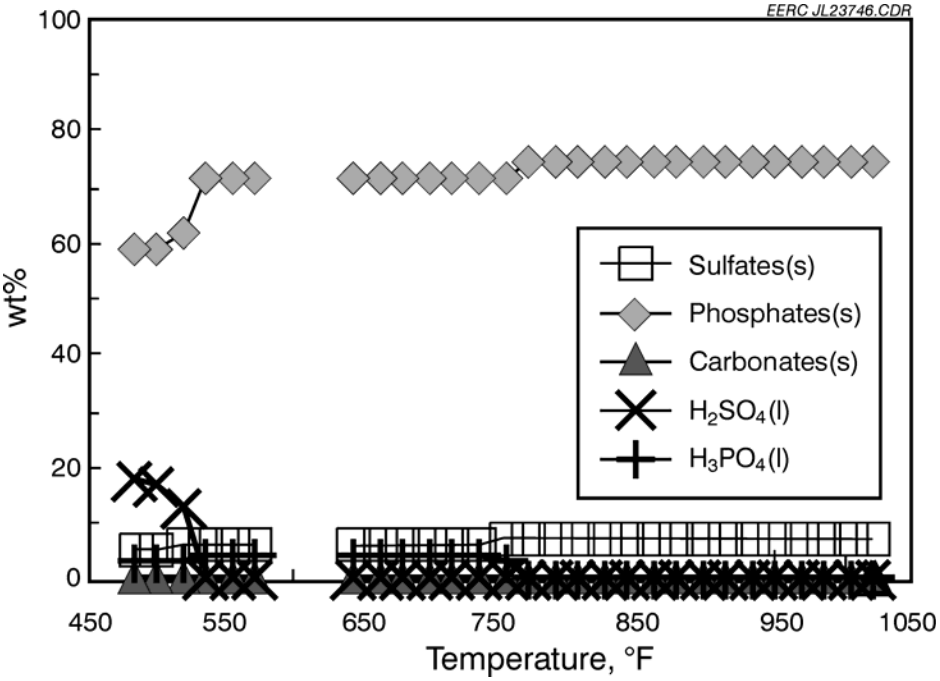


Figure 10. FACT modeling results for Beulah with 300 ppm ammonia and 1000 ppm P_2O_5.

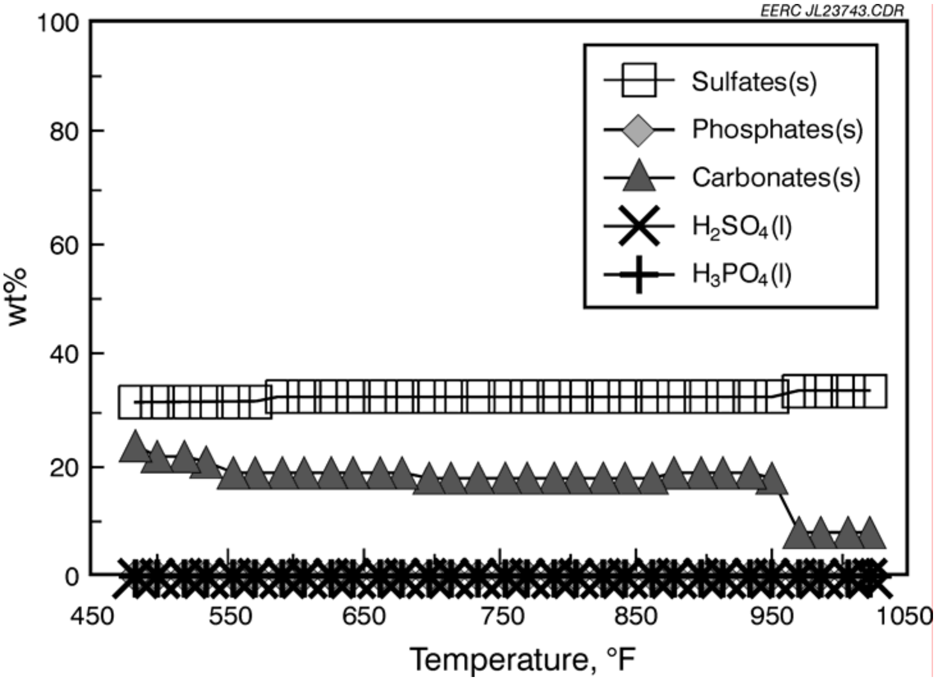


Figure 11. FACT modeling results for Nanticoke PRB with 100 ppm ammonia and 1 ppm P_2O_5.

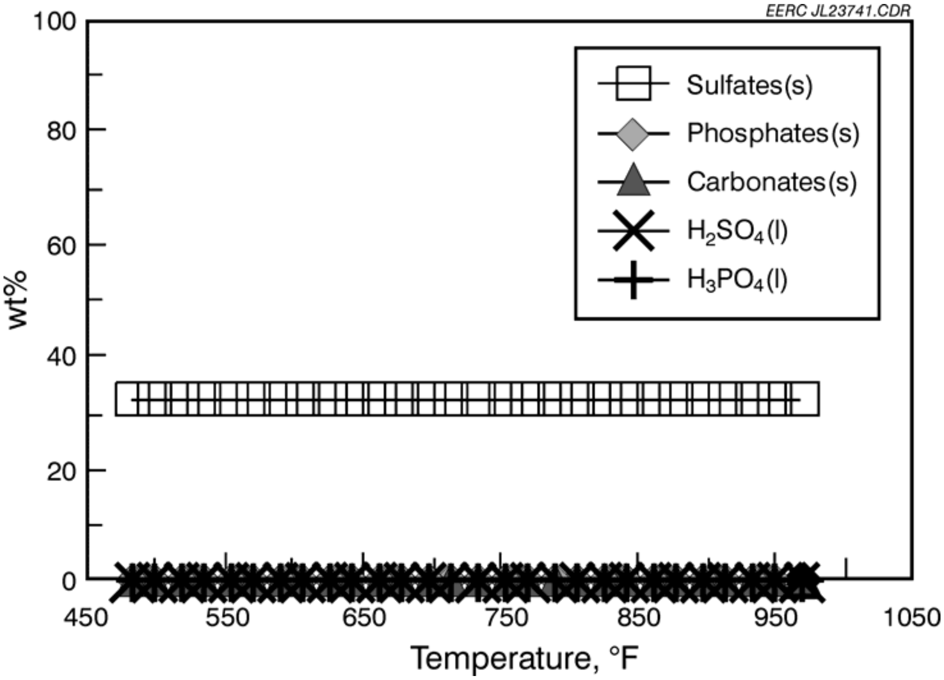


Figure 12. FACT modeling results for Nanticoke PRB–LSUS blend with 100 ppm ammonia and 1 ppm P_2O_5.

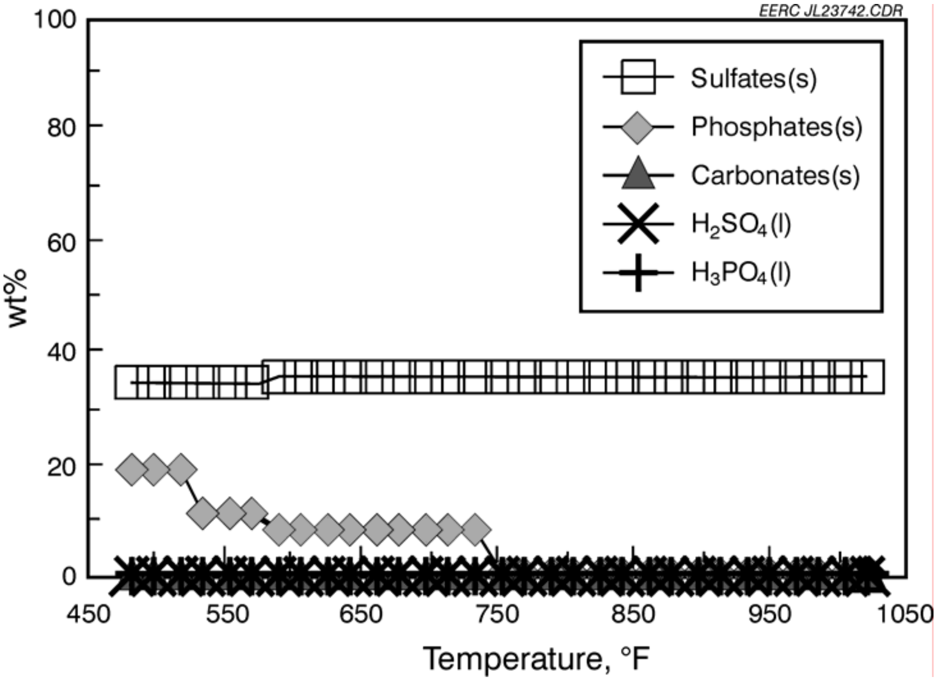


Figure 13. FACT modeling results for Beulah with 100 ppm ammonia and 1 ppm P_2O_5.

Characterization of Reaction Products from Bench-Scale Tests

The reaction products from three of the bench-scale tests were analyzed with SEM to validate the FACT modeling and to determine that the material gained during the tests was indeed a sulfate. Figures 14–16 are SEM micrographs of the fly ash from the Nanticoke PRB, Nanticoke PRB–LSUS blend, and the Beulah lignite. Corresponding Tables 8–10 contain the chemical analysis of several fly ash particles. Sulfur is present in almost all analyses and increases along with calcium. This indicates that most of the sulfur is present as calcium sulfate. These results are also consistent with the FACT modeling predictions. One exception may be that phosphates were not present in large quantities.

Task 3 – Design and Construction of the SCR Slipstream Test Chamber

The SCR slipstream system consists of two primary components: the control room and the SCR reactor. The reactor section consists of a catalyst section, an NH_3 injection system, and sampling ports for NO_x at the inlet and exit of the catalyst section. The control room houses a computer system that logs data and controls the gas flow rates, temperatures, pressure drop across the catalyst, and sootblowing cycles. The computer was programmed to maintain constant temperature of the catalyst, gas flow rates, sootblowing cycles, and NH_3 injection. The computer is equipped with a modem that allowed for downloading of data and modification of the operation of the reactor from a remote computer located at the EERC.

A schematic diagram of the SCR slipstream system is shown in Figure 17. Flue gas is isokinetically extracted from the convective pass of the boiler upstream of the air heater. The temperature is typically about 790°F. The flue gases pass through a 4-inch pipe equipped with sampling, thermocouple, and pressure ports. NH_3 is injected into the piping upstream of the reactor section. The reactor consists of a steel housing that is approximately 8.5 inches square and 8 feet long. The reactor section illustrated in Figure 18 has three components, including a flow straightener, a pulse section or sootblower, and a catalyst test section. A metal honeycomb is used as a flow straightener upstream of the catalyst section and is about 6 inches long. A purge section was installed ahead of the catalyst test section to remove accumulated dust and deposits. The catalyst test section is located downstream of the purge section. The entire catalyst section is insulated and equipped with strip heaters for temperature control. The catalyst test section is 1 m (3.28 ft) in length and houses three catalyst sections. Thermocouple and pressure taps are located in the purge sections for measurements before and after each section.

The induced-draft fan is used to extract approximately 5.6 scmm (200 scfm) of flue gas from the convective pass of the utility boiler to achieve an approach velocity of 5.2 m/s (17.0 ft/s). The total gas flow through the reactor represents a thermal load of approximately 300 kW.

The range of operating conditions for the reactor is listed below:

- Gas temperature: ~371°–426°C (700°–800°F)
- Gas flow rate: 11.3–14.2 acmm (400–500 acfm)
- Approach velocity range: 5.0–5.5 m/sec (16.4–18 ft/s)

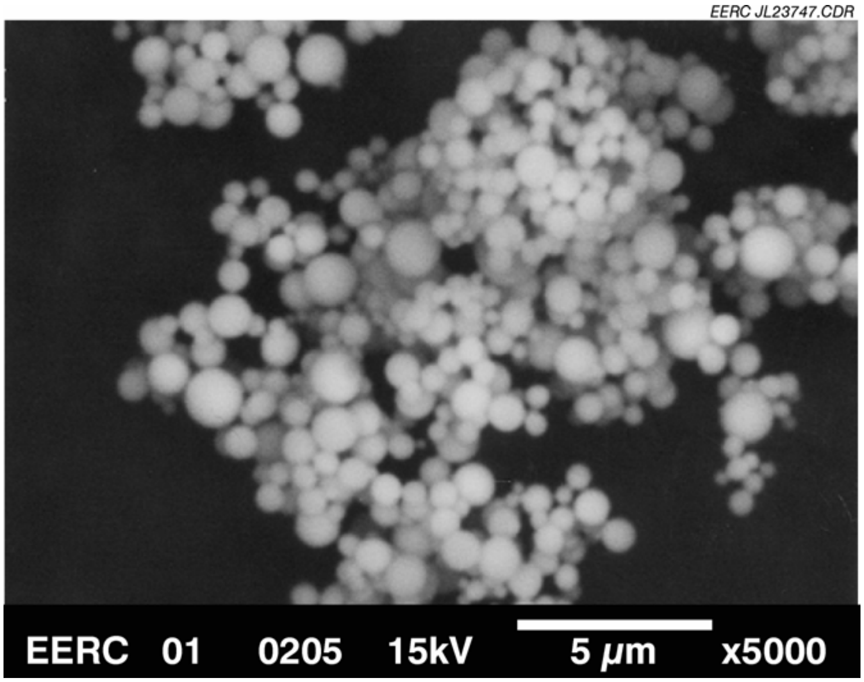


Figure 14. SEM micrograph of reaction products from Nanticoke PRB.

Table 8. SEM/Energy-Dispersive Spectroscopy (EDS) Analysis Results from Nanticoke PRB at 800°F

Element	Percent	Percent
Na	0.50	0.00
Mg	5.60	5.00
Al	9.22	11.30
Si	9.00	8.30
P	1.80	1.30
S	0.70	2.10
Cl	0.00	0.00
K	0.30	0.00
Ca	32.40	31.00
Ti	0.00	1.40
Cr	0.00	0.00
Fe	11.60	7.70
Ba	1.50	1.10
O	27.00	30.60

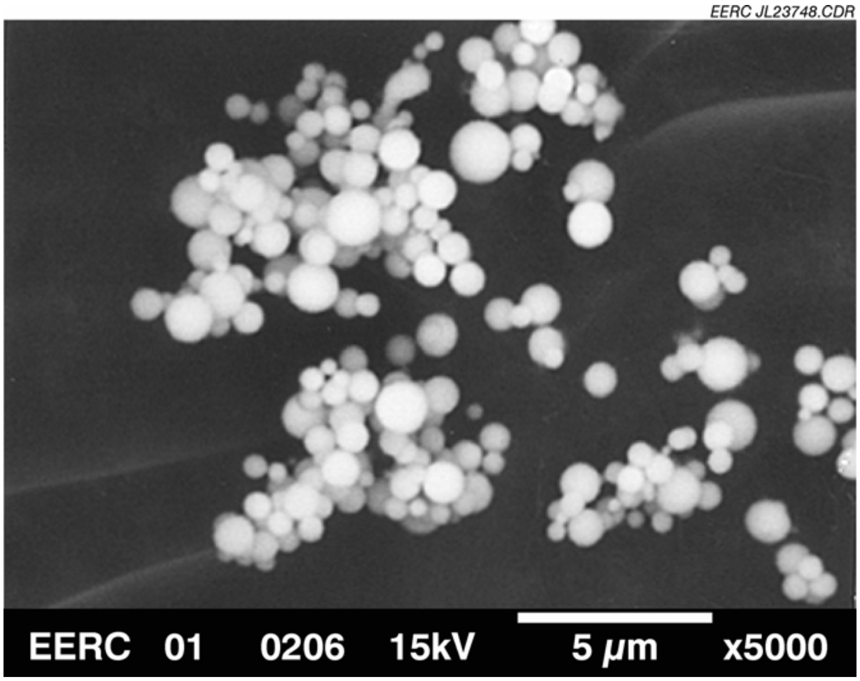


Figure 15. SEM micrograph of reaction products from Nanticoke PRB–LSUS blend.

Table 9. SEM/EDS Analysis Results from Nanticoke PRB–LSUS blend at 800°F

Element	Percent	Percent
Na	0.40	0.50
Mg	2.10	3.10
Al	15.90	12.60
Si	14.50	21.80
P	2.00	4.00
S	1.00	0.00
Cl	0.10	0.00
K	1.70	1.00
Ca	20.00	10.60
Ti	0.90	3.00
Cr	0.00	0.00
Fe	4.90	5.60
Ba	0.00	1.00
O	36.40	36.50

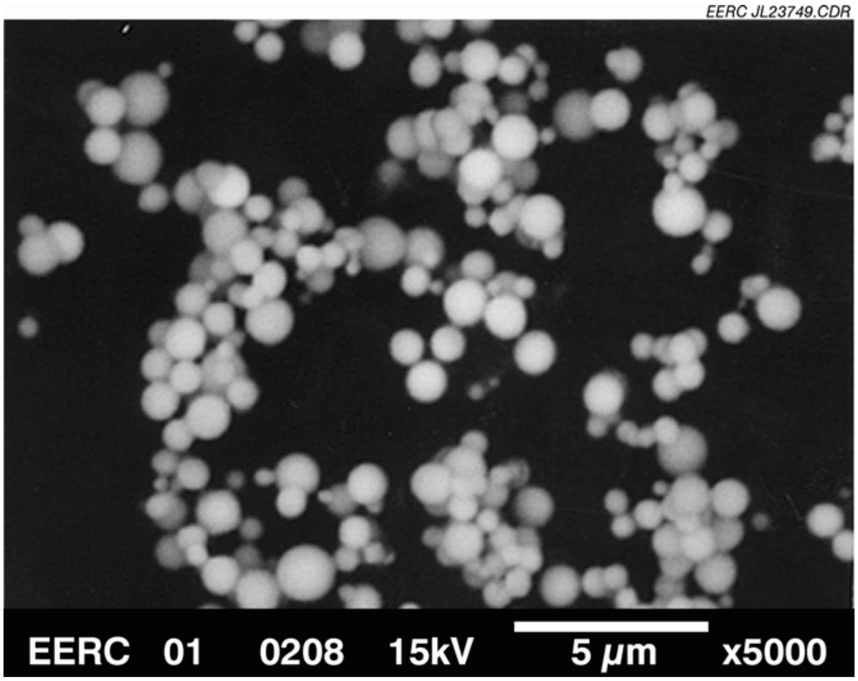


Figure 16. SEM micrograph of reaction products from Beulah lignite.

Table 10. SEM/EDS Analysis Results from Beulah Lignite at 800°F

Element	Percent	Percent
Na	1.60	1.00
Mg	4.00	5.30
Al	7.10	9.00
Si	22.70	18.10
P	0.00	0.00
S	1.60	2.80
Cl	0.00	0.00
K	1.40	0.50
Ca	17.10	25.00
Ti	0.00	1.50
Cr	0.10	0.00
Fe	5.40	4.00
Ba	5.90	4.60
O	33.00	28.00

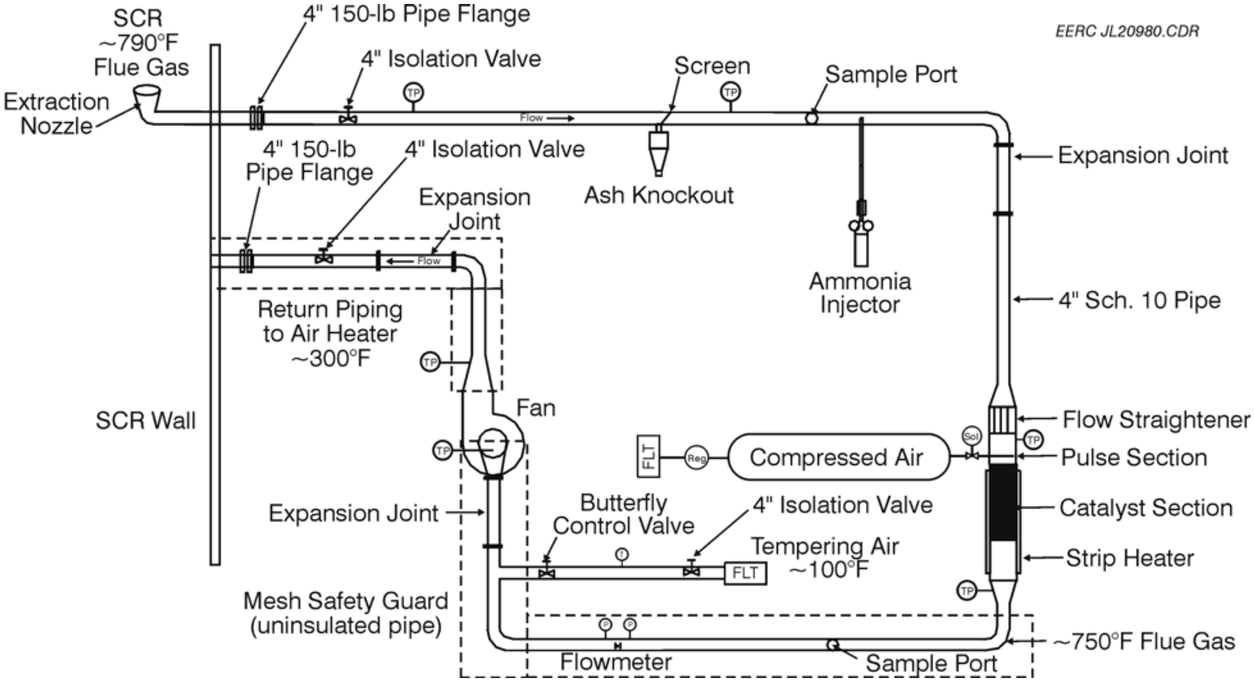


Figure 17. Conceptual schematic of the SCR reactor slipstream field test unit.

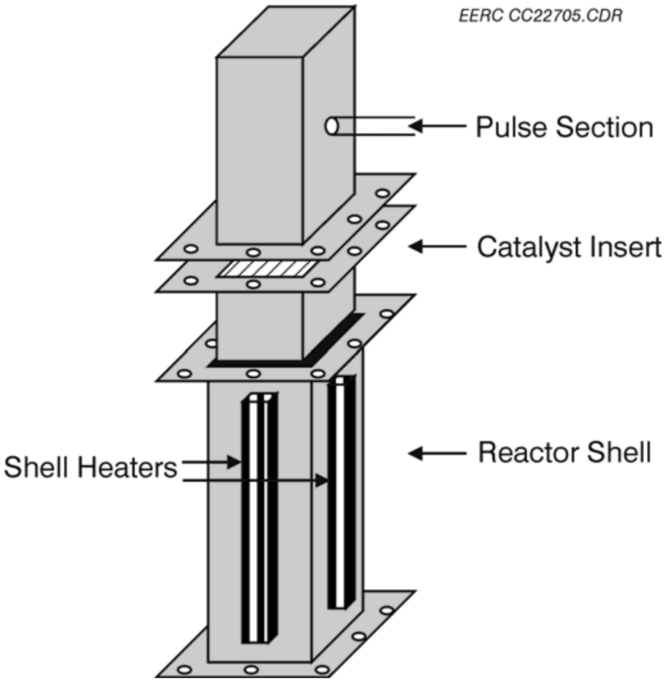


Figure 18. SCR catalyst section.

- NH_3 injection rate: 0.5:1 with NO_x level
- Tempering air for fan: ~1.4–5.7 scmm (50–200 scfm)
- Catalyst dP: 0.5–1.0 inches water column
- Fan sized for up to 30 inches water column

For catalyst inspection or replacement, the catalyst section can be unbolted and slid out from the reactor (support brackets hold the remaining reactor pieces in place). Once a catalyst reactor section is removed, the top catalyst holder can be removed, and the section(s) of interest removed by pushing it up from the bottom and out the top. A new section is then inserted from the top to replace the piece removed.

Task 4 – SCR Test Chamber Installation and Data Collection at Utility Host Sites

The catalyst installed at the Baldwin and Coyote Stations was the Haldor Topsoe catalyst. Topsoe's DNX-series of catalysts comprises SCR DENOX catalysts tailored to suit a comprehensive range of process requirements. DNX-series catalysts are based on a corrugated, fiber-reinforced TiO_2 carrier impregnated with the active components V_2O_5 and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels. The unique catalyst design provides a highly porous structure with a large surface area and an ensuing large number of active sites. Figure 19 is an image of the Haldor Topsoe SCR catalyst. The pitch of the catalyst was approximately 6 mm.

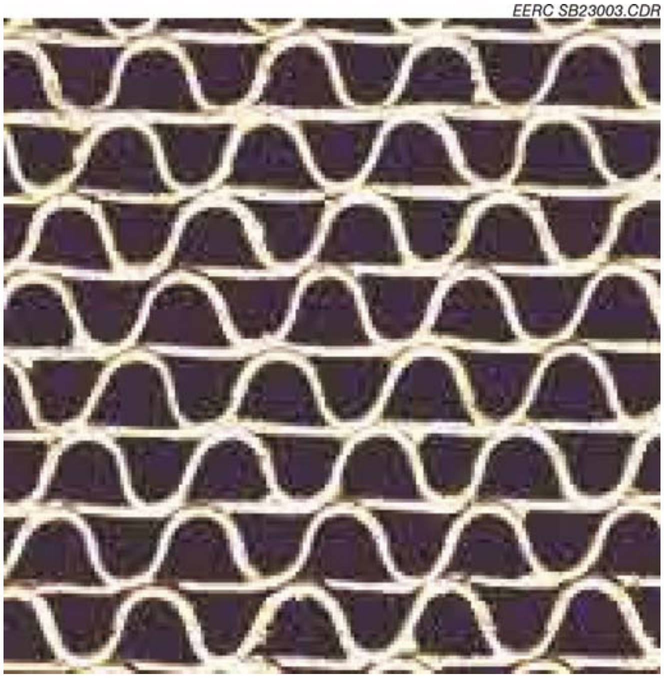


Figure 19. Haldor Topsoe SCR catalyst showing the gas flow passages.

The catalyst installed at the Columbia Station was a Babcock Hitachi plate-type catalyst. This catalyst is a TiO_2-based plate catalyst, developed and manufactured by Hitachi. Figure 20 shows the design of the catalyst. The pitch of the catalyst was approximately 10 mm.

Upon installation at each utility boiler unit, flue gas temperature, composition, and velocity measurements were obtained using portable equipment. Shakedown testing of the unit was conducted to ensure that all components were operating properly and that data were being logged and could be retrieved. After installation and shakedown were completed, the reactor was operated in a computer-controlled, automated mode and monitored on a daily basis to ensure proper operation and data quality. During operation of the SCR slipstream system, catalyst temperature, sootblowing frequency, and pressure drop across the catalyst were monitored and logged. Samples of the exposed SCR catalyst and associated deposits were obtained after exposure to flue gas and particulate for 2, 4, and 6 months. The samples of the catalyst were analyzed to determine the components that were bonding and filling pores, resulting in decreased reactivity.

The characteristics of ash that accumulated on the catalyst were examined using SEM–x-ray microanalysis and XRD (18). Correlations between the physical and chemical characteristics of any ash deposits on the SCR test section and entrained-ash sample collected at the chamber inlet and the coal inorganic composition were made to discern mechanisms of SCR blinding. Entrained ash was collected at Columbia Station only and characterized as to composition and size.


EERC SB23006.CDR

Figure 20. Babcock Hitachi SCR catalyst showing the gas flow passages.

Baldwin Station Data

The data presented in the following section represent a small portion of the operational data collected. The remainder of the data is available upon request. The reactor was installed at the Baldwin Station and operated for a 6-month time period on the Haldor Topsoe catalyst. The information obtained from testing included pressure drop, sootblowing cycles, and reactor temperatures. Table 11 summarizes the operating conditions of the reactors during the testing periods at all plants. Figures 21–23 show the pressure drop across the catalyst test periods from 0 to 2 months, 2 to 4 months, and 4 to 6 months, respectively. During the first 2 months of operation, the pressure shown in Figure 21 was about 0.5 inches of water; at the end of 2 months, the pressure drop was about 0.8 inches of water, indicating plugging had occurred. The air was pulsed a minimum of every 8 hours in an attempt to maintain cleanliness. The reactor was monitored on a daily basis, and adjustments in pulsing cycles were made in order to minimize deposit accumulation. However, for the first 2 months, the pressure drop steadily increased. During several periods when the unit was taken off-line, the temperature of the catalyst was maintained. At 2-month intervals, a section of catalyst was removed and replaced with a new one.

For Months 2 through 4, the pressure drop was highly variable initially but was about 0.8 inches of water. From Months 4 through 6, the pressure drop was maintained between 0.6 and 0.8 inches of water. This is due to the installation of a fresh catalyst section and leaving two-thirds of the catalysts in place that were partially plugged. The gas velocity in the single section of new, clean catalyst was high because of channeling, and the result of the high gas flow was less deposition and accumulation. Gas velocity has a significant impact on the potential for deposits to form. However, at high gas velocity, low NO_x conversion is likely.

Columbia Station Data

The reactor was installed at the Columbia Station and operated for a 6-month period of time for the Babcock Hitachi catalyst. The information obtained from the testing included pressure drop information, sootblowing cycles, and reactor temperature. Table 11 shows the reactor temperature, air-pulsing cycles, and airflow rates. Figures 24–26 show the test periods from 0 to 2 months, 2 to 4 months, and 4 to 6 months, respectively. The pressure drop across the SCR upon installation was about 0.4 inches of water and increased to an average of about 0.5 inches of water, but ranged from less than 0.4 to greater than 0.8 inches of water. Figure 25

Table 11. Selected Operating Conditions of the SCR Catalysts

Plant Name	Average SCR Inlet Temp., °F	Average SCR Outlet Temp., °F	Air Pulse Frequency	Flue Gas Flow Rate, acfm
Baldwin	645	549	Once a day and on demand	393
Columbia	672	662	Once a day and on demand	385
Coyote	675	667	Once a day and on demand	385

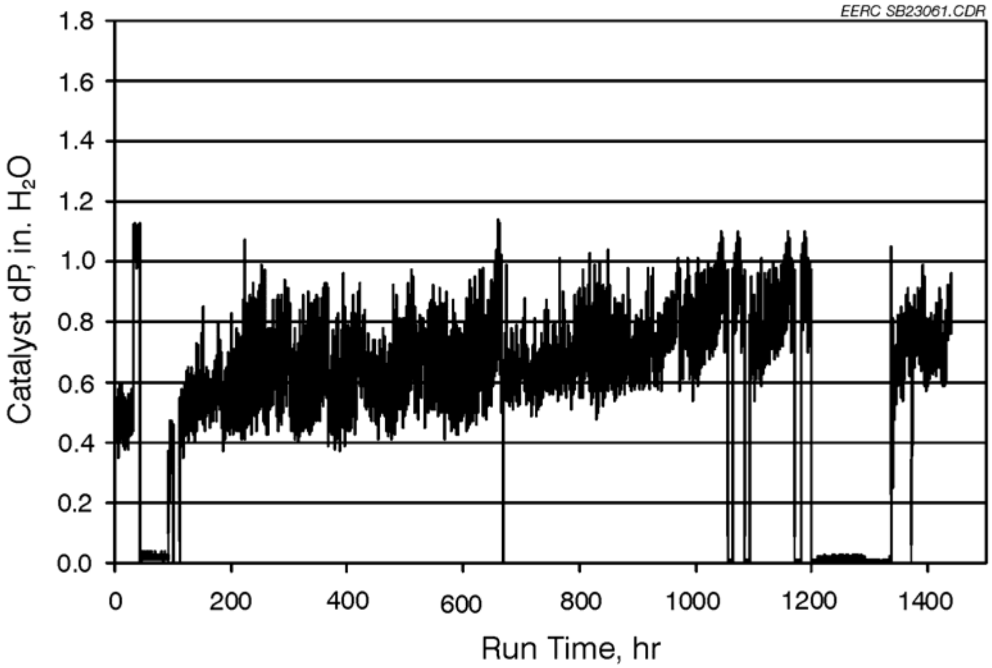


Figure 21. Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.

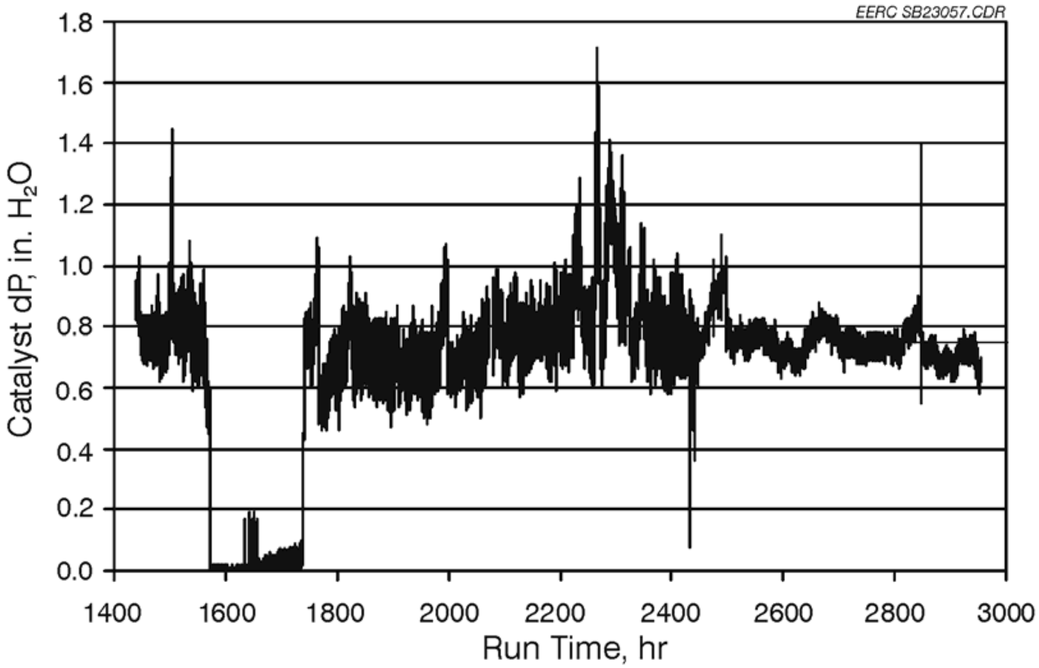


Figure 22. Catalyst pressure drop at Baldwin Station at 2 to 4 months of operation.

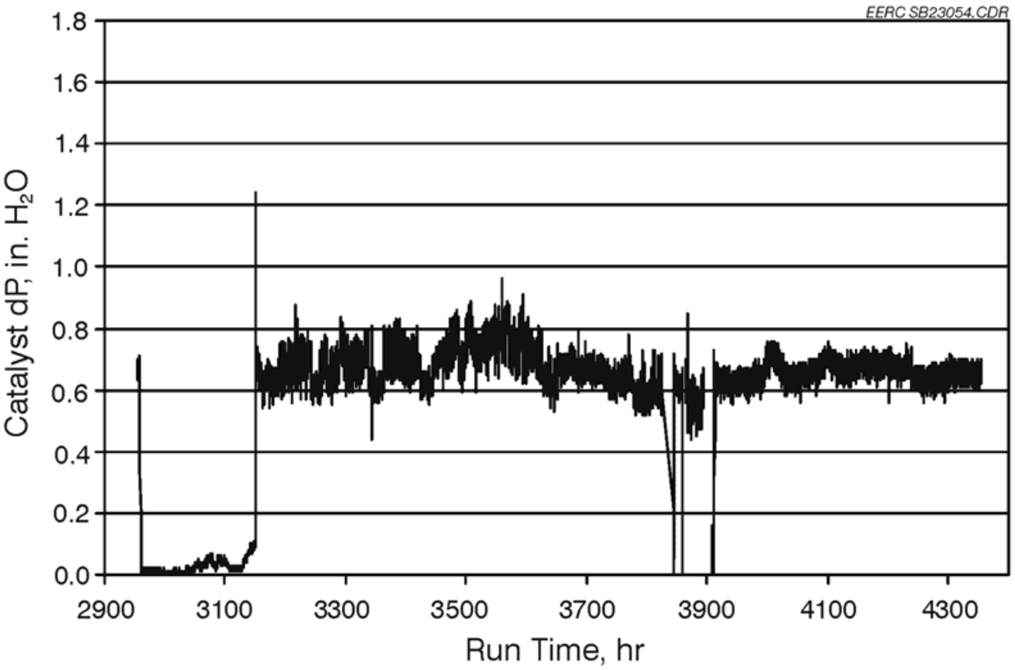


Figure 23. Catalyst pressure drop at Baldwin Station at 4 to 6 months of operation.

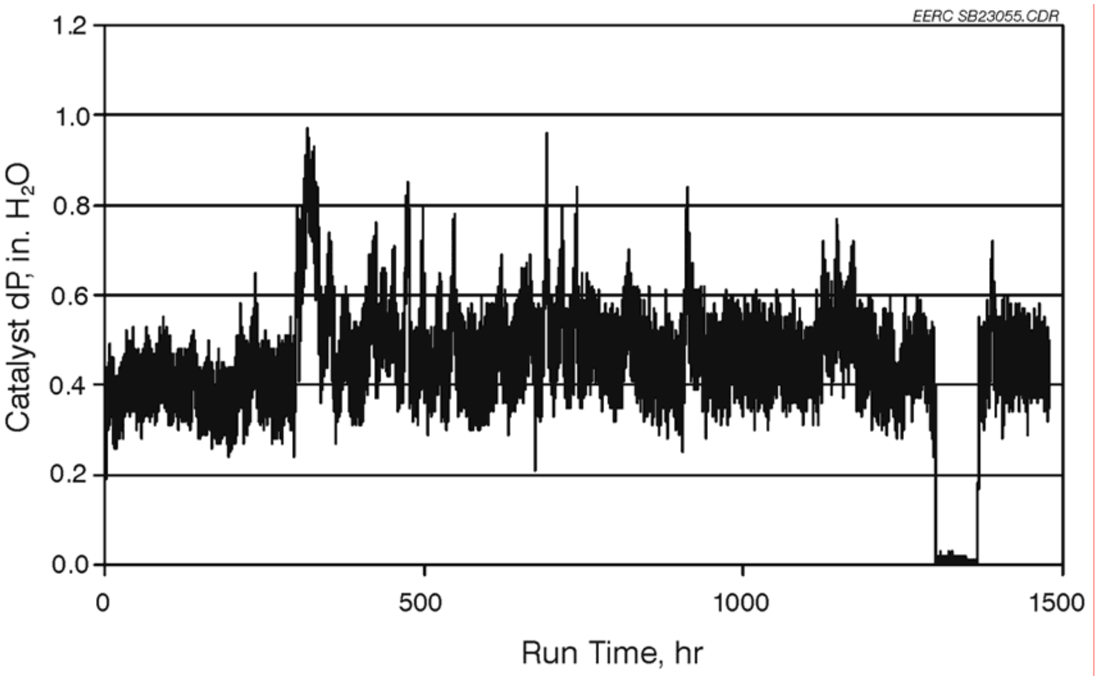


Figure 24. Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.

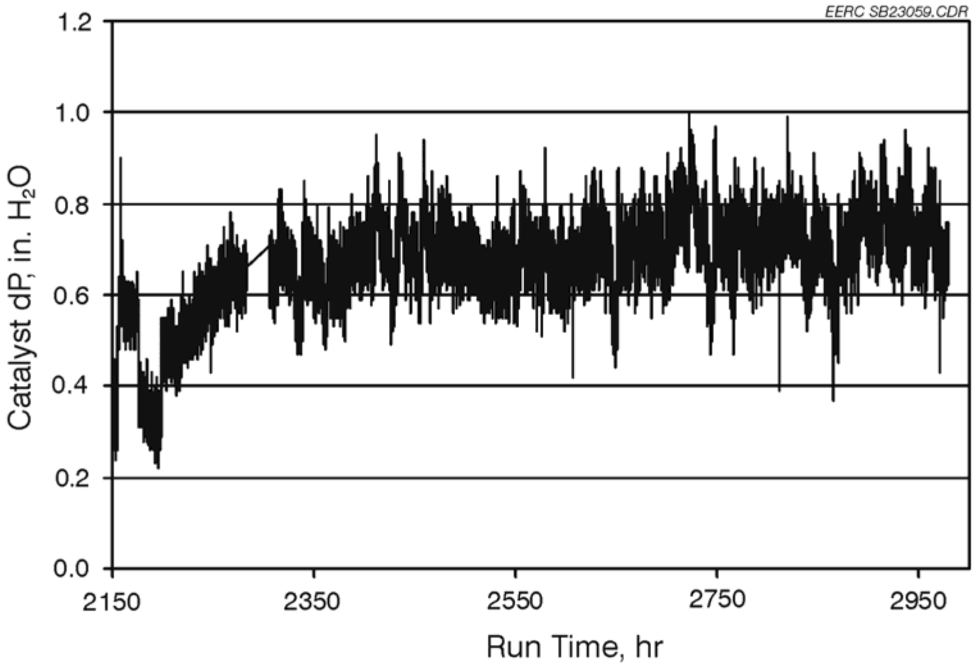


Figure 25. Catalyst pressure drop at Columbia Station at 2 to 4 months of operation.

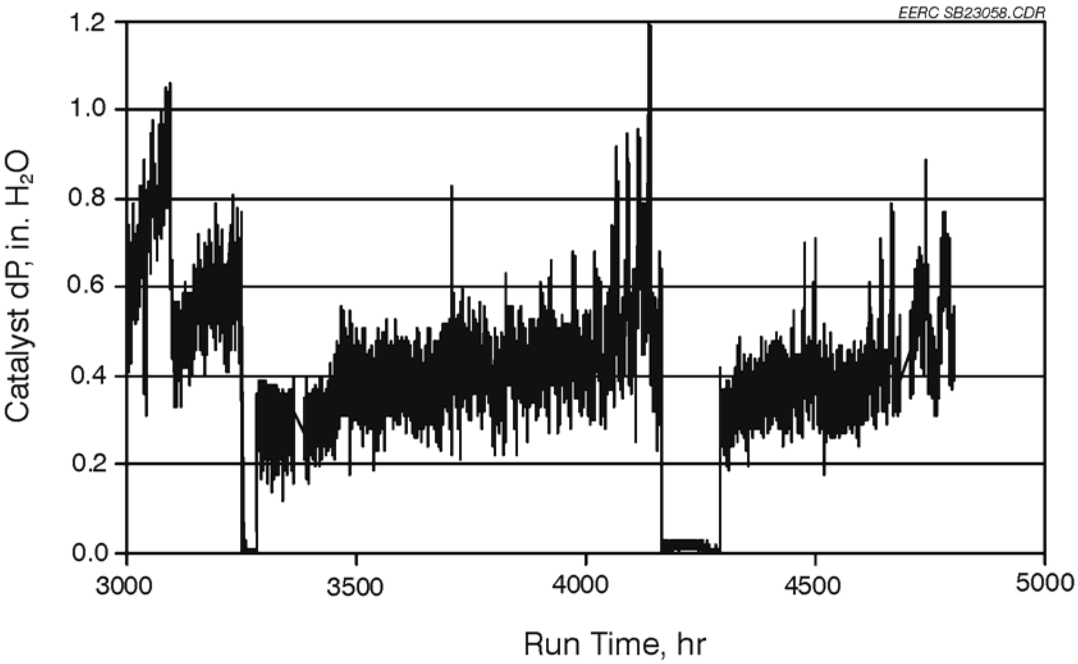


Figure 26. Catalyst pressure drop at Columbia Station at 4 to 6 months of operation.

shows the pressure drop for Months 2–4. The pressure drop increased from about 0.5–0.7 inches of water because of accumulation of ash. Figure 26 shows a rapid increase in pressure drop across the catalyst at about 3000 hours of operation, and aggressive pulsing brought it down to 0.4 inches of water until the catalyst section was changed out at about 3200 hours. After the reactor was cleaned and one catalyst section was replaced, the pressure drop was about 0.3 but increased to over 0.6 inches of water up to about 4100 hours. There was an outage at the plant, and aggressive pulsing of the reactor was conducted; the pressure drop was brought back down to 0.3 but rapidly increased to over 0.5 inches of water within 500 hours.

Coyote Station Data

The same reactor that was installed at the Baldwin Station was moved and installed at the Coyote Station. In addition, the same Haldor Topsoe catalyst formulation was used in the reactor. The cleaning cycles, temperatures, and gas flow rates are listed in Table 11. The reactor was operated for 6 months. Figures 27–29 show the test periods from 0 to 2 months, 2 to 4 months, and 4 to 6 months, respectively. The pressure drop across the catalyst upon installation was about 0.4 inches of water. After only 750 hours, the pressure drop was 1.5 inches of water, indicating significant plugging and blinding. Aggressive air pulsing was conducted, with little success in removing the deposits. The pressure drop for the catalyst was over two times greater than the pressure drop observed for the Baldwin Station utilizing the same reactor and the same catalyst. At about 1700 hours, the reactor was cleaned, and a section of catalyst was removed for characterization. The pressure drop after cleaning was 0.8–1.0 inches of water. The pressure drop did not increase as rapidly because of the higher velocities through the clean section of the catalyst. Figure 29 shows the pressure drop for 4–6 months of operation. The pressure drop

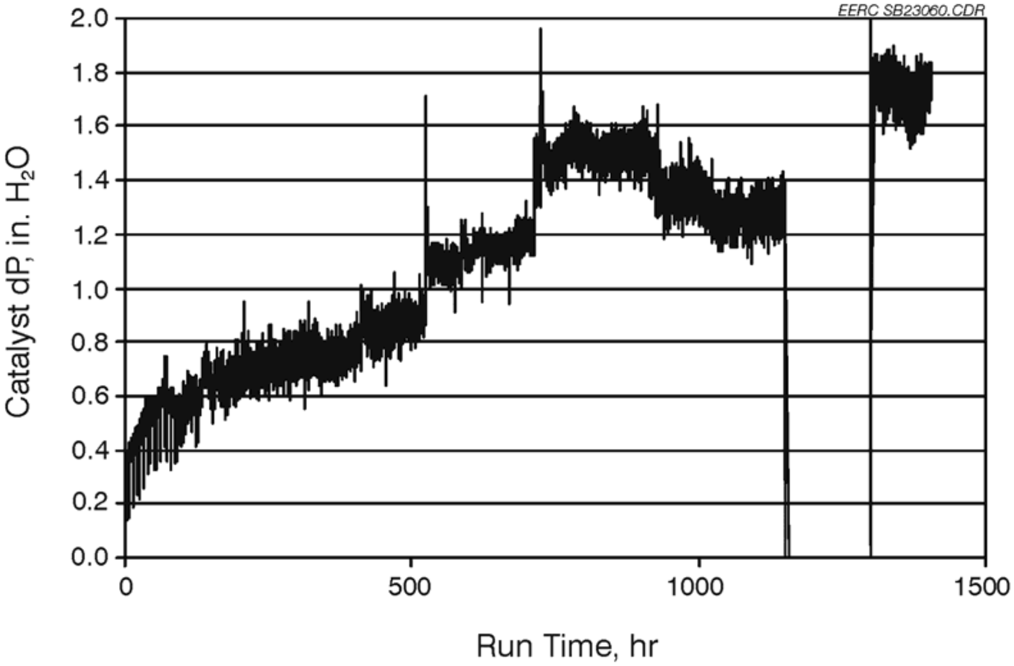


Figure 27. Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.

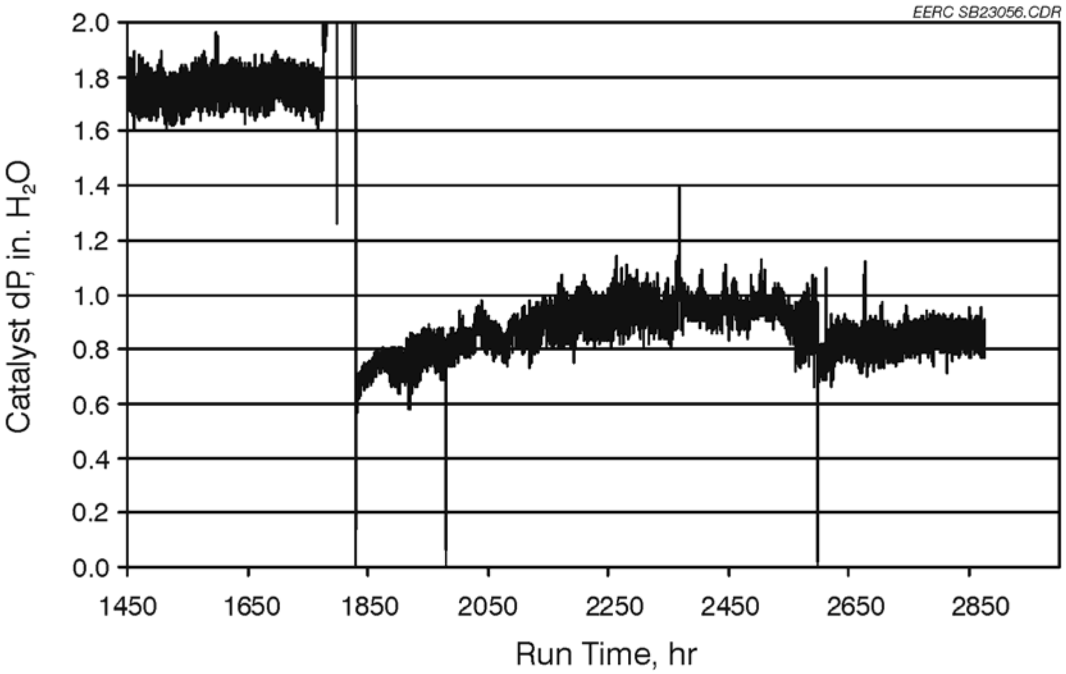


Figure 28. Catalyst pressure drop at Coyote Station at 2 to 4 months of operation.

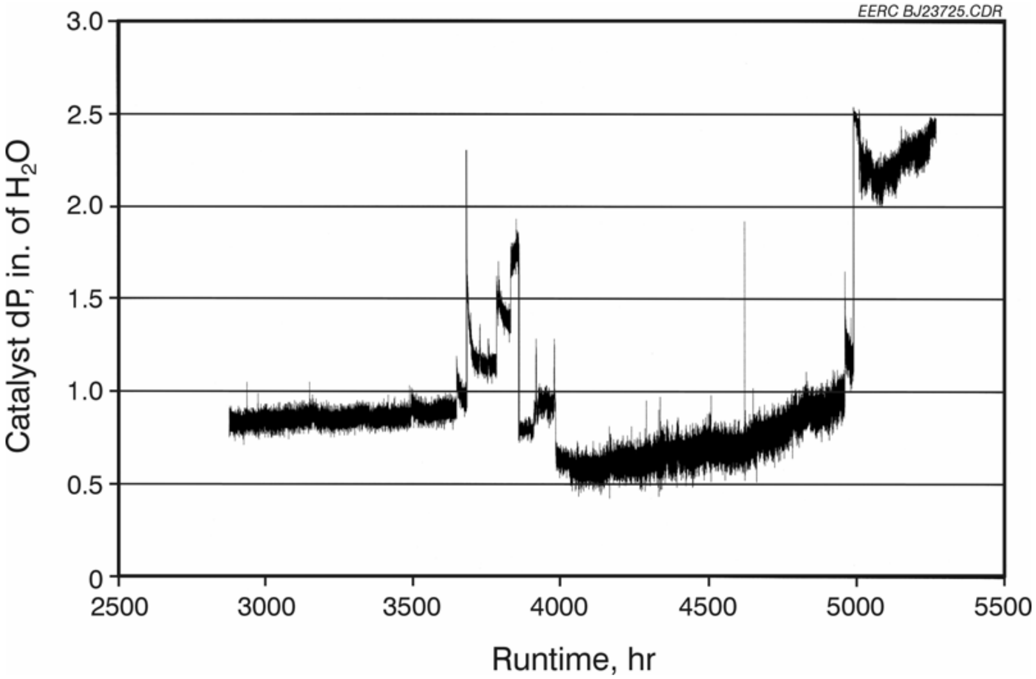


Figure 29. Catalyst pressure drop at Coyote Station at 4 to 6 months of operation.

during the last 2 months of testing was highly variable and at times reached values over 2 inches of water.

Visual Observations and Chemical Analysis

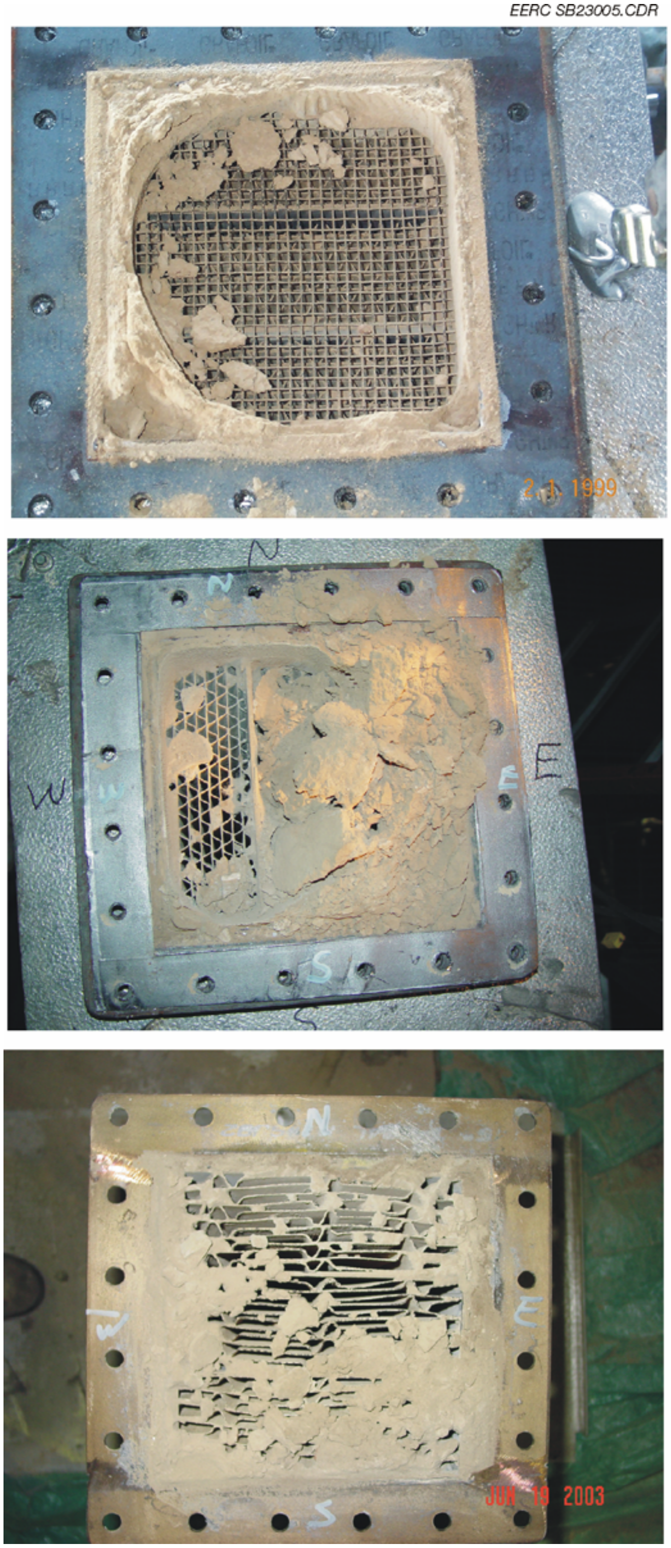
The tops of the catalysts were photographed during inspection and sampling of the catalyst sections. Figure 30 shows the ash materials that accumulated on the catalyst inlet after 2 months of operation. The most significant accumulation was noted for the Coyote Station, followed by Columbia and Baldwin. The Coyote Station had some larger pieces of ash deposit material on the surface as well as plugging of the catalyst passages. The Baldwin Station showed some obvious deposition along the walls of the reactor and some accumulation on the inlet sections. The Columbia Station showed more significant accumulation and plugging than the Baldwin Station. After 4 months, the tops of the catalysts were photographed during inspection and sampling of the catalyst sections, as shown in Figure 31. The most significant accumulation was noted for the Coyote Station and some accumulation for the Baldwin Station.

The ash materials that collected on the catalyst surfaces and pores were characterized by SEM and x-ray microanalysis, and in selected cases, XRD was used to determine the crystalline phases present. The catalysts were sampled after 2, 4, and 6 months. The sections were sampled, and approximately 2.5-cm squares were mounted for SEM analysis on double-stick tape and in epoxy resin. The double-stick tape samples allowed for characterization of the external morphology of the particles and catalyst surface. The samples mounted in resin were cross-sectioned and polished, which allowed for more detailed and quantitative analysis of the bonding materials and materials that accumulated in the pores of the catalyst. The data presented in the following section represent a small portion of the data collected by SEM analysis. The remainder of the data is available upon request.

Baldwin Station Deposits

Samples of catalyst were removed from the Baldwin Station after exposure to flue gas and particulate after 2, 4, and 6 months. Figure 32 shows the characteristics of the ash deposit material on the SCR catalyst after 2 months of exposure. This is a polished cross section of a deposit on the surface of the catalyst. Figure 32a shows particles on the surface of the catalyst that range in size from <1 to 15 µm. The larger particles range from oxides of solely silicon and iron to complex mixtures rich in aluminum and calcium; aluminum, silicon, and calcium; aluminum, calcium, and iron; and sodium, calcium, aluminum, and silicon. Chemical analysis of selected particles is summarized in Table 12. The samples of ash mounted on double-stick tape allow for the characterization of the external surfaces of the particles. The surface of a typical particle that is accumulating on the surface of the catalyst is shown in Figure 32b. The blebs on the surface are composed of calcium and sulfur, with some iron and minor amounts of sodium and potassium. Figure 32c shows a cross section of the deposited particles showing calcium- and aluminum-rich particles bonded together with a calcium- and sulfur-rich phase. This phase is in the form of calcium sulfate based on XRD analysis conducted on the deposited ash samples.

The 4-month sample from the Baldwin Station showed more extensive sulfation of the alkaline-earth elements present in the deposits. Figure 33 shows the images of a polished cross



Baldwin Station after 2 months
PRB Coal

Coyote Station after 2 months
Lignite Coal

Columbia Station after 2 months
PRB Coal

Figure 30. Pictures of catalyst inlet after about 2 months of testing at each plant.

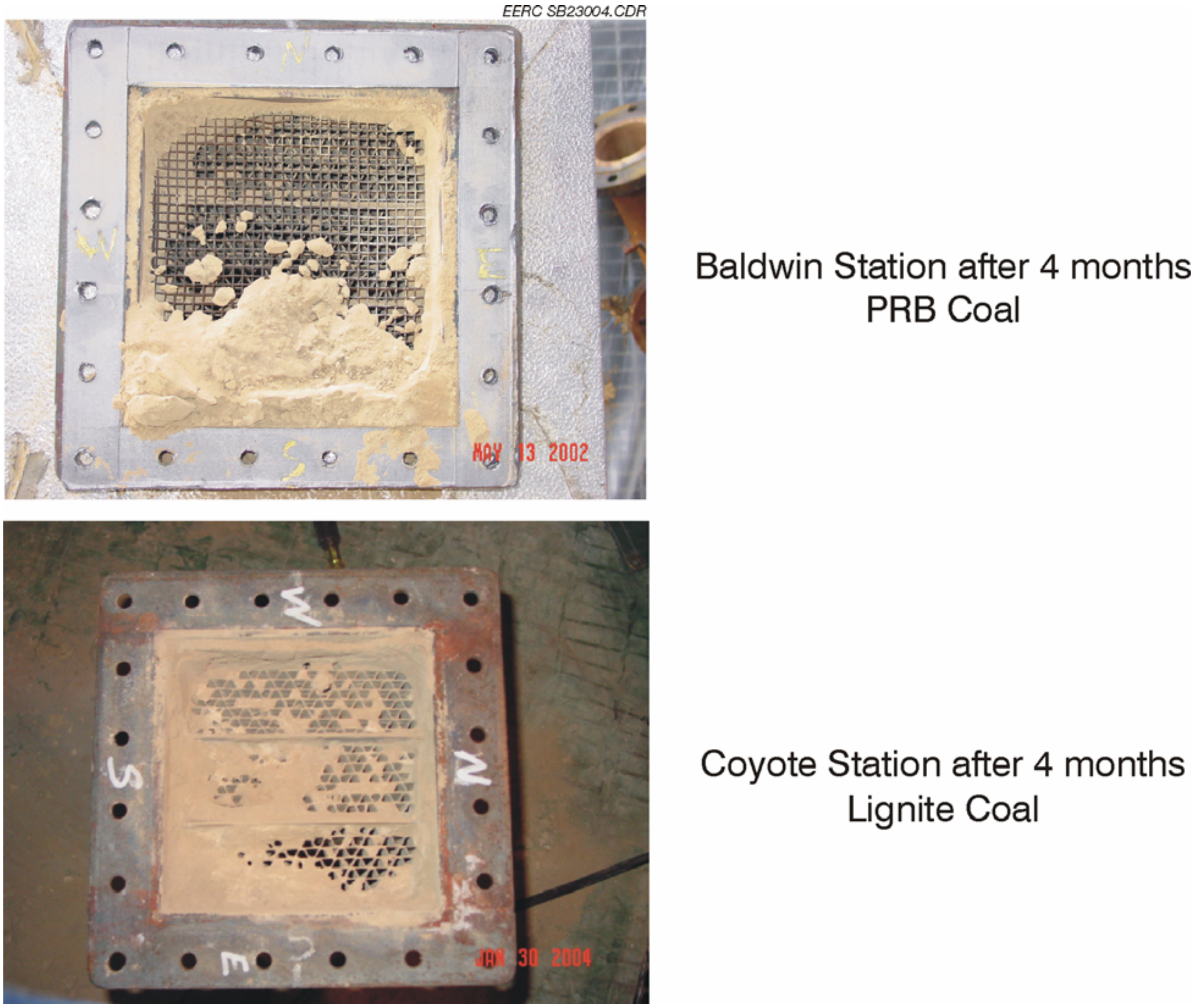


Figure 31. Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.

section of an ash deposit on the surface of the catalyst. The deposit formed both on the surface of the catalyst and within the catalyst pores, as shown in Figure 33a. Figure 33b shows a higher-magnification view of the deposit on the catalyst surface. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical composition of selected points shown in Table 13 shows high levels of calcium and sulfur. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample.

The 6-month sample from the Baldwin Station showed extensive sulfation of the alkaline-earth elements present in the deposits. Figures 34a and 34b show regions of the catalyst where all the pores were blocked and a minimal amount of deposit on the surface of the catalyst. Figure 34c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical compositions of selected points that

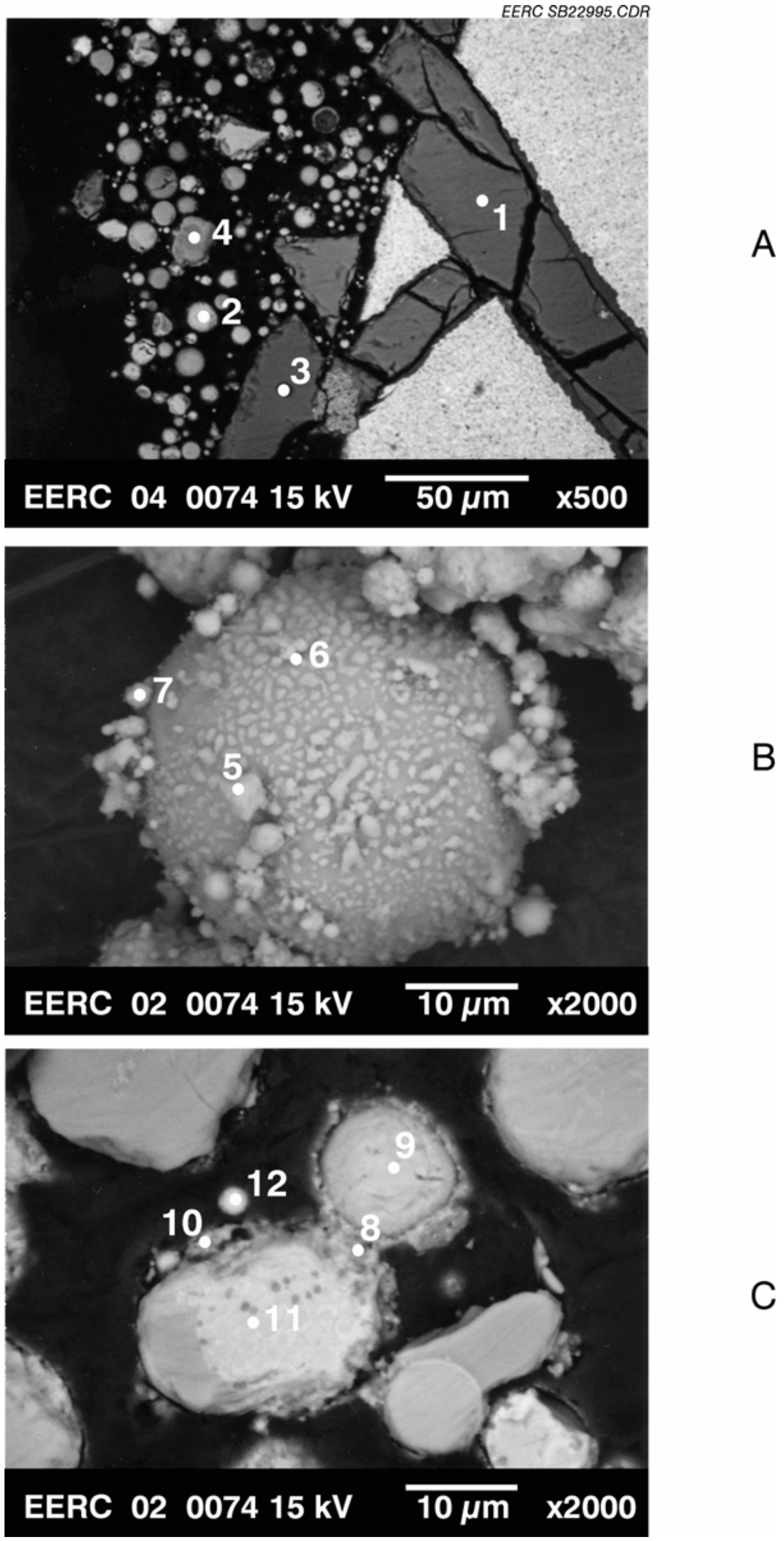


Figure 32. SEM images of ash collected on catalyst surface at the Baldwin Station after 2 months of exposure: A) low-magnification image of ash deposit on catalyst surface, B) high-magnification image of coated ash particle, and C) high-magnification image of polished cross section showing coatings on particles.

Table 12. Chemical Composition of Selected Points and Areas in Figure 32

	Element, wt%					
	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6
Oxide						
Na_2O	0.2	0.0	0.2	2.3	2.5	3.0
MgO	0.0	6.3	0.0	3.1	3.0	1.3
Al_2O_3	3.6	17.9	6.9	29.6	8.4	5.5
SiO_2	92.1	5.9	86.5	39.9	3.4	53.2
P_2O_5	0.1	0.4	0.0	0.0	1.8	0.0
SO_3	3.3	0.4	5.2	0.1	51.8	18.1
K_2O	0.0	0.0	0.0	0.6	0.4	0.5
CaO	0.0	49.4	0.1	18.6	16.4	14.6
TiO_2	0.7	4.5	0.4	1.0	0.0	0.0
Fe_2O_3	0.0	14.6	0.7	3.6	12.3	3.8
BaO	0.0	0.6	0.0	1.1	0.0	0.0
Total	100	100	100	100	100	100
	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
Oxide						
Na_2O	3.6	0.7	0.6	1.6	0.4	0.9
MgO	1.6	2.5	4.5	3.0	3.6	3.5
Al_2O_3	4.4	5.4	22.7	12.2	21.2	14.2
SiO_2	15.7	3.4	16.1	1.0	8.1	2.3
P_2O_5	1.5	0.3	0.5	2.3	0.0	4.6
SO_3	52.4	53.0	0.0	46.4	0.0	19.7
K_2O	0.7	0.2	0.0	0.1	0.0	0.0
CaO	13.0	28.8	41.5	27.1	51.1	39.2
TiO_2	0.0	0.0	0.0	0.0	0.0	0.0
Fe_2O_3	7.1	5.7	14.2	6.5	15.6	15.6
BaO	0.0	0.0	0.0	0.0	0.0	0.0
Total	100	100	100	100	100	100

indicate the presence of high levels of calcium and sulfur are listed in Table 14. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample. In addition, there are some regions of high levels of calcium, aluminum, and sulfur present. The calcium aluminum materials are likely derived from the calcium aluminum phosphate minerals found in the coal fired at this plant.

Columbia Station Deposits

The 2-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst, as shown in Figure 35. Figure 35a shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in Table 15. The 2-month sample shows significant evidence of sulfation after only 2 months of exposure. It appears to be more

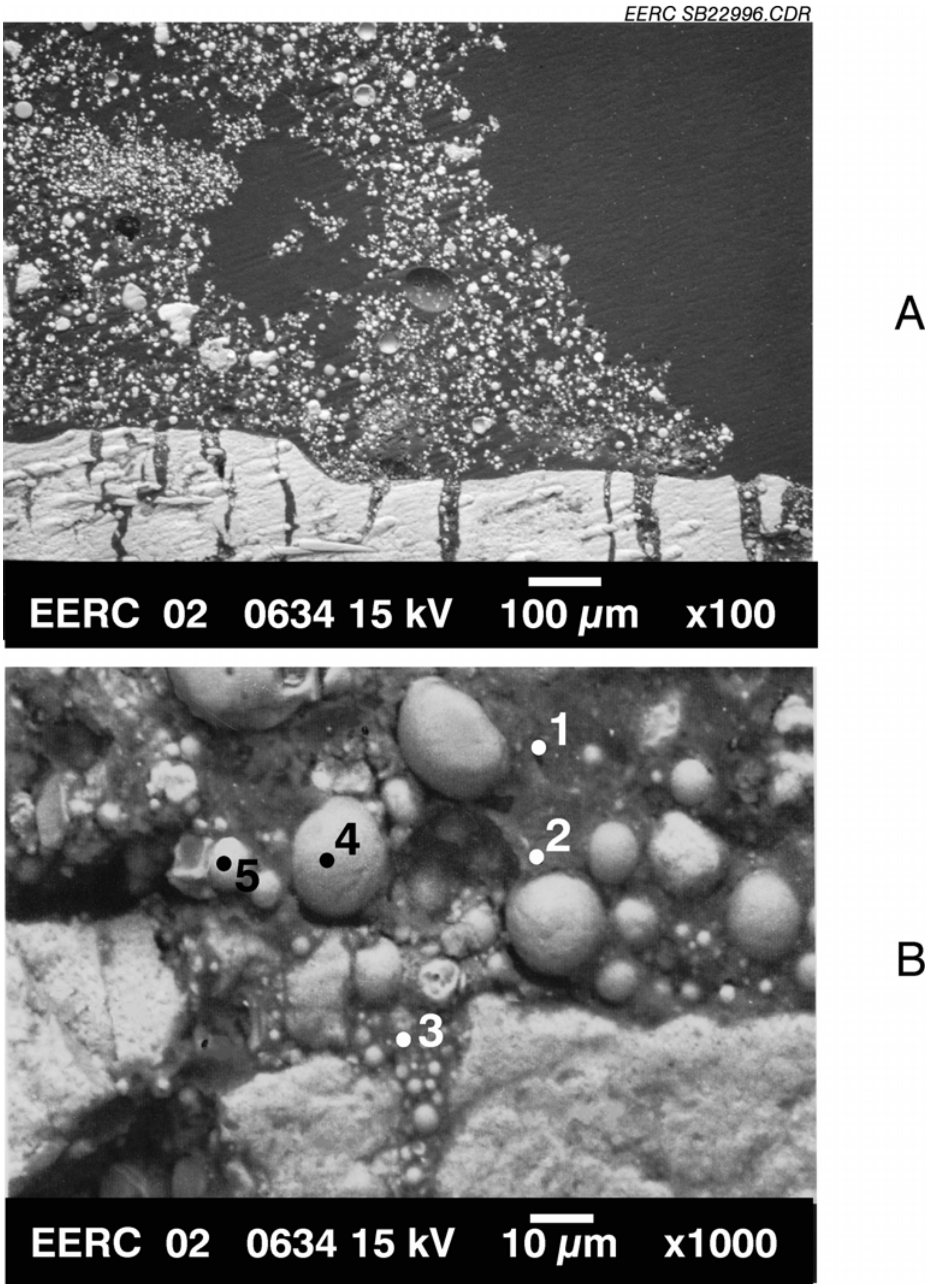


Figure 33. SEM images of ash collected on catalyst surface at the Baldwin Station after 4 months of exposure: A) low-magnification image of ash deposit on catalyst surface and B) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

Table 13. Chemical Composition of Selected Points and Areas in Figure 33

	Element, wt%				
	Point 1	Point 2	Point 3	Point 4	Point 5
Oxide					
Na_2O	1.7	2.3	0.0	0.3	1.0
MgO	5.9	3.0	1.2	1.8	3.8
Al_2O_3	3.7	2.5	3.3	5.7	6.3
SiO_2	9.7	31.5	13.3	70.0	18.5
P_2O_5	3.1	2.7	0.8	0.0	2.6
SO_3	48.1	31.0	35.8	0.0	32.1
K_2O	0.5	0.7	0.0	1.5	0.0
CaO	22.0	8.8	38.0	13.9	14.7
TiO_2	1.8	10.8	4.1	1.6	15.1
Fe_2O_3	2.1	6.6	3.4	4.2	5.9
BaO	1.4	0.0	0.0	0.9	0.0
Total	100	100	100	100	100

significant than that observed for the Baldwin 2-month sample. Figures 35b and 35c show a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate.

The 4-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst, as shown in Figure 36. Figure 36a shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in Table 16. It appears to be more significant than that observed for the Baldwin 2-month sample. Figures 36b and 36c show a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate.

The 6-month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst, as shown in Figure 37. Figure 37a shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in Table 17. Figures 37b and 37c show a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The 6-month samples show the most extensive degree of sulfation of the Columbia Station samples.

Coyote Station Deposits

The 2-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst, as shown in Figure 38. Figure 38a shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical

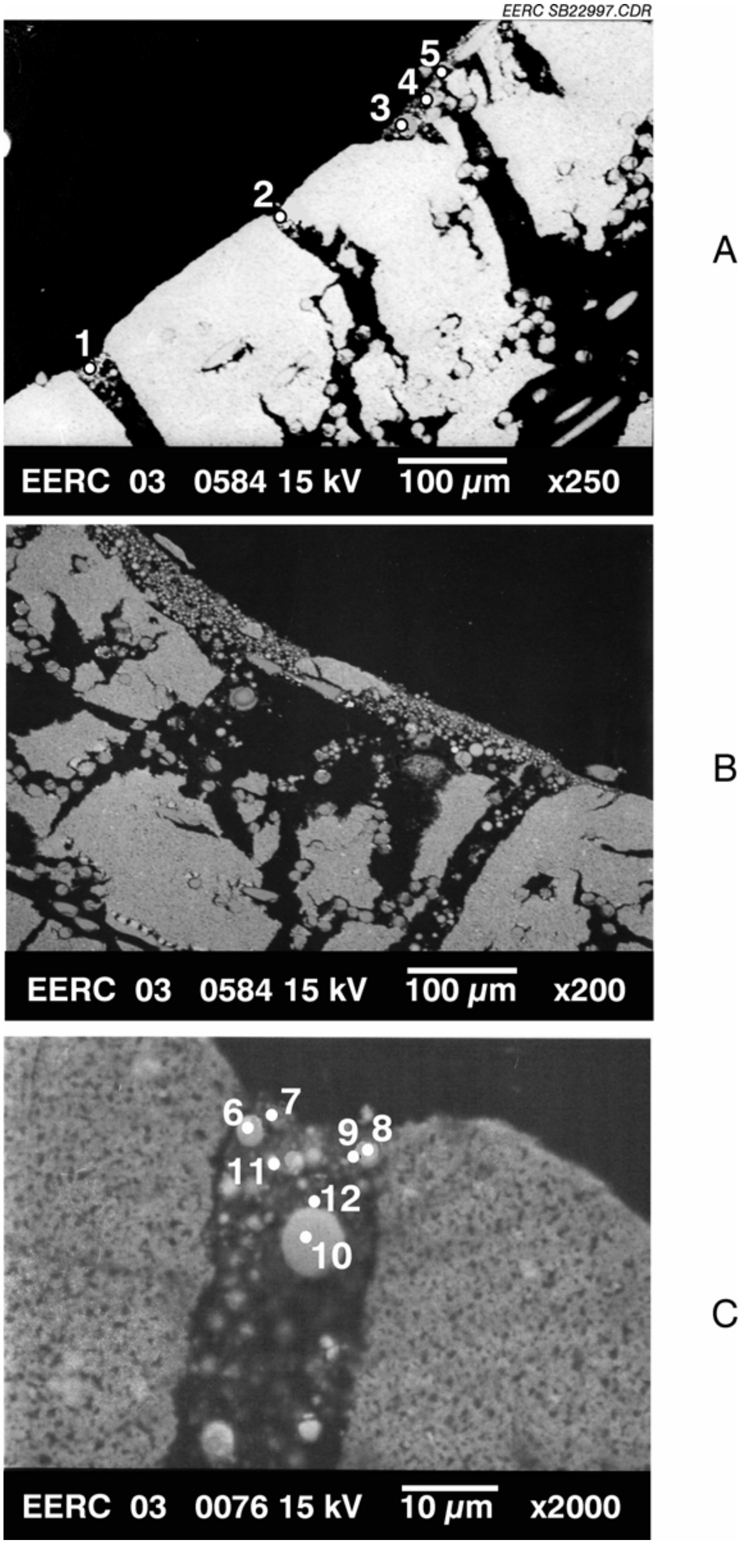


Figure 34. SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure: A) low-magnification image of ash deposit on catalyst surface, and C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

Table 14. Chemical Composition of Selected Points and Areas in Figure 34

	Element, wt%					
	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6
Oxide						
Na_2O	0.6	1.0	2.1	0.3	0.5	2.7
MgO	4.3	2.5	6.3	0.7	1.6	7.6
Al_2O_3	14.8	16.0	15.6	15.5	14.7	0.9
SiO_2	3.3	7.8	18.8	57.7	7.7	47.3
P_2O_5	2.3	2.1	0.5	0.6	1.8	0.0
SO_3	30.7	20.4	17.7	0.0	29.0	0.8
K_2O	0.7	0.0	1.0	0.4	0.9	0.9
CaO	28.8	28.7	28.1	22.5	34.9	28.4
TiO_2	2.0	7.2	2.2	0.3	1.3	1.1
Fe_2O_3	11.4	12.9	6.2	0.0	7.6	7.9
BaO	1.1	1.4	1.4	2.0	0.0	2.5
Total	100	100	100	100	100	100
	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
Oxide						
Na_2O	1.7	0.4	0.5	2.2	1.3	1.7
MgO	4.5	6.4	5.9	5.0	3.4	6.4
Al_2O_3	5.0	2.4	3.0	19.2	10.8	3.8
SiO_2	8.4	18.4	18.5	31.0	17.9	16.7
P_2O_5	1.8	0.9	1.0	0.0	1.7	1.2
SO_3	37.9	1.7	5.3	0.0	22.5	13.9
K_2O	0.4	0.0	0.0	0.9	0.8	0.0
CaO	31.4	52.6	49.0	28.9	30.6	45.4
TiO_2	1.9	6.9	7.4	2.4	2.0	1.1
Fe_2O_3	7.1	5.7	6.0	6.3	6.1	6.5
BaO	0.0	4.6	3.5	4.2	2.9	3.3
Total	100	100	100	100	100	100

compositions of selected points are shown in Table 18. The 2-month sample shows significant evidence of sulfation after only 2 months of exposure and was much more pronounced than the 2-month samples for the Baldwin and Columbia Stations that are fired on PRB coals. Figures 38b and 38c show a higher-magnification view of the deposit that is filling the catalyst pores. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The presence of sodium enhances the bonding and sulfation of the particles to form a strongly bonded matrix.

The 4-month sample from the Coyote Station showed particles adhering to the surface and completely filling and masking the pores in the catalyst as shown in Figure 39. Figure 39a shows the external morphology of the catalyst surface showing the masking of the catalyst surface. Chemical compositions of selected points are shown in Table 19. The 4-month sample shows more sulfation than the 2 months of exposure samples. Figures 39b and 39c show a higher-magnification view of the deposit that is filling the catalyst pores. The deposit consists of

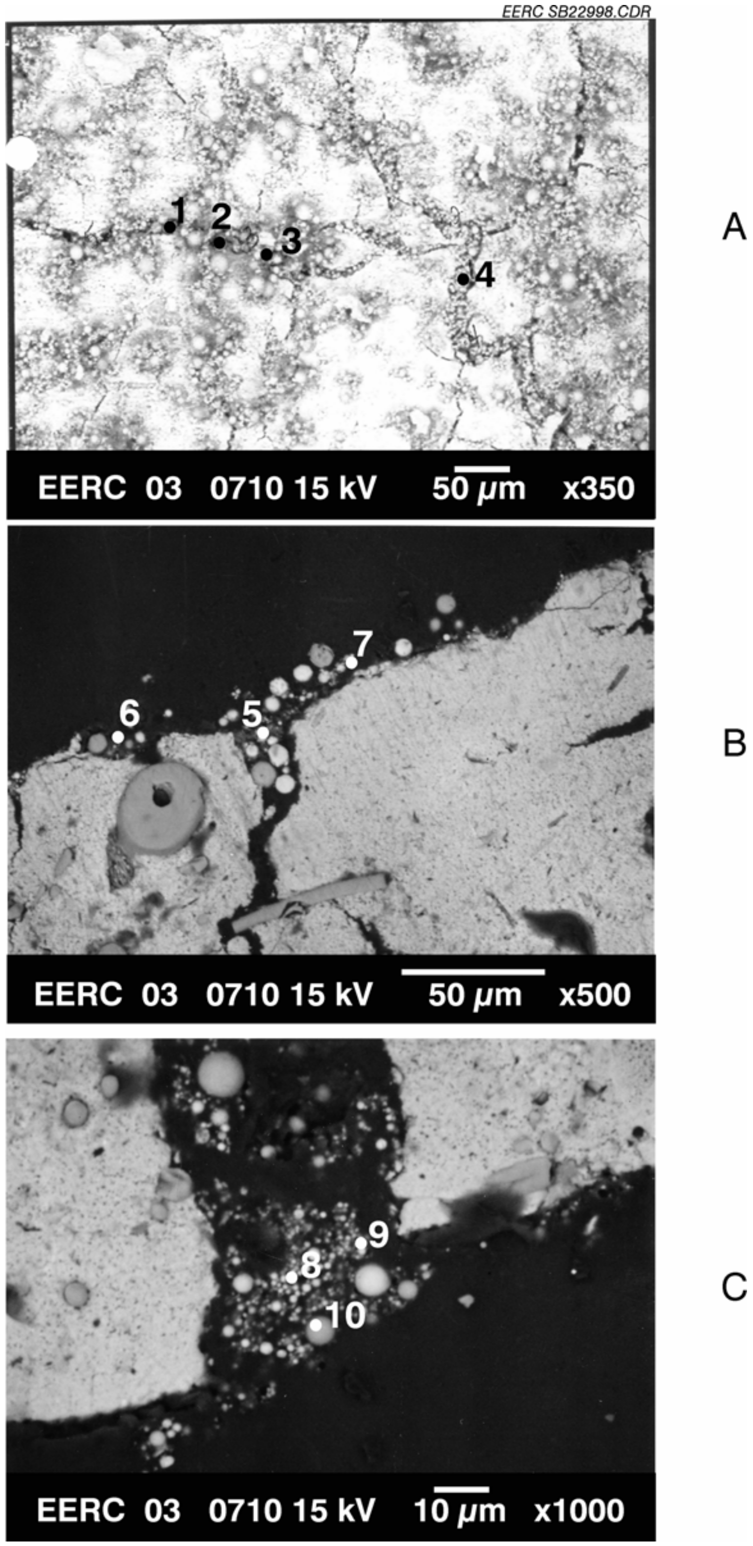


Figure 35. SEM images of ash collected on catalyst surface at the Columbia Station after 2 months of exposure: A) low-magnification image of ash deposit on catalyst surface, B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

Table 15. Chemical Composition of Selected Points and Areas in Figure 35

	Element, wt%				
	Point 1	Point 2	Point 3	Point 4	Point 5
Oxide					
Na_2O	0.0	0.9	1.3	0.1	0.3
MgO	0.7	1.5	3.2	3.9	0.9
Al_2O_3	12.2	17.6	20.9	12.2	5.9
SiO_2	10.8	4.1	23.3	7.3	6.3
P_2O_5	0.9	0.1	0.0	1.4	2.6
SO_3	15.2	17.6	16.8	17.1	32.3
K_2O	0.2	0.0	0.5	0.0	0.1
CaO	14.1	43.1	25.0	42.0	34.9
TiO_2	44.8	2.8	1.1	10.5	5.2
Fe_2O_3	1.1	12.3	3.9	5.5	11.5
BaO	0.0	0.0	4.2	0.0	0.0
Total	100	100	100	100	100
	Point 6	Point 7	Point 8	Point 9	Point 10
Oxide					
Na_2O	0.0	0.6	1.0	0.5	1.8
MgO	0.0	1.5	2.9	1.4	0.7
Al_2O_3	5.5	12.4	13.6	9.0	20.7
SiO_2	9.4	6.1	15.4	7.9	61.8
P_2O_5	1.2	0.6	1.7	3.1	0.2
SO_3	33.3	22.0	19.5	30.7	0.0
K_2O	0.0	0.0	0.1	0.2	2.5
CaO	44.1	48.5	34.1	38.3	4.4
TiO_2	0.5	4.4	2.4	2.6	2.2
Fe_2O_3	3.1	2.3	6.0	6.3	4.4
BaO	2.8	1.6	3.3	0.0	1.3
Total	100	100	100	100	100

particles of fly ash bonded together by a matrix of sodium-, calcium-, and sulfur-rich material, likely in the form of calcium sulfate. The presence of sodium and potassium enhances the bonding and sulfation of the particles to form a strongly bonded matrix. Significant sodium was found in the deposits, as shown in Table 19.

The 6-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst, as shown in Figure 40. Figure 40a shows the external morphology of the catalyst surface showing particles trapped in the pores of the catalysts. Chemical compositions of selected points are shown in Table 20. Figures 40b and 40c show a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of sodium-, calcium- and sulfur-rich material, likely in the form of sulfate. The 6-month samples show the most extensive degree of sulfation of the Coyote Station samples.

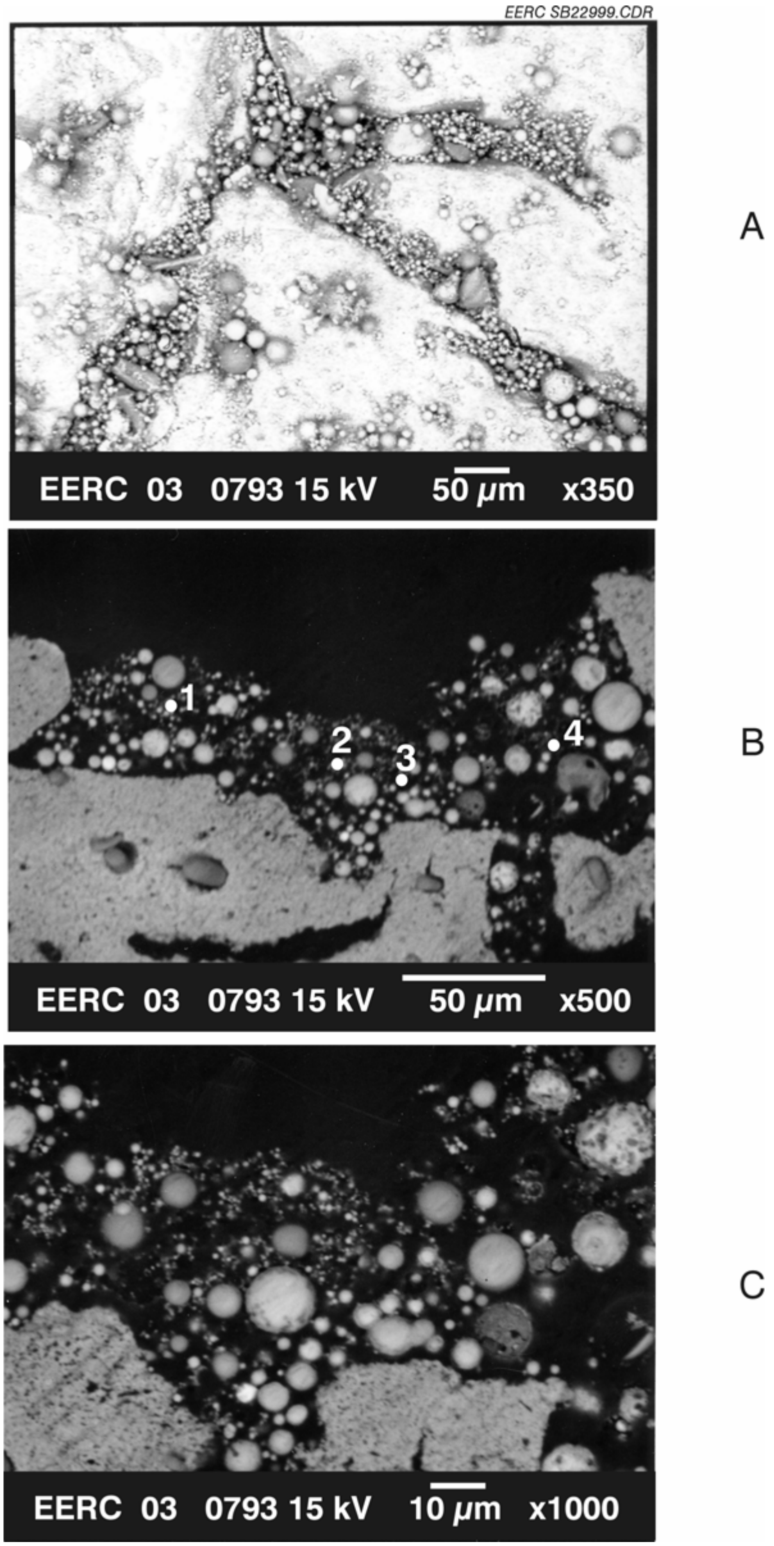


Figure 36. SEM images of ash collected on catalyst surface at the Columbia Station after 4 months of exposure: A) low-magnification image of ash deposit on catalyst surface, B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

Table 16. Chemical Composition of Selected Points and Areas in Figure 36

	Element, wt%			
	Point 1	Point 2	Point 3	Point 4
Oxide				
Na_2O	0.5	0.0	0.6	0.3
MgO	3.3	1.9	3.2	2.4
Al_2O_3	13.1	10.2	13.0	6.3
SiO_2	12.4	8.4	8.4	3.6
P_2O_5	1.3	0.5	2.1	0.6
SO_3	27.7	29.9	32.2	47.4
K_2O	0.2	0.6	0.1	0.8
CaO	32.1	38.1	28.9	33.2
TiO_2	1.0	2.7	1.3	0.0
Fe_2O_3	6.3	6.3	7.6	2.6
BaO	2.0	1.4	2.5	2.6
Total	100	100	100	100

Reactivity Testing

Samples of the catalyst from 2, 4, and 6 months of operations were submitted to the appropriate catalyst vendor for reactivity testing. The results of only the samples from the Baldwin installation are available at the time of this report. An addendum to this report will be sent when the results from Coyote and Columbia are made available to the EERC.

Table 21 contains the results of the reactivity analysis on the 2-, 4-, and 6-month samples from the Baldwin Station. After 2 months of operation, the catalyst had no noticeable loss of reactivity when compared to the reference catalyst. After 4 months, the reactivity was 96% of the reference, and after 6 months, the reactivity had dropped to 84% of the reference catalyst.

Task 5 – Determination of SCR Blinding Mechanisms

The mechanism for the formation of deposits that blind SCR catalysts involves the transport of very small particles rich in alkali and alkaline-earth elements, the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. The formation of SO_3 from SO_2 is catalyzed by the SCR; this, in turn, increases the reaction rate of SO_3 to form sulfates. In some cases, the alkali and alkaline-earth elements will also react with CO_2 to form carbonates. XRD analysis shown in Figure 41 identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements, including sodium, magnesium, calcium, and potassium, in addition to mineral phases. The primary minerals present in these coals include quartz, clay minerals, carbonates, sulfates, sulfides, and phosphorus-containing minerals (18).

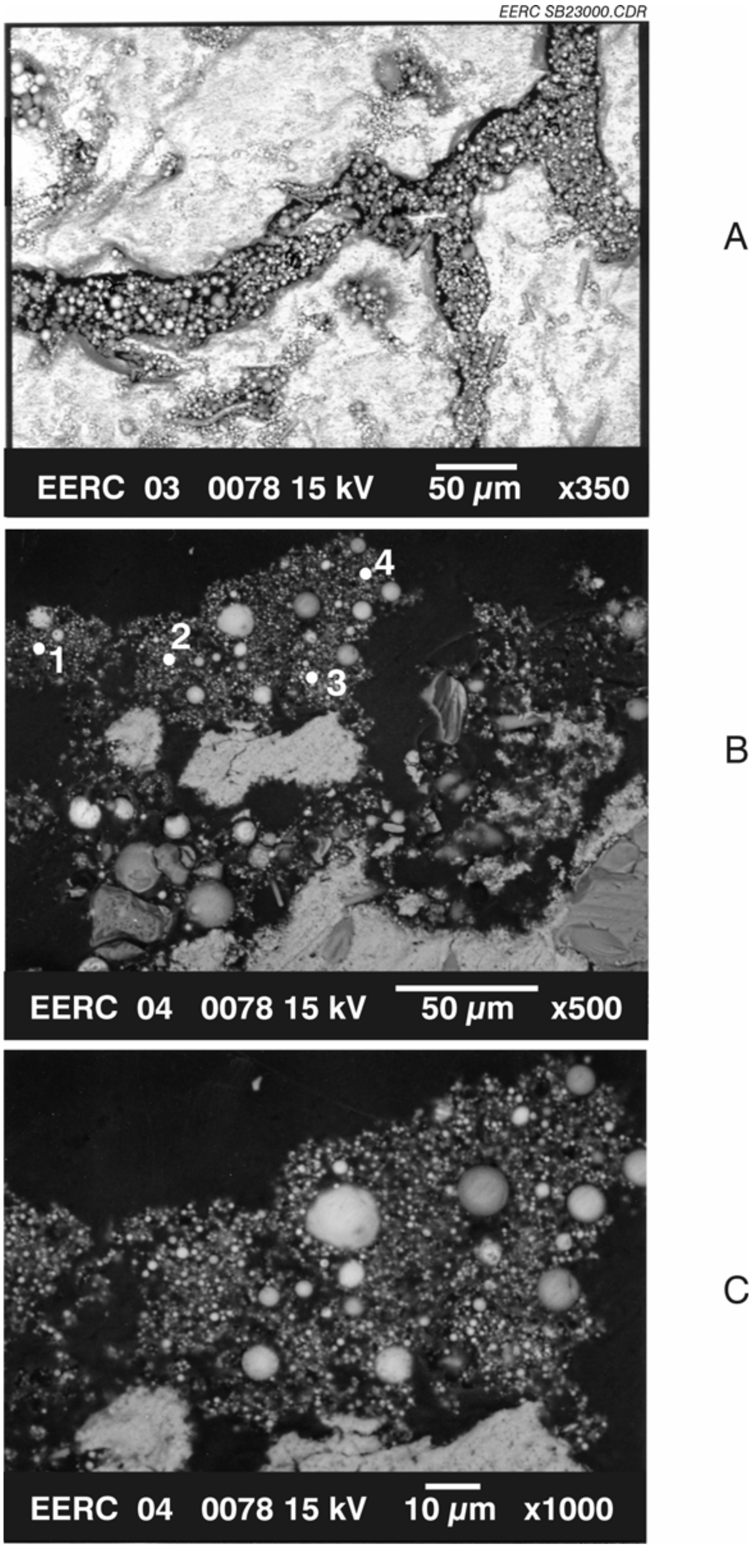


Figure 37. SEM images of ash collected on catalyst surface at the Columbia Station after 6 months of exposure: A) low-magnification image of ash deposit on catalyst surface, B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

Table 17. Chemical Composition of Selected Points and Areas in Figure 37

	Element, wt%			
	Point 1	Point 2	Point 3	Point 4
Oxide				
Na_2O	0.1	0.0	0.3	0.6
MgO	1.8	0.7	1.7	2.2
Al_2O_3	10.9	9.6	6.2	11.3
SiO_2	13.1	11.3	12.4	19.5
P_2O_5	3.9	4.8	0.2	2.1
SO_3	27.6	34.0	35.5	30.0
K_2O	0.5	0.3	0.1	1.2
CaO	33.0	25.9	39.8	25.8
TiO_2	0.8	2.5	1.6	3.3
Fe_2O_3	6.1	9.7	1.9	2.9
BaO	2.1	1.2	0.0	1.1
Total	100.00	100.00	100.00	100.00

During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component, their association in the coal, and combustion system design and operating conditions. Significant research has been conducted on ash formation mechanisms and relationships and their resulting impacts on power plant performance (18–34). Typically, during combustion the inorganic components associated with western subbituminous and lignite coal are distributed into various size fractions of ash, as shown in Figure 42. The results shown in Figure 42 were obtained from isokinetic sampling, aerodynamically size-fractionating ash particles from a full-scale pc-fired boiler firing subbituminous coal, and analyzing each size fraction. The results show that the smaller-sized fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. These ash particles are largely derived from the organically associated cations in the coal. The larger-sized fraction has higher levels of aluminum and silicon derived from the mineral fraction of the ash-forming component of the coal.

Entrained ash was extracted from the Columbia Station at the point of the inlet to the SCR reactor and was aerodynamically classified and analyzed. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst, as shown in Figure 43. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-µm size fraction. The deposited material shows significantly more sulfation than the entrained-ash size fraction, indicating that the sulfation process occurs after the particles are deposited in the catalyst.

The mechanism of SCR catalyst blinding when lignite or subbituminous coals are fired is shown in Figure 44 (35). The requirements for the formation of deposits that blind SCR catalyst include firing a coal that produces significant levels of <5-µm-sized particles. The particles are transported into the pores of the catalyst and subsequently react with SO_3 to form sulfates. The sulfate forms a matrix that bonds other ash particles. The SCR catalyzes the formation of SO_3 and thereby increases the rate of sulfation (9, 15). The sulfation of CaO increases the molar

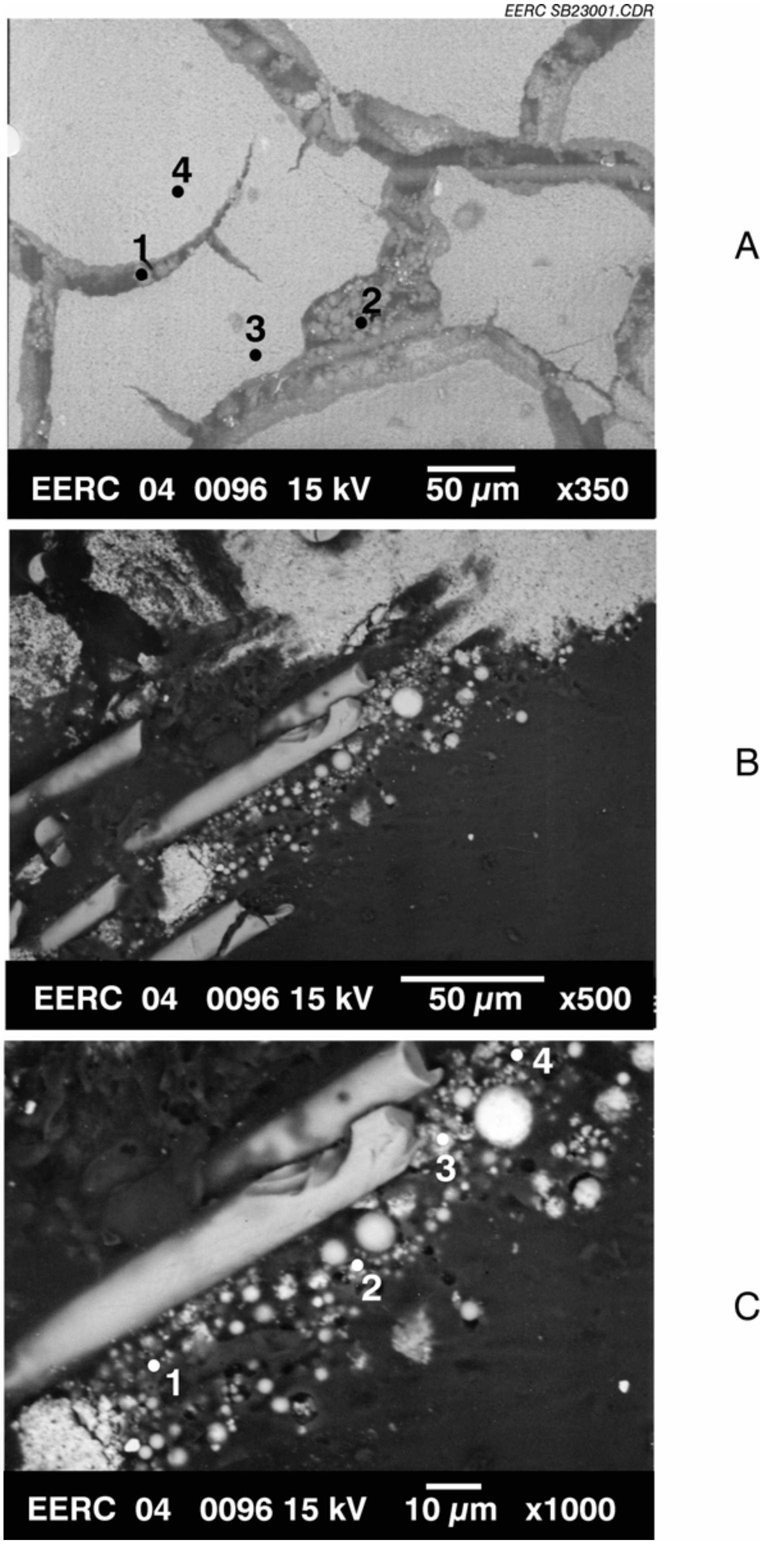


Figure 38. SEM images of ash collected on catalyst surface at the Coyote Station after 2 months of exposure: A) low-magnification image of ash deposit on catalyst surface, B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

Table 18. Chemical Composition of Selected Points and Areas in Figure 38c

	Point 1	Point 2	Point 3	Point 4
Oxide				
Na_2O	0.9	0.7	1.2	1.0
MgO	5.0	1.6	5.6	1.7
Al_2O_3	12.3	5.8	11.9	5.5
SiO_2	24.6	3.1	21.1	2.6
P_2O_5	0.7	0.0	0.5	0.0
SO_3	23.5	44.0	17.4	31.8
K_2O	0.5	0.3	0.8	0.4
CaO	14.9	36.4	19.6	46.9
TiO_2	7.2	1.9	8.0	2.1
Fe_2O_3	9.2	5.5	11.8	6.9
BaO	1.3	0.7	2.1	1.1
Total	100	100	100	100

volume, resulting in the filling of the pore. For coals that have high sodium contents, formation of low melting point phases such as pyrosulfates are possible (36). Pyrosulfate materials can melt at temperatures as low as 279°C (535°F) in coal-fired power systems.

Add-On Task – Characterization of Mercury Transformations Across SCR Catalysts for a Lignite Coal-Fired Boiler

The ability of mercury to be oxidized across the SCR catalyst was investigated at the Coyote Station. The Coyote Station is fired on North Dakota lignite, and the flue gas is dominated by elemental mercury. Measurement of mercury speciation was conducted using the OH method at the inlet and the outlet of the SCR catalyst. The measurements were made upon installation of the catalyst and after 2 and 4 months of operation. The results of the mercury speciation measurement at the inlet and outlet of the SCR catalyst conducted upon installation are shown in Figure 45. The inlet and outlet measurements were repeated three times and are shown in Figure 45. The level of elemental mercury at the inlet was approximately 76% to 92%, with the remaining in the oxidized form ranging from 8% to 24%. Very little was in the form of particulate mercury at the inlet. Measurement of mercury speciation was conducted with the NH_3 on and off. The results with the NH_3 off showed an increase in the oxidized mercury to 43% of the total mercury occurring across the SCR catalyst. However, when the NH_3 was introduced into the SCR catalyst, the amount of mercury oxidation decreased from 43% to 19%. There was an increase in the particulate mercury from 1.0% to 7.2%.

The mercury oxidation after the SCR catalyst was exposed to flue gas and particulate for 2 months is shown in Figure 46. The level of oxidized mercury at the inlet ranges from 7.5% to 11.1% of the total mercury. The level of oxidized mercury at the outlet ranged from 7.6% to 14% of the total mercury. The level of particulate mercury increased from a negligible level to 3% of the total mercury at the outlet.

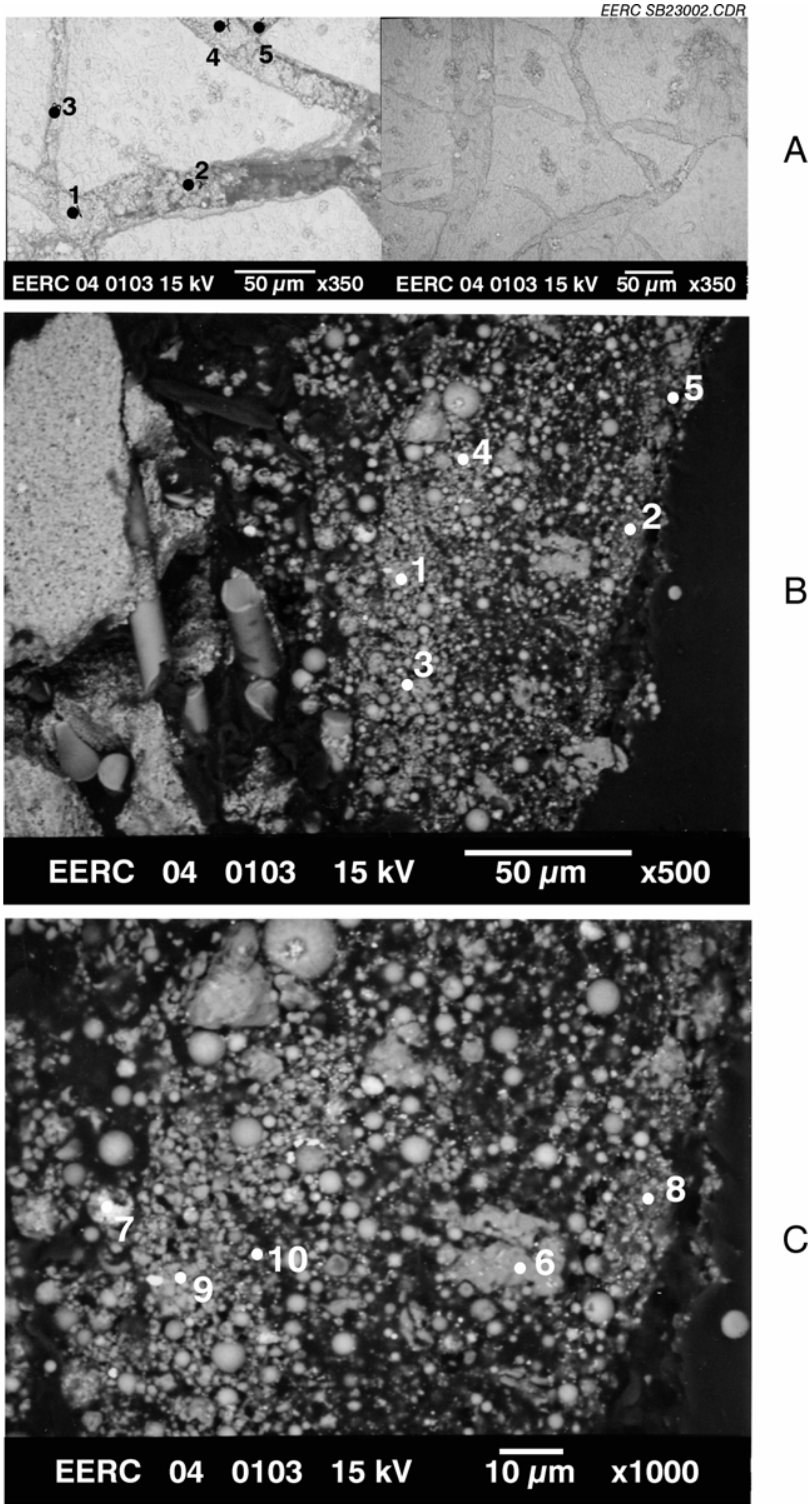


Figure 39. SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure: A) low-magnification image of ash deposit on catalyst surface, B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

Table 19. Chemical Composition of Selected Points and Areas in Figure 39b and 39c

	Element, wt%				
	Point 1	Point 2	Point 3	Point 4	Point 5
Oxide					
Na_2O	6.7	1.9	7.1	6.2	3.1
MgO	1.1	1.7	1.1	2.6	3.2
Al_2O_3	2.6	8.8	4.0	4.8	10.5
SiO_2	7.0	21.1	11.3	5.6	32.2
P_2O_5	0.2	2.4	0.0	0.2	0.9
SO_3	54.7	38.5	56.4	57.5	30.4
K_2O	2.0	2.8	0.7	2.8	2.4
CaO	18.0	3.4	15.8	9.3	2.3
TiO_2	0.6	0.8	1.1	1.3	1.5
Fe_2O_3	5.8	5.1	2.1	6.5	9.8
BaO	1.4	13.5	0.5	3.4	3.6
Total	100	100	100	100	100
	Point 6	Point 7	Point 8	Point 9	Point 10
Oxide					
Na_2O	9.5	2.6	10.4	8.9	4.4
MgO	1.2	1.9	1.3	3.0	3.7
Al_2O_3	2.6	8.6	4.2	4.9	10.6
SiO_2	6.3	18.2	10.5	5.0	28.9
P_2O_5	0.1	1.9	0.0	0.1	0.7
SO_3	41.8	28.4	44.9	44.5	23.4
K_2O	3.2	4.3	1.2	4.4	3.8
CaO	24.5	4.4	22.5	12.8	3.1
TiO_2	0.6	0.8	1.3	1.5	1.8
Fe_2O_3	7.7	6.6	2.9	8.9	13.2
BaO	2.4	22.3	0.9	5.9	6.3
Total	100	100	100	100	100

The results of mercury oxidation across the SCR catalyst after 4 months of exposure to flue gas and particulate are shown in Figure 47. The results show a higher level of oxidized mercury at the inlet as compared to testing conducted at installation and after 2 months. The level of oxidized mercury at the inlet ranges from 32% to 38% of the total, with about 5% of the total in the particulate form. The outlet levels of oxidized mercury decrease after passing through the catalyst to about 20% of the total. The level of particulate mercury remained about the same across the catalyst.

The results of mercury oxidation across the SCR catalyst after 6 months of exposure to flue gas are shown in Figure 48. The amount of oxidized mercury at the inlet ranges from 6.5% to 10.5% of the total with about 2.0% in the particulate form. The levels of oxidized mercury at the outlet increases slightly to 8.5% to 11.0% of the total mercury, while the particulate bound mercury also increases to as high as 12.0%.

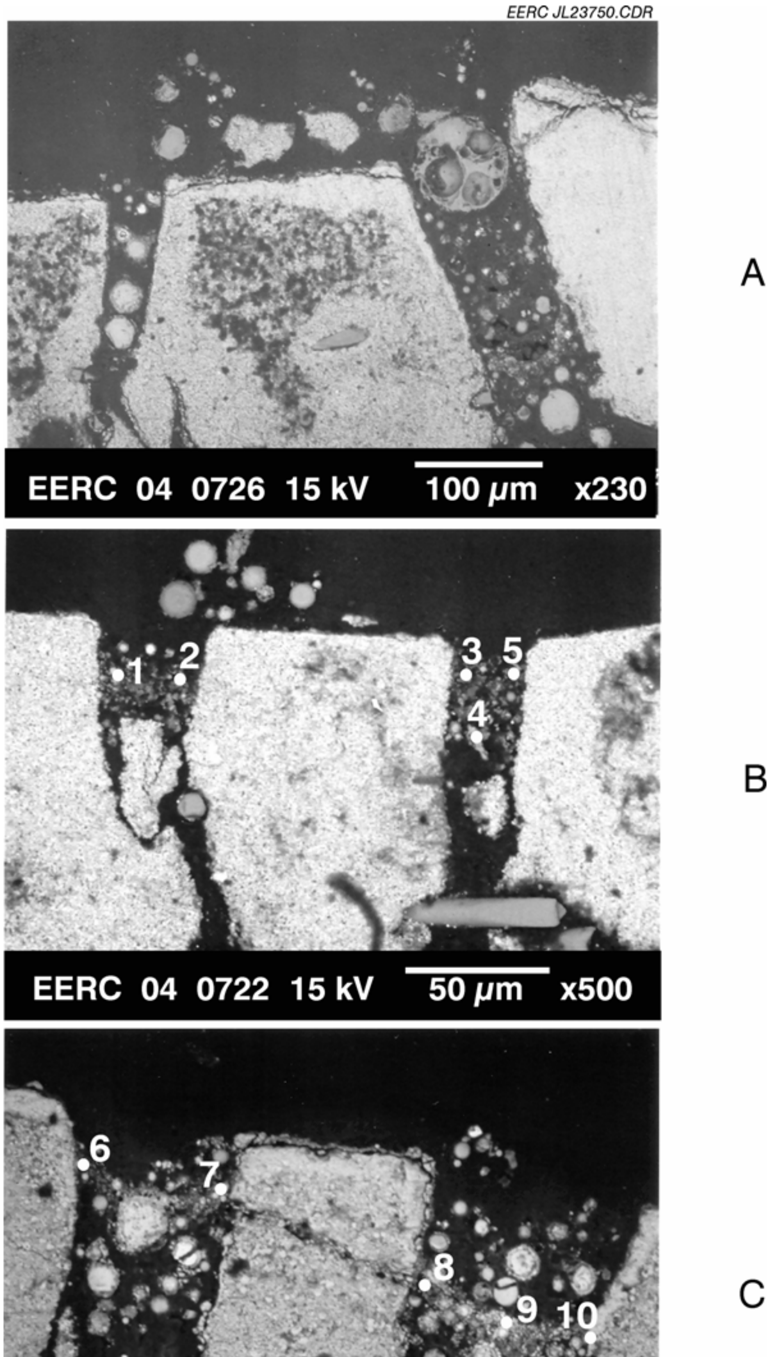


Figure 40. SEM images of ash collected on catalyst surface at the Coyote Station after 6 months of exposure: A) low-magnification image of ash deposit on catalyst surface, B) low-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

Table 20. Chemical Composition of Selected Points and Areas in Figure 40

	Element, wt%				
	Point 1	Point 2	Point 3	Point 4	Point 5
Oxide					
Na_2O	5.0	3.2	6.6	5.8	4.1
MgO	1.6	0.0	0.0	7.6	1.4
Al_2O_3	2.1	3.3	0.6	0.8	1.7
SiO_2	10.7	12.8	3.6	2.6	14.4
P_2O_5	0.0	0.0	0.0	0.0	0.0
SO_3	57.9	40.7	67.0	71.0	52.7
K_2O	0.5	0.8	0.8	1.3	0.4
CaO	13.7	6.2	12.7	7.7	16.3
TiO_2	2.0	33.0	0.0	1.7	2.1
Fe_2O_3	6.5	0.0	8.8	1.4	7.0
BaO	0.0	0.0	0.0	0.0	0.0
Total	100	100	100	100	100
	Point 6	Point 7	Point 8	Point 9	Point 10
Oxide					
Na_2O	6.5	4.1	5.7	8.1	6.7
MgO	4.6	3.1	4.4	7.5	3.7
Al_2O_3	3.3	10.2	1.6	5.4	2.4
SiO_2	11.5	2.3	4.1	10.1	9.6
P_2O_5	2.2	0.5	0.0	0.9	7.2
SO_3	52.5	48.2	61.4	53.1	56.7
K_2O	1.9	1.0	10.0	3.0	0.9
CaO	13.6	23.9	2.6	8.6	10.5
TiO_2	2.7	3.7	0.7	0.0	0.0
Fe_2O_3	1.2	3.0	9.5	3.3	2.3
BaO	0.0	0.0	0.0	0.0	0.0
Total	100	100	100	100	100

Table 21. Results of Reactivity Tests for the Baldwin Station

Catalyst	K–NO_x 350°C (662°F) (scfh/ft^3)	K/K_o 350°C (662°F)
Reference	22,808	—
2 month	23,400	1.03
4 month	21,361	0.96
6 month	19,510	0.84

Task 6 – Final Interpretation, Recommendations, and Reporting

Lignite and subbituminous coals contain high levels of organically bound alkali and alkaline-earth elements, including sodium, calcium, potassium, and magnesium. During combustion, partitioning of these elements occurs based on the size of particles, their association in the coal, and system configuration. This phenomenon, coupled with the fact that SCR catalyst

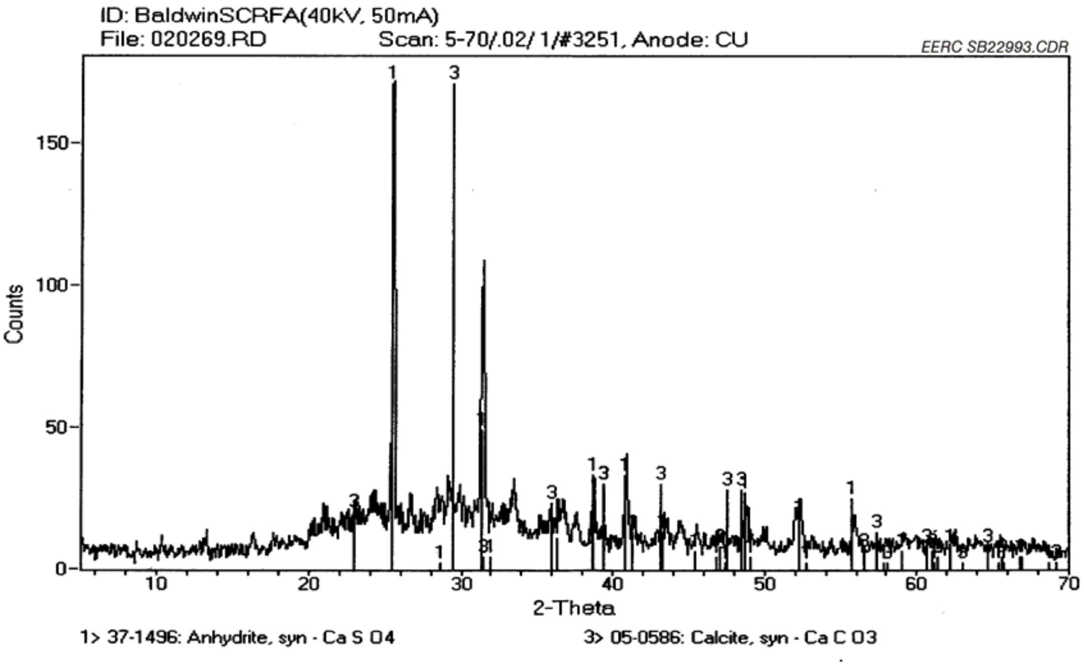


Figure 41. X-ray diffraction of ash collected on SCR catalyst (1 – $CaSO_4$, 2 – $Ca_3Mg(SiO_4)_2$, and 3 – $CaCO_3$).

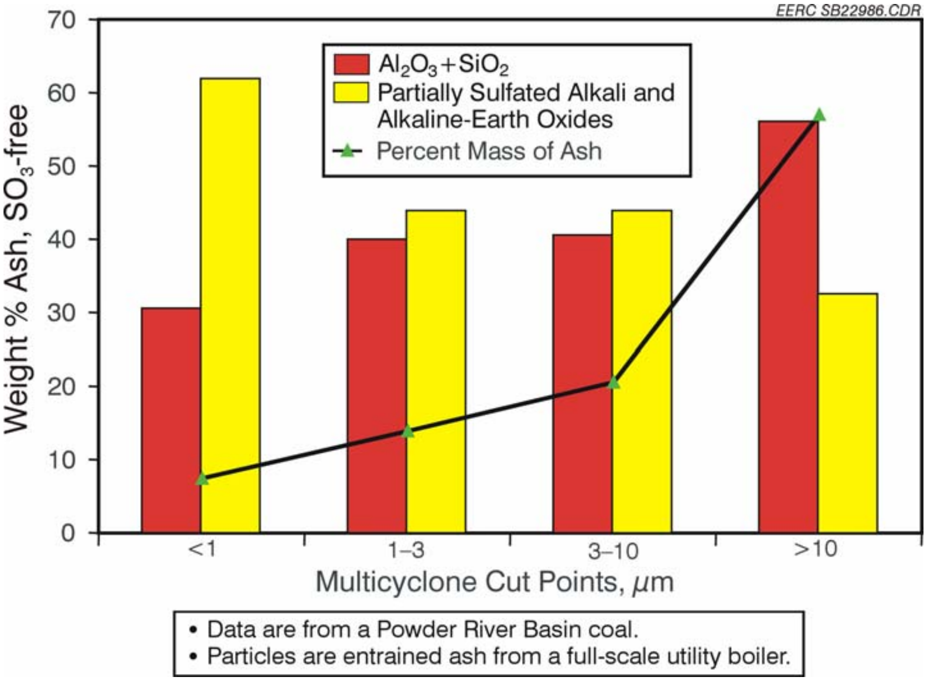


Figure 42. Simplified illustration of ash partitioning in combustion systems (18).

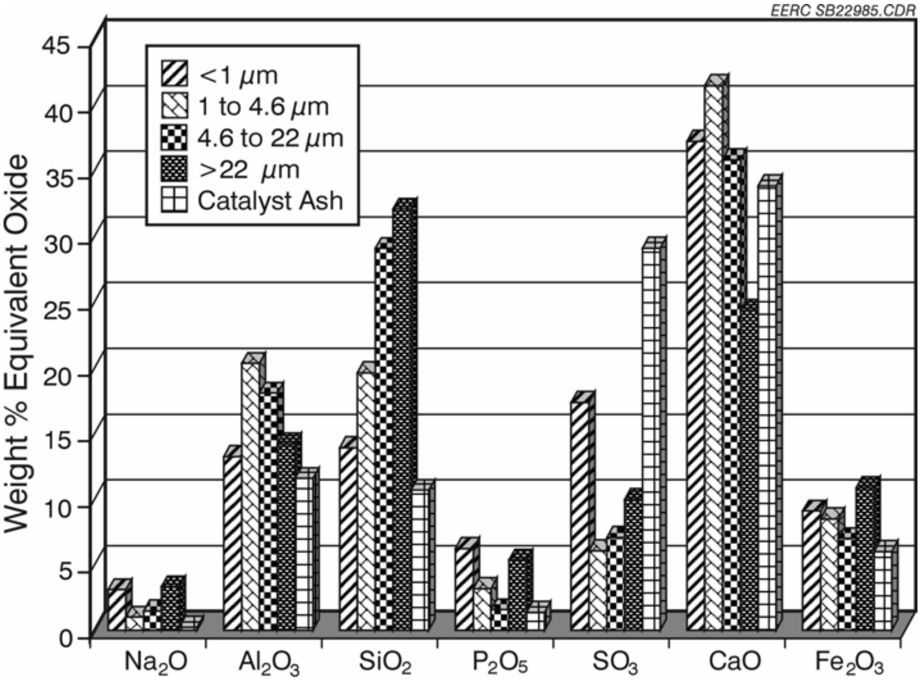


Figure 43. Comparison of entrained ash and deposited ash on catalyst for Columbia Station.

increases the oxidation of SO_2 to SO_3, will lead to extensive blinding of SCR catalyst by the formation of alkali or alkaline-earth sulfates. The results of this study lead the authors to suggest careful evaluation of each SCR installation on applications using subbituminous coals and suggest no installations of SCRs on plants firing lignite coal until further evaluations or improvements to the current technology can be carried out. Installations involving lignite fuels will need advanced cleaning techniques to handle the high-sodium and high-dust loads associated with burning most lignite fuels. The presence of SCR catalyst did not enhance mercury oxidation in the lignite-fired combustion system tested in this study.

CONCLUSIONS

The EERC evaluated the effects that ash from lignite- and PRB-fired combustion has on the performance of SCR catalyst. In order to conduct these tests, a slipstream reactor was designed to expose the SCR catalyst to coal combustion-derived flue gases and particulates. The system is computer-controlled and operates in an automated mode. The system can be operated and monitored remotely through a modem connection. SCR catalyst testing was conducted at two subbituminous-fired plants and one lignite-fired plant. The boiler configurations for the subbituminous-fired plants included a cyclone- and a tangentially fired boiler. The lignite plant was cyclone-fired.

The pressure drop across the catalyst was found to be the most significant for the lignite-fired plant as compared to the subbituminous-fired plants. Both coals had significant accumulations of ash on the catalyst, on both macroscopic and microscopic levels. On a

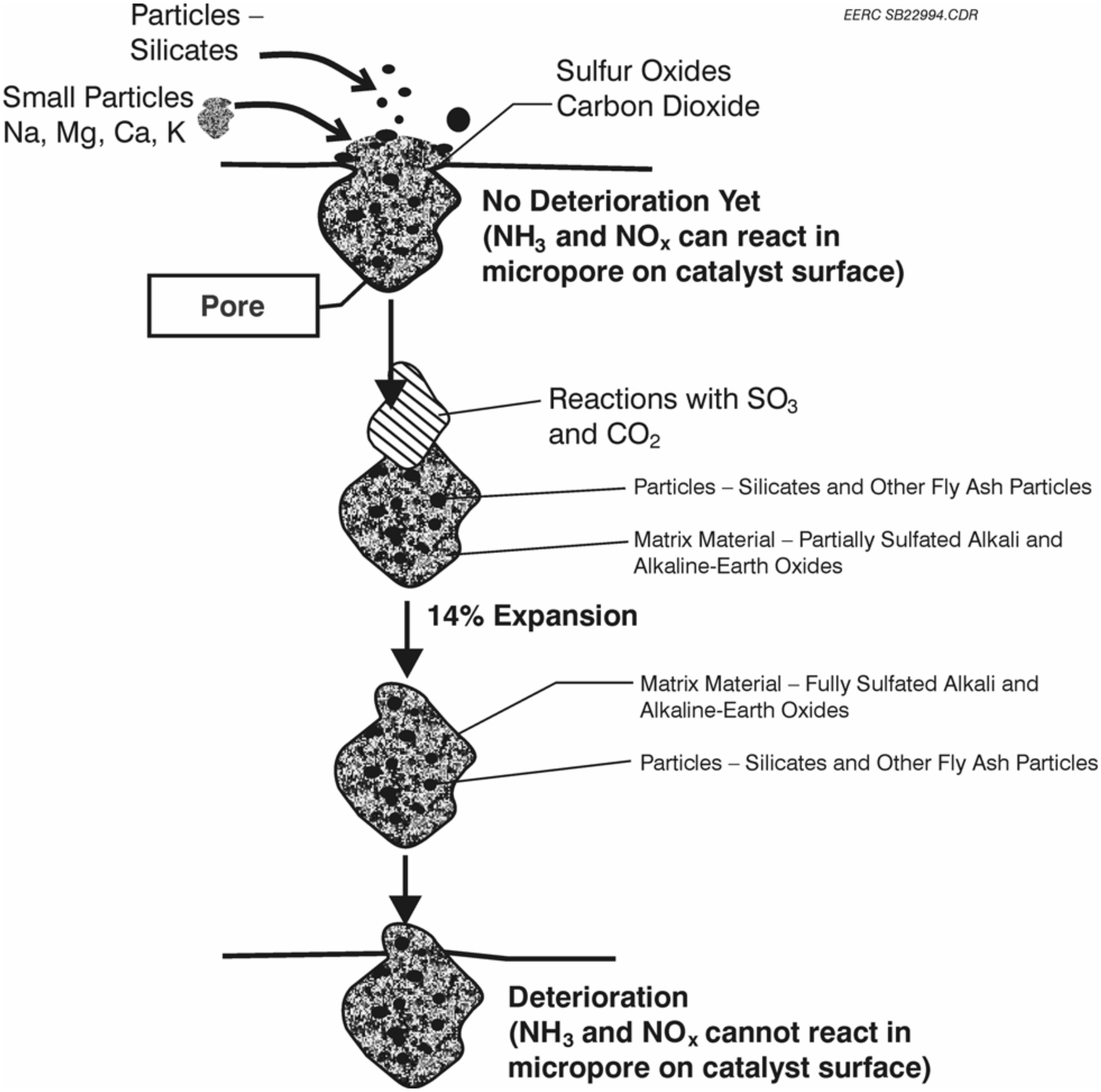


Figure 44. Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard and others [35]).

macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation. After 6 months of operation, the reactivity of the catalyst from the Baldwin Station was 84% of a comparable reference value.

The deposits on the surfaces and within the pores of the catalyst consisted mainly of sulfated alkali and alkaline-earth element-rich phases. The mechanism for the formation of the

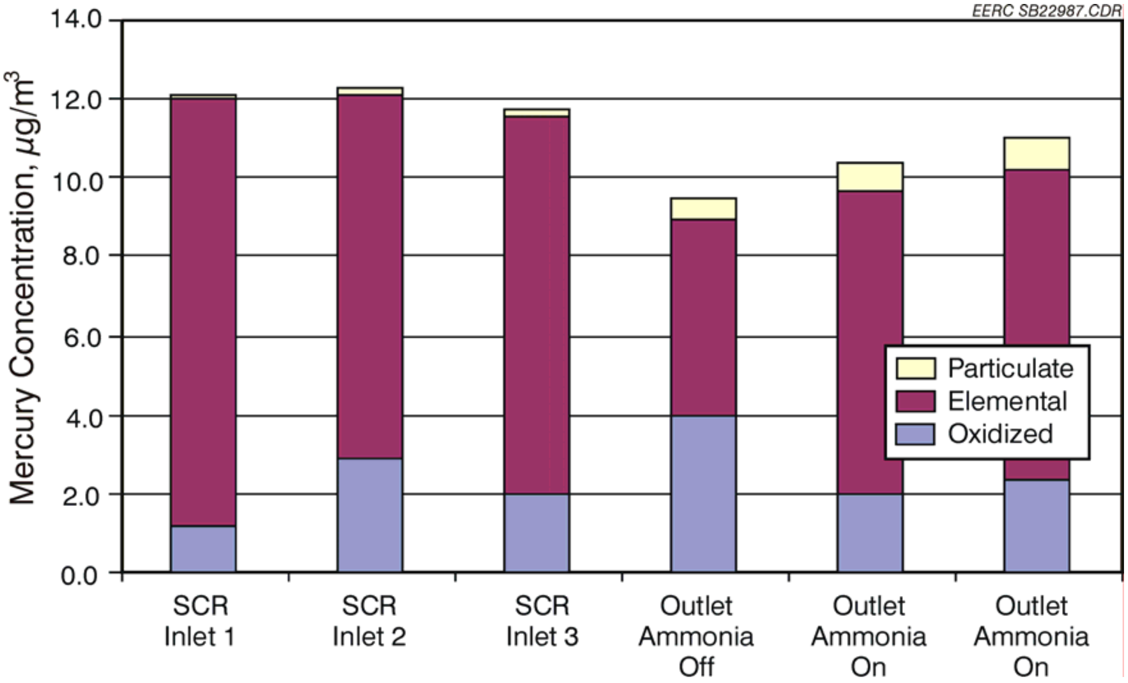


Figure 45. Mercury speciation measurement at the inlet and outlet of the SCR catalyst upon installation of the catalyst.

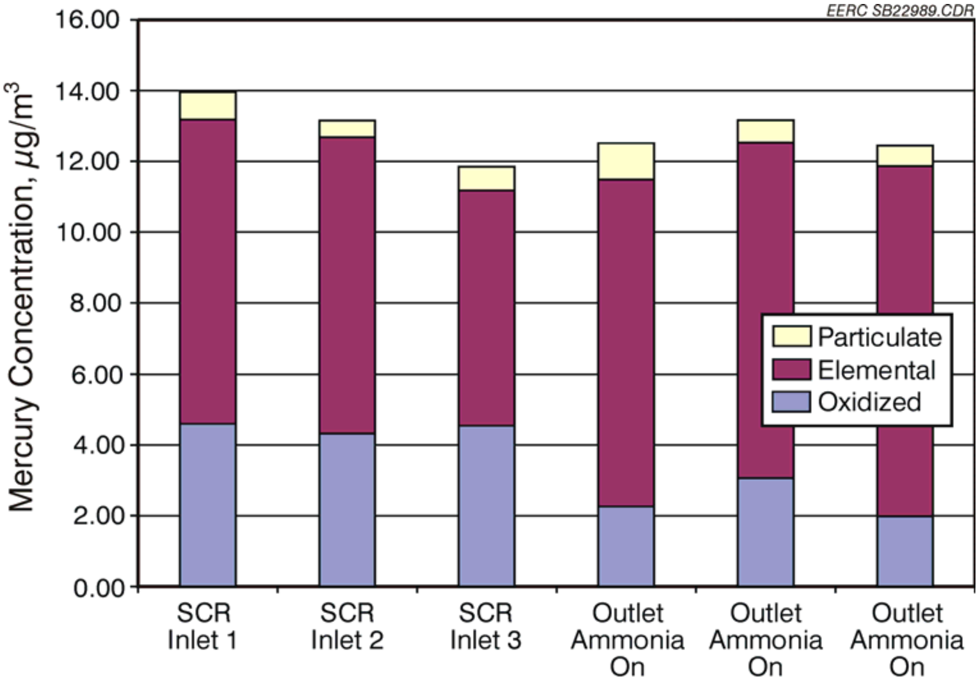


Figure 46. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gas and particulate for 4 months.

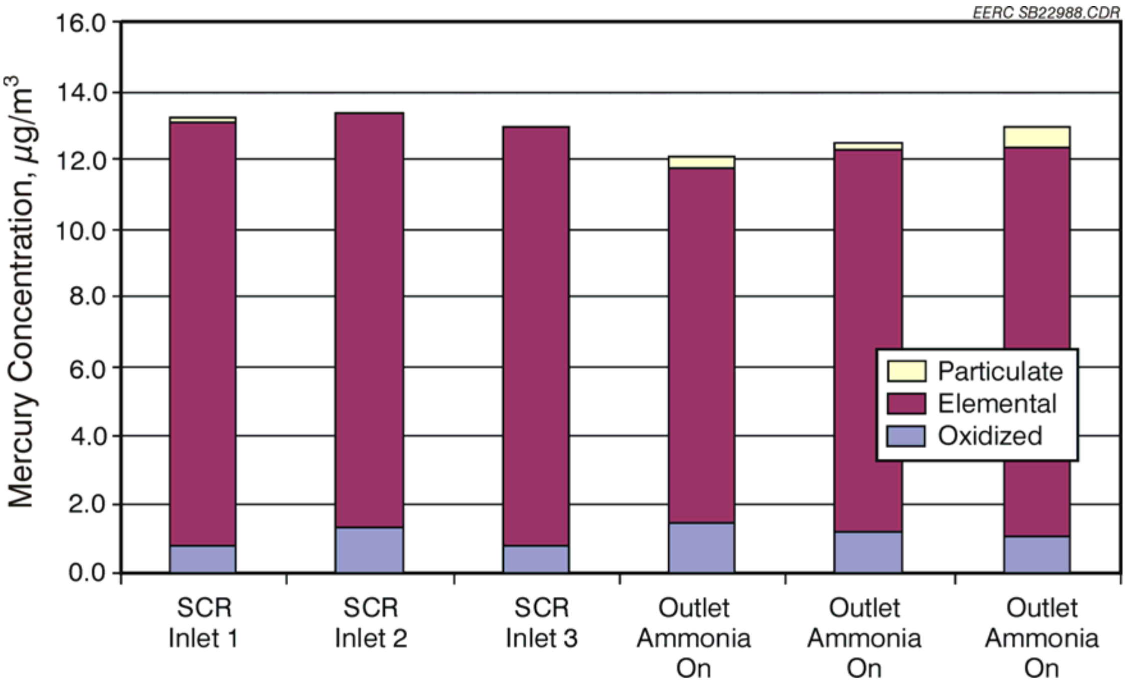


Figure 47. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gas and particulate for 2 months.

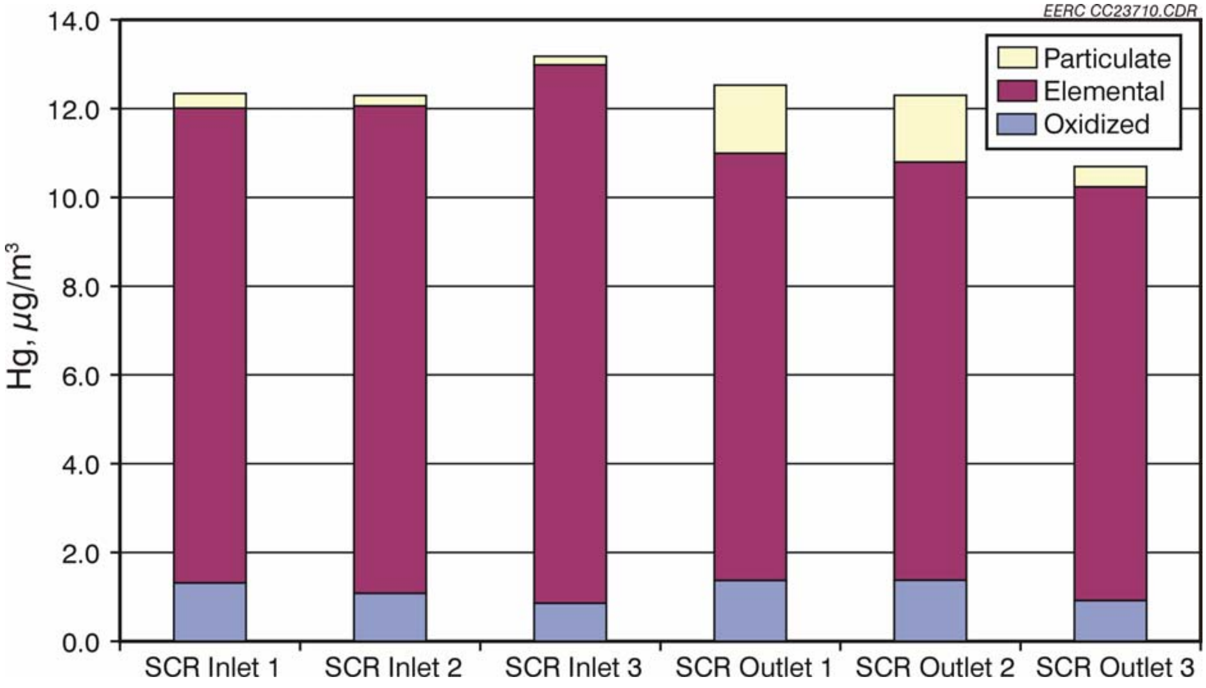


Figure 48. Mercury speciation measurement at the inlet and outlet of the SCR catalyst after exposure to flue gas and particulate for 6 months.

sulfate materials involves the formation of very small particles rich in alkali and alkaline-earth elements, transport of the particles to the surface of the catalyst, and reactions with SO_2–SO_3 to form sulfates. XRD analysis identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases. These results are consistent with the bench-scale TGA and FACT modeling results. The only exception may be the absence of phosphate materials predicted in the FACT modeling; one possible explanation is that FACT considers each reaction independently and does not consider the selectivity of one reaction over another.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements, including sodium, magnesium, calcium, and potassium in addition to mineral phases. During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component and their association in the coal and combustion system design and operating conditions. The results of this testing found that the smaller-sized fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-µm size fraction.

This study suggests careful evaluation of each SCR installation in applications using subbituminous and lignite coals. Improvements are needed to ensure technical feasibility, especially with lignite-fired units. Installations involving lignite fuels will need advanced cleaning techniques to handle the high sodium and high dust loads associated with burning most lignite fuels.

The ability of mercury to be oxidized across the SCR catalyst was investigated at the Coyote Station. The Coyote Station is fired on North Dakota lignite, and the flue gas is dominated by elemental mercury. Measurement of mercury speciation was conducted using the OH method at the inlet and the outlet of the SCR catalyst. These results show limited oxidation of mercury across the SCR catalyst when lignite coals are fired. The reasons for the lack of mercury oxidation include the following: no chlorine present in the coal and flue gas to catalytically enhance the oxidation of Hg^0, higher levels of alkali and alkaline-earth elements acting as sorbents for any chlorine present in the flue gas, and lower levels of acid gases present in the flue gas.

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Dear Ms. Anderson, Mssrs. Edwards, Arnold, Jones, and Gribovicz

RE: WRAP's Reasonable Progress Four Factor Evaluation Project
This letter provides WEST Associates' comments on the Western Regional Air Partnership's (WRAP) reports entitled "Supplementary Information for Four-Factor Analyses for Selected Individual Facilities…" (Four Factor Reports) that were recently prepared by EC/R Incorporated. WEST Associates (WEST) members consist of fifteen utilities operating in the western states with a number of electric generating plants subject to BART and potentially affected by the states' Regional Haze – Reasonable Progress Goal (RH-RPG) assessments.

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WEST Associates members reviewed the Four Factor Reports for the following states for selected electric generating plants, as follows:

- Colorado -- 11 Electric Generating Plants
- North Dakota -- 2 Electric Generating Plants
- South Dakota -- 2 Electric Generating Plants
- Wyoming -- 1 Electric Generating Plant

WEST Associates focused its review of the Four Factor Reports on information affecting electric generating units (EGUs) at these plants.

The Four Factor Reports are Inadequate and Should Be Withdrawn

After reviewing the reports, WEST concludes that each of them are wholly inadequate, especially taking into account EPA's *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 2007 Revision)*[1] ("RP Guidance"). **Therefore, WEST Associates requests that the Four Factor Reports covering Electric Generating Plants be withdrawn from the decision-making and regulatory processes related to regional haze.** In the comments below, WEST provides examples of approaches employed by EC/R in the reports that support this conclusion and request.

WEST is concerned that these Four Factor Reports, as currently constituted, will set a pattern, both in substance and in analytical procedure, that will be followed in response to other states' requests for Four Factor evaluations of other selected EGUs. To perpetuate Four Factor analyses based on the methods used by EC/R in preparation of these reports as currently constituted would not be adequate or helpful to any state in preparing the RPG portions of their RH-SIPs.

Programmatic Consideration of Visibility Improvement Benefit to Achieving the Reasonable Progress Goal is Absent

While the Four Factors do not list visibility improvement as one of the factors, per se, the 40 CFR Part 51.308 regulation governing the development of states' reasonable progress goals, does require consideration of visibility improvement as the results of the Four Factor Reports are used in each state's RPG design and formulation, as follows:

- <u>*First*</u>, the state must not only complete the Four Factor analyses relating to cost effectiveness of control measures on specific sources, the state must also demonstrate *how those factors were taken into account in selecting the goal*. This clearly requires the state to consider cost effective measures in the context of what they will achieve in visibility improvement that is aligned with the desired RPG goal in the RH-SIP. See the following Sec. 308 citations:

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[1] http://www.wrapair.org/forums/amc/documents/RPguidance.pdf

> 40 CFR 51.308(d)(1)(i) -- "In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must:
>
> > (A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, *and include a demonstration showing how these factors were taken into consideration in* ***selecting the goal***."
> >
> > (B) ... In establishing the reasonable progress goal, the *State must consider the uniform rate of improvement in visibility and* ***the emission reduction measures needed to achieve it*** for the period covered by the implementation plan."
>
> 40 CFR 51.308(d)(3)(v) -- "The State must consider, at a minimum, the following factors in developing its long-term strategy:
>
> > "... (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment; ....
> >
> > (G) The ***anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions*** over the period addressed by the long-term strategy."

- *Second*, the RP Guidelines state that for assessing individual, large scale sources such as EGUs simple cost effectiveness estimates may not be as meaningful as consideration of the value of emission reductions on visibility improvement, as follows:

> "In considering the cost of compliance factor, you should keep in mind that different
> pollutants differently impact visibility impairment. For example, on a ton basis, sulfur dioxide related particles have a greater impact on visibility impairment than crustal material. Therefore, in assessing additional emissions reduction strategies for source categories or individual, large scale sources, ***simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation***, especially if the strategies reduce different groups of pollutants." [RP Guidance, pg. 5-2].
>
> "Another approach you could take, consistent with the "back out" approach discussed in section 2.3, would involve *identifying the set of emissions control measures that achieves the target percentage reductions in visibility-impairing pollutants associated with progress* at or
> beyond the uniform rate of progress. The *selection of control measures to*

> *include in this set*
> *would be guided by your consideration of the statutory factors* and any other factors you have determined are relevant." ."
>
> "Note that for some sources determined to be subject to BART, the State will already have
> completed a BART analysis. *Since the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in establishing the RPG, it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first RPG planning period*. Hence, you may conclude that no additional emissions controls are necessary for these sources in the first planning period." [RP Guidance, pg. 4-2].

The Four Factor Reports need to include a clear discussion of how their Four Factor cost effectiveness findings are to be integrated within each state's obligation under the EPA's Regional Haze Rule and the RP Guidelines to assess the benefit of and contribution to visibility improvement for achieving the state's RPG.

Nevertheless, WEST is providing the following detailed analysis and comments on the cost effectiveness analyses contained in the above referenced EC/R developed Four Factor Reports, as follows:

Incomplete and Cursory Application of the Four Factors

The "Four Factors"[2] required to be evaluated pursuant to the Clean Air Act and the Regional Haze Rule are acknowledged by the WRAP and EC/R to be necessary review elements for evaluating and setting reasonable progress goals as states develop their Regional Haze SIPs (RH-SIPs). Yet, the essential ingredients for thoroughly and accurately evaluating "cost of compliance" and "remaining useful life of any existing source subject to such requirements" are fundamentally ignored in the EC/R reports.

For example, EPA's RP Guidance includes knowledge and evaluation of site-specific factors, and specific design parameters unique to the evaluated electric generating unit (EGU), cited as follows:

> "To assess compliance costs *for individual sources* or source categories potentially subject to emission limitations, we suggest that you *use established control cost analysis techniques*. For stationary sources, generally this involves the following:
>
> > a) Identify *the emissions units* to be controlled;

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[2] Cost of compliance; Time necessary for compliance; Energy and non-air quality environmental impacts of compliance; and, Remaining useful life of any existing source subject to such requirements.

> b) Identify *the design parameters for emissions controls*; and
>
> c) Develop cost estimates *based upon those design parameters*.
>
> [States] should evaluate both average *and incremental costs....*"[3] (Emphasis added).

Clearly, EPA's RP Guidance points to a four-factor evaluation process that selects individual EGUs and evaluates "design parameters for emissions controls" unique to each EGU evaluated. Furthermore, "cost estimates based upon those design parameters" must be applied to the "emissions units to be controlled" – once those units are identified. The RP Guidance provides no latitude for the apparent "boiler plate" approach taken in these reports by EC/R.

Inadequate Evaluation of Cost of Compliance

"Established control cost evaluation techniques" include, but are not limited to, the following *essential* evaluative factors:[4]

- Control Options Feasibility for specific EGUs
- Control Option percent Reduction Achievable for specific EGUs
- Control Costs Based on EGU Site-Specific and Operational Factors
- Baseline Emissions Adjusted for Regulatory Required and Committed Control Retrofits to the EGU Prior to RPG Evaluation
- Control Cost Amortization Adjusted for EGU Remaining Useful Life

The Four Factor Reports fail on most of the above "established control cost evaluative techniques." From its review of these reports, WEST supplies examples below to support this conclusion. For purposes of simplicity, WEST is referencing the "2009-05-22 Individual Facility Analyses -- Colorado." The same issues appear in each of the Four Factor Reports.

Control Options Feasibility for the specific EGU

EC/R performed a partial evaluation of control options feasibility for reviewed Colorado EGUs. WEST notes for example, in Table 3-2, that EC/R varies the control technology options between each EGU, based on some knowledge of existing or committed controls. However, there is no discussion in the report to verify EC/R's technical reasons for the

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[3] *"Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 2007 Revision)"*; Pg. 18; http://www.wrapair.org/forums/amc/documents/RPguidance.pdf

[4] These evaluative factors are a combination of the steps required pursuant to the RP Guidance document for evaluation of control measure options, and practical engineering analysis steps commonly used by power plant engineers when EGUs prepared BART Assessments required by EPA's BART Guidance document (2005).

options listed. As it relates to NOx, each of the reports contain a common listing of low-NOx burners (LNB), LNB with over-fired air (OFA), selective non catalytic reduction (SNCR), and selective catalytic reduction (SCR) (with the lower level controls not listed if currently installed).

This approach has the following two flaws.

First, there is no discussion about whether EGU boiler specific operational and existing design factors would accommodate the listed control option and whether the specific control option would yield NOx reduction capabilities within the percent reduction ranges stated. For example, installation of NOx, PM, and SO2 controls required to meet recently-adopted BART emission limits (unique to the specific EGU design parameters), will directly affect the volume and grid size of SCR catalyst beds required to resolve back pressure issues that can impact the NOx percent removal achievable with SCR. Under some conditions, this will result in infeasibility of SCR.

Also, some EGUs have specific design parameters and operational characteristics that can make installation of SNCR either not feasible or ineffective in achievable NOx percent removal. SNCR involves injection of urea or ammonia within the ductwork flow of combustion flue gas at a carefully designed and tested location of optimum flue gas temperature and residence time. Retrofit installation of SCR or SNCR controls, along with BART-required SO2 scrubbers and PM control devices, require sufficient space. In some cases, limited space is inadequate or unavailable to accommodate the footprint of retrofit equipment. There is no discussion of these specific factors in the reports.

Second, Table 3-2 does not "winnow" the list of control options based on a "baseline" that takes into account BART emission limits for SO2, NOx and PM that most states have promulgated or are in the process of promulgating. There cannot be an accurate Four Factor cost assessment unless baselines are updated with states' adopted BART limits and other EGU committed controls to establish an accurate foundation for Four Factor analyses that may be needed for RPG planning. Nevertheless, achievement of reasonable progress goals may require no further changes in emissions controls after BART is taken into account, and the Four Factor Reports should be revised to reflect this and other possibilities.

Control Option Percent Reduction Achievable for Specific EGUs

Table 3-2 lists Estimated Control Efficiency for each control option in most cases as a range (e.g., SNCR, 30-75%; SCR, 40-90%). It appears that EC/R selected a single percent reduction range for each control technology. This error is repeated across all reports, even though specific EGU analyses will yield unique percent reduction capabilities when taking into account individual EGU parameters.

For example, SNCR and SCR list an average control efficiency of 40% and 80%, without respect to whether these efficiencies are achievable. Given the direct effect this percent reduction assumption has on the outcome of the $/ton cost effectiveness, it is critical that any useful evaluation of control technology options take into account situational and operational factors and characteristics. The generic and unjustified information provided in Table 3-3 is a disservice to both the states that requested these analyses and the EGU sources.

Clearly, there is no attempt by EC/R to identify what achievable percent reduction is appropriate for each specific EGU, given site specific and operational design parameters and performance. Both the minimum achievable percent reduction and the range of expected control performance could differ substantially due to individual EGU site specific and operational/design factors.

Further, no discussion indicates that variability in fuel sulfur content, ash content, and nitrogen content was evaluated. It is well known that these fuel constituents vary, with significant effects on emission control performance. Even in cases where EGU fuel sources are relatively constant (e.g., mine-mouth plants, use of western low sulfur coal), fuel constituent variability exists. A change in coal seam can be accompanied by a shift in ash content, nitrogen content, and sulfur content of coal. Fuel factors such as these need to be evaluated specific to each EGU.

Control Costs Based on EGU Site Specific and Operational Factors

None of the Four Factor Reports indicate that control costs were adjusted or tailored to address individual EGU design parameters and site-specific factors. It appears that EC/R used "look up" tables provided by EPA and other sources to make basic nominal adjustments to capital costs of controls based on capacity, combustion configuration, and other commonly known EGU factors. The purpose of these Four Factor Reports is to inform decisions about reasonableness of control measures to achieve reasonable progress goals. Capital and annual operating costs for controls may vary according to the following:

- Space limitations (after BART controls are installed)
- Requirements to replace, add, or reroute flue gas ducting
- Requirements to add induced draft fans to overcome back pressure accrued by addition of more controls
- Moving and reinstallation of major power plant components to provide space for added controls, such as moving the power plant stack.
- Variability in ammonia or urea use required to achieve minimum required percent control for NOx
- Catalyst replacement schedules.
- Secondary increases in other pollutants resulting from installation of SCR, that further need to be controlled.

An example of how major EGU site and operational specific parameters can significantly affect control costs and, therefore, the need to adjusted control costs to address individual

EGU design and site-specific factors is the retrofit of SCR on coal-fired EGUs operating in the west. Costs associated with SCR may require inclusion of sorbent injection for sulfuric acid mist control, and then potentially a polishing bag house for those EGUs that have ESPs and a scrubber. From at least one WEST utility's experience, SCR will result in a significant increase in sulfuric acid mist that requires the installation of BACT technology. Thus use of sorbent injection to mitigate sulfuric acid mist can in turn result in a significant increase in PM10, which triggers the need for a polishing bag house. Again, this practical example reinforces our comment that there is no generic NOX template that can be applied to western EGUs.

The variability in capital and operating costs can be enough to significantly affect the outcome of the cost effectiveness. Again, there is no evidence in the report to indicate that EC/R considered these practical issues.

Finally, the cost of installing controls (evaluated as $/ton cost effectiveness) has significant variability due to two additional factors not considered by EC/R. First, EC/R used a capital amortization period of 30 years at 7 percent. WEST takes a position that use of a "one size fits all" amortization period is inappropriate and ignores consideration of the remaining useful life of a plant.

With respect to the 7% cost of capital, this is overly simplistic since the actual cost of capital by individual electric generating plants varies substantially in the case of Investor Owned Utilities (IOUs). Depending on the regulatory decision made by the public utilities commission with jurisdiction, and the individual IOU's financial condition, the cost of capital ranges more typically from 8% or 9% up to 13% or higher. At a minimum, EC/R could have surveyed the range of costs of capital that exist among western IOUs and picked a median % cost of capital to use more appropriately in these analyses.

Baseline Emissions Adjusted for Regulatory Required and Committed Control Retrofits to the EGU Prior to RPG Control Measure Evaluation

Table 3-3 cost effectiveness calculations provide only an annual average $/ton result. As cited above, it is *a major omission to not also include incremental $/ton cost effectiveness calculations and results for each EGU*, pursuant to EPA's RP Guidance. The baseline emissions listed for each EGU in Table 3-1 are used for calculating emission reductions, and thereby calculating cost effectiveness results for control options in Tables 3-2 and 3-3. However, the listed NOx and SO2 historical annual emissions in Table 3-1 do not reflect adjustments for the states' recently adopted BART emission limits. Unless, these baseline emissions are adjusted to reflect adopted BART and other EGU committed controls, any Four Factor analysis to be used by states for their 2018 RPG Planning will be inaccurate.

Calculations of cost effectiveness and incremental costs are driven directly by the baseline emissions that will occur after installation and operation of pre-existing regulatory requirements and committed emission controls. Such changes will result in fewer annual tons of emissions by the time the first reasonable progress goal milestone arrives in 2018. As a result, additional reductions to achieve reasonable progress goals will be less or unnecessary, and the $/ton cost effectiveness and incremental costs will be significantly higher (less cost effective) than posed by EC/R in Table 3-3.

Control Cost Amortization Adjusted for EGU Remaining Useful Life

As discussed above, EC/R applied a constant, universal capital cost amortization method based on a 30-year amortization period at 7% cost of capital. EC/R could have surveyed the BART Assessments required by EPA's BART Guidelines (2005) that have been submitted by each EGU owner to each state's air quality regulatory agency. Those BART Assessments (in their cost effectiveness calculations) make statements and assumptions about the remaining useful life of each affected EGU.
EC/R should have used EGU specific information and calculated the cost effectiveness of each control option accordingly.

Conclusion:

WEST Associates strongly urges the WRAP and its states to reject the severely flawed Four Factor Reports. The Four Factor Reports produced by EC/R Incorporated comprise an inadequate and incomplete foundation on which to base discussions regarding the creation of reasonable progress goals and consideration of control measures in developing Regional Haze SIPs.

If you have any questions, or need further information regarding these comments, please contact Lyle Nelson, at lylen@simginc.com.

Sincerely,

Kevin Wanttaja
President of the Board
WEST Associates

//lrn

Appendix I
Response to Comments

A. **Commentor**: OtterTail Power Co.

Comment 1: It was suggested that 1.01% sulfur be used for evaluating a new wet scrubber for the Coyote Station and the cost effectiveness be recalculated.
Department Response: Agreed. The Department also believes that a new wet scrubber can achieve 95% removal efficiency. The cost effectiveness was recalculated based an average sulfur content of 1.075% for the baseline period of 2004-2005.

Comment 2: OtterTail suggested adding a reference to the concern regarding technical feasibility for high dust SCR.
Department's Response: The Department has addressed this issue as part of the BART process. A reference was added to this assessment.

B. **Commentor**: Basin Electric Power Coop.

Comment 1: Basin believes that a fifth statutory factor, visibility impairment, should be addressed in the document.
Department Response: In determining reasonable progress, Section 169A(g)(1) of the Clean Air Act lists the following factors to be considered:

a. Cost of compliance.
b. Time necessary to compliance.
c. The energy and nonair quality environmental impacts.
d. The remaining useful life of the source.

Visibility impacts are not one of the four factors. However, EPA guidance for determining reasonable progress allows the cost to be determined on a dollar per deciview of visibility improvement.

Comment 2: The text describing the tables in Section 3 does not agree with the labeling of the table.
Department Response: Agreed

Comment 3: Additional options for improving the existing dry FGD system should be evaluated.
Department Response: Such an evaluation was beyond the scope of the general analysis that was prepared.

Comment 4: Agreed with the report statement that high dust SCR may not be technically feasible. Also, visibility improvement should be taken into account in the evaluation of the control technology.
Department Response: See response to Comment A.2 and B.1.

Comment 5: The time to achieve compliance may not be sufficient if the outage schedule for the units (every 3 years) does not fit perfectly into the 5½ - 6½ years for

compliance.
Department Response: Agreed

C. **Commentor**: Hess Corp.

Comment 1: The SRU has a sulfur recovery efficiency of 98.8% instead of the 97.5% used in the calculation of cost effectiveness.

Department Response: The cost effectiveness was recalculated using a 98.55% recovery efficiency which is the value during the baseline period.

Comment 2: Expectations are that the amount of sulfur in the inlet gas will drop in the future due to more sweet gas processed from the Bakken formation.

Department Response: This fact will be considered in the Department's evaluation of the source under the reasonable progress portion of the SIP.

Comment 3: The tail gas cleanup unit cost was extrapolated from a 1982 report which could lead to significant errors.

Department Response: The potential inaccuracy in the cost estimate will be considered in determining whether additional controls will be required under the reasonable progress portion of the SIP.

Comment 4: Electric motors are not a technically feasible option for the Clark engines since the compressor cylinder connecting rods are an integral part of the engines main crankshaft.

Department Response: Agreed

Comment 5: Catalytic convertors are not technically feasible for two cycle lean burn engines.

Department Response: Agreed. However, the cost in the report was for an ammonia/urea based SCR system with a catalyst.

D. **Commentor**: Dakota Gasification Co.

Comment 1: DGC believes the cost of the NO_x control technology in underestimated and control efficiency is overestimated. In order to achieve the proper temperature for SCR, the heat recovery section of the Riley boilers would have to be modified in order to achieve the proper temperature. The required modifications would reduce the capability of the boilers to make enough steam to operate and thereby reduce the plant capacity. In addition, there is limited space for either SNCR or SCR.

Department Response: The Department believes the actual analysis of SCR by DGC has merit. The higher end of cost range will be used to evaluate this alternative.

Comment 2: SCR and SNCR may not be technically feasible for application on the Riley boilers. Testing in 1997 indicated rapid accumulation of ammonium sulfate deposits on the heat recovery section of the boilers.

Department Response: In 1992, the Department determined that SCR and SNCR were not technically feasible for the Riley boilers because of the high CO_2 and high sulfur content of the flue gas. However, SCR and SNCR technology has advanced significantly since that time. The Department agreed that a technical analysis would be required, and perhaps pilot testing, before it could be determined whether the technology could be made to work.

Comment 3: Visibility improvement needs to be included as a fifth factor in the analysis.
Department Response: See response to Comment B.1.

Supplementary Information for Four Factor Analyses by WRAP States

May 4, 2009

Revised Draft Report

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Scope of Document

This document provides an initial analysis of the four factors which must be considered in establishing a reasonable progress goal toward achieving natural visibility conditions in mandatory Class I areas. These factors were examined for several candidate control measures for priority pollutants and emission sources. The results of this report are intended to inform policymakers in setting reasonable progress goals for the Class I areas in the Western Regional Air Partnership (WRAP) region.

This document does not address policy issues, set reasonable progress goals, or recommend a long-term strategy for regional haze. Separate documents will be prepared by the States which address the reasonable progress goals, each state's share of emission reductions, and coordinated emission control strategies.

Disclaimer

The analysis described in this document has been funded by the Western Governors' Association. It has been subject to review by the WGA and the WRAP. However, the report does not necessarily reflect the views of the sponsoring and participating organizations, and no official endorsement should be inferred.

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Abbreviations

ACT	Alternative Control Techniques
ALAPCO	Association of Local Air Pollution Control Officials
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAA	Clean Air Act
CO_2	Carbon Dioxide
EC	Elemental Carbon
EDMS	Emissions Data Management System
EGU	Electric Generating Units
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FCC	Fluid Catalytic Cracking
FGR	Flue Gas Recirculation
FF	Fabric Filters
H_2S	Hydrogen Sulfide
ICAC	Institute of Clean Air Companies
ICI	Industrial/Commercial/Institutional
LEC	Low-Emission Combustion
LNB	Low-NOx Burners
MRPO	Midwest Regional Planning Organization
N_2O_5	Dinitrogen Pentoxide
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NEI	National Emissions Inventory
NESCAUM	Northeast States for Coordinated Air Use Management
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NSCR	Nonselective Catalytic Reduction
NSPS	New Source Performance Standards
OC	Organic Carbon
OFA	Overfire Air
PM	Particulate Matter
PM_{10}	Particulate Matter Particles of 10 Micrometers or Less
$PM_{2.5}$	Particulate Matter Particles of 2.5 Micrometers or Less
PSD	Prevention of Significant Deterioration
RPO	Regional Planning Organizations
SCC	Source Classification Codes
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide

STAPPA	State and Territorial Air Pollution Program Administrators
ULNB	Ultra-Low NOx Burners
VOC	Volatile Organic Compounds
WRAP	Western Regional Air Partnership

Units

acfm	Actual Cubic Feet per Minute
cfm	Cubic Feet per Minute
kWh	Kilowatt Hour
MM-BTU/hr	Million British Thermal Units per Hour
MW	Megawatt
ppmv	Parts per Million by Volume
scfm	Standard Cubic Feet per Minute

1. Introduction

The Regional Haze Rule requires States to set reasonable progress goals toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064. The first reasonable progress goals will be established for the planning period 2008 to 2018. The Western Regional Air Partnership (WRAP), along with its member states, tribal governments, and federal agencies, are working to address visibility impairment due to regional haze in Class I areas. The Regional Haze Rule identifies four factors which should be considered in evaluating potential emission control measures to meet visibility goals. These are as follows:

1. Cost of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of any existing source subject to such requirements

The purpose of this report is to analyze these factors for possible control strategies intended to improve visibility in the WRAP region. The following priority source categories of emissions are addressed:

1. Reciprocating internal combustion engines and turbines
2. Oil and natural gas exploration and production field operations
3. Natural gas processing plants
4. Industrial boilers
    a. Coal- and oil- fired
        i. By size category
            Up to and including 200 million British Thermal Units (BTU) per hour
            Greater than 200 million BTU/hour
        ii. By age category
            Constructed prior to regulations for Prevention of Significant Deterioration (PSD) (before August 7, 1977)
            After PSD regulations but before the Clean Air Act Amendments of 1990 (August 7, 1977 through December 31, 1990)
            After the Clean Air Act Amendments of 1990
    b. Wood fired industrial boilers
    c. Natural gas fired industrial boilers
5. Cement manufacturing plants
6. Sulfuric acid manufacturing plants
7. Pulp and paper plant lime kilns
8. Petroleum refineries

We have identified control measures for emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2), which can react in the atmosphere to produce visibility-obscuring particulate matter on a regional scale, and also for direct emissions of particulate matter. For direct particulate matter emissions, we have evaluated the impacts of control measures on various particulate matter components, including $PM_{2.5}$, PM_{10}, elemental carbon (EC) particulate matter, and particulate organic carbon (OC). Data on emissions of volatile organic compounds (VOC) were also collected. In addition, although VOC emission control measures were not explicitly evaluated in this study, the impacts of NO_X, SO_2, and particulate matter controls on VOC were calculated where co-control benefits would occur.

It must be noted that the source category analyses in this report are general in nature. In developing their Regional Haze State Implementation Plans (SIPs), states will also draw on other category-specific analyses and source-specific analyses.

This report is organized in 10 sections, including this introduction. Section 2 describes the methodology for the four factor analysis. The next 8 sections present the results of factor analyses for the priority emission source categories listed above.

2. Methodology

The first step in the technical evaluation of control measures for a source category was to identify the major sources of emissions from the category. Emissions assessments were initially based on 2002 emissions inventory in the WRAP Emissions Data Management System (EDMS),[1] which consists of data submitted by the WRAP states in 2004. The states then reviewed the emissions data and parameters from the EDMS used for this analysis and provided updated data when applicable. In some cases, detailed data on PM_{10} and $PM_{2.5}$ emissions were not available from the WRAP inventory. Therefore, PM_{10} and $PM_{2.5}$ data from the U.S. Environmental Protection Agency's (EPA) 2002 National Emissions Inventory (NEI) were used to supplement the WRAP inventory where necessary.

Once the important emission sources were identified within a given emission source category, a list of potential additional control technologies was compiled from a variety of sources, including control techniques guidelines published by the EPA, emission control cost models such as AirControlNET[2] and CUECost,[3] Best Available Retrofit Technology (BART) analyses, White Papers prepared by the Midwest Regional Planning Organization (MRPO),[4] and a menu of control options developed by the National Association of Clean Air Agencies (NACAA).[5] The options for each source category were then narrowed to a set of technologies that would achieve the emission reduction target under consideration. The following sections discuss the methodology used to analyze each of the regional haze factors for the selected technologies.

2.1 Factor 1 – Costs

Control costs include both the capital costs associated with the purchase and installation of retrofit and new control systems, and the net annual costs (which are the annual reoccurring costs) associated with system operation. The basic components of total capital costs are direct capital costs, which includes purchased equipment and installation costs, and indirect capital expenses. Direct capital costs consist of such items as purchased equipment cost, instrumentation and process controls, ductwork and piping, electrical components, and structural and foundation costs. Labor costs associated with construction and installation are also included in this category. Indirect capital expenses are comprised of engineering and design costs, contractor fees, supervisory expenses, and startup and performance testing. Contingency costs, which represent such costs as construction delays, increased labor and equipment costs, and design modification, are an additional component of indirect capital expenses. Capital costs also include the cost of process modifications. Annual costs include amortized costs of capital investment, as well as costs of operating labor, utilities, and waste disposal. For fuel switching options, annual costs include the cost differential between the current fuel and the alternate fuel.

The U.S. EPA's *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program* (June 1, 2007) indicates that the four-factor analyses should conform to the methodologies given in the *EPA Air Pollution Control Cost Manual*.[6] This study draws on cost analyses which have followed the protocols set forth in the Cost Manual. Where possible, we have used the primary references for cost data. Cost estimates have been updated to 2007 dollars using the Marshall & Swift Equipment Cost Index or the Chemical Engineering Plant Cost Index, both of which are published in the journal, *Chemical Engineering.*

For Factor 1, results of the cost analysis are expressed in terms of total cost-effectiveness, in dollars per ton of emissions reduced. A relevant consideration in a cost-effectiveness calculation is the economic condition of the industry (or individual facility if the analysis is performed on that basis). Even though a given cost-effectiveness value may, in general, be considered "acceptable," certain industries may find such a cost to be overly burdensome. This is particularly true for well-established industries with low profit margins. Industries with a poor economic condition may not be able to install controls to the same extent as more robust industries. A thorough economic review of the source categories selected for the factor analysis is beyond the scope of this project.

2.2 Factor 2 – Time Necessary for Compliance

For Factor 2, we evaluated the amount of time needed for full implementation of the different control strategies. The time for compliance was defined to include the time needed to develop and implement the regulations, as well as the time needed to install the necessary control equipment. The time required to install a retrofit control device includes time for capital procurement, device design, fabrication, and installation. The Factor 2 analysis also included the time required for staging the installation of multiple control devices at a given facility.

2.3 Factor 3 – Energy and Other Impacts

Table 2-1 summarizes the energy and environmental impacts analyzed under Factor 3. We evaluated the direct energy consumption of the emission control device, solid waste generated, wastewater discharged, acid deposition, nitrogen deposition, and climate impacts (e.g., generation and mitigation of greenhouse gas emissions).

In general, the data needed to estimate these energy and other non-air pollution impacts were obtained from the cost studies which were evaluated under Factor 1. These analyses generally quantify electricity requirements, steam requirements, increased fuel requirements, and other impacts as part of the analysis of annual operation and maintenance costs.

Costs of disposal of solid waste or otherwise complying with regulations associated with waste streams were included under the cost estimates developed under Factor 1, and were evaluated as to whether they could be cost-prohibitive or otherwise negatively affect the facility.

Energy needs and non-air quality impacts of identified control technologies were aggregated to estimate the energy impacts for the specified industry sectors. However, indirect energy impacts were not considered, such as the different energy requirements to produce a given amount of coal versus the energy required to produce an equivalent amount of natural gas.

Table 2-1 Summary of Energy and Environmental Impacts Evaluated Under Factor 3

Energy Impacts
Electricity requirement for control equipment and associated fans
Steam required
Fuel required
Environmental Impacts
Waste generated
Wastewater generated
Additional carbon dioxide (CO_2) produced
Reduced acid deposition
Reduced nitrogen deposition
Benefits from reductions in $PM_{2.5}$ and ozone, where available
Impacts Not Included
Impacts of control measures on boiler efficiency
Energy required to produce lower sulfate fuels
Secondary environmental impacts to produce additional energy (except CO_2) produced

2.4 Factor 4 – Remaining Equipment Life

Factor 4 accounts for the impact of the remaining equipment life on the cost of control. Such an impact will occur when the remaining expected life of a particular emission source is less than the lifetime of the pollution control device (such as a scrubber) that is being considered. In this case, the capital cost of the pollution control device can only be amortized for the remaining lifetime of the emission source. Thus, if a scrubber with a service life of 15 years is being evaluated for a boiler with an expected remaining life of 10 years, the shortened amortization schedule will increase the annual cost of the scrubber.

The ages of major pieces of equipment were determined where possible, and compared with the service life of pollution control equipment. The impact of a limited useful life on the amortization period for control equipment was then evaluated, along with the impact on annualized cost-effectiveness.

2.5 References for Section 2

1. WRAP (2008), *Emissions Data Management System*, Western Regional Air Partnership, Denver, CO, http://www.wrapedms.org/app_main_dashboard.asp.

2. E.H. Pechan & Associates (2005), *AirControlNET*, *Version 4.1 - Documentation Report*, U.S. EPA, RTP, NC, http://www.epa.gov/ttnecas1/AirControlNET.htm.

3. *Coal Utility Environmental Cost (CUECost) Model Version 1.0*, U.S. EPA, RTP, NC, http://www.epa.gov/ttn/catc/products.html.

4. MRPO (2006), *Interim White Papers*-- *Midwest RPO Candidate Control Measures*, Midwest Regional Planning Organization and Lake Michigan Air Directors Consortium, Des Plaines, IL, www.ladco.org/reports/control/white_papers/.

5. NACAA (formerly STAPPA and ALAPCO) (2006), *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, National Association of Clean Air Agencies, www.4cleanair.org/ PM25Menu-Final.pdf.

6. EPA (2002), *EPA Air Pollution Control Cost Manual*, *6th ed.*, EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP, NC, Section 5 - SO_2 and Acid Gas Controls, pp 1-30 through 1-42, http://www.epa.gov/ttncatc1/products.html#cccinfo.

3. Reciprocating Internal Combustion Engines and Turbines

Reciprocating engines and turbines at industrial, commercial, and institutional facilities in the WRAP region are estimated to emit about 274,000 tons of NO_X per year, based on the 2002 emissions inventory for the region.[1] These sources are commonly grouped together under the general category of internal combustion engines. Most of the emissions from this category, about 247,000 tons per year, are from sources that are listed in the point source inventory; however, the area sources inventory also includes about 27,000 tons of NO_X emissions from internal combustion engines. The area source emissions estimates are derived from industrial, commercial, and institutional fuel consumption in the WRAP states. NO_X emissions from internal combustion engines represent about 23% of total point source emissions of NO_X in the WRAP region, and about 19% of all stationary source (point and area source) NO_X emissions in the region.

Table 3-1 shows estimated emissions of NO_X, SO_2, PM_{10}, $PM_{2.5}$ and VOC in the WRAP region, broken down by state, engine type, and fuel. The emissions estimates for NO_X, SO_2, and VOC were taken from the WRAP emissions data management system.[1] Estimates for PM_{10} and $PM_{2.5}$ were taken from the National Emissions Inventory (NEI). As the table shows, SO_2, VOC and particulate matter emissions from reciprocating engines and turbines sources are much lower than NO_X emissions. Emissions of OC and EC are not specifically quantified in either the WRAP inventory or the NEI, but can be estimated as a percentage of PM_{10} emissions using data from EPA's SPECIATE database.[2] EC and OC are estimated to comprise 78.8% and 18.5% of diesel PM_{10} emissions; and 38.4% and 24.7% of natural gas combustion PM_{10} emissions, respectively.

The point source emissions estimates in Table 3-1 include reciprocating engines and turbines used in oil and natural gas production and exploration operations, and at natural gas processing facilities. These emissions are included again in Chapters 3 and 4, which discuss control measures for these operations.

Reciprocating engines account for about 64% of the NO_X emissions from point sources in the internal combustion category, and turbines account for about 36%. The area source inventory does not differentiate between reciprocating engines and turbines, but reciprocating engines are expected to make up the bulk of area sources. Most of the turbines burn gaseous fuels, which include natural gas, liquefied petroleum gas, and industrial process gas. Reciprocating engines are divided between gaseous fuels and liquid fuels, such as kerosene and diesel oil.

Emissions from individual diesel reciprocating engines range up to 850 tons of NO_X per year, and natural gas fired reciprocating engine emissions range up to 1,370 tons of NO_X per year. Individual diesel-fired turbines range up to 1,400 tons of NO_X per year, and natural gas turbines range up to 877 tons NO_X per year.[1]

Table 3-1. Emissions from Reciprocating Internal Combustion Engines and Turbines in the WRAP Region

	AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY	Tribes	Total
NO_X emissions in 2002 (tons/year)																
Point sources																
Turbines - gaseous fuel	44,293	3,593	11,832	4,233	697	321	524	9,433	4,088	2,028	372	1,302	1,267	2,113	1,890	87,987
Turbines - liquid	4,446	15	411	90	3	0	0	109	9	0	3	48	0	0	6	5,142
Reciprocating - gas	50	2,979	10,114	18,628	1,715	2,511	3,861	41,962	84	348	0	3,097	875	1,258	2,348	89,830
Reciprocating - liquid	12,779	1,370	12,735	5,336	312	3,968	305	6,714	209	0	7	2,156	114	13,060	5,051	64,116
Area source (unspecified)																
Natural gas	0	0	14,778	0	0	0	0	0	70	0	0	0	0	0	0	14,848
Kerosene	0	0	11,327	0	0	0	0	922	75	0	0	0	0	0	0	12,323
Total	61,569	7,957	61,197	28,287	2,726	6,800	4,691	59,141	4,535	2,376	383	6,602	2,256	16,431	9,294	274,246
SO_2 emissions in 2002 (tons/year)																
Point sources																
Turbines - gaseous fuel	705	31	352	143	7	9	20	20	20	31	11	22	85	4	18	1,479
Turbines - liquid	2,539	1	75	3	0	0	0	0	0	3	0	4	0	0	0	2,628
Reciprocating - gas	0	2	180	65	0	0	12	244	0	0	0	8	53	11	200	774
Reciprocating - liquid	670	37	689	71	23	234	8	53	14	0	0	185	553	1	19	2,557
Area source (unspecified)																
Natural gas	0	0	12	0	0	0	0	0	0	0	0	0	0	0	0	12
Kerosene	0	0	708	0	0	0	0	84	0	0	0	0	0	0	0	793
Total	3,915	71	2,016	281	31	243	40	402	34	35	11	219	691	17	238	8,243
PM_{10} emissions in 2002 (tons/year)																
Turbines - gas	167	765	459	335	976	115	0	105	27	542	4	6	13	0	2,481	5,995
Turbines - liquid	140	1	88	10	0	0	0	4	5	0	0	2	2	0	0	254
Reciprocating - gas	0	25	232	294	25	0	25	158	0	1	0	27	10	32	14	843
Reciprocating - liquid	179	14	436	42	201	56	2	64	135	1	0	26	1	0	279	1,435
Total	486	806	1,215	681	1,202	171	27	330	167	544	4	61	26	33	2,774	8,527
$PM_{2.5}$ emissions in 2002 (tons/year)																
Turbines - gas	66	665	450	242	966	36	0	53	25	129	3	5	11	0	1,743	4,394
Turbines - liquid	127	1	80	10	0	0	0	3	5	0	0	2	2	0	0	231
Reciprocating - gas	0	24	231	294	25	0	25	160	0	1	0	23	10	32	13	837
Reciprocating - liquid	168	13	418	34	69	38	2	63	131	1	0	22	1	0	127	1,089
Total	361	703	1,179	580	1,060	74	27	280	161	131	4	52	23	33	1,884	6,551
VOC emissions in 2002 (tons/year)																
Turbines - gas	665	93	1,088	652	27	66	40	548	20	217	35	81	65	49	69	3,715
Turbines - liquid	2	0	33	6	0	0	0	2	70	0	0	5	0	0	1	119
Reciprocating - gas	1	133	1,884	3,440	53	88	106	2,326	1	26	0	90	83	441	232	8,904
Reciprocating - liquid	466	29	824	1,340	11	216	23	3,044	9	0	0	198	7	1,236	128	7,531
Total	1,133	256	3,829	5,439	90	370	169	5,920	100	242	36	375	156	1,726	429	20,270

Source: NOX, SO2, and VOC emissions were taken from the WRAP emissions data management system, and PM10 and PM2.5 emissions were taken from the NEI.

Table 3-2 lists potential control measures for NO_X emissions from reciprocating engines and turbines. A number of options were identified for stationary reciprocating engines in an Alternative Control Techniques (ACT) guidance document written by the U.S. EPA in 1993, and in more recent analyses for New Source Performance Standards.[3,4] Reciprocating engines can be designed to operate under rich fuel mixture, or lean fuel mixture conditions. Air-to-fuel-ratio adjustments and ignition retarding adjustments can be used to control emissions under either fuel mixture condition and for diesel or natural gas engines. This approach typically requires the installation of an electronic control system. In addition, fuel efficiency is generally reduced and emissions of soot may be increased. Low-Emission Combustion (LEC) retrofit technology can also reduce emissions from lean burn reciprocating engines by an average of 89%.[5] LEC involves modifying the combustion system to achieve very lean combustion conditions (high air-to-fuel ratios). EPA prepared an update to the ACT guidance for reciprocating engines in 2002 which focused on LEC technology.[5] Selective Catalytic Reduction (SCR) can also be used either alone or in conjunction with the above technologies to reduce NO_X emissions from reciprocating engines or turbines by 90%.[6] In addition, Non-Selective Catalytic Reduction (NSCR) can be used for rich-burn natural gas engines.[4]

A separate ACT guidance document identifies control options for particulate matter emissions from diesel engines.[7] In addition, the WRAP sponsored a study of control options for engines used in the oil and gas industry.[8] This study covered control measures for NO_X, particulate matter, and VOC.

Another ACT guidance document analyzed control options for turbines using gaseous and liquid fuels. [9] Turbines can be retrofit with water or steam injection to reduce emissions by up to 80%. In addition, SCR can be used in conjunction with water or steam injection or low-NO_X burner technology to reduce emissions by 93 to 96%. The ACT did not analyze retrofit installations or low-NOX burner technology for turbines, or impact of SCR used alone (without water or steam injection or low-NO_X burner technology).

3.1 Factor 1 – Costs

Table 3-3 provides cost estimates for the emission control options which have been identified for reciprocating engines and turbines. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. Retrofit costs were not available for low-NO_X burners.

The capital and annual cost figures are expressed in terms of the cost per unit of engine size, where the engine size is expressed in horsepower for reciprocating engines and million British thermal units per hour (MM-Btu/hr) for turbines. The table shows a range of values for each cost figure, since the cost per unit of engine size will depend on the engine size and other factors. The lower ends of the cost ranges typically reflect larger engines, and the higher ends of the cost ranges typically reflect lower engine sizes. Table 3-3 also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

Table 3-2. Control Options for Reciprocating Engines and Turbines

Source Type	Control Technology	Pollutant controlled	Baseline emissions (1000 tons/yr)	Estimated control effieiency (%)	Potential emission reduction (1000 tons/year)	Refer-ences
Turbines	Water or steam injection	NO_X	95	68 - 80	65 - 76	9
	Low-NO_X burners	NO_X	95	68 - 84	65 - 80	9
	SCR	NO_X	95	90	80	6,7,9
	Water or steam injection with SCR	NO_X	95	93 - 96	88 - 91	9
Reciprocating engines, gaseous fuels	Air-fuel ratio adjustment	NO_X	105	10 - 40	10 - 42	3
	Ignition retarding technologies	NO_X	105	15 - 30	16 - 31	3
	Low-emission combustion (LEC) retrofit	NO_X	105	80 - 90	84 - 94	5
	SCR	NO_X	105	90	94	3,4,6
	NSCR	NO_X	a	90 - 99	a	4
		VOC	a	40 - 85	a	4
	Replacement with electric motors	NO_X	105	100	105	8
		SO_2	0.79	100	0.79	
		PM_{10}	0.84	100	0.84	
		$PM_{2.5}$	0.84	100	0.84	
		EC	0.32	100	0.32	
		OC	0.21	100	0.21	
		VOC	8.9	100	8.9	
		Overall[b]	115		116	
Reciprocating engines, diesel and other liquid fuels	Ignition timing retard	NO_X	76	15 - 30	11 - 23	3,8
	EGR	NO_X	76	40	31	3,8
	SCR	NO_X	76	80 - 95	61 - 73	3,4,6,8
	Replacement of Tier 2 engines with Tier 4	NO_X	76	87	67	8
		PM_{10}	1.4	85	1.2	
		$PM_{2.5}$	1.1	85	0.9	
		EC	0.6	85	0.5	
		OC	0.5	85	0.4	
		VOC	7.5	87	6.6	
		Overall[b]	85		75	
	Diesel oxidation catalyst	PM_{10}	1.4	25	0.4	7,8
		$PM_{2.5}$	1.1	25	0.3	
		EC	0.6	25	0.2	
		OC	0.5	25	0.1	
		VOC	7.5	90	6.8	
		Overall[b]	9.0		7.2	

[a] NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[b] For control measures reducing multiple pollutants, overall emissions and emission reductions reflect the sum of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the totals.

Table 3-3. Estimated Costs of Control Options for Reciprocating Engines and Turbines

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/unit)	Estimated annual cost ($/year /unit)	Units	Cost effectiveness ($/ton)	Refer-ences
Turbines	Water or steam injection	NO_X	68 - 80	4.4 - 16	2 - 5	1000 Btu	560 - 3,100	9
	Low-NO_X burners[a]	NO_X	68 - 84	8 - 22	2.7 - 8.5	1000 Btu	5,200 - 16,200	9
	SCR	NO_X	90	8 - 22	2.7 - 8.5	1000 Btu	2000 - 10,000	6,7,9
	Water or steam injection with SCR	NO_X	93 - 96	13 - 34	5.1 - 13	1000 Btu	1,000 - 6,700	9
Reciprocating engines, gaseous fuels	Air-fuel ratio adjustment	NO_X	10 - 40	4.4 - 43	13 - 86	hp	320 - 8,300	3
	Ignition retarding technologies	NO_X	15 - 30	na	10 - 32	hp	310 - 2,000	3
	LEC retrofit	NO_X	80 - 90	120 - 820	30 - 210	hp	320 - 2,500	5
	SCR	NO_X	90	20 - 180	40 - 461	hp	430 - 4,900	3,4,6
	NSCR[b]	NO_X	90 - 99	17 - 35	3 - 6	hp	16 - 36	4
		VOC	40 - 85				1,500 - 6,200	4
		Overall[c]					16 - 36	
	Replacement with electric motors	NO_X	100	120 - 140	38 - 44	hp	100 - 4,700	8
		SO_2					>13,000	
		PM_{10}					>13,000	
		$PM_{2.5}$					>13,000	
		EC					>33,000	
		OC					>50,000	
		VOC					1,000 - 60,000	
		Overall[c]					90 - 4,300	
Reciprocating engines, diesel and other liquid fuels	Ignition timing retard	NO_X	15 - 30	16 - 120	14 - 66	hp	1,000 - 2,200	3,8
	EGR	NO_X	40	100	26 - 67	hp	780 - 2,000	3,8
	SCR	NO_X	80 - 95	100 - 2,000	40 - 1,200	hp	3,000 - 7,700	3,4,6,8
	Replacement of Tier 2 engines with Tier 4	NO_X	87	125	20	hp	900 - 2,400	8
		PM_{10}	85				25,000 - 68,000	
		$PM_{2.5}$	85				25,000 - 68,000	
		EC	85				>50,000	
		OC	85				>50,000	
		VOC	87				22,000 - 59,000	
		Overall[c]					840 - 2,200	
	Diesel oxidation catalyst	PM_{10}	25	10	1.7	hp	1,400	7,8
		$PM_{2.5}$	25				1,400	
		EC	25				3,300	
		OC	25				4,200	
		VOC	90				350	
		Overall[c]					280	

[a] Costs estimates for low-NO_X burners reflect the incremental costs of new low-NO_X burners versus standard burners. Retrofit costs for existing burners were not available.

[b] NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[c] For control measures reducing multiple pollutants, the overall cost-effectiveness is the cost per total reduction of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the emission reduction total.

3.2 Factor 2 – Time Necessary for Compliance

Once a state decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[10] However, the time necessary will depend on the type and size of the unit being controlled. For instance, state regulators' experience indicates that closer to 18 months is required to install this technology.[11] Additional time up to 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required achieve emission reductions for reciprocating engines and turbines is estimated at a total of 5½ years.

3.3 Factor 3 – Energy and Other Impacts

Table 3-4 shows the estimated energy and non-air pollution impacts of control measures for reciprocating engines and turbines. In general, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value of about 2.5%.[12,13] This increased fuel consumption would result in increased CO_2 emissions. LEC technology is not expected to increase fuel consumption; and may provide some fuel economy.[12]

Diesel oxidation catalyst and diesel filtration technologies would produce an increase in fuel consumption in order to overcome the pressure drop through the catalyst bed and the filter. This is assumed to be roughly the same as the increase in fuel consumption for SCR installations, about 0.5%.[12] In the case of diesel oxidation catalyst, the catalyst would have to be changed periodically, producing an increase in solid waste disposal.[14] If diesel reciprocating engines are replaced with electric motors, there would be an increase in electricity demand, but this would be offset by the fuel consumption that would be avoided by replacing the engine.

For turbines, water injection and steam injection would require electricity to operate pumps and ancillary equipment.[14] Water injection would produce an increase in fuel consumption in order to evaporate the water, and steam injection would require energy to produce the steam. The increased electricity, steam, and fuel demands would produce additional CO_2 emissions.

Installation of SCR on any type of engine would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed.[12] This would produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[14]

Table 3-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Reciprocating Engines and Turbines

					Energy and non-air pollution impacts (per ton of emission reduced)				
Source Type	Control Technology	Pollutant controlled	Potential emission reduction (1000 tons/year)	Additional fuel requirement (%)	Electricity requirement (kW-hr)	Steam requirement (tons steam)	Solid waste produced (tons waste)	Wastewater produced (1000 gallons)	Additional CO_2 emitted (tons)
Turbines	Water or steam injection	NO_X	65 - 76	a		31			8.1
	Low-NO_X burners	NO_X	65 - 80	a					
	SCR	NO_X	80	a					
	Water or steam injection with SCR	NO_X	88 - 91	0.45			0.026		1.7
Reciprocating engines, gaseous fuels	Air-fuel ratio controllers	NO_X	10 - 42	a					
	Ignition retarding technologies	NO_X	16 - 31	a					
	LEC retrofit	NO_X	84 - 94	a					
	SCR	NO_X	94	0.5			0.008		0.43
	NSCR	NO_X, VOC	d	0.5			0.008		0.24
	Replacement with electric motors	NO_X	105	(100)	66,000				b
		SO_2	0.79						
		PM_{10}	0.84						
		$PM_{2.5}$	0.84						
		EC	0.32						
		OC	0.21						
		VOC	8.9						
		Overall[e]	116						
Reciprocating engines, diesel and other liquid fuels	Ignition timing retard	NO_X	11 - 23	a					
	EGR	NO_X	31	2.7					2.0
	SCR	NO_X	61 - 73	0.5			0.008		0.38
	Replacement of Tier 2 engines with Tier 4	NO_X	67	c					c
		PM_{10}	1.2						
		$PM_{2.5}$	0.9						
		EC	0.5						
		OC	0.4						
		VOC	6.6						
		Overall[e]	75						
	Diesel oxidation catalyst	PM_{10}	0.4	0.5			b		316
		$PM_{2.5}$	0.3						
		EC	0.2						
		OC	0.1						
		VOC	6.8						2.5
		Overall[e]	7.2						2.6[d]

NOTES:

blank indicates no impact is expected.

[a] The measure is expected to improve fuel efficiency.

[b] CO_2 from the generation of electricity would be offset by avoided emissions due to replacing the diesel engine

[c] EPA has estimated that the control measures used to meet Tier 4 standards will be integrated into the engine design so that sacrifices in fuel economy will be negligible.

[d] NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[e] For control measures reducing multiple pollutants, overall emissions and reflect the sum of all pollutants. However, EC, OC, and $PM_{2.5}$ are components of PM_{10}, and therefore are not added separately to the totals. Impacts are expressed as the impact per ton of total polluants reduced.

3.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of reciprocating engines and turbines in the WRAP region. However, engines in industrial service are often refurbished to extend their lifetimes. Therefore, the remaining lifetime of most reciprocating engines and turbines is expected to be longer than the projected lifetime of pollution control technologies which have been analyzed for this category. In the case of add-on technologies such as SCR, the projected lifetime is 15 years.

If the remaining life of a reciprocating engine or turbine is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1-(1+r)^{-m}}{1-(1+r)^{-n}}$$

where:

A_1 = the annual cost of control for the shorter equipment lifetime ($)
A_0 = the original annual cost estimate ($)
C = the capital cost of installing the control equipment ($)
r = the interest rate (0.07)
m = the expected remaining life of the emission source (years)
n = the projected lifetime of the pollution control equipment

3.5 References for Section 3

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4. Oil and Gas Exploration and Production Field Operations

The WRAP region is an important domestic source of crude oil and natural gas. Many of the WRAP states have active production fields for oil and natural gas; and exploration operations are also underway to identify additional reserves. Both the production and exploration industries involve a number of operations which emit NO_X, SO_2, particulate matter and VOC. Turbines are used to drive compressors and other equipment, and diesel engines are used in a variety of applications. Flares and incinerators are used to dispose of waste gases, and process heaters are used in various operations. In addition, emissions emanate from various gas treatment operations, such as glycol dehydrators and amine treatment units.

Table 4-1 summarizes emissions from the industry, broken down by state and by the various emission sources. Point source emissions of NO_X, SO_2, and VOC from these operations were extracted from the 2002 WRAP emissions inventory, which catalogs emission sources by their Standard Industrial Classification (SIC).[1] SIC 131 covers crude petroleum and natural gas production, and SIC 138 covers oil and gas field exploration services. Estimates for PM_{10} and $PM_{2.5}$ were extracted from the 2002 National Emissions Inventory (NEI), which also classifies emissions by SIC. It must be noted that the point source emissions in Table 4-1 for reciprocating engines and turbines in the oil and gas production and exploration sector are also included in the emission totals reported in Table 3-1 (for all reciprocating engines and turbines). However, the point source inventories do not include small engines such as oil well motors and gas well engines. Emissions for these sources have been estimated by the WRAP in a separate oil and gas industry study,[2] and these estimates are also included in Table 4-1.

Based on the inventory emissions estimates, NO_X emissions are the predominant regional haze precursor emissions in oil and gas exploration and production operations. Overall NO_X emissions from these operations are estimated at about 294,000 tons/year, which represent about 20% of stationary source (point and area source) NO_X emissions in the region. These result from combustion processes in engines, turbines, heaters, incinerators, and flares. It should be noted that emissions from point source engines and turbines, about 166,000 tons/year, also fall into the reciprocating engines and turbines category discussed in Chapter 3. However, according to an analysis of oil and gas emission sources sponsored by the WRAP, emissions estimates from small engines at oil and gas operations are not believed to be included in the area source inventory internal combustion estimates.[2]

Most turbines at oil and gas production and exploration operations are fired by natural gas. Emissions from individual natural gas turbines at production operations range up to about 877 tons of NO_X per year, which is comparable to natural gas turbines at industrial facilities. Emissions from individual natural gas turbines at exploration operations range up to 131 tons of NO_X per year. Natural gas reciprocating engines at oil and gas production and exploration operations are somewhat smaller than natural gas reciprocating engines at industrial facilities. NO_X emissions from individual gas reciprocating engines range up to 700 tons per year for oil

Table 4-1. Emissions from Oil and Gas Production and Exploration in the WRAP Region

Emission source			AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WY	Tribes	Total
NO$_X$ emissions (tons/year)																	
Production	Point sources	Recip. Engines (mostly gas)	4,208	642	8,050	24,525	2,590	3,996	4,838	52,219	83	1,182	323	2,983	12,272	1,127	119,519
		Turbines, gas	40,987		2,490	571		0	0	345	0			66	956	630	46,044
		Process heaters	935		1,518	100		4	84	339	0			12	92	1	3,085
		Flares	361		72	17		0	164	48	0			12	95	2	772
	Other engines	Oil well motors	0	0		9		42	75	329	1		3	31	111		601
		Compressor engines		8		3,271		1,791	2,920	35,140	33	73	284	843	1,791		46,154
		Other gas well engines	9	9	8,070	15,946		4,678	101	14,602	4	12	44	2,127	6,398		52,000
		Coal methane pumps				1,489				92					1,428		3,009
Exploration	Point sources	Recip. Engines (mostly gas)	235		268	123		0	0	3,447	0			0	195	0	4,269
		Turbines, gas	0		0	0		0	0	890	0			0	0	0	890
		Other	64		128	93		0	0	187	0			18	182	2	673
	Non-point engines	Drill rig motors	877			2,803		1,046	1,536	5,476	24		29	334	4,997		17,122
Total			47,677	659	20,597	48,947	2,590	11,557	9,718	113,113	145	1,267	683	6,426	28,517	1,762	293,658
SO$_2$ **emissions (tons/year)**																	
Production	Point sources	Incinerators	0		17	0		0	199	0	0			1,420	7,404	0	9,041
		Flares	38		158	3		2	77	3,822	0			33	4,318	48	8,499
		Sulfur recovery units	0		0	0		0	283	820	0			0	1,284	0	2,387
		Process heaters (gas)	92		730	1		0	0	69	0			0	0	3	896
		Turbines, gas	704		57	1		0	0	0	0			1	0	10	773
		Recip. Engines (mostly gas)	17		43	35		0	11	0	0			0	0	196	302
		Other	8		95	55		0	0	36	0			0	2	1	197
Exploration	Non-point engines	Drill rig motors	66			118		225	358	244	1		6	17	150		1,185
Total			926		1,099	212		227	929	4,992	1		6	1,472	13,159	258	23,280
PM$_{10}$ emissions (tons/year)																	
Production	Point sources	Process heaters, gas	50	0	268	7	0	0	0	12	0	0	0	0	2	0	339
		Recip. Engines (mostly gas)	0		11	189		0	0	3	0			3	5	0	211
		Turbines, gas	144		36	13		0	0	1	0			0	0	0	194
		Other	107	0	70	14	0	0	0	14	0	0	0	3	1	0	209

Table 4-1. Emissions from Oil and Gas Production and Exploration in the WRAP Region

Emission source			AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WY	Tribes	Total
Exploration	Point sources	General	0	0	10	2	0	0	0	7	0	0	0	0	0	0	19
Total			301	0	395	224	0	0	0	37	0	0	0	6	8	0	972
PM $_{2.5}$ emissions (tons/year)																	
Production	Point sources	Process heaters, gas	44		268	7		0	0	12	0			0	2	0	333
		Recip. Engines (mostly gas)	0		11	189		0	0	3	0			1	5	0	209
		Turbines - natural gas	60		34	12		0	0	1	0			0	0	0	108
		Other	65	0	69	13	0	0	0	12	0	0	0	2	1	0	162
Exploration	Point sources	General	0	0	10	1	0	0	0	7	0	0	0	0	0	0	18
Total			169	0	392	222	0	0	0	35	0	0	0	4	8	0	830
VOC emissions (tons/year)																	
Production	Point sources	Recip. Engines (mostly gas)	209		647	3,697		28	55	670	0			96	294	213	5,908
		Fugitive emissions	0		1,302	1,079		6	0	125	3			75	747	50	3,388
		Glycol dehydrator	25		3	2,669		2	0	126	0			48	229	95	3,195
		Other	2		602	1,313		0	0	1	17			61	297	48	2,340
		Storage	0		405	611		2	0	125	3			41	43	20	1,251
		Process heaters	49		167	751		0	6	159	0			1	11	20	1,163
		Turbines	641		210	103		0	0	11	0			14	42	46	1,066
		Flares	527		67	10		0	6	33	0			25	33	3	704
Exploration	Point sources	Recip. Engines (mostly gas)	5		6	34		0	0	1,900	0			0	107	0	2,052
		Storage	0		1	0		0	0	979	0			0	1	0	981
		Glycol dehydrator	0		0	34		0	0	605	0			0	6	0	645
		Fugitive emissions	0		0	2		0	0	180	0			0	30	0	213
		Other	11		15	113		0	0	233	0			1	252	1	626
Total			1,469		3,424	10,417		38	67	5,148	22			361	2,090	497	23,533

and gas production operations, and up to 210 tons per year for exploration operations, compared with a maximum of 1,370 tons per year for reciprocating engines at industrial facilities. Diesel engines at oil and gas operations are also smaller than those at industrial facilities. NO_X emissions from individual diesels range up to 46 tons per year for production operations, and 10 tons per year for exploration operations, compared with 850 tons per year for the largest industrial diesel engine.[1]

SO_2 emissions from oil and gas exploration and production are estimated to be an order of magnitude lower than NO_X emissions. SO_2 emissions from incinerators and flares result from the presence of sulfur compounds in waste gases that are burned at the production site. These are generally the waste gases from natural gas sweetening operations such as amine treatment units. Although the process heaters at oil and gas production facilities are listed as using natural gas fuel, SO_2 emissions from these sources are reported to be about 4,000 tons/year. These emissions may result from the combustion of unsweetened natural gas at the well head. SO_2 emissions from drill rig motors also result from the presence of sulfur compounds in the motor fuels.

PM_{10}, $PM_{2.5}$, and VOC emissions from oil and gas exploration and production are also estimated to be an order of magnitude lower than NO_X emissions. Emissions of OC and EC are specifically quantified in either the WRAP inventory or the NEI, but can be estimated as a percentage of PM_{10} emissions using data from EPA's SPECIATE database.[3] EC and OC are estimated to comprise 78.8% and 18.5% of diesel PM_{10} emissions; and 38.4% and 24.7% of natural gas combustion PM_{10} emissions, respectively.

Table 4-2 lists potential control measures for oil and gas production and exploration emissions. The table includes options for reciprocating engines and turbines, process heaters, flares and incinerators, and sulfur recovery units. As discussed in Chapter 3, a number of options are available to control emissions from gas-fired reciprocating engines, diesel-fueled reciprocating engines, and turbines.[2,4,5,6,7,8] Reciprocating engines can be designed to operate under rich fuel mixture, or lean fuel mixture conditions. Air-to-fuel-ratio adjustments and ignition retarding technologies can be used to control emissions under either fuel mixture condition. Low-Emission Combustion (LEC) retrofit technology which can also reduce emissions from lean burn reciprocating engines by an average of 89%. LEC involves modifying the combustion system to achieve very lean combustion conditions (high air-to-fuel ratios). Selective Catalytic Reduction (SCR) can also be used either alone or in conjunction with the above technologies to reduce NO_X emissions from reciprocating engines or turbines by 90%. In addition, Non-Selective Catalytic Reduction (NSCR) can be used for rich-burn natural gas engines.[8]

SO_2 emissions from incinerators and flares could be avoided by installing sulfur recovery units to remove sulfur from the waste gases prior to incineration or flaring.[9] These emissions can also be reduced by compressing sulfur-containing acid gases and injecting these gases into non-producing rock formations.[10] Flue gas scrubbing has also been used to control SO_2 emissions from incinerators.[11,12] SO_2 emissions from existing sulfur recovery units can be reduced by adding additional recovery stages, or by adding a tail gas treatment unit.[12] In some cases, it may be possible to avoid SO_2 emissions from process heaters by substituting a lower-sulfur sweetened natural gas for the gas currently being burned. A number of options are available to

Table 4-2. Control Options for Oil and Gas Production and Exploration

Source Type	Control Technology	Pollutant controlled	Baseline emissions (1000 tons/yr)	Estimated control efficiency (%)	Potential emission reduction (1000 tons/year)	Refer-ences
Compressor engines and gas fueled reciprocating engines	Air-fuel ratio adjustment	NO_X	166	10 - 40	17 - 66	2,5
	Ignition timing retard	NO_X	166	15 - 30	25 - 50	2
	Low-emission combustion (LEC) retrofit	NO_X	166	80 - 90	130 - 150	2,5
	SCR	NO_X	166	90	150	2,8,12
	NSCR	NO_X	a	90 - 99	a	8
		VOC	a	40 - 85	a	8
	Replacement with electric motors	NO_X	166	100	166	2
		SO_2	0.30	100	0.30	
		PM_{10}	0.21	100	0.21	
		$PM_{2.5}$	0.21	100	0.21	
		EC	0.08	100	0.08	
		OC	0.05	100	0.05	
		VOC	5.9	100	5.9	
		Overall[b]	172		172	
Drilling rig engines and other diesel engines	Ignition timing retard	NO_X	60	15 - 30	9 - 18	2
	Exhaust gas recirculation	NO_X	60	40	24	2
	SCR	NO_X	60	80 - 95	48 - 57	2,8,12
	Replacement of Tier 2 engines with Tier 4	NO_X	60	87	52	2
		PM_{10}	0.2	85	0.2	2
		$PM_{2.5}$	0.2	85	0.2	
		EC	0.1	85	0.1	
		OC	0.1	85	0.1	
		VOC	8.0	87	6.9	2
		Overall[b]	68		59	
	Diesel oxidation catalyst	PM_{10}	0.23	25	0.06	2
		$PM_{2.5}$	0.18	25	0.05	
		EC	0.10	25	0.03	
		OC	0.08	25	0.02	
		VOC	8.0	90	7.2	2
		Overall[b]	8.2		7.3	
Turbines	Water or steam injection	NO_X	47	68 - 80	32 - 38	11
	Low-NO_X burner (LNB)	NO_X	47	68 - 84	32 - 39	11
	SCR	NO_X	47	90	42	6,7,12
	Water or steam injection with SCR	NO_X	47	93 - 96	44 - 45	11

Table 4-2. Control Options for Oil and Gas Production and Exploration

Source Type	Control Technology	Pollutant controlled	Baseline emissions (1000 tons/yr)	Estimated control efficiency (%)	Potential emission reduction (1000 tons/year)	Refer-ences
Flares	Add or expand sulfur recovery unit	SO_2	8.5	90 - 95	c	9
	Acid gas injection	SO_2	8.5	100	c	10
Incinerators	Spray dryer absorber	SO_2	9.0	80 - 95	7.2 - 8.6	12
	Wet FGD	SO_2	9.0	90 - 99	8.1 - 9	11,12
	Acid gas injection	SO_2	9.0	100	c	10
Sulfur recovery units	Additional recovery stages	SO_2	2.4	94 - 96	2.2 - 2.3	11,14
	Tail gas treatment unit (TGTU)	SO_2	2.4	90 - 99.5	2.1 - 2.4	11,14
Process heaters	Substitution of lower sulfur fuel	SO_2	4.0	up to 90	0 - 3.6	9,12
	LNB	NO_X	3.1	40	1.2	13,14
	ULNB	NO_X	3.1	75 - 85	2.3 - 2.6	12,13,14
	LNB and FGR	NO_X	3.1	48	1.5	13,14
	SNCR	NO_X	3.1	60	1.9	12,13,14
	SCR[d]	NO_X	3.1	70 - 90	2.2 - 2.8	12,13,14
	LNB and SCR	NO_X	3.1	70 - 90	2.2 - 2.8	12,13,14
Glycol dehydrators	Optimize glycol circulation rate	VOC	3.8	33 - 67	1.3 - 2.6	2

[a] NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[b] For control measures reducing multiple pollutants, overall emissions and emission reductions reflect the sum of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the totals.

[c] Insufficient information is available in the emissions inventory to determine the percentage of flare or incinerator emissions in this category that is amenable to these control strategies.

[d] SCR can be used for mechanical draft process heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR.

reduce NO_X emissions from process heaters. Combustion modifications including low-NO_X burners (LNB), ultralow-NO_X burners (ULNB), and flue gas recirculation (FGR) reduce the formation of NO_X. In addition, flue gases from the process heaters can be treated with selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) to reduce NO_X emissions. These post-combustion controls can be used either alone or in conjunction with combustion controls.[13,14]

4.1 Factor 1 – Costs

Table 4-3 provides cost estimates for the emission control options which have been identified for oil and gas production and exploration operations. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The capital and annual cost figures are expressed in terms of the cost per unit of engine size or per unit of process throughput. Engine size is expressed in horsepower for reciprocating engines and MMBtu/hour for turbines. Throughput for process heaters is also expressed in MMBtu/hour. Process throughput for sulfur recovery units is expressed in terms of the amount of sulfur recovered.

Sulfur recovery units are believed to be more cost-effective than post-combustion controls for reducing SO_2 emissions from flares and incinerators at oil and gas production operations. Recent analyses of controls for Regional Haze precursors have focused on add-on controls for SO_2, rather than such process modifications. However, costs of sulfur recovery units were estimated in an earlier study of model refineries in different size ranges.[9] These estimates have been updated to current dollars using the Chemical Engineering plant cost index.

Table 4-3 shows a range of values for each cost figure, since the cost per unit of process throughput size will depend on the process size and other factors. The lower ends of the cost ranges typically reflect larger engines or processes, and the higher ends of the cost ranges typically reflect smaller engines or processes. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

4.2 Factor 2 – Time Necessary for Compliance

Once a state decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[15] However, the time necessary will depend on the type and size of the unit being controlled. For instance, state regulators' experience indicates that closer to 18 months is required to install this technology.[16] In the CAIR analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[17] The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required to achieve emission reductions for oil and gas production and exploration operations is estimated at a total of 6½ years.

Table 4-3. Estimated Costs of Control for Oil and Gas Production and Exploration

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/unit)	Estimated annual cost ($/year /unit)	Units	Cost effectiveness ($/ton)	Refer-ences
Compressor engines	Air-fuel ratio adjustment	NO_X	10 - 40	5.3 - 42	0.9 - 6.8	hp	68 - 2,500	2,5
	Ignition timing retard	NO_X	15 - 30	na	1 - 3	hp	42 - 1,200	2
	LEC retrofit	NO_X	80 - 90	120 - 820	30 - 210	hp	320 - 2,500	5
	SCR	NO_X	90	100 - 450	40 - 270	hp	870 - 31,000	2,8,12
	NSCR[a]	NO_X	90 - 99	17 - 35	3 - 6	hp	16 - 36	8
		VOC	40 - 85				1,500 - 6,200	8
		Overall[b]					16 - 36	
	Replacement with electric motors	NO_X	100	120 - 140	38 - 44	hp	100 - 4,700	2
		SO_2					>55,000	
		PM_{10}					>79,000	
		$PM_{2.5}$					>79,000	
		EC					>205,000	
		OC					>319,000	
		VOC					3,000 - 130,000	
		Overall[b]					100 - 4,500	
Drilling rig engines and other engines	Ignition timing retard	NO_X	15 - 30	16 - 120	14 - 66	hp	1,000 - 2,200	2
	EGR	NO_X	40	100	26 - 67	hp	780 - 2,000	2
	SCR	NO_X	80 - 95	100 - 2,000	40 - 1,200	hp	3,000 - 7,700	2,8,12
	Replacement of Tier 2 engines with Tier 4	NO_X	87	125	20	hp	900 - 2,400	2
		PM_{10}	85	125	20	hp	25,000 - 68,000	2
		$PM_{2.5}$						
		EC						
		OC						
		VOC	87	125	20	hp	22,000 - 59,000	2
		Overall[b]					840 - 2,200	
	Diesel oxidation catalyst	PM_{10}	25	10	1.7	hp	1400	2
		$PM_{2.5}$					1400	
		EC					3,300	
		OC					4,200	
		VOC	90	10	1.7	hp	350	2
		Overall[b]					280	

Table 4-3. Estimated Costs of Control for Oil and Gas Production and Exploration

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/unit)	Estimated annual cost ($/year /unit)	Units	Cost effectiveness ($/ton)	Refer-ences
Turbines	Water or steam injection	NO_X	68 - 80	4.4 - 16	2 - 5	1000 BTU	560 - 3,100	7
	Low-NO_X burners[c]	NO_X	68 - 84	8 - 22	2.7 - 8.5	1000 BTU	2,000 - 10,000	7
	SCR	NO_X	90	13 - 34	5.1 - 13	1000 BTU	1,000 - 6,700	6,7,12
	Water or steam injection with SCR	NO_X	93 - 96	13 - 34	5.1 - 13	1000 BTU	1,000 - 6,700	7
Flares	Add or expand sulfur recovery unit	SO_2	90 - 95	0.1 - 1.1	28 - 190	ton-Sulfur/year	14 - 95	9
	Acid gas injection	SO_2	100					10
Incinerators	Spray dryer absorber	SO_2	80 - 95				1,500-1,900	12
	Wet FGD	SO_2	90 - 99				1,500 - 1,800	11,12
	Acid gas injection	SO_2	100					10
Sulfur recovery units	Additional recovery stages	SO_2	94 - 96					11,14
	Tail gas treatment unit (TGTU)	SO_2	90 - 99.5				1,100 - 1,200	11,14
Process heaters	Substitution of lower sulfur fuel	SO_2	up to 90					9,12
	LNB	NO_X	40	3.8 - 7.6	0.41 - 0.81	1000 BTU	2,100 - 2,800	13,14
	ULNB	NO_X	75 - 85	4.0 - 13	0.43 - 1.3	1000 BTU	1,500 - 2,000	12,13,14
	LNB and FGR	NO_X	48	16	1.7	1000 BTU	2,600	13,14
	SNCR	NO_X	60	10 - 22	1.1 - 2.4	1000 BTU	4,700 - 5,200	12,13,14
	SCR[d]	NO_X	70 - 90	33 - 48	3.7 - 5.6	1000 BTU	2,900 - 6,700	12,13,14
	LNB and SCR	NO_X	70 - 90	37 - 55	4 - 6.3	1000 BTU	2,900 - 6,300	12,13,14
Glycol dehydrators	Optimize glycol circulation rate	VOC	33 - 67	31 - 170	5 - 28	gal/hr		2

[a] NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[b] For control measures reducing multiple pollutants, the overall cost-effectiveness is the cost per total reduction of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the emission reduction total.

[c] Costs estimates for low-NO_X burners for turbines reflect the incremental costs of new low-NO_X burners versus standard burners. Retrofit costs for existing burners were not available.

[d] SCR cost estimates for process heaters apply to mechanical draft heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR. This would increase both the capital and annualized costs of control by about 10%.

4.3 Factor 3 – Energy and Other Impacts

Table 4-4 shows the estimated energy and non-air pollution impacts of control measures for sources at oil and gas production and exploration operations. For gas-fired reciprocating engines and diesel engines, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value of about 2.5%.[18,19] This increased fuel consumption would result in increased CO_2 emissions. LEC technology is not expected to increase fuel consumption; and may provide some fuel economy.[18]

Diesel oxidation catalyst and diesel filtration technologies would produce an increase in fuel consumption in order to overcome the pressure drop through the catalyst bed and the filter. In the case of diesel oxidation catalyst, the catalyst would have to be changed periodically, producing an increase in solid waste disposal.[20] If diesel reciprocating engines are replaced with electric motors, there would be an increase in electricity demand, but this would be offset by the fuel consumption that would be avoided by replacing the engine.

For turbines, water injection and steam injection would require electricity to operate pumps and ancillary equipment.[20] Water injection would produce an increase in fuel consumption in order to evaporate the water, and steam injection would require energy to produce the steam. The increased electricity, steam, and fuel demands would produce additional CO_2 emissions.

Installation of SCR on any type of engine would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed.[18] This would produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[20]

Sulfur recovery units require electricity and steam. Wet or dry scrubbers applied to incinerators and tail gas treatment units applied to sulfur recovery units would use electricity for the fan power needed to overcome the scrubber pressure drop. These systems would also produce solid waste, and wet scrubbers would produce wastewater which would require treatment. Injection of acid gases would require the consumption of fuel to compress the gases. However, this option would also result in the sequestration of CO2 present in the injected gas stream.[10]

Low-NO_X burners for process heaters are expected to improve overall fuel efficiency. FGR would require additional electricity to recirculate the fuel gas into the heater. In SCR systems for process heaters, fans would be required to overcome the pressure drop through the catalyst bed. The fans would require electricity, with resultant increases in CO_2 to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[20]

Table 4-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Oil and Gas Production and Exploration

					Energy and non-air pollution impacts (per ton of emission reduced)				
Source Type	**Control Technology**	**Pollutant controlled**	**Potential emission reduction (1000 tons/year)**	**Additional fuel requirement (%)**	**Electricity requirement (kW-hr)**	**Steam requirement (tons steam)**	**Solid waste produced (tons waste)**	**Wastewater produced (1000 gallons)**	**Additional CO_2 emitted (tons)**
Compressor engines	Air-fuel ratio adjustment	NO_X	17 - 66	a					
	Ignition retarding technologies	NO_X	25 - 50	a					
	LEC retrofit	NO_X	130 - 150	a					
	SCR	NO_X	150	0.5			0.008		0.43
	NSCR	NO_X, VOC	e	0.5			0.008		0.24
	Replacement with electric motors	NO_X	166	(100)	66,000				b
Drilling rig engines and other engines	Ignition timing retard	NO_X	9 - 18	a					
	EGR	NO_X	24	2.7					2.0
	SCR	NO_X	48 - 57	0.5			0.008		0.38
	Replacement of Tier 2 engines with Tier 4	NO_X	52	c					c
		$PM_{2.5}$, PM_{10}, EC, OC	0.2	c					c
		VOC	6.9	c					c
		Total[e]	59						
	Diesel oxidation catalyst	$PM_{2.5}$, PM_{10}, EC, OC	0.1	0.5			b		316
		VOC	7.2						2.5
		Total[f]	7.3						2.6[e]
Turbines	Water or steam injection	NO_X	32 - 38	a		31			8.1
	Low-NO_X burner (LNB)	NO_X	32 - 39	a					
	SCR		42	a					
	Water or steam injection with SCR	NO_X	44 - 45	0.45			0.026		1.7

Table 4-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Oil and Gas Production and Exploration

					Energy and non-air pollution impacts (per ton of emission reduced)				
Source Type	Control Technology	Pollutant controlled	Potential emission reduction (1000 tons/year)	Additional fuel requirement (%)	Electricity requirement (kW-hr)	Steam requirement (tons steam)	Solid waste produced (tons waste)	Wastewater produced (1000 gallons)	Additional CO_2 emitted (tons)
Process heaters	Substitution of lower sulfur fuel	SO_2	0 - 3.6	b					b
	LNB	NO_X	1.2	a	g				
	ULNB	NO_X	2.3 - 2.6	a	g				
	LNB and FGR	NO_X	1.5		3,300				3.3
	SNCR	NO_X	1.9	0.16	460				3.2
	SCR	NO_X	2.2 - 2.8		8,400		0.073		8.4
	LNB and SCR	NO_X	2.2 - 2.8		8,400		0.073		8.4
Flares	Add or expand sulfur recovery unit	NO_X	up to 8.5		270	3.2	<0.01		1.1
	Acid gas injection	SO_2	up to 8.5	d					h
Incinerators	Spray dryer absorber	SO_2	7.2 - 8.6		400		3.7		1.1
	Wet FGD	SO_2	8.1 - 9		1,100	3.1	2.8	3.7	2.6
	Acid gas injection	SO_2	up to 9.0	d					h
Sulfur recovery units	Additional recovery stages	SO_2	2.2 - 2.3		270	3.2	<0.01		1.1
	Tail gas treatment unit (TGTU)	SO_2	2.1 - 2.4		190	3.5		3.7	1.1
Glycol dehydrators	Optimize glycol circulation rate	VOC	1.3 - 2.6	a					

NOTES:

blank indicates no impact is expected.

[a] The measure is expected to improve fuel efficiency.

[b] CO_2 from the generation of electricity would be offset by avoided emissions due to replacing the diesel engine

[c] EPA has estimated that the control measures used to meet Tier 4 standards will be integrated into the engine design so that sacrifices in fuel economy will be negligible.

[d] Some impact is expected but insufficient information is available to evaluate the impact.

[e] NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[f] For control measures reducing multiple pollutants, energy and other impacts are expressed as the impact per per total reduction of all pollutants. (However, EC, OC, and $PM_{2.5}$ are components of PM_{10}, and therefore are not added separately to the emission reduction total.)

[g] Some designs of low-NOX burners and ultralow-NOX burners require the use of pressurized air supplies. This would require additional electricity to pressurize the combustion air.

[h] Acid gas injection is also expected to result in sequestration of the CO_2 present in the acid gas stream.

4.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of oil and gas production and exploration equipment in the WRAP region. The remaining lifetime of most equipment is expected to be longer than the projected lifetime of pollution control technologies which have been analyzed for this category. In the case of add-on technologies, the projected lifetime is 15 years.

If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1-(1+r)^{-m}}{1-(1+r)^{-n}}$$

where:

A_1 = the annual cost of control for the shorter equipment lifetime ($)
A_0 = the original annual cost estimate ($)
C = the capital cost of installing the control equipment ($)
r = the interest rate (0.07)
m = the expected remaining life of the emission source (years)
n = the projected lifetime of the pollution control equipment

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5. Natural Gas Processing Operations

Natural gas processing facilities carry out a number of operations to remove impurities from natural gas before it is piped to consumers. In addition, the gas is typically fractionated to remove propane and heavier hydrocarbons, which are then processed as separate products. Emission sources at natural gas processing facilities include many of the same sources found at gas production operations, discussed in the previous chapter. Turbines and natural gas reciprocating engines are used to drive compressors and other equipment. Flares and incinerators are used to dispose of waste gases, and process heaters are used in various operations. In addition, emissions of SO_2 emanate from sulfur recovery operations at sour natural gas processing plants.

Table 5-1 summarizes emissions from the natural gas processing industry, broken down by state and by the various emission sources. Point source emissions of NO_X, SO_2, and VOC from these operations were extracted from the 2002 WRAP emissions inventory, which catalogs emission sources by their Standard Industrial Classification (SIC).[1] SIC 132 covers natural gas processing. Estimates for PM_{10} and $PM_{2.5}$ were extracted from the 2002 NEI, which also classifies emissions by SIC. It must be noted that the point source emissions in Table 5-1 for reciprocating engines and turbines in the natural gas processing industry are also included in the emission totals reported in Table 3-1 for all reciprocating engines and turbines. However, these emissions are separate from those reported in Table 4-1 for the oil and gas production and exploration sector.

Total NO_X emissions from natural gas processing are estimated at about 31,000 tons/year, and SO_2 emissions are estimated at about 12,000 tons/year. These emissions represent about 2% of stationary source (point and area source) NO_X emissions, and 1% of stationary source SO_2 emissions in the region.

PM_{10} and $PM_{2.5}$ emissions from natural gas processing facilities are estimated to be an order of magnitude lower than NO_X emissions. Emissions of OC and EC are not specifically quantified in either the WRAP inventory or the NEI, but can be estimated as a percentage of PM_{10} emissions using data from EPA's SPECIATE database.[2] EC and OC are estimated to comprise 38.4% and 24.7% of natural gas combustion PM_{10} emissions, respectively.

Emissions from individual reciprocating engines at natural gas processing plants range up to about 1,000 tons per year, compared with 1,373 tons per year for the largest natural gas fired reciprocating engines at industrial facilities. Emissions from individual turbines range up to 338 tons of NO_X per year, compared with 845 tons per year for the largest natural gas turbines at industrial facilities.[1]

Table 5-2 lists potential control measures for natural gas processing emissions. The table includes options for reciprocating engines and turbines, process heaters, flares and incinerators, and sulfur recovery units. As discussed in Chapter 3, a number of options are available to control emissions from gas-fired reciprocating engines, diesel-fueled reciprocating engines, and

Table 5-1. Emissions from Natural Gas Processing in the WRAP Region

Emission source	AK	CA	CO	MT	ND	NM	NV	UT	WY	Tribes	Total
NO_X emissions (tons/year)											
Reciprocating engines (natural gas)	86	626	1,027	33	2,428	15,976	0	612	1,935	1,140	23,863
Turbines	1,533	11	107	0	0	4,317	0	0	27	486	6,482
Process heaters	19	7	30	0	55	263	0	1	122	1	498
Boilers	1	29	60	0	0	193	0	20	6	26	335
Flares	0	14	1	0	0	56	0	1	25	0	97
Other[a]	0	14	5	0	10	122	0	1	82	0	234
Total	1,639	686	1,228	33	2,493	20,871	0	634	2,172	1,654	31,411
SO_2 emissions (tons/year)											
Sulfur recovery units	0	0	0	0	1,604	4,739	0	0	196	0	6,539
Flares	0	1	0	0	67	3,628	0	0	506	0	4,203
Incinerators	0	0	0	0	358	417	0	0	0	0	775
Process heaters	0	0	0	0	0	274	0	0	0	7	281
Other[a]	0	1	1	0	0	14	0	0	6	113	136
Total	0	2	1	0	2,030	9,072	0	0	708	119	11,934
PM_{10} emissions (tons/year)											
Reciprocating engines - natural gas	0	3	0	0	25	70	0	4	0	0	102
Other[a]	2	3	4	0	0	20	0	1	1	0	31
Total	2	6	4	0	25	90	0	5	1	0	134
$PM_{2.5}$ emissions (tons/year)											
Reciprocating engines - natural gas	0	3	0	0	25	70	0	3	0	0	102
Other[a]	2	3	4	0	0	19	0	1	1	0	30
Total	2	6	4	0	25	90	0	4	1	0	131
VOC emissions (tons/year)											
Storage	0	10	52,006	0	5	395	0	12	146	35	52,610
Reciprocating engines	0	687	102	20	44	1,135	0	13	278	29	2,308
Fugitive emissions	0	308	91	0	0	317	0	5	242	132	1,095
Glycol dehydrator	0	2	118	0	0	113	0	31	55	5	324
Turbines	10	0	0	0	0	187	0	0	0	21	219
Other[a]	1	89	210	0	2	54	0	90	35	35	515
Total	11	1,095	52,527	20	51	2,202	0	151	757	257	57,070

[a] Includes glycol dehydrator reboilers, incinerators, amine treatment units, and sources not specifically classified in the emissions inventory. For SO_2, incinerators are broken out separately.

Table 5-2. Control Options for Natural Gas Processing

Source Type	Control Technology	Pollutant controlled	Baseline emissions (1000 tons/yr)	Estimated control efficiency (%)	Potential emission reduction (1000 tons/year)	Refer-ences
Reciprocating engines, gas	Air-fuel ratio adjustment	NO_X	24	10 - 40	2 - 10	3,7
	Ignition timing retard	NO_X	24	15 - 30	4 - 7	3,7
	Low-emission combustion (LEC) retrofit	NO_X	24	80 - 90	19 - 21	4,7
	SCR	NO_X	24	90	21	7,8,12
	NSCR	NO_X	a	90 - 99	a	8
		VOC	a	40 - 85	a	8
	Replacement with electric motors	NO_X	24	100	24	7
		PM_{10}	0.10	100	0.10	
		$PM_{2.5}$	0.10	100	0.10	
		EC	0.04	100	0.04	
		OC	0.03	100	0.03	
		VOC	2	100	2	
		Overall[b]	26		26	
Turbines	Water or steam injection	NO_X	6.5	68 - 80	4.4 - 5.2	6
	Low-NO_X burner (LNB)	NO_X	6.5	68 - 84	4.4 - 5.4	6
	SCR	NO_X	6.5	90	5.8	5,6
	Water or steam injection with SCR	NO_X	6	93 - 96	6	6
Process heaters	Substitution of lower sulfur fuel	SO_2	0.28	up to 90	0 - 0.25	9,12
	LNB	NO_X	0.50	40	0.20	13,14
	ULNB	NO_X	0.50	75 - 85	0.37 - 0.42	12,13,14
	LNB and FGR	NO_X	0.50	48	0.24	13,14
	SNCR	NO_X	0.50	60	0.30	12,13,14
	SCR[c]	NO_X	0.50	70 - 90	0.35 - 0.45	12,13,14
	LNB and SCR	NO_X	0.50	70 - 90	0.35 - 0.45	12,13,14
Boilers	LNB with OFA	NO_X	0.33	30 - 50	0.1 - 0.17	11,12
	LNB, OFA, and FGR	NO_X	0.33	30 - 50	0.1 - 0.17	11,12
	SNCR	NO_X	0.33	30 - 75	0.1 - 0.25	11,12
	SCR	NO_X	0.33	40 - 90	0.13 - 0.3	11,12
Flares	Add or expand sulfur recovery unit	SO_2	4.2	90 - 95	d	9
	Acid gas injection	SO_2	4.2	100	d	10
Sulfur recovery units for amine treatment units	Additional recovery stages	SO_2	6.5	94 - 96	6.1 - 6.3	11,14
	Tail gas treatment unit (TGTU)	SO_2	6.5	90 - 99.5	5.9 - 6.5	11,14
Incinerators	Spray dryer absorber	SO_2	0.78	80 - 95	0.62 - 0.74	12
	Wet FGD	SO_2	0.78	90 - 99	0.7 - 0.77	11,12
	Acid gas injection	SO_2	0.78	100	d	10
Glycol dehydrators	Optimize glycol circulation rate	VOC	0.32	33 - 67	0.11 - 0.22	7

[a] NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not

[b] For control measures reducing multiple pollutants, overall emissions and emission reductions reflect the sum of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the totals.

[c] SCR can be used for mechanical draft process heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR.

[d] Insufficient information is available in the emissions inventory to determine the percentage of flare or incinerator emissions in this category that is amenable to these control strategies.

turbines.[3,4,5,6,7,8] Reciprocating engines can be designed to operate under rich fuel mixture, or lean fuel mixture conditions. Air-to-fuel-ratio adjustments and ignition retarding technologies can be used to control emissions under either fuel mixture condition. Low-Emission Combustion (LEC) retrofit technology can also reduce emissions from lean burn reciprocating engines by an average of 89%. LEC involves modifying the combustion system to achieve very lean combustion conditions (high air-to-fuel ratios). Selective Catalytic Reduction (SCR) can also be used either alone or in conjunction with the above technologies to reduce NO_X emissions from reciprocating engines or turbines by 90%. In addition, Non-Selective Catalytic Reduction (NSCR) can be used for rich-burn natural gas engines.[8]

SO_2 emissions from incinerators and flares could be reduced by installing sulfur recovery units to remove sulfur from the waste gases prior to incineration or flaring.[9] These emissions can also be reduced by compressing sulfur-containing acid gases and injecting these gases into non-producing rock formations.[10] Flue gas scrubbing has also been used to control SO_2 emissions from incinerators.[11,12] SO_2 emissions from existing sulfur recovery units can be reduced by adding additional recovery stages, or by adding a tail gas treatment unit.[12] In some cases, it may be possible to avoid SO_2 emissions from process heaters by substituting a lower-sulfur sweetened natural gas for the gas currently being burned. A number of options are available to reduce NO_X emissions from process heaters. Combustion modifications including LNB, ULNB, and FGR reduce the formation of NO_X. In addition, flue gases from the process heaters can be treated with SCR or SNCR to reduce NO_X emissions. These post-combustion controls can be used either alone or in conjunction with combustion controls.[13,14]

5.1 Factor 1 – Costs

Table 5-3 provides cost estimates for the emission control options which have been identified for the natural gas processing industry. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The capital and annual cost figures are expressed in terms of the cost per unit of engine size or per unit of process throughput. Engine size is expressed in horsepower for reciprocating engines and MMBtu/hour for turbines. Throughput for process heaters is also expressed in MMBtu/hour. Process throughput for sulfur recovery units is expressed in terms of the amount of sulfur recovered.

Sulfur recovery units are believed to be more cost-effective than post-combustion controls for reducing SO_2 emissions from flares and incinerators at natural gas processing facilities. Recent analyses of controls for Regional Haze precursors have focused on add-on controls for SO_2, rather than such process modifications. However, costs of sulfur recovery units were estimated in an earlier study of model refineries in different size ranges.[9] These estimates have been updated to current dollars using the Chemical Engineering plant cost index.

Table 5-3 shows a range of values for each cost figure, since the cost per unit of throughput will depend on the engine or process size and other factors. The lower ends of the cost ranges typically reflect larger engine or process sizes, and the higher ends of the cost ranges typically reflect smaller engine or process sizes. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

5.2 Factor 2 – Time Necessary for Compliance

Once a state decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[15] However, the time necessary will depend on the type and size of the unit being controlled. For instance, state regulators' experience indicates that closer to 18 months is required to install this technology.[16] In the CAIR analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[17] The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required achieve emission reductions for natural gas processing facilities is estimated at a total of 6½ years.

5.3 Factor 3 – Energy and Other Impacts

Table 5-4 shows the estimated energy and non-air pollution impacts of control measures for sources at natural gas processing facilities. For gas-fired reciprocating engines and diesel engines, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value of about 2.5%.[18,19] This increased fuel consumption would result in increased CO_2 emissions. LEC technology is not expected to increase fuel consumption; and may provide some fuel economy.[18]

For turbines, water injection and steam injection would require electricity to operate pumps and ancillary equipment.[13] Water injection would produce an increase in fuel consumption in order to evaporate the water, and steam injection would require energy to produce the steam. The increased electricity, steam, and fuel demands would produce additional CO_2 emissions.

Installation of SCR on any type of engine would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed.[18] This would produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[13]

Table 5-3. Estimated Costs of Control for Natural Gas Processing

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/unit)	Estimated annual cost ($/year /unit)	Units	Cost effectiveness ($/ton)	References
Reciprocating engines, gas	Air-fuel ratio adjustment	NO_X	10 - 40	5.3 - 42	0.9 - 6.8	hp	68 - 2,500	3,7
	Ignition timing retard	NO_X	15 - 30	na	1 - 3	hp	42 - 1,200	3,7
	LEC retrofit	NO_X	80 - 90	120 - 820	30 - 210	hp	320 - 2,500	4,7
	SCR	NO_X	90	100 - 450	40 - 270	hp	870 - 31,000	7,8,12
	NSCR[a]	NO_X	90 - 99	17 - 35	3 - 6	hp	16 - 36	4
		VOC	40 - 85				1,500 - 6,200	4
		Overall[b]					16 - 36	
	Replacement with electric motors	all[b]	100	120 - 140	38 - 44	hp	100 - 4,700	7
Turbines	Water or steam injection	NO_X	68 - 80	4.4 - 16	2 - 5	1000 Btu/hr	560 - 3,100	6
	Low-NO_X burners[c]	NO_X	68 - 84	8 - 22	2.7 - 8.5	1000 Btu/hr	5,200 - 16,200	6
	SCR	NO_X	90	13 - 34	5.1 - 13	1000 Btu/hr	1,000 - 6,700	5,6
	Water or steam injection with SCR	NO_X	93 - 96	13 - 34	5.1 - 13	1000 Btu/hr	1,000 - 6,700	6
Process heaters	Substitution of lower sulfur fuel	SO_2	up to 90					9,12
	LNB	NO_X	40	3.8 - 7.6	0.41 - 0.81	1000 BTU	2,100 - 2,800	13,14
	ULNB	NO_X	75 - 85	4.0 - 13	0.43 - 1.3	1000 BTU	1,500 - 2,000	12,13,14
	LNB and FGR	NO_X	48	16	1.7	1000 BTU	2,600	13,14
	SNCR	NO_X	60	10 - 22	1.1 - 2.4	1000 BTU	4,700 - 5,200	12,13,14
	SCR[d]	NO_X	70 - 90	33 - 48	3.7 - 5.6	1000 BTU	2,900 - 6,700	12,13,14
	LNB and SCR	NO_X	70 - 90	37 - 55	4 - 6.3	1000 BTU	2,900 - 6,300	12,13,14
Boilers	LNB with OFA	NO_X	30 - 50				500 - 5,300	11,12
	LNB, OFA, and FGR	NO_X	30 - 50				500 - 11,000	11,12
	SNCR	NO_X	30 - 75				400 - 2,500	11,12
	SCR	NO_X	40 - 90				2,400 - 7,200	11,12
Flares	Add or expand sulfur recovery unit	NO_X	90 - 95	0.1 - 1.1	28 - 190	ton-Sulfur/year	14 - 95	9
	Acid gas injection	SO_2	95					10
Sulfur recovery units for amine treatment units	Additional recovery stages	SO_2	94 - 96	0.1 - 1	28 - 150	ton-Sulfur/year	14 - 75	9
	Tail gas treatment unit (TGTU)	SO_2	90 - 99.5	0.3 - 1.1	67 - 190	ton-Sulfur/year	33 - 95	9
Incinerators	Spray dryer absorber	SO_2	80 - 95				1,500-1,900	12
	Wet FGD	SO_2	90 - 99				1,500 - 1,800	11,12
	Acid gas injection	SO_2	100					10
Glycol dehydrators	Optimize glycol circulation rate	VOC	33 - 67	31 - 170	5 - 28	gal/hr		7

[a] NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[b] For control measures reducing multiple pollutants, the overall cost-effectiveness is the cost per total reduction of all pollutants. However, EC, OC, and PM2.5 are components of PM10, and therefore are not added separately to the emission reduction total.

[c] Costs estimates for low-NO_X burners for turbines reflect the incremental costs of new low-NO_X burners versus standard burners. Retrofit costs for existing burners were not available.

[d] SCR cost estimates for process heaters apply to mechanical draft heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR. This would increase both the capital and annualized costs of control by about 10%.

Table 5-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Natural Gas Processing

					Energy and non-air pollution impacts (per ton of emission reduced)				
Source Type	**Control Technology**	**Pollutant controlled**	**Potential emission reduction (1000 tons/year)**	**Additional fuel requirement (%)**	**Electricity requirement (kW-hr)**	**Steam requirement (tons steam)**	**Solid waste produced (tons waste)**	**Wastewater produced (1000 gallons)**	**Additional CO_2 emitted (tons)**
Reciprocating engines	Air-fuel ratio controllers	NO_X	2 - 10	a					
	Ignition timing retard	NO_X	4 - 7	a					
	LEC retrofit	NO_X	19 - 21	a					
	SCR	NO_X	21	0.5			0.008		0.43
	NSCR	NO_X, VOC	e	0.5			0.008		0.24
	Replacement with electric motors	NO_X	24	(100)	66,000				b
Turbines	Water or steam injection	NO_X	4.4 - 5.2	a		31			8.1
	Low-NO_X burner (LNB)	NO_X	4.4 - 5.4	a					
	SCR	NO_X	5.8	0.45			0.026		1.7
	Water or steam injection with SCR	NO_X	6	0.45			0.026		1.7
Process heaters	Substitution of lower sulfur fuel	SO_2	0 - 0.25						
	LNB	NO_X	0.2	a	f				
	ULNB	NO_X	0.37 - 0.42	a	f				
	LNB and FGR	NO_X	0.24		3,300				3.3
	SNCR	NO_X	0.3	0.16	460				3.2
	SCR	NO_X	0.35 - 0.45		8,400		0.073		8.4
	LNB and SCR	NO_X	0.35 - 0.45		8,400		0.073		8.4
Boilers	LNB with OFA	NO_X	0.1 - 0.17	a					
	LNB, OFA, and FGR	NO_X	0.1 - 0.17		3,300				3.3
	SNCR	NO_X	0.1 - 0.25	0.16	460				3.2
	SCR	NO_X	0.13 - 0.3		8,400		0.073		8.4
Flares	Add or expand sulfur recovery unit	SO_2	up to 4.2		270	3.2	<0.01		1.1
	Acid gas injection	SO_2	up to 4.2	d					g
Sulfur recovery units for gas sweetening units	Additional recovery stages	SO_2	6.1 - 6.3		270	3.2	<0.01		1.1
	Tail gas treatment unit (TGTU)	SO_2	5.9 - 6.5		190	3.5		3.7	1.1
Incinerators	Spray dryer absorber	SO_2	0.62 - 0.74		400				1.1
	Wet FGD	SO_2	0.7 - 0.77		1,100	3.1		3.7	2.6
	Acid gas injection	SO_2	up to 0.78	d					g
Glycol dehydrators	Optimize glycol circulation rate	VOC	0.11 - 0.22	a					

NOTES:

blank indicates no impact is expected.

[a] The measure is expected to improve fuel efficiency.

[b] CO_2 from the generation of electricity would be offset by avoided emissions due to replacing the diesel engine

[c] EPA has estimated that the control measures used to meet Tier 4 standards will be integrated into the engine design so that sacrifices in fuel economy will be negligible.

[d] Some impact is expected but insufficient information is available to evaluate the impact.

[e] NSCR applies only to rich-burn engines. The distribution of emissions between rich-burn and lean-burn engines is not known.

[f] Some designs of low-NOX burners and ultralow-NOX burners require the use of pressurized air supplies. This would require additional electricity to pressurize the combustion air.

[g] Acid gas injection is also expected to result in sequestration of the CO_2 present in the acid gas stream.

Sulfur recovery units require electricity and steam. Wet or dry scrubbers applied to incinerators and tail gas treatment units applied to sulfur recovery units would use electricity for the fan power needed to overcome the scrubber pressure drop. These systems would also produce solid waste, and wet scrubbers would produce wastewater which would require treatment. Injection of acid gases would require the consumption of fuel to compress the gases. However, this option would also result in the sequestration of CO_2 present in the injected gas stream.[10]

Low-NO_X burners for process heaters are expected to improve overall fuel efficiency. FGR would require additional electricity to recirculate the fuel gas into the heater. In SCR systems for process heaters, fans would be required to overcome the pressure drop through the catalyst bed. The fans would require electricity, with resultant increases in CO_2 to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal. [13]

5.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of natural gas processing equipment in the WRAP region. The remaining lifetime of most equipment is expected to be longer than the projected lifetime of pollution control technologies which have been analyzed for this category. In the case of add-on technologies, the projected lifetime is 15 years.

If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1-(1+r)^{-m}}{1-(1+r)^{-n}}$$

where:

A_1 = the annual cost of control for the shorter equipment lifetime ($)
A_0 = the original annual cost estimate ($)
C = the capital cost of installing the control equipment ($)
r = the interest rate (0.07)
m = the expected remaining life of the emission source (years)
n = the projected lifetime of the pollution control equipment

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19. Center for Alternative Fuels, Engines & Emissions (2005), *Alice Austen Ferry Emissions Tests*, M.J. Bradley & Associates, Manchester, NH, Page 13.

6. Industrial Boilers

Industrial boilers encompass the category of boilers used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity. There are no specific size definitions for an industrial boiler, however for the purposes of this document, the definition described in Subpart Db of 40 CFR Part 60, New Source Performance Standards (NSPS) for Industrial, Commercial, and Institutional Steam Generating Units will be used. This NSPS regulates steam generating units with a heat input capacity between 100 to 250 MMBtu/hr (29 - 73 MW). Steam generating units greater than 250 MMBtu/hr (73 MW) are subject to the requirements of Subpart D of 40 CFR Part 60.

An industrial boiler report[1] estimated that there are approximately 43,000 industrial boilers operating in the U.S. with an aggregate capacity of 1.5 million MMBtu/hr input. The report noted that approximately half of these industrial boilers are less than 10 MMBtu/hr in size, but account for only 7% of the total capacity. The 2002 WRAP stationary point source emissions tables[2] lists a total of 2,171 facilities with industrial boilers in the 102XXX Source Classification Code (SCC). The majority of the boilers are located at facilities in the food, paper, chemicals, refining and primary metals industries. The most common fuel used for combustion is natural gas with nearly 73% of the facilities in the WRAP region operating natural gas-fired industrial boilers.

Industrial boilers in the WRAP region are estimated to emit about 43,060 tons of NO_X and 28,155 tons of SO_2, based on the 2002 emissions inventory for the region.[3] These boilers utilize the combustion of fuel which includes; coal, oil, natural gas, waste, and wood, to produce steam. Coal-fired industrial boilers comprise of 15,920 tons of NO_X, or 37% of the total NO_X emissions, and 14,376 tons, or 51% of the total SO_2 emissions from industrial boilers in the WRAP region. Industrial boilers represent about 4.1% of the total point source emissions of NO_X, and about 3.4% of the total SO_2 point source emissions in the WRAP region.

Table 6-1 shows estimated emissions of NO_X, SO_2, PM_{10}, $PM_{2.5}$, and VOC from the WRAP emissions inventory, broken down by state and fuel. The table shows that PM_{10}, $PM_{2.5}$, and VOC emissions from industrial boilers are significantly lower than the NO_X and SO_2 emissions. Emissions of PM from these sources were not included in the inventory, but are expected to be much lower than the NO_X and SO_2 emissions. As the table shows, coal-fired boilers were the most significant source of NO_X, SO_2, and VOC emissions in the WRAP region. For NO_X, coal fired boilers accounted for about 56% of the emissions from point sources, and 41% of the total stationary source emissions in the WRAP region.

Table 6-2a lists potential control measures for NO_X, SO_2, PM_{10}, $PM_{2.5}$, EC, and OC emissions from coal-fired and oil-fired industrial boilers. Table 6-2b presents control options for natural gas boilers, and Table 6-2c provides control options for wood-fired industrial boilers for each of these pollutants. Uncontrolled emission rates were obtained from the respective AP-42 section for each of the fuels.[4] Control technology options were identified using information from industrial boiler control option studies.[5] The control options were divided into appropriate control technologies for each of the four fuels; coal, oil, natural gas, and wood.

Table 6-2d lists potential control options for NO_X, SO_2, PM_{10}, $PM_{2.5}$, EC, and OC coal-fired and oil-fired industrial boilers by age. These pollutants are regulated under the Clean Air Act (CAA) to attain and maintain National Ambient Air Quality Standards (NAAQS), reduce acidic deposition, and improve visibility under regional haze regulations. To attain and maintain the NAAQS, the EPA enacted the Prevention of Significant Deterioration (PSD) regulations to establish maximum pollution concentration levels to protect public health and welfare from harmful levels of pollutants. The PSD regulations require new major sources or major modifications at existing sources to install "Best Available Control Technology (BACT)" and conduct ambient air quality analyses to show that the new source or modification will not cause or contribute to a violation of any applicable NAAQS or PSD increment. Because PSD requirements are on a case-by-case basis, the age groups were segregated into using the New Source Performance Standards (NSPS) to show control options and emission levels for coal-fired and oil-fired industrial boilers. The age groups are designated as pre-NSPS, post-NSPS, and post CAA amendments of 1990.

Table 6-1. Emissions from Industrial Boilers in the WRAP Region

Emission source	AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY	Tribes	Total
NO_X emissions (tons/year)																
Coal-fired Boilers	1,823	0	1,366	336	3,268	366	1,264	0	0	0	0	2,412	49	5,036	0	15,920
Natural gas-fired Boilers	260	786	5,555	2,706	1,184	726	140	764	114	370	224	764	2,435	685	26	16,740
Oil-fired Boilers	67	7	86	44	42	118	0	0	26	41	0	78	478	5	10	1,004
Waste-fired Boilers	0	0	49	0	480	214	94	0	0	1	0	0	72	0	0	910
Wood-fired Boilers	0	0	2,089	7	349	1,999	0	0	0	70	89	0	2,988	10	525	8,126
Total	2,150	793	9,145	3,093	5,323	3,424	1,498	765	140	481	313	3,255	6,022	5,736	561	42,700
SO_2 emissions (tons/year)																
Coal-fired Boilers	1,421	0	139	24	2,976	128	1,284	0	0	0	0	2,831	62	5,511	0	14,376
Natural gas-fired Boilers	7	5,668	969	138	6	1	3	9	11	2	497	435	1,113	544	0	9,403
Oil-fired Boilers	55	6	127	25	113	1,241	0	3	77	234	0	52	1,444	1	14	3,391
Waste-fired Boilers	0	0	2	0	8	46	14	0	0	16	0	0	5	0	0	91
Wood-fired Boilers	0	0	161	0	7	54	0	0	0	3	6	0	622	2	33	887
Total	1,483	5,674	1,396	187	3,109	1,470	1,301	12	89	255	503	3,319	3,245	6,058	47	28,147
PM_{10} emissions (tons/year)																
Coal-fired Boilers	0	19	37	7	468	36	12	0	0	100	0	100	0	581	0	1,361
Natural gas-fired Boilers	11	5	82	22	14	2	2	8	5	13	3	13	19	7	0	207
Oil-fired Boilers	2	2	16	3	4	54	0	0	77	26	0	1	223	79	0	488
Waste-fired Boilers	0	0	0	0	44	136	0	0	0	33	0	0	25	0	0	238
Wood-fired Boilers	0	0	671	6	41	267	0	0	0	2,025	75	0	1,035	0	0	4,119
Total	13	26	806	38	571	495	14	8	82	2,196	79	115	1,302	667	0	6,413
$PM_{2.5}$ emissions (tons/year)																
Coal-fired Boilers	0	3	28	1	255	27	2	0	0	63	0	43	0	123	0	543
Natural gas-fired Boilers	10	4	78	22	12	2	2	7	4	12	3	10	17	6	0	190
Oil-fired Boilers	2	1	14	3	3	45	0	0	49	2	0	1	149	49	0	318
Waste-fired Boilers	0	0	0	0	2	83	0	0	0	27	0	0	25	0	0	136
Wood-fired Boilers	0	0	625	4	41	229	0	0	0	1,776	12	0	646	0	0	3,333
Total	12	8	745	29	312	386	3	7	53	1,880	15	55	837	178	0	4,520
VOC emissions (tons/year)																
Coal-fired Boilers	6	0	3	4	31	0	9	0	0	0	0	12	0	10	0	76
Natural gas-fired Boilers	11	205	316	193	44	14	5	33	15	11	15	39	80	19	1	1,001
Oil-fired Boilers	3	0	2	1	1	0	0	0	9	1	0	1	9	1	0	28
Waste-fired Boilers	0	0	5	0	116	59	31	0	0	0	0	0	62	0	0	273
Wood-fired Boilers	0	0	373	0	15	511	0	0	0	23	47	0	284	0	110	1,363
Total	21	205	697	198	208	583	46	33	24	35	62	53	435	30	111	2,741

Table 6-2a. Control Options for Coal-Fired and Oil-Fired Industrial Boilers

Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1,2] (lb/MMBtu)	Estimated control efficiency (%)	Potential controlled emissions (lb/MMBtu)	References
Coal-fired	NO_X	LNB	1.3	50	0.63	3, 5, 6
		LNB w/OFA	1.3	50 - 65	0.63 - 0.46	3, 5, 6
		SNCR	1.3	30 - 75	0.91 - 0.33	3, 4, 5, 6
		SCR	1.3	40 - 90	0.78 - 0.13	3, 4, 6
	SO_2	Physical coal cleaning	1.3	10 - 40	1.2 - 0.78	3
		Chemical coal cleaning	1.3	50 - 85	0.63 - 0.20	3
		Switch to lower sulfur fuel	1.3	20 - 90	1.0 - 0.13	3,5
		Dry sorbent injection	1.3	50 - 90	0.63 - 0.13	3, 7, 8
		Spray dryer absorber	1.3	90	0.13	3, 5, 7, 8
		Wet FGD	1.3	90	0.13	3, 4, 7, 8
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	1.5	99.3	0.011	4, 5, 8
		ESP	1.5	99.3	0.011	4, 5, 8
Oil-fired	NO_X	LNB	0.34	40	0.20	3, 4, 5, 6
		LNB w/ OFA	0.34	30 - 50	0.24 - 0.17	3, 4, 5, 6
		LNB w/ OFA and FGR	0.34	30 - 50	0.24 - 0.17	3, 4, 5, 6
		SNCR	0.34	30 - 75	0.24 - 0.085	3, 4, 5, 6
		SCR	0.34	40 - 90	0.20 - 0.034	3, 4, 5, 6
	SO_2	Switch to lower sulfur fuel	0.67	20 - 90	0.54 - 0.067	5, 8
		Spray dryer absorber	0.67	90	0.067	5, 8
		Wet FGD	0.67	90	0.067	3, 4, 5, 8
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	0.044	95.8	0.0018	4, 5, 8
		ESP	0.044	95.8	0.0018	4, 5, 8

[1] Uncontrolled coal-fired emission rates calculated using AP-42 emission factors for PC, dry bottom, wall-fired, bituminous Pre-NSPS. The emission factor was converted to lb/MMBtu assuming MT coal with a heat rate of 17.5 MMBtu/ton, a sulfur content of 0.62 weight percent sulfur, and an ash content of 11.5 percent.

[2] Uncontrolled oil-fired emission rates calculated using AP-42 emission factors for No. 6 oil fired, normal firing. The emission factor was converted to lb/MMBtu assuming a distillate oil heat content of 140,000 Btu/gal, and a sulfur content of 0.60 weight percent sulfur.

Table 6-2b. Control Options for Industrial Natural Gas-Fired Boilers

Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1] (lb/MMBtu)	Estimated control efficiency (%)	Potential controlled emissions (lb/MMBtu)	References
Natural gas-fired	NO_X	LNB	0.27	40	0.16	4, 8
		LNB w/ OFA	0.27	60	0.11	3, 4, 5, 6
		LNB w/ OFA and FGR	0.27	80	0.054	3, 5, 6
		SNCR	0.27	30 - 75	0.19 - 0.068	4, 5, 6
		SCR	0.27	70 - 90	0.081 - 0.027	3, 4, 6

[1] Uncontrolled natural gas-fired emission rates calculated using AP-42 emission factors for Large Wall-Fired Boilers, >100 MMBtu/hr, Uncontrolled (Pre-NSPS).

Table 6-2c. Control Options for Industrial Wood-Fired Boilers

Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1] (lb/MMBtu)	Estimated control efficiency (%)	Potential controlled emissions (lb/MMBtu)	References
Wood-fired	NO_X	SNCR	0.49	70	0.15	4, 5, 8
		SCR	0.49	74	0.130	4, 5, 8
	$PM_{2.5}$, PM_{10}	Fabric filter	0.36	99.5	0.0018	5, 8
		ESP	0.36	99.5	0.0018	4, 5, 8

[1] Uncontrolled wood-fired emission rates calculated using AP-42 emission factors for Dry wood combustion, No control.

Table 6-2d. Control Options for Industrial Coal-Fired and Oil-Fired Boilers

Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1,2] (lb/MMBtu)	Estimated control efficiency (%)	Potential controlled emissions (lb/MMBtu)	References
Coal-fired (Pre PSD Regulations)[1]	NO_X	LNB	1.3	50	0.63	3, 5, 6
		LNB w/OFA	1.3	50 - 65	0.63 - 0.46	3, 5, 6
		SNCR	1.3	30 - 75	0.91 - 0.33	3, 4, 5, 6
		SCR	1.3	40 - 90	0.78 - 0.13	3, 4, 6
	SO_2	Physical coal cleaning	1.3	10 - 40	1.2 - 0.78	3
		Chemical coal cleaning	1.3	50 - 85	0.63 - 0.20	3
		Switch to lower sulfur fuel	1.3	20 - 90	1.0 - 0.13	3,5
		Dry sorbent injection	1.3	50 - 90	0.63 - 0.13	3, 7, 8
		Spray dryer absorber	1.3	90	0.13	3, 5, 7, 8
		Wet FGD	1.3	90	0.13	3, 4, 5, 7, 8
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	1.5	99.3	0.011	4, 5, 8
		ESP	1.5	99.3	0.011	4, 5, 8
Oil-fired (Pre PSD Regulations)[2]	NO_X	LNB	0.34	40	0.20	3, 4, 5, 6
		LNB w/ OFA	0.34	30 - 50	0.24 - 0.17	3, 4, 5, 6
		LNB w/ OFA and FGR	0.34	30 - 50	0.24 - 0.17	3, 4, 5, 6
		SNCR	0.34	30 - 75	0.24 - 0.085	3, 4, 5, 6
		SCR	0.34	40 - 90	0.20 - 0.034	3, 4, 5, 6
	SO_2	Switch to lower sulfur fuel	0.67	20 - 90	0.54 - 0.067	5, 8
		Spray dryer absorber	0.67	90	0.067	5, 8
		Wet FGD	0.67	90	0.067	3, 4, 5, 8
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	0.044	95.8	0.0018	4, 5, 8
		ESP	0.044	95.8	0.0018	4, 5 8
Coal-fired (Post PSD Regulations)[3]	NO_X	LNB	0.69	50	0.34	3, 5, 6
		LNB w/OFA	0.69	50 - 65	0.34 - 0.24	3, 5, 6
		SNCR	0.69	30 - 75	0.48 - 0.17	3, 4, 5, 6
		SCR	0.69	40 - 90	0.41 - 0.069	3, 4, 6
	SO_2	Physical coal cleaning	1.3	10 - 40	1.2 - 0.78	3
		Chemical coal cleaning	1.3	50 - 85	0.63 - 0.20	3
		Switch to lower sulfur fuel	1.3	20 - 90	1.0 - 0.13	3,5
		Dry sorbent injection	1.3	50 - 90	0.63 - 0.13	3, 7, 8
		Spray dryer absorber	1.3	90	0.13	3, 5, 7, 8
		Wet FGD	1.3	90	0.13	3, 4, 5, 7, 8
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	1.5	99.3	0.011	4, 5, 8
		ESP	1.5	99.3	0.011	4, 5, 8
Oil-fired (Post PSD Regulations)[4]	NO_X	LNB	0.34	40	0.20	3, 4, 5, 6
		LNB w/ OFA	0.34	30 - 50	0.24 - 0.17	3, 4, 5, 6
		LNB w/ OFA and FGR	0.34	30 - 50	0.24 - 0.17	3, 4, 5, 6
		SNCR	0.34	30 - 75	0.24 - 0.085	3, 4, 5, 6
		SCR	0.34	40 - 90	0.20 - 0.034	3, 4, 5, 6
	SO_2	Switch to lower sulfur fuel	0.67	20 - 90	0.54 - 0.067	5, 8
		Spray dryer absorber	0.67	90	0.067	5, 8
		Wet FGD	0.67	90	0.067	3, 4, 5, 8
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	0.044	95.8	0.0018	4, 5, 8
		ESP	0.044	95.8	0.0018	4, 5 8

Table 6-2d. Control Options for Industrial Coal-Fired and Oil-Fired Boilers (cont.)

Source Type	Pollutant controlled	Control Technology	Uncontrolled emissions[1,2] (lb/MMBtu)	Estimated control efficiency (%)	Potential controlled emissions (lb/MMBtu)	References
Coal-fired (Post Clean Air Act Amendments of 1990)[5]	NO_X	LNB	0.50	50	0.25	3, 5, 6
		LNB w/OFA	0.50	50 - 65	0.25 - 0.18	3, 5, 6
		SNCR	0.50	30 - 75	0.35 - 0.13	3, 4, 5, 6
		SCR	0.50	40 - 90	0.30 - 0.050	3, 4, 6
	SO_2	Physical coal cleaning	0.20	10 - 40	0.18 - 0.12	3
		Chemical coal cleaning	0.20	50 - 85	0.10 - 0.030	3
		Switch to lower sulfur fuel	0.20	20 - 90	0.16 - 0.020	3,5
		Dry sorbent injection	0.20	50 - 90	0.10 - 0.020	3, 7, 8
		Spray dryer absorber	0.20	90	0.02	3, 5, 7, 8
		Wet FGD	0.20	90	0.02	3, 4, 5, 7, 8
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	0.05	99.3	0.00035	4, 5, 8
		ESP	0.05	99.3	0.00035	4, 5, 8
Oil-fired (Post Clean Air Act Amendments of 1990)[5]	NO_X	LNB	0.20	40	0.12	3, 4, 5, 6
		LNB w/ OFA	0.20	30 - 50	0.14 - 0.10	3, 4, 5, 6
		LNB w/ OFA and FGR	0.20	30 - 50	0.14 - 0.10	3, 4, 5, 6
		SNCR	0.20	30 - 75	0.14 - 0.050	3, 4, 5, 6
		SCR	0.20	40 - 90	0.12 - 0.020	3, 4, 5, 6
	SO_2	Switch to lower sulfur fuel	0.50	20 - 90	0.40 - 0.005	5, 8
		Spray dryer absorber	0.50	90	0.050	5, 8
		Wet FGD	0.50	90	0.050	3, 4, 5, 8
	$PM_{2.5}$, PM_{10}, EC, OC	Fabric filter	0.044	95.8	0.0018	4, 5, 8
		ESP	0.044	95.8	0.0018	4, 5 8

[1] Uncontrolled coal-fired emission rates calculated using AP-42 emission factors for PC, dry bottom, wall-fired, bituminous Pre-NS The emission factor was converted to lb/MMBtu assuming MT coal with a heat rate of 17.5 MMBtu/ton, a sulfur content of 0.62 weight percent sulfur, and an ash content of 11.5 percent.

[2] Uncontrolled oil-fired emission rates calculated using AP-42 emission factors for No. 6 oil fired, normal firing. The emission factor was converted to lb/MMBtu assuming a distillate oil heat content of 140,000 Btu/gal, and a sulfur content of 0.60 weight percent sulfur.

[3] Uncontrolled coal-fired emission rates calculated using AP-42 emission factors for PC, dry bottom, wall-fired, bituminous Post-N The emission factor was converted to lb/MMBtu assuming MT coal with a heat rate of 17.5 MMBtu/ton, a sulfur content of 0.62 weight percent sulfur, and an ash content of 11.5 percent.

[4] Uncontrolled oil-fired emission rates calculated using AP-42 emission factors for No. 6 oil fired, normal firing. The emission factor was converted to lb/MMBtu assuming a distillate oil heat content of 140,000 Btu/gal, and a sulfur content of 0.60 weight percent sulfur.

[5] Uncontrolled Coal fired and oil-fired emission rates are base the the 40 CFR 60, Subpart Db limits for each of the fuels.

6.1 Factor 1 – Costs

Table 6-3 provides cost estimates for the emission control options which have been identified for each of the industrial boilers. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The capital cost values are expressed in terms of the cost per heat input (MMBtu/hr) to the boiler. The annual cost is presented in millions of dollars per year. The table shows a range of values for each cost figure, since the capital cost will depend on the rated heat input to the boiler and other factors. The lower ends of the capital and annual cost ranges typically reflect smaller sized boilers, and the higher ends of the capital and annual cost ranges reflect larger sized boilers. Table 3-3 also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction. Lower cost effectiveness values generally reflect the larger heat input boiler sizes, whereas higher cost effectiveness values reflect lower heat input boilers sizes.

6.2 Factor 2 – Time Necessary for Compliance

Once a state decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 18 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control, and approximately 30 months to design, build, and install SO_2 scrubbing technology.[9] Additional time of up to 12 months may be required for staging the installation process if multiple boilers are to be controlled at a single facility. Based on these figures, the total time required to achieve emission reductions for industrial boilers is estimated at a total of 5½ years for NO_X strategies, and 6½ years for SO_2 strategies.

6.3 Factor 3 – Energy and Other Impacts

Table 6-4 shows the estimated energy and non-air pollution impacts of control measures for industrial boilers. The values were obtained from a report summarizing the applicability and feasibility of control options for industrial boilers.[8] In general, the combustion modification technologies (LNB, OFA, FGR) do not require steam or generate solid waste, wastewater, or additional CO_2. They also do not require additional fuel to operate, and in some cases may decrease fuel usage because of the optimized combustion of the fuel.

Retrofitting of a SNCR requires energy for compressor power and steam for mixing. This would produce a small increase in CO_2 emissions to generate electricity; however the technology itself does not produce additional CO_2 emissions.

Installation of SCR on an industrial boiler is not expected to increase fuel consumption. However additional energy is required to operate the SCR, which will produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.

Table 6-3. Estimated Costs of Control for Industrial Boilers

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/MMBtu/hr)	Estimated annual cost ($M)	Cost effectiveness ($/ton)	References
Coal-fired	LNB	NO_X	50	3,435 - 6,856	0.175 - 0.317	344 - 4,080	3, 5, 6
	LNB w/OFA		50 - 65	4,908 - 9,794	NA	412 - 4,611	3, 5, 6
	SNCR		30 - 75	3,550 - 7,083	0.333 - 0.419	1,728 - 6,685	3, 4, 5, 6
	SCR		40 - 90	9,817 - 19,587	0.738 - 1.32	1,178 - 7,968	3, 4, 6
	Physical coal cleaning	SO_2	10 - 40	NA	NA	70 - 563	3
	Chemical coal cleaning		50 - 85	NA	NA	1,699 - 2,561	3
	Switch to lower sulfur fuel		20 - 90	NA	NA		3, 5
	Dry sorbent injection		50 - 90	11,633 - 36,096	NA	851 - 5,761	3, 7, 8
	Spray dryer absorber		90	27,272 - 73,549	7.93 - 9.26	3,885 - 8,317	3, 5, 7, 8
	Wet FGD		90	40,203 - 86,410	10.10 - 11.71	4,687 - 10,040	3, 4, 5, 7, 8
	Fabric filter	$PM_{2.5}$, PM_{10}	99.3	20,065 - 30,287	0.82 - 1.39	406 - 592	4, 5, 8
	ESP		99.3	17,037 - 24,293	0.66 - 1.17	342 - 485	4, 5, 8
Oil-fired	LNB	NO_X	40	1,722 - 3,435	0.190 - 0.346	412 - 7,075	3, 4, 5, 6
	LNB w/ OFA		30 - 50	1,722 - 3,435	NA	412 - 7,075	3, 4, 5, 6
	LNB w/ OFA and FGR		30 - 50	2,690 - 5,368	NA	439 - 6,689	3, 4, 5, 6
	SNCR		30 - 75	2,840 - 5,666	0.206 - 0.355	1,997 - 9,952	3, 4, 5, 6
	SCR		40 - 90	5,399 - 10,773	0.484 - 0.831	1,022 - 24,944	3, 4, 5, 6
	Switch to lower sulfur fuel	SO_2	20 - 90	NA	NA	5611	5, 8
	Spray dryer absorber		90	119,731 - 270,514	7.72 - 8.80	4,947 - 10,887	5, 8
	Wet FGD		90	36,930 - 73,660	9.85 - 11.29	6,008 - 13,156	3, 4, 5, 8
	Fabric filter	$PM_{2.5}$, PM_{10}	95.8	17,205 - 26,291	0.72 - 1.20	7,298 - 10,889	4, 5, 8
	ESP		95.8	14,302 - 21,243	0.58 - 0.98	5,983 - 8,844	4, 5, 8
Natural gas-fired	LNB	NO_X	40	1,722 - 3,435	0.190 - 0.346	412 - 7,075	4, 8
	LNB w/ OFA		30 - 50	1,722 - 3,435	NA	412 - 7,075	3, 4, 5, 6
	LNB w/ OFA and FGR		30 - 50	2,690 - 5,368	NA	439 - 6,689	3, 5, 6
	SNCR		30 - 75	2,840 - 5,666	0.206 - 0.355	1,997 - 9,952	4, 5, 6
	SCR		40 - 90	5,399 - 10,773	0.484 - 0.831	1,022 - 24,944	3, 4, 6
Wood-fired	LNB w/ OFA	NO_X	30 - 50	1,722 - 3,435	NA	412 - 7,075	5
	LNB w/ OFA and FGR		30 - 50	2,690 - 5,368	NA	439 - 6,689	5
	SNCR		30 - 75	2,840 - 5,666	0.206 - 0.355	1,997 - 9,952	4, 5, 8
	SCR		40 - 90	5,399 - 10,773	0.484 - 0.831	1,022 - 24,944	4, 5, 8
	Fabric filter	$PM_{2.5}$, PM_{10}	95.8	17,205 - 26,291	0.72 - 1.20	7,298 - 10,889	5, 8
	ESP		95.8	14,302 - 21,243	0.58 - 0.98	5,983 - 8,844	4, 5, 8

NA - Control cost not available.

Table 6-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Industrial Boilers

			Energy and non-air pollution impacts (per ton of emission reduced)				
Source Type	**Control Technology**	**Pollutant controlled**	**Electricity requirement**	**Steam requirement**	**Solid waste produced**	**Wastewater produced**	**Additional CO$_2$ emitted**
Coal-fired	LNB	NO$_X$					
	LNB w/OFA	NO$_X$					
	SNCR	NO$_X$	1 - 2 kW/1000 acfm	0.25			
	SCR	NO$_X$	0.89	0.25	0.021		
	Physical coal cleaning	SO$_2$					
	Chemical coal cleaning	SO$_2$					
	Switch to lower sulfur fuel	SO$_2$					
	Dry sorbent injection	SO$_2$	2 - 4 kW/1000 acfm	0.25	0.021		
	Spray dryer absorber	SO$_2$	0.4		3.7	0.69	
	Wet FGD	SO$_2$	4 - 8 kW/1000 acfm				
	Fabric filter	PM$_{2.5}$, PM$_{10}$	1 - 2 kW/1000 acfm				
	ESP	PM$_{2.5}$, PM$_{10}$	0.5 - 1.5 kW/1000 acfm				
Oil-fired	LNB	NO$_X$					
	LNB w/ OFA	NO$_X$					
	LNB w/ OFA and FGR	NO$_X$	6.4				
	SNCR	NO$_X$	1 - 2 kW/1000 acfm	0.25			
	SCR	NO$_X$	0.89	0.25	0.021		
	Switch to lower sulfur fuel	SO$_2$					
	Spray dryer absorber	SO$_2$	0.4		3.7	0.69	
	Wet FGD	SO$_2$	4 - 8 kW/1000 acfm				
	Fabric filter	PM$_{2.5}$, PM$_{10}$	1 - 2 kW/1000 acfm				
	ESP	PM$_{2.5}$, PM$_{10}$	0.5 - 1.5 kW/1000 acfm				
Natural gas-fired	LNB	NO$_X$					
	LNB w/ OFA	NO$_X$					
	LNB w/ OFA and FGR	NO$_X$	6.4				
	SNCR	NO$_X$	1 - 2 kW/1000 acfm	0.25			
	SCR	NO$_X$	0.89	0.25	0.021		
	Water injection	NO$_X$					
Wood-fired	LNB w/ OFA	NO$_X$					
	LNB w/ OFA and FGR	NO$_X$	6.4				
	ULNB	NO$_X$					
	SNCR	NO$_X$	1 - 2 kW/1000 acfm	0.25			
	SCR	NO$_X$	0.89	0.25	0.021		
	Fabric filter	PM$_{2.5}$, PM$_{10}$	1 - 2 kW/1000 acfm				
	ESP	PM$_{2.5}$, PM$_{10}$	0.5 - 1.5 kW/1000 acfm				

NOTES:
A blank cell indicates no impact is expected.

For SO_2 control technologies, energy is required material preparation (e.g., grinding), materials handling (e.g., pumps/blowers), flue gas pressure loss, and steam requirements. Power consumption is also affected by the reagent utilization of the control technology, which also affects the control efficiency of the control technology.

PM control technologies require energy to operate compressors, heaters, and ash handling. In addition, an additional fan may be required to reduce the flue gas pressure loss by the ESP or FF. The ESP also requires energy to operate the transformer-rectifier. These energy requirements will produce an increase in CO_2 emissions to generate the required electricity.

6.4 Factor 4 – Remaining Equipment Life

Similar to Electric Generating Units (EGUs), industrial boilers do not have a set equipment life. Since many of the strategies are market-based reductions applied to geographic regions, it is assumed that control technologies will not be applied to units that are expected to be retired prior to the amortization period for the specific control equipment. Therefore, the remaining life of an industrial boiler is not expected to affect the cost of control technologies for industrial boilers.

6.5 References for Section 6

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7. Cement Kilns

The main emission units of interest at cement plants are the cement kilns. There are two major types, wet and dry kilns; dry kilns are further categorized as long dry, preheater, or precalciner kilns. On the whole, wet kilns tend to produce more tons of cement (or "clinker") but also require more energy than dry process kilns. There was limited information on SO_2 controls for cement kilns, particularly for long wet kilns.[1] Process modification and replacement of a wet kiln with a dry process kiln are the most feasible options for SO_2 control.

Cement kilns at cement manufacturing facilities in the WRAP region are estimated to emit about 40,610 tons of NO_X; 6,230 tons of SO_2; 1,573 tons of $PM_{2.5}$; 4,245 tons of PM_{10} and 4,467 tons of VOC per year, based on the 2002 emissions inventory for the region and WRAP updates.[2] Most of the emissions from this category are from the kilns themselves; the remainder of the emissions is generated primarily from the transfer of clinker and the grinding and drying of the raw material. NO_X emissions from cement kilns represent approximately 4% of total point source emissions of NO_X in the WRAP region, and approximately 3% of all stationary source (point and area source) NO_X emissions in the region. SO_2 emissions from cement kilns represent approximately 0.75% of total point source emissions of SO_2 in the WRAP region, and approximately 0.68% of all stationary source (point and area source) SO_2 emissions in the region.

Table 7-1 shows estimated emissions of NO_X, SO_2, PM_{10}, $PM_{2.5}$ and VOC from the WRAP emissions inventory and updated data provided by the states, broken down by state and emission source. As the table shows, SO_2, PM_{10}, $PM_{2.5}$ and VOC emissions from cement kiln sources are much lower than NO_X emissions. Emissions of particulate matter from these sources were not included in the WRAP EDMS inventory – the emissions presented were gathered from the NEI. Long dry kilns produce over half of the NO_X emissions (54.8%) and most of the $PM_{2.5}$ and PM_{10} emissions (79.4 and 71.3%, respectively) generated by cement manufacturing in the WRAP region. Long wet kilns produce almost half of the SO_2 emissions generated by the cement manufacturing (48.4%), and precalciner kilns produce almost half of the VOC emissions generated by cement manufacturing (45.6%).

Table 7-2 lists potential control measures for NO_X emissions from cement kilns. A number of options were identified for cement kilns in an ACT guidance document written by the U.S. EPA in 1994.[6] Cement kilns use coal, waste products, tires, or natural gas for combustion fuel - this combustion generates primarily NO_X emissions but also produces SO_2 and PM emissions.[6] Controls can be broken into three categories: process modifications, combustion modifications and NO_X removal controls. Process modifications include fuel switching and the inclusion of steel slag into the raw kiln feed (also known as the CemStar$^{(TM)}$ process) which improves thermal efficiency. CemStar is currently used in TXI's Hunter and Midlothian, TX plants, TXI's Oro Grande, CA plant and Holcim's North Texas Cementer plant. TXI has also licensed CemStar out to RMC Pacific Materials, Inc. and to the Rio Grande Portland Cement Company.[3] Combustion modifications include low NO_X burners and mid-kiln firing. NO_X removal controls include SCR, SNCR, LoTOX^{TM}, and biosolids or sorbent injection. Low NO_X

burners reduce flame turbulence, delay fuel/air mixing and create fuel-rich zones for initial combustion, reducing the flame temperature and thus NO_X formation.[4] SCR introduces ammonia, presented as a catalyst, into the clinker making process to selectively reduce NO_X emissions from exhaust gases. SNCR, available to preheater or precalciner cement kilns[1,5,6], does not use a catalyst to reduce NO_X emissions. Instead, the process uses either ammonia or urea that is generated when reagents are injected into the kiln at specific temperatures. However, SNCR has been tested primarily in European facilities; there have been two demonstrations in the United States but no kilns have yet adopted the technology.[7,8,9,10,11]

In the LoTOx™ system, ozone is injected into the kiln which oxidizes NO_X. The resulting higher oxides of nitrogen can then be removed by a wet scrubber.[12] LoTOx is licensed by the BOC group and is currently being used on the Midlothian cement wet kilns in Texas.[1,12] Biosolid or absorbent injection is similar to SNCR, although instead of a catalyst either biosolids from wastewater treatment plants or limestone/hydrated lime are injected into the kiln.[7,13] Biosolid injection is being used in one kiln in Southern California where dewatered sewage sludge is injected into the mixing chamber where the flue gas streams from the kiln and the precalciner mix together. [14,15]

7.1 Factor 1 – Costs

Table 7-3 provides cost estimates for the emission control options which have been identified for cement kilns. For each option the table gives an estimate of the capital cost to install the necessary equipment and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The capital and annual cost figures are expressed in terms of the cost per unit of clinker tonnage produced, or cubic feet per minute (cfm) for PM emission sources. The table shows a range of values for each cost figure since the cost per unit of clinker tonnage will depend on the amount of clinker produced and other factors. The lower ends of the cost ranges typically reflect smaller kilns and the higher ends of the cost ranges typically reflect larger kiln sizes. Table 7-3 also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

7.2 Factor 2 – Time Necessary for Compliance

Once a state decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The ICAC has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[16] However, state regulators' experience indicates that closer to 18 months is required to install this technology.[17] Additional time of up to 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required to achieve emission reductions for cement kilns is estimated at a total of 5½ years.

Table 7-1. Emissions from Cement Kilns in the WRAP Region

Emission Source	AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY	Tribes	All
NO$_X$ emissions (tons/year)																
Wet Process Kiln	0	0	0	1136	461	1814	0	0	0	0	2966	0	2251	0	0	8,628
Dry Process Kiln	0	2476	11544	2162	0	0	0	804	0	1741	0	0.012	1213	2080	0	22,020
Clinker Transfer	0	0	601	0	0	0	0	0	0	0	0	0	0	0	0	601
Raw Material Grinding and Drying	0	0	78	12	0	0	0	0	0	0	0	0	0	0	0	91
Preheater/Precalciner Kiln	0	5066	1370	511	0	0	0	0	0	0	0	1322	0	0	0	8,269
Other	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	5
Total	0	7,542	13,598	3,821	461	1,814	0	804	0	1,741	2,966	1,322	3,464	2,080	0	39,613
SO$_2$ emissions (tons/year)																
Wet Process Kiln	0	0	0	240	17	233	0	0	0	0	656	0	771	0	0	1,917
Dry Process Kiln	0	61	2101	18	0	0	0	15	0	38	0	0.001	188	207	0	2,628
Clinker Transfer	0	0	86	0	0	0	0	0	0	0	0	0	0	0	0	86
Raw Material Grinding and Drying	0	0	11	32	0	0	0	0	0	0	0	0	0	0	0	43
Preheater/Precalciner Kiln	0	9	1	378	0	0	0	0	0	0	0	58	0	0	0	446
Other	0	0	0.44	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	70	2,200	667	17	233	0	15	0	38	656	58	959	207	0	5,121
PM$_{2.5}$ emissions (tons/year)																
Wet Process Kiln	0	0	14	0	3	0	0	0	0	0	91	6	6	0	0	121
Dry Process Kiln	0	0	1184	0	0	0	0	3	0	0	0	32	28	0	0	1,247
Clinker Transfer	0	0.48	105	3	0.47	0	0	0	0	0	0	1	0	0	0	110
Raw Material Grinding and Drying	0	0.26	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Preheater/Precalciner Kiln	0	74	2	15	0	0	0	0	0	0	0	5	0	0	0	95
Other	0	0	0	0	0.24	0	0	0	0	0	0	0	0	0	0	0.24
Total	0	75	1,305	18	4	0	0	3	0	0	91	44	34	0	0	1,573

Table 7-1. Emissions from Cement Kilns in the WRAP Region

Emission Source	AK	AZ	CA	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY	Tribes	All
PM$_{10}$ emissions (tons/year)																
Wet Process Kiln	0	0	20	75	4	376	0	0	0	0	185	17	14	0	0	691
Dry Process Kiln	0	0	2023	414	0	1	0	97	0	64	0	222	30	179	0	3,030
Clinker Transfer	0	1	163	5	2	0	0	0	0	0	0	4	0	0	0	175
Raw Material Grinding and Drying	0	0.47	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Preheater/Precalciner Kiln	0	132	5	26	0	0	0	0	0	0	0	14	0	0	0	178
Other	0	0	0	0	0.84	0	0	0	0	0	0	0	0	0	0	1
Total	0	134	2,211	521	7	377	0	97	0	64	185	257	44	179	0	4,075
VOC emissions (tons/year)																
Wet Process Kiln	0	0	0	0	1	0	0	0	0	0	81	0	0	0	1	84
Dry Process Kiln	0	10	114	3	0	0	0	33	0	15	0	1	0	46	0	221
Clinker Transfer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Raw Material Grinding and Drying	0	1	0	125	0	0	0	0	0	0	0	0	0	0	0	126
Preheater/Precalciner Kiln	0	5	4	2	0	0	0	0	0	0	0	42	0	0	1,984	2,038
Other	0	6	1	0	0	0	0	2	0	0	4	0	0	0	1,986	1,999
Total	0	21	119	131	1	0	0	35	0	15	85	43	0	46	3,972	4,467

Table 7-2. Control Options for Cement Kilns

Source Type	Control Technology	Pollutant controlled	Baseline emissions	Estimated control efficiency (%)	Potential emission reduction (tons/year)	References
Long Wet Kiln	Low NOX burners	NO_X	8,628	20-30	1725 - 2588	1, 6
	Mid-kiln firing	NO_X	8,628	20-50	1725 - 4313	1, 6
	SCR with ammonia	NO_X	8,628	80-90	6902 - 7764	5, 6
	SNCR with ammonia or urea	NO_X	8,628	30-70	2588 - 6039	6
	Biosolid injection	NO_X	8,628	50	4313	7
	CemStar^{TM} process	NO_X	8,628	20-60	1725 - 5176	1, 3, 7
	LoTOx^{TM}	NO_X	8,628	80-90	6902 - 7765	1, 5
	Dry ESP	PM_{10}	691	95-98	656 - 677	9
	Dry ESP	$PM_{2.5}$	121	95-98	114 - 118	9
	Dry ESP	EC	4	95-98	3	9
	Dry ESP	OC	15	95-98	14	9
	Fabric Filter	PM_{10}	691	80-99	656 - 677	9
	Fabric Filter	$PM_{2.5}$	121	80-99	114 - 118	9
	Fabric Filter	EC	4	80-99	3	9
	Fabric Filter	OC	15	80-99	14	9
	Absorbant Addition	SO_2	1,917	60-80	1150 - 1533	
	Wet FGD	SO_2	1,917	90-99	1725 - 1897	1
Long Dry Kiln	Low NOX burners	NOX	19541	40	7816	1, 6
	Mid-kiln firing	NOX	19541	11-55	2149 - 10747	1, 6
	SCR with ammonia	NOX	19541	80-90	1563 - 1758	6
	Biosolid injection	NOX	19541	50	9770	7
	LoTOx^{TM}	NO_X	19541	80 - 90	15,633 - 17,587	1, 5
	CemStar^{TM} process	NOX	19541	20-60	3908 - 1172	1, 3, 7
	Dry ESP	PM10	3,030	95-98	2878 - 2969	9
	Dry ESP	PM2.5	1,247	95-98	1184 - 1221	9
	Dry ESP	EC	37	95-98	34 - 36	9
	Dry ESP	OC	158	95-98	150 - 155	9
	Fabric Filter	PM10	3,030	99	3000	9
	Fabric Filter	PM2.5	1,247	99	1234	9
	Fabric Filter	EC	37	99	36	9
	Fabric Filter	OC	158	99	156	9
	Wet FGD	SO2	2567	90-99	2310 - 2541	1
	Dry FGD	SO2	2567	90-95	2310 - 2438	1
	Sorbent injection	SO2	2567	60-80	1540 - 2053	

Table 7-2. Control Options for Cement Kilns

Source Type	Control Technology	Pollutant controlled	Baseline emissions	Estimated control efficiency (%)	Potential emission reduction (tons/year)	References
Preheater Kiln	Low NOX burners	NOX	3204	40	1281	1, 6
	Mid-kiln firing	NOX	3204	11-55	352 - 1762	1, 6
	SCR with ammonia	NOX	3204	85	2723	5, 6
	SNCR with urea	NOX	3204	35	1121	5, 6
	SNCR with ammonia	NOX	3204	35	1121	5, 6
	LoTOx^{TM}	NO_X	3204	80 - 90	2,563 - 2,884	1, 5
	CemStar^{TM} process	NOX	19541	Unknown[a]	Unknown[a]	1, 3, 7
	Biosolid injection	NOX	3204	23 - 50	736 - 1602	7, 9
	Dry ESP	PM10	178	95-98	169 - 174	9
	Dry ESP	PM2.5	95	95-98	90 - 93	9
	Dry ESP	EC	3	95-98	2	9
	Dry ESP	OC	12	95-98	11 - 11	9
	Fabric Filter	PM10	178	99	176	9
	Fabric Filter	PM2.5	95	99	94	9
	Fabric Filter	EC	3	99	2	9
	Fabric Filter	OC	12	99	11	9
	Wet FGD	SO2	436	90-99	392 - 431	1
	Dry FGD	SO2	436	90-95	392 - 414	1
	Sorbent injection	SO2	436	60-80	261 - 348	8
Precalciner Kiln	Low NOX burners	NOX	3204	30-40	961 - 1281	6
	Mid-kiln firing	NOX	3204	11-55	352 - 1762	1, 6
	SCR with ammonia	NOX	3204	85	2723	5, 6
	SNCR with urea	NOX	3204	35	1121	5, 6
	SNCR with ammonia	NOX	3204	35	1121	5, 6
	LoTOx^{TM}	NO_X	3204	80 - 90	2,563 - 2,884	1, 5
	CemStar^{TM} process	NOX	19541	Unknown[a]	Unknown[a]	1, 3, 7
	Biosolid injection	NOX	3204	50	1602	7
	Dry ESP	PM10	178	95-98	169 - 174	9
	Dry ESP	PM2.5	95	95-98	90. - 93.	9
	Dry ESP	EC	3	95-98	2.6 - 2.7	9
	Dry ESP	OC	12	95-98	11 - 11	9
	Fabric Filter	PM10	178	99	176	9
	Fabric Filter	PM2.5	95	99	94	9
	Fabric Filter	EC	3	99	2	9
	Fabric Filter	OC	12	99	11	9
	Wet FGD	SO2	436	90-99	392 - 431	1
	Dry FGD	SO2	436	90-95	392 - 414	1
	Sorbent injection	SO2	436	60-80	261 - 348	8

a The CemStar process has been analyzed for long wet and dry kilns only although the process is currently being used in long dry kilns and preheater/precalciner kilns at two facilities, one in Texas and one in California. It is unknown what the control efficiency is of the CemStar process in preheater or precalciner kilns.

7.3 Factor 3 – Energy and Other Impacts

Table 7-4 shows the estimated energy and non-air pollution impacts of control measures for cement kilns. In general in-combustion NO_X control technologies will increase energy efficiency of the cement production process since these technologies reduce excess air and burning.[18] SCR requires additional energy input since the process required a particular gas temperature, requiring the gas stream to be reheated. An additional 9.8 percent of the total energy required in cement manufacturing will be needed to utilize the SCR control technology.[18] In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[19]

7.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of cement kilns in the WRAP region. Cement kilns have no set equipment life. The units, whether wet or dry, can be refurbished to extend their lives. In addition, it is assumed that controls will be not be applied to units that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to affect the cost of control for cement kilns.

Table 7-3. Estimated Costs of Control for Cement Kilns

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($1000/unit)	Estimated annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)	References
Long Wet Kiln	Low NOX burners (indirect fired)	NOX	20-47	401 - 564	100,000 - 144,000	ton clinker	270 - 620	1, 6, 7
	Low NOX burners (direct fired)	NOX	20-47	1,910	376,000 - 343,500	ton clinker	855 - 1,005	1, 6, 7
	Mid-kiln firing	NOX	20-50	613 - 3,205	183,500 - (192,300	ton clinker	(460) - 730	1, 6, 7, 8
	SCR with ammonia	NOX	80-90	15,100	5,780 - 4,105,000	ton clinker	3,370	5, 6, 7
	LoTOx™	NOX	80 - 90	Not available[a]			3,155 - 3,891[c]	5
	CemStar™ process	NOX	20-60	1,176	220000	ton clinker	550	7
	Dry ESP	PM_{10}, $PM_{2.5}$, OC, EC	95-98	Not available[a]			40 - 250	9
	Fabric Filter	PM_{10}, $PM_{2.5}$, OC, EC	80-99	Not available[a]			117 - 148	9
	Wet FGD	SO2	90-99	Not available[a]			2,211 - 6,917	1, 8
Long Dry Kilns	Low NOX burners (indirect fired)	NOX	30 - 40	334 - 509	83,000 - 135,500	ton clinker	300 (3) - 620	1, 6, 7
	Low NOX burners (direct fired)	NOX	40	1,455	298,000 - 272,500	ton clinker	166 - 1,299	1, 6, 7
	Mid-kiln firing	NOX	11-55	455 - 3,180	89,830 - 144,000	ton clinker	(460) - 730	1, 6, 7, 8
	LoTOx™	NOX	80 - 90	Not available[d]				5
	CemStar™ process	NOX	20-60		Not available[b]			7
	SCR with ammonia	NOX	80-90	11,485	3,000,000	ton clinker	586 - 3,400	6, 7, 8
	Dry ESP	PM_{10}, $PM_{2.5}$, OC, EC	95-98	Not available[a]			40 - 250	9
	Fabric Filter	PM_{10}, $PM_{2.5}$, OC, EC	80-99	Not available[a]			117 - 148	9
	Wet FGD	SO2	90-99	5,610 - 84,000	10,000 - 30,571	ton clinker	2,000 - 4,000	1, 8
	Dry FGD	SO2	90-95	3,300 - 95,800	9,142 - 32,286	ton clinker	1,900 - 7,000	1
Preheater Kilns	Low NOX burners (indirect fired)	NOX	30 - 40	379 - 608	94,500 - 150,000	ton clinker	300 - 620	1, 6, 7
	Low NOX burners (direct fired)	NOX	40	1,765 - 1,800	351,500 - 330,000	ton clinker	175 - 1,201	1, 6, 7
	CemStar™ process	NOX	20-60		Not available[b]			
	SCR with ammonia	NOX	85	14,400	3,850,000	ton clinker	500 - 3,805	5, 6, 7, 8
	SNCR with urea	NOX	35	799	546500	ton clinker	(310) - 2,500	5, 6, 8
	SNCR with ammonia	NOX	35	1,595	635500	ton clinker	(310) - 2,500	5, 6, 8
	LoTOx™	NOX	80 - 90	Not available[d]				5
	Biosolids Injection	NOX	50	1,200	(322,000)	ton clinker	(310)	7
	Dry ESP	PM_{10}, $PM_{2.5}$, OC, EC	95-98	0.013	Not available[a]	cfm	40 - 250	9
	Fabric Filter	PM_{10}, $PM_{2.5}$, OC, EC	99	0.029	Not available[a]	cfm	117 - 148	9
	Wet FGD	SO2	90-99	3,710 - 54,000	2,714 - 15,857	ton clinker	2,000 - 64,600	1, 8
	Dry FGD	SO2	90-95	2,100 - 61,400	2,857 - 17,571	ton clinker	10,000 - 72,800	1
	Sorbent Injection	SO2	60 - 80	Not available[a]			2,031 - 7,379	8

Table 7-3. Estimated Costs of Control for Cement Kilns

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($1000/unit)	Estimated annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)	References
Precalciner Kilns	Low NOX burners (indirect fired)	NOX	30	406 - 863	101,000 - 188,500	ton clinker	245 - 620	6, 7
	Low NOX burners (direct fired)	NOX	30	1,945 - 2,235	382,500 - 393,500	ton clinker	920 - 985	6, 7
	CemStar^{TM} process	NOX	20-60	Not available[b]				
	LoTOx^{TM}	NOX	80 - 90	Not available[a]			2,419 - 2,734[e]	5
	SCR with ammonia	NOX	85	21,950	6,240,000	ton clinker	4635	5, 6, 7
	SNCR with urea	NOX	35	1,105	709,000	ton clinker	(310) - 2,500	5, 6, 8
	SNCR with ammonia	NOX	35	1,880	779,500	ton clinker	(310) - 2,500	5, 6, 8
	Biosolids Injection	NOX	23 - 50	5,581	1,498	ton clinker	(310)	7, 8
	Dry ESP	PM$_{10}$, PM$_{2.5}$, OC, EC	99	0.013	Not available[a]	cfm	40 - 250	9
	Fabric Filter	PM$_{10}$, PM$_{2.5}$, OC, EC	99	0.029	Not available[a]	cfm	117 - 148	9
	Sorbent Injection	SO2	60-80	Not available[a]			2,031 - 7,379	8
	Wet FGD	SO2	90-99	3,710 - 54,000	2,714 - 15,857	ton clinker	2,211 - 6,917	8

a References discussing this particular control technology did not provide any capital or annual costs but only a cost effectiveness figure.

b The CemStar process has been costed for long wet kilns only although the process is currently being used in long dry kilns and preheater/precalciner kilns at two facilities, one in Texas and one in California.

c The cost effectivenes was calculated for a wet kiln that did not already have a scrubber system in place.

d Cost effectiveness figures for LoTOx were not determined for dry kilns or preheater kilns, but only for wet kilns (the kilns that currently use the system) and precalciner kilns (developed from vendor information).

e The cost effectiveness was calculated for a precalciner kiln that already has a scrubber system in place.

Table 7-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Cement Kilns

					Energy and non-air pollution impacts				
Source Type	Control Technology	Pollutant controlled	Potential emission reduction (tons/year)	Additional Fuel Requirement (%)	Additional electricity requirement (kW/ton reduced)	Steam requirement (tons steam/ton reduced)	Solid waste produced (tons waste/ton reduced)	Wastewater produced (million gallons/ton reduced)	Additional CO_2 emitted (tons/ton reduced)
Long Wet Kilns	Low NOX burners	NO_X	1725 - 2588	a	182				
	Mid-kiln firing	NO_X	1725 - 4313	a	182				
	SCR with ammonia	NO_X	6902 - 7764	9.8	57				Unknown[b]
	SNCR with ammonia or urea	NO_X	2588 - 6039		Unknown[b]				
	Biosolid injection	NO_X	4313	a					
	LoTOx™	NO_X	6902 - 7765		Unknown[c]				
	CemStar™ process	NO_X	1725 - 5176	a					
	Fabric Filter	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Dry ESP	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Wet FGD	SO_2	1725 - 1897		1,100	3.1	2.8	3.7	2.6
Long Dry Kilns	Low NOX burners	NO_X	7816	a	158				
	Mid-kiln firing	NO_X	2149 - 10747	a	158				
	SCR with ammonia	NO_X	1563 - 1758	9.8	48				Unknown[b]
	Biosolid injection	NO_X	9770						
	LoTOx™	NO_X	15,633 - 17,587		Unknown[c]				
	CemStar™ process	NO_X	3908 - 1172						
	Dry ESP	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Fabric Filter	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Wet FGD	SO_2	2310 - 2541		1,100	3.1	2.8	3.7	2.6
	Dry FGD	SO_2	2310 - 2438		Unknown[b]				

Table 7-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Cement Kilns

					Energy and non-air pollution impacts				
Source Type	Control Technology	Pollutant controlled	Potential emission reduction (tons/year)	Additional Fuel Requirement (%)	Additional electricity requirement (kW/ton reduced)	Steam requirement (tons steam/ton reduced)	Solid waste produced (tons waste/ton reduced)	Wastewater produced (million gallons/ton reduced)	Additional CO_2 emitted (tons/ton reduced)
Preheater Kilns	Low NOX burners	NO_X	1281	a	194				
	SCR with ammonia	NO_X	2723	9.8	59				Unknown[b]
	SNCR with urea	NO_X	1121		Unknown[b]				
	SNCR with ammonia	NO_X	1121		Unknown[b]				
	LoTOx™	NO_X	2,563 - 2,884		Unknown[c]				
	Biosolid injection	NO_X	736 - 1602	a					
	Sorbent injection	SO_2	261 - 348	a					
	Dry ESP	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Fabric Filter	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Wet FGD	SO_2	392 - 431		1,100	3.1	2.8	3.7	2.6
	Dry FGD	SO_2	392 - 414		Unknown[b]				
Precalciner Kilns	Low NOX burners	NO_X	961 - 1281	a	285				
	SCR with ammonia	NO_X	2723	9.8	89				Unknown[b]
	SNCR with urea	NO_X	1121		Unknown[b]				
	SNCR with ammonia	NO_X	1121		Unknown[b]				
	LoTOx™	NO_X	2,563 - 2,884		Unknown[c]				
	Biosolid injection	NO_X	1602	a					
	Sorbent injection	SO_2	60-80	a					
	Dry ESP	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Fabric Filter	PM_{10}, $PM_{2.5}$, EC, OC	1,898 - 1,958		Unknown[b]		1		
	Wet FGD	SO_2	392 - 431		1,100	3.1	2.8	3.7	2.6
	Dry FGD	SO_2	392 - 414		Unknown[b]				

a - The measure is expected to improve fuel efficiency.

b - Impacts are expected, however there is no available information to quantify these impacts.

c - According to the ERG Report (reference 3) "electricity and oxygen costs are reported to be high" although there is no quantification given.

7.5 References for Section 7

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8. Sulfuric Acid Manufacturing Plants

Sulfuric acid manufacturing plants account for about 4,700 tons/year of SO_2 emissions in the WRAP region. These emissions are from a limited number of facilities, with facility-level SO_2 emissions ranging from about 100 tons/year to about 2,000 tons/year. Table 8-1 summarizes emissions from the sulfuric acid manufacturing plants, broken down by state, based on the WRAP emissions inventory and the NEI.[1] The table also shows the amounts of SO_2 emissions from facilities at different efficiency levels for the acid recovery process. As the table shows, reported emissions of NO_X, PM_{10}, $PM_{2.5}$, and VOC emissions are much lower than SO_2 emissions from sulfuric acid plants in the region.

Emissions of SO_2 from sulfuric acid manufacturing processes can be reduced by increasing the absorption efficiency of the acid recovery process. The NSPS emission level for sulfuric acid plants corresponds to an estimated recovery efficiency of 99.75%.[2] Based on the SCC used in the WRAP inventory, the recovery efficiency ranges from 93 to 99% for most of the emission sources in the WRAP region. Increasing the efficiency of sulfuric acid plants to the NSPS level would result in emission reductions 75 to 96.4% from the current baseline level of control. This increase in efficiency is achieved by adding more absorption stages to the acid recovery process. SO_2 emissions can also be controlled using tail gas treatment units.[3,4] Table 8-2 shows the estimated control efficiencies and emission reductions which could be achieved for sulfuric acid plants operating at different baseline levels of control.

8.1 Factor 1 – Costs

Table 8-3 provides cost estimates for the emission control options which have been identified for sulfuric acid manufacturing plants. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The capital and annual cost figures are expressed in terms of the cost per unit of gas treated, in actual cubic feet per minute (acfm).

Table 8-3 shows a range of values for each cost figure, since the cost per unit of throughput will depend on the process size and other factors. The lower ends of the cost ranges typically reflect larger processes, and the higher ends of the cost ranges typically reflect lower process sizes. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

Table 8-1. Emissions from Sulfuric Acid Manufacturing Plants in the WRAP Region

	CA	ID	WA	WY	Tribes	All
			NO_X emissions (tons/year)			
General	32	0	10	54	7	103
			SO_2 emissions (tons/year)			
Contact process						
99% efficient	710					710
98% efficient			105			105
93% efficient		364				364
Unspecified				2,012	897	2,909
Chamber process	600					600
Total	1,310	364	105	2,012	897	4,688
			VOC emissions (tons/year)			
General	2			23	2	27

Table 8-2. Control Options for Sulfuric Acid Manufacturing Plants

Source Type	Control Technology	Pollutant controlled	Baseline emissions	Estimated control efficiency (%)	Potential emission reduction (tons/year)	Refer-ences
Contact process						
99% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	710	75	530	2,3
	Tailgas treatment unit	SO_2	710	90	640	3,4
98% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	105	87.5	92	2,3
	Tailgas treatment unit	SO_2	105	95	100	3,4
93% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	3,273	96.4	3,200	2,3
	Tailgas treatment unit	SO_2	3,273	98.6	3,200	3,4
Chamber process	Tailgas treatment unit	SO_2	600	98.6	590	3,4

Table 8-3. Estimated Costs of Control for Sulfuric Acid Manufacturing Plants

Source Type	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Estimated capital cost ($/unit)	Estimated annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)	References
Contact process								
99% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	75	55 - 96	23 - 29	acfm	6,800 - 7,000	2,3
	Tailgas treatment unit	SO_2	90	23 - 32	36	acfm	5,300 - 6,500	3,4
98% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	87.5				6,200	2,3
	Tailgas treatment unit	SO_2	95	48	38	acfm	3,375	3,4
93% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	96.4				1,600	2,3
	Tailgas treatment unit	SO_2	98.6	48	38	acfm	928	3,4
Chamber process	Tailgas treatment unit	SO_2	98.6	19	34	acfm	8,100	3,4

8.2 Factor 2 – Time Necessary for Compliance

Once a state decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. In the CAIR analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[5] The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required achieve emission reductions for sulfuric acid manufacturing facilities is estimated at a total of 6½ years.

8.3 Factor 3 – Energy and Other Impacts

Table 8-4 shows the estimated energy and non-air pollution impacts of control measures for sulphuric acid plants. Additional absorption stages to increase acid plant efficiency would require additional electricity and steam,[2] as would a tailgas treatment unit.[4] This would result in increased CO_2 emissions to generate the electricity and steam.

8.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of sulfuric acid plants in the WRAP region. However, industrial processes often refurbished to extend their lifetimes. Therefore, the remaining lifetime of most equipment is expected to be longer than the projected lifetime of pollution control technologies which have been analyzed for this category. In the case of add-on technologies, the projected lifetime is 15 years.

If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1-(1+r)^{-m}}{1-(1+r)^{-n}}$$

where:

A_1 = the annual cost of control for the shorter equipment lifetime ($)
A_0 = the original annual cost estimate ($)
C = the capital cost of installing the control equipment ($)
r = the interest rate (0.07)
m = the expected remaining life of the emission source (years)
n = the projected lifetime of the pollution control equipment

Table 8-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Sulfuric Acid Manufacturing Plants

				Energy and non-air pollution impacts (per ton of pollutant reduced)			
Source Type	Control Technology	Pollutant controlled	Potential emission reduction (tons/year)	Additional electricity requirement (kW-hr)	Steam requirement (tons steam)	Solid waste produced (tons waste)	Additional CO_2 emitted (tons)
Contact process							
99% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	530	2,450	29	<0.01	10
	Tailgas treatment unit	SO_2	640	1,470	27		8
98% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	92	1,050	13	<0.01	4
	Tailgas treatment unit	SO_2	100	700	12		4
93% baseline efficiency	Increase absorption efficiency to NSPS level	SO_2	3,200	270	3.2	<0.01	1
	Tailgas treatment unit	SO_2	3,200	190	3.5		1
Chamber process	Tailgas treatment unit	SO_2	590	2,450	29	<0.01	10

8.5 References for Section 8

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9. Pulp and Paper Lime Kilns

The pulp making process produces the largest amount of emissions in the pulp and paper industry, accounting for more than 75% of the sector's $PM_{2.5}$, SO_2, and NO_X emissions.[1] The role of lime kilns in the kraft pulping process is to produce white liquor and calcium carbonate.[2]

Lime kilns at pulp and paper manufacturing facilities in the WRAP region are estimated to emit about 828 tons of NO_X, 104 tons of SO_2, 603 tons of $PM_{2.5}$, 667 tons of PM_{10}, and 32 tons of VOC per year, based on the 2002 emissions inventory for the region.[3] The area source emissions estimates are derived from industrial, commercial, and institutional fuel consumption in the WRAP states. NO_X emissions from lime kilns represent approximately 0.08% of total point source emissions of NO_X in the WRAP region, and approximately 0.06% of all stationary source (point and area source) NO_X emissions in the region. SO_2 emissions from lime kilns represent approximately 0.01% of total point source emissions of SO_2 in the WRAP region, and approximately 0.01% of all stationary source (point and area source) SO_2 emissions in the region.

Table 9-1 shows estimated emissions of NO_X, SO_2, PM_{10}, $PM_{2.5}$ and VOC from the WRAP emissions inventory and updated data provided by the states, broken down by state and emission source. As the table shows, SO_2, PM_{10}, $PM_{2.5}$ and VOC emissions from lime kiln sources are much lower than NO_X emissions. PM emissions from these sources were not included in the WRAP EDMS inventory – the emissions presented were gathered from the 2002NEI.

Table 9-2 lists potential control measures for NO_X, SO_2, PM_{10} and $PM_{2.5}$ emissions from lime kilns. A number of options were identified for lime kilns in the AirControlNet documentation report written by Pechan in 2006.[4] Many of the controls listed are similar to those to control emissions from cement kilns (please see chapter 7). SCR and SNCR have been investigated as possible control technologies but have been found to be technically infeasible. Additionally, according to the NACAA, there are no technically feasible methods for controlling NO_X emissions from lime kilns.[1] Therefore NACAA discusses control options for PM emissions only.

9.1 Factor 1 – Costs

Table 9-3 provides cost estimates for the emission control options which have been identified for lime kilns used in the pulp and paper industry. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The capital and annual cost figures are expressed in terms of the cost per standard cubic feet per minute (scfm). The table shows a range of values for each cost figure, since the cost per scfm will depend on the

Table 9-1. Emissions from Lime Kilns in the WRAP Region

	AK	CA	CO	ID	MT	ND	NM	NV	OR	UT	WA	WY	Tribes	All
NO_X emissions (tons/year)														
Total*	0	66	0	99	236	0	0	0	96	0	308	23	0	828
SO_2 emissions (tons/year)														
Total*	0	1	0	3.3	2	0	0	0	57	0	40	0	0	104
$PM_{2.5}$ emissions (tons/year)														
Total*	0	40	0	87	31	0	0	0	336	0	109	0	0	603
PM_{10} emissions (tons/year)														
Total*	0	53	0	93	38	0	0	0	370	0	113	0	0	667
VOC emissions (tons/year)														
Total*	0	0.28	0	5	20	0	0	0	2.18	0	4	0	0	32

* The majority of emissions produced in the pulp and paper lime kiln operations are generated from the kilns themselves. Thus the total emissions presented in this table are emissions from kilns.

Table 9-2. Control Options for Lime Kilns

Source Type	Control Technology	Pollutant controlled	Baseline emissions	Estimated control effieiency (%)	Potential emission reduction (tons/year)	References
Kiln	Low NOX burners	NO_X	828	30	248	4
	Mid-kiln firing	NO_X	828	30	248	4
	LoTOX	NO_X	828			
	SCR with ammonia	NO_X	828	60 - 80	496 - 662	4
	SNCR with ammonia or urea	NO_X	828	50	414	4
	Wet FGD	SO_2	104	50	51	4
	Dry ESP	PM_{10}	1271	95-98	1207 - 1245	4
	Dry ESP	$PM_{2.5}$	1271	95-98	1207 - 1245	4
	Dry ESP	EC	37	95-98	35 - 36	4
	Dry ESP	OC	161	95-98	153 - 158	4

kiln size and other factors. The lower ends of the cost ranges typically reflect smaller kilns, and the higher ends of the cost ranges typically reflect larger kilns. Table 9-3 also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

9.2 Factor 2 – Time Necessary for Compliance

Once a state decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The ICAC has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[5] However, state regulators' experience indicates that closer to 18 months is required to install this technology.[6] Additional time of up to 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required to achieve emission reductions for pulp and paper lime kilns is estimated at a total of 5½ years.

9.3 Factor 3 – Energy and Other Impacts

Table 9-4 shows the estimated energy and non-air pollution impacts of control measures for pulp and paper lime kilns. Low NO_X burners negatively affect efficiency and energy usage,[7] and staged combustion, while lowering NO_X emissions, can lead to increased SO_2 emissions. SCR and SNCR require, on average, 890 kilowatt-hour (kWh) of electricity per ton of pollutant reduced, and 0.25 tons of steam for every ton of pollutant reduced. Approximately one ton of CO_2 is produced per mWh of electricity generated.[8] In addition, spent catalyst from the SCR technology would have to be changed periodically, producing an increase in solid waste disposal.[9] Installation of SCR would also require an increase in fuel consumption, which would also produce an increase in CO_2 emissions to generate the electricity.

Fabric filters and ESP technologies, on average, generate approximately one ton of solid waste for every ton of pollutant reduced. It is also likely that there will be additional electricity usage for in-combustion and post-combustion technologies.

9.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of reciprocating engines and turbines in the WRAP region. However, lime kilns, like cement kilns, have no set equipment life. These units can be refurbished to extend their lives. In addition, it is assumed that controls will be not be applied to lime kilns that are expected to be retired prior to the amortization period for the control equipment. Therefore, remaining equipment life is not expected to affect the cost of control for lime kilns.

Table 9-3. Estimated Costs of Control for Lime Kilns

Source Type	**Control Technology**	**Pollutant controlled**	Estimated control effieiency (%)	Estimated capital cost ($1000/unit)	Estimated annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)	**References**
Kilns	Low NO_X burners	NO_X	30		Not available		560	4
	Mid-kiln firing	NO_X	30		Not available		460	4
	SCR with ammonia	NO_X	60 - 80		Not available		3370	4
	SNCR with ammonia or urea	NO_X	50		Not available		770 - 850	4
	Wet FGD	SO_2	50		Not available			4
	Dry ESP	$PM_{2.5}$	95	15 - 50	4 - 40	scfm		4
	Dry ESP	PM_{10}	98	15 - 50	4 - 40	scfm	40-250	4
	Dry ESP	EC	95	15 - 50	4 - 40	scfm		4
	Dry ESP	OC	95	15 - 50	4 - 40	scfm		4
	Wet ESP	$PM_{2.5}$	95		Not available			4
	Wet ESP	PM_{10}	99	30 - 60	6 - 45	scfm	55 - 550	4
	Wet ESP	EC	95		Not available			4
	Wet ESP	OC	95		Not available			4

Table 9-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Lime Kilns

			Energy and non-air pollution impacts						
Source Type	**Control Technology**	**Pollutant controlled**	**Potential emission reduction (tons/year)**	**Additional Fuel Requirement (%)**	**Additional electricity requirement (kW-hr/ton reduced)**	**Steam requirement (tons steam/ton reduced)**	**Solid waste produced (tons waste/ton reduced)**	**Wastewater produced (million gallons/ton reduced)**	**Additional CO_2 emitted (tons/ton reduced)**
Kilns	Low NOX burners	NO_X	30	Unknown	Unknown				
	Mid-kiln firing	NO_X	30		a				
	SCR with ammonia	NO_X	60 - 80	Unknown	890	0.25			1
	SNCR with ammonia or urea	NO_X	50	Unknown	890	0.25			1
	Wet FGD	SO2	90		1,100	3.1	2.8	3.7	2.6
	Dry ESP	PM10, PM2.5, EC, OC	95-98		Unknown		1		
	Fabric Filter	PM10, PM2.5, EC, OC	95-99		Unknown		1		

a - The measure is expected to improve fuel efficiency.

9.5 References for Section 9

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10. Oil Refineries

Petroleum refineries in the WRAP region are estimated to emit about 25,000 tons of NO_X and 58,000 tons of SO_2, based on the WRAP emissions inventory. These emissions represent about 2% of stationary source (point and area source) NO_X emissions, and 6% of stationary source SO_2 emissions in the region. PM_{10} and $PM_{2.5}$ emissions from natural gas processing facilities are estimated to be an order of magnitude lower than NO_X and SO_2 emissions.

Table 10-1 summarizes estimated emissions from petroleum refineries in the WRAP region, broken down by state and by the various emission sources. These emissions estimates are based on the 2002 WRAP emissions inventory.[1] Major sources of NO_X and SO_2 emissions at refineries in the WRAP region include process heaters, catalytic cracking units, coking units and ancillary operations, flares and incinerators. Other sources include boilers, which have been discussed in Chapter 6, and reciprocating engines and turbines, which have been discussed in Chapter 3.

Emissions of OC and EC are not specifically quantified in either the WRAP inventory or the NEI, but can be estimated as a percentage of PM_{10} emissions using data from EPA's SPECIATE database.[2] EC and OC are estimated to comprise 0.07% and 0.014% of PM_{10} emissions from catalytic cracking units, respectively; 38.4% and 24.7% of natural gas combustion PM_{10} emissions; and 1% each in oil combustion PM_{10}.

Table 10-2 lists potential control measures for emissions of SO_2, NO_X, and PM at petroleum refineries. The table includes options for process heaters, fluid catalytic cracking units, fluid coking operation boilers, coke calcining boilers, and flares.

Most of the SO_2 emissions from process heaters result from the burning of refinery fuel gases containing hydrogen sulfide (H_2S). These emissions can be reduced by treating the refinery fuel gas to remove H_2S before the gas is burned. A number of options are available to reduce NO_X emissions from process heaters. Combustion modifications including LNB, ULNB, and FGR reduce the formation of NO_X. In addition, flue gases from the process heaters can be treated with SCR or SNCR to reduce NO_X emissions. These post-combustion controls can be used either alone or in conjunction with combustion controls.[3,4]

In catalytic cracking, the heavier fractions of crude petroleum are treated with a catalyst which breaks the petroleum molecules into lighter compounds. The catalyst is continuously cycled between the cracking and a separate regeneration reactor in order to burn off coke build-up. Since the catalyst coke contains relatively high levels of sulfur, the combustion products from this coke are an important source of SO_2 emissions. Uncontrolled SO_2 concentrations in the fluid catalytic cracking (FCC) regenerator exhaust stream range from 150 to 3000 parts per million by volume (ppmv). The FCC regenerator burner also emits NO_X and PM, including material abraded from the catalyst (catalyst fines). Uncontrolled NO_X emissions from the regenerator vent can range from 50 to 400 ppmv.[5]

Table 10-1. Emissions from Petroleum Refineries in the WRAP Region

	AK	CA	CO	MT	ND	NM	NV	OR	UT	WA	WY	Tribes	All
						NO_X emissions (tons/year)							
Process Heaters	573	7,778	349	1,072	864	783	48		615	3,088	192	1	15,362
Catalytic Cracking Units		1,179	239	463		193			245				2,319
Flares	102	942	12	191		7			261	57	9		1,582
Fluid Coking Units		122		25									147
Other	122	563	106	103		31		7	105	996	1,156	1,984	5,174
Total	797	10,583	707	1,854	864	1,014	48	7	1,226	4,141	1,358	1,985	24,584
						SO_2 emissions (tons/year)							
Process Heaters	62	2,093	338	628	4,592	1,268	93		715	2,330	363	10	12,491
Catalytic Cracking Units		5,567	1,197	4,649		2,044			671	2,645	379		17,152
Flares	8	4,940	2	380		31			313	936	139		6,750
Fluid Coking Units		5,937		282									6,219
Coke Calcining		3,642								186			3,828
Incinerators	41	29		183		457		1	2,105	44	629		3,489
Other	41	5,802	126	183		688		10	2,105	698	5,238	113	15,003
Total	111	24,340	1,663	6,122	4,592	4,030	93	10	3,804	6,609	6,120	122	57,615
						PM_{10} emissions (tons/year)							
Process Heaters	30	1,049	31	38		72			61	200	28		1,509
Catalytic Cracking Units		305	264	333		171			30	74			1,177
Flares	6	41	0						2	5	0		55
Fluid Coking Units		154		6									160
Other	7	51	193	2				3	280	70	536		1,142
Total	43	1,600	488	379	0	244	0	3	373	349	564	0	4,042
						$PM_{2.5}$ emissions (tons/year)							
Process Heaters	2	1,026				64			60	30			1,184
Catalytic Cracking Units		278				103			4				384
Flares		41							2	1			44
Fluid Coking Units		140											140
Other	0	54							3	2			60
Total	2	1,539	0	0	0	167	0	0	70	33	0	0	1,812
						VOC emissions (tons/year)							
Fugitive emissions	0	3,094	127	1,326	0	1,396	20	37	447	955	469	1	7,872
Wastewater treatment	1,018	960	13	531	0	221	5	2	139	344	94	0	3,327
Process heaters	9	418	67	27	161	30	1	1	22	101	2,613	10	3,461
Flares	130	2,311	17	33	0	5	0	0	63	117	27	0	2,703
Other	11	1,304	43	100	0	151	8	1	67	161	7	0	1,852
Total	1,167	8,086	268	2,017	161	1,802	34	41	738	1,678	3,210	12	19,215

Table 10-2. Control Options for Petroleum Refineries

Source Type	Control Technology	Pollutant controlled	Baseline emissions (1000 tons)	Estimated control effieiency (%)	Potential emission reduction (1000 tons/year)	References
Process heaters	Fuel treatment to remove sulfur	SO_2	12	up to 90	0 - 11	5,13
	LNB	NO_X	15	40	6.1	3,6
	ULNB	NO_X	15	75 - 85	12 - 13	5,6,3
	LNB and FGR	NO_X	15	48	7.4	3,6
	SNCR	NO_X	15	60	9.2	3,5,3
	SCR	NO_X	15	70 - 90	11 - 14	3,5,3
	LNB and SCR	NO_X	15	70 - 90	11 - 14	3,5,3
Fluid catalytic cracking units	Catalyst additives for NO_X reduction	NO_X	2.3	46	1.1	5,7
	LoTOX^{TM}	NO_X	2.3	85	2.0	5,8
	SNCR	NO_X	2.3	40 - 80	0.93 - 1.9	5,7
	SCR	NO_X	2.3	80 - 90	1.9 - 2.1	8,7
	Catalyst additives for SO_2 absorbtion	SO_2	17	20 - 60	3.4 - 10	5,7
	Desulfurization of catalytic cracker feed	SO_2	17	up to 90	0 - 15	7,13
	Wet scrubbing	SO_2	17	70 - 99	12 - 17	5,6,9
	ESP	PM_{10}	1.2	95+	1.1 - 1.2	5,6,10
		$PM_{2.5}$	0.4	95+	0.4	
		EC	0.0008	95+	0.0008	
		OC	0.0002	95+	0.0002	
Coking or coke calcining boilers	Spray dryer absorber	SO_2	10	80 - 95	8 - 10	5
	Wet FGD	SO_2	10	90 - 99	9 - 10	5,11,12
Flares	Improved process control and operator training	SO_2		varies		5
	Expand sulfur recovery unit	SO_2		varies		5
	Flare gas recovery system	SO_2		varies		5

Many refineries use catalyst additives to reduce SO_2 and NO_X emissions from fluid catalytic cracking units. SO_2 emissions can also be reduced by treating the fluid catalytic cracker feed stream to remove sulfur compounds. Some refineries in the U.S. have also used SCR to control NO_X emissions from catalytic cracking units, and one refinery in Japan has also used SNCR.[6,7] In addition, the LoTOx^{TM} process has been developed to control NO_X emissions in the catalytic cracking regenerator offgas. In this system, ozone is injected into the offgas to convert the nitrogen oxide (NO) and nitrogen dioxide (NO_2) which comprise NO_X into more highly oxidized forms of nitrogen such as dinitrogen pentoxide (N_2O_5). These more highly oxygenated compounds are more soluble in water, and are removed from the offgas stream in a wet scrubber. An emission control efficiency of 90% has been reported for this system.[5,8] However, the LoTOx^{TM} system is more cost effective if used in conjunction with a wet scrubber to control SO_2 emissions. Wet scrubbers are often used for simultaneous control of PM, SO_2, and NO_X emissions from the catalyst regenerator.[9] In addition, cyclones and ESP are commonly used to control PM emissions in the catalyst regenerator offgas.[5,10]

SO_2 emissions from fluid coking and coke calcining operations result from the combustion of a portion of the coke in a coke burner. Wet scrubbers have been used to control SO_2 emissions from the coking unit, with reported efficiencies of 95% to over 99%.[11] The emission streams from a coke calciner incinerator and from the coke burner in a fluid coking unit are similar to the emission streams from a boiler.[11] Therefore, it is believed that NO_X emissions from these streams can be controlled using SCR or SNCR.[12,13]

Petroleum refineries use flares to burn combustible gases that must be vented from various processes and cannot be practically processed or recovered. These gases generally emanate from non-steady-state operations, such as start-up, shut-down, process maintenance, and process upsets. Some of these operations are predictable, and others are not. SO_2 emissions from flaring result from the flaring of sour gases or other gases which have high concentrations of sulfur compounds. These emissions can often frequently be reduced through the use of improved process controls or improved training of process operators. Emissions can also be reduced by expanding the sulfur recovery unit to handle all of the acid gases produced by the refinery, and by optimizing the performance of the sulfur recovery unit. All of these measures are designed to reduce the number of times that sulfur-containing gases are flared.[5]
A flare gas recovery system can also be used to capture waste gases before they are flared, and hold the gases until they can be treated to remove sulfur compounds.[5] NO_X emissions during flaring events can be mitigated by combustion controls such as steam injection.

10.1 Factor 1 – Costs

Table 10-3 provides cost estimates for the emission control options which have been identified for petroleum refineries. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The capital and annual cost figures are expressed in terms of the cost per unit process throughput.

Table 10-3. Estimated Costs of Control Petroleum Refineries

Source Type	Control Technology	Pollutant controlled	Estimated control effieiency (%)	Estimated capital cost ($1000/unit)	Estimated annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)	Refer-ences
Process heaters	Fuel treatment to remove sulfur	SO_2	up to 90	3.4 - 10	28,000 - 36,000	Refinery capacity, 1000 barrels/day	1,300 - 1,700	5,13
	LNB	NO_X	40	2.7 - 7.6	290 - 810	MM-Btu/hr	650 - 2,800	3,6
	ULNB	NO_X	75 - 85	2.8 - 13	300 - 1,300	MM-Btu/hr	400 - 2,000	3,5,6
	LNB and FGR	NO_X	48	5.8 - 16	640 - 1,700	MM-Btu/hr	1,000 - 2,600	3,6
	SNCR	NO_X	60	5.2 - 22	570 - 2,400	MM-Btu/hr	890 - 5,200	3,5,6
	SCR[b]	NO_X	70 - 90	33 - 48	3,700 - 5,600	MM-Btu/hr	2,900 - 6,700	3,5,6
	LNB and SCR	NO_X	70 - 90	37 - 55	4,000 - 6,300	MM-Btu/hr	2,900 - 6,300	3,5,6
Fluid catalytic cracking units	Catalyst additives for NO_X reduction	NO_X	46	not available[a]				5,7
	LoTOX™	NO_X	85				1,700 - 2,000	5,8
	SNCR	NO_X	40 - 80				2500	5,7
	SCR	NO_X	80 - 90				2500	7,8
	Catalyst additives for SO_2 absorbtion	SO_2	20 - 60	not available[a]				5,7
	Desulfurization of catalytic cracker feed	SO_2	up to 90	23 - 54	190,000 - 250,000	Refinery capacity, 1000 barrels/day	6,200 - 8,000	7,13
	Wet scrubbing	SO_2	70 - 99				1,500 - 1,800	5,6,9
	ESP	$PM_{2.5}$, PM_{10}, EC,OC	95+				>10,000	5,6,10
Coking or coke calcining boiler offgas	Spray dryer absorber	SO_2	80 - 95				1,500-1,900	5
	Wet FGD	SO_2	90 - 99				1,500 - 1,800	5,11,12
Flares	Improved process control and operator training	SO_2	Varies	not available[a]				5
	Expand sulfur recovery unit	SO_2	Varies	not available[a]				5
	Flare gas recovery system	SO_2	Varies	not available[a]				5

[a] Costs of process modifications will depend on the specific refinery configuration.

[b] SCR cost estimates for SCR apply to mechanical draft heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR. This would increase both the capital and annualized costs of control by about 10%.

Sulfur recovery units are believed to be more cost-effective than post-combustion controls for reducing SO_2 emissions from flares and incinerators at natural gas processing facilities. Recent analyses of controls for Regional Haze precursors have focused on add-on controls for SO_2, rather than such process modifications. However, costs of sulfur recovery units were estimated in an earlier study of model refineries in different size ranges.[14] These estimates have been updated to current dollars using the Chemical Engineering plant cost index.

Table 10-3 shows a range of values for each cost figure, since the cost per unit of throughput will depend on the process size and other factors. The lower ends of the cost ranges typically reflect larger engine or process sizes, and the higher ends of the cost ranges typically reflect smaller process sizes. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

10.2 Factor 2 – Time Necessary for Compliance

Once a state decides to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The ICAC has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[15] However, state regulators' experience indicates that closer to 18 months is required to install this technology.[16] In the CAIR analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[17] The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required achieve emission reductions for oil refineries estimated at a total of 6½ years.

10.3 Factor 3 – Energy and Other Impacts

Table 10-4 shows the estimated energy and non-air pollution impacts of control measures for sources at petroleum refineries. Process modifications to desulfurize process gases burned in process heaters would generally require increases in catalytic hydrotreatment processing. These modifications may increase the generation of spent catalyst, which would need to be treated as a solid waste or a hazardous waste. Low NO_X burners for process heaters are expected to improve overall fuel efficiency.[3] FGR would require additional electricity to recirculate the fuel gas into the heater. In SCR systems for process heaters or other sources, fans would be required to overcome the pressure drop through the catalyst bed. The fans would require electricity, with resultant increases in CO_2 to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.[10]

Catalyst additives for reducing NO_X and SO_2 emissions from fluid catalytic cracking units are likely to result in increased generation of spent catalyst, which would have to be disposed as hazardous waste. These catalyst additives may also result in increases in fuel consumption. However, information is not available to quantify these impacts. A LoTOx

Table 10-4. Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Petroleum Refineries

					Energy and non-air pollution impacts (per ton of emission reduced)				
Source Type	**Control Technology**	**Pollutant controlled**	**Potential emission reduction (1000 tons/year)**	**Additional fuel requirement (%)**	**Electricity requirement (kW-hr)**	**Steam requirement (tons steam)**	**Solid waste produced (tons waste)**	**Wastewater produced (1000 gallons)**	**Additional CO_2 emitted (tons)**
Process heaters	Fuel treatment to remove sulfur	SO_2	0 - 11	b					b
	LNB	NO_X	6	a	e				
	ULNB	NO_X	12 - 13	a	e				
	LNB and FGR	NO_X	7.4		3,300				3.3
	SNCR	NO_X	9.2	0.16	460				3.2
	SCR	NO_X	11 - 14		8,400		0.073		8.4
	LNB and SCR	NO_X	11 - 14		8,400		0.073		8.4
Fluid catalytic cracking units	Catalyst additives for NO_X reduction	NO_X	1.1	d			d		
	LoTOX™	NO_X	2.0		d		d	d	
	SNCR	NO_X	0.93 - 1.9		460				3.2
	SCR	NO_X	1.9 - 2.1		8,400		0.073		8.4
	Catalyst additives for SO_2 absorbtion	SO_2	3.4 - 10	d			d		
	Desulfurization of catalytic cracker feed	SO_2	0 - 15	d		d	d		d
	Wet scrubbing	SO_2	12 - 17		1,100	3.1		3.7	2.6
	ESP	$PM_{2.5}$, PM_{10}, EC,OC	1.1 - 1.2		97		1		0.1
Coking or coke calcining boiler offgas	Spray dryer absorber	SO_2	8 - 10		400				1.1
	Wet FGD	SO_2	9 - 10		1,100	3.1		3.7	2.6
Flares	Improved process control and operator training	SO_2	Varies						
	Expand sulfur recovery unit	SO_2	Varies	d	d	d			d
	Flare gas recovery system	SO_2	Varies	d	d	d			d

NOTES:

blank indicates no impact is expected.

[a] The measure is expected to improve fuel efficiency.

[b] CO_2 from the generation of electricity would be offset by avoided emissions due to replacing the diesel engine

[c] EPA has estimated that the control measures used to meet Tier 4 standards will be integrated into the engine design so that sacrifices in fuel economy will be negligible.

[d] Some impact is expected but insufficient information is available to evaluate the impact.

[e] Some designes of low-NOX burners and ultralow-NOX burners require the use of pressurized air supplies. This would require additional electricity to pressurize the combustion

scrubbing system or wet scrubbing system applied to the fluidized catalytic cracking unit would require electricity to operate fans and other auxiliary equipment, and would produce a wastewater stream which would require treatment. In addition, sludge from the scrubber would require disposal as solid waste. SCR and SNCR systems would also require electricity for fans, and SCR systems would produce additional solid waste because of spent catalyst disposal. Dust captured by an ESP or fabric filter would also require disposal as a solid waste. The presence of catalyst fines in the dust may require treatment as a hazardous waste.

Sulfur recovery units require electricity and steam. Wet or dry scrubbers applied to incinerators and tail gas treatment units applied to sulfur recovery units would use electricity for the fan power needed to overcome the scrubber pressure drop. These systems would also produce solid waste, and wet scrubbers would produce wastewater which would require treatment.

10.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of processes at petroleum refineries in the WRAP region. However, industrial processes often refurbished to extend their lifetimes. Therefore, the remaining lifetime of most equipment is expected to be longer than the projected lifetime of pollution control technologies which have been analyzed for this category. In the case of add-on technologies, the projected lifetime is 15 years.

If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1-(1+r)^{-m}}{1-(1+r)^{-n}}$$

where:

A_1 = the annual cost of control for the shorter equipment lifetime ($)
A_0 = the original annual cost estimate ($)
C = the capital cost of installing the control equipment ($)
r = the interest rate (0.07)
m = the expected remaining life of the emission source (years)
n = the projected lifetime of the pollution control equipment

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MARCH 3, 1849

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
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AUG 2008
Received
Air Quality

August 11, 2008

N3615 (2350)

Tom Bachman, P.E.
Senior Environmental Engineer
Division of Air Quality
North Dakota Department of Health
Environmental Health Section
Gold Seal Center, 918 E. Divide Ave.
Bismarck, North Dakota 58501-1947

Dear Mr. Bachman:

Thank you for inviting us to provide comments on the Best Available Retrofit Technology (BART) analyses and draft permits provided by the North Dakota Department of Health (ND DOH) for Coal Creek Station Units #1 & #2, Leland Olds Station Units #1 & #2, Milton R. Young Station Units #1 & #2, and Stanton Station Unit #1. Our interest in this action stems from our obligation to protect visibility at Theodore Roosevelt National Park (NP) and Lostwood National Wildlife Refuge (NWR). We commend ND DOH for the progress your proposals represent toward reducing emissions from these facilities. We have enclosed our station-specific comments and provide general comments below that apply to all or several of these facilities.

By its nature, lignite is a very low-rank fuel that is relatively high in sulfur compared to its heating value. For this reason, it is also relatively inexpensive. We believe that the economic benefits derived by sources burning this fuel should be considered in determining what level of emission control can reasonably be expected from the standpoint of a level, industry-wide playing field.

For several units, ND DOH is proposing alternative sulfur dioxide (SO_2) limits that are similar to the presumptive BART limits because they allow a source to choose between a limit in terms of pounds of emissions per million Btu of heat input, or percent reduction of that pollutant. While EPA presented its BART Guidelines for SO_2 in that format, we do not believe that it was EPA's intention to allow the source to choose the more favorable limit. By definition, BART represents the highest degree of control that meets the five-factor test. Where ND DOH has determined that a lb/mmBtu limit is reasonable, it should require that that limit be met. Similarly, where ND DOH has determined that a percent reduction limit is reasonable, it should require that that limit be met. If both limits are determined to be reasonable, then to allow the source to choose only one clearly does not represent the most stringent reasonable degree of control. Therefore, where ND DOH has proposed alternative limits, both should be required.

There is also a fundamental problem with setting only a percent-reduction limit on SO_2 emissions. If fuel sulfur content increases, emissions can increase correspondingly. Unless sulfur content is limited, or a cap is placed on mass emissions (e.g., lb/hr, tons/yr), the actual amount of SO_2 emitted is unlimited.

We also have some general comments that apply to all of the Particulate Matter (PM) analyses. We believe that the BART analyses are deficient in that they neither address upgrades to the existing Electrostatic Precipitators (ESPs) or propose limits that realistically reflect the capabilities of those existing ESPs, as well as the proposed new baghouses, to control filterable PM. EPA's BART Guidelines (Guidelines) advise:

- "...it is important to include control options that involve improvements to existing controls and not to limit the control options only to those measures that involve a complete replacement of control equipment."
- "...for retrofitting existing sources in addressing BART, you should consider ways to improve the performance of existing control devises, particularly when a control device is not achieving the level of control that other similar sources are achieving in practice with the same device. For example, you should consider requiring those sources with electrostatic precipitators (ESPs) performing below currently achievable levels to improve their performance."

Although all of these sources have ESPs in place, none of them except Stanton Unit #1 is currently achieving a level of performance equivalent to the 0.015 lb/mmBtu proposed for ESPs at sources such as Peabody's Thoroughbred and LG&E's Trimble County projects in Kentucky. Furthermore, EPA has recently issued a permit limiting the Desert Rock facility to 0.010 lb/mmBtu filterable PM_{10}, new baghouses are being permitted at 0.009 – 0.012 lb/mmBtu in Virginia (Virginia Hybrid Energy Center) and Wyoming (Dry Fork, WYGEN 3), and ND DOH proposed to permit the Gascoyne project at 0.012 lb/mmBtu.

In addition to an absence of any evaluation of upgrading the existing PM control equipment, it appears that ND DOH is not following EPA guidance to consider more stringent emission rates in setting permit limits:

> "If you find that a BART source has controls already in place which are the most stringent controls available (note that this means all possible improvements to any control devices have been made), then it is not necessary to comprehensively complete each following step of the BART analysis in this section. As long as these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section."

We recommend that ND DOH establish permit limits that reflect the capabilities of the BART technology to control filterable PM.

Cost-Effectiveness Metrics

When generating cost-effectiveness numbers, it is very important to put those numbers into the proper perspective. Although ND DOH presented average cost-effectiveness of a given control strategy in terms of cost-per-ton-of-pollutant-removed ($/ton), we have a concern with the way in which the incremental cost analysis is used by ND DOH. According to EPA's BART Guidelines, "You should consider the incremental cost effectiveness **in combination with the average cost effectiveness** [*emphasis added*] when considering whether to eliminate a control option…You should exercise caution not to misuse these [average and incremental cost effectiveness] techniques… [but consider them in situations where an option shows]…slightly greater emission reductions…" Reviewing agencies are quite familiar with the concept of total average cost and expect to see costs in the \$2,000 – \$12,000 per ton range. However, incremental costs are rarely estimated and evaluated, so the much higher numbers that result appear quite high at first glance. For this reason, rigid use of incremental cost effectiveness will always result in the choice of the cheapest option if carried to the extreme. (For example, if only incremental costs were used to evaluate PM controls, it is likely that all controls more expensive than a multiple cyclone would be rejected.) To use incremental costs properly, they must be compared to incremental costs for similar situations. Despite the EPA guidance, ND DOH appears to base its determinations primarily on the incremental cost-effectiveness.

Furthermore, the simple \$/ton test does not address the issue of proximity to one or more Class I areas. We believe that the cost/deciview (\$/dv) metric can also be an appropriate tool to evaluate the costs and benefits of reducing emissions from a source that is relatively close to one or more Class I areas. For example, we calculated that the cost-effectiveness for SO_2 controls at Great River Energy's Stanton #1 would be \$12 - 15 million/dv of visibility improvement at Theodore Roosevelt NP. As can be seen, \$/dv is typically much higher (by orders of magnitude) than \$/ton.

Finally, BART is not necessarily the most cost-effective solution. Instead, it represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors.

Visibility Improvement Metrics

We believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative—not average—effects of improving visibility across all of the Class I areas affected. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas.

The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a Class I area and isolated impacts in a Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available. Therefore, until we can develop a second-level, more refined analysis, we continue to believe that our "simple summing" approach fills a void left by ND DOH in cases of power plants having significant impacts upon two Class I areas.

As an extension of our Stanton #1 example (above), we also calculated that the cumulative cost-effectiveness for SO_2 controls would be \$6 - 7 million/dv of visibility improvement at Theodore Roosevelt NP and Lostwood NWR. Such a cumulative approach can dramatically alter the way in which the cost-effectiveness of an alternative is evaluated.

Once again, we commend ND DOH for the significant progress its proposals represent. We look forward to working with ND DOH and EPA as this process advances. We believe that good communication and sharing of information will help expedite this process, and suggest that you contact Don Shepherd--NPS (don_shepherd@nps.gov, 303-969-2075), or Meredith Bond--FWS (meredith_bond@fws.gov, 303-914-3808) if you have any questions or comments.

Sincerely,

John Bunyak

John Bunyak
Chief, Policy, Planning and Permit Review Branch
National Park Service

Sincerely,

Sandra V. Silva

Sandra V. Silva
Chief, Branch of Air Quality
U.S. Fish and Wildlife Service

Enclosures

National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS) Source-Specific Comments on North Dakota Department of Health (ND DOH) Proposed BART Permits
August 11, 2008

Great River Energy (GRE) Coal Creek Units #1 & #2

Great River Energy (GRE) operates Coal Creek Units #1 & #2 near Underwood, North Dakota. Both units are tangentially-fired with lignite from an adjacent mine and are rated at 550 MW (gross) output. Current emission control equipment consists of wet limestone scrubbers, Low-NO_x Burners (LNB) and Separated Overfire Air (SOFA), and Electrostatic Precipitators (ESPs). Although each unit has a capacity greater than 200 MW at a facility with a total capacity greater than 750 MW, presumptive BART limits only apply for nitrogen oxide (NO_x) because there are existing sulfur dioxide (SO_2) controls on both units at the facility.

SO_2: GRE has proposed to upgrade the existing wet scrubbers to meet 0.15 lb/mmBtu.[1] ND DOH has proposed that Coal Creek meet either 0.15 lb/mmBtu or demonstrate 94% SO_2 control.
While we agree with the proposed scrubber upgrade, we believe that the chosen approach could be implemented more effectively. Although control-effectiveness information presented in Table 5-2 of GRE's August 2006 submittal estimates SO_2 control efficiency at 93.9% - 96% for the scrubber upgrade, it appears that ND DOH is assuming that it is not possible to upgrade the existing scrubbers to achieve better than 94% control. Furthermore, GRE has estimated in Table A-8 of that submittal that it can achieve 96% control at a cost of $330/ton. Please note that the GRE estimated cost to achieve 96% control is less than the $576/ton cost deemed "reasonable" by ND DOH to achieve 94% control.

It also appears that, not only is the ND DOH assuming that a 0.263 dv improvement is "negligible", it is using information—the relative differences in impacts among the control alternatives—that are not available to us. ND DOH should explain how it determined that upgrading the scrubbers to achieve 96% control is not economically reasonable, why a 0.263 dv improvement is "negligible", and where the modeling results cited in the ND DOH report are.

NO_x: Although GRE has proposed to meet the presumptive BART limits[2] with the existing controls LNB + SOFA, the Guidelines advise:

> "...the presumption does not limit the states' ability to consider whether a different level of control is appropriate in a particular case. If, upon examination of an individual EGU, a State determines that a different emission limit is appropriate based upon its analysis of the five factors, then the state may apply a more or less stringent limit."

Additional NO_x reductions could yield substantial benefits to the environment.

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[1] The presumptive BART limits are 0.15 lb/mmBtu or 95% SO_2 reduction on a 30-day rolling average basis.

[2] The presumptive BART limit for these tangentially-fired boilers burning North Dakota lignite is 0.17 lb/mmBtu on a 30-day rolling average basis.

GRE has assumed that Selective Non-Catalytic Reduction (SNCR) could reduce NO_x emissions by 50% (2,678 tpy) at an annual cost of $23 million or $8,551/ton. However, GRE has assumed that residual ammonia in the fly ash would render the ash, which it currently sells, unsalable. On that assumption, GRE included "sunk costs" for its ash handling infrastructure, and annual costs that represent lost ash sales revenue. While it is inappropriate to include sunk costs in future decision-making, elimination of those sunk costs would only reduce the annual cost by about $1 million. However, the loss of ash sale revenue was counted as a $16 million cost out of the total annual operating cost of $21 million, so this issue must be resolved.

Great River Energy (GRE) Stanton Unit #1

Great River Energy (GRE) operates Stanton Unit #1 in Stanton, ND. Unit #1 is wall-fired with lignite and PRB sub-bituminous coal, and is rated at 188 MW (gross) output. Current emission control equipment consists of LNB and an ESP. Presumptive BART limits do not apply.

SO_2: ND DOH is proposing to limit emissions to 0.24 lb/mmBtu on a 30-day rolling average basis when the unit is burning lignite, and to 0.16 lb/mmBtu when burning Powder River Basin (PRB) sub-bituminous coal. ND DOH has determined that the incremental cost of installing and operating a 95%-efficient wet scrubber is excessive when compared to the cost of a 90%-efficient spray dryer. ND DOH also cites additional environmental impacts on water consumption and wastewater generation, plus the potential for pollution of the adjacent Missouri River. ND DOH contends that the additional benefits of greater SO_2 removal are more than offset by the additional costs and other environmental impacts.

ND DOH's SO_2 BART analyses in general, and its analysis of installing a new wet scrubber in particular, is of concern because it failed to evaluate any of the control options under the conditions upon which it based its final BART determination. Specifically, ND DOH based all of its cost and benefit calculations on current fuels—lignite with uncontrolled SO_2 emissions of 1.81 lb/mmBtu and PRB coal with uncontrolled emissions of 0.64 – 1.2 lb/mmBtu.[3] ND DOH determined that it is cost-effective to control SO_2 at $1,330 per ton when burning lignite and $2,006 per ton when burning PRB coal. However, in setting its proposed BART limits, it assumed that future uncontrolled SO_2 emissions would rise to 2.4 lb/mmBtu for lignite and 1.6 lb/mmBtu for PRB coal. A summary of the ND DOH analysis is presented below:

Summary of Stanton Unit #1 Spray Dryer Costs and Benefits as estimated by ND DOH

Fuel	ND lignite	PRB	Units	Notes
Uncontrolled SO2	1.81	1.20	lb/mmBtu	1
Uncontrolled SO2	9,376	6,216	tpy	1
Control efficiency	90%	90%		1
Controlled emissions	0.18	0.12	lb/mmBtu	1
Controlled emissions	938	622	tpy	1
Emissions Reduction	8,438	5,594	tpy	1
Annualized Cost	$ 11,220,000	$ 11,220,000	per year	1

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[3] It appears that the actual BART determination was based upon the scenario with uncontrolled emissions at 1.2 lb/mmBtu.

Cost Effectiveness	$ 1,330	$ 2,006	per ton	1
Visibility Improvement (dv at Max Class I)	0.772		dv	2
Cost-Effectiveness ($/98th % dv at Max Class I)	$ 14,533,679		$/dv	3
Visibility Improvement (dv at Summed Class I)	1.511		dv	4
Cost-Effectiveness ($/98th % dv at Summed Class I)	$ 7,427,184		$/dv	5

(1) from ND DOH BART determination report
(2) Average 8th high visibility improvement at Theodore Roosevelt NP
(3) calculated
(4) Sum of average 8th high visibility improvements at Theodore Roosevelt NP and Lostwood NWR
(5) calculated

Because it is typically more cost-effective to control dirtier gas streams, we adjusted the cost analysis information provided by ND DOH and GRE to estimate the costs and benefits of scrubbing the higher sulfur fuels for which the BART limits were actually proposed.[4]

Summary of Stanton Unit #1 Wet Scrubber Costs and Benefits

Fuel	ND lignite	PRB	Units	Notes
Uncontrolled SO2	2.40	1.60	lb/mmBtu	1
Uncontrolled SO2	12,432	8,288	Tpy	2
Control efficiency	95%	95%		3
Controlled emissions	0.12	0.08	lb/mmBtu	4
Controlled emissions	622	414	Tpy	5
Emissions Reduction	11,811	7,874	Tpy	6
Annualized Cost	$ 13,911,294	$ 13,911,294	per year	7
Cost Effectiveness	$ 1,178	$ 1,767	per ton	8
Visibility Improvement (dv at Max Class I)	1.135	0.757	Dv	9
Cost-Effectiveness ($/98th % dv at Max Class I)	$ 12,256,349	$ 18,384,915	$/dv	10
Visibility Improvement (dv at Summed Class I)	2.114	1.410	Dv	11
Cost-Effectiveness ($/98th % dv at Summed Class I)	$ 6,579,077	$ 9,868,826	$/dv	12

(1) from ND DOH BART determination report
(2) Uncontrolled emissions from ND DOH BART determination report extrapolated for higher sulfur content
(3) from ND DOH BART determination report
(4) calculated
(5) calculated
(6) calculated
(7) Extra annual variable O&M cost from GRE report extrapolated for higher tons removed and added to Annualized Cost from ND DOH report
(8) calculated
(9) Average 8th high visibility improvement at Theodore Roosevelt NP plus additional visibility improvement extrapolated from GRE report for higher tons removed
(10) calculated
(11) Sum of average 8th high visibility improvements at Theodore Roosevelt NP and Lostwood NWR plus additional visibility improvement extrapolated from GRE report for higher tons removed
(12) calculated

It is cost-effective to achieve 95% control of SO_2 at $1,178/ton when burning lignite and $1,767/ton when burning PRB coal. On a $/ton basis, the 95% scrubbing option is more cost-effective than the less-efficient spray dryer alternative proposed by ND DOH.

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[4] Electronic files containing our calculations are attached.

The fifth required element of a proper BART analysis is an evaluation of the impact of the options considered on visibility. Based upon data provided by GRE in Table 7-4 of its report, we have compiled a table showing the current average eighth-highest impacts on visibility at Theodore Roosevelt NP and Lostwood NWR.[5]

Stanton #1 **Baseline** **Data from GRE Table 7-4**

	2000	2001	2002	2000 - 2002
	8th High	8th High	8th High	Average 8th
Class I Area	(delta dv)	(delta dv)	(delta dv)	(delta dv)
TRNP	0.947	1.205	1.675	**1.276**
Lostwood	0.991	1.351	1.150	**1.164**
Total	1.938	2.556	2.825	**2.440**

Based upon data provided by ND DOH, we have compiled a table showing the average eighth-highest impacts on visibility at Theodore Roosevelt NP and Lostwood NWR, and the corresponding visibility improvements, when SO_2 emissions are reduced by 90%

Stanton #1 **90% Dry Scrubber** Data from ND DOH BART proposal

	2000	2001	2002	2000 - 2002
	8th High	8th High	8th High	Average 8th
Class I Area	(delta dv)	(delta dv)	(delta dv)	(delta dv)
TRNP	0.458	0.385	0.668	0.504
Lostwood	0.340	0.526	0.410	0.425
Total	0.798	0.911	1.078	0.929

Change	2000	2001	2002	2000 - 2002
	8th High	8th High	8th High	Average 8th
Class I Area	(delta dv)	(delta dv)	(delta dv)	(delta dv)
TRNP	0.489	0.820	1.007	**0.772**
Lostwood	0.651	0.825	0.740	**0.739**
Total	1.140	1.645	1.747	**1.511**

and by 95%.

Stanton #1 **95% Wet Scrubber** Data from ND DOH BART proposal

	2000	2001	2002	2000 - 2002
	8th High	8th High	8th High	Average 8th
Class I Area	(delta dv)	(delta dv)	(delta dv)	(delta dv)
TRNP	0.369	0.334	0.556	0.420
Lostwood	0.340	0.526	0.410	0.425
Total	0.709	0.860	0.966	0.845

Change	2000	2001	2002	2000 - 2002
	8th High	8th High	8th High	Average 8th
Class I Area	(delta dv)	(delta dv)	(delta dv)	(delta dv)
TRNP	0.578	0.871	1.119	**0.856**
Lostwood	0.651	0.825	0.740	**0.739**
Total	1.229	1.696	1.859	**1.595**

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[5] Because neither GRE nor ND DOH evaluated visibility impacts when burning PRB coal, only the lignite-firing results are available.

At 90% SO_2 control of the baseline condition, as proposed by ND DOH, visibility would improve by more than 0.7 dv at each Class I area, and by over 1.5 dv cumulatively. The cost of these improvements is about $15 million/dv at Theodore Roosevelt NP, and about $7 million/dv cumulatively.

At 95% SO_2 control of the baseline condition, as we have proposed, and with adjustments for the higher sulfur contents used by ND DOH in its BART determination, visibility would improve by about 1.0 dv at each Class I area, and by over 2.0 dv cumulatively.

Stanton #1	**95% Wet Scrubber on future higher sulfur lignite**			
Change	2000	2001	2002	2000 - 2002
	8th High	8th High	8th High	Average 8th
Class I Area	(delta dv)	(delta dv)	(delta dv)	(delta dv)
TRNP	0.766	1.155	1.484	**1.135**
Lostwood	0.863	1.094	0.981	**0.979**
Total	1.630	2.249	2.465	**2.114**

The cost of these improvements is about $12 million/dv at Theodore Roosevelt NP, and less than $7 million/dv cumulatively.

On a cost/ton and cost/deciview basis, wet scrubbing at 95% control is more cost-effective than the spray dryer at 90% control. While ND DOH cites the added environmental impacts of wet scrubbing, any costs associated with additional water use and wastewater treatment have been reflected in GRE's cost analyses, and thus have already been accounted. The concern about polluting the Missouri River, while valid, can be alleviated by proper design, operation, and maintenance by GRE.[6] Unless the local water supply is inadequate to support a wet scrubber, or unless there is some other insurmountable environmental factor that cannot be incorporated objectively into the analysis, we conclude that wet scrubbing at 95% control (or greater) is BART for Stanton #1.

NO_x: ND DOH has proposed that Stanton #1 meet the presumptive BART limits[7] with a combination of the existing LNB plus addition of Overfire Air and Selective Non-Catalytic Reduction (SNCR). While we continue to believe that Selective Catalytic Reduction (SCR) may also be a viable alternative, we commend ND DOH for the proposed reduction in NO_x emissions.

Basin Electric (Basin) Leland Olds Station

Basin Electric (Basin) operates Leland Olds Station (LOS) Units #1 & #2 in Stanton, ND. Both units are fired with ND lignite and PRB sub-bituminous coal. Unit #1 is wall-fired and is rated at 216 MW (gross) output; current emission control equipment consists of LNB and an ESP. Unit #2 is a cyclone furnace and is rated at 440 MW (gross) output; current emission control equipment consists of an ESP. Presumptive BART limits do not apply.

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[6] This concern was not raised with respect to the proposed wet scrubbers at the Leland Olds Station, which is also located on the Missouri River.

[7] The presumptive BART limit for these wall-fired boilers is 0.29 lb/mmBtu when burning North Dakota lignite, and 0.23 lb/mmBtu when burning PRB sub-bituminous coal, on a 30-day rolling average basis.

Basin Electric (Basin) Leland Olds Unit #1

SO_2: ND DOH is proposing to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. We recommend 0.15 lb/mmBtu **and** 95% reduction on a 30-day rolling average basis because both of these levels are reasonable.

NO_x: ND DOH is proposing SNCR plus basic SOFA to limit NO_x emissions to 0.19 lb/mmBtu on a 30-day rolling average basis.[8] This is well below the 0.29 lb/mmBtu presumptive BART limit for this boiler. However, ND DOH has eliminated SCR from the five-factor analysis on the basis that it is technically infeasible when the unit is burning ND lignite. Based upon EPA's comments to ND DOH regarding the technical feasibility of applying SCR to lignite-fired boilers, ND DOH should proceed with the five-factor BART analysis.

Basin Electric (Basin) Leland Olds Unit #2

SO_2: ND DOH is proposing to limit SO_2 emissions to 0.15 lb/mmBtu or 95% removal on a 30-day rolling average basis. ND DOH has determined that, because the "most efficient control option" was selected for SO_2, no evaluation of costs or visibility impacts is necessary. We agree with EPA[9] that this approach does not meet the BART Guideline requirements for analysis and that a full five-factor analysis may find that even stricter controls would be cost-effective and/or provide greater visibility benefits.

NO_x: ND DOH is proposing application of SNCR and Advanced SOFA to limit NO_x emissions to 0.35 lb/mmBtu on a 30-day rolling average basis.

Presumptive BART for this large cyclone furnace is based upon application of SCR to achieve 0.10 lb/mmBtu on a 30-day rolling average basis. According to the BART Guidelines, "The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and ***lignite*** [emphasis added] should enable these units to cost-effectively meet NO_x rates of 0.10 lb/mmBtu."

ND DOH contends that SCR is not technically feasible for a boiler burning ND lignite. EPA has recently submitted expert testimony to ND DOH on the technical feasibility of SCR at Minnkota Power's Milton R. Young facility. We believe that EPA's analysis is valid and support EPA's conclusion that SCR is technically feasible. Because of the similarities among the cyclone furnaces at Milton R. Young and Leland Olds, we believe that the EPA conclusion is also applicable at LOS #2. ND DOH should evaluate SCR according to the remaining BART factors.

To provide a preliminary indication as to the possible economic feasibility of SCR, we applied the procedures described in Section 4, Chapter 2 of the OAQPS Control Cost Manual to the LOS #2 boiler. Using Basin's boiler and fuel information, we estimated an

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[8] In its August 4, 2008, comments to ND DOH, EPA noted a discrepancy in the proposed NO_x limit that should be corrected.

[9] August 4, 2008, EPA comments to ND DOH.

Annualized Cost of $9.3 million, and produced a cost-effectiveness estimate of $854 per ton.[10]

Basin Electric Power--Leland Olds #2

Unit	#2	
Boiler Type	cyclone	ND DOH report
Fuel	ND lignite & PRB	ND DOH report
Rating (MW Gross) each	440	ND DOH report
Rating (mmBtu/hr)	5,130	ND DOH report
Current Emissions (tpy)	10,422	ND DOH report
Current Emissions (lb/mmBtu)	0.61	ND DOH report
NPS Cost-benefit Analysis		
Overall Control Efficiency	84%	calculated
Controlled emissions (tpy)	2,976	calculated
Controlled emissions (lb/mmBtu)	0.10	NPS analysis
Emission Reductions (tpy)	10,935	NPS analysis
Capital Cost	$ 43,869,929	NPS analysis
Capital Cost ($/kW)	$ 100	calculated
O&M Cost	$ 3,502,149	NPS analysis
Annualized Cost	$ 9,336,522	NPS analysis
Cost-Effectiveness ($/ton)	$ 854	NPS analysis

While these estimates do not include measures that may be required to address issues peculiar to the boiler and its fuels, they give an indication that application of SCR may be economically feasible and that ND DOH should proceed with the five-factor analysis for SCR at LOS #2.

Milton R. Young

Minnkota Power Cooperative (Minnkota) operates the Milton R. Young Station (MRYS) near Center, ND. According to ND DOH, Unit #1 is a cyclone furnace boiler fired with ND lignite from an adjacent mine and has a capacity[11] of 257 MW. Current emission control equipment consists of an Electrostatic Precipitator (ESP); Unit #2 is similar, but with a 477 MW capacity and a wet scrubber and ESP.

On April 24, 2006, EPA, DOJ, ND DOH, and Minnkota reached a settlement (Consent Decree = CD) of a New Source Review enforcement action. As a result, limits were set for Units #1 & #2 at MRYS for filterable PM and SO_2. A Best Available Control Technology (BACT) analysis for NO_x was required to be submitted by Minnkota within the following six months. That analysis was submitted along with the BART analysis and the BACT analysis became the basis for Minnkota's BART analysis. On August 4, 2008, EPA rejected that BACT analysis on the basis that Minnkota had not demonstrated that SCR was technically infeasible.

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[10] Electronic files containing our calculations are attached.

[11] We understand that the actual capacity of both units at MRYS may still be unresolved and may bear upon the applicability of the presumptive BART limits.

We understand that EPA addressed a similar situation with respect to potential conflicts between BART and a CD at the Craig power plant in northwestern Colorado when it advised Colorado Air Pollution Control Division (APCD) that "We do not agree that the 2001 settlement and our approval of the settlement relieve APCD from meeting the requirements of our BART guidelines."[12] We understand that BART requirements must be satisfied independently of any existing CD.

Milton R. Young Unit #1

SO_2: Although Minnkota proposed addition of a wet scrubber at MRYS #1 to meet both 95% control and 0.15 lb/mmBtu on a 30-day rolling average basis, ND DOH has proposed only a 30-day average limit of 95% reduction. We believe that both limits are appropriate. ND DOH has determined that, because the "most efficient control option" was selected for SO_2, no evaluation of costs or visibility impacts is necessary. While this is a commendable level of additional control, we believe that this approach does not meet the BART Guidelines for proper analysis, and that a full five-factor analysis may find that even stricter controls would be cost-effective and/or provide greater visibility benefits.

PM: Because Minnkota is proposing a new wet scrubber for SO_2, ND DOH has also proposed to allow MRYS #1 to meet the 0.030 lb/mmBtu filterable PM limit set by the CD. We believe that a modern ESP should be capable of lower emissions, and that upgrading of the existing ESP deserves more attention.

NO_x: ND DOH proposes to reduce NO_x by applying SNCR+Advanced SOFA at 0.36 lb/mmBtu.

Presumptive BART for this large cyclone furnace is based upon application of SCR to achieve 0.10 lb/mmBtu on a 30-day rolling average basis. According to the BART Guidelines, "The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and ***lignite*** [emphasis added] should enable these units to cost-effectively meet NO_x rates of 0.10 lb/mmBtu."

ND DOH contends that SCR is not technically feasible for a boiler burning ND lignite. EPA has recently submitted expert testimony to ND DOH on the technical feasibility of SCR at MRYS. We believe that EPA's analysis is valid and support EPA's conclusion that SCR is technically feasible. ND DOH should evaluate SCR according to the remaining BART factors.

To provide a preliminary indication as to the possible economic feasibility of SCR, we applied the procedures described in Section 4, Chapter 2 of the OAQPS Control Cost Manual to the MRYS #1 boiler. Using Minnkota's boiler and fuel information, we estimated an Annualized Cost of $6.7 million, and produced a cost-effectiveness estimate of $839 per ton.[13]

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[12] July 19, 2007, letter from Callie Videtich, EPA Region 8, to Paul Tourangeau, CO APCD.

[13] Electronic files containing our calculations are attached.

Minnkota Power--MR Young #1 & #2 **rejected SCR**

Unit	#1	#2	
Boiler Type	cyclone	cyclone	ND DOH report
Fuel	ND lignite	ND lignite	ND DOH report
Rating (MW Gross) each	257	477	ND DOH report
Rating (mmBtu/hr)	3,200	6,300	ND DOH report
Current Emissions (tpy)	8,665	14,705	ND DOH report
Current Emissions (lb/mmBtu)	0.81	0.81	ND DOH report
NPS Cost-benefit Analysis			
Control Efficiency	87.7%	87.7%	calculated
Controlled emissions (tpy)	1,631	3,294	calculated
Controlled emissions (lb/mmBtu)	0.10	0.100	NPS analysis
Emission Reductions (tpy)	7,971	11,757	NPS analysis
Capital Cost	$ 23,925,181	$42,273,746	NPS analysis
Capital Cost ($/kW)	$ 93	$ 89	calculated
O&M Cost	$ 3,500,668	$ 5,456,674	NPS analysis
Annualized Cost	$ 6,688,370	$11,087,866	NPS analysis
Cost-Effectiveness ($/ton)	$ 839	$ 943	NPS analysis

While these estimates do not include measure that may be required to address issues peculiar to the boiler and its fuels, they give an indication that application of SCR may be economically feasible and that ND DOH should proceed with the five-factor analysis for SCR at MRYS#1.

Milton R. Young Unit #2

SO_2: ND DOH has proposed upgrading the existing wet scrubber to meet a 30-day average limit of 90% reduction and 0.15 lb/mmBtu, or achieve 95% reduction on a 30-day rolling average basis. We recommend that, because ND DOH has determined that both limits are reasonably achievable, MRYS #2 meet 95% reduction and 0.15 lb/mmBtu.

PM: The CD requires the existing ESP to meet a limit on filterable PM of 0.030 lb/mmBtu. We understand that, in spite of the CD, PM control is still an open issue with respect to both BACT and BART. We recommend that an evaluation of upgrading the existing ESP to meet 0.015 lb/mmBtu is therefore appropriate.

NO_x: ND DOH proposes to reduce NO_x by applying SNCR+Advanced SOFA at 0.35 lb/mmBtu. Our comments stated above for MRYS Unit #1 also apply to the NO_x BART determination for MRYS Unit #2. Once again, to provide a preliminary indication as to the possible economic feasibility of SCR, we applied the procedures described in the OAQPS Control Cost Manual to the MRYS #2 boiler. Using Minnkota's boiler and fuel information, we estimated an Annualized Cost of $11.1 million, and produced a cost-effectiveness estimate of $943 per ton. Because SCR may be economically feasible, ND DOH should proceed with the five-factor analysis for SCR at MRYS#2.

Response to 8/11/08 NPS BART Comments on Coal Creek (7/16/09)

Coal Creek SO_2. The August 11, 2008 NPS comments are summarized below followed by the Department responses.

1. NPS Comment: ND DOH should explain how it determined that upgrading the scrubbers to achieve 96% control is not economically reasonable.

   NDDH Response: The August 2006 BART Analysis to which the comment refers was the first of several versions of that document issued by GRE over a 16-month period. Subsequent versions revised previous information to reflect the best available assessment to that date. The final version was issued by GRE in December of 2007 and is the document associated with the Department's analysis. Although preliminary information from GRE indicated the possibility of modifying the existing scrubber for 96% control, they subsequently revised that to 94%.

   The Department's experience indicates that 96% control should only be expected for a unit combusting coal with a higher sulfur content typically found in Eastern coal. The Coal Creek scrubbers are nearly 30 years old and retrofitting them is not expected to achieve greater than 95% control. The Department BART determination and the Permit to Construct have been revised to require the modified wet scrubber to achieve the same level of SO_2 control efficiency as wet scrubber replacement: 95% (30-day rolling average) on the inlet SO_2 concentration to the scrubber or 0.15 lb/10^6 Btu (30-day rolling average).

2. NPS Comment: ND DOH should explain why a 0.263 dV improvement is "negligible."

   NDDH Response: The Department BART determination and the Permit to Construct have been revised to require the modified wet scrubber to achieve the same level of SO_2 control efficiency as wet scrubber replacement: 95% (30-day rolling average) on the inlet SO_2 concentration to the scrubber or 0.15 lb/10^6 Btu (30-day rolling average). With this change, wet scrubber replacement would provide no improvement in visibility at any Class I area and would result in additional cost over wet scrubber modification ($24,987/ton incremental cost).

3. NPS Comment: ND DOH should explain where the modeling results cited in the ND DOH report are.

   NDDH Response: A previous NPS email dated 8/4/08 at 6:02 p.m. indicates this comment likely refers to modeling that would allow a comparison of the effects on visibility due to SO_2 reductions provided by wet scrubber replacement (95%), wet scrubber modification (then 94%, now 95%), and the addition of a spray dryer (90%). Pages 51-53 of the GRE analysis contain the modeling results of the impact on visibility associated with wet scrubber modification (at 94%) and wet scrubber replacement in conjunction with the most favorable NOx control options. Although the spray dryer option is not represented, that option would provide only 90% control while the scrubber modification and replacement options that are presented would provide 95% control. The Department does not require additional modeling details to determine that the spray dryer option at 90% control is not BART.

4. NPS Comment: GRE has assumed that residual ammonia in the fly ash would render the ash, which it currently sells, unsalable. This issue must be resolved.

   NDDH Response: In conjunction with previous comments in an NPS email dated 8/4/08 at 4:53 p.m., this comment appears to refer to a request for additional information to support the GRE position that employing SNCR technology may negatively affect fly ash sales due to ammonia slip. The attached GRE emails dated 8/8/08 at 3:19 p.m. and 8/17/08 at 2:22 p.m. provide additional information on this issue. The Department also considered a summary of a University of Kentucky study on the issue (attached) and has reached the following conclusions.

   - SCR and SNCR use at Coal Creek Station will likely result in ammonia in the fly ash.
   - The level of ammonia in the fly ash cannot be predicted with a reasonable certainty.
   - The maximum level of ammonia in fly ash that would still avoid negative impacts on the salability of the ash cannot be predicted.

   Therefore, the Department cannot determine with reasonable certainty that SCR or SNCR will not result in a level of ammonia in the ash that could reduce or eliminate future ash sales. Any regulator who determines that SCR or SNCR will not jeopardize ash sales would be obligated to present the evidence in support of that position. While another regulator might determine that even a small improvement in visibility is worth GRE taking the risk of lost ash sales, making a wrong decision on this one will inflict a significant financial penalty on GRE and send ash to a landfill instead of it being used beneficially. Having considered all of the information available, the NDDH BART determination on this matter remains unchanged and the Department considers the issue resolved.

FLM Comments on
Draft BART Assessments
Milton R. Young Station
and Leland Olds Station

Comment No.: 8
Commentor: FLMs
Affected Source: Leland Olds 2
Comment Summary: A 5 factor analysis is required even though the most efficient control technology is used.
Response: The BART Guideline Step 1, Paragraph 9, states "... if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section." Basin had proposed the highest available control efficiency and lowest possible emission rate. Therefore, the other steps of a BART analysis were not required. The Department has now determined that SCR w/reheat is technically feasible. A visibility analysis of SCR vs SNCR has been included.

Comment No.: 22
Commentor: FLMs
Affected Source: Leland Olds Unit 1 & 2
Comment Summary: Recommend that the limit be written as 0.15 lb/10^6 Btu <u>and</u> 95% reduction.
Response: The BART Guideline lists the presumptive levels as 0.15 lb/10^6 Btu <u>or</u> 95% reduction. We believe applying both limits would be inappropriate. Basin Electric has justified a limit of 0.19 lb/10^6 Btu. The Department was able to reduce this limit to 0.15 lb/10^6 Btu by allowing Basin to comply with the 95% reduction requirement when higher sulfur coal is encountered.

Comment No.: 23
Commentor: FLMs
Affected Source: Leland Olds 1 & 2
Comment Summary: The FLMs believe SCR is technically feasible based on EPA's opinion.
Response: The Department believes high dust SCR is not technically feasible due to catalyst poisoning by sodium and potassium. A detailed examination of this issue is found in Appendix B.5. The Department now believes low dust and tail end SCR are technically feasible for North Dakota lignite-fired power plants.

Comment No.: 25
Commentor: FLMs
Affected Source: General
Comment Summary: The FLMs think the benefits of burning "low cost" lignite should be considered in determining BART.
Response: The BART Guideline establishes the costs that are to be considered when determining BART. In general, the cost of fuel is not one of them and fuel switching is not required.

Comment No.: 26
Commentor: FLMs
Affected Source: General
Comment Summary: There is a fundamental problem with setting only a percent-reduction limit for SO_2. As the sulfur content rises, SO_2 emissions will rise.
Response: EPA recognized that as the sulfur content rose the presumptive limit of 0.15 lb/10^6 Btu could not be met at some sources. Therefore, EPA allowed a presumptive level of 95% control. If BART had to be set based on a lb/MMBtu basis only, then this lb/MMBtu limit must be based on the higher sulfur coal. There would be no difference when higher sulfur coal is burned but higher emissions could occur if only a lb/MMBtu is set and lower sulfur coal is burned.

Comment No.: 27
Commentor: FLMs
Affected Source: General
Comment Summary: Upgrading of the ESPs for particulate control should be evaluated.
Response: Each source has evaluated replacing the ESP with a new ESP or new baghouse. In every case, the replacement of the ESP provides an insignificant amount of visibility improvement. Upgrading the ESPs would provide less visibility improvement. Therefore, there is no reason to evaluate the upgrade.

Comment No.: 28
Commentor: FLMs
Affected Source: General
Comment Summary: The allowable PM emission rates should be reduced.
Response: Each source has justified 0.10 lb/10^6 Btu as BART using the 5 factors analysis. The Department has reduced the emission limit to 0.07 lb/10^6 Btu because it is the lowest limit that can be met on a continuous basis and represents better than BART after consideration of the 5 factors.

Comment No.: 29
Commentor: FLMs
Affected Source: General
Comment Summary: It appears the Department is making its BART determinations based primarily on the incremental cost.
Response: The BART determinations where made based on the 5 factors in the BART Guideline. The Guideline gives the Department discretion on the weight assigned to each factor. The Department has always used the incremental cost when determining BACT. For BART, incremental costs were considered also. The BART Guideline states “Also, the greater number of possible control options that exist, the more weight should be given to the incremental costs vs. average cost.” As suggested by the BART Guideline, the incremental cost was weighted most heavily in the economic evaluation; however, all 5 statutory factors were considered.

Comment No.: 30
Commentor: FLMs
Affected Source: General
Comment Summary: Cumulative effects on multiple Class I areas should be considered instead of the "average" effects.
Response: The BART guideline does not establish or require a cumulative type analysis. This would be a difficult analysis (results must be paired in time) and does not represent actual visibility improvement since the analysis only addresses the individual source and not all sources that affect visibility in the Class I area. The Department did review maximum impacts from BART alternatives as well as average results. Since the BART Guideline does not require a cumulative analysis, we believe it is unnecessary and of little value. We have also determined that the BART single source modeling grossly overpredicts the amount of visibility improvement. Any combining of Class I areas using a cumulative effect would make the results even worse.

Comment No.: 31
Commentor: FLMs
Affected Source: M.R. Young 1
Comment Summary: Both a 0.15 lb/10^6 Btu and 95% reduction BART limit is appropriate.
Response: Based on future coal sulfur contents, Minnkota may not be able to comply with the 0.15 lb/10^6 Btu emission limit. Therefore, the 95% reduction only is appropriate and consistent with the BART Guideline.

Comment No.: 32
Commentor: FLMs
Affected Source: M.R. Young 1
Comment Summary: The SO_2 analysis does not address the 5 factors.
Response: Since Minnkota has selected the most efficient technology operating at the highest continuous efficiency, a 5 factor analysis is not required per the BART Guideline. Visibility modeling results which show the improvement have been provided.

Comment No.: 33
Commentor: FLMs
Affected Source: M.R. Young 1
Comment Summary: A lower emission limit for PM should be established.
Response: The BART analysis submitted by Minnkota justified 0.10 lb/10^6 Btu as BART based on the 5 statutory factors. Since the Consent Decree requires a limit of 0.03 lb/10^6 Btu, this rate was established as BART.

Comment No.: 34
Commentor: FLMs
Affected Source: M.R. Young 1
Comment Summary: Believe SCR is technically feasible.
Response: See response to Comment No. 23.

Comment No.: 35
Commentor: FLMs
Affected Source: M.R. Young 2
Comment Summary: Recommend SO_2 limit be 95% reductions and 0.15 lb/10^6 Btu.
Response: The Department determined that the 0.15 lb/10^6 Btu limit could not be met when higher sulfur coal is burned. Therefore, requiring both limits would be inappropriate.

Comment No.: 36
Commentor: FLMs
Affected Source: M.R. Young 2
Comment Summary: Recommend upgrading ESP to meet a 0.015 lb/10^6 Btu PM limit.
Response: Minnkota has justified a BART limit of 0.10 lb/10^6 Btu based on the 5 statutory factors. The limit of 0.03 lb/10^6 Btu is based on the Consent Decree.

Comment No.: 37
Commentor: FLMs
Affected Source: M.R. Young 2
Comment Summary: Believe SCR is technically feasible.
Response: See response to Comment No. 23.

Response to August 11, 2008 FLM BART Comments for Stanton Unit 1

The FLMs comments relating to the BART determination for Stanton Unit 1 are summarized below:

Comment #1:

The FLMs are concerned that the economic analysis was based on low uncontrolled SO_2 emissions while the BART emission limit was based on unreasonably high SO_2 emissions.

Response to Comment #1:

The Department's economic analyses were based on uncontrolled annual SO_2 emissions of 1.81 lb/million Btu for lignite and 1.2 lb/million Btu for PRB coal. The proposed BART emission limits for SO_2 are based on a 30-day rolling average (as opposed to an annual average) with 90% reduction and also includes emissions from startups, shutdowns and malfunctions. Based upon historical SO_2 emissions data for spray dryers and fabric filters at facilities burning North Dakota lignite, we have determined that an increase of 33% is warranted to adjust from an annual average SO_2 emission rate to a 30-day rolling average emission rate. The discussion regarding potential SO_2 emission rates as high as 2.4 lb/million Btu for lignite and 1.6 lb/million Btu for PRB coal was intended to show that higher sulfur coal could be encountered (see Appendix E, Sulfur Content Statistical Analysis, of the GRE BART Analysis).

Comment #2:

The FLMs contend that "On a $/ton basis, the 95% scrubbing option is more cost-effective than the less-efficient spray dryer alternative proposed by ND DOH" and "On a cost/ton and cost/deciview basis, wet scrubbing at 95% control is more cost-effective than the spray dryer at 90% control." Based upon the contention that wet scrubbing at 95% control is more cost-effective than a spray dryer at 90% control, the FLMs conclude that BART for Stanton #1 is a wet scrubber.

Response to Comment #2:

The FLMs chose to conduct the economic analysis for the wet scrubber based upon uncontrolled SO_2 emissions of 2.40 lb/million Btu for lignite and 1.60 lb/million Btu for PRB. The FLMs then compare the cost effectiveness for a wet scrubber (calculated at the 2.40 lb/million Btu and 1.60 lb/million Btu uncontrolled emission rates) to the cost effectiveness for a spray dryer calculated using uncontrolled SO_2 emission rates of 1.81 lb/million Btu for lignite and 1.20 lb/million Btu for PRB.

When comparing the cost effectiveness of different control technologies, it is necessary to use the same baseline uncontrolled emission rate for all control technologies. Since the FLMs failed to use the same baseline uncontrolled emission rates when calculating the cost effectiveness values for the wet scrubbing and spray dryer technologies, a comparison of the resulting cost effectiveness values is meaningless.

It should be noted that, since the annualized cost of a wet scrubber is estimated to be at least 15% greater than a spray dryer and only achieves a 5% greater emissions reduction, the FLMs contention that a wet scrubber is more cost effective than a spray dryer is not mathematically possible if the economic analysis is done correctly.

The Department correctly used the same baseline emission rate when calculating the cost effectiveness values for the SO_2 control technologies. When determining BART for SO_2, the Department also considered additional environmental considerations such as the additional water usage of a wet scrubber and the fact that a wet scrubber will remove a relatively small amount of SO_2 when compared to a dry scrubber (with a small corresponding visibility improvement).

Based upon the Department's analysis, the Department maintains the position that a spray dryer at 90% SO_2 control is more cost-effective than a wet scrubber at 95% SO_2 control. Considering the above factors, the Department has determined that BART is represented by the use of a spray dryer and fabric filter.

United States Department of Agriculture **Forest Service** **Superior National Forest**

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File Code: 2580-2
Date: October 14, 2009

Mr. Terry L. O'Clair, P.E.
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

Dear Mr. O'Clair:

On August 26, 2009, the State of North Dakota submitted a draft implementation plan describing your proposal to improve air quality regional haze impacts at mandatory Class I areas across your region. We appreciate the opportunity to work closely with the State through the initial evaluation, development, and, now, subsequent review of this plan. Cooperative efforts such as these ensure that together we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I wilderness areas and parks.

This letter acknowledges that the U.S. Department of Agriculture Forest Service has received and conducted a substantive review of your proposed Regional Haze Rule implementation plan. Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination about the document's completeness, and therefore, only the EPA has the ability to approve the document. Participation by the Forest Service in the State of North Dakota's administrative process does not waive any legal defenses or sovereignty rights it may have under the laws of the United States, including the Clean Air Act and its implementing regulations.

As outlined in a letter to North Dakota dated September 19, 2006, our review focused on eight basic content areas. The content areas reflect priorities for the Federal Land Manager agencies, and we have attached comments to this letter associated with these priorities. We look forward to your response required by 40 CFR 51.308(i)(3). For further information, please contact Eastern Region Air Resource Specialist Trent Wickman at (218) 626-4372 or Northern Region Air Resource Specialist Thomas Dzomba at (406) 329-3672.

Again, we appreciate the opportunity to work closely with the State of North Dakota. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

/s/ Mark Hummel
MARK HUMMEL
Deputy Forest Supervisor

cc: Charles E Sams
Thomas C Dzomba

Amy Platt
Don Shepherd
Bruce Polkowsky
Tim Allen

USDA Forest Service Technical Comments on the Regional Haze State Implementation Plan (RH SIP) for North Dakota

We appreciate the significant resources devoted by the State of North Dakota (ND) in developing a comprehensive, well organized, and easy to follow RH SIP. The projected emissions reductions in the SIP are an important first step toward improving visibility and other air quality related values at the affected Federal Class I areas (CIAs). We do have some concerns with some of the technical analyses and the some of the conclusions made in the RH SIP. These concerns are outlined below.

General Comments

1. We agree with previous comments by the National Park Service (NPS) that Theodore Roosevelt National Park should be treated as one Class I area, not three.

2. In a number of places in the RH SIP, ND characterizes its impact on its own class CIAs as "small." We note that this is a subjective term. Based on our review of RH SIPs from other states, we do not consider ND's percent contribution to visibility impairment in its own CIAs as being significantly different (i.e. smaller) than the other CIA owner states. For example ND's contribution to its CIAs is very similar to Minnesota's contribution to its CIAs. If ND feels this is not true, ND should include data to support this position. Nevertheless each State must demonstrate that it is obtaining "*its share of the emission reductions needed to meet the progress goal for the area*," per 40 CFR 51.308 (d) 3.

3. The RH SIP should explain how the reasonable progress goals (RPGs) will be revised once the RH SIPs from the neighboring contributing states are available.

4. We note that the State of Minnesota specifically asked ND to analyze the feasibility of reducing electrical generating unit (EGU) emissions in the state to less than 0.25 pounds per million Btu (lb/MMBtu) for sulfur dioxide (SO_2) and less than 0.22 lb/MMBtu for nitrogen oxides (NOx). We found a response from ND that outlined their disagreement with the premise of Minnesota's "ask." Additional information would be helpful comparing the emission level of ND's EGUs after the installation of controls prescribed under the Best Available Retrofit Technology (BART) and Reasonable Progress (RP) analyses.

5. We ask US EPA Regions 5 and 8 to arbitrate the disagreement between ND and Minnesota regarding Minnesota's "ask," as well as working with Canada on reducing emissions from sources in that country, especially the power plants mentioned by ND on page 53 of the RH SIP. This is especially relevant since power is sent across the US-Canada border.

General BART

6. We feel the decision to make Heskett Unit 2 not subject to BART is based on inappropriate modeling. Technical reasons were discussed on the call between ND and

the Federal Land Managers (FLMs) on September 22, 2009, including the use of using fine grid (1 km) modeling. Department of Interior modeling staff will provide more details. Please complete a full BART analysis for this unit. Alternatively, if Heskett is not found to be subject to BART it should be included in the State's reasonable progress analysis and a complete suite of possible control options examined in detail.

7. We would also like to note that the statement that Heskett is proposing a 70% SO_2 emission reduction is misleading. Baseline SO_2 emissions were reported as 2400 tons and the reduction project was reported to reduce emissions by 740 tons. This results in a 31% reduction.

8. EPA BART guidelines (Federal Register, July 6, 2005) on page 39170 directs the State to compare the 98 percentile days, pre-control versus post-control, so we disregarded the 90 percentile days presented in the RH SIP on Page 67.

9. On page 68 ND states "Though single-source modeling is specified in the BART guidance for determining degree of visibility improvement, it is clear that this modeling overstates the real single-source visibility impact." Please add a reference or basis for this statement. ND also adds "an observer's perception of visibility change is affected by the total loading of visibility-affecting species in the atmosphere." We agree. On clean days visibility can be impaired by a small amount of air pollution. That is why it is important to use clean days as a baseline from which to measure impairment from a source. Otherwise clean days are not protected.

10. In the BART section of the SIP ND appears to disregard the importance of EPA's presumptive BART limits. EPA considers these limits to be "generally cost effective" and in the case of scrubbers states, "We expect that scrubber technology will continue to improve and control costs continue to decline" (FR, 7/6/07, pg 39171).

SO_2 BART

11. MR Young Unit 2
    a. We feel the form of the emission limit needs to be reviewed. For example, the emission limit is specified as 95% control efficiency (CE). Therefore the pounds per million Btu (lb/MMBtu) limit should be 0.1 or else the effective limit becomes 0.15 lb/MMBtu which is 90% control. MR Young unit 1 is specified as having just a CE limit and no alternative lb/MMBtu. If Unit 1 can comply with just a CE limit we see no reason why Unit 2 can't also do the same.
    b. At the end of the BART analysis, ND changes the baseline emission level from 2.0 lb/MMBtu to 3.5 lb/MMBtu, which effectively raises the final BART limit. We feel the same baseline emission level should be used throughout the whole BART analysis, which includes calculating the costs per ton, as well as setting the limits.
12. Stanton
    a. It is unclear why this unit can't install a wet scrubber and meet the same limit as the Leland Olds Unit 1 (95% CE) which is a boiler of similar size, age, firing

type, and is also along the Missouri river. Please include a discussion of how the relevant BART factors are different for the two units. The costs for a wet scrubber at Stanton appear to be reasonable ($1480/ton).

b. Again, for this source, ND adjusted the baseline emission rate up for both fuels (i.e. from 1.8 to 2.4 lb/MMBtu for lignite and from 1.2 to 1.6 lb/MMBtu for sub-bituminous). As stated above we feel the baseline emission rate should be the same throughout the analysis. If the baseline emission rate were the same throughout the analysis, it would reduce the cost per ton presented, which already appears to be reasonable.

NOx BART

Over the past few years there has been much discussion regarding the application of SCR to lignite fired boilers. Due to the amount of time the EPA and the NPS have spent on this issue we believe they will respond most effectively and we will not offer specific comments on it other than to support the position of the NPS.

13. We would like to comment on an ancillary issue. ND states in the individual BART determinations, “The Department believes pilot scale testing would prove to be very beneficial in addressing the items of concern and provide a more detailed professionally reliable cost estimate. However, the BART process cannot mandate pilot testing be conducted to determine costs.” We agree and suggest that should a decision be made not to apply SCR with this SIP, additional pilot testing would be useful and encourage ND to include enforceable schedules in the long term strategy portion of its RH SIP. Minnesota took just such an approach in its RH SIP for the taconite industry which, like lignite fired power plants in North Dakota, had little data on NOx controls and is almost entirely in one state.

14. We note that Leland Olds Unit 2, and MR Young Units 1 and 2 do not meet presumptive BART, which as noted above is described by EPA as “generally cost effective.”

15. The startup/shutdown BART exemptions proposed for MR Young Units 1 and 2 are not necessary since the limit will be in the format of a 30 day rolling average. We have not seen such exemptions in BART determinations in other states. Four other BART units in ND are also using SNCR and are not asking for similar treatment. If these exemptions are allowed they should be severely limited by enforceable permit conditions, otherwise the integrity of the BART limit will be compromised.

Modeling – Chapter 8

We support comments from the Department of Interior agencies pertaining to this chapter.

Reasonable Progress

16. We applaud ND for the process it took to identify sources for which additional controls could be potentially applied under reasonable progress. Based on the Q/d metric, clearly Coyote and Antelope Valley Station (AVS) have visibility impacts that are on par with,

or exceed many of the subject to BART sources. These subject to BART sources were all prescribed to install additional SO_2 and NOx controls by ND in the draft SIP.

   a. SO_2 - Improvements to the existing spray dryer system should be included as an option, and costs determined, in the control technology analyses done for the AVS units. EPA states the following for existing flue gas desulfurization systems in their BART guidelines, "There are numerous scrubber enhancements available to upgrade the average removal efficiencies of all types of existing scrubber systems…" This is the approach taken by ND for the Coal Creek units and MR Young Unit 2.
   b. NOx - When comparing the emission rates from AVS and Coyote to the rest of the State's EGUs, AVS and Coyote would be the newest and the dirtiest. We note that ND states that moderate control options such as LNB/SNCR at 65% CE for AVS and ASOFA/SNCR at 55% CE at Coyote are reasonable (page 180 of the RH SIP).

   ND claims that the improvement in visibility from installing controls at AVS and Coyote is too small to require their installation. It is unclear which modeling method/protocol was used to produce the visibility results in Table 9.9, which makes their use problematic. Nevertheless AVS and Coyote are of the same general size, and located in the same general area, as the BART sources. Therefore we feel reductions at AVS and Coyote are equally important to those at the BART sources. ND required controls at the BART sources. The amount of reductions from AVS and Coyote are significant – in the range of 30,000 tons of combined NOx and SO_2, not including any additional SO_2 that could be reduced from upgrading the spray dryers at AVS. Please consider controls on AVS and Coyote such as LNB/SNCR at 65% CE for AVS and ASOFA/SNCR at 55% CE at Coyote.

17. Under the section on "Energy and non-air quality environmental impacts," we encourage ND to include the environmental and health *benefits* of installing additional controls. In general, the benefits of installing controls on EGUs far outweigh the costs.
    a. For example the report EC/R did for Midwest RPO (http://www.ladco.org/reports/rpo/consultation/index.php) shows that the health benefits of reducing SO_2 and NOx emissions under a region-wide SO2 and NOx control strategy are generally expected to outweigh the costs of control. These health benefits stem from the reduced ambient levels of PM and ozone which would result from the control of SO_2 and NOx. "When benefits in the entire modeling domain were considered, the estimated values of these benefits outweighed the projected costs of control by more than a factor of 10" (page 106). This does not include other environmental benefits of controls which are harder to quantify but nonetheless important (e.g. reduction in mercury deposition).
    b. In the original Clean Air Interstate Rule (CAIR), the range of annual *net* benefits (benefits less costs) to society were calculated to be approximately \$71.4 to \$60.4 billion in 2010 and \$98.5 to \$83.2 billion in 2015 (FR 5/12/05, pg 25305)

Other Comments

18. We do not support the method used to adjust the glidepath to account for Canadian emissions used in the RH SIP. We do support DOIs suggestion of using species-specific information provided by the Western Regional Air Partnership (WRAP).

19. We found no specific discussion in the draft SIP that considered contingency measures or procedures which could be triggered if the unexpected or unforeseen occurs. For example, if projected future emissions reductions do not materialize, or are distributed differently over an alternate geographic area, emission inventories could be found to be incorrect or flawed. Are there adaptive management strategies or increased review strategies which could be implemented in those situations? What will be done in five-years if North Dakota is over their projected emissions inventory? The SIP should provide a contingency plan to address these concerns.

20. We request that ND note that there is a linkage between the PSD program, its visibility impacts, and the need to protect the 20 percent best visibility days. An adequate relationship between the SIP and ND's PSD program also helps ensure that new sources not jeopardize the reasonable progress goals established by the RH SIP.

Department of the Interior Comments on the August 2009 draft of the North Dakota Regional Haze SIP (Plan) for Implementing Section 308 (40CFR51.308) of the Regional Haze Rules

Overall Comments

The air quality staffs of the National Park Service and U.S. Fish and Wildlife Service applaud the North Dakota Division of Air Quality (NDDAQ) on drafting a well-written and comprehensive Regional Haze Plan (Plan). It covers all of the policy areas of concern to us as outlined in our August 2006 letter to the States regarding development of regional haze plans.

In particular, we appreciate the comprehensive documentation of the visibility conditions and information base for each of the Class I areas. This information provides a firm foundation for tracking visibility conditions going forward as envisioned by the regional haze rule. We agree that the three major pollutants of concern for improving visibility in North Dakota are sulfates, nitrates, and organic particulates. We commend NDDAQ for the Plan's requirements to reduce approximately 90,000 tons per year of sulfur dioxide emissions. These reductions are a substantial step in making reasonable progress toward no human-caused impairment at Class I areas. We agree with concerns raised in the Plan that emissions controls in North Dakota alone are not sufficient to achieve visibility improvement goals set out in the 1999 Regional Haze Regulations. We look forward to working with NDDAQ, other States, and our Federal partners in a cooperative effort to achieve progress in reducing all human-caused impairment in a cost-effective manner.

The Department of the Interior noted in the enclosure to its letter to NDDAQ, dated February 29, 2008, regarding assessing air quality impacts from the Gascoyne Generating Station, the three units of Theodore Roosevelt National Park (NP) are one federal mandatory class I area under the Clean Air Act. We continue to take exception to the method NDDAQ used to calculate visibility impacts and assesses progress for that Class I area under various sections of the draft Plan by treating Theodore Roosevelt NP as three separate Class I areas.

We have serious concerns regarding the determination of the emissions limits representing Best Available Retrofit Technology (BART) for nitrogen oxide controls. In addition, we have serious concerns with the exemption of the Unit #2 at the R. M. Heskett Station from BART review, and the methods used for demonstrating reasonable progress at Class I areas affected by emissions from North Dakota sources.

Section Comments

Section One: Purpose / Legal Authority

No comments

Section Two: Overview

We disagree with the statement on page 8 claiming that North Dakota has four mandatory federal Class I areas as defined under the Clean Air Act. Based on the legislation establishing Theodore Roosevelt National Park and the Clean Air Act, North Dakota has two mandatory federal Class I areas (i.e., Theodore Roosevelt NP and the Lostwood Wilderness Area). The entire acreage of Theodore Roosevelt NP is one Class I area under the Clean Air Act, and should be treated as such for all protection purposes, such as assessing for increment consumption and calculating visibility impacts.

Section Three: Plan Development and Consultation

The plan addresses the State of Minnesota's request for NDDAQ to analyze the feasibility of reducing electrical generating unit (EGU) emissions in the North Dakota to less than 0.25 pounds per million Btu (lb/MMBtu) for sulfur dioxide (SO_2) and less than 0.22 lb/MMBtu for nitrogen oxides (NO_X). While NDDAQ listed reasons why it did not believe the State of Minnesota's request was supported by assessments of impact, we request that ND supply the emission rates established by the regional haze plan from EGUs across the State so we and the public can be informed of any differences between the request from Minnesota and the final requirements of the NDDAQ plan.

The U.S. Environmental Protection Agency (EPA) will need to review any discrepancy between the Minnesota regional haze plan and the North Dakota regional haze plan during its review and approval process. In addition, we agree with NDDAQ that the EPA should address the significant contribution of international emissions, particularly from power generation in Canada, in support of NDDAQ's efforts for reasonable progress.

Section Four: Monitoring Strategy and Other Implementation Plan Requirements

We note that the language in the footnote of Table 4.1 implies that the visibility monitoring conducted under the cooperative Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) system at Theodore Roosevelt NP is covering more than one Class I area. While the monitoring is at one unit, it is representative of all three units of that one Class I area.

We appreciate NDDAQ's efforts to enhance monitoring of visibility with additional collection of data. We support the ongoing efforts to collect and periodically update state-wide inventories of pollutant emissions that may contribute to the visibility impairment noted on page 24 of the Plan.

Section Five: Baseline and Natural Conditions and Uniform Rate of Progress for North Dakota Class I Areas

As previously noted, we do not agree with the statement on page 30 that North Dakota has four distinct Class I areas. We do agree that the IMPROVE data collected at Theodore Roosevelt NP sufficiently tracks the long-term visibility conditions across the entire park and can be used for implementing the requirements of the regional haze rule.

Section Six: Sources of Visibility Impairment in North Dakota Class I Areas

We appreciate the presentation of the Western Regional Air Partnership (WRAP) assessment of sources of visibility impairment at the two North Dakota Class I areas. In particular, Table 6.6 is a useful summary of North Dakota's contribution to impairment listed by component of light extinction. This forms a baseline to compare projected conditions in the reasonable progress section of the Plan. We ask that NNDAQ clarify in the narrative that the sulfate and nitrate results are based on regional modeling using the CAMx-PSAT source apportionment tool, while the analyses of weighted emissions potential for organic carbon (OC), elemental carbon (EC), and particulate matter (PM) are based on emissions and residence time, not modeling. Figures 6.1, 6.2, 6.7, and 6.8 would be more informative if they also included 2018 results for sulfate and nitrate as is shown in the other figures for OC, EC, and PM.

Section Seven: Best Available Retrofit Technology (BART)

General Comments on BART

We appreciate this opportunity to comment upon the North Dakota Department of Health's (NDDAQ's) proposal for Best Available Retrofit Technology (BART) for the seven Electric Generating Units (EGUs) in North Dakota that it has identified as being subject to BART. We are impressed with the effort and expertise that went into this effort, and we are pleased that NDDAQ is proposing major reductions in the visibility-impairing pollutants sulfur dioxide (SO_2), and nitrogen oxides (NO_x). We are especially appreciative of the approximately 90,000 tons per year reduction in sulfur dioxide emissions from application of BART in the draft Plan. However, we believe that additional reductions can be achieved under the BART program. Based on our analyses summarized below and discussed in detail in the enclosed documents, we believe that additional reductions beyond those identified by NDDAQ are reasonable. Our comments below address the five-step BART process described by EPA's BART Guidelines and documented by NDDAQ.

As noted, we recognize that NDDAQ and the affected sources expended considerable effort in developing these analyses over several years and generated large amounts of useful information. However, it would be helpful, when NDDAQ advances this process into the public arena, if the NDDAQ BART determinations could provide more guidance as to the origins of the data used in their analyses. In our analyses of the data provided by NDDAQ and the sources, we generated several electronic files that we would be pleased to share with NDDAQ if those files could assist in providing a clearer understanding of this complex BART process.

Purpose of the BART Program

The core purpose of the BART program is to improve visibility in our Class I areas. BART is not necessarily the most cost-effective solution. Instead, BART represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. We believe that it is essential to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected.

Five-Step BART Process

Step 1: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES
Except for Great River Energy's (GRE's) analysis for NO_x from Coal Creek, all of the other SO_2 and NO_x analyses included a reasonable suite of options.

We also have some general comments that apply to all of the PM_{10} analyses. We believe that the BART analyses are deficient in that they neither address upgrades to the existing Electrostatic Precipitators (ESPs) or propose limits that realistically reflect the capabilities of those existing ESPs, as well as the proposed new baghouses, to control filterable PM. EPA's BART Guidelines (Guidelines) advise:

- "...it is important to include control options that involve improvements to existing controls and not to limit the control options only to those measures that involve a complete replacement of control equipment."
- "...for retrofitting existing sources in addressing BART, you should consider ways to improve the performance of existing control devises, particularly when a control device is not achieving the level of control that other similar sources are achieving in practice with the same device. For example, you should consider requiring those sources with electrostatic precipitators (ESPs) performing below currently achievable levels to improve their performance."

Although all of these sources have ESPs in place, none of them except Stanton Unit #1 is currently achieving a level of performance equivalent to the 0.015 lb/mmBtu proposed for ESPs at sources such as Peabody's Thoroughbred and LG&E's Trimble County projects in Kentucky. Furthermore, EPA has recently issued a permit limiting the Desert Rock facility to 0.010 lb/mmBtu filterable PM_{10}, new baghouses are being permitted at 0.009 – 0.012 lb/mmBtu in Virginia (Virginia Hybrid Energy Center) and Wyoming (Dry Fork, WYGEN 3), and ND DOH proposed to permit the Gascoyne project at 0.012 lb/mmBtu. Instead, the limits on filterable PM_{10} proposed by NDDAQ are two – to – three times the emission rates measured by stack testing and cited by NDDAQ. While we understand that a certain "safety margin" must be allowed, we believe that the BART limits should be set to encourage continued good operation and maintenance of the pollution control equipment.

Step 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

This step was handled appropriately.

Step 3: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The ability of SCR to reduce emissions, as assumed by NDDAQ, was inconsistent and sometimes underestimated. For example, for the LNB/OFA+SCR option, GRE, Basin Electric Power Cooperative (BEPC), and NDDAQ sometimes assumed 0.07 lb/mmBtu for all averaging periods. However, for example, the WY Department of Environmental Quality has issued permits for new EGUs requiring that they meet 0.05 lb/mmBtu over averaging periods of 24-hours[1] and 30-days.[2] Furthermore, EPA's Clean Air Markets (CAM) data (Appendix A) and vendor guarantees[3] show that SCR can typically meet 0.05 lb/mmBtu (or lower) on an annual average basis. GRE, BEPC, and NDDAQ have not provided any documentation or justification to support the higher values used in their analyses. Our review of operating data (Appendix A) suggests that a NO_X limit of 0.06 lb/mmBtu is appropriate (with an adequate "safety-margin") for LNB/OFA+SCR for a 30-day rolling average, and 0.07 lb/mmBtu for a 24-hour limit and for modeling purposes, but a lower rate (e.g., 0.05 lb/mmBtu or lower) should be used for annual average and annual cost estimates. When the annual NO_x reductions are underestimated, the cost-effectiveness of the control option is negatively affected.

Step 4: EVALUATE IMPACTS AND DOCUMENT RESULTS

The cost of SCR was consistently overestimated. EPA's BART Guidelines recommend use of the OAQPS Control Cost Manual. Neither Minnkota Power Cooperative (Minnkota), GRE, BEPC, nor NDDAQ provided justification or documentation for their cost estimates. We were not provided with any vendor estimates or bids, and none used the recommended Control Cost Manual. This resulted in much-higher SCR costs than suggested by available literature (see Appendix B cost summaries) which shows SCR costs ranging from $50 - $267/kW. As recommended by the BART Guidelines, we applied the OAQPS Control Cost Manual to the EGUs and derived costs that fell within the Appendix B cost-survey range. As a result, we believe that capital and annual costs are overestimated by NDDAQ.

According to EPA's BART Guidelines, "the basis for equipment cost estimates should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option."

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[1] Basin Electric—Dry Fork

[2] WYGEN3

[3] Minnesota Power has stated in its Taconite Harbor BART analysis that "The use of an SCR is expected to achieve a NO_X emission rate of 0.05 lb/mmBtu based on recent emission guarantees offered by SCR system suppliers."

EPA's belief that the Control Cost Manual should be the primary source for developing cost analyses that are transparent and consistent across the nation and provide a common means for assessing costs is further supported by this November 7, 2007, statement from EPA Region 8 to NDDAQ:

> The SO_2 and PM cost analyses were completed using the CUECost model. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual. Therefore, these analyses should be revised to adhere to the Cost Manual methodology.

We are especially concerned about the lack of justification and support for the estimates of costs for reheating the exhaust gas streams to facilitate addition of "tail-end" SCR. Reheat costs are a critical issue affecting the economic feasibility of SCR, and, even in those cases where some data were presented (by GRE), it was still not adequate for us to be able to understand the assumptions that formed the bases for the natural gas usage estimates. Furthermore, we are concerned that the costs of catalyst, ammonia, electricity, and natural gas were inflated beyond what we typically see, or what is projected by the Energy Information Administration (EIA) with respect to future natural gas prices. Finally, we are concerned that this critical cost was simply scaled from a few examples and applied to other SCR analyses—we believe that it deserves individual analyses specific to each case.

Step 5: VISIBILITY IMPROVEMENT DETERMINATION

We believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. And, it does not make sense to evaluate impacts at one Class I area, while ignoring others that are similarly significantly impaired. If we look at only the most-impacted Class I area, we ignore that the other Class I areas are all suffering from impairment to visibility "caused"[4] by the BART source. It follows that, if emission from the BART source are reduced, the benefits will be spread well beyond only the most impacted Class I area, and this must be accounted for.

The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a large Class I area and isolated impacts in a small Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated

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[4] EPA defines a source with an impact greater than one deciview as "causing" impairment.

approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available.

We are concerned that NDDAQ has not adequately considered the visibility benefits of the control strategies it evaluated. In many cases, instead of evaluating a candidate BART strategy by determining the visibility improvement that would result from that particular strategy versus a "standard" baseline (e.g., the proposed SO_2 control options), the only analyses of visibility improvements were of the incremental differences between competing BART options. In most cases, were able to develop estimates of the actual improvements for a given strategy, but that was a very difficult process that required many assumptions and extrapolations that fail the test of "transparency."

The State's BART protocol was developed and approved by EPA Region 8 several years ago. Although we honor approved protocols from that time period, our modeling results indicate that use of current methods produces estimates of visibility impairment and improvement that are usually greater than the estimates provided by NDDAQ and the BART sources. For example, we evaluated the impacts of emissions from Leland Olds Station (LOS) Unit #2 using both the EPA-recommended Pasquill-Gifford (P-G) atmospheric stability approach and the turbulence-based approach used in ND. We first estimated the impacts from baseline emissions, but included condensable PM_{10} emissions using estimates derived from EPA's Compilation of Air Pollutant Emission Factors (AP-42). Next, we established a new "baseline" based upon emissions from LOS #2 after application of the proposed wet scrubber. Finally, we modeled the options in which Selective Non-Catalytic Reduction (SNCR) and SCR were added to the wet scrubber and compared each of those results to the "scrubber-only" results. We found that our modeling results (see Appendix C) consistently predicted significantly higher impacts and that the benefits of reducing NO_x were also substantially higher (by as much as a factor of two for addition of SCR to LOS #2). This has major implications for a program aimed at improving visibility.

BART DETERMINATIONS

It appears to be more beneficial to reduce NO_x than to reduce SO_2 in this cool climate. However, by placing more emphasis upon cost-per-ton ($/ton) of pollutants removed than on visibility improvement, the advantages of reducing NO_x versus SO_2 are overlooked if both are measured with the same $/ton yardstick. For this reason, we recommend that the primary emphasis should be placed upon the cost – per – deciview ($/dv) of improvement.

Compared to the typical control cost analysis in which estimates fall into the range of $2,000 - $10,000 per ton of pollutant removed, spending millions of dollars per deciview to improve visibility may appear extraordinarily expensive. However, our compilation[5] of BART analyses across the U.S. reveals that the **average cost per dv proposed by either**

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[5] http://www.wrapair.org/forums/ssjf/bart.html

a state or a BART source is $9 - $20 million,[6] with a maximum of almost $50 million per dv proposed by Colorado at the Martin Drake power plant in Colorado Springs. A comparison of the cost/dv values resulting from NDDAQ's BART proposals shows that addition of Advanced Separated Over-Fire Air (ASOFA) and SNCR to LOS #1 would result in cost-effectiveness values of $27.3 million/dv at the most-impacted Class I area and $13.6 million/dv when the benefits to both Class I areas are considered. Likewise, the addition of combustion controls and SNCR at Stanton #1 would result in cost-effectiveness values of $33.1 - $41 million/dv at the most-impacted Class I area and $16.9 – $20.9 million/dv when the benefits to both Class I areas are considered. We suggest that NDDAQ should reconsider its other BART determinations in view of these cost-effectiveness values it has effectively accepted.

Another concern with the visibility analyses presented by NDDAQ is the over-emphasis on the incremental improvements to visibility resulting from SCR. NDDAQ calculated only the incremental improvement in visibility resulting from addition of some potential controls. Although incremental benefits are an appropriate consideration, they should not become the sole basis for a BART decision. NDDAQ should have presented the total visibility improvement that would result from a control option instead of presenting only the incremental improvement.

For several units, ND DOH is proposing alternative sulfur dioxide (SO_2) limits that are similar to the presumptive BART limits because they allow a source to choose between a limit in terms of pounds of emissions per million Btu of heat input, or percent reduction of that pollutant. While EPA presented its BART Guidelines for SO_2 in that format, we do not believe that it was EPA's intention to allow the source to choose the more favorable limit. By definition, BART represents the highest degree of control that meets the five-factor test. Where ND DOH has determined that a lb/mmBtu limit is reasonable, it should require that that limit be met. Similarly, where ND DOH has determined that a percent reduction limit is reasonable, it should require that that limit be met. If both limits are determined to be reasonable, then to allow the source to choose only one clearly does not represent the most stringent reasonable degree of control. Therefore, where ND DOH has proposed alternative limits, both should be required.

There is also a fundamental problem with setting only a percent-reduction limit on SO_2 emissions. If fuel sulfur content increases, emissions can increase correspondingly. Unless sulfur content is limited, or a cap is placed on mass emissions (e.g., lb/hr, tons/yr as proposed by Wyoming, for example), the actual amount of SO_2 emitted is unlimited.

In addition to an absence of any evaluation of upgrading the existing PM control equipment, it appears that ND DOH is not following EPA guidance to consider more stringent emission rates in setting permit limits:

> "If you find that a BART source has controls already in place which are the most stringent controls available (note that this means all possible improvements to any control

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[6] For example, PacifiCorp has stated in its BART analysis for its Bridger Unit #2 that "The incremental cost effectiveness for Scenario 1 compared with the baseline for the Bridger WA, for example, is reasonable at $580,000 per day and $18.5 million per deciview."

> devices have been made), then it is not necessary to comprehensively complete each following step of the BART analysis in this section. As long as these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section."

We recommend that ND DOH establish permit limits that reflect the capabilities of the BART technology to control filterable PM.

Primary Conclusions & Recommendations

Our analyses of the information provided by NDDAQ lead us to the following preliminary conclusions and recommendations (as discussed in detail in the following documents):

- The loss of ash sales at Coal Creek is a critical, but unsupported, cost of adding SNCR or SCR. If ash sales are not adversely affected, addition of SNCR becomes a reasonable BART selection.
- Space constraints likely justify selection of the spray-dry/fabric filter option at Stanton #1.
- The cost of reheating stack gas to facilitate addition of SCR is a critical factor in the feasibility of that option and must be better-documented, along with better justification for the costs of SCR itself.
- The differing modeling approaches have a significant impact upon the visibility modeling results and should be evaluated and resolved.
- More emphasis should be placed upon the cumulative visibility benefits that could be derived from the BART program.
- SCR may become a more viable option when these issues of effectiveness, cost, and benefits are resolved.
- NDDAQ should consistently and transparently determine and apply an objective approach to its BART determinations.

Heskett Exemption

In Section 7.3.4, the Plan describes the steps taken that result in excluding the Montana Dakota Utilities R.M. Heskett Unit No. 2 from BART review. We are aware of the modeling protocol used by the WRAP and of a revised protocol developed from discussions between the U.S. EPA Region 8 staff and the NDDAQ staff regarding certain sources in the State. After the Heskett Unit No. 2 failed the exclusion modeling analysis under the revised North Dakota protocol, ENSR Corporation developed a third protocol for Heskett Unit No. 2. We have no record of receiving or reviewing the third modeling protocol conducted by ENSR Corporation for the Heskett facility. Our concerns with the work performed by ENSR Corporation center on the use of a 1 kilometer grid, and that the calculation for maximum impact separates Theodore Roosevelt NP into three separate Class I areas. Based on agreed-upon methods and its baseline emissions, we believe that Heskett Unit No. 2 is subject to BART requirements.

The draft Plan cites a reduction of Heskett Station's emissions of sulfur dioxide from a baseline of 2400 tons per year to a rate of 1660 tons per year within five years of Plan approval by the EPA. This reduction is a 31 percent reduction not the 70 percent reduction claimed in the draft Plan. This BART-like requirement is not based on assessing the full range of engineering options appropriate to Heskett Unit No. 2, nor is it consistent with the requirements of a voluntary reduction that would reduce the impact of the BART-eligible unit below the threshold that triggers BART requirements. To be accepted as a voluntary reduction, the source's emission limit would need to be in place upon submission of the Plan to the EPA.

Specific Comments on BART Determinations

Great River Energy (GRE) Coal Creek Units #1 & #2:

Great River Energy (GRE) operates Coal Creek Units #1 & #2 near Underwood, North Dakota. Both units are tangentially-fired with lignite from an adjacent mine and are rated at 550 MW (gross) output. Current emission control equipment consists of wet limestone scrubbers, Low-NO_x Burners (LNB) and Separated Overfire Air (SOFA), and Electrostatic Precipitators (ESPs). Although each unit has a capacity greater than 200 MW at a facility with a total capacity greater than 750 MW, presumptive BART limits only apply for nitrogen oxide (NO_x) because there are existing sulfur dioxide (SO_2) controls on both units at the facility.

Out of 1,228 power plants in EPA's Clean Air Markets (CAM) database in 2008, the Coal Creek plant ranked #104 for SO_2 at 23,142 tons and #101 for NO_x at 9,457 tons. According to modeling results provided by GRE, emissions from Coal Creek cause 2.9 dv of impairment in visibility at Theodore Roosevelt NP and 5.4 dv cumulatively when Lostwood WA is included. Without additional emission controls, SO_2 emissions are expected to almost double by 2019 due to deteriorating lignite quality (higher sulfur, lower heating value).

A. Sulfur Dioxide

Step 1: Identify All Available Technologies
We agree that NDDAQ has chosen a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options
We agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology
We agree with NDDAQ's estimates of control effectiveness.

Step 4: Evaluate Impacts and Document Results
While the proposed costs ($139/kW) for upgrading the scrubbers (and eliminating the flue gas by-pass) appear high when compared to similar projects in MN, ND and WY,[7] they have been accepted by both GRE and NDDAQ.

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[7] Sherburne Country 1 MN, Bridger and WYODAK in WY, and MR Young in ND.

NDDAQ Estimates for Coal Creek Wet Scrubber Upgrade (each)

Total Capital Cost:	$ 76,222,700
Total Capital Cost $/kW):	$ 139
O&M Cost:	$ 2,090,296
Total Annual Cost:	$ 11,520,000
Cost per Ton	$ 555

Step 5: Evaluate Visibility Results

By comparing scenarios provided by GRE in which NO_x is constant but SO_2 changes, we have estimated that the proposed scrubber upgrades will each result in an approximately one dv improvement in visibility at Theodore Roosevelt NP and 1.9 dv cumulatively when Lostwood WA is included.

Determine BART

NDDAQ is proposing upgrading the existing wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. This results in cost-effectiveness values of $11.0 million per dv at Theodore Roosevelt NP and $5.9 million per dv cumulatively when Lostwood WA is included.

Scrubber Upgrade Cost-effectiveness

Annual Cost ($million)	$ 11.52
Visibility Improvement at TRNP (dv)	1.04
Cost-Effectiveness ($million/dv)	$ 11.06
Cumulative Visibility Improvement (dv)	1.94
Cost-Effectiveness ($million/dv)	$ 5.94

Because NDDAQ has proposed no absolute limits on emissions, the proposed BART limits would result in a 72% reduction in current SO_2 emissions on a lb/mmBtu basis and a 72% reduction on a tons-per-year basis.

Sulfur content of the coal was the primary constituent of concern because SO_2 emissions are directly related to the amount of sulfur in the coal and are not as related to equipment design. NDDAQ estimated that future delivered coal will have a maximum annual average sulfur content of approximately 1.10%.

Instead, we recommend 0.15 lb/mmBtu **and** 95% reduction on a 30-day rolling average basis because NDDAQ has determined that both of these levels are reasonable. Even if coal quality deteriorates to the anticipated worst-case (1.49 lb/mmBtu), 90% control would still meet the 0.15 lb/mmBtu limit.

B. Nitrogen Oxides

Step 1: Identify All Available Technologies
We believe that NDDAQ should have included a combination of combustion controls (e.g., Low-NO_X Burners, Over-Fire Air) coupled with Selective Catalytic Reduction (SCR) to its suite of options.

Step 2: Eliminate Technically Infeasible Options
Except as noted above, we agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology
Based on the 0.22 lb/mmBtu NO_X baseline emission rate, outlet emissions projected by NDDAQ for SCR at 0.07 lb/mmBtu represent only a 80% SCR control efficiency and a reduction of 4,286 tpy. (This is much lower than other analyses[8] in which NDDAQ has assumed 88% - 90% for SCR control effectiveness.) We believe that a combination of combustion control plus SCR can achieve 90% NO_x removal as opposed to the 80% estimated by NDDAQ for SCR alone.

Step 4: Evaluate Impacts and Document Results
NDDAQ estimated the following costs for LNB + SOFA:

NDDAQ Estimates for Coal Creek LNB+SOFA

Total Capital Cost:	$ 5,260,000
Total Capital Cost $/kW):	$ 10
O&M Cost:	$ 7,942
Total Annual Cost:	$ 660,000
Cost per Ton	$ 411

In its evaluations of SNCR and SCR, GRE included $13.75 million (per boiler) "sunk costs" for its ash handling infrastructure, and $14.4 million (per boiler) annual costs that represent lost ash sales revenue. It is inappropriate to include sunk costs in future decision-making.

If true, the loss of ash sale revenue and the consequent need to pay for ash disposal represent a major portion of the total $22.9 million annual operating cost for SNCR, and the total $37.1 million annual operating cost for SCR, so this issue becomes the critical factor affecting the cost-effectiveness of these technologies. However, NPS can find no examples of cases where ammonia contamination has resulted in lost ash sales, so we are presenting estimates that adjust the NDDAQ costs to eliminate the sunk costs as well as the costs associated with lost ash sales (as well as another $2 million per boiler annual cost for ash disposal). Our $1,072 cost was derived from applying the EPA Control Cost Manual. (Please see Appendix B.)

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[8] Leland Olds #2, MR Young #1 & #2, Stanton #1

Coal Creek SNCR Cost Estimates

Cost	NDDAQ	NDDAQ (adj)	NPS
Total Capital Cost:	$ 19,909,069	$ 6,159,069	$ 6,862,904
Total Capital Cost $/kW):	$ 36	$ 11	$ 12
O&M Cost:	$ 21,231,102	$ 4,828,001	$ 2,265,878
Total Annual Cost:	$ 22,900,000	$ 6,496,899	$ 2,913,687
Cost per Ton	$ 8,551	$ 2,426	$ 1,072

NDDAQ has estimated a total annual cost for low-dust SCR with reheat at $56.2 million. Of that total, $19.2 million is a result of installing and operating a natural gas-fired gas reheating system to bring the flue gas back up to a temperature suitable for efficient SCR operation. The result of NDDAQ's assumptions is that SCR would cost over $13,000 per ton, which it deemed to be excessively costly.

Coal Creek SCR Cost Estimates

Cost	NDDAQ	NPS
Total Capital Cost:	$ 84,110,657	$ 41,718,972
Total Capital Cost $/kW):	$ 153	$ 76
O&M Cost:	$ 49,011,624	$ 11,389,572
Total Annual Cost:	$ 56,150,000	$ 15,327,547
Cost per Ton	$ 13,102	$ 3,722

NPS eliminated the sunk costs and the costs associated with lost ash sales and applied the EPA Control Cost Manual (Please see Appendix B.) to produce a much lower $3,722 per ton estimate for SCR.

Step 5: Evaluate Visibility Results

By comparing scenarios in which SO_2 is constant but NO_x changes, we have estimated that visibility improves at Lostwood WA 0.00006 dv per ton of NO_x removed, and 0.00012 dv/ton cumulatively. The visibility improvement values shown in the tables below are based upon those estimates.

Determine BART

NDDAQ is proposing LNB + SOFA at 0.17 lb/mmBtu on a 30-day rolling average basis.

LNB + SOFA Cost-effectiveness	NDDAQ
Annual Cost ($million)	$ 0.66
Visibility Improvement at Lostwood WA (dv)	0.10
Cost-Effectiveness ($million/dv)	$ 6.58
Cumulative Visibility Improvement (dv)	0.19
Cost-Effectiveness ($million/dv)	$ 3.52

NDDAQ rejected SNCR on the basis of excessive cost. However, when we adjusted the NDDAQ estimates to eliminate the effects of sunk costs and lost ash sales, the resulting cumulative cost-effectiveness of $20.1 million per dv becomes marginally cost-effective. NDDAQ should reevaluate SNCR in more depth.

SNCR Cost-effectiveness	**NDDAQ**	**NDDAQ (adj)**	**NPS**
Annual Cost ($million)	$ 22.90	$ 6.50	$ 2.91
Visibility Improvement at Lostwood WA (dv)	0.17	0.17	0.17
Cost-Effectiveness ($million/dv)	$ 137.02	$ 38.87	$ 17.18
Cumulative Visibility Improvement (dv)	0.31	0.31	0.32
Cost-Effectiveness ($million/dv)	$ 73.30	$ 20.80	$ 9.19

We estimate SNCR cost-effectiveness at $17.2 million per dv at Lostwood WA and $9.2 million per dv on a cumulative basis. We believe these costs are reasonable.

NDDAQ rejected SCR on the basis of excessive cost. When we adjusted the NDDAQ estimates to eliminate the effects of sunk costs and lost ash sales and applied the methods from the EPA Control Cost Manual, the results were still not cost-effective.

SCR cost-effectiveness	**NDDAQ**	**NPS**
Annual Cost ($million)	$ 56.15	$ 15.33
Visibility Improvement at Lostwood WA (dv)	0.27	0.26
Cost-Effectiveness ($million/dv)	$ 209.93	$ 59.64
Cumulative Visibility Improvement (dv)	0.50	0.48
Cost-Effectiveness ($million/dv)	$ 112.31	$ 31.91

Conclusions & Recommendations

- NDDAQ is proposing upgrading the existing wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. The proposed scrubber upgrades will each result in an approximately one dv improvement in visibility at Theodore Roosevelt NP and 1.9 dv cumulatively when Lostwood WA is included.
- We commend NDDAQ for the proposed new wet scrubber, but recommend that the limits require **both** 95% control **and** 0.15 lb/mmBtu, as well as specific caps on emissions.
- NDDAQ is proposing LNB + SOFA at 0.17 lb/mmBtu on a 30-day rolling average basis as BART for NO_X. As a result, visibility would improve by 0.10 dv at Lostwood and 0.19 dv cumulatively.
- NDDAQ has underestimated the effectiveness of SCR at only 80% control efficiency.
- NDDAQ has overestimated the costs of SNCR and SCR Many of the costs associated with SNCR and SCR presented by GRE and NDDAQ were not supported by GRE's documentation. Costs associated with lost ash sales and ash disposal were not adequately justified. More reliance should be placed upon use

of the EPA Control Cost Manual when the source fails, as GRE did, to provide sufficient supporting documentation of its costs. Our application of the EPA Control Cost Manual yielded much lower cost estimates for SNCR and SCR.

- NDDAQ has not adequately considered the visibility benefits of the control strategies it evaluated.
- NPS' analysis of addition of SNCR indicates that visibility would improve by 0.17 dv at Lostwood and 0.32 dv cumulatively. This yields a cost-effectiveness of $17.2 million per dv at Lostwood WA and $9.2 million per dv cumulatively when Theodore Roosevelt NP is included, which we believe to be reasonable based upon BART determinations and proposals we have seen nationwide to date.
- NPS' estimates for addition of SNCR show cost-effectiveness values below the $17 - $21 million per cumulative dv that NDDAQ accepted for adding SNCR at Stanton #1. Considering that the BART program is intended to improve visibility, it follows that any cost-effectiveness value below the costs per dv accepted by NDDAQ at Leland Olds #1 and Stanton should also be acceptable at Coal Creek.
- We conclude that SNCR is BART for control of NO_X emissions from GRE Coal Creek Units #1 and #2.

Great River Energy (GRE) Stanton Station Unit #1

Great River Energy (GRE) operates the 256 MW Stanton Station near Stanton, ND. The plant is located about 150 km from Theodore Roosevelt National Park NP, a Class I area administered by the National Park Service.[9] Out of 1,228 power plants in EPA's Clean Air Markets (CAM) database in 2008, the Stanton plant ranked #335 for sulfur dioxide (SO_2) at 2,873 tons and #324 for nitrogen oxides (NO_x) at 2,033 tons.

Stanton Unit #1

Unit #1 is a front-wall-fired boiler that burns sub-bituminous coal from the Powder River Basin (PRB) and local lignites. Unit #1 began operation in 1966 and is rated at 1,800 mmBtu/hr heat input. Unit #1 is equipped with Low-NO_x Burners (LNB) and an Electrostatic Precipitator (ESP) to control particulate matter (PM). Out of 3,558 units in EPA's CAM database in 2008, Stanton #1 ranked #667 for SO_2 at 2,726 tons and #696 for NO_x at 1,174 tons. According to modeling results provided by GRE, emissions from Stanton #1 cause 1.3 dv of impairment in visibility at Theodore Roosevelt NP and 2.4 dv cumulatively when Lostwood WA is included. Therefore, it is subject to Best Available Retrofit Technology (BART).

A. Sulfur Dioxide

NDDAQ has assumed that future uncontrolled SO_2 emissions may increase by 33% due to deteriorating coal quality.

Step 1: Identify All Available Technologies

We agree that NDDAQ has chosen a reasonable suite of options.

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[9] The Lostwood National Wildlife Refuge, a Class I area administered by the U.S. Fish & Wildlife Service, is located about 150 km from the Stanton plant.

Step 2: Eliminate Technically Infeasible Options

We agree with NDDAQ's selection of technically feasible options. However, we also agree with NDDAQ that applying a wet scrubber at this site has so many adverse environmental consequences[10] that we will not consider that option further, and will confine our review to the Spray-Dryer/Fabric Filter (SD/FF) option.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

NDDAQ has estimated that a new SD/FF will reduce SO_2 emissions by 90% for both lignite and PRB coal combustion. We believe that higher control efficiency is warranted for the both the lignite and PRB sub-bituminous coal scenarios. For example, a SD/FF on 2.4 lb/mmBtu lignite or 1.6 lb/mmBtu PRB sub-bituminous coal should be capable of at least 93% control and achieve an emission limit of 0.09 lb/mmBtu on a 30-day rolling average basis.[11] Because the larger Stanton Unit #10 also located at this site is achieving less 0.06 lb/mmBtu on an annual basis (presumably burning PRB coal) using the same SD/FF technology proposed for Stanton #1, NDDAQ should explain why a newer installation of that technology at Stanton #1 cannot perform as well, at least on PRB coal.

Step 4: Evaluate Impacts and Document Results

The proposed cost ($423/kW) for adding the 90% efficient SD/FF appears reasonable. The result of NDDAQ's assumptions is that the new SD/FF would cost $1,330 per ton while burning lignite, and $2,006 per ton while burning PRB coal, which NDDAQ deemed reasonable. It is likely that increasing the SD/FF efficiency to achieve 0.09 lb/mmBtu would be even more cost-effective on a $/ton basis.

Stanton #1 SD/FF Cost Summary

	lignite	PRB
Total Capital Cost:	$ 79,514,000	$ 79,514,000
Total Capital Cost $/kW):	$ 423	$ 423
O&M Cost:	$ 4,071,674	
Total Annual Cost:	$ 11,220,000	$ 11,220,000
Cost per Ton	$ 1,330	$ 2,006

Step 5: Evaluate Visibility Results

Based upon data supplied by GRE and by NDDAQ, we have estimated that, when burning lignite, the proposed new 90% efficient SD/FF will result in an approximately 0.8 dv improvement in visibility at Theodore Roosevelt NP and 1.5 dv cumulatively when Lostwood WA is included. When burning PRB coal, the proposed new 90% efficient SD/FF will result in an approximately 0.5 dv improvement in visibility at Theodore Roosevelt NP and 1.0 dv cumulatively when Lostwood WA is included. Our review of NDDAQ visibility modeling yields a SO_2 control-effectiveness factor for the

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[10] We are especially concerned about the problems associated with disposal of the wet scrubber sludge in this space-limited site adjacent to the Missouri River.

[11] Please see the entry in Appendix D for the permit issued by Wyoming to Black Hills Power for its WYGEN 3 project.

new SD/FF of 0.00009 dv/ton at Theodore Roosevelt NP and 0.00018 dv/ton cumulatively when Lostwood WA is included.[12]

Determine BART

NDDAQ is proposing addition of a new SD/FF to limit SO_2 emissions while burning lignite to 0.24 lb/mmBtu **or** 90% reduction on a 30-day rolling average basis. The proposed BART limits would result in an 86% reduction in current SO_2 emissions on a lb/mmBtu basis. However, because NDDAQ has proposed no absolute limits on emissions, unlimited operation at 0.24 lb/mmBtu could result in only a 77% reduction on a ton-per-year basis. If coal quality deteriorates to the anticipated worst-case (2.4 lb/mmBtu uncontrolled), the proposed BART limits would default to a 90% reduction on a lb/mmBtu basis and an 80% reduction in future SO_2 emissions on a ton/year basis.

While burning PRB sub-bituminous coal, NDDAQ is proposing 0.16 lb/mmBtu **or** 90% reduction on a 30-day rolling average basis. The proposed BART limits would result in a 91% reduction in current SO_2 emissions on a lb/mmBtu basis and an 85% reduction on a ton-per-year basis. If coal quality deteriorates to the anticipated worst-case (1.6 lb/mmBtu uncontrolled), the proposed BART limits would default to a 90% reduction on a lb/mmBtu basis and an 80% reduction in future SO_2 emissions on a ton/year basis.

Based upon NDDAQ's analysis, addition of the new SD/FF yields the cost-effectiveness values shown below, which we believe to be reasonable based upon BART determinations and proposals we have seen nationwide to date:

NDDAQ Estimates for SO_2 from burning	lignite	PRB
Annual Cost ($million)	$ 11.22	$ 11.22
Visibility Improvement at TRNP (dv)	0.77	0.51
Cost-Effectiveness ($million/dv)	$ 14.53	$ 21.92
Cumulative Visibility Improvement (dv)	1.51	1.00
Cost-Effectiveness ($million/dv)	$ 7.43	$ 11.20

We recommend limits of 0.09 lb/mmBtu **and** 93% reduction on a 30-day rolling average for both fuels based upon recent determination by other states for EGUs burning coals with similar uncontrolled emissions. Even if coal quality deteriorates to the anticipated worst-case 2.4 lb/mmBtu, 96% control would still meet the 0.0.09 lb/mmBtu limit. We also recommend short and long-term absolute (e.g., lb/hr, tpy) caps on emissions to insure that emissions will not increase greatly over time.

B. Nitrogen Oxides

Step 1: Identify All Available Technologies

We believe that NDDAQ should have included SOFA with tail-end SCR with reheat in its analysis.

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[12] Our control-effectiveness factor is simply dv/ (tons per year reduced) and assumes a linear relationship for a given pollutant.

Step 2: Eliminate Technically Infeasible Options
Except as noted above, we agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology
NDDAQ's estimates of control effectiveness appear reasonable. For example, based on the 0.44 lb/mmBtu NO_X baseline emission rate, outlet emissions projected by NDDAQ for SCR at 0.044 lb/mmBtu represent 90% SCR control efficiency and a reduction of 1,929 tpy.

Step 4: Evaluate Impacts and Document Results
NDDAQ's estimates of costs for low-dust SCR with reheat are summarized below. In developing that estimate, NDDAQ relied upon GRE's estimates which included a total capital cost for SCR with reheat of $56.6 million or $301/kW. Because this exceeds the expected range of $50 - $267/kW presented in our Appendix B, we request that GRE/NDDAQ document and justify this estimate.

GRE/NDDAQ also estimate that $3.2 million of the $7.7 million annual cost is a result of installing and operating a natural gas-fired gas reheating system to bring the flue gas back up to a temperature suitable for efficient SCR operation.

The result of NDDAQ's assumptions is that SCR would cost $6,475 per ton when burning lignite, and $8,163 per ton when burning PRB coal, which it deemed to be excessively costly.

As recommended by the BART Guidelines, we applied the methods described in Section 4.2 of EPA's Control Cost Manual and estimated the costs, including GRE's reheat cost estimates, which we believe to be more representative, as summarized below:

Stanton #1 SCR on Lignite Cost Summary

	GRE/NDDAQ	NPS
Total Capital Cost:	$ 56,554,445	$ 18,986,724
Total Capital Cost $/kW):	$ 301	$ 101
O&M Cost:	$ 7,676,364	$ 4,311,537
Total Annual Cost:	$ 12,490,000	$ 6,103,749
Cost per Ton	$ 6,475	$ 3,288

Stanton #1 SCR on PRB Cost Summary

	GRE/NDDAQ	NPS
Total Capital Cost:	$ 56,554,445	$ 18,388,465
Total Capital Cost $/kW):	$ 301	$ 98
O&M Cost:	$ 7,676,364	$ 4,120,838
Total Annual Cost:	$ 12,490,000	$ 5,856,579
Cost per Ton	$ 8,163	$ 5,880

NDDAQ has estimated a total annual cost for its proposed LNB+OFA+SNCR at $3.0 million with cost-effectiveness of $3,052 per ton when burning lignite, and $3,778 per ton when burning PRB coal, which it deemed to be reasonable.

Step 5: Evaluate Visibility Results
Based upon data supplied by GRE and by NDDAQ, we have estimated that, when burning lignite, the proposed LNB+OFA+SNCR will result in an approximately 0.09 dv improvement in visibility at Theodore Roosevelt NP and 0.18 dv cumulatively when Lostwood WA is included. When burning PRB coal, the proposed LNB+OFA+SNCR will result in an approximately 0.07 dv improvement in visibility at Theodore Roosevelt NP and 0.14 dv cumulatively when Lostwood WA is included.

Contrary to the BART Guidelines, NDDAQ did not evaluate the visibility benefits of LNB+OFA+SCR However, our review of NDDAQ visibility modeling yields a NO_x control-effectiveness factor for basic LNB+OFA+SNCR of 0.0004 dv/ton at Theodore Roosevelt NP and 0.0008 dv/ton cumulatively when Lostwood WA is included. By applying the NO_x control-effectiveness factor to NDDAQ's estimated 1,929 tpy reduction from burning lignite with LNB+OFA+SCR with reheat, we have estimated that addition of LNB+OFA+SCR with reheat will result in an approximately 0.3 dv improvement in visibility at Theodore Roosevelt NP and 0.5 dv cumulatively when Lostwood WA is included. By applying the NO_x control-effectiveness factor to NDDAQ's estimated 1,530 tpy reduction from burning PRB coal with LNB+OFA+SCR with reheat, we have estimated that addition of LNB+OFA+SCR with reheat will result in an approximately 0.2 dv improvement in visibility at Theodore Roosevelt NP and 0.3 dv cumulatively when Lostwood WA is included.

Determine BART
NDDAQ is proposing addition of a LNB+OFA+SNCR to limit NO_x emissions when burning lignite to 0.29 lb/mmBtu, and 0.23 lb/mmBtu when burning PRB coal. Based upon NDDAQ's analysis, addition of the proposed LNB+OFA+SNCR yields a cost-effectiveness values shown below:

NDDAQ estimates for NOx from LNB+OFA+SNCR	lignite	PRB
Annual Cost ($million)	$ 3.00	$ 3.00
Visibility Improvement at TRNP (dv)	0.09	0.07
Cost-Effectiveness ($million/dv)	$ 33.09	$ 40.96
Cumulative Visibility Improvement (dv)	0.18	0.14
Cost-Effectiveness ($million/dv)	$ 16.92	$ 20.94

NDDAQ rejected tail-end SCR with reheat on the basis of excessive cost. NDDAQ's and NPS' analyses of addition of SCR with reheat yields the cost-effectiveness values shown below:

Estimates for NOx from **LNB+OFA+SCR burning**	**NDDAQ** **lignite**	**NPS** **lignite**	**NDDAQ** **PRB**	**NPS** **PRB**
Annual Cost ($million)	$ 12.49	$ 6.10	$ 12.49	$ 5.86
Visibility Improvement at TRNP (dv)	0.30	0.29	0.24	0.16
Cost-Effectiveness ($million/dv)	$ 41.31	$ 20.98	$ 52.09	$ 37.52
Cumulative Visibility Improvement (dv)	0.55	0.52	0.43	0.28
Cost-Effectiveness ($million/dv)	$ 22.90	$ 11.63	$ 28.88	$ 20.80

Based upon BART determinations and proposals we have seen nationwide to date, our cumulative cost-effectiveness values appear to be reasonable

Conclusions & Recommendations

- We agree with NDDAQ that applying a wet scrubber at this site has so many adverse environmental consequences that we will not consider that option further.
- NDDAQ proposed adding a new SD/FF to limit SO_2 emissions while burning lignite to 0.24 lb/mmBtu **or** 90% reduction on a 30-day rolling average basis. We recommend limits of 0.09 lb/mmBtu **and** 93% reduction on a 30-day rolling average for both fuels. Even if coal quality deteriorates, 96% control would still meet the 0.09 lb/mmBtu limit. We also recommend short and long-term absolute (e.g., lb/hr, tpy) caps on emissions to insure that emission will not increase greatly over time.
- NDDAQ is proposing addition of a LNB+OFA+SNCR to limit NO_x emissions when burning lignite to 0.29 lb/mmBtu, and 0.23 lb/mmBtu when burning PRB coal. NDDAQ has estimated a total annual cost at $3.0 million with cost-effectiveness of $3,052 per ton when burning lignite, and $3,778 per ton when burning PRB coal.
- When burning lignite, the proposed LNB+OFA+SNCR will result in an approximately 0.09 dv improvement in visibility at Theodore Roosevelt NP and 0.18 dv cumulatively. When burning PRB coal, the proposed LNB+OFA+SNCR will result in an approximately 0.07 dv improvement in visibility at Theodore Roosevelt NP and 0.14 dv cumulatively.
- NDDAQ estimates that SCR would cost $6,475 per ton when burning lignite, and $8,163 per ton when burning PRB coal, which it deemed to be excessively costly. NDDAQ has overestimated the costs associated with SCR. Many of the costs presented by GRE and NDDAQ were much higher than we have seen presented at similar facilities and were not supported by GRE's documentation. More reliance should be placed upon use of the EPA Control Cost Manual when the source fails, as did GRE, to provide sufficient supporting documentation of its costs. Our application of the Control Cost Manual yielded much lower cost estimates for SCR.
- When burning lignite, addition of LNB+OFA+SCR will result in an approximately 0.3 dv improvement in visibility at Theodore Roosevelt NP and 0.5 dv cumulatively when Lostwood WA is included. Cost-effectiveness is $11.6 million/dv - $20.1 million/dv, on a cumulative basis.

- When burning PRB coal, addition of LNB+OFA+SCR with reheat will result in an approximately 0.2 dv improvement in visibility at Theodore Roosevelt NP and 0.3 dv cumulatively when Lostwood WA is included. Cost-effectiveness is $20.1 - $28.9 million/dv, on a cumulative basis.
- We believe that SCR may represent BART, especially when the modeling issues identified in other reviews are resolved.

Basin Electric Power Cooperative (BEPC) Leland Olds Station (LOS) Units #1 & #2

Basin Electric Power Cooperative (BEPC) operates Leland Olds Station (LOS) Units #1 & #2 in Stanton, ND. Both units are fired with ND lignite and PRB sub-bituminous coal. Out of 1,228 power plants in EPA's Clean Air Markets (CAM) database in 2008, the Leland Olds plant ranked #12 for sulfur dioxide (SO_2) at 47,948 tons and #90 for nitrogen oxides (NO_x) at 11,065 tons. According to modeling results provided by BEPC, emissions from Leland Olds cause 5.6 dv of impairment in visibility at Theodore Roosevelt NP and 10.9 dv cumulatively when Lostwood WA is included. Without additional emission controls, SO_2 emissions are expected to more than double by 2019 due to deteriorating lignite quality (higher sulfur, lower heating value).[13]

Leland Olds Unit #1

Unit #1 is wall-fired and is rated at 216 MW (gross) output; current emission control equipment consists of LNB and ESP. Of 3,558 units in EPA's Clean Air Markets (CAM) database in 2008, LOS #1 ranked #95 for SO_2 at 17,926 tons and #90 for NO_x at 2,855 tons. According to modeling results provided by BEPC, emissions from LOS #1 cause 2.2 dv of impairment in visibility at Theodore Roosevelt NP and 4.1 dv cumulatively when Lostwood WA is included.

A. Sulfur Dioxide

Step 1: Identify All Available Technologies
We agree that NDDAQ has chosen a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options
We agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

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[13] BEPC has determined that historic rates are not representative of future maximum 24-hour emissions and has requested NDDAQ to allow the use of an alternative baseline. NDDAQ agreed to the alternative baseline. The alternative baseline and post-control scenarios are based upon various control technology emission reductions being applied to emissions from burning future coal at a heat input equal to the 100% of the boiler design capacity rating.

We agree with NDDAQ's estimates of control effectiveness on current lignite. However, we believe that higher control efficiency is warranted for the future lower quality (3.90 lb/mmBtu) lignite.

Step 4: Evaluate Impacts and Document Results
The proposed cost ($496/kW) for adding the 95%-efficient wet scrubber appears reasonable. The result of NDDAQ's assumptions is that the new wet scrubber would cost $586 per ton, which it deemed reasonable.

NDDAQ estimates for FGD on LOS #1 Cost Summary

Total Capital Cost:	$ 107,220,000
Total Capital Cost $/kW):	$ 496
O&M Cost:	$ 8,350,000
Total Annual Cost:	$ 19,310,000
Cost per Ton	$ 586

Step 5: Evaluate Visibility Results
NDDAQ did not evaluate the impact of the new wet scrubber versus the baseline condition. Therefore, we based our analysis on NDDAQ's modeling report for addition of a new scrubber to LOS #2. From that data we calculated a SO_2 control-effectiveness factor for the new wet scrubbers of 0.00004 dv/ton at Theodore Roosevelt NP and 0.00007 dv/ton cumulatively when Lostwood WA is included.[14] We have estimated that the proposed new wet scrubber will result in an approximately 1.2 dv improvement in visibility at Theodore Roosevelt NP and 2.4 dv cumulatively when Lostwood WA is included.

Determine BART
NDDAQ is proposing addition of a new wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. According to NDDAQ:

> Sulfur content of the coal was the primary constituent of concern because SO_2 emissions are directly related to the amount of sulfur in the coal and are not as related to equipment design. A forty year mining plan was analyzed to determine the future maximum annual sulfur content to be used in the BART analysis. The results indicated that future delivered coal will have a maximum annual average sulfur content of approximately 1.13% with a standard deviation of 0.12%. A 30-day rolling average SO_2 emission rate was calculated using the maximum sulfur content plus 1 standard deviation (i.e., 1.25% S).

Because NDDAQ has proposed no absolute limits on emissions, the proposed BART limits would result in a 92% reduction in current SO_2 emissions on a lb/mmBtu basis and a 90% reduction on a ton-per-year basis. If coal quality deteriorates to the anticipated worst-case (3.90 lb/mmBtu[15] uncontrolled), the proposed BART limits would default to a 95% reduction in future SO_2 emissions.

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[14] Our control-effectiveness factor is simply dv/ (tons per year reduced) and assumes a linear relationship for a given pollutant.

[15] assumes unit-specific 37.4S SO_2 emission factor

Based upon NDDAQ's analysis, we estimate that addition of the new wet scrubber yields a cost-effectiveness of $15.9 million at Theodore Roosevelt NP and $8.0 million per dv cumulatively when Lostwood WA is included.

NDDAQ Cost-Effectiveness for SO_2 from	LOS #1
Annual Cost ($million)	$ 19.31
Visibility Improvement at TRNP (dv)	1.22
Cost-Effectiveness ($million/dv)	$ 15.89
Cumulative Visibility Improvement (dv)	2.43
Cost-Effectiveness ($million/dv)	$ 7.96

We recommend 0.15 lb/mmBtu **and** 95% reduction on a 30-day rolling average basis because NDDAQ has determined that both of these levels are reasonable. Even if coal quality deteriorates to the anticipated worst-case, 96% control would still meet the 0.15 lb/mmBtu limit.[16] We also recommend short and long-term absolute (e.g., lb/hr, tpy) caps on emissions to insure that emissions will not increase greatly over time.

B. Nitrogen Oxides

Step 1: Identify All Available Technologies

We believe that NDDAQ should have included a combination of combustion controls (e.g., Low-NO_X Burners, Separated Over-Fire Air) coupled with SCR to its suite of options.

Step 2: Eliminate Technically Infeasible Options

Except as noted above, we agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on the 0.285 lb/mmBtu NO_X baseline emission rate, outlet emissions projected by NDDAQ for SCR at 0.07 lb/mmBtu represent only a 75% SCR control efficiency and a reduction of 2,225 tpy. (This is much lower than other analyses[17] in which NDDAQ has assumed 88% - 90% for SCR control effectiveness.)

We believe that a combination of combustion controls (e.g., SOFA) plus SCR can achieve 0.05 lb/mmBtu (83% NO_x removal from the 0.29 lb/mmBtu 2000 – 2008 CAM average) as opposed to the 75% estimated by NDDAQ for SCR alone. EPA's CAM data[18] (Appendix A) and vendor guarantees[19] show that SCR can typically meet 0.05

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[16] For example, West Virginia issued a permit on 3/01/04 to Longview Power to burn coal with an uncontrolled emission rate of 4.04 lb/mmBtu and meet a 24-hour average limit of 0.12 lb/mmBtu, which is equivalent to 97% control.

[17] Leland Olds #2, MR Young #1 & #2, Stanton #1

[18] We found at least 17 examples (Please see Appendix A., Table A.1.) of wall-fired boilers similar to LOS #1 that have been retrofitted with SCR and are achieving annual emission rates below 0.06 lb/mmBtu. We were able to find 2006 hourly emissions in EPA's CAM database for 14 of those EGUs, and charts showing those emissions are included in the wall-fired boilers portion of Appendix A. We believe that inspection of the data leads to the conclusion that these SCRs retrofit to eastern EGUs burning bituminous coal can

lb/mmBtu (or lower) on an annual average basis. BEPC has not provided any documentation or justification to support the higher values used in its analyses. Our review of operating data (Appendix A) suggests that a NO_X limit of 0.06 lb/mmBtu is appropriate (with a safety-margin) for LNB/OFA+SCR for a 30-day rolling average, and 0.07 lb/mmBtu for a 24-hour limit and for modeling purposes, but a lower rate (e.g., 0.05 lb/mmBtu or lower) should be used for annual average and annual cost estimates.

Step 4: Evaluate Impacts and Document Results
NDDAQ has estimated a total annual cost for its proposed basic SOFA with SNCR at $3.0 million with cost-effectiveness of $2,487 per ton, which it deemed to be reasonable.

NDDAQ estimates for Basic SOFA + SNCR on LOS #1 Cost Summary

Total Capital Cost:	$ 6,234,000
Total Capital Cost $/kW):	$ 29
O&M Cost:	$ 2,030,000
Total Annual Cost:	$ 3,099,000
Cost per Ton	$ 2,487

According to BEPC:[20]

> The capital costs to implement the various NO_x control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. In the cases with SNCR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. The capital costs for combinations of NOx reduction technologies evaluated were typically estimated based upon simple arithmetic addition of the individual unit output capital cost factors for these technologies, multiplied by the nameplate capacity ratings of the steam-electric generating units at Leland Olds Station. These cost estimates were adjusted for inflation where appropriate (to 2005$), and are considered to be study grade, which is + or – 30% accuracy, or better.

For its LOS #1 SCR with reheat cost estimates, NDDAQ simply scaled the costs estimated by BEPC for the ASOFA+tail-end SCR with reheat option at LOS #2 based on the electrical output.[21] (Please see our discussion of the LOS #2 NO_x control cost estimates.) As a result, the $377 - $388/kW capital cost estimates actually used by BEPC are much higher than suggested by available information (Please see Appendix B cost summaries.) which suggests SCR costs ranging from $50 - $267/kW. BEPC has provided no justification for these extraordinarily high costs. Furthermore, neither BEPC nor NDDAQ provide any basis for their operating cost estimates which are roughly double those we estimated by applying the methods recommended by EPA in its Control Cost Manual. (Please see Appendix B.) NDDAQ has estimated a total annual cost for low-dust

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typically reduce NO_x emissions by 90% and achieve 0.05 lb/mmBtu (or lower) on a 30-day rolling average basis during the eastern ozone season.

[19] Minnesota Power has stated in its Taconite Harbor BART analysis that "The use of an SCR is expected to achieve a NO_X emission rate of 0.05 lb/mmBtu based on recent emission guarantees offered by SCR system suppliers."

[20] from Burns & McDonnel 8/2006 **A2.1 Capital Cost Estimates for NO_x Controls**

[21] However, it is likely that this approach overestimated costs because of the higher cost of ASOFA at LOS #2 relative to SOFA at LOS #1.

SCR with reheat at $21.5 – 31.0 million. The result of NDDAQ's assumptions is that SCR would cost $9,600 - 14,000 per ton, which it deemed to be excessively costly.

NDDAQ estimates for SCR w Reheat on LOS #1 Cost Summary		
Cost	low	high
Total Capital Cost:	$ 81,392,727	$ 83,847,273
Total Capital Cost $/kW):	$ 377	$ 388
Catalyst ($/m^3)	$ 7,500	$ 7,500
Catalyst Life (hours)	$ 8,000	$ 4,000
Electricity ($/MWh)	$ 50	$ 50
Ammonia ($/ton)	$ 750	$ 750
Natural Gas ($/mcf)	$ 8	$ 12
O&M Cost:	$ 12,091,091	$ 19,867,091
Total Annual Cost:	$ 21,517,000	$ 31,011,000
Cost per Ton	$ 9,669	$ 13,936

In the absence of supporting documentation by BEPC or NDDAQ, as recommended by the BART Guidelines, we applied the methods described in Section 4.2 of EPA's Control Cost Manual and estimated a capital cost range of $101 - $142/kW which is much more consistent with available information. (Please see Appendix B.) We also estimated a total annual cost for basic SOFA+SCR with reheat at $6.5 – $15.0 million and $3,275 – $7,563 per ton.[22]

NPS estimates for SCR w Reheat on LOS #1 Cost Summary			
Cost	low	mid	high
Total Capital Cost:	$ 21,792,974	$ 21,792,974	$ 30,606,301
Total Capital Cost $/kW):	$ 101	$ 101	$ 142
Catalyst ($/m^3)	$ 3,000	$ 3,000	$ 7,500
Catalyst Life (hours)	$ 24,000	$ 8,000	$ 4,000
Electricity ($/MWh)	$ 38	$ 38	$ 50
Ammonia ($/ton)	$ 304	$ 304	$ 750
Natural Gas ($/mcf)	$ 8	$ 10	$ 12
O&M Cost:	$ 4,440,089	$ 5,634,987	$ 12,132,706
Total Annual Cost:	$ 6,512,534	$ 7,707,432	$ 15,037,898
Cost per Ton	$ 3,275	$ 3,876	$ 7,563

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[22] The low end of this range, which we believe to be more representative of likely costs, is based upon an estimated 1,988 tpy reduction (@ 0.05 lb/mmBtu) and these operating costs estimated by NPS:

- Catalyst = $3,000/cubic meter (estimated by PacifiCorp in its BART analyses for its Wyoming EGUs) replaced every 24,000 hours[22]
- Electricity = $38/MWh (estimated by BEPC in its 8/2006 BART report)
- Ammonia = $304.45/ton (estimated by BEPC in its 8/2006 BART report)
- Natural gas = 56,455 mcf/hr @ $8/mcf from EIA forecast to 2030

Step 5: Evaluate Visibility Results
Based upon data supplied by BEPC and by NDDAQ, we have estimated that the proposed basic SOFA+SNCR will result in an approximately 0.1 dv improvement in visibility at Theodore Roosevelt NP and 0.2 dv cumulatively when Lostwood WA is included.

Contrary to the BART Guidelines, NDDAQ did not evaluate the visibility benefits of any of the technically-feasible options except for the proposed basic SOFA+SNCR. However, our review of NDDAQ visibility modeling yields a NO_x control-effectiveness factor for basic SOFA+SNCR of 0.00010 dv/ton at Theodore Roosevelt NP and 0.00019 dv/ton cumulatively when Lostwood WA is included. By applying the NO_x control-effectiveness factor to NDDAQ's estimated 2,225 tpy reduction from basic SOFA+SCR with reheat, we have estimated that addition of basic SOFA+SCR with reheat will result in an approximately 0.2 dv improvement in visibility at Theodore Roosevelt NP and 0.4 dv cumulatively when Lostwood WA is included.

Determine BART
Presumptive BART for this large wall-fired EGU burning lignite is 0.29 lb/mmBtu. NDDAQ is proposing that BART is an emission limit of 0.19 lb/10^6 Btu on a 30-day rolling average basis. Because NDDAQ has proposed no absolute limits on emissions, the proposed BART limits would result in a 30% reduction in current NO_x emissions on a lb/mmBtu basis and a 13% reduction on a ton-per-year basis.

Based upon NDDAQ's analysis, addition of the proposed basic SOFA+SNCR yields a cost-effectiveness of $25.6 million per dv at Theodore Roosevelt NP and $13.2 million per dv cumulatively when Lostwood WA is included.

NDDAQ Cost-Effectiveness Estimates for Basic SOFA+SNCR	**LOS #1**
Annual Cost ($million)	$ 3.10
Visibility Improvement at TRNP (dv)	0.11
Cost-Effectiveness ($million/dv)	$ 27.26
Cumulative Visibility Improvement (dv)	0.23
Cost-Effectiveness ($million/dv)	$ 13.59

NDDAQ rejected tail-end SCR with reheat on the basis of excessive cost. NDDAQ's analysis of addition of SCR with reheat yields a cost-effectiveness of $99.6 – $143.5 million per dv at Theodore Roosevelt NP and $51.2 – $73.8 million per dv cumulatively when Lostwood WA is included.

Cost-Effectiveness for SCR with Reheat on LOS Unit #1	NDDAQ		NPS		
	low	high	low	mid	high
Annual Cost ($million)	$ 21.52	$ 31.01	$ 6.80	$ 7.71	$ 15.04
Visibility Improvement at TRNP (dv)	0.20	0.20	0.62	0.62	0.61
Cost-Effectiveness ($million/dv)	$ 106.01	$ 152.78	$ 7.68	$ 9.16	$ 19.78
Cumulative Visibility Improvement (dv)	0.41	0.41	1.08	1.08	1.08
Cost-Effectiveness ($million/dv)	$ 52.85	$ 76.17	$ 4.37	$ 5.20	$ 11.24

NPS' analysis of addition of basic SOFA+SCR with reheat yields a cost-effectiveness of $7.7 – $19.8 million per dv at Theodore Roosevelt NP and $4.4 – $11.2 million per dv cumulatively when Lostwood WA is included.[23] We would normally consider costs above $20 million/dv to be above the average that most states/sources are proposing, but believe that these results warrant further analysis, as we will discuss in more detail with respect to LOS #2.

<u>Conclusions & Recommendations for LOS #1</u>

- NDDAQ is proposing addition of a new wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu **<u>or</u>** 95% reduction on a 30-day rolling average basis. We have estimated that the proposed new wet scrubber will result in an approximately 1.2 dv improvement in visibility at Theodore Roosevelt NP and 2.4 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubbers, but recommend that the limits require **<u>both</u>** 95% control **<u>and</u>** 0.15 lb/mmBtu, as well as specific caps on emissions.
- Presumptive NO_x BART for LOS #1 is 0.29 lb/mmBtu. NDDAQ is proposing that BART is an emission limit of 0.19 lb/10^6 Btu on a 30-day rolling average basis; this would improve visibility by 0.12 dv at Theodore Roosevelt NP and 0.24 dv cumulatively when Lostwood WA is included.
- Based upon NDDAQ's analysis, addition of the proposed basic SOFA+SNCR to LOS #1 yields a cost-effectiveness of $25.6 million per dv at Theodore Roosevelt NP and $13.2 million per dv cumulatively when Lostwood WA is included. NDDAQ has not adequately considered the visibility benefits of the control strategies it evaluated. NPS' analysis of addition of basic SOFA+SCR with reheat yields a cost-effectiveness of $12.6 – $32.3 million per dv cumulatively. We would normally consider costs above $20 million/dv to be above the average that most states/source are proposing, but believe that these results warrant further analysis, as we will discuss in more detail with respect to LOS #2.
- NDDAQ underestimated the effectiveness of adding SCR to LOS #1. Outlet emissions projected by NDDAQ for SCR at 0.07 lb/mmBtu represent only a 75% SCR control efficiency We believe that a combination of combustion controls (e.g., SOFA) plus SCR can achieve 0.05 lb/mmBtu, and represents BART.

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[23] Our estimates were based upon the average NO_x emission rate in the CAM database for 2000 – 2008 and thus are significantly lower than the baseline emission estimated used by NDDAQ. As a consequence, our emission reductions are less, on a tpy basis, and our cost-effectiveness is negatively affected.

- NDDAQ overestimated the costs associated with adding SCR to LOS #1.Our application of the EPA Control Cost Manual yielded much lower cost estimates for SCR. Many of the costs associated with SCR presented by BEPC and NDDAQ were much higher than we have seen presented at similar facilities and were not supported by BEPC's documentation. More reliance should be placed upon use of the EPA Control Cost Manual when the source fails, as BEPC did for LOS, to provide sufficient supporting documentation of its costs.

Leland Olds Unit #2

Unit #2 is a cyclone furnace and is rated at 440 MW (gross) output; current emission control equipment consists of an ESP. Of 3,558 units in EPA's CAM database in 2008, the LOS #2 ranked #34 for SO_2 at 30,022 tons and #49 for NO_x at 8,210 tons. According to modeling results provided by BEPC, emissions from LOS #2 cause 3.4 dv of impairment in visibility at Theodore Roosevelt NP and 6.8 dv cumulatively when Lostwood WA is included.

However, NPS model results predict that emissions from LOS #2 cause 7.9 dv of impairment in visibility at Theodore Roosevelt NP and 13.5 dv cumulatively when Lostwood WA is included.[24]

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

We agree that NDDAQ has chosen a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options

We agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

We agree with NDDAQ's estimates of control effectiveness on current lignite. However, we believe that higher control efficiency is warranted for the future lower quality (4.04 lb/mmBtu) lignite.

Step 4: Evaluate Impacts and Document Results

The proposed costs ($335/kW) for adding the scrubbers appear reasonable. However, NDDAQ did not include any estimates of cost-effectiveness because it contends that it chose the most efficient option. We used NDDAQ's data to estimate that the new scrubber would cost $463/ton.

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[24] Our analysis was based upon the design values presented by BEPC in Table 1.2-1 of its 8/06 BART report. BEPC has determined that historic rates are not representative of future maximum 24-hour emissions and has requested NDDAQ to allow the use of an alternative baseline. NDDAQ agreed to the alternative baseline. The alternative baseline and post-control scenarios are based upon various control technology emission reductions being applied to emissions from burning future coal at a heat input equal to the 100% of the boiler design capacity rating.

NDDAQ Estimates for FGD on LOS #2 Cost Summary

Total Capital Cost:	$ 147,600,000
Total Capital Cost $/kW):	$ 335
O&M Cost:	$ 14,210,000
Total Annual Cost:	$ 29,840,000
Cost per Ton	$ 463

Step 5: Evaluate Visibility Results
Based upon data supplied by BEPC and by NDDAQ, we have estimated that the proposed scrubber will result in an approximately 2.4 dv improvement in visibility at Theodore Roosevelt NP and 4.7 dv cumulatively when Lostwood WA is included. The NDDAQ visibility modeling yields a control-effectiveness factor for the new wet scrubber of 0.00004 dv/ton at Theodore Roosevelt NP and 0.00007 dv/ton cumulatively when Lostwood WA is included.

We re-modeled LOS #2 assuming that the new wet scrubber would reduce SO_2 emissions to 0.15 lb/mmBtu and held all other emissions to their baseline rates. Our results estimate that the scrubber would improve visibility by 5.6 dv at Theodore Roosevelt NP and 9.4 dv cumulatively when Lostwood WA is included. This yields a control-effectiveness factor for the new wet scrubber of 0.00009 dv/ton at Theodore Roosevelt NP and 0.00015 dv/ton cumulatively when Lostwood WA is included. We suggest that we investigate these major differences in modeling results further with NDDAQ.

Determine BART
NDDAQ is proposing to limit SO_2 emissions to 0.15 lb/mmBtu <u>or</u> a 95% reduction on a 30-day rolling average basis. As with Unit #1, sulfur content of the coal was the primary concern.

Because NDDAQ has proposed no absolute limits on emissions, the proposed BART limits would result in a 92% reduction in current SO_2 emissions on a lb/mmBtu basis and an 89% reduction on a ton-per-year basis. If coal quality deteriorates to the anticipated worst-case (4.04 lb/mmBtu[25] uncontrolled), the proposed BART limits would default to a 95% reduction in future SO_2 emissions.

Based upon NDDAQ's analysis, addition of the new wet scrubber yields a cost-effectiveness of $12.6 million, and $6.3 million per dv cumulatively when Lostwood WA is included.

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[25] assumes unit-specific 38.7S SO_2 emission factor

NDDAQ Cost-Effectiveness for SO_2 from	LOS #2
Annual Cost ($million)	$ 29.84
Visibility Improvement at TRNP (dv)	2.38
Cost-Effectiveness ($million/dv)	$ 12.55
Cumulative Visibility Improvement (dv)	4.74
Cost-Effectiveness ($million/dv)	$ 6.29

We recommend 0.15 lb/mmBtu **and** 95% reduction on a 30-day rolling average basis because NDDAQ has determined that both of these levels are reasonable. Even if coal quality deteriorates to the anticipated worst-case, 96% control would still meet the 0.15 lb/mmBtu limit. We also recommend short and long-term absolute (e.g., lb/hr, tpy) caps on emissions to insure that emissions will not increase greatly over time.

B. Nitrogen Oxides

Step 1: Identify All Available Technologies

We agree that NDDAQ has chosen a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options

We agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on the 0.67 lb/mmBtu NO_X baseline emission rate, outlet emissions projected by NDDAQ for SCR at 0.07 lb/mmBtu represent a 90% SCR control efficiency and a reduction of 10,821 tpy. We suggest that, if ASOFSA can reduce emissions to 0.5 lb/mmBtu as estimated by NDDAQ, then addition of SCR at 90% as assumed by NDDAQ could bring emissions down to 0.05 lb/mmBtu.

Step 4: Evaluate Impacts and Document Results

NDDAQ has estimated a total annual cost for ASOFA with SNCR at $10.9 million with cost-effectiveness of $1,659 per ton, which it deemed to be reasonable.

NDDAQ Estimates for ASOFA + SNCR on LOS #2 Cost Summary

Total Capital Cost:	$ 16,800,000
Total Capital Cost $/kW):	$ 38
O&M Cost:	$ 7,830,000
Total Annual Cost:	$ 10,870,000
Cost per Ton	$ 1,659

BEPC submitted a separate analysis of ASOFA+tail-end SCR with reheat to NDDAQ in May 2009. (This became the basis for NDDAQ's scaling approach to its LOS #1 cost estimates.) BEPC based its capital cost estimates upon assumed ranges of costs for the control options evaluated. However, BEPC did not explain the origin of its cost ranges, and we believe that the ">$300/kW" estimate for ASOFA+tail-end SCR with reheat may be too high. In fact, the $377 - $388/kW capital cost estimates actually used by BEPC are much higher than suggested by available information (see Appendix B cost summaries) which suggests SCR costs ranging from $50 - $267/kW. BEPC has provided no justification for these extraordinarily high costs. Furthermore, neither BEPC nor NDDAQ provide any basis for their operating cost estimates which are roughly double those we estimated by applying the methods recommended in the Control Cost Manual. (Please see Appendix B.) NDDAQ has estimated a total annual cost for ASOFA+tail-end SCR with reheat at $43.8 – 63.2 million. The result is that ASOFA+tail-end SCR with reheat would cost over $4,000 - $5,800 per ton, which it deemed to be excessively costly.

NDDAQ Estimates for ASOFA + SCR with Reheat on LOS #2 Cost Summary		
	low	high
Total Capital Cost:	$ 165,800,000	$ 170,800,000
Total Capital Cost $/kW):	$ 377	$ 388
Catalyst ($/m^3)	$ 7,500	$ 7,500
Catalyst Life (hours)	8,000	4,000
Electricity ($/MWh)	$ 50.00	$ 50.00
Ammonia ($/ton)	$ 750.00	$ 750.00
Natural Gas ($/mcf)	$ 8.00	$ 12.00
O&M Cost:	$ 24,630,000	$ 40,470,000
Total Annual Cost:	$ 43,830,000	$ 63,170,000
Cost per Ton	$ 4,051	$ 5,838

In the absence of supporting documentation by BEPC or NDDAQ, as recommended by the BART Guidelines, we applied the methods described in the Control Cost Manual to the ASOFA+tail-end SCR with reheat option and estimated a capital cost range of $84 - $131/kW which is much more consistent with available literature which suggests SCR costs ranging from $50 - $267/kW. We applied the methods recommended by EPA and its Control Cost manual and estimated total annual costs for ASOFA+tail-end SCR with reheat at $13.8 – $28.7 million and $1,773 - $3,807 per ton.[26] (Please see Appendix B.)

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[26] The low end of this range, which we believe to be more representative of likely costs, is based upon an estimated 7,530 tpy reduction (@ 0.06 lb/mmBtu)[26] and these operating costs estimated by NPS:

- Catalyst = $3,000/cubic meter (estimated by PacifiCorp in its BART analyses for its Wyoming EGUs) replaced every 24,000 hours
- Electricity = $38/MWh (estimated by BEPC in its 8/2006 BART report)
- Ammonia = $304.45/ton (estimated by BEPC in its 8/2006 BART report)
- Natural gas = 115,000 mcf/hr @ $8/mcf from EIA forecast to 2030

NPS Estimates for ASOFA + SCR with Reheat on LOS #2 Cost Summary			
	low	mid	high
Total Capital Cost:	$ 37,089,544	$ 37,089,544	$ 57,541,216
Total Capital Cost $/kW):	$ 84	$ 84	$ 131
Catalyst ($/m^3)	$ 3,000	$ 3,000	$ 7,500
Catalyst Life (hours)	24,000	8,000	4,000
Electricity ($/MWh)	$ 38.00	$ 38.00	$ 50.00
Ammonia ($/ton)	$ 304.45	$ 304.45	$ 750.00
Natural Gas ($/mcf)	$ 8.00	$ 10.00	$ 12.00
O&M Cost:	$ 8,918,956	$ 11,141,667	$ 22,307,414
Total Annual Cost:	$ 13,349,450	$ 15,572,161	$ 28,668,401
Cost per Ton	$ 1,773	$ 2,068	$ 3,807

Step 5: Evaluate Visibility Results

Based upon data supplied by BEPC and by NDDAQ, we have estimated that the proposed ASOFA + SNCR will result in an approximately 0.6 dv improvement in visibility at Theodore Roosevelt NP and 1.2 dv cumulatively when Lostwood WA is included. Our review of NDDAQ visibility modeling yields a NO_x control-effectiveness factor for the proposed combustion controls of 0.0004 dv/ton at Theodore Roosevelt NP and 0.0008 dv/ton cumulatively when Lostwood WA is included.

We re-modeled LOS #2 assuming that the proposed ASOFA + SNCR would reduce NO_X emissions to 0.35 lb/mmBtu. (We modeled SO_2 at 0.15 lb/mmBtu and held all other emissions to their baseline rates.) Our results estimate that ASOFA + SNCR would improve visibility by 1.1 dv at Theodore Roosevelt NP and 1.7 dv cumulatively when Lostwood WA is included.

Based upon data supplied by BEPC and by NDDAQ, we have estimated that addition of ASOFA+tail-end SCR with reheat will result in an approximately 1.1 dv improvement in visibility at Theodore Roosevelt NP and 2.0 dv cumulatively when Lostwood WA is included. Our review of NDDAQ visibility modeling for LOS #2 yields a NO_x control-effectiveness factor for the ASOFA+tail-end SCR with reheat option of 0.00010 dv/ton at Theodore Roosevelt NP and 0.00019 dv/ton cumulatively when Lostwood WA is included.

We re-modeled LOS #2 assuming that ASOFA + SCR would reduce NO_X emissions to 0.06 lb/mmBtu. (We modeled SO_2 at 0.15 lb/mmBtu and held all other emissions to their baseline rates.) Our results estimate that ASOFA + SCR would improve visibility by 2.3 dv at Theodore Roosevelt NP and 4.1 dv cumulatively when Lostwood WA is included. This yields a control-effectiveness factor for ASOFA + SNCR of 0.00031 dv/ton at Theodore Roosevelt NP and 0.00054 dv/ton cumulatively when Lostwood WA is included. Our higher control-effectiveness results show that we are estimating that removing a ton of NO_x has greater benefits than estimated by BEPC/NDDAQ.

Determine BART

Presumptive BART for this large cyclone furnace is based upon application of SCR to achieve 0.10 lb/mmBtu on a 30-day rolling average basis. According to the BART Guidelines, "The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and ***lignite*** [emphasis added] should enable these units to cost-effectively meet NO_x rates of 0.10 lb/mmBtu."

Instead of meeting the presumptive BART limit of 0.10 lb/mmBtu, NDDAQ is proposing application of SNCR and Advanced SOFA (ASOFA) to limit NO_x emissions to 0.35 lb/mmBtu on a 30-day rolling average basis. This equates to a cost-effectiveness of $17.1 million per dv at Theodore Roosevelt NP and $8.8 million per dv cumulatively when Lostwood WA is included.

NDDAQ Cost-Effectiveness for ASOFA+SNCR	**LOS #2**
Annual Cost ($million)	$ 10.87
Visibility Improvement at TRNP (dv)	0.64
Cost-Effectiveness ($million/dv)	$ 17.08
Cumulative Visibility Improvement (dv)	1.24
Cost-Effectiveness ($million/dv)	$ 8.78

Because NDDAQ has proposed no absolute limits on emissions, the proposed BART limits would result in a 43% reduction in current NO_x emissions on a lb/mmBtu basis and a 35% reduction on a ton-per-year basis.

NDDAQ rejected ASOFA+tail-end SCR with reheat on the basis of excessive cost. NDDAQ's analysis of addition of SCR with reheat yields a cost-effectiveness of $41.7 – $60.1 million per dv at Theodore Roosevelt NP and $21.4 – $30.9 million per dv cumulatively when Lostwood WA is included.

Cost-Effectiveness for SCR with Reheat on LOS #2	**NDDAQ**		**NPS**		
	low	**high**	**low**	**mid**	**high**
Annual Cost ($million)	$ 43.83	$ 63.17	$ 13.35	$ 15.57	$ 28.71
Visibility Improvement at TRNP (dv)	0.99	0.99	2.33	2.33	2.33
Cost-Effectiveness ($million/dv)	$ 44.41	$ 64.00	$ 3.83	$ 4.78	$ 9.59
Cumulative Visibility Improvement (dv)	1.98	1.98	4.10	4.10	4.10
Cost-Effectiveness ($million/dv)	$ 22.14	$ 31.91	$ 2.18	$ 2.72	$ 5.45

NPS' analysis of addition of basic ASOFA+SCR with reheat and using NDDAQ modeling results yields a cost-effectiveness of $3.8 – $9.6 million per dv at Theodore Roosevelt NP and $2.2 – $5.5 million per dv cumulatively when Lostwood WA is included.[27] We believe that our cost estimates indicate that addition of SCR with reheat is

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[27] Our estimates were based upon the average NO_x emission rate in the CAM database for 2000 – 2008 and thus are significantly lower than the baseline emission estimated used by NDDAQ. As a consequence, our emission reductions are less, on a tpy basis, and our cost-effectiveness is negatively affected.

reasonable based upon BART determinations and proposals we have seen nationwide to date. We also believe that the great disparity between modeling results produced by BEPC/NDDAQ and NPS requires resolution.

Conclusions & Recommendations for LOS #2

- NDDAQ is proposing to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. We recommend 0.15 lb/mmBtu **and** 95% reduction on a 30-day rolling average basis.
- Based upon data supplied by NDDAQ, we have estimated that the proposed scrubber will result in an approximately 2.4 dv improvement in visibility at Theodore Roosevelt NP and 4.7 dv cumulatively when Lostwood WA is included.
- We re-modeled LOS #2 assuming that the new wet scrubber would reduce SO_2 emissions to 0.15 lb/mmBtu and held all other emissions to their baseline rates. Our results estimate that the scrubber would improve visibility by 5.6 dv at Theodore Roosevelt NP and 9.4 dv cumulatively when Lostwood WA is included.
- Instead of meeting the presumptive NO_x BART limit of 0.10 lb/mmBtu, NDDAQ is proposing application of SNCR and ASOFA to limit NO_x emissions to 0.35 lb/mmBtu on a 30-day rolling average basis.
- Based upon data supplied by BEPC and by NDDAQ, we have estimated that the proposed ASOFA + SNCR will result in an approximately 0.64 dv improvement in visibility at Theodore Roosevelt NP and 1.24 dv cumulatively when Lostwood WA is included.
- We agree with NDDAQ's estimates of control effectiveness, but suggest that, if ASOFSA can reduce emissions to 0.5 lb/mmBtu as estimated by NDDAQ, then addition of SCR at 90% as assumed by NDDAQ could bring emissions down to 0.05 lb/mmBtu.
- NDDAQ overestimated the costs associated with adding SCR to LOS #2.Our application of the EPA Control Cost Manual yielded much lower cost estimates for SCR. Many of the costs associated with SCR presented by BEPC and NDDAQ were much higher than we have seen presented at similar facilities and were not supported by BEPC's documentation. More reliance should be placed upon use of the EPA Control Cost Manual when the source fails, as BEPC did for LOS #2, to provide sufficient supporting documentation of its costs.
- We re-modeled LOS #2 and estimate that ASOFA + SCR would improve visibility by 2.3 dv at Theodore Roosevelt NP and 4.1 dv cumulatively when Lostwood WA is included. Our higher control-effectiveness results show that we are estimating that removing a ton of NO_x has greater benefits than estimated by BEPC/NDDAQ.
- NPS' analysis of addition of ASOFA+SCR with reheat and using NDDAQ modeling results yields a cost-effectiveness of \$4.0 – \$9.6 million per dv at Theodore Roosevelt NP and \$2.3 – \$5.5 million per dv cumulatively when Lostwood WA is included. We believe that our cost estimates indicate that addition of SCR with reheat is reasonable based upon BART determinations and proposals we have seen nationwide to date.
- The great disparity between modeling results produced by BEPC/NDDAQ and NPS requires resolution.

Minnkota Power Cooperative Milton R. Young Station Units #1 & #2

Minnkota Power Cooperative (Minnkota) operates Milton R. Young Station (MRYS) Units #1 and Square Butte Electric Cooperative (Square Butte) operates MRYS Unit #2 near Center, ND. MRYS is located within 300 km of two Class I areas, Lostwood National Wildlife Refuge Wilderness Area (WA) administered by the U.S. Fish & Wildlife Service and Theodore Roosevelt National Park (NP) administered by the National Park Service.

Both units are cyclone boilers fired with ND lignite. Of 1,228 power plants in EPA's Clean Air Markets (CAM) database in 2008, MRYS ranked #75 for sulfur dioxide (SO_2) at 28,910 tons and #41 for nitrogen oxides (NO_x) at 16,793 tons. According to modeling results provided by Minnkota, emissions from MRYS cause 5.8 dv of impairment in visibility at Theodore Roosevelt NP and 10.6 dv cumulatively when Lostwood WA is included.

On April 24, 2006, EPA, the U. S. Department of Justice, NDDAQ, and Minnkota reached a settlement (Consent Decree = CD) of a New Source Review enforcement action. A Best Available Control Technology (BACT) analysis was required to be submitted by Minnkota within the following six months. That BACT analysis was submitted along with the BART analysis and is the basis for the BART analysis. However, a revised BACT analysis is expected soon.

Minnkota claims that the MRYS facility is not a "750 MW power plant" and thus does not have to meet EPA's presumptive BART limits. This claim is based upon the nameplate capacities of the BART-eligible units at MRYS, but it avoids the issue that, by modifying those units, MRYS now substantially exceeds the nameplate capacities. If the presumptive BART limits were triggered only by nameplate capacity, a source such as MRYS would be able to increase its capacity without ever triggering presumptive BART. Because MRYS is capable of generating more than 750 MW, presumptive BART limits apply.

Milton R. Young Station Unit #1

MRYS Unit #1 is a lignite-fired cyclone boiler rated at 257 MW (gross) output; current emission control equipment consists of an ESP. Out of 3,558 units in EPA's CAM database in 2008, MRYS #1 ranked #82 for SO_2 at 19,608 tons and #50 for NO_x at 8,193 tons. According to modeling results provided by Minnkota, emissions from MRYS #1 cause 3.0 dv of impairment in visibility at Theodore Roosevelt NP and 5.3 dv cumulatively when Lostwood WA is included.

A. Sulfur Dioxide

Step 1: Identify All Available Technologies
We agree that NDDAQ has chosen a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options
We agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology
We agree with NDDAQ's estimates of control effectiveness.

Step 4: Evaluate Impacts and Document Results
The proposed cost ($435/kW) for adding the 95%-efficient wet scrubber appears reasonable. The result of NDDAQ's assumptions is that the new wet scrubber would cost $1,105 per ton, which it deemed reasonable.

NDDAQ estimates for FGD on MRYS #1 Cost Summary

Total Capital Cost:	$ 111,776,000
Total Capital Cost $/kW):	$ 435
O&M Cost:	$ 10,282,000
Total Annual Cost:	$ 22,584,000
Cost per Ton	$ 1,105

Step 5: Evaluate Visibility Results
Our analysis of Minnkota's modeling report determined that the proposed new wet scrubber will result in an approximately 1.8 dv improvement in visibility at Theodore Roosevelt NP and 3.2 dv cumulatively when Lostwood WA is included.

Determine BART
NDDAQ proposed adding a new wet scrubber that achieves 95% reduction on a 30-day rolling average basis.

Based upon NDDAQ's analysis, we estimate that addition of the new wet scrubber yields a cost-effectiveness of $12.3 million per dv at Theodore Roosevelt NP and $7.0 million per dv cumulatively when Lostwood WA is included.

NDDAQ Cost-Effectiveness for SO_2 from	**MRYS #1**
Annual Cost ($million)	$ 22.58
Visibility Improvement at TRNP (dv)	1.83
Cost-Effectiveness ($million/dv)	$ 12.33
Cumulative Visibility Improvement (dv)	3.19
Cost-Effectiveness ($million/dv)	$ 7.09

We recommend addition of short and long-term absolute (e.g., lb/hr, tpy) caps on emissions to insure that emissions will not increase greatly over time.

B. Nitrogen Oxides

Step 1: Identify All Available Technologies
We agree that NDDAQ has chosen a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options
We agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology
Based on the 0.849 lb/mmBtu NO_X baseline emission rate, outlet emissions projected by NDDAQ for SCR at 0.085 lb/mmBtu represent a 90% SCR control efficiency and a reduction of 8,129 tpy. We agree with NDDAQ's estimates of control effectiveness, but suggest that, if ASOFSA can reduce emissions to 0.513 lb/mmBtu as estimated by NDDAQ, then addition of SCR at 90% could bring emissions down to 0.05 lb/mmBtu.

Step 4: Evaluate Impacts and Document Results
NDDAQ has estimated a total annual cost for its proposed ASOFA with SNCR at $7.4 million with cost-effectiveness of $2,541 per ton, which it deemed to be reasonable.

NDDAQ Estimates for ASOFA + SNCR on MRYS #1

Total Capital Cost:	$ 8,113,000
Total Capital Cost $/kW):	$ 32
O&M Cost:	$ 5,417,000
Total Annual Cost:	$ 7,472,000
Cost per Ton	$ 2,541

For its MRYS #1 SCR cost estimates, NDDAQ scaled the costs estimated for the ASOFA+tail-end SCR with reheat option at Leland Olds Station (LOS) #2 based on the electrical output. (Please see our discussion of the LOS #2 NO_x cost estimates.) As a result, the $377 - $388/kW capital cost estimates used by NDDAQ are much higher than suggested by available information (Please see Appendix B.) which suggests SCR costs ranging from $50 - $267/kW. NDDAQ has provided no justification for these extraordinarily high costs. Furthermore, NDDAQ did not provide any basis for their operating cost estimates which are roughly double those we estimated by applying the methods recommended the Control Cost Manual. NDDAQ has estimated a total annual cost for SCR with reheat at $25.6 – 36.9 million. The result of NDDAQ's assumptions is that SCR would cost $3,100 – 4,600 per ton, which it deemed to be reasonable.

SCR on MRYS #1 Cost Summary	**NDDAQ**		**NPS**
	low	high	
Total Capital Cost:	$ -	$ -	$ 17,762,559
Total Capital Cost $/kW):	$ -	$ -	$ 69
Catalyst ($/m^3)	$ 7,500	$ 7,500	$ 3,000
Catalyst Life (hours)	$ 8,000	$ 4,000	$ 24,000
Electricity ($/MWh)	$ 50	$ 50	$ 38
Ammonia ($/ton)	$ 750	$ 750	$ 304
Natural Gas ($/mcf)	$ 8	$ 12	$ 8
O&M Cost:	$ -	$ -	$ 5,578,686
Total Annual Cost:	$ 25,600,000	$ 36,897,000	$ 9,744,345
Cost per Ton	$ 3,149	$ 4,539	$ 1,028

In the absence of supporting documentation by NDDAQ, as recommended by the BART Guidelines, we applied the methods described in the Control Cost Manual and estimated a capital cost of $69/kW which is much more consistent with available information. (Please see Appendix B.) We also estimated a total annual cost for ASOFA+SCR with reheat at $9.7 million and $1,028 per ton.

Step 5: Evaluate Visibility Results

Based upon data supplied by Minnkota and by NDDAQ, we have estimated that the proposed ASOFA+SNCR will result in an approximately 0.12 dv improvement in visibility at Theodore Roosevelt NP and 0.24 dv cumulatively when Lostwood WA is included.

Contrary to the BART Guidelines, NDDAQ did not evaluate the visibility benefits of any of the technically-feasible options except for the proposed ASOFA+SNCR. However, our review of NDDAQ visibility modeling yields a NO_x control-effectiveness factor for ASOFA+SNCR of 0.00020 dv/ton at Theodore Roosevelt NP and 0.00032 dv/ton cumulatively when Lostwood WA is included. By applying the NO_x control-effectiveness factor to NDDAQ's estimated 8,129 tpy reduction from ASOFA+SCR with reheat, we have estimated that addition of ASOFA+SCR with reheat will result in an approximately 1.7 dv improvement in visibility at Theodore Roosevelt NP and 2.6 dv cumulatively when Lostwood WA is included.

Determine BART

Presumptive BART for this cyclone-fired EGU burning lignite is 0.10 lb/mmBtu. NDDAQ is proposing that BART is an emission limit of 0.36 lb/mmBtu on a 30-day rolling average basis. Because NDDAQ has proposed no absolute limits on emissions, the proposed BART limits would result in a 42% reduction on a ton-per-year basis.

NDDAQ proposes that NO_X emissions be limited to 2,070.2 lb/hr on a 24-hour rolling average basis during startup. According to NDDAQ, the State of Montana in the permit for the Highwood Generating Station, EPA Region 9 in the permit for the Desert Rock Energy Center and the State of Nebraska in the Ag Soy Processing plant permit also included alternative limits for NO_x during startup and shutdown. The normal BART limit of 0.36 lb/10mmBtu will apply during all other periods including malfunctions. This is more than double the 1,152 lb/hr that would be allowed under normal operation.

However, the final (remanded) version of the Desert Rock permit states:

> Emissions from the PC boilers during startup and shutdown events shall not be subject to the emission limits in this permit which are specified in units of lb/MMBtu but shall be subject to all other limits and shall be included in the calculations of emission rates for demonstrating compliance with those limits.

We note that the approach taken by EPA regarding Desert Rock is similar to that taken by other states and limits the mass emission rate (e.g., lb/hr) to the rate under normal operation. We recommend that NDDAQ adopt this approach.

Based upon NDDAQ's analysis, addition of the proposed ASOFA+SNCR yields a cost-effectiveness of $25.6 million per dv at Theodore Roosevelt NP and $13.2 million per dv cumulatively when Lostwood WA is included.

NDDAQ Cost-Effectiveness Estimates for ASOFA+SNCR	MRYS #1
Annual Cost ($million)	$ 8.11
Visibility Improvement at TRNP (dv)	0.12
Cost-Effectiveness ($million/dv)	$ 25.61
Cumulative Visibility Improvement (dv)	0.24
Cost-Effectiveness ($million/dv)	$ 13.17

NDDAQ rejected tail-end SCR with reheat on the basis of excessive cost. NDDAQ's analysis of addition of SCR with reheat yields a cost-effectiveness of $15.4 – $22.2 million per dv at Theodore Roosevelt NP and $9.8 – $14.4 million per dv cumulatively when Lostwood WA is included.

Cost-Effectiveness for SCR with Reheat on MRYS Unit #1	NDDAQ		NPS
	low	high	
Annual Cost ($million)	$ 25.60	$ 36.90	$ 9.74
Visibility Improvement at TRNP (dv)	1.66	1.66	1.94
Cost-Effectiveness ($million/dv)	$ 15.42	$ 22.22	$ 5.03
Cumulative Visibility Improvement (dv)	2.61	2.61	3.04
Cost-Effectiveness ($million/dv)	$ 9.81	$ 14.14	$ 3.20

NPS' analysis of addition of ASOFA+SCR with reheat yields a cost-effectiveness of $5.0 million per dv at Theodore Roosevelt NP and $3.2 million per dv cumulatively when Lostwood WA is included. We believe that our cost estimates indicate that addition of SCR with reheat is reasonable based upon BART determinations and proposals we have seen nationwide to date.

Conclusions & Recommendations for MRYS #1

- NDDAQ proposed adding a new wet scrubber that achieves 95% reduction on a 30-day rolling average basis.
- We have estimated that the proposed new wet scrubber will result in an approximately 1.8 dv improvement in visibility at Theodore Roosevelt NP and 3.2 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubbers, but recommend that the limits require **both** 95% control **and** 0.15 lb/mmBtu, as well as specific caps on emissions.
- Presumptive NO_x BART for MRYS #1 is 0.10 lb/mmBtu. NDDAQ is proposing that BART is an emission limit of 0.36 lb/10^6 Btu on a 30-day rolling average basis to be met by addition of ASOFA+SNCR; this would improve visibility by 1.1 dv at Theodore Roosevelt NP and 1.7 dv cumulatively when Lostwood WA is included.

- NDDAQ proposes that NO_X emissions be limited to 2,070.2 lb/hr on a 24-hour rolling average basis during startup. We recommend that NDDAQ limit the mass emission rate (e.g., lb/hr) to the rate under normal operation.
- NDDAQ underestimated the effectiveness of adding ASOFA+SCR to MRYS #1. We suggest that ASOFSA+SCR can achieve 0.05 lb/mmBtu.
- NDDAQ overestimated the costs associated with adding SCR. In the absence of supporting documentation by NDDAQ, we also estimated a total annual cost for ASOFA+SCR with reheat at $9.7 million and $1,028 per ton.
- NPS' analysis of addition of ASOFA+SCR with reheat yields a cost-effectiveness of $5.0 million per dv at Theodore Roosevelt NP and $3.2 million per dv cumulatively when Lostwood WA is included.
- We believe that ASOFA+SCR with reheat represents BART for MRYS #1.

Milton R. Young Station Unit #2

MRYS Unit #2 is a lignite-fired cyclone boiler rated at 477 MW (gross) output; current emission control equipment consists of an ESP and a wet Flue Gas Desulfurization (FGD) system which treats 78% of the flue gas, while the remainder bypasses the scrubber and is used to reheat the stack gases. Overall sulfur dioxide (SO_2) control for Unit #2 is estimated to be about 75%. Out of 3,558 units in EPA's Clean Air Markets (CAM) database in 2008, MRYS #2 ranked #257 for SO_2 at 9,302 tons and #43 for NO_x at 8,599 tons. According to modeling results provided by Minnkota, emissions from MRYS #2 cause 2.8 dv of impairment in visibility at Theodore Roosevelt NP and 5.2 dv cumulatively when Lostwood WA is included.

A. Sulfur Dioxide

Step 1: Identify All Available Technologies
We agree that NDDAQ has chosen a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options
We agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology
We agree with NDDAQ's estimates of control effectiveness on current lignite. However, we believe that higher control efficiency is warranted for the future lower quality (3.48 lb/mmBtu) lignite.

Step 4: Evaluate Impacts and Document Results
The proposed costs ($52/kW) for upgrading the scrubber appears reasonable. NDDAQ data estimate that the scrubber upgrade would cost $565/ton.

NDDAQ Estimates for MRYS FGD Upgrade on #2 Cost Summary

Total Capital Cost:	$ 24,989,000
Total Capital Cost $/kW):	$ 52
O&M Cost:	$ 4,993,000
Total Annual Cost:	$ 8,414,000
Cost per Ton	$ 565

Step 5: Evaluate Visibility Results

Based upon data supplied by Minnkota and by NDDAQ, we have estimated that the proposed scrubber upgrade will result in an approximately 1.2 dv improvement in visibility at Theodore Roosevelt NP and 2.2 dv cumulatively when Lostwood WA is included. The NDDAQ visibility modeling yields a control-effectiveness factor for the new wet scrubber of 0.00008 dv/ton at Theodore Roosevelt NP and 0.00015 dv/ton cumulatively when Lostwood WA is included.

Determine BART

NDDAQ proposes that BART is 95% reduction **or** 0.15 lb/10^6 Btu on a 30-day rolling average basis. However, the Consent Decree requires a minimum of 90% reduction. This requirement will also be incorporated into the BART limit.

Because NDDAQ has proposed no absolute limits on emissions, the proposed BART limits would result in a 78% reduction in current SO_2 emissions on a lb/mmBtu basis and a 67% reduction on a ton-per-year basis. If coal quality deteriorates to the anticipated worst-case (3.48 lb/mmBtu uncontrolled), the proposed BART limits would default to a 96% reduction in future SO_2 emissions.

Based upon NDDAQ's analysis, addition of the new wet scrubber yields a cost-effectiveness of $7.1 million at Theodore Roosevelt NP and $3.8 million per dv cumulatively when Lostwood WA is included.

NDDAQ Cost-Effectiveness for SO_2 from	MRYS #2
Annual Cost ($million)	$ 8.41
Visibility Improvement at TRNP (dv)	1.19
Cost-Effectiveness ($million/dv)	$ 7.10
Cumulative Visibility Improvement (dv)	2.20
Cost-Effectiveness ($million/dv)	$ 3.82

We recommend 0.15 lb/mmBtu **and** 95% reduction on a 30-day rolling average basis because NDDAQ has determined that both of these levels are reasonable. Even if coal quality deteriorates to the anticipated worst-case, 96% control would still meet the 0.15 lb/mmBtu limit. We also recommend short and long-term absolute (e.g., lb/hr, tpy) caps on emissions to insure that emissions will not increase greatly over time.

B. Nitrogen Oxides

Step 1: Identify All Available Technologies

We agree that NDDAQ has chosen a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options

We agree with NDDAQ's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

We agree with NDDAQ's estimates of control effectiveness, but suggest that, if ASOFSA can reduce emissions to 0.489 lb/mmBtu as estimated by NDDAQ, then addition of SCR at 90% could bring emissions down to 0.05 lb/mmBtu.

Step 4: Evaluate Impacts and Document Results

NDDAQ has estimated a total annual cost for ASOFA with SNCR at $11.4 million with cost-effectiveness of $1,268 per ton, which it deemed to be reasonable.

For its MRYS #2 SCR with reheat cost estimates, NDDAQ simply scaled the costs estimated for the ASOFA+tail-end SCR with reheat option at LOS #2 based on the electrical output. (Please see our discussion of the LOS #2 NO_x control cost estimates.) As a result, the $377 - $388/kW capital cost estimates actually used by NDDAQ are much higher than suggested by available information (Please see Appendix B cost summaries.). NDDAQ has provided no justification for these extraordinarily high costs. Furthermore, NDDAQ did not provide any basis for their operating cost estimates which are roughly double those we estimated by applying the methods recommended by EPA in its Control Cost Manual. (Please see Appendix B.) NDDAQ has estimated a total annual cost for low-dust SCR with reheat at $47.5 – 68.5 million. The result of NDDAQ's assumptions is that SCR would cost $3,400 – 4,900 per ton, which it deemed to be reasonable.

SCR on MRYS #2 Cost Summary	NDDAQ		NPS
	low	high	
Total Capital Cost:	$ -	$ -	$ 28,345,453
Total Capital Cost $/kW):	$ -	$ -	$ 59
Catalyst ($/m^3)	$ 7,500	$ 7,500	$ 3,000
Catalyst Life (hours)	$ 8,000	$ 4,000	$ 24,000
Electricity ($/MWh)	$ 50	$ 50	$ 38
Ammonia ($/ton)	$ 750	$ 750	$ 304
Natural Gas ($/mcf)	$ 8	$ 12	$ 8
O&M Cost:	$ -	$ -	$ 10,434,981
Total Annual Cost:	$ 47,516,000	$ 68,482,000	$ 15,599,591
Cost per Ton	$ 3,405	$ 4,907	$ 898

In the absence of supporting documentation by Minnkota or NDDAQ, as recommended by the BART Guidelines, we applied the methods described in EPA's OAQPS Control Cost Manual to the ASOFA+tail-end SCR with reheat option and estimated a capital cost range of $59 /kW which is much more consistent with available literature which suggests

SCR costs ranging from \$50 - \$267/kW. We also estimated total annual costs for ASOFA+tail-end SCR with reheat at \$15.6 million and \$898 per ton. (Please see Appendix B.)

Step 5: Evaluate Visibility Results
Based upon data supplied by Minnkota and by NDDAQ, we have estimated that the proposed ASOFA + SNCR will result in an approximately 0.7 dv improvement in visibility at Theodore Roosevelt NP and 1.4 dv cumulatively when Lostwood WA is included. Our review of NDDAQ visibility modeling yields a NO_x control-effectiveness factor for the proposed combustion controls of 0.00008 dv/ton at Theodore Roosevelt NP and 0.00015 dv/ton cumulatively when Lostwood WA is included.

Based upon data supplied by Minnkota and by NDDAQ, we have estimated that addition of ASOFA+tail-end SCR with reheat will result in an approximately 1.1 dv improvement in visibility at Theodore Roosevelt NP and 2.0 dv cumulatively when Lostwood WA is included. Our review of NDDAQ visibility modeling for MRYS #1 yields a NO_x control-effectiveness factor for the ASOFA+tail-end SCR with reheat option of 0.00010 dv/ton at Theodore Roosevelt NP and 0.00019 dv/ton cumulatively when Lostwood WA is included.

Determine BART
Presumptive BART for this large cyclone furnace is based upon application of SCR to achieve 0.10 lb/mmBtu on a 30-day rolling average basis. According to the BART Guidelines, "The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and ***lignite*** [emphasis added] should enable these units to cost-effectively meet NO_x rates of 0.10 lb/mmBtu."

Instead of meeting the presumptive BART limit of 0.10 lb/mmBtu, NDDAQ is proposing application of SNCR and Advanced SOFA to limit NO_x emissions to 0.35 lb/mmBtu on a 30-day rolling average basis. This equates to a cost-effectiveness of \$16.1 million per dv at Theodore Roosevelt NP and \$8.4 million per dv cumulatively when Lostwood WA is included.

NDDAQ Cost-Effectiveness for SOFA+SNCR	MRYS #2
Annual Cost (\$million)	\$ 11.41
Visibility Improvement at TRNP (dv)	0.70
Cost-Effectiveness (\$million/dv)	\$ 16.18
Cumulative Visibility Improvement (dv)	1.37
Cost-Effectiveness (\$million/dv)	\$ 8.35

Because NDDAQ has proposed no absolute limits on emissions, the proposed BART limits would result in a 57% reduction in current NO_x emissions on a lb/mmBtu basis and a 34% reduction on a ton-per-year basis.

NDDAQ proposes that NO_X emissions be limited to 3995.6 lb/hr on a 24-hour rolling average basis during startup, for the reasons discussed with respect to MRYS #1. This is almost double the 2,205 lb/hr that would be allowed under normal operation. We again note that the approach taken by EPA regarding Desert Rock is similar to that taken by other states and limits the mass emission rate (e.g., lb/hr) to the rate under normal operation. We recommend that NDDAQ adopt this approach.

NDDAQ rejected ASOFA+tail-end SCR with reheat on the basis of excessive cost. NDDAQ's analysis of addition of SCR with reheat yields a cost-effectiveness of \$43.4 – \$62.6 million per dv at Theodore Roosevelt NP and \$22.4 – \$32.3 million per dv cumulatively when Lostwood WA is included.

Cost-Effectiveness for SCR w Reheat on MRYS #2	**NDDAQ**		**NPS**
	low	**high**	**low**
Annual Cost ($million)	$ 47.52	$ 68.48	$ 15.60
Visibility Improvement at TRNP (dv)	1.09	1.09	1.36
Cost-Effectiveness ($million/dv)	$ 43.45	$ 62.63	$ 11.46
Cumulative Visibility Improvement (dv)	2.12	2.12	2.64
Cost-Effectiveness ($million/dv)	$ 22.42	$ 32.32	$ 5.91

NPS' analysis of addition of basic ASOFA+SCR with reheat and using NDDAQ modeling results yields a cost-effectiveness of \$11.5 million per dv at Theodore Roosevelt NP and \$5.9 million per dv cumulatively when Lostwood WA is included. We believe that our cost estimates indicate that addition of SCR with reheat is reasonable based upon BART determinations and proposals we have seen nationwide to date.

Conclusions & Recommendations for MRYS #2

- NDDAQ is proposing upgrading the existing wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. We have estimated that the proposed scrubber upgrade will result in an approximately 1.2 dv improvement in visibility at Theodore Roosevelt NP and 2.2 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubbers, but recommend that the limits require **both** 95% control **and** 0.15 lb/mmBtu, as well as specific caps on emissions.
- Presumptive NO_x BART for MRYS #2 is 0.10 lb/mmBtu. NDDAQ is proposing that BART is an emission limit of 0.35 lb/mmBtu on a 30-day rolling average basis to be met by addition of ASOFA+SNCR; this would improve visibility by 0.7 dv at Theodore Roosevelt NP and 1.4 dv cumulatively when Lostwood WA is included.
- NDDAQ proposes that NO_X emissions be limited to 3,995.6 lb/hr on a 24-hour rolling average basis during startup. We recommend that NDDAQ limit the mass emission rate (e.g., lb/hr) to the rate under normal operation.
- NDDAQ underestimated the effectiveness of adding ASOFA+SCR to MRYS #2. We suggest that ASOFSA+SCR can achieve 0.05 lb/mmBtu.
- NDDAQ overestimated the costs associated with adding SCR. In the absence of supporting documentation by NDDAQ, we estimated total annual costs for ASOFA+tail-end SCR with reheat at \$15.6 million and \$898 per ton.

- NPS' analysis of addition of basic ASOFA+SCR with reheat and using NDDAQ modeling results yields a cost-effectiveness of $11.5 million per dv at Theodore Roosevelt NP and $5.9 million per dv cumulatively when Lostwood WA is included.
- We believe that ASOFA+SCR with reheat represents BART for MRYS #2.

Section Eight: Visibility Modeling

As noted in Section 8.1, NDDAQ used a unique hybrid modeling approach to air quality modeling to project the 2018 reasonable progress goals. This approach involved nesting the local CALPUFF domain within the WRAP CMAQ domain, and applying the Lagrangian CALPUFF model in a retrospective sense to more realistically define plume geometry for local point sources.

We appreciate the effort by NDDAQ to address some of the limitations of the larger (36 km) grid and limited near-field impacts of the WRAP regional modeling. However, we are concerned that the modeling system developed by NDDAQ has shortcomings that limit its usefulness as an alternative modeling approach.

NDDAQ indicates that the purpose of the hybrid modeling is as weight of evidence to discount the impact of international (particularly Canadian) emissions and to better represent plume dispersion from point sources, particularly those closer to the Class I areas. While the CMAQ 36 km grid resolution does allow dilution of the plumes from point sources, ND's hybrid modeling assumptions raise more questions that are answered. CALPUFF does allow tracking of individual plumes but the model chemistry is much simplified compared to CMAQ and the methods required to normalize CMAQ results to CMAQ-CALPUFF hybrid results becomes quite elaborate and questionable.

We raise the following technical issues with the CALPUFF application:

- Ammonia is known to be an important input to determine the amount of ammonium nitrate (NH_4NO_3) formed in CALPUFF. Regional ambient concentrations of ammonia are poorly understood. ND has one ammonia monitor at Beuluh; please describe the type of monitor and the land use at Beuluh compared to other areas of the CALPUFF domain. We question if this monitor is representative of the CALPUFF domain. We note that monthly average NH3 from 2001-2002 was used as background ammonia in CALPUFF after removing days influenced by a source region. The draft Plan should identify that source region.

- EPA disapproved the use of the Ammonia Limiting Method to define NH3 levels in the VISTAS application cited by NDDAQ.

- For POSTUTIL, hourly ammonia data for 2001 -2003 were used and the Plan does not mention removing data. The Plan should identify if different years were used for the two applications. It appears that the ammonia levels at Lostwood were doubled compared to measured values based on the expectation that Lostwood is closer to ammonia sources in Canada. However, that adds a subjective adjustment to the CALPUFF modeling that brings into question the presumption that CALPUFF modeling is more accurate than just using CMAQ at 36 km.

- We note that four ozone monitors in central ND were selected to represent background ozone in CALPUFF. Are there only four ozone monitors in the CALPUFF domain? Table 8.6 says background value for ozone was 30 ppb, but does not link this to monitoring data.

We question the Hybrid model performance evaluation. Model performance evaluations are usually based on raw model output. We understand that the Hybrid model results were normalized before evaluation and then were normalized again to the WRAP baseline results. The need to normalize the CALPUFF relative response factors to the WRAP results, brings into question the value of using the CALPUFF hybrid regional model to discern the benefits of NDDAQ strategies.

In summation, we are not certain that the results from the Hybrid modeling have a substantial impact on the overall result. The conclusions under either the WRAP modeling or the Hybrid model are the same; the two Class I areas in North Dakota do not meet the uniform rate of progress guidance for this first planning period.

Section 8.6, including Figure 8.10, describes a possible way to account for international emissions when assessing the progress toward the goal of natural conditions. While we agree that examining the contribution to extinction for each aerosol species is a good approach to understanding if a State is meeting its fair share of emissions reductions associated with visibility impacts at a Class I area, the method described in this section and in the figure raise concerns since there was no assessment of the international component of the natural condition estimate. The value in 2064 illustrated in Figure 8.10 uses the same natural condition endpoint for the total extinction as well as the "U.S. Source" extinction, yet the 2064 natural condition estimates for aerosol species include some global or international component. We believe that a better way to address reasonable progress by extinction component is to assess the reduction needed for each aerosol species measured in the baseline period to the end of the first planning period and then assess if a state's plan achieves a comparable reduction for its share of extinction at the Class I areas.

Section Nine: Reasonable Progress Goals

The State should rely on WRAP regional modeling as the primary tool for demonstrating progress toward visibility improvement goals. The CMAQ-CALPUFF hybrid modeling is problematic in several ways and gains ND little benefits compared to using WRAP products. Two WRAP products that were omitted but should be included to help ND in making its reasonable progress determination are 1) Weighted Emissions Potential (WEP) and 2) extinction glide paths for SO_4, NO_3, and OC.

The uniform rate of progress glide path cannot be revised to account for contributions from natural sources or international sources under current or 2018 conditions without also removing these contributions from the 2064 endpoint. While the contribution from natural and international sources by 2064 is unknown, it may be comparable to current contributions. Therefore removing the estimated contributions from current conditions without also accounting for those contributions to the 2064 endpoint inappropriately changes the slope of the uniform rate of progress

It would be more appropriate to use the WRAP CAMx-PSAT results to demonstrate the relative contributions to sulfate and nitrate from Canadian and ND emissions at the North Dakota Class I areas. The Plan has already included these results in Table 6.7.

We suggest NDDAQ use the WRAP extinction glide paths to show the improvement in SO_4 or NO_3 due to emissions reductions from all sources in the WRAP 2018 inventory, and compare the ND emissions reductions by 2018 to emissions reductions from Canada and neighboring states. It would be informative for the Plan to include what percent of the State's total SO_2 and NO_X emissions from point sources is being reduced under BART. What other point source or area source reductions are reasonable?

For stationary sources, NDDAQ developed a methodology to look at options for controls for sources, beyond the source subject to BART, contributing to the major components of aerosol extinction on the worst 20 percent days. While we generally agree with the use of emissions over distance (Q/d) as a screening tool, we note that the Heskett facility was not included in Table 9.4 even though NDDAQ proposes to exclude the source from BART requirements.

Based on Q/d and some source process information, NDDAQ narrowed the focus of any additional control measures under the reasonable progress measures to the Basin Electric Antelope Valley Station (AVS) facility, the Otter Tail Power Coyote Station, the Dakota Gasification Great Plains Synfuels Plant, and the Hess Corporation Tioga Gas Plant.

Table 9.9 summarizes the results of assessing the costs and visibility improvement associated with possible controls on these facilities. The two power generation facilities, Coyote and AVS, have emissions and Q/d impacts that are similar, if not greater than, BART sources that will be required to add controls. The methodology to calculate visibility improvements noted in Table 9.9 are not explained in this section but appear to be some calculation of changes in the long-term metric of the 20 percent worst visibility days. These sources likely contribute to higher impacts on a daily basis, and a reduction in their emissions would be part of a broad strategy to reach natural conditions at the Class I areas. As such NDDAQ should examine the total improvement from the suite of sources as part of its reasonable progress assessment, not a simple unit by unit approach.

The assessment of non-air quality impacts on page 181 in the draft SIP does not address the substantial human health benefits associated with reductions in fine particulate concentrations resulting from additional control of SO_2 and NO_X emissions from Coyote and AVS since they would become the newest and highest emitters of these pollutants after implementation the SIP as drafted.

The decision on additional point source controls would be better informed by analysis of the how the emissions from sources within the State contribute to nitrate and sulfate concentrations in Class I areas, both inside and outside of the State, in the baseline period compared with the model projections in 2018. If BART controls on stationary sources as well as expected reductions from Federal mobile source, small engine, and fuel requirements would achieve a reduction that, had all other contributing States and other regions met similarly, would put the total aerosol extinction on the uniform rate of progress path, then the State could better support a limited approach to additional controls in this first planning period. However, based on our review of the information supplied in the draft Plan and its appendices, we believe there are cost-effective controls for the Coyote and AVS facilities that should be implemented under the reasonable progress provisions.

Section Ten: Long-Term Strategy

We appreciate that a description of the State's smoke management activities regarding anthropogenic fire is referenced in the Plan. We agree that current rules are sufficient to address the small extinction associated with this component. We also appreciate the Plan referencing conservation tillage as an approach to reduce windblown dust.

On Page 184, there is discussion of the reduction in sulfur dioxide emissions from the R.M. Heskett Station No. 2. As noted earlier, we believe this facility is subject to BART and should be assessed under the BART provisions. In addition, the reduction in emissions reflect a 21 percent reduction from current emissions. The 70 percent coal-to-stack removal cited in the draft Plan implies a greater reduction from current emissions.

We request that NDDAQ include in the Long-Term Strategy a linkage between the prevention of significant deterioration program and its assessment of visibility impacts and the Regional Haze Plan in the SIP. This will ensure that new sources are reviewed in a manner that does not jeopardize the reasonable progress goals established by this Plan.

Section Eleven: FLM Consultation and Coordination

We appreciate the ongoing efforts of NDDAQ to consult with the federal land management community.

Section Twelve: Public Participation and Review Process

No comment.

United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

October 23, 2009

N3615 (2350)

Mr. Terry L. O'Clair, P.E.
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, North Dakota 58501-1947

Dear Mr. O'Clair:

On August 26, 2009, we received North Dakota's draft implementation plan to address regional haze for review. We appreciate the opportunity to work closely with the State through the initial evaluation, development, and, now, subsequent review of this plan. Cooperative efforts such as these ensure that, together, we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at all of our most pristine National Parks and wilderness areas for future generations.

This letter acknowledges that the U.S. Department of the Interior, U.S. Fish and Wildlife Service (FWS), and National Park Service (NPS) have received and conducted a substantive review of your revised proposed Regional Haze Rule implementation plan in fulfillment of your requirements under the federal regulations 40 CFR 51.308(i)(2). Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination regarding the document's completeness and, therefore, ability to receive federal approval from EPA.

As outlined in a letter to each State dated August 1, 2006, our review focused on eight basic content areas. The content areas reflect priorities for the Federal Land Manager agencies, and we have enclosed comments associated with these priorities. Our major concerns with the draft plan include: 1) the separation of Theodore Roosevelt National Park units into separate Class I areas for assessing air quality impacts, 2) the exemption of the Unit #2 at the R.M. Heskett Station from Best Available Retrofit Technology (BART) review, 3) concerns over BART determinations (i.e., our review concludes that additional sulfur dioxide and nitrogen oxide emission reductions are achievable through the BART process), and 4) the methods used for determining reasonable progress at Class I areas affected by emissions from North Dakota sources. For further information regarding our comments, please contact Bruce Polkowsky of the NPS Air Resources Division at 303-987-6944, or Tim Allen of the FWS Branch of Air Quality at 303-914-3802.

Again, we appreciate the opportunity to work closely with the State of North Dakota and compliment you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

Christine

Christine L. Shaver
Chief, Air Resources Division
National Park Service

Sincerely,

Sandra V. Silva

Sandra V. Silva
Chief, Branch of Air Quality
U.S. Fish & Wildlife Service

Enclosure

cc:
Tom Bachman
Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue
Bismark, North Dakota 58501-1947

Callie Videtich
U.S. EPA Region 8
1595 Wynkoop Street
Mail Code: 8P-AR
Denver, Colorado 80202-1129

12/1/09

Response to Forest Service
Comments October 14, 2009

General Comments

Comment 1: We agree with previous comments by the National Park Service (NPS) that Theodore Roosevelt National Park should be treated as one Class I area, not three.

Response: North Dakota has two Class I areas within its boundaries: the Theodore Roosevelt National Park which consists of three separate and distinct units and the Lostwood National Wildlife Refuge Wilderness Area. The North Dakota Department of Health (Department) considers the three units of Theodore Roosevelt National Park to be three separate areas for modeling purposes for the following reasons:

A. Theodore Roosevelt National Park (TRNP) as a PSD Class I area consists of three units (see 44 FR (November 30, 1979) at 69125 and 69127, 40 CFR § 81.423 and NDAC § 33-15-15-01.2 (Scope) relating to 40 CFR 52.21(e)). The areas are not contiguous. The North Unit and South Unit are separated by approximately 38 miles.

B. Federal regulation, 40 CFR 51.301, states "*Adverse impact on visibility* **means, for purposes of section 307, visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent,** intensity, duration, frequency and time of visibility impairments and how these factors correlate with (1) times of visitor use of the Federal Class I areas, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas." (Emphasis added) Combining the three units of TRNP into a single area for visibility analysis fails to address the "geographic extent" of any visibility impairment.

C. The North Unit is not visible from the South Unit and vice versa. The commingling of receptors from the units for a visibility analysis misrepresents the ability of a park visitor to observe features in another unit.

Any viewable scenes outside any unit of TRNP from within the unit are "integral vistas". The effects on integral vistas are not considered when determining whether an adverse impact on visibility will occur. There are no geological features, terrain or structures in any unit of TRNP that are viewable from another unit across the land regions separating the units. For example, terrain peaks in the South Unit would have to rise at least 900 feet above terrain in the North Unit, due to the Earth's curvature, to be seen by a visitor in the North Unit. So the visual range of visitors in one unit does not include aspects of another unit.

D. The Department has treated the units as separate Class I areas for 30+ years for purposes of PSD increment consumption without objection from EPA or the FLMs prior to 2006.

E. Treating the three units as a single Class I area effectively extends Class I status to areas between the units which are classified as Class II by rule and law.

F. The units have three different names, the South Unit, the North Unit and the Elkhorn Range Unit.

Comment 2: In a number of places in the RH SIP, ND characterizes its impact on its own class CIAs as "small." We note that this is a subjective term. Based on our review of RH SIPs from other states, we do not consider ND's percent contribution to visibility impairment in its own CIAs as being significantly different (i.e. smaller) than the other CIA owner states. For example ND's contribution to its CIAs is very similar to Minnesota's contribution to its CIAs. If ND feels this is not true, ND should include data to support this position. Nevertheless each State must demonstrate that it is obtaining "*its share of the emission reductions needed to meet the progress goal for the area*," per 40 CFR 51.308 (d) 3.

Response: We agree that "small" is a subjective term. However, Canada and sources outside the WRAP's modeling domain are larger contributors to visibility impairment in North Dakota's Class I areas. North Dakota sources contribute 21% or less of the visibility degradation to TRNP and LWA. We believe the word "small" is an appropriate descriptor.

Comment 3: The RH SIP should explain how the reasonable progress goals (RPGs) will be revised once the RH SIPs from the neighboring contributing states are available.

Response: The following paragraph has been added to Section 11.3.
In addition, North Dakota commits to revise the implementation plan, including the reasonable progress goals, once RH SIPs from neighboring states become available and are approved by EPA, or if the unexpected or unforeseen occurs. This would include, but not limited to, projected future emissions reductions that do not occur, are distributed differently over an alternate geographic area, or are found to be incorrect or flawed. These revisions will be made within one year as required by §51.308(d)(4). North Dakota also commits to accelerate this revision schedule if the present RH SIP is found to be significantly flawed and the 2018 reasonable progress goals cannot be reasonably attained.

Comment 4: We note that the State of Minnesota specifically asked ND to analyze the feasibility of reducing electrical generating unit (EGU) emissions in the state to less than 0.25 pounds per million Btu (lb/MMBtu) for sulfur dioxide (SO_2) and less than 0.22 lb/MMBtu for nitrogen oxides (NOx). We found a response from ND that outlined their disagreement with the premise of Minnesota's "ask." Additional information would be helpful comparing the emission level of ND's EGUs after the installation of controls prescribed under the Best Available Retrofit Technology (BART) and Reasonable Progress (RP) analyses.

Response: We believe the lb/10^6 Btu metric proposed by Minnesota is inappropriate since it is not based on the four factors that must be considered as required by rule and law. We believe cost must be considered, especially on a dollar per deciview basis.

Comment 5: We ask US EPA Regions 5 and 8 to arbitrate the disagreement between ND and Minnesota regarding Minnesota's "ask," as well as working with Canada on reducing emissions from sources in that country, especially the power plants mentioned by ND on page 53 of the RH SIP. This is especially relevant since power is sent across the US-Canada border.

Response: None required

General BART

Comment 6: We feel the decision to make Heskett Unit 2 not subject to BART is based on inappropriate modeling. Technical reasons were discussed on the call between ND and the Federal Land Managers (FLMs) on September 22, 2009, including the use of using fine grid (1 km) modeling. Department of Interior modeling staff will provide more details. Please complete a full BART analysis for this unit. Alternatively, if Heskett is not found to be subject to BART it should be included in the State's reasonable progress analysis and a complete suite of possible control options examined in detail.

Response: Heskett Unit 2 is being reevaluated. This source will be addressed in a future supplement to this SIP revision.

Comment 7: We would also like to note that the statement that Heskett is proposing a 70% SO_2 emission reduction is misleading. Baseline SO_2 emissions were reported as 2400 tons and the reduction project was reported to reduce emissions by 740 tons. This results in a 31% reduction.

Response: So noted

Comment 8: EPA BART guidelines (Federal Register, July 6, 2005) on page 39170 directs the State to compare the 98 percentile days, pre-control versus post-control, so we disregarded the 90 percentile days presented in the RH SIP on page 67.

Response: The affected sources and the Department have provided both the 90th and 98th percentile results for the reader. The only facility in North Dakota that is subject to the BART guideline is Coal Creek Station for NO_x only. The BART Guideline states "For sources other than 750 MW power plants, states retain the discretion to adopt approaches that differ from the guideline." Therefore, the Department is allowed to consider any type of visibility improvement information in determining BART.

Comment 9: On page 68 ND states "Though single-source modeling is specified in the BART guidance for determining degree of visibility improvement, it is clear that this modeling overstates the real single-source visibility impact." Please add a reference or basis for this statement. ND also adds "an observer's perception of visibility change is affected by the total loading of visibility-affecting species in the atmosphere." We agree. On clean days visibility can be impaired by a small amount of air pollution. That is why it is important to use clean days as a baseline from which to measure impairment from a source. Otherwise clean days are not protected.

Response: Visibility on clean days is being protected, as demonstrated by WRAP and NDDH results for the 20% cleanest days. The modeling results for the 20% cleanest days indicate no deterioration of visibility on the 20% cleanest days at North Dakota Class I areas. But according to the Regional Haze Rule, the focus of visibility improvement demonstrations is the *20% worst visibility days*, not the cleanest days. There is no requirement to make the cleanest days cleaner, the Rule specifies only that visibility on cleanest days should not degrade. A calculated visibility change using single-source modeling is only accurate or applicable during clean visibility background conditions, when a Class I area is impacted by a single source's plume. This is certainly not the case for the 20% worst visibility days. For the 20% worst visibility days, a realistic change in visibility must be calculated with respect to current baseline conditions, which include the cumulative impact of many sources. Given that the deciview calculation is based on the observer's perception, single source modeling will overstate perceived visibility change on the 20% worst days.

The basis for the NDDH statement on single-source modeling overstating the real impact relates also to the cumulative visibility improvement analyses conducted by WRAP and NDDoH for 2018. These sophisticated analyses indicate that overall visibility improvement (20% worst days) will actually be much lower than the additive impact of single-source modeling associated with BART degree of visibility improvement. In other words, the single-source modeling results conflict with the results obtained by WRAP. You cannot claim the single-source modeling is accurate for depicting real visibility improvement without disparaging the results obtained by WRAP. The NDDoH believes the sophisticated WRAP modeling is more accurate.

Comment 10: In the BART section of the SIP ND appears to disregard the importance of EPA's presumptive BART limits. EPA considers these limits to be "generally cost effective" and in the case of scrubbers states, "We expect that scrubber technology will continue to improve and control costs continue to decline" (FR, 7/6/07, pg 39171).

Response: The Department did not disregard the presumptive BART emission rates. As pointed out earlier, only Coal Creek Station (for NO_x only) is subject to the BART guideline and presumptive BART emission rates. Coal Creek Station will meet the presumptive limits for NO_x. Although not subject to the presumptive levels, Leland Olds 1 will be below the NO_x presumptive level. All sources except Stanton 1 will be required to meet the presumptive level for SO_2 even though the presumptive levels do not apply.

SO_2 BART

Comment 11: MR Young Unit 2

A. We feel the form of the emission limit needs to be reviewed. For example, the emission limit is specified as 95% control efficiency (CE). Therefore the pounds per million Btu (lb/MMBtu) limit should be 0.1 or else the effective limit becomes 0.15 lb/MMBtu which is 90% control. MR Young Unit 1 is specified as having just a CE limit and no alternative lb/MMBtu. If Unit 1 can comply with just a CE limit we see no reason why Unit 2 can't also do the same.

B. At the end of the BART analysis, ND changes the baseline emission level from 2.0 lb/MMBtu to 3.5 lb/MMBtu, which effectively raises the final BART limit. We feel the same baseline emission level should be used throughout the whole BART analysis, which includes calculating the costs per ton, as well as setting the limits.

Response:

A. The commenter is incorrect in the assertions on the SO_2 emission rates. If average sulfur content coal is burned, 95% removal efficiency will be 0.11 lb/10^6 (annual average) and 0.17 lb/10^6 Btu based on a reasonable worst-case sulfur content of 1.46% (worst-case sample was 5.6%). To obtain a 30-day rolling average emission limit, the annual average would have to be adjusted up approximately 33%. This yields a 30-day rolling average based on 95% reduction of 0.15 lb/10^6 Btu for the average coal and 0.23 lb/10^6 Btu for a reasonable worst-case. Minnkota has agreed to limit emissions to 0.15 lb/10^6 Btu or 95% reduction. The Consent Decree for the facility requires a minimum of 90% reduction. Therefore, when Minnkota chooses to comply with the 0.15 lb/10^6 Btu, they will also have to achieve at least 90% reduction. Based on average coal sulfur 95% reduction will be required to comply with the 0.15 lb/10^6 Btu limit. Under the Consent Decree, Unit 1 does not have the option of meeting a 0.15 lb/10^6 limit.

B. The calculations in the Department's analysis have been revised based on the projected increase in sulfur content to 0.93% from the baseline of 0.86%. The annual average sulfur content was used for the analysis and the projected emission rate of 0.11 lb/10^6 Btu (annual average) was then adjusted to a 30-day rolling average of 0.15 lb/10^6 Btu. The higher "reasonable worst-case" sulfur content was not used to determine the emission limit of 0.15 lb/10^6 Btu on a 30-day rolling average basis."

Comment 12:

A. It is unclear why this unit can't install a wet scrubber and meet the same limit as the Leland Olds Unit 1 (95% CE) which is a boiler of similar size, age, firing type, and is also along the Missouri river. Please include a discussion of how the relevant BART factors are different for the two units. The costs for a wet scrubber at Stanton appear to be reasonable ($1480/ton).

Response: The Department eliminated a wet scrubber from consideration as BART at Stanton Unit 1 based upon a combination of factors. These include the relatively high incremental cost of $4,179 per ton of SO_2 removed when burning lignite and $6,302 per ton of SO_2 removed when burning PRB, the additional environmental impacts of a wet scrubber and the fact that a wet scrubber will remove a relatively small amount of SO_2 when compared to a spray dryer (with a small corresponding visibility improvement).

The additional environmental considerations are further outlined below:

- A wet scrubber is estimated by Great River Energy (GRE) to use as much as 20% more water or approximately 15 million gallons per year of additional water.

- It is assumed that a wet scrubber system will require additional on-site ponding. GRE has identified two potential areas on site that could be used for the additional ponding. The areas include the existing ash pile, which would have to be excavated and moved, or the abandoned ash disposal area adjacent to the river, which reportedly has geotechnical deficiencies.

- Dry scrubbers are purported to achieve higher mercury control efficiency on lignite and PRB as compared to a wet scrubber. In addition, future mercury control requirements could result in high concentrations of mercury in the ponds and prove problematic to discharge.

Although Leland Olds Unit 1 and Stanton Unit 1 are both located on the Missouri river, the facilities are not located at the exact same location. As indicated above, site-specific factors were considered when making the determination to eliminate a wet scrubber from consideration as BART at Stanton Unit 1. Basin Electric, operator of Leland Olds 1, also has a much larger area available for siting a dewatering pond.

B. Again, for this source, ND adjusted the baseline emission rate up for both fuels (i.e. from 1.8 to 2.4 lb/MM Btu for lignite and from 1.2 to 1.6 lb/MM Btu for sub-bituminous). As stated above we feel the baseline emission rate should be the same throughout the analysis. If the baseline emission rate were the same throughout the analysis, it would reduce the cost per ton presented, which already appears to be reasonable.

Response: The Department's economic analyses were based on uncontrolled annual SO_2 emissions of 1.81 lb/million Btu for lignite and 1.2 lb/million Btu for PRB coal. The proposed BART emission limits for SO_2 are based on a 30-day rolling average (as opposed to an annual average) with 90% reduction and also includes emissions from startups, shutdowns and malfunctions. Based upon historical SO_2 emissions data for spray dryers and fabric filters at facilities burning North Dakota lignite, we have determined that an increase of 33% is warranted to adjust from an annual average SO_2 emission rate to a 30-day rolling average emission rate. The discussion regarding potential SO_2 emissions as high as 2.4 lb/million Btu for lignite and 1.6 lb/million Btu for PRB coal was intended to show that higher sulfur coal could be encountered (see Appendix E, Sulfur Content Statistical Analysis, of the GRE BART Analysis). The Forest Service states that the cost per ton for SO_2 removal already appears to be reasonable. The Department agrees that the wet scrubber cost effectiveness of $1,480/ton of SO_2 removed when burning lignite and $2,232/ton of SO_2 removed when burning PRB are reasonable. However, the Forest Service chooses to ignore the relatively high incremental cost of $4,179 per ton of SO_2 removed when burning lignite and $6,302 per ton of SO_2 removed when burning PRB. As indicated in the response to comment #12.a. above, the Department appropriately considered the five factors when making the decision to remove a wet scrubber from consideration as BART at Stanton Unit 1.

NO_x BART

Comment 13: We would like to comment on an ancillary issue. ND states in the individual BART determinations, "The Department believes pilot scale testing would prove to be very beneficial in addressing the items of concern and provide a more detailed professionally reliable cost estimate. However, the BART process cannot mandate pilot testing be conducted to determine costs." We agree and suggest that should a decision be made not to apply SCR with this SIP, additional pilot testing would be useful and encourage ND to include enforceable schedules in the long term strategy portion of its RH SIP. Minnesota took just such an approach in its RH SIP for the taconite industry which, like lignite fired power plants in North Dakota, had little data on NOx controls and is almost entirely in one state.

Response: Although we believe it would be beneficial to have pilot test data, the Department must make its decision regarding BART based on available data. The U.S. EPA, Region 8 has indicated that such "commitments" within the regional haze SIP are unacceptable and would not be considered in determining whether to approve the SIP.

The Department has been working with industry to get pilot testing completed. By the next planning period, we expect to have much more data.

Comment 14: We note that Leland Olds Unit 2 and MR Young Units 1 and 2 do not meet presumptive BART, which as noted above is described by EPA as "generally cost effective."

Response: These sources are not subject to the BART guidelines or the presumptive BART emission limits. EPA did not address the flue gas characteristics of North Dakota lignite when determining the presumptive levels. The BART guideline states "As with other presumptive limits established in this guideline, you may determine that an alternative level of control is appropriate based on your consideration of the relevant statutory factors." The Department has based its BART decision on the relevant factors and selected a level of control different from the presumptive level. Our explanation for our selection is found in the SIP, Appendix B.

Comment 15: The startup/shutdown BART exemptions proposed for MR Young Units 1 and 2 are not necessary since the limit will be in the format of a 30 day rolling average. We have not seen such exemptions in BART determinations in other states. Four other BART units in ND are also using SNCR and are not asking for similar treatment. If these exemptions are allowed they should be severely limited by enforceable permit conditions, otherwise the integrity of the BART limit will be compromised.

Response: The BART exemption for startup is necessary since Minnkota did not build excess emissions during startup into the proposed BART limit (see discussion in Minnkota's October 2006 analysis – Appendix C). Minnkota prepared a BART analysis which is consistent with the BACT analysis required by their Consent Decree. The Consent Decree, paragraph 66 requires Minnkota to address startup NO_x emissions separately. Therefore, the BART limit is being proposed to be consistent with the BACT limits. Other facilities have included startup/shutdowns in their proposed BART limits. Leland Olds Unit 2 has a baseline emission rate of 0.67 lb/10^6 Btu compared to Minnkota Unit 1 which has a baseline of 0.78 lb/10^6 Btu.

The proposed BART limits are identical at 0.35 lb/10^6 Btu except for a separate limit for Minnkota during startup.

Comment 16: We applaud ND for the process it took to identify sources for which additional controls could be potentially applied under reasonable progress. Based on the Q/d metric, clearly Coyote and Antelope Valley Station (AVS) have visibility impacts that are on par with, or exceed many of the subject to BART sources. These subject to BART sources were all prescribed to install additional SO_2 and NO_x controls by ND in the draft SIP.

a. SO_2 - Improvements to the existing spray dryer system should be included as an option, and costs determined, in the control technology analyses done for the AVS units. EPA states the following for existing flue gas desulfurization systems in their BART guidelines, "There are numerous scrubber enhancements available to upgrade the average removal efficiencies of all types of existing scrubber systems…" This is the approach taken by ND for the Coal Creek units and MR Young Unit 2.

b. NO_x - When comparing the emission rates from AVS and Coyote to the rest of the State's EGUs, AVS and Coyote would be the newest and the dirtiest. We note that ND states that moderate control options such as LNB/SNCR at 65% CE for AVS and ASOFA/SNCR at 55% CE at Coyote are reasonable (page 180 of the RH SIP).

ND claims that the improvement in visibility from installing controls at AVS and Coyote is too small to require their installation. It is unclear which modeling method/protocol was used to produce the visibility results in Table 9.9, which makes their use problematic. Nevertheless AVS and Coyote are of the same general size, and located in the same general area, as the BART sources. Therefore we feel reductions at AVS and Coyote are equally important to those at the BART sources. ND required controls at the BART sources. The amount of reductions from AVS and Coyote are significant – in the range of 30,000 tons of combined NO_x and SO_2, not including any additional SO_2 that could be reduced from upgrading the spray dryers at AVS. Please consider controls on AVS and Coyote such as LNB/SNCR at 65% CE for AVS and ASOFA/SNCR at 55% CE at Coyote.

Response:

a. Improvements to the spray dryers at AVS I and II are underway. This has been noted in the revised SIP. The Department looked at the improvements to the scrubber system at Antelope Valley Station. This included meeting the presumptive emission rate of 0.15 lb/10^6 Btu. When this emission rate was modeled with the presumptive NO_x emission limit, it only improved visibility 0.045 deciviews at LWA and 0.031 deciviews at TRNP during the 20% worst days (total for the two units). For the Coyote Station, visibility improved only 0.04 deciviews at LWA and 0.02 deciviews at TRNP when the scrubber efficiency was 95% and NO_x emissions were reduced 55%. The Department considers this amount of improvement to be unsubstantial.

b. The Department considered the cost to be reasonable on a dollar per ton basis. However, EPA's guidance for determining reasonable progress states "Therefore, in assessing additional emissions reduction strategies for source categories or individual large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation." The Department evaluated the cost on a dollar-per-deciview basis and found it to be unreasonable.

The modeling in Table 9.9 was based on a cumulative analysis of the improvement in the 20% worst days. The Department will further describe the modeling procedure in the SIP.

Comment 17: Under the section on "Energy and non-air quality environmental impacts," we encourage ND to include the environmental and health *benefits* of installing additional controls. In general, the benefits of installing controls on EGUs far outweigh the costs.

a. For example the report EC/R did for Midwest RPO (http://www.ladco.org/reports/rpo/consultation/index.php) shows that the health benefits of reducing SO_2 and NO_x emissions under a region-wide SO_2 and NO_x control strategy are generally expected to outweigh the costs of control. These health benefits stem from the reduced ambient levels of PM and ozone which would result from the control of SO_2 and NO_x. "When benefits in the entire modeling domain were considered, the estimated values of these benefits outweighed the projected costs of control by more than a factor of 10" (page 106). This does not include other environmental benefits of controls which are harder to quantify but nonetheless important (e.g. reduction in mercury deposition).

b. In the original Clean Air Interstate Rule (CAIR), the range of annual *net* benefits (benefits less costs) to society were calculated to be approximately \$71.4 to \$60.4 billion in 2010 and \$98.5 to \$83.2 billion in 2015 (FR 5/12/05, pg 25305).

Response: (a & b)

The Energy and Non-Air Quality Environmental Impacts Analysis does not address health effects from air emissions. As stated in the BART guideline "In the non-air quality related environmental impacts portion of the BART analysis, you address impacts **other than air quality** [emphasis added] due to emissions of the pollutant in question. Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device."

Even though health effects are not evaluated under this section of the BART analysis, the Department reviewed ambient monitoring day in the vicinity of Antelope Valley Station and Coyote Station. Five ambient monitors are operated in the immediate area. In 2008, the maximum 3-hour SO_2 concentration was 39 ppb (7.8% of the NAAQS), the maximum 24-hour SO_2 concentration was 9 ppb (6.4% of the NAAQS) and the maximum annual average was 1.8 ppb (6% of the NAAQS). For NO_2, the maximum annual average was 2.7 ppb (5.1% of the NAAQS). Given the low concentration of these pollutants, any benefits to health would be extremely hard to quantify.

Comment 18: We do not support the method used to adjust the glidepath to account for Canadian emissions used in the RH SIP. We do support DOIs suggesting of using species-specific information provided by the Western Regional Air Partnership (WRAP).

Response: Regarding the statement, "we do not support the method used to adjust the glidepath for Canadian emissions used in the RH SIP", the commenter does not state what is wrong with the method, nor is any alternative provided. Therefore, the NDDoH has no basis to respond to this comment. As indicated in the SIP, the NDDoH approach for the adjusted glidepath is intuitive and consistent with proposals from other organizations (e.g., CENRAP Policy Oversight Group – Summary of PM Source Apportionment Modeling and 2018 Projection Approaches, March 2007).

WRAP species-specific information is included in Section 8 of the SIP.

Comment 19: We found no specific discussion in the draft SIP that considered contingency measures or procedures which could be triggered if the unexpected or unforeseen occurs. For example, if projected future emissions reductions do not materialize, or are distributed differently over an alternate geographic area, emission inventories could be found to be incorrect or flawed. Are there adaptive management strategies or increased review strategies which could be implemented in those situations? What will be done in five-years if North Dakota is over their projected emissions inventory? The SIP should provide a contingency plan to address these concerns.

Response: The following paragraph has been added to Section 11.3.
In addition, North Dakota commits to revise the implementation plan, including the reasonable progress goals, once RH SIPs from neighboring states become available and are approved by EPA, or if the unexpected or unforeseen occurs. This would include, but not limited to, projected future emissions reductions that do not occur, are distributed differently over an alternate geographic area, or are found to be incorrect or flawed. These revisions will be made within one year as required by §51.308(d)(4). North Dakota also commits to accelerate this revision schedule if the present RH SIP is found to be significantly flawed and the 2018 reasonable progress goals cannot be reasonably attained.

Comment 20: We request that ND note that there is a linkage between the PSD program, its visibility impacts, and the need to protect the 20 percent best visibility days. An adequate relationship between the SIP and ND's PSD program also helps ensure that new sources do not jeopardize the reasonable progress goals established by the RH SIP.

Response: A discussion of the linkage between the PSD program and Regional Haze Program will be added in Section 10 as Paragraph 10.7.

10.7 Prevention of Significant Deterioration

In North Dakota, new and modified existing major stationary sources triggering significance thresholds are analyzed under the Prevention of Significant Deterioration (PSD) permitting program. The PSD program rules are found in NDAC Chapter 33-15-15 and have been approved as a part of the North Dakota SIP by EPA. The PSD permitting program is a integral part of North Dakota's long term strategy for meeting its regional haze goals.

Among other things, the PSD permit program is designed to protect air quality and visibility in Class I areas by requiring best available control technology (BACT) and involving the public in permit decisions. The PSD permitting process requires a technical air quality analysis and additional analyses to assess the potential impacts of emissions on soils, vegetation and visibility. The cumulative impacts of emissions subject to the PSD program will be evaluated to ensure there is no degradation from baseline conditions on the 20 percent worst days and the 20 percent best days.

Therefore, North Dakota's current PSD program ensures that visibility at the Class I areas will not be impacted by growth in stationary sources.

12/2/09

Response to DOI Comments
October 23, 2009

Comment 1: (Section Two: Overview)

We disagree with the statement on page 8 claiming that North Dakota has four mandatory federal Class I areas as defined under the Clean Air Act. Based on the legislation establishing Theodore Roosevelt National Park and the Clean Air Act, North Dakota has two mandatory federal Class I areas (i.e., Theodore Roosevelt NP and the Lostwood Wilderness Area). The entire acreage of Theodore Roosevelt NP is one Class I area under the Clean Air Act, and should be treated as such for all protection purposes, such as assessing for increment consumption and calculating visibility impacts.

Response: North Dakota has two Class I areas within its boundaries: the Theodore Roosevelt National Park which consists of three separate and distinct units and the Lostwood National Wildlife Refuge Wilderness Area. The Department considers the three units of Theodore Roosevelt National Park to be three separate areas for modeling purposes for the following reasons:

A. Theodore Roosevelt National Park (TRNP) as a PSD Class I area consists of three units (see 44 FR (November 30, 1979) at 69125 and 69127, 40 CFR § 81.423 and NDAC § 33-15-15-01.2 (Scope) relating to 40 CFR 52.21(e)). The areas are not contiguous. The North Unit and South Unit are separated by approximately 38 miles.

B. Federal regulation, 40 CFR 51.301, states "*Adverse impact on visibility* **means, for purposes of section 307, visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent,** intensity, duration, frequency and time of visibility impairments and how these factors correlate with (1) times of visitor use of the Federal Class I areas, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas." (Emphasis added) Combining the three units of TRNP into a single area for visibility analysis fails to address the "geographic extent" of any visibility impairment.

C. The North Unit is not visible from the South Unit and vice versa. The commingling of receptors from the units for a visibility analysis misrepresents the ability of a park visitor to observe features in another unit.

   Any viewable scenes outside any unit of TRNP from within the unit are "integral vistas". The effects on integral vistas are not considered when determining whether an adverse impact on visibility will occur. There are no geological features, terrain or structures in any unit of TRNP that are viewable from another unit across the land regions separating the units. For example, terrain peaks in the South Unit would have to rise at least 900 feet above terrain in the North Unit, due to the Earth's curvature, to be seen by a visitor in the North Unit. So the visual range of visitors in one unit does not include aspects of another unit.

D. The Department has treated the units as separate Class I areas for 30+ years for purposes of PSD increment consumption without objection from EPA or the FLMs prior to 2006.

E. Treating the three units as a single Class I area effectively extends Class I status to areas between the units which are classified as Class II by rule and law.

F. The units have three different names, the South Unit, the North Unit and the Elkhorn Ranch Unit.

Comment 2: (Section Three: Plan Development and Consultation)

The plan addresses the State of Minnesota's request for NDDAQ to analyze the feasibility of reducing electrical generating unit (EGU) emissions in North Dakota to less than 0.25 pounds per million Btu (lb/MMBtu) for sulfur dioxide (SO_2) and less than 0.22 lb/MMBtu for nitrogen oxides (NO_X). While NDDAQ listed reasons why it did not believe the State of Minnesota's request was supported by assessments of impact, we request that ND supply the emission rates established by the regional haze plan from EGUs across the State so we and the public can be informed of any differences between the request from Minnesota and the final requirements of the NDDAQ plan.

The U.S. Environmental Protection Agency (EPA) will need to review any discrepancy between the Minnesota regional haze plan and the North Dakota regional haze plan during its review and approval process. In addition, we agree with NDDAQ that the EPA should address the significant contribution of international emissions, particularly from power generation in Canada, in support of NDDAQ's efforts for reasonable progress.

Response: We believe the lb/10^6 Btu metric proposed by Minnesota is inappropriate since it is not based on the four factors that must be considered for a reasonable progress analysis as required by rule and law. We believe cost must be considered, especially on a dollar per deciview of improvement basis.

Comment 3: (Section Four: Monitoring Strategy and Other Implementation Plan Requirements)

We note that the language in the footnote of Table 4.1 implies that the visibility monitoring conducted under the cooperative Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) system at Theodore Roosevelt NP is covering more than one Class I area. While the monitoring is at one unit, it is representative of all three units of that one Class I area.

We appreciate NDDAQ's efforts to enhance monitoring of visibility with additional collection of data. We support the ongoing efforts to collect and periodically update state-wide inventories of pollutant emissions that may contribute to the visibility impairment noted on page 24 of the Plan.

Response: The footnote to Table 4.1 will be changed.

Comment 4 (Section Five: Baseline and Natural Conditions and Uniform Rate of Progress for North Dakota Class I Areas)

As previously noted, we do not agree with the statement on page 30 that North Dakota has four distinct Class I areas. We do agree that the IMPROVE data collected at Theodore Roosevelt NP sufficiently tracks the long-term visibility conditions across the entire park and can be used for implementing the requirements of the regional haze rule.

Response: See response to Comment 1.

Comment 5: (Section Six: Sources of Visibility Impairment in North Dakota Class I Areas)

We appreciate the presentation of the Western Regional Air Partnership (WRAP) assessment of sources of visibility impairment at the two North Dakota Class I areas. In particular, Table 6.6 is a useful summary of North Dakota's contribution to impairment listed by component of light extinction. This forms a baseline to compare projected conditions in the reasonable progress section of the Plan. We ask that NDAQ clarify in the narrative that the sulfate and nitrate results are based on regional modeling using the CAMx-PSAT source apportionment tool, while the analyses of weighted emissions potential for organic carbon (OC), elemental carbon (EC), and particulate matter (PM) are based on emissions and residence time, not modeling. Figures 6.1, 6.2, 6.7, and 6.8 would be more informative if they also included 2018 results for sulfate and nitrate as is shown in the other figures for OC, EC, and PM.

Response: The Department will clarify that sulfates and nitrates are based on WRAP's tracer analysis modeling results and the results for the other pollutants are based on WRAP's weighted emissions potential analysis.

WRAP does not provide results for Case PRP18b using their tracer analysis (only Base 18b). We have included the weighted emission potential (WEP) analysis for SO_2 and NO_x that includes 2002 and PRP18b results. However, we disagree with the WRAP's estimate of oil and gas NO_x emissions in 2018.

Comment 6: (Purpose of the BART Program)

The core purpose of the BART program is to improve visibility in our Class I areas. BART is not necessarily the most cost-effective solution. Instead, BART represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. We believe that it is essential to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected.

Response: The determination of Best Available Retrofit Technology (BART) is based on the assessment of five factors: 1) Cost of compliance, 2) the energy and nonair quality environmental impacts of compliance, 3) any existing pollution control technology in use at the source, 4) the remaining useful life of the source and 5) the degree of improvement in visibility which may be reasonably be anticipated to result from the use of such technology (CAA, Sec. 169A(g)(2)). The Department has considered all five factors in its BART determinations. EPA, in Step 5 of the BART Guideline states "…you are free to determine the weight and significance to be assigned to each factor". In determining BART, visibility improvement was generally not weighted as heavily as the cost of compliance because we believe the single source modeling required by the BART guideline does not give a true representation of the degree of improvement in visibility **which may reasonably be anticipated to result from the use of the technology**.

We believe the cumulative visibility effects analysis promoted by DOI is scientifically unsound and not in accordance with rule or law. Adding the maximum improvement value (or 98th percentile) at one Class I area to the maximum improvement at another Class I area does not account for these maximums happening at different times. In addition, DOI has not defined which Class I areas should be added together to achieve the cumulative impact. This makes the analysis arbitrary. The single source modeling under BART does not provide a realistic estimate of visibility improvement of a given technology. Creating a "cumulative effects" analysis based on the flawed BART analysis only compounds the inaccuracy and misleads the reader of the SIP. In addition, the BART Guideline only requires an evaluation of the change at each receptor. It does not require adding these changes together.

Comment 7: (Five-Step BART Process)

Step 1: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES
Except for Great River Energy's (GRE's) analysis for NO_x from Coal Creek, all of the other SO_2 and NO_x analyses included a reasonable suite of options.

We also have some general comments that apply to all of the PM_{10} analyses. We believe that the BART analyses are deficient in that they neither address upgrades to the existing Electrostatic Precipitators (ESPs) or propose limits that realistically reflect the capabilities of those existing ESPs, as well as the proposed new baghouses, to control filterable PM. EPA's BART Guidelines (Guidelines) advise:

- "…it is important to include control options that involve improvements to existing controls and not to limit the control options only to those measures that involve a complete replacement of control equipment."
- "…for retrofitting existing sources in addressing BART, you should consider ways to improve the performance of existing control devises, particularly when a control device is not achieving the level of control that other similar sources are achieving in practice with the same device. For example, you should consider requiring those sources with electrostatic precipitators (ESPs) performing below currently achievable levels to improve their performance."

Although all of these sources have ESPs in place, none of them except Stanton Unit #1 is currently achieving a level of performance equivalent to the 0.015 lb/mmBtu proposed for ESPs at sources such as Peabody's Thoroughbred and LG&E's Trimble County projects in Kentucky. Furthermore, EPA has recently issued a permit limiting the Desert Rock facility to 0.010 lb/mmBtu filterable PM_{10}, new baghouses are being permitted at 0.009 – 0.012 lb/mmBtu in

Virginia (Virginia Hybrid Energy Center) and Wyoming (Dry Fork, WYGEN 3), and ND DOH proposed to permit the Gascoyne project at 0.012 lb/mmBtu. Instead, the limits on filterable PM_{10} proposed by NDDAQ are two – to – three times the emission rates measured by stack testing and cited by NDDAQ. While we understand that a certain "safety margin" must be allowed, we believe that the BART limits should be set to encourage continued good operation and maintenance of the pollution control equipment.

Response: The comment regarding the suite of options evaluated for NO_x controls at Coal Creek will be addressed later under the specific comments on the Coal Creek BART determination.

Regarding BART for PM at the BART eligible sources, in 2008 the emission rate at these sources ranged from 0.004 lb/10^6 Btu to 0.015 lb/10^6 which is generally comparable to levels achieved under BACT. The Department evaluated recent stack tests at the various power plants and found that emissions could vary up to 0.061 lb/10^6 Btu at Leland Olds Unit 1. The variation in the PM emission rate is probably due to a variation in the coal combusted (i.e. higher ash, different ash resistivity, etc.) and/or variations in the boiler and ESP operations. Sources must be able to comply with a BART limitation at all times unless specifically exempted. The Department chose to reduce the current allowable down from 0.10 lb/10^6 to 0.07 lb/10^6 Btu. This allows the sources to maintain continuous compliance yet requires the source to assure the ESP is working properly. The Department also reviewed the effect of PM from the BART sources on visibility. Based on the maximum 24-hour emission rate for the baseline period (5 years) the maximum impact was 0.027 deciviews (98th percentile). This amount of impact is considered very small and inconsequential. The newest ESP at the BART sources is 30 years old. The Department's review found that it was not cost effective to replace them and any improvement would not provide appreciable visibility improvement. We have concluded that 0.07 lb/10^6 Btu is a reasonable emission limit after considering the five statutory factors.

Comment 8:

Step 3: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES The ability of SCR to reduce emissions, as assumed by NDDAQ, was inconsistent and sometimes underestimated. For example, for the LNB/OFA+SCR option, GRE, Basin Electric Power Cooperative (BEPC), and NDDAQ sometimes assumed 0.07 lb/mmBtu for all averaging periods. However, for example, the WY Department of Environmental Quality has issued permits for new EGUs requiring that they meet 0.05 lb/mmBtu over averaging periods of 24-hours and 30-days. Furthermore, EPA's Clean Air Markets (CAM) data (Appendix A) and vendor guarantees show that SCR can typically meet 0.05 lb/mmBtu (or lower) on an annual average basis. GRE, BEPC, and NDDAQ have not provided any documentation or justification to support the higher values used in their analyses. Our review of operating data (Appendix A) suggests that a NO_X limit of 0.06 lb/mmBtu is appropriate (with an adequate "safety-margin") for LNB/OFA+SCR for a 30-day rolling average, and 0.07 lb/mmBtu for a 24-hour limit and for modeling purposes, but a lower rate (e.g., 0.05 lb/mmBtu or lower) should be used for annual average and annual cost estimates. When the annual NO_x reductions are underestimated, the cost-effectiveness of the control option is negatively affected.

Response: The 0.05 lb/10^6 Btu limit in Wyoming was for the Dry Fork Plant which is a new plant and has not demonstrated that it can meet that limit.

DOI claims that SCR can achieve 90% removal efficiency. The Department believes this is true for new units but not for retrofits. The EPA Air Pollution Control Cost Manual states "In practice, SCR systems operate at efficiency in the range of 70% to 90%." EPA's Air Pollution Control Technology Fact Sheet for SCR states "SCR is capable of NO_x reduction efficiencies in the range of 70% to 90%." In the ANPR for the Four Corners Power Plant (Federal Register 8/28/09) EPA states "APS estimated that SCR could achieve NO_x control of approximately 90% or greater from the baseline emissions. For new facilities, 90% or greater reduction in NO_x from the SCR can be reasonably expected. See May 2009 White Paper on SCR from Institute of Clean Air Companies. For SCR retrofits on an existing coal-fired power plant, Arizona Department of Environmental Quality (ADEQ) determined that 75% control from SCR (following upstream reductions by LNB) was appropriate for the Coronado Generating Station in Arizona. Based on this data, EPA has determined that an 80% control efficiency for SCR alone, rather than the 90+% control assumed by APS, is appropriate". The Department believes 80% is a reasonable estimate that allows the source to comply with the expected emission limit on a continuous basis.

Comment 9:

Step 4: EVALUATE IMPACTS AND DOCUMENT RESULTS

The cost of SCR was consistently overestimated. EPA's BART Guidelines recommend use of the OAQPS Control Cost Manual. Neither Minnkota Power Cooperative (Minnkota), GRE, BEPC, nor NDDAQ provided justification or documentation for their cost estimates. We were not provided with any vendor estimates or bids, and none used the recommended Control Cost Manual. This resulted in much-higher SCR costs than suggested by available literature (see Appendix B cost summaries) which shows SCR costs ranging from \$50 - \$267/kW. As recommended by the BART Guidelines, we applied the OAQPS Control Cost Manual to the EGUs and derived costs that fell within the Appendix B cost-survey range. As a result, we believe that capital and annual costs are overestimated by NDDAQ.

According to EPA's BART Guidelines, "the basis for equipment cost estimates should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option."

EPA's belief that the Control Cost Manual should be the primary source for developing cost analyses that are transparent and consistent across the nation and provide a common means for assessing costs is further supported by this November 7, 2007, statement from EPA Region 8 to NDDAQ:

> The SO_2 and PM cost analyses were completed using the CUECost model. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based

on the OAQPS Control Cost Manual. Therefore, these analyses should be revised to adhere to the Cost Manual methodology.

We are especially concerned about the lack of justification and support for the estimates of costs for reheating the exhaust gas streams to facilitate addition of "tail-end" SCR. Reheat costs are a critical issue affecting the economic feasibility of SCR, and, even in those cases where some data were presented (by GRE), it was still not adequate for us to be able to understand the assumptions that formed the bases for the natural gas usage estimates. Furthermore, we are concerned that the costs of catalyst, ammonia, electricity, and natural gas were inflated beyond what we typically see, or what is projected by the Energy Information Administration (EIA) with respect to future natural gas prices. Finally, we are concerned that this critical cost was simply scaled from a few examples and applied to other SCR analyses—we believe that it deserves individual analyses specific to each case.

Response: The DOI used the EPA Air Pollution Control Cost Manual (February 1996) to estimate the capital cost and operating costs for the SCR system. The DOI did not use the most current version of this manual which is dated January 2002. The EPA Air Pollution Control Cost Manual (both versions) is significantly out-of-date for estimating costs for SCR. This can be seen from the recently published results of EPA's review of the Four Corners Power Plant BART analysis. In the Advanced Notice of Proposed Rulemaking (August 28, 2009), EPA published the Consultant's, EPA's and the National Park Service's estimate of the cost for NO_x controls. The annualized cost of SCR was as follows:

Unit	Consultant	EPA	NPS
1	$22,297,000	$16,599,600	$2,983,000
2	$23,634,000	$17,851,500	$3,052,010
3	$23,173,000	$16,962,000	$3,497,117
4	$55,755,000	$39,810,900	$9,838,997
5	$55,755,000	$39,810,900	$9,213,942

The NPS cost estimate is 4-6 times lower than EPA's estimate.

For SCR alone the cost effectiveness was:

Unit	Consultant ($/ton)	EPA Cost ($/ton)	NPS Cost ($/ton)
1	4,343	3,758	1,558
2	5,484	4,803	1,469
3	4,582	3,646	1,684
4	4,872	4,341	1,185
5	4,872	4,330	1,357

It would appear the NPS is underestimating annualized SCR costs by as much as a factor of 6 and cost effectiveness by as much as a factor of 3. The discrepancy between the annualized cost and the cost effectiveness is apparently due to the NPS overestimating the effectiveness of SCR.

Based on this apparent underestimation, it appears the costs provided by the consultants and the Department's estimates are similar to EPA estimates and are reasonable. Any estimate by the FLM of cost on a dollar per deciview basis would be similarly flawed.

As pointed out earlier, the OAQPS Control Cost Manual is out-of-date. EPA accepted estimates based on the CUE Cost Model for the Four Corners Power Plant BART analysis. Since the OAQPS Control Cost Manual is out-of-date and drastically underestimates control costs, we believe the CUE Cost Model provides a more realistic estimate of the costs.

Comment 10: (Step 5: Visibility Improvement)

A) DOI believes it is appropriate to consider both the degree of visibility improvement as well as cumulative effects.

B) DOI is concerned that the Department did not provide the total improvement for each BART option.

Response: The total improvement under BART is not the best metric for addressing visibility associated with each option since the single source modeling under BART overpredicts (by a factor of 5-7) the actual improvement in North Dakota. Incremental differences in improvement provides an easy way to evaluate the visibility improvement benefits of one option over another. The difference is equivalent to the total improvement of one option minus the total improvement of the other option. Providing the total improvement will mislead the reader of the SIP because of the overprediction. However, this information can be extracted from the analyses conducted by the operators of the BART sources.

C) DOI is concerned about the difference in their modeling for Leland Olds Unit 2 and the Department's and Basin Electric's modeling results (the latter two sets of results agree closely).

Response: There are bound to be differences in modeling results when different model settings and options are used as well as different receptor grids. One error noted in the DOI modeling results was the input for the maximum 24-hour SO_2 emission rate for Unit 2. DOI used 17,610 lb/hr plus 1,581 lb/hr for sulfate. Unit 2 had a maximum 24-hour SO_2 (includes SO_4) of 12,205 lb/hr during the baseline period (2000-2004). DOI apparently used an SO_2 + SO_4 emission rate based on maximum future sulfur content. This is incorrect since current visibility conditions (12,205 lb/hr) are compared to conditions after controls are applied. The BART Guideline states "Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario)". The meteorological data used by the Department is from 2000-2004. Use of potential future uncontrolled emissions for the pre-control scenario is inconsistent with the BART guideline. The Department also noted that this error carried over into the emission rates for other pollutants. This error will provide a much greater improvement in visibility as found by the DOI.

Comment 11: It appears to be more beneficial to reduce NO_x than to reduce SO_2 in this cool climate.

Response: The Department does not necessarily agree with this statement. There are situations in North Dakota where reduction in NO_x has very little impact on visibility. This can be seen from the AVS I analysis. A 65% reduction NO_x (2,356 tpy) only provided a 0.01 deciview improvement in the average of the 20% worst days.

Comment 12: DOI recommends more emphasis on the dollar per deciview metric.

Response: There was no established data base for this metric when the BART analyses were developed and when the Department was making its decisions. Even the DOI's data is not very useful since the EPA has not approved the BART determinations in that database. Again, the single source modeling does not reflect the true visibility improvement. It may be more realistic in some states than in others. Therefore, the comparison of $/deciview in North Dakota to $/deciview in another State is not an apples-to-apples comparison. The Department has considered the incremental visibility improvement between BART options. We believe this is the best metric given the limitations of single source modeling to provide realistic estimates of visibility improvement.

Comment 13: For several units, NDDOH is proposing alternative sulfur dioxide (SO_2) limits that are similar to the presumptive BART limits because they allow a source to choose between a limit in terms of pounds of emissions per million Btu of heat input, or percent reduction of that pollutant. While EPA presented its BART Guidelines for SO_2 in that format, we do not believe that it was EPA's intention to allow the source to choose the more favorable limit. By definition, BART represents the highest degree of control that meets the five-factor test. Where NDDOH has determined that a lb/mmBtu limit is reasonable, it should require that that limit be met. Similarly, where NDDOH has determined that a percent reduction limit is reasonable, it should require that that limit be met. If both limits are determined to be reasonable, then to allow the source to choose only one clearly does not represent the most stringent reasonable degree of control. Therefore, where NDDOH has proposed alternative limits, both should be required.

There is also a fundamental problem with setting only a percent-reduction limit on SO_2 emissions. If fuel sulfur content increases, emissions can increase correspondingly. Unless sulfur content is limited, or a cap is placed on mass emissions (e.g., lb/hr, tons/yr as proposed by Wyoming, for example), the actual amount of SO_2 emitted is unlimited.

Response: The DOI has requested that the sulfur dioxide limitations be written as 95% reduction and 0.15 lb/10^6 Btu instead of 95% reduction or 0.15 lb/10^6 Btu. Coal quality data suggests that the source may not be able to comply with the 0.15 lb/10^6 Btu limit when the maximum sulfur coal is received. This would make the requested standard impossible to meet for high sulfur coal. The BART guidelines (40 CFR 51, Appendix Y, Section IV.E.4) states "you must require 750 MW power plants to meet specified levels of SO_2 of either 95 percent control **or** [emphasis added] 0.15 lb/10^6 Btu". The guidance does not indicate both standards apply. In addition, the BART presumptive levels are not applicable to any source in North Dakota except for NO_x at Coal Creek Station.

The DOI has also asked that a mass per unit of time limit be placed on the permit for SO_2. The Department believes this is unnecessary since the Department's evaluation of visibility impacts was based on full load and worst case sulfur (i.e. highest 24-hour emissions). The Department asked the EPA if a mass per unit of time limit (24-hour basis to ensure the accuracy of the modeling) was necessary in the permit that establishes the BART limits. In a November 21, 2005 response from Laurel Dygowski of Region 8, it was stated "we think that a 24-hour limit is unnecessary and may not be of much value". Based on EPA's guidance and the Department's determination that mass per unit of time units are not necessary, the Department will not include such limits in the permit that establishes the BART limits.

Comment 14: DOI does not believe Heskett Unit 2 should be exempt from the BART requirement.

Response: The Department is reevaluating the status of Heskett Unit 2. This unit will be addressed in a supplement to this SIP revision.

Comment 15: DOI believes the 70% reduction requirement at Heskett Unit 2 is misleading.

Response: The 70% reduction is a requirement that was placed in the draft Permit to Construct. The calculations that were provided are accurate based on the coal quality expected. The Department will clarify that the permit requirement (70% reduction) is not an actual reduction from current emissions.

Coal Creek BART Determination

Comment 16: Low NO_x burners and Over-Fire Air should have been considered coupled with SCR.

Response: The Department evaluated SCR at an emission rate of 0.043 $lb/10^6$ Btu (annual average) which is equivalent to 0.05 $lb/10^6$ Btu on a 30-day rolling average basis. This is the same as the lowest emission rate in the RBLC. We believe a lower emission rate is not achievable on a continuous basis. Because Coal Creek is already equipped with LNB and a form of overfire air, the modifications of these systems is not expected to reduce emissions below 0.043 $lb/10^6$ Btu.

Comment 17: NDDAQ is proposing upgrading the existing wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. The proposed scrubber upgrades will each result in an approximately one dv improvement in visibility at Theodore Roosevelt NP and 1.9 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubber, but recommend that the limits require **both** 95% control **and** 0.15 lb/mmBtu, as well as specific caps on emissions.

Response: The Department's BART determination is based on upgrading the existing wet scrubber to 95% efficiency, not the addition of a new wet scrubber. See response to Comment 13 regarding the BART limit.

Comment 18: NDDAQ is proposing LNB + SOFA at 0.17 lb/mmBtu on a 30-day rolling average basis as BART for NO_X. As a result, visibility would improve by 0.10 dv at Lostwood and 0.19 dv cumulatively.

Response: See response to Comment 6, Paragraph 2.

Comment 19: NDDAQ has underestimated the effectiveness of SCR at only 80% control efficiency.

Response: See response to Comment 8.

Comment 20: NDDAQ has overestimated the costs of SNCR and SCR. Many of the costs associated with SNCR and SCR presented by GRE and NDDAQ were not supported by GRE's documentation. Costs associated with lost ash sales and ash disposal were not adequately justified. More reliance should be placed upon use of the EPA Control Cost Manual when the source fails, as GRE did, to provide sufficient supporting documentation of its costs. Our application of the EPA Control Cost Manual yielded much lower cost estimates for SNCR and SCR.

Response: See response to Comment 9.

Concerning the inclusion of sunk costs of ash sales infrastructure, an assessment of the effect of removing sunk costs from the calculations has been performed and added to the BART determination. If the sunk costs for the ash sales infrastructure are disregarded, then the annualized cost for SNCR would be $21,750,000; the cost effectiveness would be $8,122 per ton; and the incremental cost would be $19,692 per ton. This change improves the favorability of the SNCR alternative by only 5%, an insignificant improvement that does not change the choice for BART.

On the matter of the possibility of lost ash sales, DOI stated elsewhere in its comments: "If ash sales are not adversely affected, addition of SNCR becomes a reasonable BART selection." However, neither DOI, EPA nor others have provided evidence to support the opinion that SNCR and its associated use of ammonia will not negatively impact GRE's ash sales; in fact, there is some evidence to the contrary. GRE emails dated 8/8/08 and 8/17/08 provide additional information on this issue, as does a summary of a University of Kentucky study on the matter. After considering all the information available, NDDAQ reached the following conclusions.

- SCR and SNCR use at Coal Creek Station will likely result in ammonia in the fly ash.
- The level of ammonia in the fly ash cannot be predicted with a reasonable certainty.
- The maximum level of ammonia in fly ash that would still avoid negative impacts on the salability of the ash cannot be predicted.

Therefore, NDDAQ cannot determine with reasonable certainty that SCR or SNCR will not result in a level of ammonia in the ash that could reduce or eliminate future ash sales. Any regulator who determines that SCR or SNCR will not jeopardize ash sales would be obligated to present the evidence in support of that position. While another regulator might determine that even a small improvement in visibility is worth GRE taking the risk of lost ash sales, making a wrong decision will inflict a significant financial penalty on GRE and send ash to a landfill, or be treated as a hazardous waste (depending on current rule development), instead of it being used beneficially. Having considered all of the information available, the NDDAQ BART determination on this matter remains unchanged.

Furthermore, in a BART and PSD analysis for the Omaha Public Power District Nebraska City Station Unit #1 coal boiler (Construction Permit Number CP07-0049, 2/26/09 fact sheet, pg. 17), Nebraska DEQ determined SCR was not BART in part because … "ammonia used in the system would cause the ash to be contaminated, thereby jeopardizing the current beneficial reuse of a portion of the ash produced by NCS Unit 1."

Comment 21: We conclude that SNCR is BART for control of NO_X emissions from GRE Coal Creek Units #1 and #2.

Response: See Comment 20 and response concerning lost ash sales.

Comment 22: NDDAQ has not adequately considered the visibility benefits of the control strategies it evaluated.

Response: Tables showing the visibility impacts of the cost effective control strategies will be added to the GRE Coal Creek BART analysis.

Comment 23: NPS' analysis of addition of SNCR indicates that visibility would improve by 0.17 dv at Lostwood and 0.32 dv cumulatively. This yields a cost-effectiveness of $17.2 million per dv at Lostwood WA and $9.2 million per dv cumulatively when Theodore Roosevelt NP is included, which we believe to be reasonable based upon BART determinations and proposals we have seen nationwide to date. NPS' estimates for addition of SNCR show cost-effectiveness values below the $17 - $21 million per cumulative dv that NDDAQ accepted for adding SNCR at Stanton #1. Considering that the BART program is intended to improve visibility, it follows that any cost-effectiveness value below the costs per dv accepted by NDDAQ at Leland Olds #1 and Stanton should also be acceptable at Coal Creek.

Response: See response to Comment 6.

Stanton Unit 1 Bart Determination

Comment 24: On page 15 of the comments, the DOI states that "Great River Energy (GRE) operates the 256 MW Stanton Station near Stanton, ND."

Response: The nameplate capacity of the Stanton Station is 200 MWe, not 256 MW as stated by DOI. The National Park Service was informed by the Department in an October 21, 2009 email that the nameplate capacity of the Stanton Station is 200 MWe. It should be noted that the BART determination is being conducted for Stanton Station Unit 1, not the entire Stanton Station (which consists of Stanton Station Unit 1 and Unit 10). Stanton Unit 1 can supply steam that will produce 140 – 170 MWe.

Comment 25: On page 16 of the comments, the DOI states, "We believe that higher control efficiency is warranted for both the lignite and PRB sub-bituminous scenarios". The DOI goes on to state that a facility burning coal with an uncontrolled SO_2 emission rate of 2.4 lb/MM Btu for lignite and 1.6 lb/MMBtu on PRB "should be capable of at least 93% control and achieve an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis[11]". Footnote 11 in the DOI comments states, "Please see the entry in Appendix D for the permit issued by Wyoming to Black Hills Power for its WYGEN3 project".

Response: The DOI states a SD/FF at Stanton #1 "should be capable of" at least 93% control and an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis. The DOI attempts to support this position by referencing the WYGEN3 facility permit. Although the WYGEN3 facility does have a 0.09 lb/MMBtu SO_2 emission limit, according to the EPA RACT/BACT/LAER clearinghouse, the 0.09 lb/MM Btu SO_2 emission limit is on a <u>12-month rolling average</u> basis, not a <u>30-day rolling average</u> basis. Also, the RACT/BACT/LAER clearinghouse does not list a required SO_2 removal efficiency. If the WYGEN3 facility burns low-sulfur coal, the facility could comply with the 0.09 lb/MMBtu emission limit with SO_2 control efficiencies below 90%. Furthermore, it is the Department's understanding that the WYGEN3 facility has yet to operate and demonstrate that the SO_2 emission limit can be achieved. Based upon these facts, the WYGEN3 facility permit does not support the DOI position that a SD/FF at Stanton Station Unit 1 "should be capable of" at least 93% control and an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis.

The Department maintains the position that a SD/FF operating at Stanton Station Unit 1 is capable of achieving an SO_2 control efficiency of 90%.

Comment 26: On page 16 of the DOI comments, the DOI states, "Because the larger Stanton Unit #10 also located at this site is achieving less 0.06 lb/MMBtu on an annual basis (presumably burning PRB coal) using the same SD/FF technology proposed for Stanton Unit #1, NDDAQ should explain why a newer installation of that technology at Stanton #1 cannot perform as well, at least on PRB coal".

Response: The DOI incorrectly states that Stanton #10 is larger than Stanton #1. In fact, Stanton #10 (with a heat input of approximately 642 MM Btu/hr) is approximately 2.8 times <u>smaller</u> than Stanton #1 (with a heat input of approximately 1,800 MM Btu/hr).

The DOI states that Stanton #10 emitted SO_2 at an emission rate of 0.06 lb/MM Btu and asks the Department to explain why Stanton #1 cannot perform as well as Stanton #10 when burning PRB coal. Although the Stanton #10 facility has recently emitted SO_2 at an emission rate of 0.06 lb/MM Btu, based upon the average sulfur content of the coal burned the SO_2 removal efficiency at Stanton #10 is estimated to be approximately 90%. The dry scrubber technology proposed as BART for Stanton #1 is expected to achieve an SO_2 control efficiency of 90%, so Stanton #1 <u>will be</u> expected to perform as well as Stanton #10.

Comment 27: On page 16 of the DOI comments, the DOI states, "It is likely that increasing the SD/FF efficiency to achieve 0.09 lb/mmBtu would be even more cost effective on a $/ton basis."

Response: The DOI provides no basis for this comment. The Department maintains the position that 90% control is a reasonable control efficiency for a SD/FF system and that the Stanton Station Unit 1 would not be able to meet an SO_2 emission limit of 0.09 lb/MM Btu when combusting higher sulfur coals.

Comment 28: On page 17 of the DOI comments, the DOI states, "We recommend limits of 0.09 lb/mmBtu and 93% reduction on a 30-day rolling average for both fuels based upon recent determination by other states for EGUs burning coals with similar uncontrolled emissions. Even if coal quality deteriorates to the anticipated worst-case 2.4 lb/mmBtu, 96% control would still meet the 0.09 lb/mmBtu limit. We also recommend short and long-term absolute (e.g., lb/hr, tpy) caps on emissions to insure that emissions will not increase greatly over time". The DOI reiterates this comment on page 20 of the DOI comments.

Response: DOI has requested that the sulfur dioxide limitations be written as 93% reduction <u>and</u> 0.09 lb/MM Btu for both fuels instead of 90% reduction <u>or</u> 0.16 lb/MM Btu for PRB <u>or</u> 0.24 lb/MM Btu for lignite. Coal quality data suggests that the source would not be able to comply with the 0.09 lb/MM Btu limit when the maximum sulfur content coal is received and emissions are controlled at 90%. This would make the requested standard impossible to meet for high sulfur coal with a 90% reduction requirement. The DOI suggests that the facility can simply control at efficiencies greater than 90% (i.e. 96%); however, the Department's position is that a SD/FF operating at Stanton Station #1 is capable of 90% SO_2 control on an on-going basis, not greater than 90% control as suggested by DOI.

The BART guidelines (40 CFR 51, Appendix Y, Section IV.E.4) states, "you must require 750 MW power plants to meet specified levels of SO_2 of either 95 percent control <u>**or**</u> [emphasis added] 0.15 lb/10^6 Btu". The guidance does not indicate both standards apply. In addition, the BART presumptive levels are not applicable to this source.

The DOI has also asked that a mass per unit of time limit be placed on the permit for SO_2. The Department believes this is unnecessary since the Department's evaluation of visibility impacts were based on full load. The Department asked the EPA if a mass per unit of time unit (24-hour basis to ensure the accuracy of the modeling) was necessary in the permit that established the BART limits. In a November 21, 2005 response from Laurel Dygowski of Region 8, it was stated, "We think that a 24-hour limit is unnecessary and may not be of much value". Based on EPA's guidance and the Department's determination that mass per unit of time units are not necessary, the Department will not include such limits in the permit that established the BART limits.

Comment 29: On page 17, the DOI states, "We believe that NDDAQ should have included SOFA with tail-end SCR with reheat in its analysis".

Response: The Department analyzed SCR with reheat in the BART analysis. A 90% control efficiency for SCR with reheat was assumed. For retrofits, the Department believes that a 90% control efficiency for SCR with reheat is highly optimistic and that 80% control is reasonable. It should be noted that conducting the BART analysis using an 80% control efficiency would make the cost of SCR with reheat even more cost prohibitive.

In the Department's judgment, SOFA with SCR with reheat would not attain greater than 90% NO_x control at Stanton #1. Since SOFA with SCR with reheat would be more expensive than SCR with reheat (which has already been determined to be cost prohibitive assuming a 90% control efficiency), it can be concluded that an analysis of SOFA with SCR with reheat would also be considered to be cost prohibitive.

Comment 30: On pages 18 and 20 the DOI indicates that the expected costs for SCR with reheat included in the BART analysis for Stanton #1 are higher than the cost estimates prepared by the DOI. The DOI requests that the Department document and justify the SCR with reheat cost estimate.

Response: The DOI requests that the Department document and justify the SCR with reheat cost estimate for Stanton #1. The Department considers the cost estimate of SCR with reheat submitted with the GRE BART analysis to be extensively documented and the Department has verified the cost estimates.

The DOI states that the expected costs for SCR with reheat included in the BART analysis for Stanton #1 are higher than the cost estimates prepared by the DOI. See response to Comment 9.

Comment 31: On page 21 of the comments, the DOI states, "We believe that SCR may represent BART, especially when the modeling issues identified in other reviews are resolved".

Response: The Department has eliminated high-dust SCR as technically infeasible and low-dust SCR with reheat has been eliminated based on cost. The DOI has questioned the Department's cost estimates for SCR with reheat and the Department has demonstrated that the costs as presented are reasonable (see response to Comment 9). Based upon a consideration of all of the factors, the Department maintains the position that SCR does not represent BART at Stanton Station Unit 1.

Leland Olds Unit 1 BART Determination

Comment 32: NDDAQ did not evaluate the impact of the new wet scrubber at Unit 1 versus the baseline condition.

Response: The Department evaluated the difference in visibility impact between the top two SO_2 control technologies, a wet scrubber and spray dryer. As indicated by the BART Guideline, Step 5, a determination of the net visibility improvement is to be made. Our analysis is consistent with the BART Guideline. The most efficient control option (wet scrubber) was selected as BART. The amount of visibility improvement versus the baseline may be extracted from BEPC's analysis. The Department did not present this result since we believe it is incorrect and misleads the reader.

Comment 33: DOI recommends that the SO_2 limit be written as 0.15 lb/10^6 Btu and 95% reduction.

Response: See response to Comment 13.

Comment 34: DOI believes SOFA + SCR can achieve 83% NO_x removal.

Response: As pointed out in the Advanced Notice of Proposed Rulemaking for the Four Corners Power Plant, the Arizona DEQ determined that 75% control was appropriate following low NO_x burners at the Coronado Generating Station. Leland Olds 1 is equipped with low NO_x burners. We believe 75% reduction for the retrofit of a 43 year old plant is appropriate. Reducing the emission rate to 0.05 lb/10^6 Btu achieves 212 tons per year additional NO_x reduction. The cost effectiveness is then $8,888/ton to $12,784/ton. These costs are still considered excessive and SCR + SOFA is not BART.

Comment 35: NDDAQ did not evaluate the visibility benefits of any of the technically feasible options except for the proposed basic SOFA + SCR.

Response: The cost analysis eliminated SCR, coal reburn + SCR, coal reburn + SOFA and SNCR + boosted SOFA on either a very high cost effectiveness basis or a very high incremental cost basis. This left SOFA + SNCR as the most efficient control option. This option was then modeled to determine the visibility effects.

Comment 36: NDDAQ is proposing addition of a new wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. We have estimated that the proposed new wet scrubber will result in an approximately 1.2 dv improvement in visibility at Theodore Roosevelt NP and 2.4 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubbers, but recommend that the limits require **both** 95% control **and** 0.15 lb/mmBtu, as well as specific caps on emissions.

Response: See response to Comment 13.

Comment 37: Based upon NDDAQ's analysis, addition of the proposed basic SOFA+SNCR to LOS #1 yields a cost-effectiveness of $25.6 million per dv at Theodore Roosevelt NP and $13.2 million per dv cumulatively when Lostwood WA is included. NDDAQ has not adequately considered the visibility benefits of the control strategies it evaluated. NPS' analysis of addition of basic SOFA+SCR with reheat yields a cost-effectiveness of $12.6 – $32.3 million per dv cumulatively. We would normally consider costs above $20 million/dv to be above the average that most states/source are proposing, but believe that these results warrant further analysis, as we will discuss in more detail with respect to LOS #2.

Response: SOFA + SCR has an estimated cost of $8,888 - $12,784/ton of NO_x removed. The incremental cost would be approximately $15,748/ton to $25,319/ton over the next most efficient option. It is clear that SOFA + SCR, or SCR alone, is not cost effective for this unit.

Comment 38: NDDAQ underestimated the effectiveness of adding SCR to LOS #1. Outlet emissions projected by NDDAQ for SCR at 0.07 lb/mmBtu represent only a 75% SCR control efficiency We believe that a combination of combustion controls (e.g., SOFA) plus SCR can achieve 0.05 lb/mmBtu, and represents BART.

Response: See response to Comment 8. This is consistent with other BACT determinations, especially for retrofits.

Comment 39: NDDAQ overestimated the costs associated with adding SCR to LOS #1.Our application of the EPA Control Cost Manual yielded much lower cost estimates for SCR. Many of the costs associated with SCR presented by BEPC and NDDAQ were much higher than we have seen presented at similar facilities and were not supported by BEPC's documentation. More reliance should be placed upon use of the EPA Control Cost Manual when the source fails, as BEPC did for LOS, to provide sufficient supporting documentation of its costs.

Response: See response to Comment 9.

Leland Olds Unit 2

Comment 40: DOI suggests we investigate the differences in their modeling results and the Department's and BEPC results.

Response: The Department has investigated the DOI modeling – See response to Comment 10(c). The DOI modeling is not consistent with the BART Guideline. The Department's and BEPC modeling is consistent with the guideline.

Comment 41: NDDAQ is proposing to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. We recommend 0.15 lb/mmBtu **and** 95% reduction on a 30-day rolling average basis.

Response: See response to Comment 13.

Comment 42: We re-modeled LOS #2 assuming that the new wet scrubber would reduce SO_2 emissions to 0.15 lb/mmBtu and held all other emissions to their baseline rates. Our results estimate that the scrubber would improve visibility by 5.6 dv at Theodore Roosevelt NP and 9.4 dv cumulatively when Lostwood WA is included.

Response: See response to Comment 10(c). The much higher future emission rate, which is not consistent with the BART Guideline which requires use of the baseline emission rate, yielded the higher inaccurate result.

Comment 43: We agree with NDDAQ's estimates of control effectiveness, but suggest that, if ASOFSA can reduce emissions to 0.5 lb/MMBtu as estimated by NDDAQ, then addition of SCR at 90% as assumed by NDDAQ could bring emissions down to 0.05 lb/mmBtu.

Response: As pointed out in our response to Comment 8, 80% efficiency is a better number for retrofit of SCR. The Department did use 90% efficiency for SCR + ASOFA.

Comment 44: NDDAQ overestimated the costs associated with adding SCR to LOS #2.Our application of the EPA Control Cost Manual yielded much lower cost estimates for SCR. Many of the costs associated with SCR presented by BEPC and NDDAQ were much higher than we have seen presented at similar facilities and were not supported by BEPC's documentation. More reliance should be placed upon use of the EPA Control Cost Manual when the source fails, as BEPC did for LOS #2, to provide sufficient supporting documentation of its costs.

Response: See response to Comment 9.

Comment 45: We re-modeled LOS #2 and estimate that ASOFA + SCR would improve visibility by 2.3 dv at Theodore Roosevelt NP and 4.1 dv cumulatively when Lostwood WA is included. Our higher control-effectiveness results show that we are estimating that removing a ton of NO_x has greater benefits than estimated by BEPC/NDDAQ.

Response: The DOI modeling is inaccurate – see response to Condition 10(c). We believe the cumulative results are inappropriate – see response to Comment 6, Paragraph 2.

Comment 46: NPS' analysis of addition of ASOFA+SCR with reheat and using NDDAQ modeling results yields a cost-effectiveness of $4.0 – $9.6 million per dv at Theodore Roosevelt NP and $2.3 – $5.5 million per dv cumulatively when Lostwood WA is included. We believe that our cost estimates indicate that addition of SCR with reheat is reasonable based upon BART determinations and proposals we have seen nationwide to date.

Response: See response to Comments 10(c), Comment 6 and Comment 9.

Comment 47: The great disparity between modeling results produced by BEPC/NDDAQ and NPS requires resolution.

Response: See response to Comment 10(c).

M.R. Young Station Unit 1

Comment 48: We have estimated that the proposed new wet scrubber will result in an approximately 1.8 dv improvement in visibility at Theodore Roosevelt NP and 3.2 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubbers, but recommend that the limits require **both** 95% control **and** 0.15 lb/mmBtu, as well as specific caps on emissions.

Response: See response to Comment 13.

Comment 49: NDDAQ proposes that NO_x emissions be limited to 2,070.2 lb/hr on a 24-hour rolling average basis during startup. We recommend that NDDAQ limit the mass emission rate (e.g., lb/hr) to the rate under normal operation.

Response: The proposed limit is under normal operating conditions without the ASOFA and SNCR, since the SNCR cannot be operated until the proper boiler temperature is reached. The actual startup emissions will be much higher (>1.0 lb/10^6 Btu). Therefore, limiting startup emissions based on normal operations with SNCR ($\leq$0.35 lb/10^6 Btu) will provide no relief to the source during startup.

Comment 50: NDDAQ underestimated the effectiveness of adding ASOFA + SCR to MRYS #1. We suggest that ASOFSA + SCR can achieve 0.05 lb/mmBtu.

Response: See response to Comment 8. The Department used 90% for ASOFA + SNCR.

Comment 51: NDDAQ overestimated the costs associated with adding SCR. In the absence of supporting documentation by NDDAQ, we also estimated a total annual cost for ASOFA + SCR with reheat at $9.7 million and $1,028 per ton.

Response: Minnkota has provided its own estimate of the cost of SCR as part of the BACT process under their Consent Decree. Minnkota's estimate has been included in the BART determination.

Comment 52: We believe that ASOFA + SCR with reheat represents BART for MRYS #1.

Response: Based on the Department's evaluation of the five statutory factors, we believe SCR + ASOFA is not BART. As explained in the Department's analysis, the cost effectiveness is excessive, the incremental cost over the next most efficient control option (ASOFA + SNCR) is excessive and there is very little visibility improvement especially when the Department's cumulative visibility modeling is considered (0.01 deciviews average in the 20% worst days). The cumulative modeling results represents the most realistic degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

M.R. Young Station Unit 2

Comment 53: NDDAQ is proposing upgrading the existing wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. We have estimated that the proposed scrubber upgrade will result in an approximately 1.2 dv improvement in visibility at Theodore Roosevelt NP and 2.2 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubbers, but recommend that the limits require **both** 95% control **and** 0.15 lb/mmBtu, as well as specific caps on emissions.

Response: See response to Comment 13.

Comment 54: NDDAQ proposes that NO_x emissions be limited to 3,995.6 lb/hr on a 24-hour rolling average basis during startup. We recommend that NDDAQ limit the mass emission rate (e.g., lb/hr) to the rate under normal operation.

Response: See response to Comment 49.

Comment 55: NDDAQ underestimated the effectiveness of adding ASOFA + SCR to MRYS #2. We suggest that ASOFSA + SCR can achieve 0.05 lb/mmBtu.

Response: See response to Comment 8.

Comment 56: NDDAQ overestimated the costs associated with adding SCR. In the absence of supporting documentation by NDDAQ, we estimated total annual costs for ASOFA+tail-end SCR with reheat at $15.6 million and $898 per ton.

Response: Minnkota has provided a much more detailed cost estimate of SCR with reheat as part of their BACT process under their Consent Decree. This estimate has been used in the Department's BART determination.

Comment 57: We believe that ASOFA + SCR with reheat represents BART for MRYS #2.

Response: Based on the Department's analysis of BART for MRYS Unit 2, we believe the cost effectiveness of ASOFA + SCR is excessive, the incremental cost over the next most efficient option (ASOFA + SNCR) is excessive and the visibility improvement is very small going from ASOFA + SNCR to ASOFA + SCR (see Department's final analysis). Therefore, we believe ASOFA + SCR is not BART.

Modeling

Comment 58: NDDAQ indicates that the purpose of the hybrid modeling is as weight of evidence to discount the impact of international (particularly Canadian) emissions and to better represent plume dispersion from point sources, particularly those closer to the Class I areas. While the CMAQ 36 km grid resolution does allow dilution of the plumes from point sources, ND's hybrid modeling assumptions raise more questions that are answered. CALPUFF does allow tracking of individual plumes but the model chemistry is much simplified compared to CMAQ and the methods required to normalize CMAQ results to CMAQ-CALPUFF hybrid results becomes quite elaborate and questionable.

Response: To address commenter's concerns, Sections 8.5.6 ("Normalizing Hybrid Model RRF to WRAP CMAQ RRF") and 8.6 ("The Impact of International Sources on North Dakota Class I Areas") of the draft SIP have been combined and extensively rewritten in a new Section 8.5.6. The purpose of this revision is to clarify the usage and purpose of the NDDoH hybrid modeling system. The emphasis of the rewrite is that the hybrid model was used only to adjust WRAP CMAQ results, and not as a "stand alone" system. We believe the new language helps to clarify the intent and legitimacy of the NDDoH hybrid modeling approach. The NDDoH also notes that values used for background ammonia and other input settings for CALMET-CALPUFF (including "alternative protocol" settings of ongoing concern to EPA and FLMs) become less critical as the effect of values used both in the numerator and denominator to a significant extent "cancel out" in the adjustment ratio applied to WRAP CMAQ results. Certainly, these settings will have less impact than if the hybrid model was used in a "stand alone" sense.

We raise the following technical issues with the CALPUFF application:

A) Ammonia is known to be an important input to determine the amount of ammonium nitrate (NH_4NO_3) formed in CALPUFF. Regional ambient concentrations of ammonia are poorly understood. ND has one ammonia monitor at Beulah; please describe the type of monitor and the land use at Beulah compared to other areas of the CALPUFF domain. We question if this monitor is representative of the CALPUFF domain. We note that monthly average NH3 from 2001-2002 was used as background ammonia in CALPUFF after removing days influenced by a source region. The draft Plan should identify that source region.

Response: The ammonia monitor at Beulah is a Thermo Scientific 17c continuous sampler, based on the chemiluminescence analytical process. Land use in the vicinity of the Beulah monitoring site is predominantly rangeland and cropland, which is typical for most of North Dakota. Land use in the State is relatively homogenous, with cropland slightly more common than rangeland in eastern and northern parts of the State, and rangeland slightly more common than cropland in the southwest part of the State. As such, the Beulah ammonia monitor should be representative of the Calpuff domain. When processing Beulah monthly background ammonia values to use with CALPUFF, hourly observations associated with the northwest wind-direction quadrant were filtered from the 2001-2002 data set. This was done to avoid bias due to the Great Plans Synfuels plant located about eight kilometers northwest of the monitor site. This plant produces significant amounts of ammonia as a result of its production process.

B) EPA disapproved the use of the Ammonia Limiting Method to define NH3 levels in the VISTAS application cited by NDDAQ.

Response: The NDDoH did not use the Ammonia Limiting Method (ALM) to define ammonia levels. Background ammonia for NDDoH hybrid modeling was based on actual ambient ammonia monitoring data. The NDDoH used the ALM simply to avoid double-counting of ammonia by multiple puffs in the modeling domain.

C) For POSTUTIL, hourly ammonia data for 2001 -2003 were used and the Plan does not mention removing data. The Plan should identify if different years were used for the two applications. It appears that the ammonia levels at Lostwood were doubled compared to measured values based on the expectation that Lostwood is closer to ammonia sources in Canada. However, that adds a subjective adjustment to the CALPUFF modeling that brings into question the presumption that CALPUFF modeling is more accurate than just using CMAQ at 36 km.

Response: Based on consultation with Joe Scire (TRC Atmospheric Studies Group), the NDDoH elected to use hourly background ammonia data (Beulah monitor) with POSTUTIL. Use of the hourly data (rather than monthly) tended to improve hybrid model agreement with sulfate and nitrate observations in the performance evaluation. As was the case in the ammonia data set used with CALPUFF, hourly data associated with the northwest wind direction quadrant were removed from the data set used with

POSTUTIL, because of bias due to a large ammonia source (Great Plains Synfuels Plant) located northwest of the Beulah monitor site. Due to resultant missing data periods, the three year period 2001-2003 of hourly ammonia data was averaged to prepare a composite hourly data set for 2002. The NDDoH considers this a refinement of the monthly data used with CALPUFF, and notes that ammonia background used with POSTUTIL completely supersedes the ammonia background used in CALPUFF (this conclusion is the result of extensive testing).

Regarding adjustment of Beulah monitoring data for the Lostwood location, the assumption of higher ammonia background at Lostwood is consistent with predominant land use and other anecdotal evidence (see Section 8.5.4), and it provided better agreement with observations in hybrid model performance evaluations for sulfate and nitrate. We note again that NDDoH hybrid modeling is not as sensitive to the specific ammonia background applied because of the ratio approach used to adjust WRAP CMAQ results (see response to Comment 58).

D) We note that four ozone monitors in central ND were selected to represent background ozone in CALPUFF. Are there only four ozone monitors in the CALPUFF domain? Table 8.6 says background value for ozone was 30 ppb, but does not link this to monitoring data.

Response: The four ozone monitors used to represent background ozone in the hybrid model (CALPUFF) are located near the primary transport path between larger North Dakota point sources and Class I areas. Though the NDDoH operates additional ozone monitors in the State, ozone observations are relatively homogeneous across North Dakota with little spatial variability. It is not likely that the inclusion of data from additional ozone monitors would have provided any meaningful difference in results. The NDDoH used hourly ozone data from the four monitors for year 2002 with CALPUFF. The 30 ppb background ozone number in Table 8.6 represents a typical annual average monitored value, and applied only in those rare cases when the hourly value was missing.

Comment 59: We question the Hybrid model performance evaluation. Model performance evaluations are usually based on raw model output. We understand that the Hybrid model results were normalized before evaluation and then were normalized again to the WRAP baseline results. The need to normalize the CALPUFF relative response factors to the WRAP results, brings into question the value of using the CALPUFF hybrid regional model to discern the benefits of NDDAQ strategies.

Response: The performance evaluation was based on raw model output from the hybrid system. Model output was not normalized or adjusted in any way prior to comparing with observations. Language has been added to Section 8.6 to clarify this point.

Comment 60: Section 8.6, including Figure 8.10, describes a possible way to account for international emissions when assessing the progress toward the goal of natural conditions. While we agree that examining the contribution to extinction for each aerosol species is a good approach to understanding if a State is meeting its fair share of emissions reductions associated with visibility impacts at a Class I area, the method described in this section and in the figure raise concerns since there was no assessment of the international component of the natural condition estimate. The value in 2064 illustrated in Figure 8.10 uses the same natural condition endpoint for the total extinction as well as the "U.S. Source" extinction, yet the 2064 natural condition estimates for aerosol species include some global or international component. We believe that a better way to address reasonable progress by extinction component is to assess the reduction needed for each aerosol species measured in the baseline period to the end of the first planning period and then assess if a state's plan achieves a comparable reduction for its share of extinction at the Class I areas.

Response: In its approach for discounting the impact of Canadian source visibility-affecting emissions, the NDDoH modified the emissions inventories used in the adjustment of WRAP CMAQ modeling results (see revised Section 8.5.6). The modification involved elimination of all Canadian sources, except for the Canadian component of natural background, which was retained through adjustment of boundary conditions in CALPUFF. Therefore, the modified emissions inventories accounted for all non-Canadian sources, including all components of natural background. Thus, there was no need to adjust the end point for the "U.S. sources" glide path. For clarification, however, further description regarding the context of "U.S. sources" has been added to Section 8.6, and labels for "U.S. sources" glide paths in Figures 8.10, 8.24, 8.26 and 8.27 have been changed to "Canadian Sources Discounted Glide Path".

Reasonable Progress Goals

Comment 61: The State should rely on WRAP regional modeling as the primary tool for demonstrating progress toward visibility improvement goals. The CMAQ-CALPUFF hybrid modeling is problematic in several ways and gains ND little benefits compared to using WRAP products. Two WRAP products that were omitted but should be included to help ND in making its reasonable progress determination are 1) Weighted Emissions Potential (WEP) and 2) extinction glide paths for SO_4, NO_3, and OC.

The uniform rate of progress glide path cannot be revised to account for contributions from natural sources or international sources under current or 2018 conditions without also removing these contributions from the 2064 endpoint. While the contribution from natural and international sources by 2064 is unknown, it may be comparable to current contributions. Therefore removing the estimated contributions from current conditions without also accounting for those contributions to the 2064 endpoint inappropriately changes the slope of the uniform rate of progress

It would be more appropriate to use the WRAP CAMx-PSAT results to demonstrate the relative contributions to sulfate and nitrate from Canadian and ND emissions at the North Dakota Class I areas. The Plan has already included these results in Table 6.7.

We suggest NDDAQ use the WRAP extinction glide paths to show the improvement in SO_4 or NO_3 due to emissions reductions from all sources in the WRAP 2018 inventory, and compare the ND emissions reductions by 2018 to emissions reductions from Canada and neighboring states.

It would be informative for the Plan to include what percent of the State's total SO_2 and NO_X emissions from point sources is being reduced under BART. What other point source or area source reductions are reasonable?

Response: The usage and purpose of the NDDoH hybrid modeling system was clarified in the response to Comment 58, and in the revision of Section 8.5.6 of the SIP. The NDDoH does not agree that the NDDoH modeling provides little benefit compared to using WRAP products. Through use of the hybrid model to adjust WRAP CMAQ results, the NDDoH was able to produce a suite of analyses related to weight of evidence, none of which were available in the original WRAP products. The NDDoH regards these weight of evidence analyses more useful than the additional WRAP products suggested by the commenter.

Regarding the uniform rate of progress glide path 2064 endpoint, see response to Comment 60.

The SIP already includes the WRAP Cam_x-PSAT results, demonstrating the relative contributions to sulfate and nitrate from Canadian and ND emissions at North Dakota Class I areas, in Table 6.7 and 9.12.

A comparison of North Dakota emissions reductions by 2018 with emission reductions from Canada and neighboring states has been added to Section 9.

The Department has reviewed other point sources, agricultural tillage operations, smoke management techniques and oil and gas operations for possible air pollution control requirements. The Department determined that additional controls were not reasonable during this planning period. However, all sources of emissions will be reevaluated during future planning periods.

Comment 62: For stationary sources, NDDAQ developed a methodology to look at options for controls for sources, beyond the source subject to BART, contributing to the major components of aerosol extinction on the worst 20 percent days. While we generally agree with the use of emissions over distance (Q/d) as a screening tool, we note that the Heskett facility was not included in Table 9.4 even though NDDAQ proposes to exclude the source from BART requirements.

Response: The status of Heskett Unit 2 is being reevaluated and will be addressed in a supplement to this SIP revision.

Comment 63: Table 9.9 summarizes the results of assessing the costs and visibility improvement associated with possible controls on these facilities. The two power generation facilities, Coyote and AVS, have emissions and Q/d impacts that are similar, if not greater than, BART sources that will be required to add controls. The methodology to calculate visibility improvements noted in Table 9.9 are not explained in this section but appear to be some calculation of changes in the long-term metric of the 20 percent worst visibility days. These sources likely contribute to higher impacts on a daily basis, and a reduction in their emissions would be part of a broad strategy to reach natural conditions at the Class I areas. As such

NDDAQ should examine the total improvement from the suite of sources as part of its reasonable progress assessment, not a simple unit by unit approach.

Response: The improvement in the 20% worst days was used to indicate the amount of visibility improvement. The SIP was revised to better explain this. Addressing individual days under reasonable progress is inconsistent with the reasonable progress goals in 40 CFR 51.308(d)(1) which states "The reasonable progress goals must provide for improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 CFR 51.301 defines the most impaired days as meaning "the average visibility impairment (measured in deciviews) for the 20% of monitored days in a calendar year with the highest amount of visibility impairment." 40 CFR 51.301 defines the least impaired days as the average visibility impairment (measured in deciviews) for the 20% of monitored days in a calendar year with the lowest amount of visibility impairment." It is clear that reasonable progress goals should be established based on the average of the "most impaired days" and the "least impaired day", not individual days.

The Department did evaluate the cumulative effects of the most efficient remaining options. As stated on p. 182, the cumulative visibility improvement was 0.11 deciviews at LWA and 0.03 deciviews at TRNP. The less efficient control options would provide even less improvement.

Comment 64: The assessment of non-air quality impacts on page 181 in the draft SIP does not address the substantial human health benefits associated with reductions in fine particulate concentrations resulting from additional control of SO_2 and NO_X emissions from Coyote and AVS since they would become the newest and highest emitters of these pollutants after implementation the SIP as drafted.

Response: Reasonable progress is evaluated based on four stationary factors 1) the cost of compliance, 2) the time necessary for compliance, 3) the energy and nonair quality environmental impacts of compliance, and 4) the remaining useful life of the source.

The Energy and Non-Air Quality Environmental Impacts Analysis does not address health effects from air emissions. As stated in the BART guideline "In the non-air quality related environmental impacts portion of the BART analysis, you address impacts **other than air quality** [emphasis added] due to emissions of the pollutant in question. Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device."

Even though health effects are not evaluated under this section of the BART analysis, the Department reviewed ambient monitoring data in the vicinity of Antelope Valley Station and Coyote Station. Five ambient monitors are operated in the immediate area. In 2008, the maximum 3-hour SO_2 concentration was 39 ppb (7.8% of the NAAQS), the maximum 24-hour SO_2 concentration was 9 ppb (6.4% of the NAAQS) and the maximum annual average was 1.8 ppb (6% of the NAAQS). For NO_2, the maximum annual average was 2.7 ppb (5.1% of the NAAQS). Given the low concentration of these pollutants, any benefits to health from additional controls and these facilities would be extremely hard to quantify.

Comment 65: The decision on additional point source controls would be better informed by analysis of the how the emissions from sources within the State contribute to nitrate and sulfate concentrations in Class I areas, both inside and outside of the State, in the baseline period compared with the model projections in 2018. If BART controls on stationary sources as well as expected reductions from Federal mobile source, small engine, and fuel requirements would achieve a reduction that, had all other contributing States and other regions met similarly, would put the total aerosol extinction on the uniform rate of progress path, then the State could better support a limited approach to additional controls in this first planning period. However, based on our review of the information supplied in the draft Plan and its appendices, we believe there are cost-effective controls for the Coyote and AVS facilities that should be implemented under the reasonable progress provisions.

Response: The Department reviewed these sources based on the four statutory factors. We looked at the visibility improvement using an emissions inventory that included all contributing sources (cumulative analysis). This analysis showed very little improvement if additional air pollution controls (SO_2 and NO_x controls) are installed. We believe an individual analysis for SO_4 and nitrate will show the same result.

Although the Department found (using the four statutory factors) that additional controls are not reasonable, Otter Tail Power Company has committed to reduce NO_x emissions at the Coyote Station by approximately 35%. This requirement will be included as part of this SIP revision. In addition, all sources will be reevaluated during the next planning period.

Long-Term Strategy

Comment 66: On Page 184, there is discussion of the reduction in sulfur dioxide emissions from the R.M. Heskett Station No. 2. As noted earlier, we believe this facility is subject to BART and should be assessed under the BART provisions. In addition, the reduction in emissions reflect a 21 percent reduction from current emissions. The 70 percent coal-to-stack removal cited in the draft Plan implies a greater reduction from current emissions.

Response: The status of Heskett 2 is being reevaluated and will be addressed in a supplement to this SIP revision.

Comment 67: We request that NDDAQ include in the Long-Term Strategy a linkage between the prevention of significant deterioration program and its assessment of visibility impacts and the Regional Haze Plan in the SIP. This will ensure that new sources are reviewed in a manner that does not jeopardize the reasonable progress goals established by this Plan.

Response: As part of the PSD program, the Department will evaluate the cumulative effect of all sources on the 20% worst and 20% cleanest days to ensure there is no degradation from baseline conditions. This has been added to the Long-Term Strategy as Paragraph 10.7.

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

August 21, 2009

FILE

Mr. Tim Allen
Fish & Wildlife Service
7333 West Jefferson Ave., Ste. 375
Lakewood, CO 80235

Re: Regional Haze SIP

Dear Mr. Allen:

Enclosed with this letter is a disk which contains the Regional Haze State Implementation Plan (SIP) revision for the State of North Dakota. In accordance with 40 CFR 51.308(i)(2), the State of North Dakota is hereby offering you the opportunity for consultation on the Regional Haze SIP. We ask that you provide any comments within 60 days of receipt of this letter.

If you have any questions, please contact Tom Bachman or myself at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc
Enc:
xc/enc: Amy Platt, EPA

NORTH DAKOTA
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www.ndhealth.gov

August 21, 2009

FILE

Mr. Bruce Polkowsky
National Park Service
P.O. Box 25287
Denver, CO 80225

Re: Regional Haze SIP

Dear Mr. Polkowsky:

Enclosed with this letter is a disk which contains the Regional Haze State Implementation Plan (SIP) revision for the State of North Dakota. In accordance with 40 CFR 51.308(i)(2), the State of North Dakota is hereby offering you the opportunity for consultation on the Regional Haze SIP. We ask that you provide any comments within 60 days of receipt of this letter.

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Sincerely,

Terry O'Clair

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Director
Division of Air Quality

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NORTH DAKOTA
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August 21, 2009

FILE

Mr. Scott Copeland
USDA Forest Service Visibility Data Analyst/COTR
Washakie Ranger District
333 East Main Street
Lander, WY 82520

Re: Regional Haze SIP

Dear Mr. Allen:

Enclosed with this letter is a disk which contains the Regional Haze State Implementation Plan (SIP) revision for the State of North Dakota. In accordance with 40 CFR 51.308(i)(2), the State of North Dakota is hereby offering you the opportunity for consultation on the Regional Haze SIP. We ask that you provide any comments within 60 days of receipt of this letter.

If you have any questions, please contact Tom Bachman or myself at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc
Enc:
xc/enc: Amy Platt, EPA
xc: Trent Wickman

Minnesota Pollution Control Agency
520 Lafayette Road North | St. Paul, MN 55155-4194 | 651-296-6300 | 800-657-3864 | 651-282-5332 TTY | www.pca.state.mn.us

Received
SEP 2007
Air Quality

September 19, 2007

TO: Participants in the Northern Class I Areas Consultation Process

RE: Northern Class I Areas Consultation Conclusion

As you are aware, Minnesota is home to two federal Class I areas, Voyageurs National Park (VNP) and the Boundary Waters Canoe Area Wilderness (BWCAW), located in the northern portion of the state. Under the federal Regional Haze Rule (40 CFR 51.300-309), the State of Minnesota is required to work to improve visibility in these two areas, with a goal of no man-made visibility impairment by 2064.

Under the portion of the Regional Haze regulations at 40 CFR 51.308(d)(1)(iv), states with Class I areas are required to develop reasonable progress goals (RPG) for visibility improvement at their Class I areas and associated measures to meet those goals, in consultation with any other State or Tribe that may reasonably cause or contribute to visibility impairment in those areas. This letter provides information on how Minnesota intends to address the reasonable progress goals, identification of the states that cause or contribute to visibility impairment in Minnesota's Class I areas, and our expectations for continued coordination with those states on haze-reducing strategies.

Beginning in 2004 and 2005, a number of discussions were held between state and tribal representatives in the upper Midwest concerning air quality planning to address regional haze in the four Class I areas in Michigan and Minnesota. Formal discussions geared toward the State Implementation Plans (SIP) consultation requirements began in July 2006, in a conference call among representatives from Iowa, Michigan, Minnesota, North Dakota, Wisconsin, the Mille Lacs and Leech Lake bands of Ojibwe, and Federal Land Managers (FLM), Regional Planning Organization (RPO) and U.S. Environmental Protection Agency (EPA) personnel. It was decided that other potentially contributing states should be asked to participate in the consultation process, and that consultation should continue through ongoing conference calls during the development of the regional haze SIP. Minutes of the conference calls and other documentation can be found on the Lake Michigan Air Directors Consortium/Midwest Regional Planning Organization (LADCO/MRPO) Web site.[1]

The group consulted on technical information, producing a document entitled *Regional Haze in the Upper Midwest: Summary of Technical Information*, which lays out the basic sources that cause and contribute to haze in the four Northern Class I areas, as agreed to by all the participating states.[2]

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[1] http://www.ladco.org/Regional_haze_consultation.htm
[2] http://www.ladco.org/Final%20Technical%20Memo%20-%20Version%205d1.pdf

Based on the technical information contained in this document and other supporting analyses, Minnesota has determined that, in addition to Minnesota, Illinois, Iowa, Missouri, North Dakota, and Wisconsin are significant contributors to visibility impairment in VNP and the BWCAW. Attachment 1 to this letter provides a summary of how Minnesota reached this conclusion.[3]

The Minnesota Pollution Control Agency (MPCA) has not yet completed modeling to determine the RPG for these two Class I Areas. However, because of the varying timelines and different non-attainment issues impacting Minnesota and other contributing states, Minnesota intends to submit a RPG resulting from implementation of the minimum interim control measures Minnesota would consider to be reasonable. This decision reflects the need for more in-depth analysis before additional control measures can be determined to be reasonable. The RPG would be revised in the Five Year SIP Assessment to reflect final control measures.

In addition to on-the-books controls, such as the Clean Air Interstate Rule (CAIR), Minnesota expects the RPG to reflect Best Available Retrofit Technology (BART) determinations in Minnesota and surrounding states (where known), the plan for a 30 percent reduction in combined sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions in Northeastern Minnesota, voluntary emission reductions planned by Minnesota utilities beyond those predicted from CAIR, and, where known, any additional control measures undertaken in other states for regional haze or attainment purposes. The MPCA expects that the modeling information needed to set the RPG would be available by October 2007.

Minnesota commits to evaluating additional control measures and implementing those that are reasonable under the four factors listed in 40 CFR 51.308(d)(1)(i)(A) in the 2008 SIP. Minnesota expects that additional control measures may be found to be reasonable, and commits to including a plan for implementation of those additional reasonable measures in the Five Year SIP Assessment. Minnesota asks the five other significantly contributing states to make these same commitments for further evaluation and implementation of reasonable control measures.

In particular, Minnesota asks Iowa, Missouri, North Dakota, and Wisconsin to evaluate further reductions of SO_2 from electric generating units (EGU) in order to reduce SO_2 emissions by 2018 to a rate that is more comparable to the rate projected in 2018 for Minnesota, approximately 0.25 lbs/mmBtu. Minnesota believes that Illinois is already in the process of meeting this goal. Emission reductions in Wisconsin are particularly important, as Wisconsin is the highest contributor outside Minnesota to visibility impairment in Minnesota's Class I areas.

Minnesota also asks North Dakota to evaluate the potential for reductions of NO_X from EGUs due to predicted higher NO_X emission rates compared with Minnesota and other contributing states. Illinois, Missouri, and Wisconsin are in the process of evaluating NO_X emission

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[3] Minnesota is relying primarily on data analysis and technical work done by MRPO and CENRAP.

reductions for their ozone SIPs. Minnesota would expect these three states to share information on the NO_X controls being undertaken as part of those ozone SIPs.

Minnesota acknowledges that each state is in a unique position; for example, North Dakota has a different regulatory background and a different fuel mix than other contributing states. Minnesota's use of emission rates to point towards areas where additional emission control strategies should be investigated does not mean that Minnesota expects all the contributing states to achieve the same emission rates. However, the contributing states with higher emission rates should evaluate potential control measures, and should, in their initial SIPs or Five Year SIP Assessments, show either enforceable plans to reduce emissions or a rationale for why such emission reductions are not reasonable (e.g., an overly high cost in $/ton or $/deciview, or lack of visibility improvement).

Minnesota, in turn, also commits to a more detailed review of potential emission reductions from large Industrial, Commercial, and Institutional (ICI) Boilers and other point sources (such as reciprocating engines and turbines) with regulations or permit limits developed by 2013 and included in the Five Year SIP Assessment if control measures on these source categories appear to be reasonable. Minnesota asks the five contributing states to make a similar commitment.

It is the intent of Minnesota to proceed with the development and submittal of a Regional Haze Plan which includes the aforementioned RPG and expectations for contributing states. Minnesota commits to continuing work with the other states to review and analyze potential region-wide control strategies and emission reductions plans and to continue on-going assessments of progress towards visibility improvement goals.

Minnesota asks that any additional control measures found to be reasonable will be included in each state's SIP or Five Year SIP Assessment in an enforceable form. This will ensure that the control measures are on track to be implemented by the 2018 deadline for submittal of SIPs covering the second phase of the Regional Haze process.

Minnesota believes that the consultations conducted to date satisfy the consultation process requirements, providing for consistency between state SIPs and allowing each state to move forward with SIP preparation and submittal. As necessary, Minnesota will engage in future consultation to address any issues identified in the review of the Regional Haze SIPs, any additional technical information, and to ensure continued coordinated efforts among the Midwestern states.

Attached to this letter is an outline of the reasonable progress discussion to appear in our SIP and additional supporting tables and graphs.

In order to document the consultation process, the MPCA is asking that the State and Tribal recipients of this letter respond within 30 days with a letter documenting that these consultations have taken place to the satisfaction of your State or Tribe, or detailing areas where additional consultation should occur. Those states that Minnesota has identified as additional contributing states should respond with your agreement or disagreement with the determination of contributing states and the additional controls strategies that will be evaluated.

Thank you for your participation and contributions in this consultation process. Your time and efforts are appreciated. If you require additional information regarding this matter, please contact John Seltz at 651-296-7801 or john.seltz@pca.state.mn.us.

Sincerely,

Brad Moore
Commissioner

BM/CN:ld:tgr

Attachments

Attachment 1: Supporting Technical Information – Determination of Contributing States

Minnesota used the LADCO 2002 – 2003 Trajectory Analyses and the LADCO 2018 PSAT analysis, using a 5% threshold of contribution from either analysis to either of Minnesota's Class I areas, to define a contributing state. Based on this information, the States identified as contributing to visibility impairment in Minnesota's Class I Areas are: Minnesota, Wisconsin, Illinois, Iowa, Missouri, and North Dakota.

The table below documents the percent contribution to visibility impairment by the States that have participated in the Northern Class I consultation process, estimated from 2000 – 2003 LADCO trajectory analysis, with supporting information from the CENRAP 2002 PSAT model of the 20% worst days.[4]

State Impacts on Minnesota's Class I Areas – Baseline Period

	LADCO Trajectory Analyses (2000-2003)		CENRAP PSAT Modeling (2002)	
	BWCAW	VNP	BWCAW	VNP
Michigan	0.7%	1.6%	2.6%	1.4%
Minnesota	37.6%	36.9%	25.4%	27.6
Wisconsin	11.1%	9.7%	8.6%	5.6%
Illinois	2.7%	1.2%	7.3%	3.7%
Indiana	1.2%		3.8%	1.8%
Iowa	7.4%	10.2%	3.9%	3.8%
Missouri	3.3%	0.3%	2.7%	2.1%
N. Dakota	5.9%	7.1%	4.8%	7.1%
TOTAL	69.9%	67.0%	59.2%	53.1%

The following table documents the percent contribution from these same states projected for the future based on LADCO's 2018 Particulate Matter Source Apportionment Technology (PSAT) analysis, with supporting information from the CENRAP 2018 PSAT model of the 20% worst days.[5] Although in some cases the percentage impacts predicted by CENRAP are lower than those predicted by the MRPO PSAT analysis (Iowa, Missouri), the identified states remain the higher contributors. The relative order of contributing states does not change much between 2002 and 2018.

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[4] Environ. (2007, July 18). *CENRAP PSAT Visualization Tool.* (Corrected Version). Available on the CENRAP Projects webpage

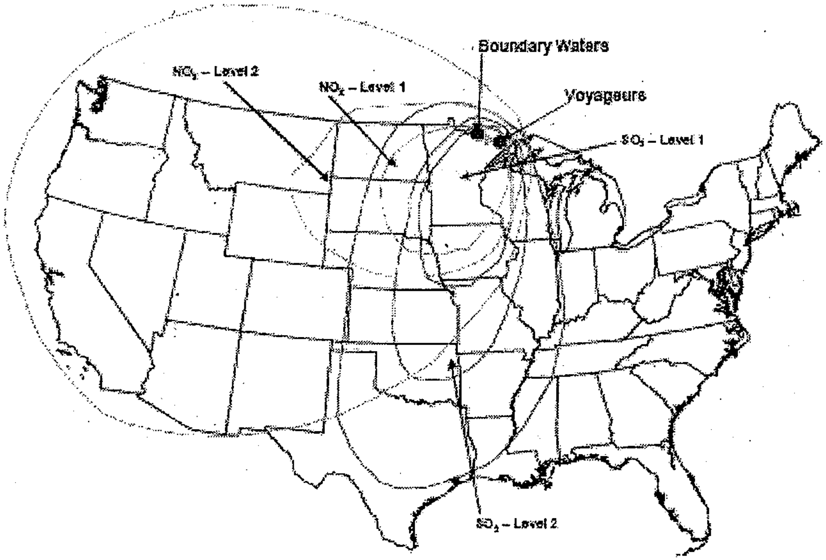
[5] Ibid.

State Impacts on Minnesota's Class I Areas – Future Year (2018 PSAT)

	LADCO PSAT Modeling (2018)		CENRAP PSAT Modeling (2018)	
	BWCAW	VNP	BWCAW	VNP
Michigan	2.6%	1.3%	2.2%	1%
Minnesota	30.5%	35.0%	19.8%	18.0%
Wisconsin	10.4%	6.3%	6.0%	3.1%
Illinois	5.2%	3.0%	3.7%	1.6%
Indiana	2.9%	1.6%	1.8%	0.8%
Iowa	7.6%	7.4%	2.9%	2.5%
Missouri	5.2%	4.3%	2.3%	1.6%
N. Dakota	5.7%	10.3%	3.7%	4.7%
TOTAL	70.1%	69.2%	42.5%	33.3%

The states with contributions over 5% to the Class I areas in these analyses generally match well with the impacting states shown in the Area of Influence (AOI) analysis done by Alpine Geophysics for CENRAP.

AOIs for Minnesota's Class I Areas[6]



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[6] Stella, G.M et al. (2006, May 9). *CENRAP Regional Haze Control Strategy Analysis Plan.* Prepared by Alpine Geophysics. Available on the CENRAP Projects webpage http://www.cenrap.org/projects.asp

Attachment 2: Outline of an Approach to Defining Reasonable Progress for Minnesota Class I Areas in the Minnesota Regional Haze SIP

Under EPA rules, Minnesota has a responsibility to set a Reasonable Progress Goal (RPG) for visibility in the Boundary Waters and Voyageurs Park. Because the states that contribute to our Class I areas will submit their SIPs at different times, Minnesota sets forth the following proposal for setting a RPG for our two Class I areas. This document lays out the elements that we plan to include.

Minnesota's Long Term Strategy section will include those control strategies which we plan to undertake and which we consider to be reasonable. It will also include any known controls that are being undertaken in the nearby states, particularly the five states (IL, WI, ND, IA, and MO) that have been identified as contributors to BWCAW and VNP.

- Minnesota's LTS Contains
  - BART
    - For Minnesota: Minimal emission reductions
    - As known for other states
  - CAIR and resulting EGU reductions
    - For Minnesota
    - As known for other states
  - Control strategies for $PM_{2.5}$ and Ozone attainment SIPs
    - As known for other states
  - Other federal on-the-books (OTB) controls:
    - Tier II for on-highway mobile sources
    - Heavy-duty diesel (2007) engine standards
    - Low sulfur fuel standards
    - Federal control programs for nonroad mobile sources
  - Additional Emission Limitations
    - NE Minnesota Plan (30% reduction in combined SO_2/NO_X as a fair share)
    - Additional voluntary reductions as a result of MN Statutes 216B.1692 (emission reduction rider)
    - Anything known for other states
  - Other long term strategy (LTS) Components (without specific emission reductions)
    - Measures to mitigate emissions from construction
    - Source retirement and replacement
    - Smoke management for prescribed burns in Minnesota

After documenting all the components of the LTS, Minnesota will lay out the RPG determined for the best and worst days at VNP and BWCAW.

Reasonable Progress Goals

Once determined, the RPG submitted in Minnesota's SIP will represent an **interim**, **minimum** visibility improvement Minnesota would consider to be reasonable, and contain emission reductions resulting from the elements of the long term strategy.

At this time, Minnesota believes that this is an appropriate goal because other impacting states are working on a multi-SIP approach and have yet to determine what reductions are reasonable in their states for both haze and attainment purposes. Although we cannot compel the states to undertake reductions, Minnesota would expect further emissions reductions than are documented here, resulting in larger visibility improvement. Minnesota intends to revise the RPG for 2018 in the Five Year SIP Assessment, in order to reflect the additional control strategies found to be reasonable.

Steps in Reviewing Control Strategies and Revising RPG

In reviewing additional control strategies to determine those that are reasonable under the Regional Haze rule, Minnesota will focus on strategies that will result in emission reductions in those states that are significant contributors to visibility impairment in either BWCAW or VNP: Minnesota, Wisconsin, Iowa, N. Dakota, Missouri and Illinois.

The MPCA commits to further evaluation of reasonable control strategies that are possible within Minnesota. Minnesota will work with the other contributing states through their submittals of the first haze SIP and through 2013 to develop reasonable control strategies.

In the Five Year SIP Assessment, the MPCA would submit enforceable documents for any additional control measures found to be reasonable within Minnesota. In addition, that report would contain a listing of the additional control measures to be implemented by the other contributing states. Minnesota would then submit modeling that includes all these enforceable measures and would revise the 2018 RPG to reflect the larger degree of visibility improvement expected from the chosen control strategies.

Specific Control Strategies to Be Reviewed

Minnesota will use the EC/R five factor analysis report, the control cost analysis carried out by Alpine Geophysics for CENRAP and the CENRAP Control Sensitivity Model run to identify reasonable region-wide emission reduction strategies. (*See Attachment 3*).

The specific strategies that at this time appear to potentially be reasonable, and Minnesota's expectation for each of these strategies for other states, are outlined below.

EGU SO_2 Reductions

Minnesota will ask the contributing states to look at their EGU emissions of SO_2; Minnesota will particularly focus on possible reductions in states with emission rates that appear to be higher than the average among the Midwestern states. Since contributor states face a variety of regulatory demands and fuel types, it may not be possible to attain uniform emission performance. An emission rate of about 0.25 lb/mmBTU should be achievable in a cost-effective manner; this is the level being achieved in Minnesota and Illinois, and the EC/R report shows that the "EGU1" scenario, a 0.15 lb/mmBTU emission rate, is generally achievable in the Midwest at a reasonable $/ton figure. (See Attachment 3).

Minnesota asks the identified states to demonstrate that reductions are occurring or being undertaken that will allow the state to reach at least the 0.25 lb/mmBTU emission rate, or to describe in their SIPs or Five-Year SIP Assessments why further reductions of SO_2 from EGU are not reasonable. Further reductions may not be reasonable due to the cost of implementation in $/ton or $/deciview or lack of impact on visibility impairment, but they should be evaluated.

At present, it appears as though Illinois has planned or proposed reductions that appear reasonable. It appears that more cost effective reductions are possible in Iowa, Missouri, North Dakota, and Wisconsin. Since Wisconsin is the largest non-Minnesota contributor to Minnesota's Class I areas, their efforts to reduce EGU SO_2 emissions are particularly important.

EGU NO_X Reductions

Wisconsin, Missouri, and Illinois have already reduced NO_X emissions to alleviate ozone standard violations, and Iowa appears to already have relatively low EGU NO_X emissions.

Minnesota will ask North Dakota to look at their EGU emissions of NO_X and to describe in their SIP or Five-Year SIP Assessment why further reductions of NO_X from EGU are not reasonable. Again, an emission rate of approximately 0.25 lb/mmBTU appears to be a reasonable benchmark. Further reductions may not be reasonable due to the cost of implementation in $/ton or $/deciview or lack of impact on visibility impairment, but they should be evaluated.

ICI Boiler Emission Reductions

Minnesota will commit to a more detailed review of potential NO_X and SO_2 reductions from large ICI boilers. Regulations or permit limits will be developed by 2013 if significant cost effective reductions prove feasible from this sector. Minnesota will expect the five contributing states to make at least this level of commitment.

Other Point Source Emission Reductions

Reciprocating engines and turbines appear to be a sector with potential cost effective NO_X controls. Minnesota commits to review this sector in more detail and if, after consideration of planned federal control programs, cost effective reductions appear feasible, Minnesota commits to develop regulations or permit limits for major sources by 2013. Minnesota will expect the five contributing states to make a similar commitment.

Mobile Source Emission Reductions

There appear to be relatively few cost effective NO_X controls for transportation available to states. Minnesota commits to work with LADCO states to implement appropriate cost effective NO_X controls to improve visibility and lower ozone levels in non-attainment areas.

NO_X Modeling, Ammonia, Agricultural Sources

It is not appropriate to commit to control of ammonia sources at this time. However, there is a clear need to improve 1) our understanding of the role of ammonia in haze formation, 2) our understanding of potential ammonia controls, and 3) the accuracy of particulate nitrate predictions. Minnesota does not consider it our responsibility to conduct such research. Minnesota therefore encourages EPA and the regional planning organizations to continue work in these areas and commits to work with EPA and the RPOs to these ends.

Timeline for Reviewing Control Strategies

Minnesota commits to reviewing these control strategies on such a timeline that the 2013 SIP Report will include the four factor analysis for these control strategies, and that any control strategies deemed to be reasonable will be in place with an enforceable document (state rule, order, or permit conditions). Although any control measures ultimately deemed to be reasonable may not be fully implemented by 2013, they will be clearly "on the way" and the SIP Report will include estimates of emission reductions and projected 2018 visibility conditions.

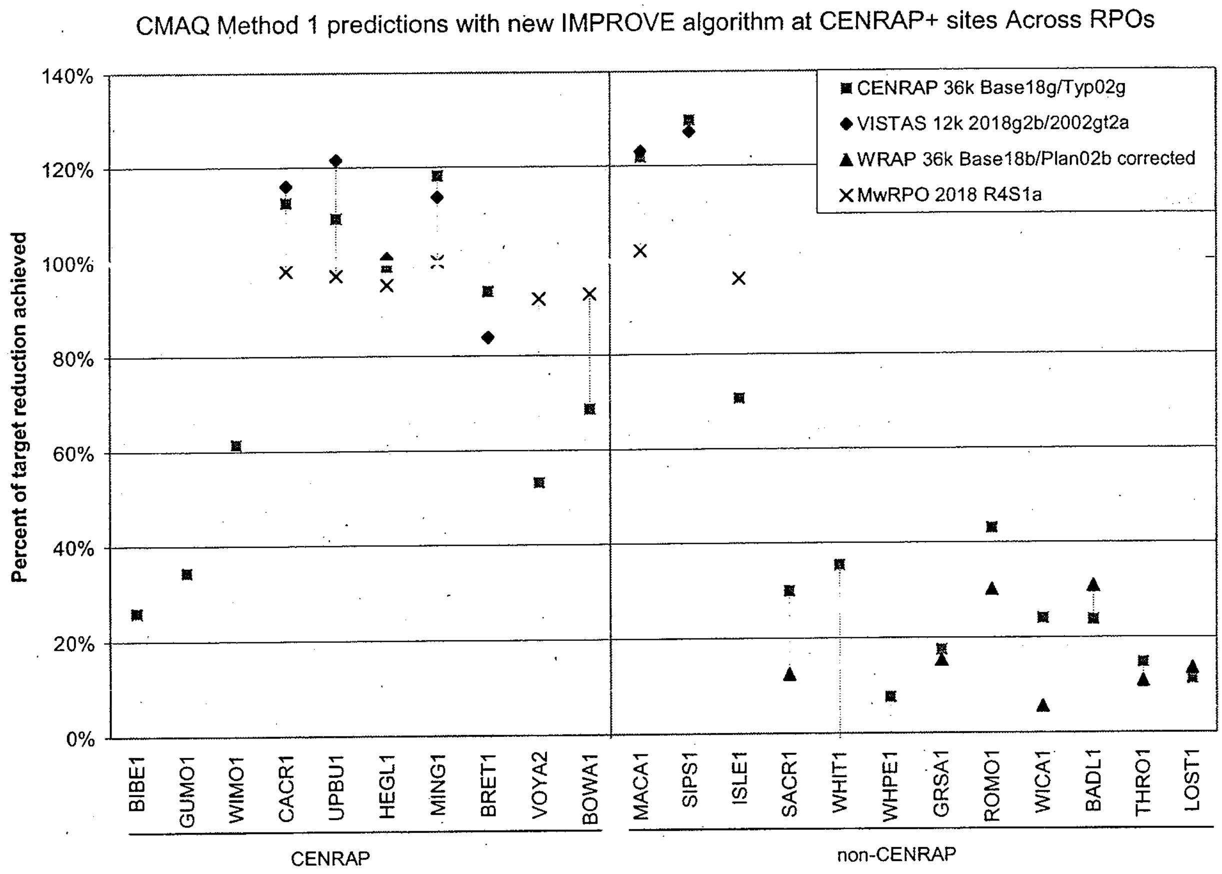
Acknowledging that most states are far along in the process of writing their Regional Haze SIPs, Minnesota would expect that all other contributing states would commit to a timeline that would allow reasonable predictions of the emission reductions and visibility improvement by 2018 from those states in the 2013 SIP Report.

Attachment 3: Supporting Technical Information – Need for Additional Control Strategies

Although there are some fairly major differences in the degree of visibility improvement expected at VNP and BWCAW due to on- the- books controls, projections by both CENRAP and Midwest RPO show that Minnesota's Class I areas are not yet projected to meet the Uniform Rate of Progress, as shown in the graph below.[7] In this graph, the URP is the "target reduction."

EPA's recent guidance on determining the reasonable progress goal (RPG) indicates that states may set a RPG that provides for more, less, or equivalent improvement as the URP. However, the guidance continues to emphasize that an analysis of control strategies with the four factors is necessary; Minnesota believes this is particularly true in light of the lesser degree of visibility improvement shown from on- the- books controls in Minnesota's Class I Areas.

The EGU 2018 Summary table, following, shows projected 2018 EGU SO2 and NOX emissions. Highlighted cells indicate specific states and pollutants of concerns, where Minnesota has requested evaluation of potential reasonable control measures.[8]


CMAQ Method 1 predictions with new IMPROVE algorithm at CENRAP+ sites Across RPOs

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[7] Morris, R. (2007, July 24). *CENRAP Emissions and Modeling Technical Support Document,* Prepared by Environ. Presentation Given at CENRAP Workgroup/POG Meeting.

[8] Provided by Midwest RPO from the IPM 3.0 base run and edits made by certain states.

EGU Summary for 2018

	Heat Input (MMBTU/year)	Scenario	SO2 (tons/year)	SO2 % Reduction (From 2001 - 03 Average)	SO2 (lb/MMBTU)	NOx (tons/year)	NOx % Reduction (From 2001 - 03 Average)	NOx (lb/MMBTU)
IL	**980,197,198**	**2001 - 2003 (average)**	**362,417**		**0.74**	**173,296**		**0.35**
	1,310,188,544	IPM3.0 (base)	277,337	23.5	0.423	70,378	59.4	0.107
		IPM3.0 - will do	140,296	61.3	0.214	62,990	63.7	0.096
		IPM3.0 - may do	140,296	61.3	0.214	62,990	63.7	0.096
IA	**390,791,671**	**2001 - 2003 (average)**	**131,080**		**0.67**	**77,935**		**0.40**
	534,824,314	IPM3.0 (base)	115,938	11.6	0.434	59,994	23.0	0.224
		IPM3.0 - will do	115,938	11.6	0.434	59,994	23.0	0.224
		IPM3.0 - may do	100,762	23.1	0.377	58,748	24.6	0.220
MN	**401,344,495**	**2001 - 2003 (average)**	**101,605**		**0.50**	**85,955**		**0.42**
	447,645,758	IPM3.0 (base)	61,739	39.2	0.276	41,550	51.7	0.186
		IPM3.0 - will do	54,315	46.5	0.243	49,488	42.4	0.221
		IPM3.0 - may do	51,290	49.5	0.229	39,085	54.5	0.175
MO	**759,902,542**	**2001 - 2003 (average)**	**241,375**		**0.63**	**143,116**		**0.37**
	893,454,905	IPM3.0 (base)	243,684	(1.0)	0.545	72,950	49.0	0.163
		IPM3.0 - will do	237,600	1.6	0.532	72,950	49.0	0.163
		IPM3.0 - may do	237,600	1.6	0.532	72,950	49.0	0.163
ND	**339,952,821**	**2001 - 2003 (average)**	**145,096**		**0.85**	**76,788**		**0.45**
	342,685,501	IPM3.0 (base)	41,149	71.6	0.240	44,164	42.5	0.258
		IPM3.0 - will do	56,175	61.3	0.328	58,850	23.4	0.343
		IPM3.0 - may do	56,175	61.3	0.328	58,850	23.4	0.343
WI	**495,475,007**	**2001 - 2003 (average)**	**191,137**		**0.77**	**90,703**		**0.36**
	675,863,447	IPM3.0 (base)	127,930	33.1	0.379	56,526	37.7	0.167
		IPM3.0 - will do	150,340	21.3	0.445	55,019	39.3	0.163
		IPM3.0 - may do	62,439	67.3	0.185	46,154	49.1	0.137

Minnesota also used the cost-curve analysis performed for CENRAP by Alpine Geophysics, originally included in the *CENRAP Regional Haze Control Strategy Analysis Plan* and updated in March 2007, to determine which states might have additional reasonable control strategies. The cost curves were used to perform a modeling run (the "Control Sensitivity Run") in order to determine the visibility improvement that could result from implementing certain control strategies.[9]

The following tables show which point sources are controlled in the CENRAP states that the MPCA has identified as contributing to visibility impairment in BWCAW and VNP (Iowa, Minnesota, Missouri) under the following assumptions: 1) a cost less than $5000/ton, and 2) facility emissions divided by the facility's distance from any Class I area, is greater than or equal to five (often called the Q/5D criteria). The tables include sources that are within Q/5D of either VNP or BWCAW.

The report prepared for the MPCA and Midwest RPO by EC/R, entitled "Reasonable Progress for Class I Areas in the Northern Midwest – Factor Analysis," also provides documentation that the various control strategies mentioned in Attachment 2 are likely to be reasonable, at least for some states. A summary table follows the tables of units controlled in the CENRAP control sensitivity run.[10]

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[9] Information on the Control Sensitivity run is available on CENRAP's Project website, http://www.cenrap.org/projects.asp, under the link entitled *Results from Control Sensitivity Run, Base18Gc1 - Cost Curve Criteria of 5k per ton, Q over 5D*

[10] Battye, W. et al (2007, July 18). Reasonable Progress for Class I Areas in the Northern Midwest – Factor Analysis. Prepared for MPCA and MRPO by EC/R. http://www.ladco.org/MRPO%20Report_071807.pdf. See Table 6.5-3, page 110.

NO_X Controls, Q/5D for BWCAW and VNP

State	County	Plant Name	Point ID	Source Type for Control	Control Measure	Tons Reduced	Annualized Cost ($2005)	Cost Per Ton Reduced
Iowa	Woodbury	MIDAMERICAN ENERGY CO. - GEORGE NEAL NOR	148766	Utility Boiler - Coal/Wall	SCR	3739	$5,252,502	$1,405
Iowa	Woodbury	MIDAMERICAN ENERGY CO. - GEORGE NEAL SOU	147140	Utility Boiler - Coal/Wall - Other Coal	LNBO	1191	$2,900,440	$2,435
Iowa	Wapello	IPL - OTTUMWA GENERATING STATION	143977	Utility Boiler - Coal/Tangential	SCR	4708	$13,000,038	$2,761
Iowa	Pottawattamie	MIDAMERICAN ENERGY CO. - COUNCIL BLUFFS	143798	Utility Boiler - Coal/Wall - Other Coal	LNBO	671	$2,960,866	$4,413
Minnesota	Cook	MINNESOTA POWER - TACONITE HARBOR ENERGY	EU001	Utility Boiler - Coal/Tangential	SCR	411	$1,536,959	$3,737
Minnesota	Cook	MINNESOTA POWER - TACONITE HARBOR ENERGY	EU002	Utility Boiler - Coal/Tangential	SCR	411	$1,574,337	$3,828
Minnesota	Cook	MINNESOTA POWER - TACONITE HARBOR ENERGY	EU003	Utility Boiler - Coal/Tangential	SCR	411	$1,592,948	$3,873
Minnesota	Itasca	MINNESOTA POWER INC - BOSWELL ENERGY CTR	EU004	Utility Boiler - Coal/Tangential - POD10	LNC3	806	$1,413,275	$1,753
Minnesota	Itasca	MINNESOTA POWER INC - BOSWELL ENERGY CTR	EU003	Utility Boiler - Coal/Tangential - POD10	LNC3	600	$884,162	$1,474
Minnesota	Koochiching	Boise Cascade Corp - International Falls	EU320	Sulfate Pulping - Recovery Furnaces	SCR	361	$939,170	$2,603
Minnesota	St. Louis	MINNESOTA POWER INC - LASKIN ENERGY CTR	EU001	Utility Boiler - Coal/Tangential	SCR	1064	$1,346,571	$1,265
Minnesota	St. Louis	MINNESOTA POWER INC - LASKIN ENERGY CTR	EU002	Utility Boiler - Coal/Tangential	SCR	1063	$1,346,571	$1,267
Minnesota	St. Louis	EVTAC Mining - Fairlane Plant	EU042	ICI Boilers - Coke	SCR	1365	$3,142,325	$2,302
Minnesota	Sherburne	NSP - SHERBURNE GENERATING PLANT	EU002	Utility Boiler - Coal/Tangential - POD10	LNC3	998	$1,873,316	$1,877
Minnesota	Sherburne	NSP - SHERBURNE GENERATING PLANT	EU001	Utility Boiler - Coal/Tangential - POD10	LNC3	701	$1,880,449	$2,682
Missouri	Pike	HOLCIM (US) INC-CLARKSVILLE	16745	Cement Manufacturing - Wet	Mid-Kiln Firing	1808	$149,510	$83
Missouri	Randolph	ASSOCIATED ELECTRIC COOPERATIVE INC-THOM	17575	Utility Boiler - Coal/Wall - Other Coal	LNBO	682	$3,114,256	$4,563

SO_2 Controls, Q/5D for BWCAW or VNP

State	County	Plant Name	Point ID	Source Type for Control	Control Measure	Tons Reduced	Annualized Cost ($2005)	Cost Per Ton Reduced
Iowa	Muscatine	CENTRAL IOWA POWER COOP. - FAIR STATION	100125	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	4504	$5,854,468	$1,300
Iowa	Woodbury	MIDAMERICAN ENERGY CO. - GEORGE NEAL NOR	148766	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	11440	$20,886,351	$1,826
Iowa	Woodbury	MIDAMERICAN ENERGY CO. - GEORGE NEAL NOR	148765	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	7020	$13,365,237	$1,904
Iowa	Woodbury	MIDAMERICAN ENERGY CO. - GEORGE NEAL SOU	147140	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	14255	$35,558,570	$2,494
Iowa	Wapello	IPL - OTTUMWA GENERATING STATION	143977	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	15894	$40,687,209	$2,560
Iowa	Louisa	MIDAMERICAN ENERGY CO. - LOUISA STATION	147281	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	12964	$36,698,267	$2,831
Iowa	Pottawattamie	MIDAMERICAN ENERGY CO. - COUNCIL BLUFFS	143798	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	12141	$36,299,373	$2,990
Iowa	Des Moines	IPL - BURLINGTON GENERATING STATION	145381	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	5384	$17,059,783	$3,169
Iowa	Allamakee	IPL - LANSING GENERATING STATION	145136	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	5926	$19,213,055	$3,242
Iowa	Clinton	IPL - M.L. KAPP GENERATING STATION	144559	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	5036	$17,331,069	$3,441
Iowa	Linn	IPL - PRAIRIE CREEK GENERATING STATION	144096	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	3753	$13,730,673	$3,658
Minnesota	Itasca	MINNESOTA POWER INC - BOSWELL ENERGY CTR	EU001	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	2329	$9,472,980	$4,068
Minnesota	Itasca	MINNESOTA POWER INC - BOSWELL ENERGY CTR	EU002	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	2315	$9,472,980	$4,092
Minnesota	Itasca	MINNESOTA POWER INC - BOSWELL ENERGY CTR	EU004	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	7403	$30,486,914	$4,118
Missouri	Clay	INDEPENDENCE POWER AND LIGHT-MISSOURI CI	5430	Utility Boilers - Very High Sulfur Content	FGD Wet Scrubber	8058	$6,232,581	$774
Missouri	Franklin	AMERENUE-LABADIE PLANT	6964	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	14741	$34,190,931	$2,319

State	County	Plant Name	Point ID	Source Type for Control	Control Measure	Tons Reduced	Annualized Cost ($2005)	Cost Per Ton Reduced
Missouri	Franklin	AMERENUE-LABADIE PLANT	7408	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	14988	$34,874,750	$2,327
Missouri	Franklin	AMERENUE-LABADIE PLANT	7262	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	14912	$34,874,750	$2,339
Missouri	Jefferson	AMERENUE-RUSH ISLAND PLANT	11565	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	13979	$32,994,250	$2,360
Missouri	Franklin	AMERENUE-LABADIE PLANT	7087	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	14285	$34,019,977	$2,382
Missouri	Henry	KANSAS CITY POWER & LIGHT CO-MONTROSE GE	7847	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	6362	$15,425,097	$2,425
Missouri	Henry	KANSAS CITY POWER & LIGHT CO-MONTROSE GE	7849	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	6191	$15,134,675	$2,445
Missouri	Jefferson	AMERENUE-RUSH ISLAND PLANT	11563	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	13276	$32,994,250	$2,485
Missouri	Henry	KANSAS CITY POWER & LIGHT CO-MONTROSE GE	7848	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	5928	$14,840,835	$2,504
Missouri	St. Louis	AMERENUE-MERAMEC PLANT	21421	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	8494	$21,733,761	$2,559
Missouri	St. Louis	ANHEUSER-BUSCH INC-ST. LOUIS	20274	Bituminous/Subbituminous Coal (Industrial Boilers)	SDA	1996	$5,303,934	$2,658
Missouri	Platte	KANSAS CITY POWER & LIGHT CO-IATAN GENER	16912	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	14332	$38,179,875	$2,664
Missouri	Jackson	AQUILA INC-SIBLEY GENERATING STATION	9953	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	9166	$24,430,935	$2,665
Missouri	St. Louis	AMERENUE-MERAMEC PLANT	21423	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	7081	$19,721,240	$2,785
Missouri	Randolph	ASSOCIATED ELECTRIC COOPERATIVE INC-THOM	17575	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	9469	$38,179,875	$4,032
Missouri	New Madrid	ASSOCIATED ELECTRIC COOPERATIVE INC-NEW	14944	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	8132	$33,051,234	$4,064
Missouri	New Madrid	ASSOCIATED ELECTRIC COOPERATIVE INC-NEW	14942	Utility Boilers - Medium Sulfur Content	FGD Wet Scrubber	8026	$33,051,234	$4,118
Missouri	Jefferson	DOE RUN COMPANY-HERCULANEUM SMELTER	11722	Primary Metals Industry	Sulfuric Acid Plant	10653	$46,396,391	$4,355

Table 6.5-3. Summary of Visibility Impactes and Cost Effectiveness of Potential Control Measures

Emission category	Control strategy	Region	Pollutant	Average estimated visibility improvement for the four Midwest Class I areas (deciviews)	Cost effectiveness ($/ton)	Cost effectiveness per visibility improvement ($million/ deciview)
EGU	EGU1	3-State	SO2	0.32	1,540	2,249
			NOX	0.06	2,037	2,585
		9-State	SO2	0.74	1,743	2,994
			NOX	0.17	1,782	2,332
	EGU2	3-State	SO2	0.41	1,775	2,281
			NOX	0.09	3,016	3,604
		9-State	SO2	0.85	1,952	3,336
			NOX	0.24	2,984	4,045
ICI boilers	ICI1	3-State	SO2	0.055	2,992	1,776
			NOX	0.043	2,537	1,327
		9-State	SO2	0.084	2,275	2,825
			NOX	0.068	1,899	2,034
	ICI Workgroup	3-State	SO2	0.089	2,731	1,618
			NOX	0.055	3,814	1,993
		9-State	SO2	0.136	2,743	3,397
			NOX	0.080	2,311	2,473
Reciprocating engines and turbines	Reciprocating engines emitting 100 tons/year or more	3-State	NOX	0.015	538	282
		9-State	NOX	0.052	506	542
	Turbines emitting 100 tons/year or more	3-State	NOX	0.008	754	395
		9-State	NOX	0.007	754	810
	Reciprocating engines emitting 10 tons/year or more	3-State	NOX	0.037	1,286	673
		9-State	NOX	0.073	1,023	1,095
	Turbines emitting 10 tons/year or more	3-State	NOX	0.011	800	419
		9-State	NOX	0.012	819	880
Agricultural sources	10% reduction	3-State	NH3	0.10	31 - 2,700	8 - 750
		9-State	NH3	0.16	31 - 2,700	18 - 1,500
	15% reduction	3-State	NH3	0.15	31 - 2,700	8 - 750
		9-State	NH3	0.25	31 - 2,700	18 - 1,500
Mobile sources	Low-NOX Reflash	3-State	NOX	0.007	241	516
		9-State	NOX	0.010	241	616
	MCDI	3-State	NOX	0.015	10,697	7,595
		9-State	NOX	0.015	2,408	4,146
	Anti-Idling	3-State	NOX	0.009	(430) - 1,700	(410) - 1,600
		9-State	NOX	0.006	(430) - 1,700	(410) - 1,600
	Cetane Additive Program	3-State	NOX	0.009	4,119	3,155
		9-State	NOX	0.008	4,119	10,553

Attachment 4: Organizations Participating in Northern Class I Consultation Process

States and Provinces
Illinois Environmental Protection Agency
Indiana Department of Environmental Management
Iowa Department of Natural Resources
Michigan Department of Environmental Quality
Minnesota Pollution Control Agency
Missouri Department of Natural Resources
North Dakota Department of Health
Wisconsin Department of Natural Resources
Ontario Ministry of the Environment

Tribes
Leech Lake Band of Ojibwe
Fond du Lac Band of Lake Superior Chippewa
Mille Lacs Band of Ojibwe
Upper and Lower Sioux Community
Red Lake Band of Chippewa
Grand Portage Band of Chippewa
Nottawaseppi Huron Band of Potawatomi

Regional Planning Organizations
Midwest Regional Planning Organization
Central Regional Air Planning Association

Federal Government
USDA Forest Service
U.S. Fish and Wildlife Service
National Park Service
USDA Forest Service
Environmental Protection Agency, Region 5

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
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August 22, 2008

FILE

Brad Moore, Commissioner
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: Northern Class I Areas Consultation
Conclusion Memorandum

Dear Mr. Moore:

We have reviewed your memorandum of September 19, 2007 regarding consultation with States that have sources which emit air contaminants which impact visibility (regional haze) in the Voyageurs National Park and Boundary Waters Canoe Area Wilderness. The State of North Dakota is committed to addressing regional haze in accordance with the requirements of the Clean Air Act. This includes an evaluation of appropriate emission limitations under the Best Available Retrofit Technology (BART) requirements [40 CFR 51.308(e)] as well as the other requirements [40 CFR 51.208(d)-(i)]. This will include an assessment of additional emission reductions from electric utility steam generating units and other source categories unaffected by the BART requirements. This assessment will be conducted as prescribed in the Regional Haze rule.

In your memorandum, you requested that North Dakota "evaluate further reductions of SO_2 from electric generating units (EGU) in order to reduce SO_2 emissions by 2018 to a rate that is more comparable to the rate projected in 2018 from Minnesota, approximately 0.25 lbs/MMBTU". You also requested that North Dakota evaluate the potential for reductions of NO_x from EGUs due to predicted higher NO_x emission rates compared with Minnesota and other contributing states. We believe that the use of lb/MMBtu as the metric for seeking additional emission reductions is flawed. The North Dakota EGUs are located more than 500 kilometers from Voyageurs National Park and further from the Boundary Waters Canoe Area Wilderness. The EGUs in Minnesota are located much closer and will have a much greater impact on visibility in the Minnesota Class I areas for a given emission rate (e.g. lb/MMBtu or tons/yr). Given the proximity of the sources located in Minnesota and the major contribution those sources have on the Class I areas in

Minnesota, we believe Minnesota should closely examine the impact on visibility of those sources as compared to the impact of sources in neighboring states. Additional reductions from Minnesota sources may provide much greater reduction of visibility impacts. The lb/MMBtu metric, if retained, should be adjusted to take into account the actual visibility impact of the neighboring states sources.

In reviewing your memorandum, the EGU Summary for 2018 (p.12) indicated that the "IPM3.0-will do" scenario predicts a reduction of SO_2 and NO_x emissions from Minnesota EGUs of 83,757 tons per year (44.7%) while North Dakota EGUs will reduce emissions by 106,859 tons per year (48.2%). Yet, Attachment 1 to your memorandum indicates Minnesota sources contribute 25.4-37.6% of the baseline visibility impairment (depending on the Class I area, the time period, and the group doing the modeling) while North Dakota sources only contribute 4.8-7.1%. We believe the substantial reductions of sulfur dioxide and nitrogen oxides from North Dakota EGUs will assist Minnesota in making reasonable progress toward the national visibility goal.

The lb/MMBtu metric is also flawed because it does not account for the type of fuel burned or the firing configuration of the EGU. The EGUs in North Dakota primarily fire lignite which has a higher sulfur content than subbituminous coal. This requires a higher removal rate of SO_2 to achieve MPCA's 0.25 lb/MMBtu benchmark than it would for Minnesota sources. In addition, four of the EGUs in North Dakota are cyclone fired units which have much higher uncontrolled NO_x emission rates than other pulverized coal fired units. The constituents of the North Dakota lignite (e.g. soluble sodium in the ash) makes it much more difficult and expensive to control NO_x emissions. Again, greater reductions would be required for North Dakota sources to achieve the MPCA's benchmark than for Minnesota EGUs.

Your memorandum of September 19, 2007 suggests that Minnesota is counting on reductions from the Clean Air Interstate Rule (CAIR) by stating "In addition to on-the-books controls, such as the Clean Air Interstate Rule (CAIR), Minnesota expects....". Given the recent vacature of CAIR, such reliance on reductions may be premature. In addition, your request for additional reductions from other states should be reevaluated.

In summary, we believe the metric (lb/MMBtu) for asking other states to make additional emission reductions is inappropriate. North Dakota will continue to seek appropriate emissions reductions commensurate with the law and available technology. Through the effort of each state significant improvements in air quality will be achieved. As we work through the process, we will afford you more opportunities to discuss our State Implementation Plan (SIP) and the emission reductions that will be achieved. North Dakota's SIP is expected to be available by the end of this year.

If you have any questions, please feel free to contact me at (701)328-5150.

Respectfully,

L. David Glatt, Chief
Environmental Health Section

LDG/TB:csc
xc: Terry O'Clair, Air Quality Division
Amy Platt, EPA Region 8

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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AUG - 4 2008

Ref: 8P-AR

Terry O'Clair, Director
Division of Air Quality
Environmental Health Section
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: EPA Region 8 Comments on May 2008 Draft BART SIP (FLM Consultation Version)

Dear Terry:

EPA has completed a preliminary review of North Dakota's May 2008 draft Regional Haze SIP to meet Best Available Retrofit Technology (BART) requirements ("BART SIP"), as requested via email by Tom Bachman on June 2, 2008. Our comments and questions are detailed in Enclosure 1 to this letter. For the record, we are also including the numerous comments we've made previously on the company BART analyses that are now contained in Appendix C of the BART SIP (see Enclosure 2). We understand that you intend to consider all comments received on this Federal Land Manager (FLM) consultation version of the BART SIP prior to finalizing the documents. The final draft of the BART SIP, which will include a summary of the FLMs' comments and your responses, will then undergo a broader public hearing process prior to adoption and submission to EPA. We emphasize that we will only come to a final conclusion regarding the adequacy of North Dakota's BART determinations and SIP when we act on the North Dakota Regional Haze SIP revision, through our own public notice and comment rulemaking.

We want to acknowledge your tremendous efforts in developing BART for the subject-to-BART electric generating units in North Dakota and in working up front with us as issues arose. For the most part, your draft SIP is comprehensive and contemplates commendable reductions - approximately 90,000 tons/year SO_2 and 21,000 tons/year NO_x based on our calculations using current actual annual emissions minus BART emission limits. Our comments are meant to ensure that the relevant BART analyses and determinations are robust and well-supported and that the SIP is in a form we can approve. We hope that you will give consideration to our comments to assure truly "best available" BART levels and reasonable progress toward the National visibility goal.

You have previously indicated that the remainder of the Regional Haze SIP requirements, including reasonable progress and the long-term strategy, will be addressed separately, and we look forward to working with you on those SIP revisions. Please be aware that a BART SIP alone probably will not be adequate to avoid a finding of failure to submit the Regional Haze SIP by the required due date. Such a finding would initiate a 2-year clock for the completion of a Federal Implementation Plan to address any outstanding regional haze requirements.

We have appreciated working with you during the review of this FLM consultation version of the draft BART SIP and look forward to continued communications during the public hearing process. If you have any questions on EPA's comments, please contact me at 303-312-6434, or have your staff contact Amy Platt at 303-312-6449.

Sincerely,

Callie A. Videtich, Director
Air Program

Enclosures

cc: Tom Bachman, NDDH
Chris Shaver, NPS
Sandra Silva, USFWS
Thomas Dzomba, USFS
John Mooney, EPA Region 5

ENCLOSURE 1

EPA Region 8 Preliminary Comments on May 2008 Draft BART SIP (FLM Consultation Version)

Summary of Major Concerns - (see detailed comments for more information):

1. There are numerous inconsistencies between the SIP text, North Dakota Department of Health (NDDH) BART determinations, and proposed permits regarding the BART limits. Please clarify/resolve.
2. We disagree regarding the technical feasibility of SCR for NO_x control at the 3 cyclone units burning North Dakota lignite (Milton R. Young Units 1 & 2 and Leland Olds Unit 2).
3. NDDH's Leland Olds 5-factor analysis lacks SO_2 cost and visibility analyses for Unit 2.
4. NDDH's Milton R. Young 5-factor analysis lacks NO_x visibility analyses entirely and relies on an incomplete BACT process to satisfy BART analysis requirements.
5. Startup/shutdown exemption for Milton R. Young NO_x limit is not acceptable.
6. We believe that the inferior control technology proposed for Stanton Unit 1 (spray dryer/fabric filter), coupled with what we find to be an inflated uncontrolled emission rate, produces too high of an SO_2 limit (0.24 for lignite, 0.16 for PRB). Although this is the smallest of the subject-to-BART units in terms of megawatts, this and other power plants are among the largest emitters in the State. It may be more cost-effective to consider further controls now in order to meet reasonable progress requirements, rather than waiting to address these requirements with other sources during the development of the remainder of your Regional Haze SIP.

Detailed Comments

BART SIP text:

1. Definitions, pp. 11-15: Definitions are accurately cited from 40 CFR 51.301, however, each definition is designated by letter (*e.g.*, hh, e, w, d, l, m, etc.). Since 40 CFR 51.301 does not assign letters to the definitions, what is the basis for these letter designations? In addition, we suggest rewording 1st sentence on p. 13 to clarify that the definition for "existing stationary facility" is much broader than simply "a stationary source."
2. Screening Impact Threshold, pp. 16-17: A more robust discussion regarding NDDH's process for selection of the 0.5 deciview threshold should be provided to justify your selection. For example, the addition of a discussion of the number and relative impacts of BART-eligible units above and below 0.5 deciviews, and the potential for plume overlap due to the relative clustering of sources, would be useful.

3. Exclusion of Montana Dakota Utilities Heskett Unit No. 2, p. 23:
   (A)We have concerns with ENSR's CALPUFF modeling. They reduce the CALMET/CALPUFF grid size from 3 km to 1 km. EPA has recently seen data indicating that Calpuff may inappropriately reduce predicted concentrations with such grid size manipulation. In addition, ENSR's use of annual average background visibility conditions will also decrease delta deciview impacts. According to NDDH's approved "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota," the 20% cleanest days should be used. Given that ENSR's refined results move Heskett from "subject-to-BART" to "exempt," a more robust discussion is necessary regarding why NDDH found ENSR's analysis "acceptable," including an explanation of why you think this approach will not lead to underestimates of visibility impacts.
   (B) NDDH notes that MDU has committed to increase SO_2 removal efficiency to a minimum of 70% by 2013. How is this voluntary agreement formalized? We note that in a June 9, 2006 letter from MDU to Terry O'Clair, they commit to "control SO_2 emissions by installing and operating the necessary equipment to use limestone as the bed material in the boiler." They state that they will agree to include a condition in their Title V permit implementing this change, including a permit shield pertaining to BART applicability. Is NDDH taking credit for these emissions reductions in the BART SIP, *i.e.*, are these reductions included in the 99,000 tons/year figure provided in the SIP text? Does NDDH intend to use these reductions to satisfy reasonable progress requirements? If so, how do you intend to make this agreement federally enforceable?
4. SO_2 BART Determinations, pp. 24-26: As we have commented previously, we would like you to consider establishing limits that require the BART units to meet both lb/MMBtu emission rates *and* control efficiencies, rather than just one *or* the other. The potentially cost-effective additional reductions you can achieve now by having both limits apply to these large sources will be beneficial toward meeting reasonable progress requirements during the development of the remainder of your Regional Haze SIP.
5. SO_2 discussion on p. 25-26 doesn't match the table on p. 33, *e.g.*, the 90% reduction requirement for Milton R. Young Unit 2 is not included in the text, nor is the separate PRB limit for Stanton included in the table (see more detail below under source BART determination specific comments).
6. NO_x discussion on p. 27 states that "[t]he seven BART sources determined SCR is not technically feasible for installation on boilers in North Dakota burning lignite coal." However, this statement is inconsistent with the Great River Energy BART analyses which found low-dust SCR feasible for the units burning lignite at their Coal Creek and Stanton Station facilities.
7. NO_x BART section: In the absence of a final NO_x BACT determination under the Consent Decree process for Minnkota's Milton R. Young facility, a full 5 factor NO_x BART analysis is required for Milton R. Young in the BART SIP. If a final BACT decision is reached, and NDDH wants to rely on the BACT determination to satisfy BART, NDDH will need to include a discussion of BACT as a surrogate for BART in this section of the BART SIP text.
8. Tables 3 & 4, regarding SO_2 and NO_x emissions reductions, pp. 32-34: These tables are

confusing in that the BART level of control (% reduction) column is not easily reproduced from the data presented. These tables should be revised for more transparent public review.

9. Section 3.5, Air Pollution Control Permit to Construct for Subject-to-BART Sources, pp. 34-36: (A) NDDH indicates that emission limits, monitoring, recordkeeping, and reporting requirements specified in the BART determinations are included in federally enforceable permits to construct that will be issued to the owner/operator of the facility before the SIP is submitted to EPA. Later, the text indicates that the four permits are included in Appendix D. As we have commented previously, the limits, monitoring, recordkeeping, and reporting requirements must be part of the SIP. For the sake of clarity, the text in section 3.5 should state that the four permits are included in Appendix D and are incorporated "as part of this SIP." (B) The public notice for the BART SIP needs to include notification that the BART permits are included.
10. Section 4.3, Consultation with Other States, pp. 37-38: We note that in its September 19, 2007 Northern Class I Areas Consultation Conclusion, the Minnesota Pollution Control Agency determined that North Dakota is a significant contributor to visibility impairment at both Voyageurs National Park and Boundary Waters Canoe Area Wilderness. As a result, Minnesota requested that North Dakota evaluate further reductions of SO_2 and NO_x emissions from its electric generating units (EGUs). We understand that you were a participant in that process, in part to meet the state-to-state consultation requirements under the regional haze rule. EPA will be evaluating Minnesota's and North Dakota's Regional Haze SIPs to assess both Minnesota's request that you evaluate further reductions of emissions from EGUs, and your response to that request.
11. Appendix B.5, BART SCR Technical Feasibility Analysis for ND Lignite: As we have commented previously, we do not agree with your rationale for determining that SCR is technically infeasible when burning North Dakota lignite. We have done a thorough review of the technical feasibility analyses submitted by Minnkota for Units 1 and 2 at Milton R. Young Station and NDDH's preliminary BACT determination published for public notice on June 11, 2008. Our comments and supplemental information were provided in a July 31, 2008 letter from Andrew M. Gaydosh, Assistant Regional Administrator, Office of Enforcement, Compliance, and Environmental Justice, to Terry O'Clair, Director, North Dakota Department of Health, Division of Air Quality. Our letter provided substantial information and evidence that the SCR technology is technically feasible at facilities burning North Dakota lignite.
12. Appendix E, Public Hearing Record: need to ensure that E.8, Response to Public Comments, includes a summary of all public comments received as well as the State's response.

Chapter 33-15-25 Regional Haze Requirements:

13. 33-15-25-02.2: insert "part 51" before "section 301."
14. 33-15-25-04: This section cross references the State's Acid Rain Program (33-15-21) and Title V Program (33-15-14-06), neither of which is included in the federally approved SIP.

This may not be problematic if the specific requirements are spelled out in the SIP text and permits. If the requirements are not spelled out in the SIP text and permits, then the specific requirements need to be specified in this rule or the rule should cite to the federal regulations.

NDDH BART Determinations – Pertaining to All 4 Determinations

15. SO_2 analyses, Step 2: Eliminate Technically Infeasible Options: The arguments presented for Coal Cleaning/Washing and K-Fuel go more to environmental impacts and economic concerns than to technical feasibility. In addition, NDDH provides only a cursory discussion of the commercial history of the K-Fuel technology and vendor and source experiences. It's not clear whether the technology has been successfully employed elsewhere, or why or whether coal type, or the specific source mine, is really a significant distinguishing factor. Also, for TurboSorp, NDDH cites lack of commercial availability in the U.S., but this begs the question whether it's been in commercial use elsewhere. Based on the limited discussion presented, EPA wouldn't necessarily concur with NDDH's conclusion that these options are technically infeasible. Additional information should be provided to support the technical infeasibility determination, or it may be more appropriate to discuss your concerns under the analysis sections for cost effectiveness and/or energy and non-air quality impacts.
16. The References section should include a cite to the company BART analyses that were relied upon by NDDH in preparing these determinations. While we realize that Appendix C of the BART SIP incorporates the company analyses, the BART determinations should also reference them for ease of public review.

NDDH Proposed Permit to Construct for BART – Pertaining to All 4 Permits

The proposed permits were reviewed against the draft "model" BART permit format NDDH developed in March 2008. Concerns with deviations from that format are discussed here as applicable to all four proposed permits. Deviations of concern to specific proposed permits are addressed below under comments for the specific facilities.

17. II.A.1., 1st paragraph: Added a new last sentence citing to 40 CFR Part 60, Subpart Da. As our staffs have discussed, we recommend deleting all references to Da since the relevant language from Da on how to calculate 30-day rolling averages is already spelled out in the permit, and since the references to Da are problematic. The specific subsections of Da that describe how to calculate 30-day rolling averages also contain exemptions from emission limits for startup, shutdown and malfunction. We are concerned that the references to Da could be construed by permittees to mean BART sources get those same exemptions from BART limits, even though the permits say elsewhere that the BART limits apply at all times. An alternative would be to put a statement in the permits that the exemptions in Da do not apply to BART limits, but as we have noted, the references to Da do not appear to be necessary in the first place. The references to Da are also problematic since Da explicitly

prohibits use of Part 75 for data substitution procedures, whereas condition II.A.4.b.(3) of the BART permits allows it.

18. II.A.4.b.(7), Notes: Added a reference to Condition II.A.1. under 30-day rolling average which refers back to Da. This reference is problematic if the concerns noted above in II.A.1. are not corrected. However, if II.A.1. is corrected as described above, then the reference in II.A.4.b.(7), Notes, is a good idea.
19. II.A.6.g.: To avoid the implication that the source can determine the effective date of the BART emission limits, the phrase "and the effective date of the BART emission limits" should be deleted from the end of the sentence. Based on conversations between our staffs, we understand that you have agreed to this change.

Leland Olds:

NDDH BART Determination

20. Unit 1 SO_2 BART evaluation: On p. 8, the emission factor for SO_2 is incorrectly stated as 35S. EPA's AP-42 states that for lignite firing (either wall-fired or cyclone boilers), the emission rate is 30S. It appears that NDDH's calculations for both the corrected and uncorrected emission rates are too high.
21. Unit 2 SO_2 BART evaluation: NDDH determines that because the "most efficient control option" was selected for SO_2 control, no evaluation of costs or visibility impacts is necessary. This approach does not meet the BART Guideline requirements for analysis. In fact, a full 5-factor analysis may find that even stricter controls would be cost effective and/or provide greater visibility benefits.
22. Unit 1 NO_x BART evaluation: It is not clear how some of the 16 control options listed were eliminated from further consideration. However, the selection of SNCR plus SOFA at 0.19 lbs/MMBtu is a commendable level of control.
23. Unit 2 NO_x BART evaluation: NDDH determined that SCR is not technically feasible. As you know, we disagree with this conclusion, based on our analyses related to Milton R. Young NO_x BACT, analyses performed to support the BART Guidelines, and other sources of information. We note that NDDH, in reaching its conclusion regarding technical infeasibility of SCR, relies on the Milton R. Young NO_x BACT evaluation; however, the Milton R. Young BACT process has not been completed.
24. Page 39: Typo in table heading – should be Unit 2?
25. Summary, p. 44-45: Units 1 and 2 PM limits are listed as 0.05 lbs/MMBtu; however, the text of the PM BART evaluation and the proposed Permit to Construct for BART lists 0.07 lbs/MMBtu. Please clarify.
26. Summary, p. 44-45: Unit 1 NO_x limit is listed as 0.18 lbs/MMBtu with 849 tons/yr emissions reductions; however, the NO_x BART evaluation lists 0.19 lbs/MMBtu as the limit and the BART SIP text, Table 4, lists 757 tons/yr emissions reduction. The proposed Permit to Construct for BART also lists the limit as 0.19. Please clarify.

27. We appreciate the revision to the visibility impacts analysis to present the required 98th percentile results, as previously requested.

NDDH Proposed Permit to Construct for BART – Leland Olds

28. II.A.1.c., PM emission limits: The expression "Unit 1 and Unit 2" is problematic since it could be construed to mean emission averaging across both units is allowed. For clarity, we recommend NDDH list the Units and the applicable PM limits individually.
29. II.A.4.b.(5): The phrase "EPA-approved" was deleted from the last sentence regarding other test methods and should be corrected.
30. II.A.4.b.(8): Added "Average AER" equation and allowable emission rate. Based on a conversation between our staffs, we understand that you have agreed to add a footnote clarifying that "Average ER = average actual emission rate," so as not to confuse it with "AER" which is "allowable emission rate."
31. II.A.6.d.: There appears to be an inadvertent deletion of the phrase "or portable analyzer test." Based on a conversation between our staffs, we understand that this will be corrected.

Coal Creek:

NDDH BART Determination

32. We believe there may be an error in the computation used in the Future Case table, p. 10. Uncontrolled SO_2 emissions are scaled up by the ratio of 1.1%/0.61%, to account for dried vs. as-received lignite, to yield 76,888 tons/yr. This fails to recognize that Btu content will increase by the same ratio, thus, requiring less total tonnage of lignite to be burned. If an error was made, these calculations should be redone. The Future Case table also has 2 rows labeled "Existing Scrubber & 27% Bypass," having control efficiencies of 68% and 83.1%. The first label should be changed and the scenario should be described.
33. SO_2 analyses, Step 6: Select BART, p. 12: We do not agree with NDDH's characterization of the degree of visibility improvement (0.263 deciviews) achieved by selecting wet scrubber replacement versus wet scrubber modification as a "negligible improvement." We note that NDDH selected a wet scrubber over a spray dryer in the Leland Olds BART determination, with a visibility improvement of 0.198 deciviews. In addition, it may be difficult to achieve similar visibility improvement more cost effectively for purposes of reasonable progress.
34. The NPS has raised concerns over Great River Energy's (GRE's) inclusion of almost $14 million infrastructure "sunk costs" in its analysis of future economic costs for SCR and SNCR. We understand that you are continuing your discussions with GRE regarding the potential loss of future ash sales and cost of future ash disposal and expect to provide additional information. We will review any additional information when it becomes available.

NDDH Proposed Permit to Construct for BART – Coal Creek

35. II.A.1.c.: We note that the PM limit is worded as applicable to "either Unit 1 or Unit 2." The expression "either Unit 1 or Unit 2" is problematic since it could be construed to mean that compliance must be demonstrated at only one of the two units. For clarity, we recommend that NDDH list the Units and the applicable PM limits individually.

Milton R. Young

NDDH BART Determination

36. Minnkota's August 2007 analyses appear to rely heavily on Consent Decree (CD) options. As we have noted in previously submitted comments, the language of the CD does not indicate that EPA considered the controls to be BACT or BACT-equivalent. The BART analyses need to be a robust review of control technologies – not a validation of what was already agreed to in the CD.
37. SO_2 BART evaluation: Unit 1 visibility impacts for the 90th percentile are referenced from the source's August 2007 BART analysis, and the reader is directed to extrapolate the required 98th percentile results from Appendix A of that document. This is not an adequate presentation of the required 98th percentile results. See previously submitted comments.
38. NO_x BART evaluation:
(A) The startup/shutdown exemption and separate limits for these periods are not acceptable. The BART Guidelines contemplate pounds per million Btu limits that apply continuously, with a 30-day rolling average period. Minnkota argues that SNCR does not function properly during startup and shutdown periods when operating outside of a specified temperature range. We understand that various types of control technologies, including SNCR, may not be fully effective outside specified temperature ranges. However, one of the purposes of a 30-day averaging period for the BART limits is to accommodate potential short-term fluctuations in the emissions rate that may result during startups and shutdowns and other conditions. NDDH indicates that, if historical worst-case startup durations occur, compliance with the 30-day rolling average limits will be "extremely difficult;" NDDH does not say it would be impossible. It is not clear what steps, if any, Minnkota may have taken historically to reduce emissions during startups or to limit the duration or frequencies of startups. NDDH does not indicate why startups lasted 61 or 115 hours, whether such durations were typical, or how frequently they occurred. We are concerned that NDDH's proposed approach could result in a very large NO_x emission event with resultant visibility impacts and no real incentive for Minnkota to minimize its emissions during startup and shutdown. We do not believe that startup/shutdown exemptions are necessary or appropriate for Milton R.Young's 30-day NO_x BART limits and that the exemptions should be eliminated. We also note that the same exemptions have not been sought by, or provided to, other facilities (Leland Olds & Stanton) for which SNCR is proposed as BART, and we know of no reason Milton R. Young warrants

special treatment. Leland Olds Unit 2 is also a cyclone unit.

(B) No visibility impacts analyses are provided since the source proposed the "most efficient technology." First, we do not agree that the most efficient technology was selected since SNCR is proposed instead of SCR. Second, this approach does not meet the BART Guidelines requirements for a full 5-factor analysis and should be corrected. A full analysis may find that stricter controls provide greater visibility benefits.

(C) We believe that the presumptive limits should apply since the total generating capacity is actually greater than the reported nameplate capacity of 734 MW, in fact, > 750 MW (see previously submitted comments).

(D) On p. 21, NDDH refers to a "completed" BACT determination and on p. 45, the preliminary BACT determination is incorporated by reference. However, the NO_x BACT process is not completed, and as we have commented previously, NDDH cannot rely upon an incomplete BACT process to satisfy the BART analysis requirements. Therefore, the NO_x BART analysis for Milton R. Young is deficient.

39. Summary, p. 51: The Unit 2 SO_2 limit does not list the minimum 90% reduction with the 0.15 lbs/MMBtu limit, as is presented in both the table in the SIP text on p. 33 and in the proposed Permit to Construct for BART. Please clarify.

NDDH Proposed Permit to Construct for BART – Milton R. Young

40. II.A.1.c., NO_x limits: The startup/shutdown exemption and separate limits for these periods are not acceptable. See discussion above in comment #38(A).
41. II.A.1.c., PM limits: The expression "Unit 1 and Unit 2" is problematic since it could be construed to mean emission averaging across both units is allowed. For clarity, we recommend that NDDH list the Units and the applicable PM limits individually.
42. II.A.1.e.: The condition that SO_2 and PM limits apply at all times, including startup, shutdown, emergency and malfunction should also apply to NO_x limits.
43. II.A.4.b.(5): The phrase "EPA-approved" has been deleted from the last sentence regarding other test methods and should be corrected.

Stanton:

NDDH BART Determination

44. SO_2 BART evaluation in general: We believe that the proposed technology (spray dryer/fabric filter) is inferior, and coupled with what we find to be an inflated uncontrolled emission rate, results in SO_2 limits that are too high (0.24 for lignite, 0.16 for PRB coal). A lower emission limit can be achieved by using a more realistic uncontrolled rate and increasing the design removal efficiency. Although this is the smallest of the subject-to-BART units in terms of megawatts, this and other power plants are among the largest emitters in the State. It may be more cost-effective to consider further controls now in order

to meet reasonable progress requirements, rather than waiting to address these requirements with other sources during the development of the remainder of your Regional Haze SIP.

45. SO_2 BART evaluation for lignite: (A) On p. 8, NDDH uses an uncontrolled emission rate of 2.4 lbs/MMBtu for calculation of BART limits. This number appears to be inflated since a value of 1.81 lbs/MMBtu is used on p. 4 and the highest year's value from CAMD (prior to the fuel switch) was 1.92 lbs/MMBtu. (B) A wet scrubber was eliminated from consideration based on environmental considerations, but it is not clear how significant these other considerations were and why they were not significant at any other plant. Please explain. We believe that consideration should be given to using a wet scrubber.
46. SO_2 BART evaluation for PRB coal: On p. 22, a possible future sulfur content of 1.6 lbs/MMBtu is used to calculate the BART limit. We find this assumption unrealistic given that recent content at Stanton, since the switch to PRB coal, is closer to 0.5 lb/MMBtu. Please clarify if you disagree or provide a more realistic assumption for future sulfur content.
47. The SO_2 analyses do not address the scenario for when a combination of PRB coal and lignite are burned, although this scenario is included in the proposed permit to construct for BART. If NDDH intends to keep this option in the permit, then the BART determination must include the necessary analyses.
48. NO_x BART evaluation for lignite and PRB coal: (A) On pp. 13 & 24, the amount of emission reductions that can be achieved is underestimated in these tables. Greater control efficiencies are generally achieved by combining combustion controls plus SNCR. (B) The State's proposal of LNB+OFA+SNCR is commendable since it goes beyond what can be achieved with just combustion controls. However, the BART limit should be tightened since current (pre-BART) emissions using PRB coal at Stanton are already very close to the proposed limit (0.26 lb/MMBtu vs. 0.23 lb/MMBtu).
49. PM BART limit: We note that the proposed spray dryer/fabric filter would reduce PM emissions as well, but the BART determination does not seem to account for it in the proposed PM limit.
50. Summary table, p. 27: (A) The SO_2 limit provided for PRB coal is not listed in the table of the SIP text, p. 33. (B) Neither this summary table nor the SIP text, p. 33, includes the SO_2 and NO_x limits when a combination of lignite and PRB coal are burned, even though the proposed permit does include these "combination" limits. Please clarify/resolve these inconsistencies.

<u>NDDH Proposed Permit to Construct for BART – Stanton</u>

51. II.A.1.c. and II.A.1.f: These calculations for determining the SO_2 and NO_x limits when a combination of lignite and PRB coals is burned do not seem consistent with the language in the SIP text, pp. 24 & 26, which states that the limits are the same whether burning PRB coal alone or in any combination with lignite. Please clarify/resolve this inconsistency.
52. II.A.1.g.: There appears to be a typo in the last sentence. The reference should be to II.A.4.b.(5), not III.A.4.b.5.
53. II.A.4.b.(5): The phrase "EPA-approved" was deleted from the last sentence regarding other

test methods and should be corrected.

54. II.A.4.b.(7): A cross-reference to II.A.1.c. should be included. Based on conversations between our staffs, we understand that you have agreed to make this change.

ENCLOSURE 2

Previously Submitted Region 8 Comments on Company BART Analyses

1. November 1, 2006 letter from Richard R. Long, EPA Region 8, Air & Radiation Program, to Terry O'Clair, NDDH, Division of Air Quality, regarding comments on draft BART analyses.
2. November 7, 2007 letter from Callie A. Videtich, EPA Region 8, Air & Radiation Program, to Terry O'Clair, NDDH, Division of Air Quality, regarding comments on revised Minnkota BART analyses.
3. December 19, 2007 email message from Amy Platt, EPA Region 8, Air & Radiation Program, to Craig Thorstenson, NDDH, Division of Air Quality, regarding comments on revised Stanton BART analyses.
4. February 26, 2008 email message from Amy Platt, EPA Region 8, Air & Radiation Program, to Craig Thorstenson, NDDH, Division of Air Quality, regarding comments on revised Stanton BART analyses.

Response to August 4, 2008 EPA BART Comments for Stanton Unit 1

Comments 44-50 apply to the Department's BART Determination

Comment #44:

We believe that the proposed technology (spray dryer/fabric filter) is inferior, and coupled with what we find to be an inflated uncontrolled emission rate, results in SO_2 limits that are too high (0.24 for lignite, 0.16 for PRB coal). A lower emission limit can be achieved by using a more realistic uncontrolled rate and increasing the design removal efficiency. Although this is the smallest of the subject-to-BART units in terms of megawatts, this and other power plants are among the largest emitters in the State. It may be more cost-effective to consider further controls now in order to meet reasonable progress requirements, rather than waiting to address these requirements with other sources during the development of the remainder of your Regional Haze SIP.

Response to Comment #44:

The Department agrees that higher SO_2 control efficiencies can be attained. Control technologies with higher SO_2 removal efficiencies (a wet scrubber and a circulating dry scrubber) were included in the BART analyses for both lignite and PRB coal combustion. As indicated in the BART determination, these technologies were eliminated from consideration as BART due to economic and environmental considerations.

The Department's economic analyses were based on uncontrolled annual SO_2 emissions of 1.81 lb/million Btu for lignite and 1.2 lb/million Btu for PRB coal. The proposed BART emission limits for SO_2 are based on a 30-day rolling average (as opposed to an annual average) with 90% reduction and also includes emissions from startups, shutdowns and malfunctions. Based upon historical SO_2 emissions data for spray dryers and fabric filters at facilities burning North Dakota lignite, we have determined that an increase of 33% is warranted to adjust from an annual average SO_2 emission rate to a 30-day rolling average emission rate. The discussion regarding potential SO_2 emission rates as high as 2.4 lb/million Btu for lignite and 1.6 lb/million Btu for PRB coal was intended to show that higher sulfur coal could be encountered (see Appendix E, Sulfur Content Statistical Analysis, of the GRE BART Analysis).

The EPA also states, "it may be more cost-effective to consider further controls now in order to meet reasonable progress requirements...". This statement appears to be based almost entirely on speculation as EPA provides no basis for the comment. In addition, the Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program states, "Note that for some sources determined to be subject to BART, the State will already have completed a BART analysis. Since the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in establishing the RPG, it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first RPG planning period. Hence, you may conclude that no additional emissions controls are necessary for these sources in the first planning period".

Comment # 45(A):

On p. 8, NDDH uses an uncontrolled emission rate of 2.4 lbs/MM Btu for calculation of BART limits. This number appears to be inflated since a value of 1.81 lbs/MM Btu is used on p.4 and the highest year's value from CAMD (prior to the fuel switch) was 1.92 lbs/MM Btu.

Response to Comment #45(A):

This comment is addressed in the Department's response to Comment #44 above.

Comment #45(B):

A wet scrubber was eliminated from consideration based on environmental considerations, but it is not clear how significant these other considerations were and why they were not significant at any other plant. Please explain.

Response to Comment #45(B):

The Department eliminated a wet scrubber from consideration as BART at Stanton Unit 1 based upon a combination of factors. These include the relatively high incremental cost of $4,179 per ton of SO_2 removed when burning lignite and $6,302 per ton of SO_2 removed when burning PRB, the additional environmental impacts of a wet scrubber and the fact that a wet scrubber will remove a relatively small amount of SO_2 when compared to a spray dryer (with a small corresponding visibility improvement).

The additional environmental considerations are further outlined below:

- A wet scrubber is estimated by GRE to use as much as 20% more water or approximately 15 million gallons per year of additional water.

- It is assumed that a wet scrubber system will require additional on-site ponding. GRE has identified two potential areas on site that could be used for the additional ponding. The areas include the existing ash pile, which would have to be excavated and moved, or the abandoned ash disposal area adjacent to the river, which reportedly has geotechnical deficiencies.

- Dry scrubbers are purported to achieve a higher mercury control efficiency on lignite and PRB as compared to a wet scrubber. In addition, future mercury control requirements could result in high concentrations of mercury in the ponds and prove problematic to discharge.

Comment #46:

On p. 22, a possible future sulfur content of 1.6 lb/MM Btu is used to calculate the BART limit. We find this assumption unrealistic given that recent content at Stanton, since the switch to PRB coal, is closer to 0.5 lb/MM Btu. Please clarify if you disagree or provide a more realistic assumption for future sulfur content.

Response to Comment #46:

The sulfur content of coal varies considerably. The sulfur content of the PRB coal recently combusted at GRE Stanton has no bearing on the sulfur content of coal which might be burned at the facility in the future. Based on the data contained in Appendix E, Sulfur Content Statistical Analysis, of the GRE BART Analysis, the Department considers a future sulfur content of 1.6 lb/MM Btu to be realistic.

Comment #47:

The SO_2 analyses do not address the scenario for when a combination of PRB coal and lignite are burned, although this scenario is included in the proposed permit to construct for BART. If NDDH intends to keep this option in the permit, then the BART determination must include the necessary analyses.

Response to Comment #47:

The BART analyses were conducted assuming 100% lignite combustion and 100% PRB coal combustion. Since the same control technologies were chosen for both scenarios, any BART analysis conducted assuming a blending of lignite and PRB coal would result in the choice of the same control technologies as BART. The Department has included language in the BART determination addressing the limits when combusting lignite and PRB coal in combination. It should be noted that GRE has indicated that lignite and PRB coal will likely only be burned in the same 30-day averaging period during a switch from one coal to another (i.e., fuel blending is not likely to occur on an extended basis).

Comment #48(A):

On pp. 13 and 24, the amount of emission reductions that can be achieved is underestimated in these tables. Greater control efficiencies are generally achieved by combining combustion controls plus SNCR.

Response to Comment #48(A):

The EPA states that the amount of NOx emission reductions that can be achieved are generally underestimated in the BART determination; however, the EPA provides no information supporting this statement. The Department has determined that the control efficiencies assumed are reasonable and the EPA provided no information to the contrary.

Comment #48(B):

The State's proposal of LNB+OFA+SNCR is commendable since it goes beyond what can be achieved with just combustion controls. However, the BART limit should be tightened since current (pre-BART) emissions using PRB coal at Stanton are already very close to the proposed limit (0.26 lb/MM Btu vs. 0.23 lb/MM Btu).

Response to Comment #48(B):

EPA states that "current (pre-BART) emissions using PRB coal at Stanton are already very close to the proposed limit (0.26 lb/MMBtu vs. 0.23 lb/MMBtu)". As with the SO_2 emission rates, the EPA fails to distinguish between annual emissions and 30-day rolling average emissions. Also, the most recent annual average annual NOx emission rates from Stanton Unit 1 for 2006 and 2007 are 0.28 lb/MM Btu, not 0.26 lb/MM Btu.

There exist operational considerations at Stanton Unit 1 which are likely to affect the NOx emission rate on a short-term basis. These operational considerations are summarized below:

- Under normal operating conditions, Unit 10 is run at full utilization while Unit 1 varies (swings) to meet Midwest Independent System Operators (MISO) power demands. These load swings can impact NOx emissions on a short-term basis.

- If Unit 10 trips due to a tube leak or other maintenance problem, Unit 1 needs to operate all three mills in order to fully supply steam to the single turbine. Under the three mill operational scenario, NO_x emission rates are higher than under the two mill scenario. It is possible for Unit 1 to operate on all three mills for as much as 30 days.

- Nitrogen can vary by coal type, which will impact NO_x emissions.

Comment #49:

We note that the proposed spray dryer/fabric filter would reduce PM emissions as well, but the BART determination does not seem to account for it in the proposed PM limit.

Response to Comment #49:

As indicated in the BART determination, BART for filterable PM for both lignite and PRB coal is proposed as no additional control due to the prohibitive cost of additional PM controls and the insignificant visibility improvement expected from additional PM controls. The fact that a spray dryer / fabric filter is being installed to control SO_2 emissions is a separate issue and does not affect the BART determination for PM.

Comment #50:

Summary table, p. 27: (A) The SO_2 limit provided for PRB coal is not listed in the table of the SIP text, p. 33. (B) Neither this summary table nor the SIP text, p. 33, includes the SO_2 and NO_x limits when a combination of lignite and PRB coal are burned, even though the proposed permit does include these "combination" limits. Please clarify/resolve these inconsistencies.

Response to Comment #50:

The SIP has been corrected to account for the different proposed limits.

Comments 51-54 Apply to the Proposed Permit to Construct for Stanton Unit 1

Comment #51:

II.A.1.c. and II.A.1.f: These calculations for determining the SO_2 and NO_x limits when a combination of lignite and PRB coal is burned do not seem consistent with the language in the SIP text, pp. 24 and 26, which states that the limits are the same whether burning PRB coal alone or in combination with lignite. Please clarify/resolve this inconsistency.

Response to Comment #51:

The language in the SIP has been corrected.

Comment #52:

II.A.1.g.: There appears to be a typo in the last sentence. The reference should be to II.A.4.b.(5), not III.A.4.b.5.

Response to Comment #52:

The change has been made to the permit.

Comment #53:

II.A.4.b.(5): The phrase "EPA-approved" was deleted from the last sentence regarding other test methods and should be corrected.

Response to Comment #53:

The requested change has been made.

Comment #54:

II.A.4.b.(7): A cross-reference to II.A.1.c. should be included. Based on conversations between our staffs, we understand that you have agreed to make this change.

Response to Comment #54:

The requested change has been made.

EPA Comments on
Draft BART Assessments
Milton R. Young Station
and Leland Olds Station

Comment No.: 1
Commentor: EPA (4)
Affected Source: General
Comment Summary: Suggest BART limit be written as % reduction and lb/10^6 Btu.
Response: The BART Guideline provides a choice. The Department's proposed limits are consistent with the BART Guideline. If the BART limit is only written as a lb/10^6 Btu limit, it will be higher than 0.15 lb/10^6 Btu.

Comment No.: 2
Commentor: EPA (5)
Affected Source: M.R. Young 2
Comment Summary: The 90% reduction requirement is not included in the Department's analysis.
Response: This is incorrect. There is a discussion of the 90% reduction requirement on p. 38.

Comment No.: 3
Commentor: EPA (10)
Affected Source: General
Comment Summary: EPA will be evaluating our response to Minnesota's "ask" memorandum.
Response: A response has been sent to Minnesota.

Comment No.: 4
Commentor: EPA (15)
Affected Source: General
Comment Summary:
(A) More information is needed to determine if K-Fuels is a viable option.
(B) EPA believes TurboSorp is technically feasible.
Response:
(A) K-Fuels has been under development for 20 years or more. The only commercial demonstration facility was near Gillette, Wyoming. According to Evergreen Energy's website the Wyoming plant has been idled in order to direct its capital and management resources to support a new design. At this time, we believe the K-Fuels process is not commercially available for North Dakota lignite.
(B) TurboSorp is a trademark for Babcock Power's circulating dry scrubber. The Minnkota, Basin Electric and GRE Stanton analyses all found circulating dry scrubbers to be technically feasible. The GRE Coal Creek analyses has been modified to address a circulating dry scrubber.

Comment No.: 5
Commentor: EPA (17), (18), (28)
Affected Source: General
Comment Summary: The citation of 40 CFR 60, Subpart Da in the proposed permit is problematic.
Response: The citation has been removed.

Comment No.: 6
Commentor: EPA (19), (29)
Affected Source: General
Comment Summary: The phrase "and the effective dates of the BART emission limits" should be removed.
Response: The phrase has been removed.

Comment No.: 7
Commentor: EPA (20)
Affected Source: Leland Olds Unit 1
Comment Summary: The emission factor of 35(s) is incorrect.
Response: The factor is not incorrect. Based on actual CEM data, a factor higher than AP-42 is warranted. In the Department's periodic review of PSD SO_2 increment consumption an emission factor of 37.4(s) was justified. For the BART analysis, an emission factor of 35(s) was used to provide a conservative estimate of the uncontrolled emission rate.

Comment No.: 8
Commentor: EPA (21) FLMs
Affected Source: Leland Olds 2
Comment Summary: A 5 factor analysis is required even though the most efficient control technology is used.
Response: The BART Guideline Step 1, Paragraph 9, states "... if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section." Basin had proposed the highest available control efficiency and lowest possible emission rate. Therefore, the other steps of a BART analysis were not required. The Department has now determined that SCR w/reheat is technically feasible. A visibility analysis of SCR vs SNCR has been included.

Comment No.: 9
Commentor: EPA (22)
Affected Source: Leland Olds 1
Comment Summary: It is unclear how some of the 16 control options were eliminated.
Response: The explanation is found on p. 47-50 of the Basin Electric analysis.

Comment No.: 10
Commentor: EPA (23)
Affected Source: Leland Olds 2
Comment Summary: EPA believes SCR is technically feasible.

Response: The Department believes high dust SCR is not technically feasible due to catalyst poisoning by sodium and potassium. A detailed explanation of this issue is found in Appendix B.5. The Department now believes low dust and tail end SCR are technically feasible for North Dakota lignite-fired power plants.

Comment No.: 11
Commentor: EPA (24)
Affected Source: Leland Olds 2
Comment Summary: Typo on table heading on p. 39.
Response: Agreed - Correction made.

Comment No.: 12
Commentor: EPA (25)
Affected Source: Leland Olds
Comment Summary: PM limits listed on p. 44-25 are 0.05 lb/10^6 Btu.
Response: The table has been corrected to list the limit of 0.07 lb/10^6 Btu.

Comment No.: 13
Commentor: EPA (26)
Affected Source: Leland Olds
Comment Summary: Summary lists an NO_x emission limit of 0.18 lb/10^6 Btu.
Response: The limit has been revised to 0.19 lb/10^6 Btu and the emission reduction calculated accordingly.

Comment No.: 14
Commentor: EPA (27)
Affected Source: Leland Olds
Comment Summary: Appreciate the 98th percentile results.
Response: No response necessary.

Comment No.: 15
Commentor: EPA (30)
Affected Source: Leland Olds
Comment Summary: Add “Average ER = average actual emission rate” to permit.
Response: Agreed

Comment No.: 16
Commentor: EPA (31)
Affected Source: Leland Olds
Comment Summary: The phrase “or portable analyzer” was deleted and should be included in the permit.
Response: Agreed

Comment No.: 17
Commentor: EPA (36)
Affected Source: M.R. Young
Comment Summary: The August 2007 analysis relies too heavily on the CD.

Response: Minnkota prepared a BART analysis dated October 2006 and supplemented it with additional information dated August 2007. The two documents combined address all 5 factors for the three pollutants evaluated.

Comment No.: 18
Commentor: EPA (37)
Affected Source: M.R. Young 1
Comment Summary: The presentation of the 98th percentile visibility results in Appendix A is not an acceptable presentation.

Response: M.R. Young is not subject to the BART Guidelines. If it were, an evaluation of visibility impacts is not required since Minnkota has agreed to install the most stringent technology with the lowest possible emission rate.

Comment No.: 19
Commentor: EPA (38), (40), (42)
Affected Source: M.R. Young
Comment Summary:

A. Startup/shutdown exemption are not acceptable.
B. No visibility analysis was provided.
C. They believe the presumptive limits apply.
D. The NO_x BART analysis is deficient since the NO_x BART analysis process has not been completed.

Response:

A. Alternative limits for startup/shutdown is an accepted practice for BACT permits. EPA, in the Desert Rock PSD permit, included alternative NO_x limits for startup/shutdown. Minnkota has justified the alternative limits for startup. The BART Guidelines do not preclude these alternative limits. Therefore, the Department will maintain the limits for startup.
B. The visibility modeling results have been provided.
C. The nameplate capacity of the station is 734 MWe. The URGE is based on the capability of the unit for four hours. It does not represent long-term capability. Other rules such as the Acid Rain Program uses the nameplate capacity which is a verifiable value. We believe the Regional Haze Program should use it also. We disagree that the facility is subject to the presumptive emission limits. The DOE lists the M.R. Young Station as having a net summer capacity of 705 MWe for 2006.
D. An analysis of BART has been provided that is independent of the BACT assessment.

Comment No.: 20
Commentor: EPA (41)
Affected Source: M.R. Young
Comment Summary: PM limits are problematic.
Response: The PM limits will be listed separately in the Permit to Construct.

Comment No.: 21
Commentor: EPA (43)
Affected Source: M.R. Young
Comment Summary: The phrase “EPA approved” should be added back into the permit.
Response: Agreed

Comment No.: 24
Commentor: EPA (3)
Affected Source: MDU Heskett
Comment Summary:

A. A one km grid size may inappropriately reduce predicted concentrations. MDU used the annual average background visibility conditions while the North Dakota protocol requires use of the 20% cleanest days background.

B. MDU has volunteered SO_2 reductions at Heskett 2. How is this voluntary reduction formalized? Is NDDH taking credit for these reductions under reasonable progress and are the reductions included in the 99,000 tpy figure. How does NDDH intend to make the agreement federally enforceable?

Response:

A. The North Dakota modeling protocol only indicates that the “preferred” grid cell size is 3 km. The protocol does not prohibit a source from using a smaller size grid cell. We have no evidence to suggest that the smaller grid cells provides inaccurate results. MDU has provided justification for the one kilometer spacing (see Appendix A.2).

The North Dakota protocol was developed when EPA was interpreting the BART Guideline to require the use of 20% cleanest days background. EPA subsequently changed its position and allowed the use of the annual average background. Since EPA changed its interpretation, the Department had to allow the use of the annual average background since the State cannot, by law, be more stringent than Federal requirements.

B. The voluntary reductions were formalized by letter. The requirement for 70% reduction will be included in a Federally enforceable Permit to Construct.

The Department will take credit for the reduction under the reasonable progress goals and the reduction is included in our calculation of total SO_2 emissions reductions.

By issuing a Permit to Construct, which will be included in the regional haze SIP, the reductions will be made federally enforceable.

NDDH BART Determination:

32. Relative to the Future Case Table on page 10, we agree that the alternative labeled "Existing Scrubber & 27% Bypass" and that also has 83.1% control efficiency is in error. It has been corrected to read "Existing Scrubber & 0% Bypass."

You are correct that the Future Case Table does not contain an adjustment to Btu content to reflect dried coal. The BART Determination text will be revised to be clear on that point. The only adjustment made to the baseline uncontrolled SO_2 emissions was to reflect the projected increase in coal sulfur content based on mine core sampling. The 1.1% future coal sulfur content is an "as received for raw coal" value. If the SO_2 baseline is adjusted to reflect the switch from past raw coal at 6,200 Btu/lb to future dried coal at 7,200 Btu/lb, then the future coal sulfur content also must be adjusted (to approximately 1.4%) to reflect the drying so that the Btu/lb and the sulfur content remain on the same basis. The results of applying these adjustments are shown in Table 1 and Table 2 below for information only. These adjustments make the wet scrubber modification an even more favorable choice when compared to the wet scrubber replacement.

We do not intend to make these changes to the BART Determination because we cannot be reasonably sure of the future fuel moisture or Btu content. Although the GRE analysis indicates the intent to use dried lignite, the BART determination and the Permit to Construct neither require dried lignite nor limit the moisture content. Limiting the fuel characteristics is unnecessary because the BART determination recommends, and the Permit to Construct limits, the maximum SO_2 lb/10^6 Btu or minimum percent reduction.

Table 1: Future Case (Dried Lignite)

Alternative	**Control Efficiency (%)**	**Baseline Uncontrolled Emissions (tons/yr)***	**Controlled Emissions***	
			(tons/yr)	**(lb/10^6 Btu)****
Wet Scrubber Replacement***	95	66,209	3,310	0.126
Wet Scrubber Modification***	95	66,209	3,310	0.126
Spray Dryer***	90	66,209	6,621	0.251
Existing Scrubber***	83.1	66,209	11,189	0.424
Dry Sorbent Injection***	70	66,209	19,863	0.753
Existing Scrubber & 27% Bypass	68****	66,209	21,187*****	--

* Future dried lignite at 1.4% sulfur content. GRE-predicted 1.10% worst-case sulfur content for Falkirk Mine raw lignite. This was adjusted to 1.4% due to drying. As a

result, the Department's baseline future emission estimates are somewhat higher than GRE's estimates.

** Annual

*** 0% bypass

**** Current control rate

***** Current controlled emissions = 76,888(1-0.68) = 24,604 tpy (6200/7200 Btu/ton) = 21,187 tpy

Table 2: Costs of Compliance (Dried Lignite)

Alternative	**Emissions Reduction (tons/yr)**	**Annualized Cost ($)***	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Wet Scrubber Replacement	17,877	30,760,000	1,721	29,020
Wet Scrubber Modification	17,877	11,520,000	644	--
Spray Dryer**	14,566	29,220,000	2,006	--
Existing Scrubber	9,998	9,840,000	984	N/A
Dry Sorbent Injection**	1,324	12,520,000	9,456	N/A

* Costs provided by GRE

** Inferior option to wet scrubber modifications

*** 0% bypass

N/A -- Not applicable since the cost of the less efficient alternative is more than the more efficient alternative

33. The Permit to Construct has been revised to require the modified wet scrubber to achieve the same level of SO_2 control efficiency as wet scrubber replacement: 95% (30-day rolling average) on the inlet SO_2 concentration to the scrubber or 0.15 lb/10^6 Btu (30-day rolling average). With this change, wet scrubber replacement would provide no improvement in visibility at any Class I area and would result in additional cost over wet scrubber modification ($24,987/ton incremental cost).

34. While we are not certain it is inappropriate to consider capital recovery of at least some of the ash sales infrastructure, we looked at the impact of disregarding all of that cost in the analysis of SNCR. It appears the annualized cost would change from $22,900,000 to $21,750,000; the cost effectiveness would change from $8,551/ton to $8,122/ton; and the incremental cost would change from $20,766/ton to $19,692/ton. These changes appear small when compared to the values for the NOx control option selected, SOFA/LNB Opt 1.

Regarding the request for additional information to evaluate the GRE position that employing SCR or SNCR technology may negatively affect fly ash sales due to ammonia slip, the attached GRE email dated 8/8/08 at 3:19 p.m. provides that additional information. The Department also considered a summary of a University of Kentucky study on the issue (attached) and has reached the following conclusions.

- SCR and SNCR use at Coal Creek Station will likely result in ammonia in the fly ash.
- The level of ammonia in the fly ash cannot be predicted with a reasonable certainty.
- The maximum level of ammonia in fly ash that would preclude negative impacts on the salability of the ash cannot be predicted.

Therefore, the Department cannot determine with reasonable certainty that SCR or SNCR will not result in a level of ammonia in the ash that could reduce or eliminate future ash sales. Any regulator who determines that SCR or SNCR will not jeopardize ash sales would be obligated to present the evidence in support of that position. While another regulator might determine that even a small improvement in visibility is worth GRE taking the risk of lost ash sales, making a wrong decision on this one will inflict a significant financial penalty on GRE and send ash to a landfill instead of it being used beneficially. Having considered all of the information available, the NDDH BART determination on this matter remains unchanged and the Department considers the issue resolved.

NDDH Proposed Permit to Construct for BART – Coal Creek:

35. The Coal Creek Permit to Construct wording at Condition II.A.1.c has been changed as suggested.

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
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February 27, 2008

FILE

Mr. Ken Cronin
WRAP Tribal Caucus Coordinator
National Tribal Environmental Council
2501 Rio Grande Boulevard NW, Ste. A
Albuquerque, NM 87104

Re: Regional Haze Contacts

Dear Mr. Cronin:

The North Dakota Department of Health is in the process of preparing a State Implementation Plan (SIP) to reduce the impact from regional haze in the Class I areas of the North Dakota. The Department has been involved with the Western Regional Air Partnership (WRAP) which serves as the coordinating body for the consultation process in the development of the SIP. The North Dakota Department of Health would like to provide you the opportunity to participate in our SIP development process.

Enclosed is a list of the contacts within the Department of Health who are involved in the North Dakota SIP development process. We encourage you to share this letter with any tribe that wishes to coordinate with the Department in the development of North Dakota's regional haze SIP.

If you have any questions regarding the SIP preparation or schedule, please feel free to contact Dana Mount at (701)328-5150.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:saj
Enc:
xc: Don Arkell, Western States Air Resources Council

Environmental Health Section Chief's Office 701.328.5150
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REGIONAL HAZE CONTACTS
NORTH DAKOTA DEPARTMENT OF HEALTH

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